

**Are Distributed Energy Technologies a Viable Alternative for Institutional Settings?
Lessons from MIT Cogeneration Plant**

by

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Submitted to the Engineering Systems Division
in Partial Fulfillment of the Requirements for the Degree of
Master of Science in Technology and Policy

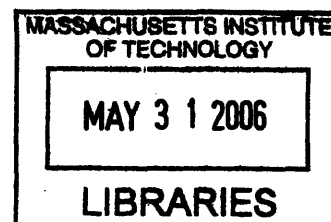
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ABSTRACT

During the last decades, distributed energy (DE) resources received considerable attention and support because of the confluence of technology development – particularly gas turbines – and deregulation – which would allow access to the distribution systems. DE was seen as addressing numerous issues, including transmission constraints, reliability, power quality, energy efficiency, and environmental quality through combined heat and power (CHP) applications. Numerous barriers, such as stranded asset requirements and lack of uniform interconnection standards, were recognized but viewed as manageable. Nevertheless, the penetration of DE/CHP has been considerably less than anticipated by many. More recent developments in the DE technology, regulatory environment, and fuel prices call for a re-examination of the cost-benefit balance for DE owners and of the societal implications that underpin public policy.

This study addresses the MIT Cogeneration Plant in that context, motivated by the fact MIT was an early mover in adopting CHP technology in institutional settings. After a decade addressing numerous obstacles, the plant was put into operation about a decade ago with the expectations of reducing energy costs, improving the quality of power, and reducing net atmospheric emissions. This study reviews the major drivers for deciding on-campus power generation, and analyzes the project retrospectively in the context of today's market and regulatory conditions. Alternative scenarios are also evaluated in terms of technology improvements, standby rates, and fuel prices with the further goal of understanding their impact on the viability of DE/CHP projects.

Our baseline results lead us to conclude that MIT Cogeneration Plant is a better alternative than generating the steam and purchasing the electricity needs separately. The present value of the economic savings are about \$43m for the period 2006 to 2020, while the environmental benefits in terms of CO₂ emissions represent in average about 65,000 metric tons/yr. These numbers represent about 10% cost savings and 22% CO₂ reduction under the set of assumptions and projections in the base case.

Then, we performed four sensitivity analyses to understand the impact of technology efficiency, electricity rate structure, market fuel cost uncertainties and a carbon tax on the viability of DE/CHP projects:

- Better turbine electrical efficiency represents more economic and CO₂ emission benefits for the cogeneration alternative, with economic savings increasing up to about \$73m and CO₂ benefits up to 93 metric tons/yr.
- If the utility's new rate structure were applicable to the MIT cogeneration facility, it would have additional economic benefits of about \$4.6m.
- The project can be particularly sensitive to market conditions, especially natural gas prices. If fuel price conditions are not favorable, the cogeneration alternative becomes uneconomic with incremental costs of almost \$56m.
- Finally, the economic recognition of the CO₂ reductions can change the economics of a cogeneration project. A DE/CHP project may displace emissions from less efficient technology and fossil fuel sources – depending on the utility's energy portfolio. For example, a \$100/tonne carbon-tax brings additional economic savings of about \$16m for the Cambridge utility fuel mix (about two thirds fossil). However, this particular cogeneration project would have additional costs of \$2m if the Cambridge utility used entirely "carbon-free" sources.

In summary, this study illustrates that CHP systems provide real economic and environmental benefits, through better efficiency, reutilization of exhaust gases, and displacement of polluting technologies. However, changes in current operational, market and regulatory conditions may greatly affect the benefits and viability of DE projects, requiring institutions to perform an in-depth analysis to weigh the pros and cons of specific projects.

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A ti Ari por tu amor e incondicional apoyo.

A nuestro bebito Matías por ser la luz de nuestras vidas.

To Ari for your love and unconditional support.

To our little baby boy Matías for being the light of our lives.

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ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AC	Alternating Current
BACT	Best Available Control Technology
CCGT	Combined Cycle Gas Generation Technology
CELC _o	Cambridge Electric Light Company
CGT	Combustion Gas Turbine
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
COMGas	Commonwealth Gas
CO	Carbon Monoxide
CPI	Consumer Price Index
CT	Combustion Turbine
CTC	Customer Transition Cost
CUP	Central Utilities Plant
CZM	Coastal Zone Management
DC	Direct Current
DE	Distributed Energy
DEP	Department of Environmental Protection
DG	Distributed Generation
DTE	Massachusetts Department of Telecommunications and Energy
EFSB	Energy Facilities Siting Board
EIA	Energy Information Administration
EIR	Environmental Impact Report
ENF	Environmental Notification Form
EOEA	Executive Office of Environmental Affairs
EOP	Emission of Offset Policy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FO	Fuel Oil
LHV	Low Heat Value

HHV	High Heat Value
HRSG	Heat Recovery Steam Generator
IC	Internal Combustion Engine
ICR	Indirect Cost Recovery
ISO-NE	New England Independent System Operator
LAER	Lowest Achievable Emissions Reduction
LPG	Liquefied Petroleum Gas
MA	Massachusetts
MAAQS	Massachusetts Ambient Air Quality Standards
MEPA	Massachusetts Environmental Policy Act unit
MCFC	Molten Carbonate Fuel Cells
MEPA	Massachusetts Environmental Policy Act
MTC	Massachusetts Technology Collaborative
η	Efficiency
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NEPOOL	New England Power Pool
NG	Natural Gas
NO ₂	Nitrogen Dioxide
NO _x	Nitrogen Oxides
NPC	National Petroleum Council
NPV	Net Present Value
NSPS	New Source Performance Standards
NSR	New Source Review
O ₃	Ozone
O&M	Operation and Maintenance
OPEC	Organization of the Petroleum Exporting Countries
OSGF	On-Site Generating Facility
PAFC	Phosphoric Acid Electrolyte Fuel Cells
pm	Particulate Matter
PSD	Prevention of Significant Deterioration
PURPA	Public Utility Regulatory Policies Act
PV	Present Value
QF	Qualifying Facility

RTP	Real-Time Pricing
SCR	Selective Catalytic Reduction
SI	Spark Ignition Engine
SILs	Significant Impact Levels
SO ₂	Sulfur Dioxide
SOFC	Solid Oxide Fuel Cells
TOU	Time Of Use
VOCs	Volatile Organic Compounds

1. INTRODUCTION

1.1. PROBLEM DEFINITION

Distributed energy (DE) is generally referred to as energy generation and storage systems placed at or near the energy consumer's site. However, since continuous debate exists about the capacity size and the type of technology to be included in the definition, we will take the term as defined in Chapter 164 of the General Laws of Massachusetts (G.L.c.164, §1):

“Distributed generation is the generation facility or renewable energy facility connected directly to distribution facilities or to retail customer facilities which alleviate or avoid transmission or distribution constraints or the installation of new transmission facilities or distribution facilities”.

Reciprocating internal combustion engines, combustion turbines and microturbines are among the technologies widely accepted as qualifying for distributed generation. Other technologies are fuel cells, and renewable technologies such as photovoltaic systems and wind turbines. DE can be fueled from a broad variety of sources, from coal, oil and natural gas, to solar and other renewable resources.

The major drivers for the deployment of grid-connected DE resources have been the potential to provide benefits on both sides of the utility meter¹, such as:

- Increase of the net energy efficiency.
- Lower energy costs.
- Improvement of system reliability.
- Environmental benefits.
- Improvement of power quality.
- Lower energy losses in transmission lines.
- Reduction of transmission congestion.
- Reduction of large capital investments in the distribution and transmission systems.

According to the Energy Information Administration's 2003 Annual Energy Review, in the United States almost 70% of all energy used to generate electricity coming from fuels is lost as waste heat (from the conversion of heat into mechanical energy), and as line losses from the transmission and distribution of electricity across the grid (see Diagram A.1 from Appendix A). Therefore, there is a great potential for efficiency improvements that could be achieved using DE resources when configured as Combined Heat and Power (CHP) applications.

CHP is a system that “efficiently generates electricity and takes advantage of the heat to produce steam, hot water, and /or chilled water” (Aspen, 2000, pp. 2). The heat, that normally would be wasted in the conversion process, is captured and used for thermal applications.

¹ United States, Department of Energy, Distributed Energy Program, Energy Efficiency and Renewable Energy, *Major Potential Benefits of DE* (http://www.eere.energy.gov/de/major_potential_benefits.html)

The simultaneous production of electricity and use of thermal energy improves considerably the total net efficiency of the facility. As shown in Table 1.1, the efficiency of large generating technologies is generally less than 50%. However, when adding CHP to the current technology to capture the wasted heat, the efficiency increases to over 65% (Casten, 1998, pp. 66) (GRI and NREL, 2003).

Technology	Without heat recovery	With heat recovery
Coal-fired power plant	36-38%	78%
Internal combustion engine	30-37%	69-78%
Steam turbine	5-15%	80%
Gas turbine in simple cycle	22-37%	65-72%
Gas turbine in combined cycle	55%	85-90%
Microturbine	23-26%	61-67%
Fuel cells	30-46%	65-72%

Table 1.1: Efficiency of generating technologies

Regardless of the multiple benefits mentioned above, according to the EIA's 2003 Annual Review the proportion of electricity generated by CHP applications in the commercial² and industrial³ sectors measured over the total net generation has been decreasing over the past years. In 1990 it accounted for 4.5%, and in 2003 it represented 4.17% of the total generation (see Figure 1.1 and Appendix A).

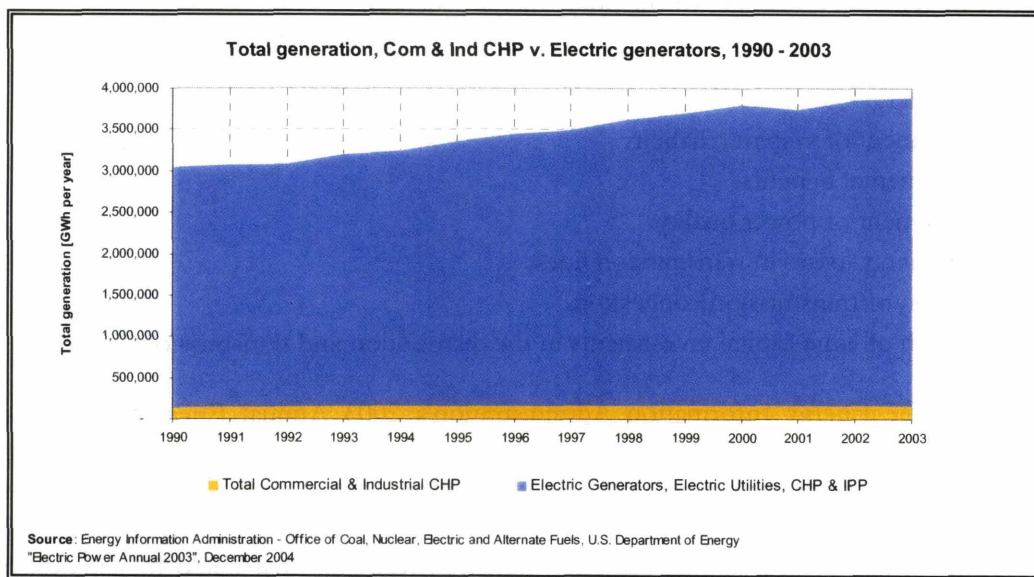


Figure 1.1: Total generation, 1990 - 2003

² Commercial sector includes institutional sector, comprising private and government services such as college and universities, district energy, government, hospitals, offices, airports, and health/sport centers.

³ Industrial sector includes agriculture, forestry, fishing, and hunting; mining, including oil and gas extraction; construction; manufacturing; natural gas distribution; and water supply and irrigation systems.

During 2003, the power generated by CHP facilities in commercial/institutional settings was 7,496 GWh representing only 0.62% of the total electricity used in that sector of 1,199,718GWh⁴

Since 1990, the additional generation in the commercial/institutional area has been minimal, with a decrease starting in 2000 (see green line in Figure 1.2 and Table A.1 from Appendix A). In 2003, the level of capacity for CHP commercial/institutional settings was similar to that back in 1994, accounting for only 2,100MW (less than 0.25% of the total installed capacity in the nation). If we take into consideration CHP industrial applications, the proportion over the total capacity was 3.14% during 2003, one of the lowest since 1990 (see Figure 1.3, Figure 1.4, and Table A.2 from Appendix A).

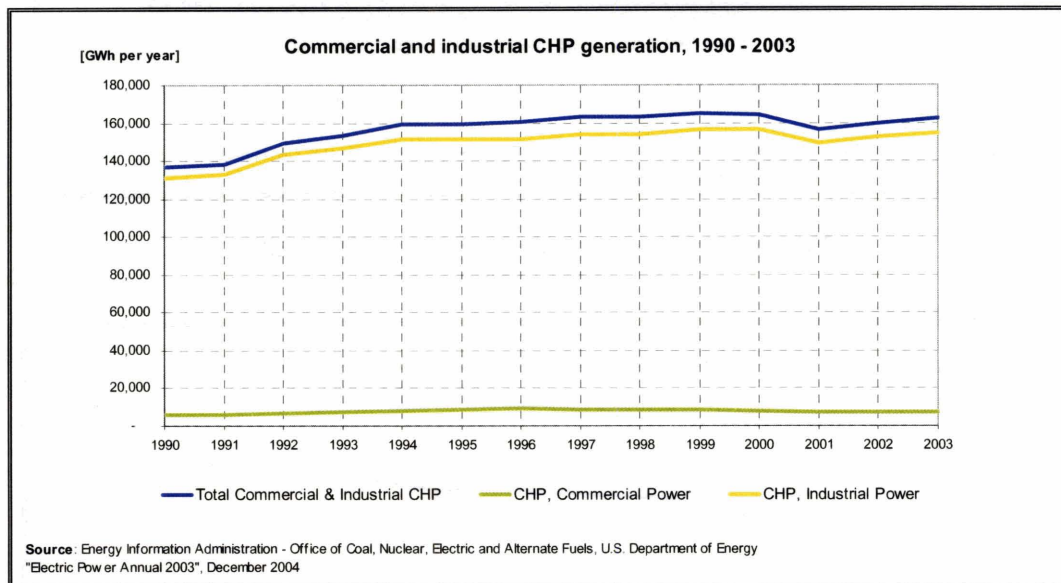


Figure 1.2: Commercial and industrial CHP generation, 1990 - 2003

⁴ The total electricity in commercial/institutional sector was calculated taken the total sales to ultimate commercial customers during 2003.

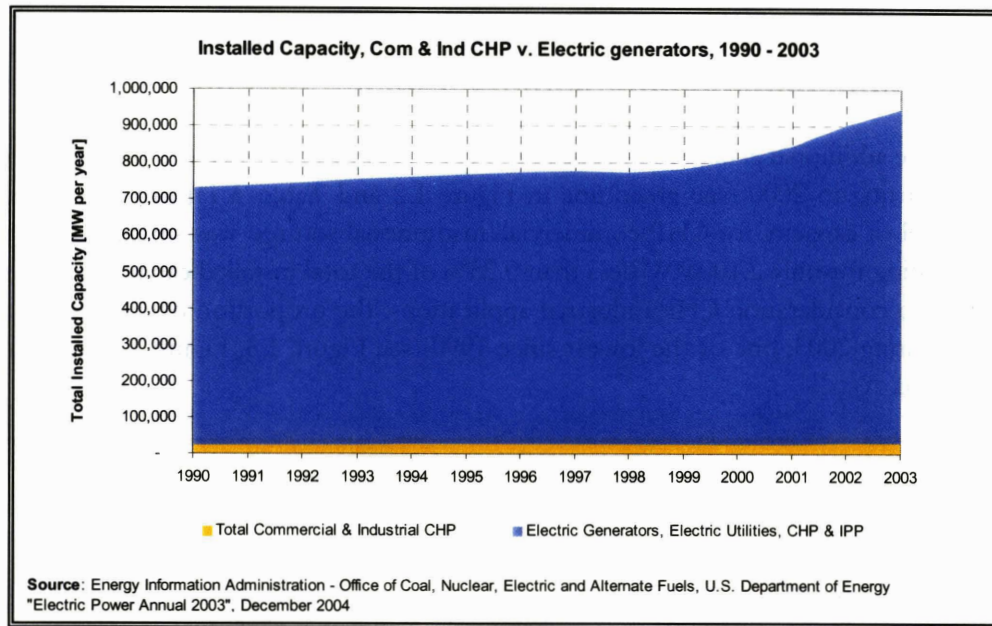


Figure 1.3: Total installed capacity, 1990 - 2003

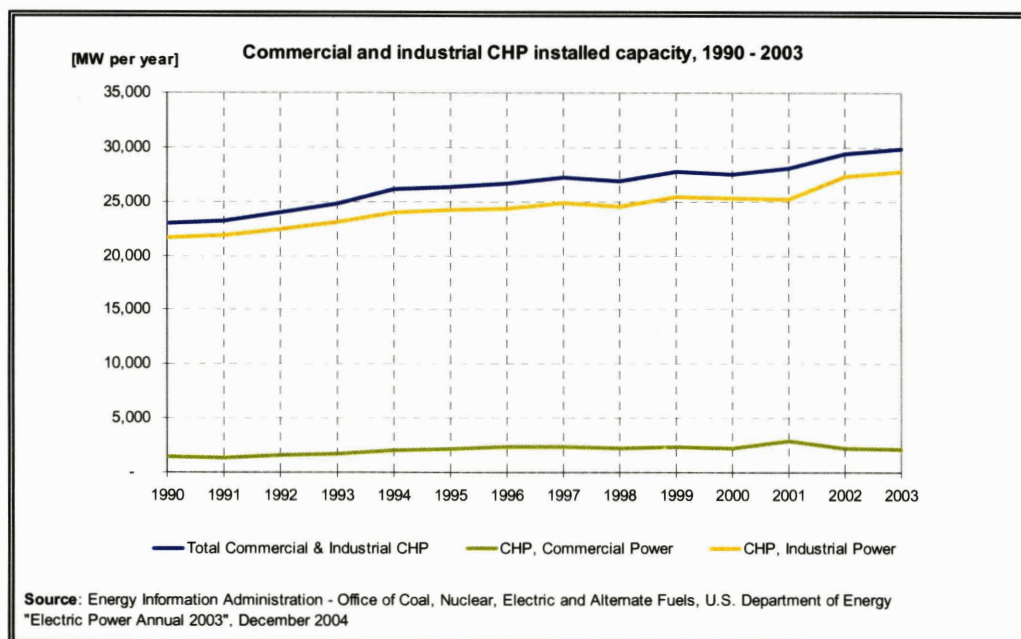


Figure 1.4: Commercial and industrial CHP installed capacity, 1990 - 2003

As we observed from the above information, CHP in the commercial/institutional sector has decreased its market share. The current deployment levels are extremely low, despite the apparent benefits that this technology is able to provide. An explanation can be found in the hurdles to CHP applications created by various technology, regulatory framework and market conditions. In addition, owners and operators may stay away from the challenge of operating a moderately complex physical plant.

On the technology side, the adoption of CHP technologies will depend on the availability and suitability of the technology to the customer's electrical and thermal needs. While the current state in combustion turbines makes them an attractive choice for large commercial applications, reciprocating engines may become more appealing for smaller facilities with efficiency levels that will depend on the size of the application. On the other hand, cleaner technologies have prohibitive installed costs making them only available for niche applications.

On the market side, CHP technologies use a wide range of fuels and the decision of adopting the application will be affected by the variations in the price of fuels and electricity. Particularly for natural gas and oil fuels, current prices are high. The spot price for natural gas at Henry Hub is \$7.3150/MMBtu⁵ when a year ago it was \$5.8950/MMBtu, a nominal increment of 24%. For the New York Harbor No. 2 fuel oil the spot price is \$1.4078/gal compared to that from last year of \$0.9367/gal, an increase of 50%.

Looking at the historical wellhead natural gas⁶ and oil prices, an increasing trend since 2002 is clear, with current levels being one of the highest of the past years. Moreover, over a fifteen year period, a period of interest for planning, building and operating a DE facility, natural gas prices have about tripled (see Figure 1.5 and Figure 1.6).

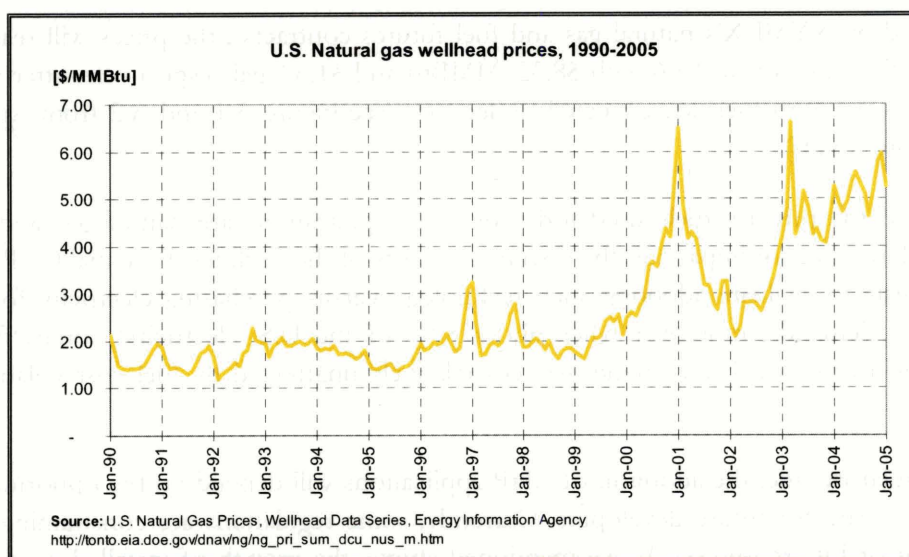


Figure 1.5: U.S. natural gas wellhead prices, 1990 - 2005

⁵ Prices as of April 13th 2005. Source: Wall Street Journal (WSJ), *Markets data and resources: Spot Prices – Oil Statistics* (<http://online.wsj.com/documents/mktindex.htm?oilstat.htm>)

⁶ It is important to mention that there are some differences between Wellhead and Henry hub prices: i) Wellhead prices represent real-time transactions, ii) Henry hub prices represent contracted natural gas sales delivered at the Henry Gas processing plant in Louisiana which include some processing and transportation costs.

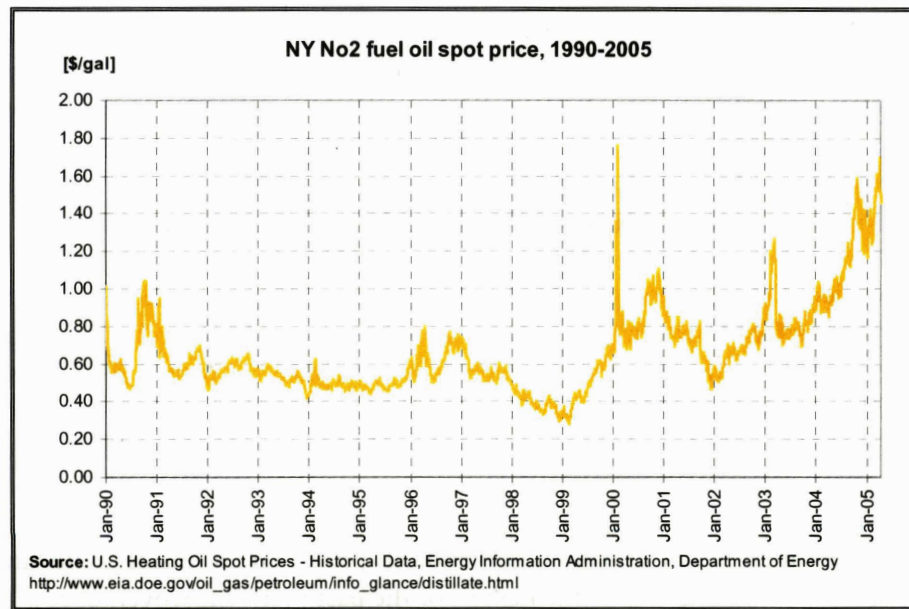


Figure 1.6: New York Harbor No.2 fuel oil spot prices, 1990 - 2005

As indicated by NYMEX's natural gas and fuel futures contracts⁷, the prices will reach a peak during the first quarter of 2006 with \$8.32/MMBtu and \$1.58/gal respectively, after which the future prices for both fuels are expected to decrease (see Figure A.1 and A.2 from Appendix A for the future trends).

Therefore, if the primary fuels used today by CHP applications are natural gas and oil, high prices will have a major impact on the operational costs of the facilities. Potential CHP users will need seriously to evaluate adopting such technology versus purchasing electricity for meeting their energy demands, moreover when about 80% of the U.S. electricity⁸ comes from coal, nuclear, and hydro which are energy sources relatively unaffected by fuel cost volatility (EIA, 2004).

On the regulatory side, the adoption of CHP applications will depend on the opportunities that regulations create for future developers. Currently, some regulations are constraining a greater deployment of DE resources. As we mentioned above, the growth of installed capacity at the commercial/institutional levels has been small over the past decade. The growth of CHP installed capacity has been mostly from independent power producers during the first half of the last decade and the last few years (compare "CHP Commercial Power" and "CHP Industrial Power" in Table A.2 with "CHP Electric Generators" in Table A.2b from Appendix A).

⁷ NYMEX's natural gas and No. 2 fuel oil futures - 4/14/05 session.

⁸ More precisely 79% during 2003.

1.2. MOTIVATION

Broadly speaking, present regulation was initially conceived in addressing the barriers that the traditional vertical production model presented for new independent power producers. Although the 1978 Public Utility Regulatory Policies Act (PURPA) motivated the introduction of cogenerators in the wholesale electricity market, it seems that it was not enough for encouraging a greater DE market. When developing a project, small and mid-sized DE developers need to consider a series of critical issues such as stranded costs and standby rates payable to the electrical utility, interconnection standards to the existing distributions systems, and environmental requirements.

Having in mind the issues initially introduced in this chapter, the main motivation for this study is to respond to the question,

“Given the widely-recognized benefits of DE resources, why has the deployment of such resources in the commercial and institutional sectors not grown over the past years?”

Often advocates for DE resources rely on simple models that take into account only efficiency considerations to conclude that CHP is valuable to the public good. However, it is crucial to look at a more complex analysis where institutions need to weigh the pros and cons of the potential project versus continuing as a utility customer. The need for an in-depth case study appraisal is essential for determining the total value of the project.

Along these lines, we took MIT’s Cogeneration Plant as our case study. We were stimulated by the fact that MIT was a pioneer among institutions in building a facility of these characteristics, and also by the challenges it had to face to finally operate the plant. We will take a deep look into the operational mode of the facility, and we will understand how technical, market and regulatory barriers shape the project. Moreover, we will conduct an analysis on how the attenuation of those barriers will impact a new project with similar characteristics in the Cambridge area, and we will analyze the viability of such projects given the new conditions.

1.3. THESIS OUTLINE

In Chapter 2 we will review the MIT cogeneration project. The analysis will focus on the historical economical and technical reasons that the Institute took into consideration when deciding to start the project, and the barriers that MIT had to overcome especially with the utility distribution company regarding the settlement on stranded costs. Sections 2.3 and 2.4 will contain the central analyses and core results of this study. The quantitative analysis will be based on the evaluation of the plant’s future operational costs, together with an evaluation of a hypothetical reference scenario where all MIT’s electricity needs are satisfied by the utility company servicing the Cambridge area. Operational savings and carbon emission benefits will be analyzed for determining if under current conditions the plant is still an attractive alternative for MIT and, by extension, other institutions.

In Chapter 3 we will study in more detail the Combined Heat and Power technologies. Specifically we will focus on the applications and potential benefits, the technical barriers of the existing technology, and the main features of new emerging technologies and their contributions to CHP applications. Additionally, in section 3.4 we will carry out a quantitative analysis of the impact of new technologies, looking at the monetary savings and environmental benefits due to improvements in the efficiency levels.

In Chapter 4 we will review the market and regulatory barriers for a larger deployment of CHP in the commercial and institutional sectors. We will look at the main PURPA provisions for “qualifying facilities”, the state’s regulatory framework for DE generation, as well as the electricity rate and charges applicable to DE projects. In section 4.4, a quantitative analysis will be based on how the rate structure affects the viability of new projects, and how the volatility of fuel prices impacts the operational costs of the projects. In the latter analysis, especially important will be the sensitivity of the model to the natural gas prices.

Finally, in Chapter 5 we will discuss the lessons learned from MIT’s experience for a better understanding of the viability of CHP in commercial and institutional sectors. We will conclude with some issues that are interesting for further analysis, and a series of observations regarding the problems this technology is facing, which are constraining a more rapid development and wider DE market deployment.

2. CASE STUDY: MIT COGENERATION PLANT PROJECT

In this chapter we will review the main features of MIT's cogeneration project, starting with an overview of the history of the project and the challenges the Institute had to tackle to put the plant in operation. We will also study the technical characteristics of the main subsystems that comprise the whole Central Utilities Plant (CUP), as well as their most recent operational features and MIT's electrical and thermal load characteristics.

Finally, we will make an in-depth analysis of the facility where we will perform a cost-benefit analysis of the project in today's and future market conditions. The study will be based on two cases where the campus' electricity and steam needs will be met in different ways. We will compare the results in terms of the economics of the projects, as well as the environmental benefits that each of them represents in terms of CO₂ emissions.

2.1. BACKGROUND

In 1985, MIT started a feasibility study for installing an on-campus gas-fired cogeneration facility that would provide more cost effective electricity and heating to the buildings with a better quality of service⁹, addressing at the same time state and local environmental considerations. The continuous fluctuations and price increases in electricity and imported oil fuel prices, as well as the low natural gas prices were some of the major drivers for taking the decision of installing a cogeneration plant.

At that time, most winter heating steam was supplied by the CUP, which also supplied the steam for the steam-driven chillers for cooling purposes during the summer. There were five boilers with a total capacity of 400klb/h of steam that could use natural gas on an interruptible basis, and No.6 fuel oil when gas was not available, representing 15-30% of the annual fuel requirements. Natural gas was supplied by Commonwealth Gas (COMGas), and fuel oil was stored in underground tanks with a total capacity of about three week supply.

Cambridge Electric Light Company (CELCo) supplied most of the electricity to the campus through three main service points East, West and Main Campus, each with two underground 13.8KV feeders from CELCo, electrically isolated from each other. However, at that time CELCo was considering to upgrade its Cambridge distribution system to 115kV, with subsequent changes in the interconnection of MIT with CELCo (Fluor, 1986, pp. 2-1 to 2-4).

MIT's considerations for choosing a gas turbine cogeneration plant were¹⁰: i) the constant electricity growth that the Institute experienced over the preceding years and the substantial growth estimations for the future, ii) because of air quality permits, a natural gas fired combustion turbine would have an easier permitting process than a diesel generator based system. In addition, according to the steam and energy load data of the base year (1984), the

⁹ Occasional outages made the power supply unstable and unreliable for MIT's needs. The rate of interruptions was in average 1+event per year.

¹⁰ Memorandum sent to Paul F. Barrett from MIT's Cogeneration Study Committee related to MIT Cogeneration Feasibility Study (May 16th, 1986), Cambridge, MA (USA), pp.1.

Institute's annual average heat to power ratio was 6.25lb/kWh¹¹, that from a technical point of view, indicated the simple and combined cycle gas turbine-based cogeneration system as the most suitable alternative (Fluor, 1986, pp. 3-5 and Table 3-2).

Given the characteristics of the steam and electrical loads, MIT had to decide the electrical and thermal size of the new plant assessing the tradeoffs between large systems with excess capacity versus small systems requiring the additional use of the existing boilers and the local utility's service for providing the remaining electricity needs. For the steam sizing, the decision was based on the quantity coming from the unfired steam production¹², the supplemental-fired¹³ and the existing boilers¹⁴ of the CUP that would best meet MIT's steam requirements.

After reviewing more than 20 cogeneration alternatives, the study narrowed down the alternatives to five cases because of the attractiveness that each case represented to MIT. This analysis took into consideration technical issues such as: excess of steam and power depending on the size of the turbine, flexibility of the technologies to match steam and electric demands by either varying the steam or electricity production¹⁵, supplemental firing capability, space constraints, efficiency rates, among others. Other analyzed issues were the equipment required for each of the cases for the water supply, electrical distribution and control systems (Fluor, 1986, Sections 5-6).

In April and May of 1992, the project acquired the required environmental permits from the Massachusetts Department of Environmental Protection. The construction of plant started in spring 1993 and the plant began its operations in September 13th, 1995 including the replacement of two of the five existing boilers and upgrading the other ones. Also, the plant was designed to be interconnected to CELCo and the regional grid, configured in a way that would MIT permit to sell excess energy to CELCo if it was cost effective.

The plant was expected to provide about 94% of the campus energy needs with a technology that was designed to reduce emissions to low levels and, therefore, improve Cambridge's air quality. Emissions of the criteria pollutants – PM_x, SO₂, NO_x, CO, VOC's – of the new plant compared to the emissions of the old one were estimated to be 259tons/yr versus 470tons/yr respectively.(MIT, 1992, pp. 9).

¹¹ During 1984, the total steam consumption was 687.375 million lbs and the total electrical consumption was 110,370MWh.

¹² Unfired steam production is steam coming from the waste heat of the gas turbine. It is used as a base load and any excess must be condensed.

¹³ Supplemental-fired steam production uses fuel to increase the temperature of the gas turbine exhaust increasing the steam production. It can be controlled to meet steam demand and the efficiency is higher than conventional boilers.

¹⁴ Boilers are commonly used for meeting peak steam loads.

¹⁵ Depending on the technology, the steam can be used for varying electricity either through injection to a gas turbine or use in a steam turbine. On the other hand, supplemental firing can be used for varying the amount of steam.

Regarding the fuel and electricity supply contracts, at that time MIT signed a twenty year term contract for firm gas supply with COMGas. The gas purchase contract included an escalating commodity charge and a fixed monthly demand charge for a maximum capacity of 5,500MMBtu/day that will be ending in 2016. For standby power – in case of maintenance and generation failure – and the supplemental power¹⁶ service – for peak demand – the service was agreed to be supplied by CELCo at a standard rate or contractual agreement.

The total project capitalization was \$48,477,265 (1996US\$) including the initial investment, contingency costs and interest during construction. The project was 100% financed through a 30 years taxable-bond at a 7.125% real rate of return, and a 25 years straight line depreciation rate.

2.1.1. CHALLENGES TO THE DEVELOPMENT OF THE PROJECT

When the project was conceived, there were issues that challenged the feasibility of the project. Specifically, the subjects of concern were¹⁷: i) adequate gas supply, ii) local utility rates for electricity purchase, excess generation sale and stranded costs, and iii) regulations and environmental permits.

For the supply of gas MIT had to undertake extensive discussions with the local utility COMGas, and also with other suppliers to get a contract at a competitive price and suitable availability. The capacity of the local utility's distribution system was not enough for the supply of gas, since the available quantity of firm gas was sufficient only for a small base load cogeneration plant of about 10-12MW of capacity. Therefore, the upgrade of the distribution system and a new gas supply were needed before proceeding with the installation of a larger cogeneration facility (Fluor, 1986, pp. 4-21).

Regarding the sale of electricity¹⁸, the local utility was reluctant to provide a rate for excess power generated by the cogeneration plant, driven in part by the regulatory changes being carried out in Massachusetts and also for the threat that the plant represented as a competitor for the supply of energy. Other main issues of concern were the plant interconnection with CELCo's distribution system, and the rates that CELCo would charge for supplemental and standby power. At the time the study was conducted, it was assumed that the G-3 rate¹⁹ would be applicable to the purchases of supplemental power. In the case of standby power, the study assumed that MIT would buy the power from the local utility at nondiscriminatory prices according to PURPA requirements. However, it was not clear what charges and terms CELCo would apply to the plant and further negotiations between the parties were required to define a reasonable standby charge (Fluor, 1986, pp. 4-9).

¹⁶ Supplemental power refers to MIT's power purchases in excess of the cogeneration plant's rate capacity.

¹⁷ Memorandum sent to Paul F. Barrett from MIT's Cogeneration Study Committee related to MIT Cogeneration Feasibility Study (May 16th, 1986), Cambridge, MA (USA), pp. 2.

¹⁸ MIT could sell excess power on a firm basis if the plant capacity exceeded the Institute's maximum electrical demand.

¹⁹ Rate G-3 for large general Time-of-use, 13.8kV service is available for those customers with a demand no less than 100kW during each billing month. The rate include a monthly demand charge, energy charges depending on the peak load period, power costs charge as defined in the default service and other charges such as energy conservation service charge.

Additionally, in 1995 CELCo expressed “concerns for the impact of the project on its Cambridge base revenue stream”, which could represent higher electrical prices paid by the other Cambridge rate payers (MIT, 1992, pp. 2). The utility had claimed that the investments made by the company to supply MIT’s energy needs would be stranded once the Institute had installed the plant. The company required MIT to pay a “customer transition cost (CTC)” of \$5.62/kVA/month to recover the costs that it had incurred to serve its customers, and that year the DTE required MIT to pay that charge to CELCo. The Institute started a long litigation process that included the DTE, the FERC and the Supreme Judicial Court. In March 1998, Massachusetts restructured its electricity market and the Electric Utility Restructuring Act required utilities to divest assets and hence to recover the stranded costs. In 2001, under a new regulatory environment dealing with stranded costs and exit charges, MIT reached an agreement with NSTAR²⁰ approved by the DTE. In this settlement, NSTAR had to refund MIT for the payments it had made between 1995 and 1997.

Concerning permitting process, MIT’s project required the approval of several environmental and regulatory permits related to emissions, water discharge, solid waste and land use (Fluor, 1986, section 8). At the state level, the Massachusetts Environmental Policy Act (MEPA) is a review and evaluation process for new projects with environmental consequences depending of the Executive Office of Environmental Affairs. During the process, comments from agencies, commissions and the general public were received. Once the process was complete, MIT received a certificate of compliance with MEPA in 1992 and the Institute was able to start the construction of the cogeneration plant.

Air permit was one of the critical ones for the development of the project. There were at least five major regulations the project had to comply with:

- New Source Performance Standards (NSPS). Enforceable at state level, it establishes the emission limits applicable to stationary gas turbines for NO_x and SO₂.
- New Source Review (NSR). New or modified sources must obtain approval from the Massachusetts Department of Environmental Protection (DEP)²¹ subject to meeting air quality standards, emissions limitations and any additional requirement.
- Ambient Air Quality Standards (AAQS). The major concern for the project was the Massachusetts’ one-hour NO₂ standard applicable to sources of potential NO₂ emissions exceeding 250ton/yr
- Prevention of Significant Deterioration (PSD)
- Emission of Offset Policy (EOP)

The whole air emissions permitting process was estimated to last between 6 and 15 months, conditional to adding water injection into the turbine to reduce NO_x emissions and post-operational tests to verify compliance with regulations.

²⁰ CELCo and its partner Commonwealth Energy merged with Boston Electric to form NSTAR.

²¹ Formerly known as Massachusetts Department of Environmental Quality Engineering (DEQE).

2.2. TECHNICAL CHARACTERISTICS OF THE PROJECT

2.2.1. TECHNICAL FEATURES

Source: MIT's Department of Facilities

The screenshot displays a complex process control system (PCS) interface for a power plant, showing various process parameters, equipment status, and fuel data.

Process Parameters (Left Side):

- Temp: 74 degF
- Humidity: 18 pct
- Dew Point: 28 degf
- CTG (Control Temperature Gauge) status: Yellow circle (Running/Closed)
- T7 Limit: 13,174 BTU/kWh

Process Parameters (Top Right):

- Bad Inputs: 1, 2, 3, 4, 5, 6, 7, 8
- 1,042 tons
- 0 tons
- 3,019 tons
- 23 tons
- 266 tons
- 0 tons
- 22 tons

Process Parameters (Bottom Right):

- 43.0 degF
- dT 7.9 degF
- FlowCalc Failed gpm
- Cooling Tons: 100 %
- Total Bad Input: 100 %
- 42 Bad Input: 100 %
- N16A 20: 100 %
- 197 psig #1 10
- 198 psig #2 10
- 195 psig East 1
- 193 psig East2
- 195 psig West 2

Equipment Status (Bottom Center):

- HRSG (Heat Recovery Steam Generator) status: Yellow square (Running/Closed)
- B6/HRSG
- 124.6 kpph
- 17.9 MW
- 2.07 MW
- 2.04 MW

Fuel Data (Bottom Right):

- Oil Fuel: 8.0 \$/MMBTU
- Gas Fuel: 5.5 \$/MMBTU
- OFF

Legend:

- Stopped/Opened (Green square)
- Running/Closed (Red square)
- Live Value (Blue square)

The prime mover of the plant is a simple-cycle, dual-fuel, low nitrogen oxides (NOx) combustion turbine²³ – ABB GT10A – with a heat recovery system. The electrical capacity is 21MW nominal, the steam capacity is 170,000lb/hr with a supplementary fired high pressure boiler rated at 615psi and 705°F, and the cooling capacity is 23,500tons expandable to 28,000tons. The electrical heat rate is 11,400 Btu/kWh (LHV) and 12,800 Btu/kWh (HHV), the

²³ Technology endorsed by the Massachusetts Department of Environmental Protection (DEP) that meets the environmental permitting constraints.

maximum exhaust temperature is approximately 1050° F, and the exhaust flow is approximately 628,000 lb/hr. The primary fuel of the turbine is natural gas and the secondary one is distillate (No.2) fuel oil.

As with all gas turbine systems, the atmospheric air is compressed (1), the system is fueled and ignited (2), and the heated combustion gas is expanded through the gas producing and power turbines (3). Finally, the generated power is used to drive the compressor and electric generator. MIT's turbine has an industrial design, so it is more suitable for base-load operation, with more operational hours and highly reliable, although less efficient than the turbines with the aeroderivate design. The gas turbine produces a high quality thermal output appropriate for CHP applications (ONSITE, 2000, pp. 71-76).

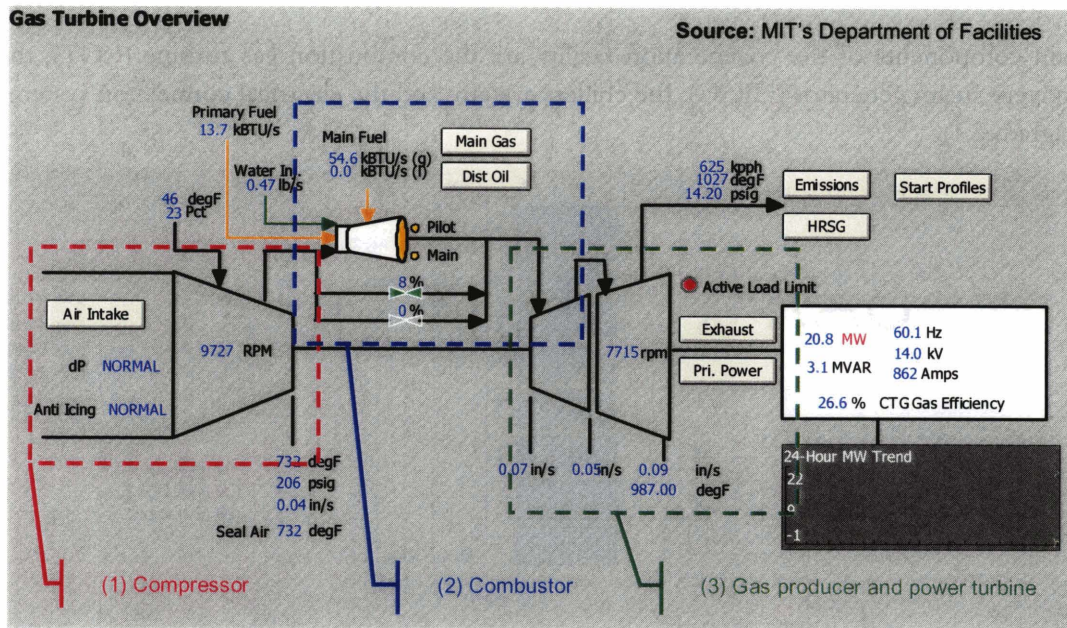


Diagram 2.2: Combustion gas turbine

The waste heat of the exhaust gas of the CGT is used by a HRSG to generate steam. The system can use supplemental firing to provide for additional combustion. This is possible because of the oxygen content in the gas turbine exhaust that permits the duct burners to increase the exhaust gas temperature entering the HRSG, and increase the steam production relative to an unfired unit (Energy Nexus, 2002). In MIT's system, the supplemental firing adds 60,000lb/hr of capacity to the existing 100,000lb/hr capacity of the waste heat. Besides incrementing of the overall efficiency of the plant, supplemental firing increases the operating flexibility through the control of steam output.

The thermal output of the HRSG is used as steam directly for heating purposes or converted to chilled water by absorption chillers for the campus' cooling needs (see Diagram 2.3).

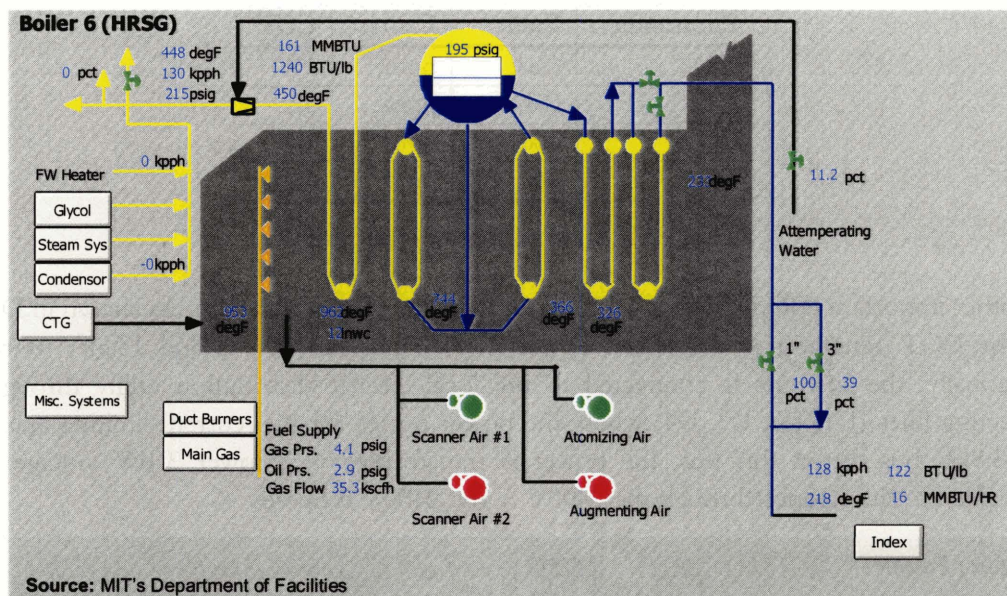


Diagram 2.3: Heat recovery steam generator

For controlling CO and NO_x emissions, MIT's plant uses two control methods. First, the turbine uses water injection into the combustion zone for reducing the temperature of the flame which also helps in reducing NO_x levels. The water needs to be demineralized to avoid forming deposits and corrosion in the turbine expansion unit. However, the water injection process increases CO emissions since the temperature in the burnout zone decreases.

Second, the turbine has an environmental (EV) combustor that uses premixed, swirling combustion flow to generate low NO_x levels (dry low NO_x combustor). A mixture of natural gas and compressed air is mixed prior to entering the combustion chamber which avoids local zones of high temperatures, or hot spots, in the combustor where NO_x forms (Energy Nexus, 2002).

Finally, a selective catalytic reduction (SCR) control method is used for carbon monoxide (CO) control in the gas turbine exhaust. CO results primarily from incomplete combustion either because of the water injection process or a partial load operation of the turbine. The CO catalyst is made of platinum, and it removes over 90% of CO.

With the three mentioned emissions control methods, the current CGT's air emission permit limits approved by the Massachusetts Department of Environmental Protection (DEP) are²⁴:

Parameter	Fuel	Units	CGT
NO _x	Gas	ppm	15
NO _x	Oil	ppm	42
CO	Gas	ppm	10
CO	Oil	ppm	10

Table 2.1: Air emissions permit limits

The other important component of MIT's facilities is the electrical system. As shown in Diagram 2.4, the CGT generator is connected to the 13.8kV bus (13.8kV A and 13.8kV B busses). Additionally, the Institute is connected to the local electric distribution utility through four connecting lines (U1, U2, U3, U4) where the power passes for two current-limiting reactors to the 13.8kV bus. From this bus, the power is transformed to a lower 2.4kV voltage that is transmitted to the campus through the 2400V A and 2400V B busses.

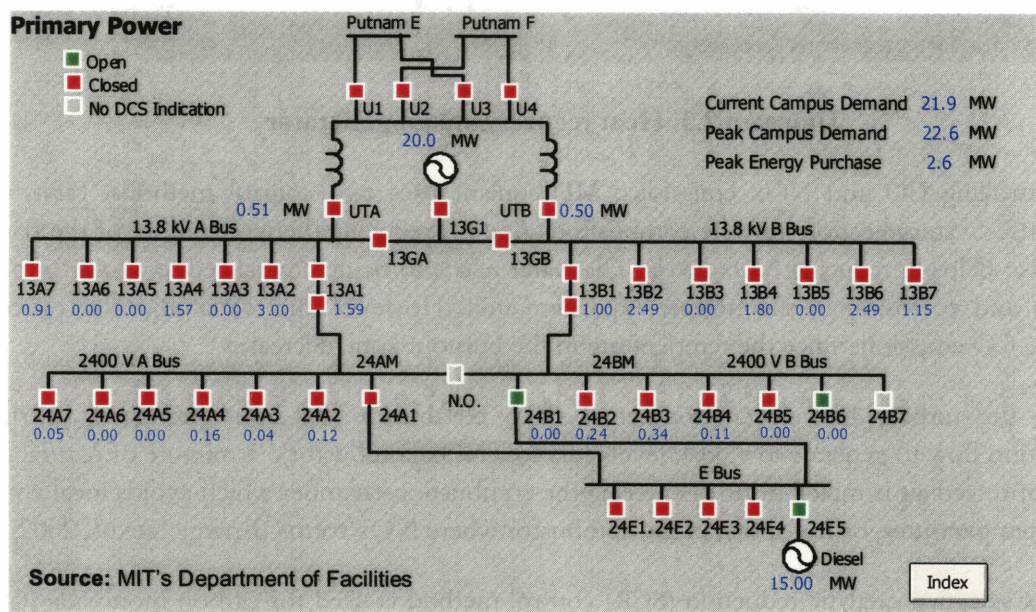


Diagram 2.4: Main electrical system

²⁴ MIT Cogeneration Project, *Air Emissions Permit Limits* (<http://cogen.mit.edu/emissions.cfm>)

2.2.2. PLANT'S OPERATING MODE

Prior to making a future projection of the operation of the plant, it is important to analyze the past performance of the facility, especially that from year 2004²⁵.

The Institute's electrical and thermal loads have been constantly increasing over the past years. When the project was conceived, the campus power requirement for 1995 was estimated at 135,000MWh and the average peak electrical demand was estimated at 21,327KVA per month (MIT, 1992, pp. 18). During 2004, the total electrical load was 192,270MWh with a 42% total increase, and the average peak load was 27,988KVA with a 30% increase. As shown in Table 2.2, over the past four years the electrical load has increased in average almost 7% per year.

Regarding the steam load, the maximum campus requirement for 1995 was estimated at 132klb/h. During 2004, total steam production was 1,426,796klb and the average peak demand was 223klb/h, with an important increment of 70% with respect to that in 1995. Table 2.2 shows that, for the past four years, the steam load has grown almost 8% per year in average.

		2001	2002	2003	2004
Electrical load growth	%	3.53	10.28	7.72	6.26
Average peak electrical demand	kW	23,407	25,954	25,556	27,428
Peak electrical demand	kW	27,310	28,241	27,840	31,639
Steam load growth	%	0.58	9.23	16.68	5.38
Average peak steam demand	klb/h	209	223	241	223
Peak steam demand	klb/h	466	315	306	318

Table 2.2: MIT's load, 2001 - 2004

From Figure 2.1, we can clearly see the increasing trend of MIT's energy loads. Moreover, we can analyze the monthly electrical and steam load profiles for each year:

- Electricity is used year-round for general purposes.
- Electrical demand is higher during summers because of the air conditioning needs, with a peak of 31,639kW in 2004.
- The highest steam demand occurs during winters due to the heating needs, with a peak of 318klb/h in 2004.

²⁵ All operating data provided by MIT's facilities department.

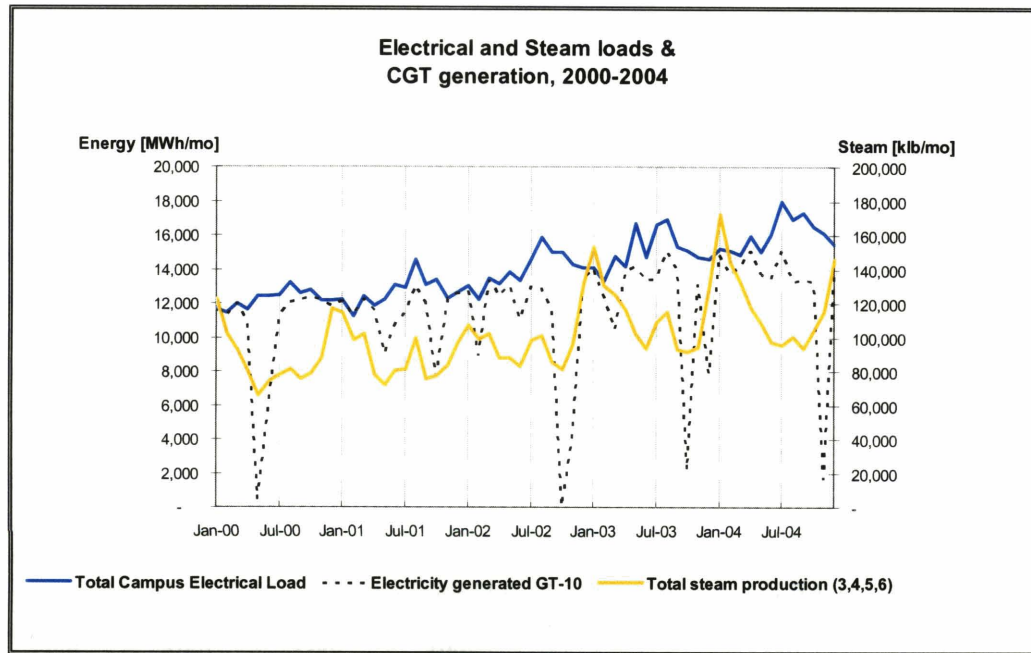


Figure 2.1: MIT's energy loads, 2000 - 2005

The nominal capacity of the CGT is 21MW, but depending on the season of the year it can generate between 19.5MW and 22MW. The historical annual capacity factor²⁶ of the plant shows that the turbine has been used mostly as a base load power. The value over the past year has been over 70%, and during 2004 the capacity factor was almost 91% with 7,936 operating hours (see Table 2.3). This latter value indicates not only more operating hours, but also an upgrade of the blades of the turbine that increased the capacity by at least 1MW.

Historically, the project has provided over 75% of the electricity load. During year 2004, the plant generated 155,544MWh which represented almost 81% of the Institute's electrical needs. For meeting the remaining 19% of the load, MIT's had to buy 36,726MWh from the local electric utility NSTAR (see Table 2.3).

		2001	2002	2003	2004
Capacity factor CGT over 19.5MW	%	79.54	73.90	84.35	90.81
CGT generation over electrical load	%	89.20	75.15	79.63	80.90
Energy purchase over electrical load	%	10.80	24.85	20.37	19.10

Table 2.3: CGT operation, 2000 - 2004

From Figure 2.2, we can see the CGT operational characteristics during year 2004. Mostly in the summer and in November, additional electricity is needed from NSTAR because of the high levels of load and the maintenance of the turbine respectively.

²⁶ Capacity factor is defined as the ratio of the generated electricity to the maximum capacity of the plant.

The steam load was mostly provided by the HRSG system, where the unfired waste heat (maximum capacity of 100klb/hr) is used in a base load operation, and the supplemental firing system (maximum capacity of 60klb/hr) is used to provide flexibility to the system when more steam is needed. As we will explain below, additional steam can be provided by steam boilers.

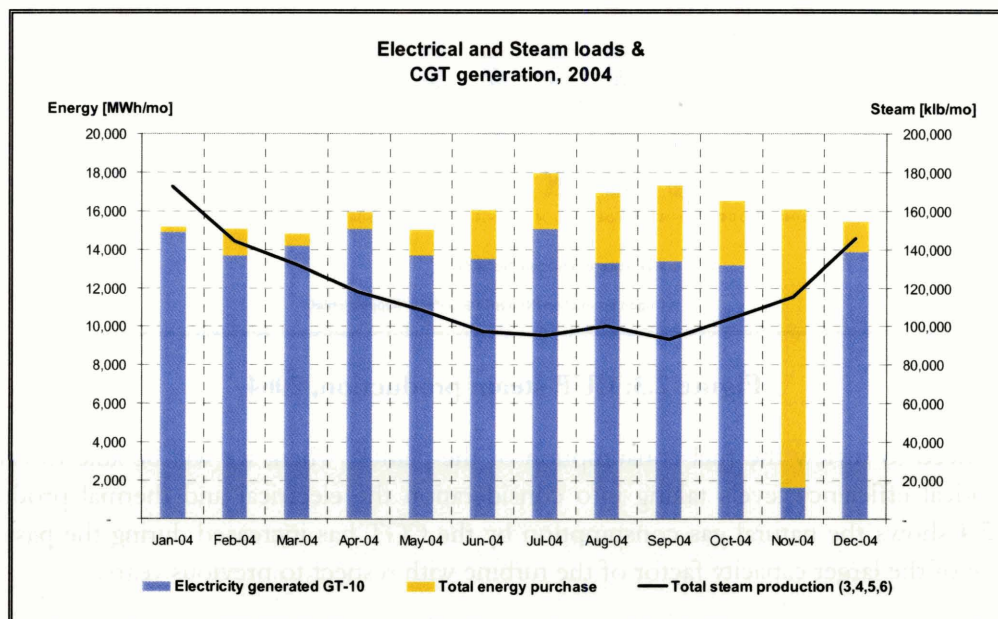


Figure 2.2: MIT energy loads, 2004

Prior to the cogeneration project, the steam in the campus was supplied by 5 boilers. Currently, there are 3 from the original boilers and 2 temporary ones. Table 2.4 shows the capacities, fuel type and efficiencies²⁷ for each of them.

Boilers		Capacity	Fuel	Efficiencies
Additional No.3	klb/h	80	No6 FO & NG	80%
Additional No.4	klb/h	80	No6 FO & NG	80%
Additional No.5	klb/h	100	No6 FO & NG	80%
Temporary No.7	klb/h	60	No2 FO & NG	82%
Temporary No.8	klb/h	60	NG	82%

Table 2.4: Boilers technical features

The boilers work in coordination with the HRSG system to supply the required steam, especially during peak hours, winter and at the time the CGT maintenance is made (see Figure 2.3). The temporary boilers No.7 and 8 are operated when there is a contingency in the system, and they must be fully-load operated. Boilers No.3, 4 and 5 will give flexibility to the system when providing the steam. During 2004, the boilers supplied 459,459klb/yr that represented 32% of the total steam consumption.

²⁷ Efficiency levels for loads over 70%.

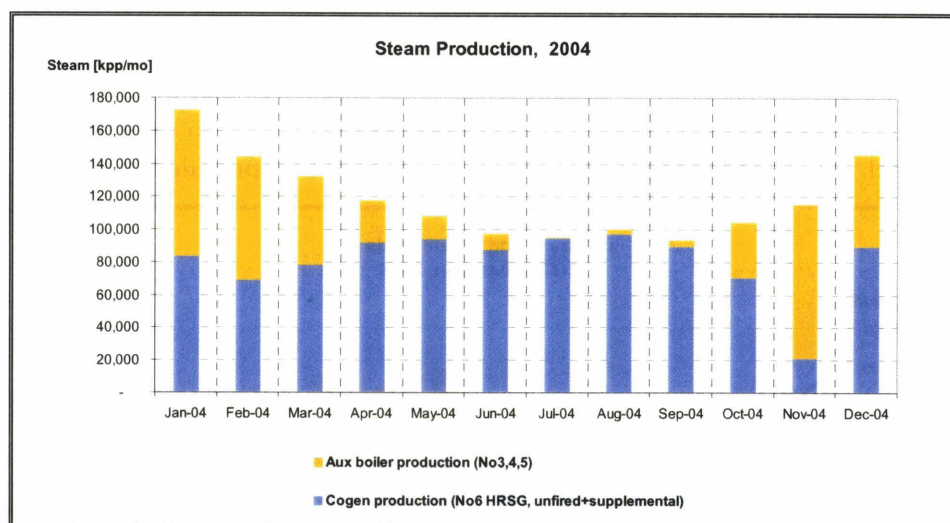


Figure 2.3: CUP steam production, 2004

We also need to review the fuel consumption of the plant²⁸. Then, we will be able to calculate the historical efficiency levels taking into consideration the electrical and thermal production. Figure 2.4 shows the natural gas consumption by the CGT has increased during the past years, indicative of the larger capacity factor of the turbine with respect to previous years.

In addition, we can observe a dramatic change in the proportion of fuel being used in the boilers. In 2002, boilers burned gas and No.6 in almost the same proportion, however during the last year almost 91% of the total Btu consumed by the boilers was due to No.6 fuel oil.

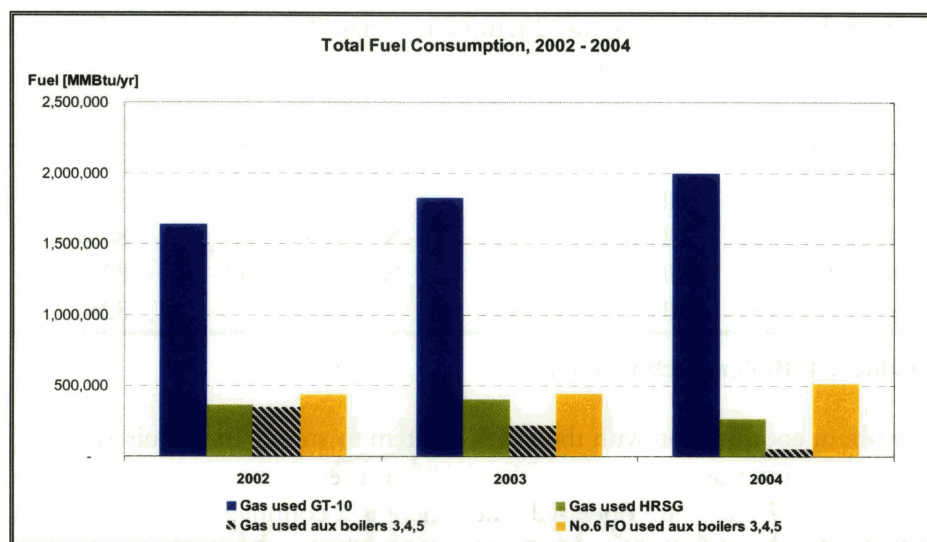


Figure 2.4: CUP fuel consumption, 2000 - 2004

²⁸ We took HHV of 1,050Btu/cf and 150,500Btu/gal for Natural Gas and No.6 fuel oil respectively.

This important change in fuel consumption in the boilers can be explained because of the considerable difference in fuel prices paid by MIT. The average price for No.6 was 5.73\$/MMBtu, while the average price for natural gas was 8.69\$/MMBtu²⁹. Therefore, it was more economic to burn oil than natural gas during the last year. Regarding environmental consequences, the change did not have great CO₂ implications because the boilers have consumed less fuel overall over the past few years. Total CO₂ emissions coming from the boilers – measured in metric tons – were about 55,000 in 2002 and 45,000 in 2004.

We can observe from Figure 2.5, the monthly characteristics in fuel consumption for year 2004. During winter, No.6 fuel oil was largely used by the boilers for supplying the additional campus' steam needs. In November, more No.6 fuel oil was needed to replace the steam that was not provided by the CGT that was under maintenance.

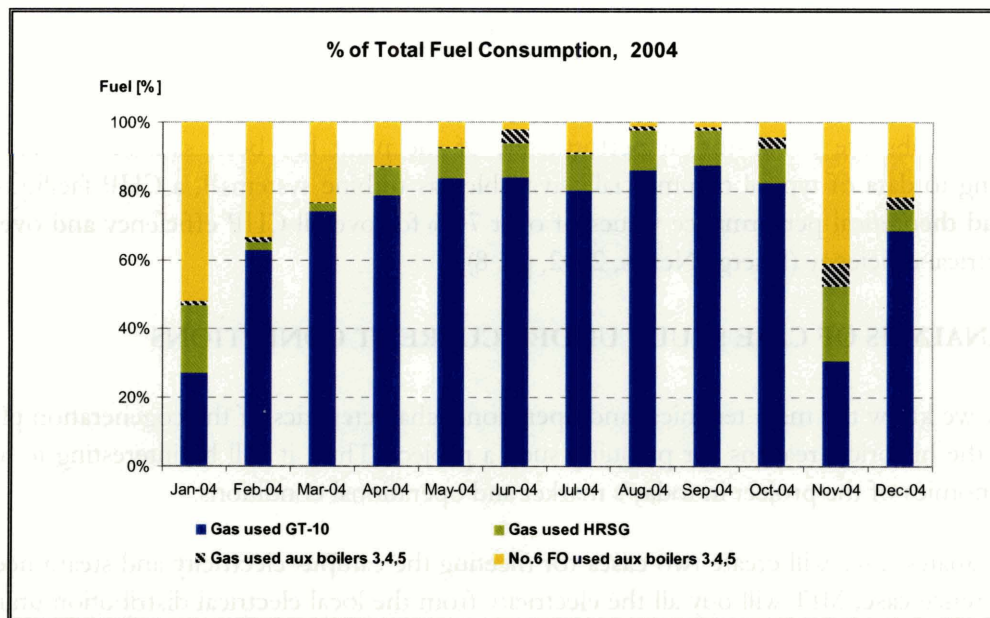


Figure 2.5: CUP fuel consumption, 2004

Finally, we can analyze the plant's performance. As Table 2.5 shows, we calculated two set of historical values:

		2002	2003	2004
Overall cogeneration efficiency	%	61.78%	63.18%	68.17%
CGT efficiency	%	26.27%	27.02%	26.60%

Table 2.5: Plant efficiencies, 2002 - 2004

²⁹ Prices extracted from MIT energy bills year 2004. Source: MIT's Department Facilities.

where,

- Overall efficiency ($\eta_{cogeneration}$) is defined as the sum of the energy content in Btu of the electricity generated by the CGT (q_{CGT}) and the energy content in Btu of the steam generated by the HRSG (q_{HRSG}), divided by the total fuel consumption of the turbine (f_{CGT}) and the HRSG (f_{HRSG}) in Btu:

$$\eta_{cogeneration} = \frac{q_{CGT} + q_{HRSG}}{f_{CGT} + f_{HRSG}}$$

- CGT efficiency (η_{CGT}) is defined as the energy content in Btu of the electricity generated by the CGT ($q_{electricity}$) divided by the total fuel consumption of the turbine (f_{CGT}) in Btu³⁰:

$$\eta_{CGT} = \frac{q_{electricity}}{f_{CGT}}$$

As we can observe the historical performance of the plant has been satisfactory. However, according to data of typical commercially available gas turbine systems³¹, a CHP facility should have had theoretical performance values of over 70% for overall CHP efficiency and over 30% for electrical efficiency (Energy Nexus, 2002, pp. 8).

2.3. ANALYSIS OF CASE STUDY UNDER CURRENT CONDITIONS

By now we know the main technical and operational characteristics of the cogeneration plant, as well as the historical reasons for pursuing such a project. Thus, it will be interesting to analyze the economics of the project in today's market and operational conditions.

For the analysis, we will create two cases for meeting the campus electricity and steam needs. In the reference case, MIT will buy all the electricity from the local electrical distribution utility and generate the steam through its boilers. In the alternative case, MIT will generate the electricity needs and buy the remainder to meet the total load, and additionally use the turbine exhaust heat in CHP. This latter case will be a replica of the current facility operations, where most of the steam is supplied by the CGT.

Finally, we will quantify the operational savings (if any) and environmental benefits of the project when comparing both cases. The savings and benefits will be calculated over a period of 15 years, from 2006 to 2020, taking 2005 as a base year. For the environmental benefits, we will focus on CO₂ emissions, recognizing that a reduction in criteria pollutants is also achieved.

³⁰ High electrical heat value (HHV) of the turbine is about 12,800Btu/kWh.

³¹ According to Energy Nexus Group, a 25MW CHP system is expected to have an electrical efficiency of 34.3% (with HHV of 9,945Btu/kWh) and a total CHP efficiency of 73%.

2.3.1. COMMON ASSUMPTIONS TO BOTH CASES

In both cases there are common assumptions regarding the energy load and the fuel prices. For base year 2005 we took the electrical and steam load values of year 2004, and we applied an escalator of 3.5% (see Table 2.6).

		2005
Average peak electrical demand	KVA-mo	28,967
Total campus electrical load	MWh	198,999
Peak steam demand	klb/h	329
Total campus steam load	MMBtu	1,547,617

Table 2.6: Electricity and steam loads, 2005

For the load projection until year 2020 we applied the escalators shown in Table 2.7. These values were taken from a previous study prepared for MIT in December 2004 (from now on, Vanderweil report). As we already mentioned, the average growth rate over the past four years for electricity and steam has been almost 7% and 8%, respectively. The escalators used in these projections are more conservative and they represent the futures loads that will be added from the new buildings that are under construction and will become online, such as the Brain and Cognitive Science Project in 2005; the East Campus Project that will integrate the Sloan School, the Economics Department and the Dewey Library in 2008; and the Cancer Center in 2012³² (Vanderweil, 2004).

Year	Electrical load %	Steam load %
2005	-	-
2006	3.50%	3.50%
2007	3.50%	3.50%
2008	3.50%	3.50%
2009	1.50%	1.50%
2010	1.50%	1.50%
2011	1.50%	1.50%
2012	2.00%	2.00%
2013	1.50%	1.50%
2014	1.50%	1.50%
2015	1.50%	1.50%
2016	1.50%	1.50%
2017	1.50%	1.50%
2018	1.50%	1.50%
2019	1.50%	1.50%
2020	1.50%	1.50%

Table 2.7: Load growth, 2005 - 2020

³² MIT Building Projects (<http://web.mit.edu/evolving/projects/index.html>)

Key assumptions in our model are the future fuel and electricity prices. Table 2.8 shows the values used in the projections.

Year	Electricity supply rate \$/MWh	Natural gas rate \$/MMBtu	Oil rate \$/MMBtu
2005	75.97	8.23	6.04
2006	79.22	7.78	6.35
2007	82.47	7.32	6.65
2008	83.03	6.99	6.35
2009	83.54	6.68	6.07
2010	83.99	6.38	5.79
2011	85.00	6.25	5.68
2012	85.97	6.12	5.56
2013	86.93	6.00	5.45
2014	87.85	5.88	5.34
2015	88.75	5.76	5.24
2016	89.61	5.65	5.13
2017	90.43	5.53	5.03
2018	91.23	5.42	4.93
2019	91.98	5.32	4.83
2020	92.71	5.21	4.73

Table 2.8: Energy cost rate, 2005 - 2020
(2005 USD)

For the electricity prices, from 1998 to February of 2005, MIT received the “standard offer service” provided by NSTAR which represented a transition generation service for customers that did not select a competitive supplier as of March 1, 1998 when the restructuring of the electric industry in Massachusetts started. The rates for this type of service were regulated by the Department of Telecommunications and Energy (DTE) and historically provided a 15 percent overall bill reduction. After February 2005, customers are required to choose either a “default service” provided by the utility company or a “competitive generation service” provided by competitive suppliers³³. Thus for year 2005, we took a simple average of the 2005 monthly default service price for Industrial Customers (see Table 2.9) of the Cambridge Electric Light Company reported by the DTE³⁴.

³³ Massachusetts, Department of Telecommunications and Energy, Electric Division, *Electric Restructuring in Massachusetts: Standard Offer Service* (<http://www.mass.gov/dte/restruct/competition/standardoffer.htm>)

³⁴ Massachusetts, Department of Telecommunications and Energy, Electric Division, *Electric Restructuring in Massachusetts: Default Service* (<http://www.mass.gov/dte/restruct/competition/defaultservice.htm>)

	Industrial customers
	\$/MWh
Jan - 05	88.92
Mar - 05	88.94
Apr - 05	79.98
May - 05	65.59
Jun - 05	65.09
Jul - 05	67.29

Table 2.9: Default service price for industrial customers, 2005

From the Vanderweil report, we took an electricity price of 82.47\$/MWh for year 2007 with the escalators for future prices shown in Table 2.10. For year 2006, we made an interpolation of the prices for 2005 and 2007. In general, as the electricity costs are a function of fuel costs and fixed assets values, the prices are expected to slightly increase as the demand for electricity increases.

For the natural gas and oil prices, we took the historical values for year 2004, and the predicted values for year 2007 from the Vanderweil report, as well as the escalators contained in it. For years 2005 and 2006 we made an interpolation of the values (see Tables 2.8 and 2.10). The cost the of the fuels in New England are expected to decrease over time because of the new gas infrastructure that will support an increasing demand of gas.

Year	Electricity	Natural gas	Oil
	%	%	%
2005	-	-	-
2006	-	-	-
2007	-	-	-
2008	0.68%	-4.50%	-4.50%
2009	0.61%	-4.50%	-4.50%
2010	0.54%	-4.50%	-4.50%
2011	1.20%	-2.00%	-2.00%
2012	1.15%	-2.00%	-2.00%
2013	1.11%	-2.00%	-2.00%
2014	1.06%	-2.00%	-2.00%
2015	1.02%	-2.00%	-2.00%
2016	0.97%	-2.00%	-2.00%
2017	0.92%	-2.00%	-2.00%
2018	0.88%	-2.00%	-2.00%
2019	0.83%	-2.00%	-2.00%
2020	0.79%	-2.00%	-2.00%

Table 2.10: Energy cost escalators, 2005 - 2020

2.3.2. UTILITY CASE: ALL ELECTRICITY BOUGHT FROM NSTAR AND STEAM GENERATED BY THE CUP

We constructed a theoretical case, where we used MIT's electrical and thermal loads and the escalators described in Tables 2.6 and 2.7. Then, we allocated the steam load among the boilers No.3, 4, 5, 7, and 8 according to their individual maximum capacities, totaling 380klb/h.

For calculating the fuel consumption of the boilers ($f_{boilers}$) in MMBtu, we used the following expression,

$$f_{boilers} = \frac{steam_{Campus}}{\eta_{boilers}}$$

where the campus steam load ($steam_{Campus}$) is in MMBtu, and the boiler efficiency values ($\eta_{boilers}$) for high load conditions are the ones shown in Table 2.11:

		Efficiency	% Load
Aux boilers 3,4,5	%	80%	Over > 70%
Temp boilers 7,8	%	82%	100%

Table 2.11: Boilers efficiency

For distributing the overall consumption among the several fuels, we used last year's ratio of consumption for natural gas and No.6 fuel oil of 9.26% and 90.74% respectively.

Contingency considerations arise if we analyze the projected peak steam demand of this case. The peak steam demand for year 2005 is estimated to be about 330klb/h, and the overall maximum capacity for the five boilers is 380klb/h. If the No.5 boiler trips off (with 100klb/h of capacity) the plant will not be able to provide for the remaining steam. Thus, a back up boiler is needed for reliability purposes in 2005³⁵.

Once we have calculated the estimations for future production data, we can calculate the operational costs of the plant given by the cost incurred in electricity, fuel, and non-fuel operation and maintenance (O&M). We also added the carrying capital costs associated to investments that our case would need for the operations to be feasible in the future.

First we estimated the electricity costs, assuming that the plant needs to buy its overall needs from NSTAR. The plant will be subject to G-3 rate, since its metered load will exceed 0.1MW for 12 consecutive months. We used the latest NSTAR rate effective from January 2005³⁶ and we used the escalators shown in Table 2.12 (a further explanation of each component will be presented in Chapter 4, Section 4.2).

³⁵ In 2011, the plant will experience steam capacity problems again. However, the extra backup boiler will not be a differential investment cost for the two analyzed cases.

³⁶ For details see Rate G-3, Large General Time-of-use, NSTAR Electric (http://www.nstaronline.com/customer_service/tariffs/3/233c.pdf)

		Rate	Escalator
Customer charge for G-3 rate	\$-month	90.00	0.00%
Distribution demand charge	over 100KVA \$/KVA-mo	1.47	Elec. costs esc.
Transition demand charge	1 st 100 KVA \$ month	121.87	Elec. costs esc.
	over 100KVA \$/KVA-mo	1.22	Elec. costs esc.
Transmission demand charge	1 st 100 \$ month	323.00	Elec. costs esc.
	over 100KVA \$/KVA-mo	6.18	Elec. costs esc.
Distribution Energy	\$/MWh	1.22	Elec. costs esc.
Transition energy charge	\$/MWh	0.00	n/a
Renewable energy	\$/MWh	0.50	Elec. costs esc.
Energy conservation	\$/MWh	2.50	Elec. costs esc.
Supplier - Default service rate	\$/MWh	75.97	Elec. costs esc.

Table 2.12: G-3 rate and escalators

For calculating the fuel purchase costs required to provide the campus steam, we took the prices for natural gas and residual No.6 fuel oil from Table 2.8.

Then we estimated the non-fuel productions costs, which represented the operation and maintenance labor and materials costs. For labor costs we used the current values of FY 2004 and subtracted the costs of additional personnel required by the operations of the cogeneration plant. For material costs, we used the values of FY 2004 and deducted the additional costs incurred in the parts and service contract for the turbine generator. For other costs, we used the FY 2004 values for water and sewage treatment and subtracted the incremental costs required by the operation of the cogeneration plant. Currently, the cogeneration plant uses the same closed-circuit system that the CUP used when it operated with only the boilers, and the operation of the plant produces slightly higher levels of leakage in the system because of the larger volumes of water from the water injections for NO_x control. So, for other costs in the "Utility case" we assumed the costs to be 10% less than those of the FY 2004. All values were adjusted by the Consumer Price Index (CPI) for year 2005 (Table 2.13 shows the values used in the model).

		Costs
O&M labor	\$/yr	2,575,071
O&M materials	\$/yr	1,546,325
Others - Water & Sewage	\$/yr	4,036,356

Table 2.13: Non-fuel operational and maintenance costs

As we mentioned earlier, the plant in "Utility case" will need a back-up boiler in year 2005. Therefore, we assumed an investment of \$6m for a 100klb/h capacity boiler in an existing building, with an economic life of 15 years³⁷. We assumed the financing structure and financial parameters shown in Table 2.14, values representative of the MIT cogeneration plant's current financing structure:

³⁷ In conversation with Roger Moore, Superintendent of Utilities, he estimated a capital cost of \$6m for a 100klb/h capacity boiler installed within an existing building of similar characteristics as those of MIT plant's building.

Tax rate	%	0%
Initial investment	\$	6,000,000
Equity	%	0%
Debt	%	100%
Return on Equity (real)	%	n/a
Return on Debt (real)	%	7.125%
Economic life	yr	15
Discount rate (real)	%	7.125%

Table 2.14: Financing parameters

Then, we calculated the carrying costs from 2006 until 2020, including interest and principal payments which were added up to the total operations costs of this case. Finally, those cash flows were discounted at a real rate of 7.125% and added together to get the Present Value (PV) of the costs of the project. Table 2.15 shows a summary of the results:

		Costs
Total electric purchase	\$	228,075,176
Total fuel purchase	\$	117,262,984
Total O&M	\$	73,717,031
Total operational costs	\$	419,055,191
Total debt payment	\$	6,000,000
NPV project	\$	425,055,191

Table 2.15: Summary of results for costs, 2006 - 2020

Finally, we calculated the Carbon Dioxide (CO₂) emissions for this case. It is important to mention that we need to consider not only the emissions coming from the boiler operations but also from the portion of electricity bought from NSTAR.

For boilers emissions, we used the following expression:

$$EB_{CO_2} = f_{boilers}^{NG} \times EF_{CO_2}^{NG} + f_{boilers}^{No.2} \times EF_{CO_2}^{No.2} + f_{boilers}^{No.6} \times EF_{CO_2}^{No.6}$$

where,

EB_{CO_2} = Total CO₂ emissions from boilers in Metric tons,
 $f_{boilers}^{NG}, f_{boilers}^{No.2}, f_{boilers}^{No.6}$ = Natural gas, No.2 and No.6 fuels burned by boilers in MMBtu,
 $EF_{CO_2}^{NG}, EF_{CO_2}^{No.2}, EF_{CO_2}^{No.6}$ = Uncontrolled CO₂ emission factors in Metric tons/MMBtu from stationary turbines for NG, No2. and No.6 according to Table 2.16³⁸.

³⁸ United States, Energy Information Administration, *Electric Power Annual 2003 - Data Tables and Illustrations - Table A.1 Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors* (<http://www.eia.doe.gov/cneaf/electricity/epa/epata1.html>)

	Factors [lb CO ₂ /MMBtu]	Factors [Metric ton CO ₂ /MMBtu]
CO ₂ emission factor for Gas	116.97	0.0531
CO ₂ emission factor for No.6 FO (Residual)	173.72	0.0788
CO ₂ emission factor for No.2 FO (Distillate)	161.27	0.0732
CO ₂ emission factor for Coal	225.13	0.1021

Table 2.16: Uncontrolled CO₂ emission factors

For calculating the CO₂ emissions that the local utility or competitive supplier will incur in providing the electricity to MIT, we used a general methodology for estimating those emissions. Thus, as shown in Table 2.17, we looked at NSTAR's energy portfolio as of March 2005³⁹ which is about 36% "carbon-free" (NSTAR, 2005):

Source	%
Coal	15%
Natural gas	35%
Oil	14%
Fossil	64%
Nuclear	27%
Hydro	6%
Other renewables	1%
Other sources	2%
"Carbon free"	36%

Table 2.17: NSTAR energy sources

Then, we assumed average efficiency values for coal-fired, natural gas-fired and oil-fired generation. For estimating these numbers, we looked at the typical values of efficiency for power generation plants, and we also looked the total electricity production from combustible fuels in electricity plants in U.S. from 1980 and 2001 (IEA, 2004, pp. II.666). Table 2.18 shows the range of values for each type of plant⁴⁰.

Power generation	Average efficiency
Coal-fired	34 - 37%
Natural gas-fired	33 - 37%
Oil-fired	34 - 38%

Table 2.18: U.S. efficiency for type of power generation

³⁹ We also looked at a second source, EIA, for determining this information. We aggregated the net generation by type of producer (electric utilities and independent power producers) by energy source for year 2004 for New England and we found the results similar to those provided by NSTAR. See "Appendix C: New England net generation by energy source, 2004" for a summary of these results.

⁴⁰ For our calculations we used efficiency values of 37% for coal-fired plants, 34% for natural gas-fired plants, and 38% for oil-fired plants.

We had to take an average value for the transmission and distribution losses in the U.S. The value ranges between 9% and 10% of the gross generation of electricity^{41,42}, so we will assume for the analysis 9.5% (OETD, 2003) (EIA, 2004, pp. 219).

Thus, for the utility CO₂ emissions we used the following expression:

$$EU_{CO_2} = P^{NSTAR} \times ER \times \frac{1}{1 - L^{US}} \times \left[ES^{COAL} \times \frac{1}{\eta^{COAL}} \times EF_{CO_2}^{COAL} + ES^{NG} \times \frac{1}{\eta^{NG}} \times EF_{CO_2}^{NG} + ES^{OIL} \times \frac{1}{\eta^{OIL}} \times EF_{CO_2}^{OIL} \right]$$

where,

- EU_{CO_2} = Total CO₂ emissions from utility in Metric tons,
 P^{NSTAR} = Remaining electrical load that MIT buys from NSTAR in MWh,
 ER = Energy rate equal to 3.4128MMBtu/MWh,
 L^{US} = U.S average value for transmission and distribution losses in %,
 $ES^{COAL}, ES^{NG}, ES^{OIL}$ = Proportion of energy sources within NSTAR portfolio in % according to Table 2.17,
 $\eta^{COAL}, \eta^{NG}, \eta^{OIL}$ = U.S. average efficiency values in % for coal, natural gas, and oil fired power generation plants according to Table 2.18,
 $EF_{CO_2}^{COAL}, EF_{CO_2}^{NG}, EF_{CO_2}^{OIL}$ = Uncontrolled CO₂ emission factors in Metric tons/MMBtu from stationary turbines for Coal, NG, Oil (No.6) according to Table 2.16.

Finally, we estimated the cumulative CO₂ emissions for the period 2006 to 2020. The summary of the results is shown in Table 2.19 below:

CO ₂ emissions		Average per year [Metric ton CO ₂ /yr]	Cumulative 2006-2020 [Metric ton CO ₂]
From boilers	Gas	11,365	170,479
	No.6	165,495	2,482,431
Total from boilers		176,861	2,652,911
From purchased electricity	Gas	49,037	735,558
	No.6	26,064	390,967
	Coal	37,169	557,538
Total from utility		112,271	1,684,064
TOTAL boilers & utility		289,132	4,336,975

Table 2.19: Summary of results for CO₂ emissions

For details of the calculations see “Appendix B: Utility case - Electricity bought from NSTAR /steam generated by CUP”.

⁴¹ According to the OETD, the U.S - wide transmission and distribution losses during 2001 accounted for 9.5%.

⁴² According to the EIA, the U.S - wide transmission and distribution losses during 2003 accounted for 9.00%.

2.3.3. COGENERATION CASE: STEAM AND MOST ELECTRICITY GENERATED BY THE CUP

The second case is based on the current operational characteristics of the cogeneration plant supplemented by the boilers and by power purchased from the utility. Based on the past performance of the plant, reviewed in section 2.2.2, we will project the operations of the facilities until year 2020.

The electricity load demand will be supplied, in part, by the CGT and the remaining needs will be purchased from NSTAR. We assumed CGT to operate in a base-load mode with the following parameters (Table 2.20):

CGT capacity without auxiliary services	kVA	19.5
Power factor	%	98%
Auxiliary services	%	5%
Maintenance	%	9.59%
Emergency	%	0.23%
Capacity factor	%	90.2%

Table 2.20: CGT parameters

We assumed 5% in auxiliary services for the plant's own electrical needs, and 98% for the plant's power factor. Also, according to data from past operations, the plant will need to stop 35 days/yr for maintenance service, and it may have 20 hours of unscheduled emergency situations per year. Thus, the capacity factor of the plant was calculated taking into consideration these two factors. The electricity generated by CGT for each year will be 154,087MWh.

Since, the MIT load is larger than the power the plant can provide, there are three services that it needs to contract from the local distribution utility: supplemental, maintenance and standby services⁴³. The provisions contained in each closed-rate are applicable to MIT. For new customers, new rates will be applicable.

a. Supplemental service.

The service is provided to those customers, such as MIT, that have an alternative source of power. Supplemental power is delivered when the power coming from the customer's plant is less than its maximum electrical load. This service includes a supplemental demand ($D^{Supplemental}$) and supplemental energy ($P^{Supplemental}$) calculated as follows:

$$D^{Supplemental} = D^{Peak} - D^{Contract}$$

where,

D^{Peak} = Monthly average of the campus maximum demand load in kVA,

⁴³ NSTAR Electric - Cambridge Electric Light Company's rates SS-1 M.D.T.E. No.239D, MS-1 M.D.T.E. No.238D, and SB-1 M.D.T.E. No.237D.

$D^{Contract}$ = Maximum firm replacement demand that the customer can take from NSTAR in case alternative power is less than the expected. Historically MIT has contracted 19,500kVA per month of capacity.

$$P^{Supplemental} = P_{Campus} - P_{CGT}^{Max}$$

where,

P_{Campus} = Total annual campus energy load in MWh,

P_{CGT}^{Max} = Maximum energy CGT can provide in MWh with capacity factor of 100%.

b. Maintenance service.

The maintenance service provides capacity ($D^{Transmission}$) in kVA and energy ($P^{Maintenance}$) in MWh to the customer to replace the output that is normally generated by its own plant when the facility is withdrawn from service for scheduled maintenance. The quantities that the cogeneration plant will require were calculated as follow:

$$D^{Transmission} = D^{Contract}$$

The charge related to this service will be allocated once per month, either to the maintenance or the standby service. Thus, if the plant requests maintenance service in a particular month, then the transmission capacity charge ($D^{Transmission}$) will be added to this service only. On the other hand, if the plant requests standby service, the charge will be added to this service instead. For simplification of the model, we allocated the transmission capacity charge under the maintenance service for all the years.

Maintenance energy charge ($P^{Maintenance}$) was calculated as follows,

$$P^{Maintenance} = MF \times P_{CGT}^{Max}$$

where,

MF = Maintenance factor that accounts for 9.59% of the time during one year for scheduled maintenance tasks,

P_{CGT}^{Max} = Maximum energy CGT can provide in MWh with capacity factor of 100%.

c. Standby service.

This service provides to the customer a replacement supply power when its own plant is either partially or totally unavailable. The service includes replacement capacity ($D^{Transmission}$) in kVA and energy (P^{Energy}) in MWh. The quantities used in the case were calculated as follows:

$$D^{Transmission} = D^{Contract}$$

As we stated above, this charge will depend on whether it was already included in the maintenance service. It is important to point out that the local utility company will charge for this service either through maintenance or standby service.

There is a second transmission capacity charge ($D^{Reservation}$) in kVA that will be the greater of the “peak transmission capacity” (TC^{Peak}) or the “transmission capacity reservation” ($TC^{Reservation}$) charges whose capacities will be given by the contract demand.

$$D^{Reservation} = \begin{cases} TC^{Peak} & , \text{ peak hours} \\ TC^{Reservation} & , \text{ off - peak hours} \end{cases}$$

The main difference between these charges will be the time when each of them is allocated to the plant. If the facility is unavailable during peak hours⁴⁴, then the peak transmission capacity will be charged. Historically, the plant has had this type of event at least once or twice per year of 10 hours long each, so we assumed for our model the latter one. For the remaining 10 months of the years, the minimum monthly charge will be the transmission capacity reservation charge.

Then, the emergency energy charge ($P^{Emergency}$) in MWh was calculated as follows,

$$P^{Emergency} = EMF \times P_{CGT}^{Max}$$

where,

EMF = Emergency factor that accounts for 0.23% of the time during one year for unscheduled unavailability of the plant,

P_{CGT}^{Max} = Maximum energy CGT can provide in MWh with capacity factor of 100%.

Once we established the campus electricity needs for each service, we need to estimate the portion of steam that will be provided through the CHP and the boilers.

Since the CGT will be operating in a base-load mode at a capacity factor of 90.2%, it will provide for the unfired steam to the HRSG unit up to 828,121MMBtu per year. Then, using the supplemental firing, the HRSG will additionally supply 496,873MMBtu/yr. Therefore, the total steam provided by the HRSG will be 1,324,994MMBtu for each year of the analysis.

The remaining steam will be met with the boilers No.3, 4, and 5. In case of emergency situations, boilers No.7 and 8 will be operated subject to their individual capacity constraints.

As we already explained for the “Utility Case”, we need to take into consideration contingency situations. The total capacity of the facility is 540klb/h (HRSG and boilers), so if the CGT trips off (160klb/h) the remaining boilers will have the necessary capacity to supply the steam until year 2010 when the peak steam demand is almost 380klb/h. Hence, starting year 2011 the plant

⁴⁴ Peak load period for eastern daylight savings time is from 9am-6pm, Monday-Friday. For eastern standard time it is from 4pm - 9pm, Monday - Friday.

will require the installation of a back-up boiler. However, since the same situation occurs with the “Utility Case”, we did not analyze the extra investment because it is not a differential cost.

With the electricity and steam quantities, we were able to estimate the consumption of fuel for each equipment within the facility.

For calculating the fuel consumption of the CGT (f_{CGT}) in MMBtu, we used the following expression:

$$f_{CGT} = \frac{P_{CGT} \times HHR}{1,000}$$

where,

P_{CGT} = Electricity generated by the CGT in MWh per month,
 HHR = Electrical high heat rate of the turbine as shown in Table 2.21.

The HRSG fuel consumption (f_{HRSG}) in MMBtu was calculated as follows,

$$f_{HRSG} = \frac{steam_{supplemental}}{\eta_{HRSG}}$$

where,

$steam_{supplemental}$ = Steam generated by the HRSG through supplemental fired in MMBtu.
 η_{HRSG} = HRSG efficiency for high load conditions as shown in Table 2.21.

Table 2.21 shows the values for each parameter,

		Efficiency
CGT electrical HHR	Btu/KWh_th	12,800
HRSG No.6	%	90%

Table 2.21: CGT and HRSG parameters

For fuel consumption of the boilers, we used the same expression, efficiency values and fuel ratios we used in the “Utility Case”.

We need to point out that currently MIT’s plant has two gas contracts. The first one is a 20 year contract for 5,500MMBtu/day with Commonwealth Gas Company (NSTAR Gas Company), finishing in 2016. The second one is a 12 year contract for 1,500MMBtu/day with Distrigas, finishing in 2016 also. Therefore, the total facility’s gas consumption will be limited by these contracts to a maximum of 2,555,000MMBtu per year. The remaining fuel needs will be met using No.2 or No.6 fuel oil; in particular, for our model, the boilers will need to burn more oil than historically.

With the estimation of the production data, we are able to calculate the efficiencies related to the operation of the plant. First, the efficiency for the CHP application (η_{CHP}) in % considers the electrical and thermal energies in MMBtu generated in the CGT (q_{CGT}) and HRSG (q_{HRSG}) systems, and the input of fuel burned in both systems (f_{CGT} and f_{HRSG}) also in MMBtu:

$$\eta_{CHP} = \frac{q_{CGT} + q_{HRSG}}{f_{CGT} + f_{HRSG}}$$

Second, we also calculated the overall efficiency of the CUP (η_{CUP}) in % considering not only the CGT and HRSG but also the thermal energy ($q_{Boilers}$) and fuel consumption ($f_{Boilers}$) of the boilers in MMBtu:

$$\eta_{CUP} = \frac{q_{CGT} + q_{HRSG} + q_{Boilers}}{f_{CGT} + f_{HRSG} + f_{Boilers}}$$

Finally, the efficiency of the facility according to PURPA requirements (η_{QF}^{PURPA}) to be certified as a “qualifying cogeneration facility” was calculated according to,

$$\eta_{QF}^{PURPA} = \frac{q_{CGT} + \frac{1}{2}q_{HRSG}}{f_{CGT} + f_{HRSG}}$$

which needs to be greater than 42.5% (additional PURPA requirements will be explained in more detail in Chapter 4).

The summary of these results is shown in the following table:

		Efficiency
CHP efficiency	%	73.3%
CUP efficiency	%	74.0% - 75.1%
QF efficiency	%	47.1%

Table 2.22: Estimated efficiencies

Once we projected the production data, we can calculate the operational costs of the facility incurred in electricity purchase and generation, fuel and non-fuel O&M.

As we mentioned earlier, MIT needs to buy that portion of electricity not covered by the CGT. NSTAR will provide three services each subject to specific provisions and rates. The supplemental service will be subject to G-3 rate, the maintenance and standby services will be subject to the current rates applicable to MIT with the escalators shown in Table 2.23⁴⁵.

⁴⁵ For details see NSTAR Electric, Rate SS-1

(http://www.nstaronline.com/customer_service/tariffs/3/239d.pdf), Rate MS-1

(http://www.nstaronline.com/customer_service/tariffs/3/238d.pdf), and Rate SB-1

(http://www.nstaronline.com/customer_service/tariffs/3/237d.pdf).

		Rate	Escalator
Customer charge for suppl/maint/standby	\$-month	511.00	0.00%
Administrative charge for suppl/maint/standby	\$-month	270.00	0.00%
Capacity charges:			
Maintenance transmission capacity charge	\$/KVA-mo	1.32	Elec. costs esc.
Standby transmission capacity charge	\$/KVA-mo	1.32	Elec. costs esc.
Greater of Standby peak transmission capacity charge	\$/KVA-mo	9.23	Elec. costs esc.
Or, Standby transmission capacity reserve charge	\$/KVA-mo	1.22	Elec. costs esc.
Energy charges:			
Distribution Energy	\$/MWh	1.22	Elec. costs esc.
Transition energy charge	\$/MWh	0.00	n/a
Renewable energy	\$/MWh	0.50	Elec. costs esc.
Energy conservation	\$/MWh	2.50	Elec. costs esc.
Supplier - Default service rate	\$/MWh	75.97	Elec. costs esc.

Table 2.23: Maintenance and standby rates for MIT (closed rate)

Table 2.24 shows a summary with the 2005 present values of the electricity costs from 2006 to 2020 for each category of service:

		Costs
Total electric supplemental purchase	\$	63,503,734
Total electric maintenance purchase	\$	16,553,328
Total electric emergency purchase	\$	4,705,788
Total electric purchase	\$	84,762,850

Table 2.24: PV electricity costs

As with the “Utility case”, for estimating the overall fuel cost we took the prices for natural gas and No.6 fuel oil from Table 2.8. We have to consider not only the fuel consumption from the boilers, but also the fuel used by the CGT and the HRSG to provide for the additional steam and electricity. Table 2.25 summarizes the 2005 PV of the estimated fuel costs from year 2006 to 2020.

		Costs
Natural gas purchase for CGT, HRSG and boilers	\$	146,970,771
No.6 purchase for boilers No.3, 4, 5	\$	29,014,103
No.2 purchase for boiler No.7	\$	-
Total fuel purchase	\$	175,984,875

Table 2.25: PV fuel purchase costs

For estimating the annual non-fuel O&M costs we used those from the FY 2004. The same approximation was made for the costs incurred in water and sewage treatment. All the values were adjusted by the estimated 2005 CPI (Table 2.26 shows the values used in the case).

		Costs
O&M labor	\$/yr	3,036,321
O&M materials	\$/yr	2,547,955
Others - Water & Sewage	\$/yr	4,484,840

Table 2.26: Non-fuel operational and maintenance costs

Finally, with the electricity, fuel and O&M costs we can calculate the total operational costs for the “Cogeneration case”. The cash flows were discounted at a real rate of 7.125% and added to get the PV of the operational costs. Table 2.27 shows the summary of the results:

		Costs
Total electric supplemental purchase	\$	63,503,734
Total electric maintenance purchase	\$	16,553,328
Total electric emergency purchase	\$	4,705,788
Total electric purchase	\$	84,762,850
Total fuel purchase	\$	175,984,875
Total O&M	\$	90,988,956
NPV costs project	\$	351,736,680

Table 2.27: Summary of results for costs

As we did with the “Utility case”, we estimated the CO₂ emissions coming from the CHP and boilers, and also the emissions NSTAR incurred to provide for the additional electricity. We used the same mathematical expressions employed in section 2.3.2, as well as the values for emission factors contained in Table 2.16. For NSTAR’s CO₂ emissions, we used the same methodology used in the previous section but now with the fraction of electricity that MIT needs buy to meet its total demand.

We estimated the cumulative CO₂ emissions for the period 2006 and 2020. Table 2.28 shows the summary of the results:

CO ₂ emissions		Average per year [Metric ton CO ₂ /yr]	Cumulative 2006-2020 [Metric ton CO ₂]
From CHP and boilers	Gas	135,560	2,033,397
	No.6	49,457	741,854
Total from CHP and boilers		185,017	2,775,251
From purchased electricity	Gas	17,301	259,512
	No.6	9,196	137,937
	Coal	13,114	196,704
Total from utility		39,610	594,153
TOTAL CUP & Utility		224,627	3,369,403

Table 2.28: Summary of results for CO₂ emissions

For details of the calculations see “Appendix D: Cogeneration case - Steam and most electricity generated by CUP”.

2.4. ANALYSIS OF RESULTS

With the results from the previous section, we are able to compare both cases. In general, we can observe that the “Cogeneration case” is the better alternative under the assumed market and regulatory conditions. The “Utility case” has higher operational costs because of the high electricity supplier costs that keep increasing in the future. Even though the fuel purchase costs are lower than those of the “Cogeneration case”, still the boilers need to burn large quantities of fuel to provide for the campus’ steam. In this particular point, it is clear the benefits the CHP provides to the system is the advantage of the CGT waste steam. This feature makes possible a lower utilization rate of the boilers and the subsequent reduction of fuel consumption for steam purposes. From Table 2.29 we can observe that the PV of operational savings from 2006 to 2020 of the “Cogeneration case” with respect to the “Utility case” is close to \$73m.

		Utility case (1)	Cogeneration case (2)	Savings (2-1)
Total electric purchase	\$	228,075,176	84,762,850	-143,312,326
Total fuel purchase	\$	117,262,984	175,984,875	58,721,891
Total O&M	\$	73,717,031	90,988,956	17,271,925
Total operational costs	\$	419,055,191	351,736,680	-67,318,511
NPV project 2006-2020	\$	425,055,191	351,736,680	-73,318,511

Table 2.29: PV of operational savings, 2006 - 2020

We also need to take into consideration the carrying capital costs of the Cogeneration project conceived in 1996. We will need to add them up to the operational savings flows from 2006 to 2020.

In 1995, the financing structure for the cogeneration plant project was the following⁴⁶:

Tax rate for a non-profit institution	%	0%
Initial investment	\$	48,477,265
Equity	%	0%
Debt	%	100%
Return on Equity (real)	%	n/a
Return on Debt (real)	%	7.125%
Economic life	yr	25
Discount rate (real)	%	7.125%
Indirect Cost Recovery (ICR) on interests	%	45%

Table 2.30: Financing parameters for cogeneration project

⁴⁶ Source: MIT’s Department of Facilities, Finance and Accounting.

The initial investment considered the installation and construction costs of the cogeneration plant, contingency costs and interest during construction⁴⁷. Because of the new plant, there were maintenance jobs that were deferred such as the construction of a 2.3kV substation, the upgrade of the boiler controls, flame safety system and chiller control upgrade. The total project capitalization was \$51.804m; when subtracting the deferred maintenance costs of \$3.326m we have a total investment cost of \$48.477m.

The investment was 100% financed through a “30 year taxable-bond”, 7.125% real rate of return. It was sold by MIT in November 1996. At that time, MIT analyzed the alternative of issuing a tax-exempt bond which is common practice for non-profit institutions. However, the analysis took into consideration the possibility that the cogeneration plant could sell part of the production back to NSTAR.

Even though MIT is a non-profit institution, depreciation has been required for this type of organization since 1998 for accounting purposes. Thus, the chosen depreciation method was a 25 year straight line one. Since the corporate tax rate for MIT is 0%, there is no effect on tax savings due to depreciation.

Because research sponsors pay a fraction of indirect costs, such as light and heat, MIT receives a reimbursement between 40% and 50% on the interest rate. We assumed in our model an Indirect Cost Recovery (ICR) to be 45% on interest.

The rate for discounting the project was assumed to be the same used for the rate of return on the debt.

Finally, according to this financing structure, we estimated MIT’s annual debt payment to be about \$4,206,809/yr, including interest and principal payment until year 2020. Thus, to the operational savings that the “Cogeneration case” represents in comparison to the “Utility case”, we needed to add the debt payment and the indirect recovery cost on the annual interest payments. The annual cash flows were discounted using a 7.125% real interest rate, and added together to get the final PV of the project (see Table 2.31 for a summary of the results).

		PV 2006-2020
Operational savings	\$	73,318,511
Total debt payment	\$	(38,014,575)
Net cash flow	\$	35,303,936
Indirect Cost Recovery	\$	7,665,880
NPV project	\$	42,969,816

Table 2.31: Summary of results for costs

⁴⁷ Interest during construction accounted for \$3,103,603

Regarding the CO₂ emissions benefit that the “Cogeneration case” represents, we calculated the cumulative benefits from year 2006 to 2020. Table 2.32 shows a summary of the results.

Cumulative 2006-2020 [Metric ton CO ₂]		Utility case (1)	Cogeneration case (2)	Benefits (2-1)
From CHP and boilers	Gas	170,479	2,033,397	
	No.6	2,482,431	741,854	
Total from CHP and boilers		2,652,911	2,775,251	122,340
From purchased electricity	Gas	735,558	259,512	
	No.6	390,967	137,937	
	Coal	557,538	196,704	
Total from utility		1,684,064	594,153	(1,089,911)
TOTAL CUP & utility		4,336,975	3,369,403	(967,571)

Table 2.32: Summary of results for cumulative CO₂ emissions, 2006 - 2020

The “Cogeneration case” releases almost 1,000,000 metric tons less CO₂ emissions than the “Utility case”, which in average is almost 65,000 metric tons per year representing a net 22% reduction in CO₂ emissions. While significant, it is substantially less than what might be anticipated based simply on the net CHP system efficiency of around 70%. Many factors enter into this, including the relatively low CGT efficiency of 27% and the utility mix of fuel (about a third “carbon-less” fuels and about a third natural gas).

For details of the results and calculations see “Appendix E: Comparison Cogeneration and Utility cases”.

3. COMBINED HEAT AND POWER

As we have analyzed in the MIT case, combined heat and power applications (CHP) can bring significant economic and environmental benefits. When assessing the future installation of CHP units, developers need take into consideration not only their thermal and electrical load profile, but also the supporting physical infrastructure, and the coordination and integration that the DE unit will have with that system. Once developers have these issues in mind, they will need to evaluate what type of CHP technology is the most suitable for their needs, and whether that alternative will be cost-effective in the long run.

In this chapter we will analyze the salient features of CHP and of three prime mover technologies, along with their advantages and disadvantages. Also, we will outline the current technical barriers that small and medium size organizations encounter when they initiate a DE project. We will finish by assessing quantitatively the benefits that technology improvements represent in our MIT study case.

3.1. CHP APPLICATIONS AND BENEFITS

As we mention in the Introduction, combined heat and power or cogeneration is a system that generates electricity and takes advantage of the heat to produce steam, hot water or chilled water. When thermal requirements of a particular facility are considered, on-site CHP applications have the potential of being a more attractive alternative than traditional centralized power production. As we reviewed in Chapter 2, MIT's cogeneration facility offers not only economic advantages, but also environmental benefits over the "Utility case".

As shown in Diagram 3.1, in CHP systems the power is produced by a prime mover technology. This is a device that converts fuel or heat energy into mechanical energy which will be used to run generators or motors. The heat produced is a by-product of the process, and so instead of being wasted in the conversion process it is captured and used for other thermal applications. Normally, a heat recovery system is used for capturing and using the waste heat, providing for additional thermal energy that will be used for other processes.

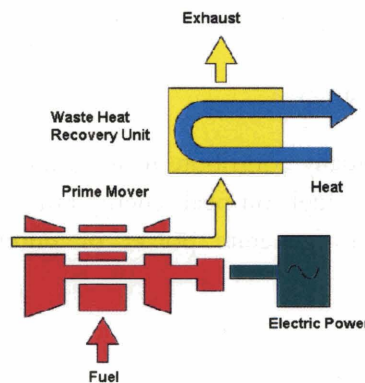


Diagram 3.1: CHP basic operation

Cogeneration can be applied to a series of applications ranging from hot water, steam, chilled water, space heating, to electricity. Applications may include small units that serve apartment buildings, health clubs to large units serving industrial and manufacturing facilities, refineries, hospitals, military facilities, hotels, universities, and other industrial, institutional or commercial applications. As with MIT's case, the facilities can produce part of their electrical and thermal needs, while still purchasing that portion of the electricity from the utilities to balance out their loads. Also, they can export electricity to the grid in some periods when they are generating more power than they need, although this requires a more sophisticated engineering design of the facility and interconnection infrastructure, as well as resolution of regulatory and legal issues.

Electricity cogeneration can be applied for base-load, load peak shaving and back-up operations (Kolanowski, 2003, pp. 458-471). For base-load operation, an effective use of the recovered heat is key for achieving appropriate overall efficiencies and this type of operation is preferred when the facility has a year round high load factor. For load-peak operation, it is important to have in mind the seasonal and time of use variations of the facility's electricity. In this particular case, the electric power production is used mostly in peak periods for reducing peak demand charges, or for back-up services in emergency cases where the power supply may be interrupted – critical for research institutions and life sustaining operations, for example.

Finally, among the potential benefits that CHP systems can provide, we can mention:

a. Higher overall efficiency and reduction of air emissions.

From a single fuel two or more energy sources can be generated, so this simultaneity in the production of electricity and thermal energy improves the total net efficiency of the facility and lessens the pollutants emitted into the atmosphere. On-site typical efficiency ranges between 75 and 85%, whereas the efficiency of delivered power⁴⁸ provided by central power stations will be between 28 and 38% (Kolanowski, 2003, pp. 31).

b. System reliability and power quality improvements.

Currently the U.S. electrical grid has a reliability factor of 99.7% – almost three “9’s” – while hospitals require at least four “9’s”, and e-commerce demands at least six “9’s” with high standards for power quality to operate efficiently sensitive electronic equipment.

c. Alternative load-management strategy.

A peak shaving strategy can eventually contribute to lowering the electricity costs, especially in areas with high demand charges or high on-peak energy rates. On-site CHP can also offer the flexibility of choosing whether to generate power or purchase it, depending on market conditions.

⁴⁸ Taking into consideration transmission and distribution losses.

d. Reduction of transmission and distribution losses, when connected to the electrical grid.

High voltage transmission systems have efficiency losses between 4% and 10%, and under high load conditions and elevated temperatures, this may increase up to 15% (Kolanowski, 2003, pp. 30). Transformers also contribute between 2% and 10% additional efficiency losses.

e. Reduction of congestion problems.

Particularly in congested “load pockets”, where generation supply is low and transmission capacity is inadequate, congestion problems may yield expensive electricity prices at the consumer side with consequent extremely high congestion charges.

However, on-site power generation may not be suitable for all facilities. As we analyzed for MIT’s cogeneration facility, diverse factors need to be taken into consideration before adopting this type of technology. Issues such as the specific site conditions, the particularities of the prime mover technologies and auxiliary services, and whether these are appropriate for the operational characteristics of the facility, need to be analyzed before adopting a CHP system

3.2. CHP TECHNOLOGIES

Since cogeneration can use a wide range of technologies, we will only describe three prime mover technologies – generation power sources – that are or are becoming commercially available: i) internal combustions engines (ICs), ii) combustion gas turbines (CTs), and iii) high temperature fuel cells. The first two approaches base their operations on the combustion of fossil fuel where the produced heat is converted into a mechanical rotation that spins an electric generator. The other approach is based on a chemical reaction that produces DC current that later is converted to AC power. All these technologies are under development programs to enhance their performance through better efficiency and lower emission levels at reasonable costs (CECA, 2001, pp. 26).

In Table 3.1 we can see the main parameters of each commercially available CHP technology (CECA, 2001). For a detailed description of the characteristics of each technology, refer to “Appendix F: Description of prime mover technologies”.

Parameter		Diesel engine	Natural gas engine	Combustion gas turbine	Phosphoric acid electrolyte fuel cells
Capacity	MW	0.05-5	0.05-5	3-200	0.2-2
Electric efficiency	%	28-50	23-45	20-40 simple 40-60 combined	30-40
CHP capital cost	\$/kW	500-1,000	600-1,200	650-900	>3,000
O&M cost	\$/kWh	0.005-0.010	0.007-0.015	0.003-0.008	0.005-0.010
Availability	%	90-95	92-97	90-98	>95
Start-up time		10sec	10 sec	10 min-1 hr	3 hrs-2 days
Noise		high	high	moderate	low
NOx emissions	lbs/MWh	3-33	2.2-28	0.3-4	<0.02

Table 3.1: Commercial CHP technologies comparison

In general, IC engines have higher full and part-loaded simple-cycle thermal efficiencies than do CTs, while CTs are particularly sensitive to changes in ambient air conditions with the consequent efficiency and power output degradation. ICs are usually available for small capacity applications, while CTs are commonly used for applications larger than 22MW. CTs have a high quality exhaust that can be used to increase the production of high-pressure steam for other high-temperature applications. CTs usually have lower initial and maintenance costs than other technologies. Despite the high initial capital costs of fuel cells, their operations are almost air emissions-free with attractive efficiency levels, low maintenance, quiet operation, and an expected lifetime between 10,000 to 40,000 hours or more as the technology matures (CECA, 2001, pp. 27,36).

3.3. TECHNICAL BARRIERS

As we outlined in the previous section and in Appendix F, each technology has disadvantages that make some of them immature and not ready for widespread market penetration. IC engines can be very noisy, produce high levels of vibration, emit large amounts of particulates when using diesel fuel, and generate a poor quality waste heat. CTs require specialized knowledge necessary for maintenance, have low efficiency levels for small gas turbine and if operated under partial load mode. Finally, fuel cells have high capital costs, can be very sensitivity to fuel impurities, and also require specialists for maintenance and repair purposes.

Manufacturers and research programs are constantly looking for enhancing their performance at reasonable costs. Thus for those already commercial technologies new developments are being targeted to cleaner and quieter systems such as natural gas packaged IC engines and emission control technologies; and modular and more flexible technologies suitable for diverse sizes such as gas microturbines. In addition, most of the research on fuel cells is aimed at making this technology cost effective and readily available for large deployment. Other issues of concern for combustion turbines and fuel cells, is the lack of knowledgeable technicians and networked service programs able to perform overhauls in a straightforward way, as is the case for ICs.

Besides the technical issues particular to each prime mover technology, interconnection to the electrical grid is one major technical barrier for DE developers. The reason is rooted in reliability, safety, and power quality issues that the local utility must guarantee. New sources of generation close to load at the consumer side and connected to the grid, have effects not only on the distribution system but also on the bulk transmission network. New energy transactions need to be supported by a robust physical infrastructure that includes protective and auxiliary equipment, control and monitoring, metering, and efficient coordination between the local utility and the DE operator for a safe operation.

The interconnection process may become expensive and burdensome for non-utility owned onsite CHP systems, especially the smaller developers. The process will mostly depend on the local utility, where the requirements will increase with the size of the facility and the operating coordination with the grid. In this regard, a parallel operation with a combination of DE and grid connection will pose the greatest challenges in the interconnection process.

Additional protective relay or utility-testing requirements will increase the costs and the construction time of the projects. The same applies to pre-interconnection studies required by the utilities to evaluate the potential effects of a particular DE facility on the utility system, and whether upgrades are needed to accommodate that new generation (Alderfer et al, 2000). However, some states like New York and Texas⁴⁹ have limited the scope and costs of such studies, including issues such as time limit, size and connection mode of the facilities, estimation of the study costs, among others.

However, the utilities need to assure that the system, once connected to the grid, will properly work. This principle is applicable the other way around, since DE developers also need to make sure that their systems will keep running when failures or reliability problems occur on the utility side.

3.4. ANALYSIS OF CASE STUDY WITH EFFICIENCY IMPROVEMENTS

As part of the analysis, we quantified the effects that efficiency improvements have on the “Cogeneration case”. Particularly, we focused this sensitivity analysis on the operational savings and environmental benefits.

We looked at the combustion gas turbines commercially available in the market, and we found at least three turbines from manufacturers⁵⁰ with similar characteristics to that used by MIT’s cogeneration facility (see Table 3.2 below):

⁴⁹ As of May 2000.

⁵⁰ Particularly, we looked at the MS5001 from General Electric, SGT-600 from Siemens, and RB211-6562 from Rolls Royce.

Parameter		CT #1	CT #2	CT #3
Electrical output	MW	26.8	24.8	27.5
Electrical efficiency	%	28.4	34.2	36.2
Turbine speed	Rpm	5,090	7,700	4950
Heat rate	Btu/kWh	12,030	9,990	9,415
Exhaust gas T°	°C	480	540	500
Primary fuel		NG	NG	NG
Combustion system		DLE ⁵¹	DLE	DLE

Table 3.2: Technical parameters for combustion gas turbines

Each turbine is best designed for continuous operation, long life operations, easy maintenance and high reliability. All of them are provided with NO_x emission control systems when operating on natural gas, and steam or water injection when burning liquid fuel. These technologies can be used for cogeneration in industrial plants or district heating systems; and for power generation in either simple cycle or combined cycle operations.

MIT's combustion gas turbine has currently an efficiency of about 26.6% and, as we can observe from the table, the efficiency levels developed by these manufacturers for medium-size CTs technology have greatly improved over the past years. Thus, taking into consideration these efficiency levels, we quantified the additional benefits of the "Cogeneration case". In this analysis we did not change the CGT costs, or include the higher power ratings of the new models.

Using the same economic parameters of Chapter 2, we estimated the economic benefits of each case when compared to the "Utility case". We discounted back the yearly economic savings from 2006 to 2020, and we added them together to get the NPV of that savings for each case. For the environmental benefits, we calculated the difference of CO₂ emissions between each case and the utility case for each year, and we added them together to get a cumulative value for the whole time horizon.

⁵¹ Dry low emission combustion system.

In Table 3.3 we can see a summary of the results, where Δ denotes the results of that particular case when compared to the “Utility case”, and η symbolizes the electrical efficiency in each case. We also included in this summary an annual average of the CO₂ emission benefits.

		NPV savings [\$]	Total CO ₂ benefits [Metric ton CO ₂]	Annual CO ₂ benefits [Metric ton CO ₂ /yr]
Δ Cogen	$\eta=26.6\%$	42,969,816	967,571	64,505
Δ CT #1	$\eta=28.4\%$	49,691,488	1,074,038	71,603
Δ CT #2	$\eta=34.2\%$	67,773,960	1,324,216	88,281
Δ CT #3	$\eta=36.2\%$	72,832,346	1,394,201	92,947

Table 3.3: NPV savings and CO₂ emission benefits, 2006 - 2020

These results show a clear relationship between benefits and efficiencies. The better the efficiency, the greater the monetary savings and the lesser the CO₂ emissions. Further analysis should be made to find out how the costs of the turbines increases as efficiency levels improve.

However, we noticed that there is a decreasing marginal trend (see Figure 3.1) for both economic savings and environmental benefits. The greatest incremental benefits are realized for the first units of improvement with \$3.7M per 1% declining down to \$2.5M per 1%; and 60,000 Metric ton CO₂ per 1% down to 35,000 Metric ton CO₂ per 1%.

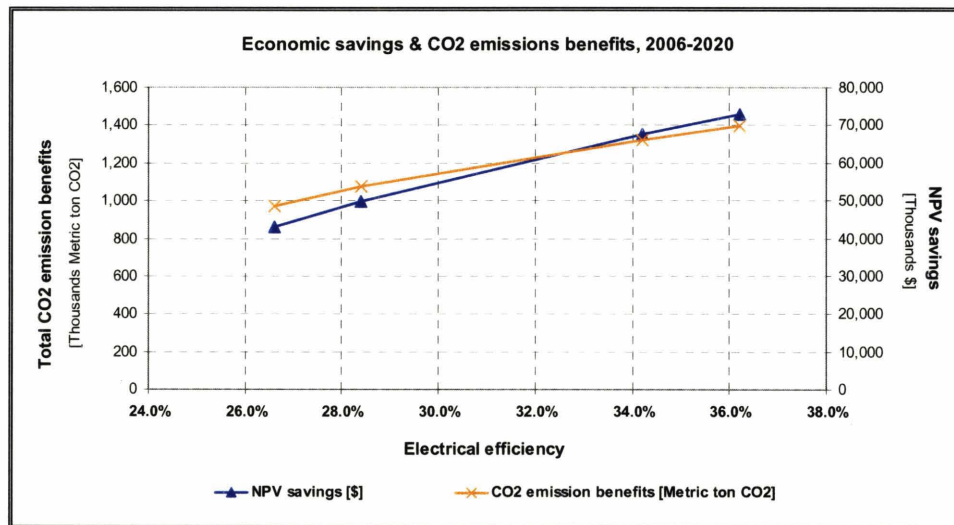


Figure 3.1: Efficiency sensitivity analysis

4. REGULATORY AND MARKET ENVIRONMENTS

Before recognizing some of the barriers that currently restrict the development of DE/CHP projects, we will outline the main issues that potential developers need to be aware of when dealing with either DE regulations in Massachusetts or market fuel price uncertainties. Then, we will discuss the main regulatory and market barriers for the development of DE resources.

Finally, we will finish this chapter analyzing quantitatively the impact of particular utility rates, market conditions – particularly natural gas price – and environment regulations on the attractiveness of DE projects.

4.1. REGULATORY FRAMEWORK

The regulatory framework for DE projects can be extensive and somewhat confusing. Regulations vary across the nation from state to state, and most of the time they will depend also on local requirements. Potential investors need to spend resources and time to find out what policies and regulations are applicable to the type of project they are planning to construct. The requirements may become burdensome, and frequently they may discourage the investment in DE technologies.

Particularly, future developers need to be well-informed about federal permits regarding distributed generation, as well as the regulations in the state and the incentives being provided to DE projects. In addition, they should know the electricity rates that utilities apply to self-generation customers within their servicing territory. Standby charges, stranded cost, and exit fees can be issues of special concern among DE developers, since they can clearly affect the cost-effectiveness of a project.

As we mentioned in Chapter 2, the past dispute between MIT and the local utility regarding stranded costs was seen by self-generating facilities as an explicit barrier of entry to the electricity market. The dispute lasted from 1995 until 2001 when the issue was finally settled in a direct agreement between the parties. During the process, MIT had to spend resources to be able to litigate for several years. Although, the issue related to stranded costs in Massachusetts has been settled through the restructuring process, smaller developers saw that dispute as a clear deterrent for DE projects in the region.

Finally, DE developers should be aware of the major environmental permits governing self-generation. Special focus should be on the entities involved and the permitting process that the projects need to follow.

In “Appendix G: Regulatory framework” we have included a detailed description of the main regulations that may affect the development of DE projects. We provide information regarding the Public Utilities Regulatory Policy Act (PURPA); and DE regulations, electrical utility rates, and environmental regulations in Massachusetts.

4.2. MARKET CONDITIONS

Market conditions may become highly uncertain especially when local and worldwide settings are constantly in flux. Future market projections are difficult to formulate, depending mostly on the underlying assumptions that the analysts adopt. Clearly, this unpredictability impacts investors' decisions as to what the proper opportunity is, if any, to embark on a project that may entail important initial costs and ongoing operational expenses.

As we reviewed earlier, particularly important within MIT's feasibility study were the projected energy prices – both electricity and fuel – that would directly impact the cost-effectiveness of the future cogeneration plant (to demonstrate the influence of variations in fuel prices in the economics of a project, we will make a sensitivity analysis of the “Cogeneration case” in the last section of this chapter). The 1992 plant's economic analysis projected natural gas prices for 2004 to be about \$5.2/MMBtu and \$3.2/MMBtu in nominal values without and with supply contract respectively, and No.6 oil price about \$5.2/MMBtu⁵². When we reviewed the prices paid by MIT over the last years⁵³ we found the following:

		2002	2003	2004
Gas price	\$/MMBtu	5.31	7.87	8.69
No.6 FO price	\$/MMBtu	3.66	6.03	5.73

Table 4.1: CUP average fuel costs, 2002 - 2004

(nominal USD)

As we can observe, the projected prices for natural gas were well below the levels MIT experienced over the last years. One of the reasons is that, at the time of the evaluation, the contracts for gas supply were still under negotiation with four gas companies. But most importantly, there was the inherent difficulty of estimating the future conditions of a market that currently is struggling to balance the supply and demand of natural gas and oil.

The spot prices for natural gas at Henry Hub and fuel oil had had important increments with respect to last year's values, with nominal increments of 24% and 50% respectively. These current levels are one of the highest over the last years, and this growing trend is expected to continue until 2006, at least.

The oil market has experienced significant price volatility with prices that have reached historic levels. According to EIA's projections, the scenario in the short-term has been recognized to be highly uncertain with the probability that current high oil prices trend will continue due to several factors such as: the sustained oil demand growth – both at worldwide and U.S. levels – which is projected to continue during this year and 2006; the potential demand from China for filling its strategic oil reserves at the end of this year (CNN, 2005); and the tight refining and shipping capacity that may restrict oil supply especially for meeting the upcoming winter peak demand – unlikely that new refineries will be built in the near future within the U.S. For the

⁵² \$3.52/MMBtu and \$2.17/MMBtu (1995 USD), using a 4.2%/yr fuel escalator rate and historical CPI for electricity.

⁵³ Prices extracted from MIT energy bills, years 2000 to 2004. Source: MIT's Department Facilities.

medium term, projections of crude oil prices indicate that they are expected to decline as new capacity is added in the Gulf of Mexico, West Africa and Canada, in addition to the expansion of the capacity in the Organization of the Petroleum Exporting Countries (OPEC) and Russia (EIA, 2005a) (EIA, 2005b).

Regarding the natural gas market, gas prices in the short term are projected to continue to increase due the upcoming summer cooling peak demand, as well as the winter heating season. This trend is supported by the continued strength of the economy with a sustained natural gas consumption, expected below normal Pacific Northwest hydroelectric resources through the summer, and flat domestic natural gas production. The increasing gas consumption has been driven, in part, by the addition of natural gas-fired generating power plants, a trend that is expected to continue in the future. However, medium-term projections show a decline of gas prices as drilling levels increase, new production capacity is added, and Liquefied Natural Gas (LNG) imports increase. In the long-term, higher exploration and development costs are likely to increase again the prices. The National Petroleum Council (NPC) has predicted that natural gas production from traditional North American sources will remain at the same level and they will be able to meet 75% of the domestic demand by 2025, requiring increase of the imports – especially through LNG infrastructure expansion – and gas coming from Alaska (National Commission on Energy Policy, 2004, pp. 4).

Particularly in New England, natural gas has become vital especially for heating purposes, industrial processes, and electricity generation. Regarding the latter, the reliance on natural gas accounted for more than 35% of the region's total generation during 2004 (see Appendix C) and it is expected to reach 50% or more in some areas by 2010, driven by the operation of new electricity generating plants. In addition, New England's natural gas prices have constantly been higher than the rest of the nation due to region's lack of native supply of natural gas, leaving it to rely on the transportation of that fuel from other areas and on LNG imports. Moreover, the current natural gas infrastructure has low spare capacity to deal with future demand growth or peak winter months. Therefore, increasing demand, price volatility and constrained pipeline capacity have led some entities in New England⁵⁴ to claim that additional natural gas supplies – either through LNG or pipeline upgrading/construction – are needed within the region before 2010 (New England Council, 2005, pp. 3).

4.3. REGULATORY AND MARKET BARRIERS

Having in mind the regulatory frameworks and the current market conditions, we can discuss some of the issues of concern regarding the development of DE resources. The interconnection and planning of DE resources brings into debate issues such as grid reliability and safety especially at the distribution level; exit fees and rates charged to the DE developers when they leave the grid; electrical rate increases imposed on the remaining utility's customers; siting and environmental permitting requirements; and whether the market signals are appropriate for developing DE projects.

⁵⁴ FERC, the New England Governor's Conference, Governors of Massachusetts and Rhode Island, and the New England Council.

The DTE recognized that there may be technical, economic, and regulatory barriers to distributed generation, and it was particularly concerned that the “lack of uniformity and uncertainty regarding interconnection standards and back-up rates could be inhibiting the installation of distributed generation in Massachusetts” (D.T.E. 02-38, 2002, pp. 2). DE developers were faced with interconnection requirements that, depending on the type of interconnection, varied from utility to utility.

On one hand, some interconnection requirements were recognized as too restrictive, imposing extra burdens in terms of costs and length on DE projects, especially on the small ones. On the other hand, distribution companies needed to guarantee the safety, quality and reliability of the operations of their systems when new facilities are interconnected into the grid. Thus, the DTE decided in June 2002 to investigate the development of state-wide interconnection standards and procedures for DE resources, as part of its investigation into distributed generation in Massachusetts. As a result, in October 2002 the DTE ordered⁵⁵ the Massachusetts distribution companies, along with other DE stakeholders, to start a collaborative process for proposing interconnection standards, policies and procedures that would be “uniformly applicable to all Distribution Companies” (D.T.E. 02-38-A, 2002). The Massachusetts Distributed Generation (DG) Collaborative was formed to develop that task, which submitted its recommendations to the DTE. In February 2004, the DTE released the final uniform interconnection standard (D.T.E. 02-38-B, 2004) to be adopted by the state’s distribution companies by April 2004⁵⁶.

Within this initiative, the technical requirements are based on national safety standards⁵⁷, the utilities are required to collect and track information on the interconnection process, and each utility is required to file a standard interconnection tariff. Regarding this last point, the standard is intended to provide an easier and less expensive process for small-scale, inverter-based technologies below 10kW to interconnect on radial systems with no application or study fees. For other facilities, the interconnection can either qualify for “expedited interconnection”, where the timeframes and fees are limited and the generators need a certification as a prerequisite⁵⁸, or “standard interconnection” review. The order is expected to provide a more streamlined and less expensive process for the interconnection of renewable and distributed energy systems within the state, and currently the Collaborative group is evaluating – until 2006 – the performance of the standards, and their compatibility with other state and national standards. According to the Massachusetts Distributed Generation Collaborative 2005 Annual Report (MA Distributed Generation Collaborative, 2005) “the Interconnection Process appears to be working well” as of March 31, 2005 in terms of timelines and costs, and one of the major causes for delays has been the submission of incomplete applications due to confusion among customers. However, we need to mention that from the information provided, the “simplified process” is the one with the most rates of acceptance, while in the “expedited and standard processes” most of the

⁵⁵ Fitchburg Gas and Electric Light Company, Massachusetts Electric Company and Nantucket Electric Company, NSTAR Electric, and Western Massachusetts Electric Company.

⁵⁶ Database of State Incentives for Renewable Energy (DSIRE), *Massachusetts Incentives for Renewable Energy* (<http://www.dsireusa.org/index.cfm>)

⁵⁷ IEEE 1547, IEEE 929, UL 1741.

⁵⁸ A registry with a list of the approved certified generators and equipment will be maintained by the Massachusetts Division of Energy Resources (DOER)

applications are still under review⁵⁹. Finally, the Collaborative group has been working mainly on interconnection standards, and further work is required for addressing standby service tariff, and the role of distributed generation with respect to the provision of service by the utility companies.

As we outlined in the beginning, other issues of concern refer to exit fees and back up tariff charges. In MIT's case, before it started the construction of the plant the Institute began litigation with the local utility company regarding "customer transition charges" (CTC). At that time, the DTE⁶⁰ approved the utility request for a CTC of \$5.62/kVA/month – about \$1.3 million a year – taking into consideration the utility's interests in recovering costs that it had made to serve its customers, and also the ratepayer's interests given the economic impact associated with MIT leaving the Cambridge system⁶¹. NSTAR argued that, among other reasons, CTC is a cost-based mechanism to "recover stranded costs directly from the customer who bears the responsibility for those costs being incurred", and the company's obligation to serve requires the utility to "plan its system to meet the existing and expected loads of all of its customers". On the other hand, MIT argued that it was already paying backup charges, that the fee represented an attempt to prevent self-generation, that Cambridge Electric Light Company (CELCo) knew for about 10 years about the Institute's plan, and that the plant was part of normal business risk. Therefore, MIT claimed that the utility company had enough time to plan its resources accordingly. In 1997, the Massachusetts Supreme Judicial Court reversed the DTE's approval of the CTC, and stated that such charges should not be paid by other potential DE developers being CELCo's clients⁶². However, we need to point out that exit fees should not be a problem in Massachusetts anymore, as current regulations do not allow charging of these fees to DE projects whenever their developers give a proper notice to the distribution companies.

Regarding backup tariff charges, the main concern rests on the proper level of costs that utilities should charge to the developers of distributed generation facilities, while providing an appropriate price signal to customers planning to install DE resources. On July 2004, the DTE approved a new standby service tariff for large and medium commercial and industrial customers that would install DE resources, to be effective August 2004 by NSTAR (D.T.E. 03-121, 2004). The order was not free of debate, since some entities⁶³ argued that the proposed rates did not represent the actual cost of standby service, that the DTE's rates approval will deter distributed generation in NSTAR's service territory, and that the exemptions contained in the provisions are discriminatory for those customers with similar load characteristics not being exempted. They also claimed that the standby rates should take into account both the costs and benefits of DG, and that the contract demand – a fixed level of demand – used in the tariff "implicitly assumed

⁵⁹ Taking into consideration all the applications for the three processes in terms of MW, 18.5MW of total DG capacity applied for interconnection, where 3.9MW were approved, and 14.5MW are in review process for the period Q2 2004 through Q1 2005.

⁶⁰ Formerly called Massachusetts Department of Public Utilities (DPU).

⁶¹ CELCo estimated an average rate increase of over 6%.

⁶² For details of the case refer to Massachusetts Department of Telecommunications and Energy, D.P.U. 94-101/95-36 (<http://www.mass.gov/dte/electric/95-36.pdf>)

⁶³ Particularly the New England Distributed Generation Coalition (NEDGC) formed by Aegis Energy Services, Inc., American DG, Inc., Equity Office Properties Trust, Inc., Northern Power Systems, Inc., OfficePower LLC, RealEnergy, Inc., Tecogen Inc., and Turbosteam Corporation; and TEC formed by the Energy Consortium, Harvard University, Polaroid Corporation, MIT, USG Corporation, and Shaw's Supermarket.

not only that all standby customers will require that service simultaneously, but also they will require it at the time of system peak” meaning that the contract demand is likely to cause over-recovery of the distributions costs. On the other hand, NSTAR argued that the rates were cost-based and that they did not violate any DTE or federal regulations. It also claimed that its distribution system is built to serve all customers and must be ready to serve them all, and that the company’s planning criteria for capacity is based on the unavailability of the customers at peak hours to provide for the necessary reliability. Finally, NSTAR claimed that the exemptions provided “tangible support for the important public policy objective of the development and promotion of renewable energy projects in the Commonwealth” (details of this new standby rate structure are outlined in next section).

Finally, environmental regulations may result in significant barriers for the development of DE projects. As with MIT’s case, the air permitting process included the participation of several agencies at the state and local levels, with a total time-span of between 6 to 15 months. The Institute finally obtained the DEP’s environmental permit in April 1992, and it was crucial for the project since the receipt of the approval allowed MIT to start construction of the plant. Additionally, the approval required an advanced combustion gas turbine with low NO_x combustion technology that, at that time, was not available by domestic turbine designers – a Swedish manufacturer was chosen for accomplishing the task.

In general, even though the permitting process is federally regulated, its implementation is administered mostly by the states, varying highly across the nation. It has been recognized that the process can be overwhelming especially for smaller developers who need to go into a variety of rules and regulations whenever they embark on a project. The requirements that the authorities require, such as environmental testing and expensive emission control technologies⁶⁴ tend to be basically the same required for larger projects, rendering the economics of the small ones unattractive – for example, NSR program applies to all sources regardless of the size of the project. At the local level, the permits and approval also vary considerably from town to town adding more confusion among potential DE developers.

Additionally, some case study reports have recognized that current regulations do not give the proper recognition to the benefits that CHP applications bring (Bluestein et al, 2002) (Alderfer et al, 2000). In the particular case of MIT, the CHP application represents an annual CO₂ emissions avoidance of about 65,000tons when taking into account the displaced emissions from off-site generation. However, either the displacement of older boilers – two 1950’s boilers were discontinued – or emissions displacement from utilities’ power plants, or the use of wasted gases for providing thermal energy are not recognized in the form of emission credits, as is the case for California and Texas.

Regarding the benefits associated to improvements in the overall efficiency that CHP applications bring out, it has been recognized that several cogeneration facilities are assessed based on combustion efficiency rather than the overall energy output efficiency, with no consideration of the thermal energy. For example, within Massachusetts policies some that try to

⁶⁴ Additionally, add-on NO_x control technologies (initially designed for large power plants) are too complex for small projects.

incentivize the development of renewables and DE, one of them refers to a performance standard based on the emissions produced per unit of electric output.

As with MIT's cogeneration facility, one of the major hurdles for DE projects come from meeting the state's more stringent NO_x standard. Particularly, MIT was concerned about the one-hour NO₂ standard applicable to sources of potential NO₂ emissions exceeding 250ton/yr. This restriction required the DEP's approval of cleaner and more expensive control technologies in a non-attainment area such as Massachusetts. This requirement clearly increases the final cost of a distributed generation project, as it involves advanced engineering design necessary to meet the air emissions constraints and post-operational tests to verify compliance with such regulations. In addition, an operating permit is required that lasts for 5 years and the renewable application process can take one year or longer.

Another issue of concern is the application of BACT that needs to be evaluated and negotiated on a case-by-case basis by the reviewing authority. The process starts with the most stringent technology that is established as the BACT, unless the applicant can demonstrate that it is not achievable. If necessary, the process continues with the second most stringent technology and so on (Bluestein et al, 2002). Therefore, this process involves several negotiations with the regulator – the same with LAER. The case-by-case evaluation it is relatively insensitive to the size of the project, impacting the economic viability of DE projects, especially the smaller ones.

It is important to mention that although MEPA establishes some criteria for energy projects that might require ENF, EIR and other MEPA review; projects that do not meet these thresholds can still be subject to MEPA review when asked by agencies or persons under a “fail-safe” provision, or when the project meets other criteria – for example the construction or modification of a major stationary source (DOER, 2001).

We need to point out that even though most of the emissions regulations are applicable to major sources – electric generating facilities above 25MW according to MEPA's review thresholds – a growing concern has been focused on smaller sources. IC engines, typically within this category, are being employed not only as backup power but also for other purposes with more hours of operation. This technology releases large amounts of particulates, especially when running with diesel fuel. Therefore, if a wider deployment and more hours of operation are expected, then larger emissions should also be expected.

Finally, market uncertainties may become an important deterrent when deciding the construction of DE projects. Current conditions are not the most suitable for natural gas and oil-fueled distributed generation facilities, and it may be more economic for potential developers to buy the electricity than produce it. Since the increasing price trend is expected to continue at least until 2006, the expectations for investments in oil and gas-fired DE resources are extremely low in the short term⁶⁵.

⁶⁵ Electricity prices are also affected by fuel prices, especially in New England with a high proportion of the electricity generated by natural gas-fired power plants that may set the marginal spot market price. However, this analysis is out of the scope of this work.

4.4. ANALYSIS OF CASE STUDY WITH NEW REGULATORY AND MARKET CONDITIONS

The following quantitative analysis has been focused on how particular utility rates, market conditions and environment regulations may impact the attractiveness of DE projects. Specifically, we will analyze the economic implications of standby rates which DE owners have to pay on a fixed monthly basis to the local utility. In addition, we will show how uncertainties in the natural gas and oil markets may threaten the construction of new projects and existing ones, with high operational costs due to soaring fuel prices. We will further discuss the environmental consequences of the utility's decision to change the proportion of its energy portfolio to alleviate the effect of high natural gas price on the electricity supply rates. Finally, we will work with a hypothetical carbon tax that will value the displacement of CO₂ emissions by a cogeneration project. We intend with this policy to give an economic recognition to the environmental benefits of CHP systems.

4.4.1. ANALYSIS CONSIDERING STANDBY SERVICE CHARGES

There are some provisions within the rate schedules that represent expensive charges for self-generators and QFs. Specifically, some utilities require this type of customer to purchase backup services primarily due to reliability issues related to the physical interconnection of the facility. Usually this is an expensive monthly demand charge, that will be charged regardless of whether the facility uses or not this service. For MIT's cogeneration facility, the "standby transmission capacity charge" will be particularly expensive if an outage occurs on peak hours. Therefore, in cases where these charges are high, the savings of a cogeneration project may become insignificant.

Particularly, when we analyzed the impact of those charges on the MIT facility, we found that there are additional savings over the 2006-2020 period if we eliminate these charges. As we explained in section 2.3.3, the "standby transmission capacity charge" will be added to MIT operational costs depending on the time when the facility is unavailable – peak or off-peak hours. Since NSTAR's new rate structure does not include this fee for new customers, it is of interest to quantify the economic impact of this grandfathered charge on the MIT project. The results show an additional discounted savings of almost \$4.4m for the period ("Δ Cogen no SB" case).

Regarding the “transmission capacity charge” that is allocated every month either through the maintenance or standby service, we believe that the utility companies have the right to charge it because of their readiness and obligation to serve all their customer base. When we estimated the impact of this cost on the cogeneration alternative, it represents about \$3.15m that MIT has to pay for receiving standby or maintenance services (“Δ Cogen no SB&MS” case). Table 4.2 shows a summary of these results.

Cases	NPV savings [\$]
Δ Cogen	42,969,816
Δ Cogen no SB	47,356,472
Δ Cogen no SB&MS ¹	50,506,274

Table 4.2: NPV savings without SB charges, 2006 - 2020

1: SB – standby, MS – maintenance

These results are similar to those obtained when we applied the new NSTAR rate schedule – general service rate SB-G3 – for standby and supplemental services to self-generators projects, instead of MIT’s current rate. The Institute is under a closed rate structure that is not applicable to other facilities generating all or a portion of their load after December 31, 2004⁶⁶.

The new rate applies for those customers with 250kW generation units that satisfy at least 30% of their maximum load, or customers with installed generation units greater than 1MW. Some exclusions include municipal public schools under special circumstances; and “renewable energy technologies” except for the case where that technology is a fuel cell operating primarily on natural gas with an installed capacity greater than 2MW or the combined capacity of all fuel cells installed in the service territories of BECo, CELCo, and ComElec⁶⁷ is greater than 10MW.

⁶⁶ For details see NSTAR Electric’s Rate SS-1

(http://www.nstaronline.com/customer_service/tariffs/3/239d.pdf), Rate MS-1

(http://www.nstaronline.com/customer_service/tariffs/3/238d.pdf), Rate SB-1

(http://www.nstaronline.com/customer_service/tariffs/3/237d.pdf), and Rate SB-G3.

⁶⁷ ComElec includes Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company respectively.

Table 4.3 shows a comparison of the rate schedule applicable to MIT and new customers with a contract demand equal or greater than 1MVA (shaded areas point up differences in charges):

Charges	MIT	Other
General for SS/MS/SB¹:		
Customer charge	\$511.00/mo	\$90.00/mo
Administrative charge	\$270.00/mo	n/a
Capacity:		
SS distribution	First 100kVA: \$0.00/mo	First 100kVA: \$0.00/mo
	Over 100kVA: \$1.47/kVA	Over 100kVA: \$1.47/kVA
SS transmission	First 100kVA: \$323.00/mo	First 100kVA: \$323.00/mo
	Over 100kVA: \$6.18/kVA	Over 100kVA: \$6.18/kVA
SS transition	First 100kVA: \$121.87/mo	First 100kVA: \$121.87/mo
	Over 100kVA: \$1.22/kVA	Over 100kVA: \$1.22/kVA
MS/SB transmission capacity	\$1.32/kVA	\$0.00/kVA
MS/SB distribution demand	n/a	First 100kVA: \$0.00/kVA
		Over 100kVA: \$1.25/kVA
SB peak transmission capacity ²	\$9.23/kVA	n/a
SB transmission capacity reserve ³	\$0.36/kVA	n/a
Energy:		
Distribution energy	\$1.22/MWh	\$1.22/MWh
Transition energy	\$0.00/MWh	\$0.00/MWh
Renewable energy	\$0.50/MWh	\$0.50/MWh
Energy conservation	\$2.50/MWh	\$2.50/MWh
Supplier default service	\$75.97/MWh	\$75.97/MWh

Table 4.3: Supplemental, maintenance & standby rates for MIT plant and new facilities

1: SS – supplemental, MS – maintenance, SB – standby

2,3: Greater charge between 2 and 3

As we can observe, the new rate structure does not contain some charges while others are cheaper than those currently billed to MIT. When we quantified these differences over the 15 year time horizon, we found the following results (see Table 4.4 below):

Cases	NPV savings [\$]
Δ Cogen	42,969,816
Δ Cogen new rate	47,579,969
Δ Cogen new rate no SB&MS	50,563,216

Table 4.4: NPV savings without SB charges, 2006 - 2020

The results are similar to those showed in Table 4.2, because the new rate does not include the “standby transmission capacity charge” provision contained in MIT’s current rate (compare “Δ Cogen new rate” in Table 4.4 with “Δ Cogen no SB” in Table 4.2).

As with the previous case, the impact of the “transmission capacity charge” on the cogeneration alternative is almost \$3m. We interpret this cost as the value for MIT for receiving standby or maintenance services (“Δ Cogen new rate no SB&MS” case).

The numbers are slightly larger because of the differences in the “customer charges” and the “transmission/distribution capacity charges”. In summary, we conclude that if the new SB-G3 were applicable to MIT cogeneration facility, the rate would represent more economic benefits than the current rate structure being paid by the Institute.

4.4.2. ANALYSIS CONSIDERING FUEL PRICES

As we mentioned earlier, there have been important changes in the prices during the past years. The baseline analysis – “Cogeneration case” – was made under a conservative scenario where the prices assumed for both natural gas and oil slightly decreased in real terms because of the expectation of new gas infrastructure to support the increasing demand of gas.

Given the uncertainty of the future prices for both fuels, we quantified the effects of higher prices on the economics of the project. However, we did not incorporate the effects of fuel prices on the electricity rates.

For the first scenario we assumed real escalators for natural gas of 1.217 for 2010, 1.327 for 2015, and 1.471 for 2020 with respect to year 2005⁶⁸ – for the prices of the years in between we interpolated the values– and for oil prices we continued to use the same values used in the “Cogeneration case”. For the second scenario, we used the same high natural gas prices as in the first scenario, but we kept the ratio between oil and gas price constant at 0.91 energy equivalent for the whole time horizon. This approach was originally used in the “Cogeneration case” to represent the tight relationship between both prices (see Table 4.5 for the values used in each scenario).

⁶⁸ Data provided by James McFarland – ESD Ph. D. student at MIT – as part of a simulation about the future gas prices in U.S. under business as usual scenario.

Year	Cogeneration case		High NG price case		High NG & Oil prices case	
	NG rate \$/MMBtu	Oil rate \$/MMBtu	NG rate \$/MMBtu	Oil rate \$/MMBtu	NG rate \$/MMBtu	Oil rate \$/MMBtu
2005	8.23	6.04	8.91	6.04	8.91	5.88
2006	7.78	6.35	9.29	6.35	9.29	8.44
2007	7.32	6.65	9.68	6.65	9.68	8.79
2008	6.99	6.35	10.06	6.35	10.06	9.14
2009	6.68	6.07	10.45	6.07	10.45	9.49
2010	6.38	5.79	10.84	5.79	10.84	9.84
2011	6.25	5.68	11.03	5.68	11.03	10.02
2012	6.12	5.56	11.23	5.56	11.23	10.20
2013	6.00	5.45	11.42	5.45	11.42	10.38
2014	5.88	5.34	11.62	5.34	11.62	10.56
2015	5.76	5.24	11.82	5.24	11.82	10.74
2016	5.65	5.13	12.07	5.13	12.07	10.97
2017	5.53	5.03	12.33	5.03	12.33	11.20
2018	5.42	4.93	12.59	4.93	12.59	11.44
2019	5.32	4.83	12.85	4.83	12.85	11.67
2020	5.21	4.73	13.10	4.73	13.10	11.90

Table 4.5: Fuel prices, 2005 – 2020
(2005 USD)

We focused the analysis on whether there will be operational savings for the “Cogeneration case” under the new scenarios when compared to the “Utility case”. As usual, we discounted back the yearly economic savings/costs from 2006 to 2020, and we added them together to get the NPV of that savings/costs for each case.

In Table 4.6 we can see a summary of the analysis, where Δ denotes the results of a particular case when compared to the “Utility case”.

Cases	NPV savings [\$]
Δ Cogeneration	42,969,816
Δ High NG price (1 st)	-55,694,730
Δ High NG & Oil prices (2 nd)	1,669,140

Table 4.6: NPV savings with new fuel prices, 2006 - 2020

To understand these results, we need to recall first the results of the baseline case. Most of the savings came from self-generation which allowed MIT to buy less electricity from NSTAR, and save fuel costs for the operation of the boilers (see Table 4.7).

		Utility case	Cogeneration case	Δ Cogeneration
Total electric purchase	\$	228,075,176	84,762,850	143,312,326
Total fuel purchase	\$	117,262,984	175,984,875	-58,721,891
NG	\$	11,957,405	146,970,771	-135,013,366
No.6	\$	105,305,579	29,014,103	76,291,476
Total O&M	\$	73,717,031	90,988,956	-17,271,925
Total operational costs	\$	419,055,191	351,736,680	67,318,511
Total cost project	\$	425,055,191	351,736,680	73,318,511
Operational savings	\$			73,318,511
Total debt payment	\$			-38,014,575
Indirect Cost Recovery	\$			7,665,880
NPV project	\$			42,969,816

Table 4.7: NPV savings Δ Cogeneration, 2006 - 2020

However, the results in Table 4.6 show that changes in fuel prices importantly affect the economics of the project. In the first scenario – high natural gas price – those savings disappear and the project become uneconomic in the long run, with discounted incremental costs of almost \$56m when compared to the “Utility case” (see Table 4.8).

The new result shows that it is more economic to buy the electricity from the utility and produce the steam rather than generate it with cogeneration. However, it is important to notice that under this scenario we are penalizing self-generation. Most of the electricity is produced using natural gas which is the only fuel with soaring prices while oil and electricity remain the same as in the baseline case. Of course, the project owner may be able to hedge against such long term natural gas prices through long term contracts or other instruments. This scenario simply demonstrates the importance of natural gas price stability to project economics.

		Utility case	High NG price case	Δ 1 st
Total electric purchase	\$	228,075,176	84,762,850	
Total fuel purchase	\$	126,363,596	283,750,033	-157,386,437
NG	\$	21,058,017	254,735,930	-233,677,913
No.6	\$	105,305,579	29,014,103	76,291,476
Total O&M	\$	73,717,031	90,988,956	
Total operational costs	\$	428,155,803	459,501,838	
Total cost project	\$	434,155,803	459,501,838	
Operational savings	\$			-25,346,035
Total debt payment	\$			-38,014,575
Indirect Cost Recovery	\$			7,665,880
NPV project	\$			-55,694,730

Table 4.8: NPV savings Δ High NG price, 2006 - 2020

The second scenario may be slightly more realistic, since we tied the variation of gas prices with those of oil prices. In this analysis we assumed high prices for both type of fuels, and we found economic savings being not as large as those obtained in the baseline case, accounting for about \$1.7m (see Table 4.9). The reasons behind these results are that:

- Under the first scenario, oil and electricity prices were much cheaper than natural gas price. So, in the “Utility case”, oil consumption of the boilers and electricity purchase was more economic than self-generation in the “Cogeneration case” where natural gas was the main fuel.
- Under the second scenario, oil became expensive and electricity maintained its original price level. Thus, in the “Utility case”, oil consumption of the boilers was expensive as well, and part of the economic advantages found in the first scenario – coming from cheaper electricity and oil – disappeared as the boilers had to use oil which was also expensive

		Utility case	High NG&Oil prices case	Δ 2 nd
Total electric purchase	\$	228,074,348	84,762,407	
Total fuel purchase	\$	208,629,006	308,651,187	-100,022,181
NG	\$	21,058,017	254,735,930	-233,677,913
No.6	\$	187,570,988	53,915,257	133,655,731
Total O&M	\$	73,717,031	90,988,956	
Total operational costs	\$	510,420,384	484,402,549	
Total cost project	\$	516,420,384	484,402,549	
Operational savings	\$			32,017,835
Total debt payment	\$			-38,014,575
Indirect Cost Recovery	\$			7,665,880
NPV project	\$			1,669,140

Table 4.9: NPV savings Δ High NG & Oil prices, 2006 - 2020

A third scenario (not analyzed in this study) would be to increase the utility electricity rates to reflect the consequences of higher natural gas and oil prices. This would make the “Cogeneration case” more cost-effective, with the impact depending on the utility’s evolving fuel mix in respond to the higher fuel prices.

As a result of this analysis, we can conclude that that the economics of the project is not so evident as we demonstrated in Chapter 2. Clearly, the volatility of fuel price affects the cost-effectiveness of DE projects, a fact that becomes more relevant now that the prices of fuels are extremely high with an unclear prospect of whether they will decline in the future. The deployment of DE projects that base their operation on natural gas and oil may be highly constrained by this particular market uncertainty and the associated changing fuel mix of the utility.

Regarding CO₂ emissions, we also need to have in mind that the utility company or the other competitive suppliers may change their behavior regarding an optimum use of their energy sources. Under an uncertain fuel scenario, they may prefer to decrease the use of natural gas

within its energy portfolio and increase the use of coal, which is a cheaper fuel but with great environmental impact.

In the baseline case, the NSTAR energy portfolio is comprised of 15% coal and 35% natural gas (recall Table 2.17). If the utility company replaces part of the consumption of natural gas for coal, in the “Utility case” we will have a larger increase of CO₂ emissions when compared to the “Cogeneration case”, with the resulting major cumulative benefits for the cogeneration alternative for the 15 year time horizon as shown in Table 4.10

Cases		Total CO ₂ benefits [Metric ton CO ₂]	Annual CO ₂ benefits [Metric ton CO ₂ /yr]
Δ Cogeneration	Coal=15%, NG=35%	967,571	64,505
Δ Coal/NG equal	Coal=25%, NG=25%	1,072,114	71,474
Δ More coal	Coal=35%, NG=15%	1,176,656	78,444

Table 4.10: Cumulative CO₂ emissions under different energy portfolio, 2006 - 2020

As we can see, a 10% change of coal and natural gas in the energy portfolio represents almost 7,000 Metric ton of additional CO₂ benefits per year for the CHP case (although a net negative impact on CO₂ emissions because of higher utility emissions in serving its customer base).

4.4.3. ANALYSIS CONSIDERING CARBON TAX

From the previous results we can observe a tradeoff that may result from higher energy prices and changes within the energy portfolio. On one hand, as we showed, the economic benefits of the baseline case can greatly diminish with increases in the price of natural gas. On the other hand, the utility company may change its fuel consumption pattern, and the environmental benefits of the “Cogeneration case” may increase.

If we consider a carbon-tax policy that internalizes the social cost of CO₂ emissions we will have additional savings that will need to be included in our analyses. For example, an emission cost of \$100/tonne carbon – equivalent to \$27.27/tonne CO₂ – would account for the savings shown in Table 4.11:

Cases		Annual CO ₂ benefits [Metric ton CO ₂ /yr]	Annual CO ₂ savings [\$ /yr]	NPV CO ₂ savings [\$]
Δ Cogeneration	Coal=15%, NG=35%	64,505	1,759,227	15,925,850
Δ Coal/NG equal	Coal=25%, NG=25%	71,474	1,949,298	17,643,470
Δ More coal	Coal=35%, NG=15%	78,444	2,139,375	19,361,089

Table 4.11: NPV CO₂ savings with a \$100/tonne carbon tax, 2006 - 2020

As we can observe, the initial discounted savings in our baseline case of almost \$43m increase up to almost \$60m when considering a \$100/tonne C tax – with additional savings of about \$16m. In the case that the utility changes its energy portfolio because of high fuel prices, the economics of a cogeneration project will change according to the carbon intensity of the modified generation portfolio.

In these analyses we worked with an energy portfolio of the local utility where almost two thirds is fossil. In the hypothetical case this particular DE project was located in a “carbon-less” area, where the fuel mix comes from renewables and nuclear sources, the CO₂ emissions of the cogeneration alternative would be greater than in the utility case. If a \$100/tonne C tax were applicable, the results show that a fossil DE/CHP project within a carbon-free region will have additional discounted costs of almost \$2m. Moreover, the project will probably have extra costs as a result of air regulations concerning the fossil fuel fired operation of its boilers and combustion gas turbine (see Table 4.12).

Case	Annual extra CO ₂ Emissions [Metric ton CO ₂ /yr]	Annual CO ₂ costs [\$ /yr]	NPV CO ₂ costs [\$]
ΔCarbon-free Coal=0%, NG=0%	-8,156	-222,436	-1,981,268

Table 4.12: NPV CO₂ costs in a carbon-free region, 2006 - 2020

In summary, depending on the carbon content of the utility company’s fuel mix of its energy portfolio, the incorporation of emission costs within the analyses may bring extra economic savings to the cogeneration alternative, in addition to the environmental benefits of the CHP system.

5. CONCLUSIONS

In this chapter we will recap the main results of our analysis based on the comparison of two cases that treated differently the way MIT acquires electricity and steam. Several sensitivity analyses were performed to re-examine the viability of a cogeneration project under different technical, regulatory and market assumptions, and their results will also be summarized.

In addition, we will outline at least three issues that were out of the scope of this study, but are interesting directions for further research. Finally, we will conclude with some general observations regarding the required conditions for a widespread deployment of DE resources.

5.1. SUMMARY OF RESULTS

Recall that in the “Utility case” all electricity was assumed to come from the local electrical distribution utility and the steam was generated through the boilers of the Central Utility Plant. In the “Cogeneration case” most of the steam and most electricity was generated by MIT’s cogeneration plant, with the remaining electricity needs met by NSTAR and remaining steam needs by supplementary boilers.

Our study leads us to conclude that, under baseline conditions, the “Cogeneration case” is a better alternative than the “Utility case” in terms of the economics and CO₂ emissions. However, further analyses showed us that changes in current operational, market and regulatory conditions may greatly affect the economic savings and environmental benefits of the cogeneration alternative. We found that although some market conditions may possibly eliminate the economic benefits of a DE project, the economic recognition of the displacement of CO₂ emissions may give additional value to the Cogeneration case.

Initially, we found that the “Cogeneration case” has economic benefits over the Utility case. The net present value of the operational savings from 2006 to 2020 discounted at 7.125%, are close to \$73m, and when we take into consideration the carrying capital costs of the Cogeneration project undertaken in 1996, we obtained net savings of about \$43m (see Table 5.1).

		Utility case	Cogeneration case
Total electric purchase	\$	228,075,176	84,762,850
Total fuel purchase	\$	117,262,984	175,984,875
Total O&M	\$	73,717,031	90,988,956
Total operational costs	\$	419,055,191	351,736,680
Others	\$	6,000,000	
Total cost project	\$	425,055,191	351,736,680
Operational savings	\$		73,318,511
Total debt payment	\$		(38,014,575)
Net cash flow	\$		35,303,936
Indirect Cost Recovery	\$		7,665,880
NPV project	\$		42,969,816

Table 5.1: NPV savings Utility case vs. Cogeneration case, 2006 - 2020

From the table we observe that the “Utility case” has higher operational costs because of the high levels of electricity costs that continue to increase over time. Even though the total fuel purchase cost is lower than that of the “Cogeneration case”, we need to recall that in the first case the boilers are burning large quantities of fuel to provide steam only, while in the second case two systems – CHP and boilers – are operating together to supply electricity and steam. The recuperation of the CGT exhaust gas by the HRSG for supplying the additional steam yield to operate the boilers less hours than in the “Utility case”. Therefore, a lower utilization rate of the boilers makes possible the reduction of fuel consumption for steam purposes only.

Second, we also found that the “Cogeneration case” has environmental benefits when compared to the Utility case, in terms of CO₂ emissions. As we can observe from Table 5.2, the “Cogeneration case” releases almost 1,000,000 metric tons less CO₂ emissions than the Utility case, which in average represents almost 65,000 metric ton per year – 225,000 vs. 290,000 metric ton/yr.

Cumulative 2006-2020 [Metric ton CO ₂]	Utility case	Cogeneration case	Benefits
Total from CHP and boilers	2,652,911	2,775,251	(122,340)
Total from purchased electricity	1,684,064	594,153	1,089,911
TOTAL CUP & Utility	4,336,975	3,369,403	967,571

Table 5.2: Cumulative CO₂ emissions Utility case vs. Cogeneration case, 2006 - 2020

The environmental benefits come mostly from the emissions being displaced when: i) MIT generates its own power needs instead of buying the electricity from NSTAR, and ii) generates the campus steam with a CHP system. First, distant large power plants supply the majority of the electricity to the load center, subject to important transmission and distribution grid losses and facilities that do not take advantage of recuperating wasted heat. Second, MIT facility uses mostly natural gas, which is a cleaner fuel than oil; and consumes in overall less fuel for steam purposes only, especially oil.

Then we performed a series of sensitivity analyses that help us to understand the impact of technical, regulatory and market conditions on the viability of a cogeneration project of similar characteristics to the MIT cogeneration plant.

We started analyzing the effects of improvements of the electrical efficiency in the combustion gas turbine of the CHP system in the Cogeneration case. Clearly, the results show that the better the efficiency the more the economic and CO₂ emission benefits when compared to the Utility case, although at a decreasing marginal trend (see Table 5.3).

Cases	NPV savings [\$]	Total CO₂ benefits [Metric ton CO ₂]
Δ Cogen η=26.6%	42,969,816	967,571
Δ CT #1 η=28.4%	49,691,488	1,074,038
Δ CT #2 η=34.2%	67,773,960	1,324,216
Δ CT #3 η=36.2%	72,832,346	1,394,201

Table 5.3: NPV savings and CO₂ emissions under different efficiency scenarios, 2006 - 2020

Our second sensitivity analysis was centered on the economic impact of standby charges on the cogeneration facility. Since NSTAR's new rate structure for self-generation projects does not include the "standby transmission capacity charge", we quantified the economic impact of this fee currently being charged to MIT. Thus, the cogeneration alternative under MIT closed rates without this charge would have additional savings of almost \$4.4m for the analyzed horizon period. We also estimated the value of NSTAR's "obligation to serve" to MIT, which accounted for \$3.15m. This value represents the costs for the utility company for being ready to provide standby or maintenance service at any moment to DE projects connected to the distribution system (see Table 5.4).

According to these results, we conclude that if the new rate structure were applicable to the MIT cogeneration facility, the cogeneration alternative would have additional economic benefits when compared to the current rate structure being paid by the Institute.

Cases	NPV savings MIT closed rate [\$]
Δ Cogen	42,969,816
Δ Cogen no SB	47,356,472
Δ Cogen no SB&MS ¹	50,506,274

Table 5.4: NPV savings without SB charges, 2006 - 2020

1: SB – standby, MS – maintenance

Our third sensitivity analysis was focused on future fuel prices. First, we quantified the effects of high natural gas prices and the results show that the preliminary savings disappear under this new scenario with a total incremental cost of almost \$56m. Therefore, the project becomes uneconomic in the long run where it is more attractive for the institution to buy the electricity rather than produce it through cogeneration. These results depend on the utility maintaining a reasonably small part of its generation portfolio in natural gas with the consequence of precluding elevated electricity rates.

In the second scenario, we assumed high prices for both natural gas and fuel oil and we found that there are economic savings, although much smaller than in the baseline case representing about \$1.7m. As oil becomes expensive, oil consumption of the boilers in the "Utility case" becomes expensive as well (see Table 5.5).

Cases	NPV savings [\$]
Δ Cogeneration	42,969,816
Δ High NG price	(55,694,730)
Δ High NG & Oil prices	1,669,140

Table 5.5: NPV savings under different fuel prices scenario, 2006 - 2020

As we can observe, changes in fuel prices affect the economics of the project. Fuel price volatilities impact the cost-effectiveness of DE projects, especially of those that base their operations on natural gas and fuel oil.

We also mentioned that, under an uncertain fuel scenario, the utility company or the other competitive suppliers may change their behavior regarding an optimum use of their energy sources. Thus, they may prefer to decrease the use of natural gas within its energy portfolio and increase the use of coal – cheaper and with greater carbon content. When comparing the “Cogeneration case” with respect to the “Utility case”, we found that a 10% coal increase and 10% natural gas decrease within the current NSTAR energy portfolio represents almost 7,000 Metric ton/yr of additional CO₂ benefits for the CHP approach.

Finally, for the forth sensitivity analysis we took into consideration the economic impact of a \$100/tonne carbon tax – equivalent to \$27.27/tonne CO₂ – that will value the displacement of CO₂ emissions by a cogeneration project. The additional economic savings in the baseline case would be about \$16m, with total savings increasing up to almost \$60m. Thus, in addition to the environmental benefits of a CHP system, a potential economic recognition of CO₂ reduction can make a cogeneration project even more attractive.

Nevertheless, we showed that these results will change according to the carbon intensity of the utility’s generation portfolio. When we assumed a carbon-free portfolio, the CO₂ emissions of the cogeneration alternative become greater than in the utility case. In this scenario, a carbon tax will have an additional cost of \$2m for the cogeneration project, with no regard of the CO₂ emissions generated by the boilers and turbine.

5.2. FURTHER RESEARCH

Out of the scope of our study were at least three issues that are interesting for further analysis. The first one is to find out the optimum point between the benefits and the additional costs associated with efficiency improvements for a particular technology. As we noted in Chapter 3, there is a decreasing marginal trend for both economic savings and environmental benefits, meaning that the greatest incremental benefits are realized for the first units of technology improvement. Therefore, even though a continuous technology development will represent increasing benefits, at some point the costs of those improvements may be too high when compared to the combined economic and environmental benefits. For this type of analysis we require from the manufacturers information regarding the costs of prime mover technologies, and the incremental costs for each level of improvement. We will also need to express the environmental benefits in monetary value to be able to calculate the combined expected benefits of the new technology, and compare them with its development cost.

The second issue we would like to further analyze is the relationship between energy prices and, hence, estimate more precisely their future economic impact on a DE project. Within this analysis, we would be interested in find out whether there is a correlation between the prices of natural gas and oil in New England, and the proportion each of them contribute to the final electricity price. Given the uncertainty of future energy prices, these findings could help us to perform several scenarios with different prices – both electricity and fuel – and analyze a more ample spectrum of the impact of these on the cost-effectiveness of a DE project fueled with oil or natural gas. The options for hedging against fuel price volatility for different CHP projects would be an important part of such a study.

Finally, we would like to explore the market potential for CHP applications in the Boston Metropolitan Area. Particularly, we are interested in look at the feasible capacity within the commercial and institutional sectors, the type of technologies most likely to be adopted, as well as whether they will be configured as stand-alone or connected to the grid. Once we know the market potential for CHP systems, we would like to make an estimation of the Greenhouse gas emissions impact of a wide-spread DE deployment in the area.

5.3. FINAL REMARKS

It is important to note that our analysis was focused on a particular technology using mostly natural gas. The analysis was helpful for understanding the effects of external conditions on the development of a DE project, and a re-examination of the cost-benefit equilibrium of the case showed us how sensitive a project can be to technical, regulatory or market conditions. As we reviewed in our study, these conditions may become important barriers for the development of DE technologies and they may constrain a future widespread deployment of these resources. Solutions for stimulating a larger market penetration are not simple and usually they require some time for allowing new technologies to mature, current resource planning to materialize, and regulations to oversee the effects of ongoing changes on DE applications.

From a technical point of view, a wider deployment of DE resources will require acknowledging the type of technology suitable for a particular facility and whether it is mature enough to support the operations, in terms of performance quality, operational flexibility and available technical support. According to this, it seems that reciprocating engines are one of the most suitable technologies for small DE systems less than 10MW. Most fuel cells are still under development and they have extremely high initial costs that make them unattractive for DE developers. Combustion gas turbines are mostly used for larger facilities, and maintenance requirements may become expensive. However, ICs as a technology option for a larger market penetration raises some concerns in terms of the environmental consequences, since an increase of GHG emissions could be expected especially when the facility is being fueled with oil instead of natural gas, and not configured as a CHP system.

Additionally, the integration of DE resources with the existing physical infrastructure will be crucial for enabling this deployment. Even though the interconnection to the electrical grid is being standardized to facilitate the process, especially for small projects, a larger DE market will require utility companies to develop the capability to integrate and coordinate the operations of several small systems in order to maintain the reliability, safety, and quality of the service. But not only the electrical infrastructure will be under stress, the natural gas system will also be impacted as the consumption of this fuel increases. More infrastructure will be necessary at the production and transport levels, and within the cities the capacity of the pipelines will need to be expanded in order to minimize service interruptions during peak periods. Regarding facilities fueled with oil, they will need to have the necessary space for storage, and the oil tanks will need to comply with standards in order to guarantee the safety and health of the public. In summary, a robust physical infrastructure will be required to support a widespread deployment of DE resources. A systems analysis is essential.

Stable market conditions would certainly help to encourage the development of DE resources. However, current conditions and uncertainties about the future within the fuel markets are not giving the proper incentives to embark on fossil fuel-fired DE projects. As we analyzed, a natural gas or oil fired project may be negatively impacted due to high prices and it may become unviable in the long term. For minimizing the impact of unstable fuel market conditions, DE developers have at least two alternatives: i) negotiate long term supply contracts, or ii) wait for the expansion and upgrade of the infrastructure. Neither alternative is particularly attractive for small DE projects, since in one case the settled conditions will depend mostly on the negotiating power of the parties and still the conditions will be subject to market variations, and in the other case developers will depend on the time horizon planning of others while still experiencing the unfavorable market conditions.

Finally, a widespread DE deployment needs transparent and straightforward processes. As we have learned, the regulatory framework for DE resources in Massachusetts is extensive and complex. It can be overwhelming for potential new developers, as they need to learn the multiple requirements for both air permitting in a non-attainment area and interconnection to the utility grid. They also need to be aware of the charges they have to pay when requiring standby service, and the incentives the state gives for further DE development.

Although the uniform interconnection standards and new utility rates for self-generation in Massachusetts are important steps towards encouraging the development of these technologies for small DE projects, these state initiatives require time to mature. Massachusetts will serve as a field experience for DE projects, and it will be interesting to see how a future market develops. In this regard, we would like to suggest some recommendations that could ease the process for new projects, and allow a greater deployment of DE applications within the state.

Uniform interconnection standards for DE resources have been recently adopted. The performance of the standards as well as potential barriers (plus other issues) are being reviewed by the Massachusetts DG Collaborative group over a period of two years, until 2006. We propose to *extended that period for further evaluation* since, until now, most of the applications under the “expedited” and “standard” interconnection processes are still under review. A more extended period will allow the Collaborative group to analyze issues such as network interconnection, standby service tariff and the role of distributed generation in distribution planning.

The utility company must provide the necessary power quality and guarantee the reliability of the electrical grid with new DE resources. However, self-generation projects offer benefits to the distribution systems such as relief of grid congestion, and reduction of transmission and distribution losses. Therefore, as DE projects help to avoid or delay capital investments, we propose a *reasonable standby service charge that incorporates the benefits of grid-connected DE projects on the local utility's system* and their impact on the company's planning criteria. We also believe that the *applicability of standby rates should not discriminate between customers*. To make the process more transparent for all customers, the exemptions regarding renewable energy technologies should not be included in the provision.

For some DE projects over 1MW and all the facilities greater than 5MW that intend to interconnect to the system, they require the additional review of the ISO-NE because of the potential impact on the transmission system. However, the coordination between local utilities, ISO-NE, and DE developers needs to improve to make the process more clear for future projects. Hence, we propose the *ISO-NE and local utilities to work closely on the interconnection process*, making explicit the timeframes, as well as the technical requirements, and all related costs required by each entity.

Regarding air permitting process, we mentioned that, for potential new DE developers, it can be difficult to understand. Taking as an example the “interconnection guide for DG” developed by the Massachusetts DG Collaborative Group, we recommend to *create a comprehensive “air permitting roadmap” that provides all the necessary information to developers*. This roadmap should supply a general outline of the process, including the steps to follow, organizations, requirements, and timeframes among others.

Most of the incentives in Massachusetts to promote the development of DE are focused on renewable resources. The economic support is mainly focused on carbon-free sources, while CHP systems – with high energy efficiency levels – are almost excluded. Hence, we recommend to *introduce DE/CHP systems as a technology category to be supported either through tax incentives or energy funds* to attract new investors and promote its development.

Massachusetts is one of the participating states in the Regional Greenhouse Gas Initiative (RGGI) of the Northeast and Mid-Atlantic States where, along with other states, they are designing a regional cap-and-trade program related to CO₂ emissions. Although the first stage of this initiative is aimed at power plants, *subsequent phases should include DE/CHP systems*. They provide environmental benefits through the use of cleaner fuel and more efficient technology, a better energy utilization, and the displacement of emissions – from off-site plants that burn fuels with greater CO₂ content. Thus, we recommend the introduction of *economic incentives that recognize the benefits of CHP applications in the form of a carbon tax*, whereas the economic value of CO₂ emission reductions will contribute to improve the economics of DE projects with additional savings.

Important is to recognize the efficiency value of CHP systems in terms of the overall produced energy. Under Chapter 111, section 142N of the General Laws of Massachusetts (G.L.c.111, §142N), the DEP is required to adopt and implement regulations for generation performance standards of certain emissions produced per unit of electric output emitted by fossil-fuel fired generators. The impact of such regulations may be significant on CHP applications, where the electrical efficiency is not particularly high. Hence, we propose to *include in those standards the efficiency benefits of CHP systems, taking into consideration the combined thermal and electrical system efficiency*.

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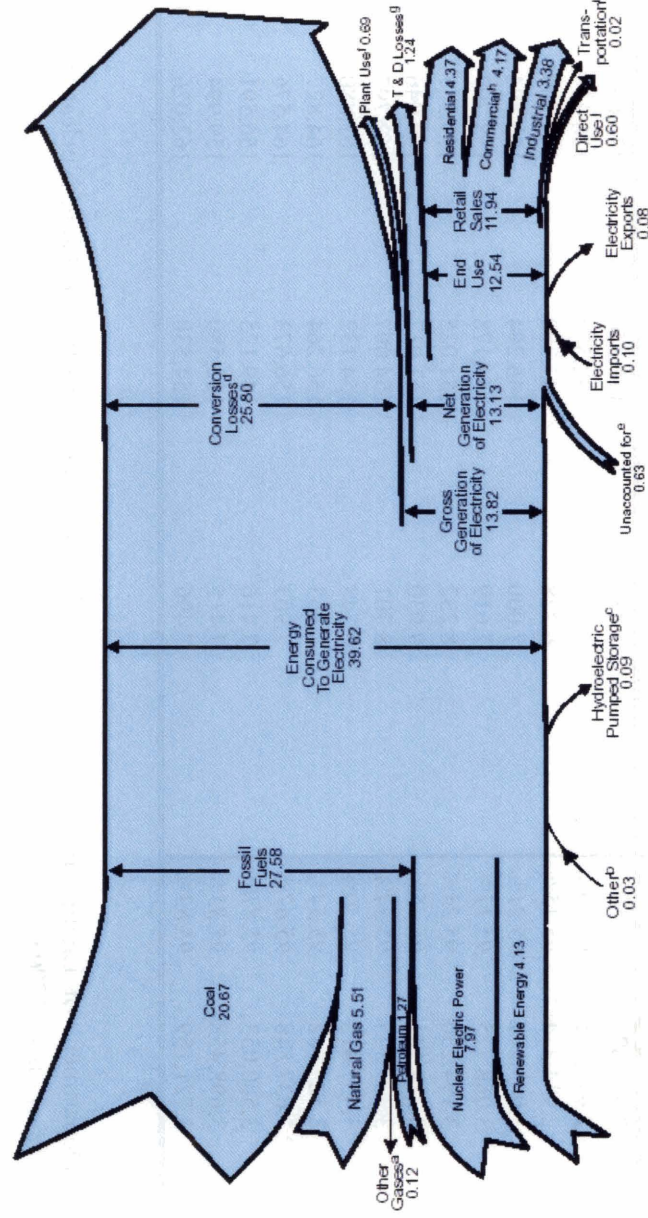
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APPENDIX A: HISTORICAL ELECTRICITY DATA AND FUEL FUTURES

Diagram A.1: Electricity flow, 2003

Diagram 5. Electricity Flow, 2003
(Quadrillion Btu)



Source: United States, Department of Energy, Energy Information Administration - Office of Coal, Nuclear, Electric and Alternate Fuels (September 2004), *Annual Energy Review 2003: Electricity Flow Diagram*, pp. 219.

Table A.1: Net generation (GWh/year), 1990 - 2003

	Electric generators: electric utilities, CHP & IPP	% Total	CHP commercial power	CHP industrial power	Total commercial & industrial CHP	% Total	Total electric power industry
1990	2,901,322	95.50%	5,837	130,830	136,667	4.50%	3,037,988
1991	2,935,561	95.50%	5,659	132,579	138,238	4.50%	3,073,799
1992	2,934,374	95.15%	6,228	143,280	149,509	4.85%	3,083,882
1993	3,043,897	95.21%	7,000	146,294	153,294	4.79%	3,197,191
1994	3,088,725	95.11%	7,619	151,178	158,797	4.89%	3,247,522
1995	3,194,230	95.25%	8,232	151,025	159,257	4.75%	3,353,487
1996	3,284,141	95.35%	9,030	151,017	160,046	4.65%	3,444,188
1997	3,329,375	95.34%	8,701	154,097	162,797	4.66%	3,492,172
1998	3,457,416	95.50%	8,748	154,132	162,880	4.50%	3,620,295
1999	3,529,982	95.54%	8,563	156,264	164,827	4.46%	3,694,810
2000	3,637,548	95.67%	7,903	156,673	164,576	4.33%	3,802,124
2001	3,580,053	95.81%	7,416	149,175	156,591	4.19%	3,736,644
2002	3,698,458	95.85%	7,415	152,580	159,994	4.15%	3,858,452
2003	3,721,159	95.83%	7,496	154,530	162,026	4.17%	3,883,185

Source: United States, Department of Energy, Energy Information Administration - Office of Coal, Nuclear, Electric and Alternate Fuels (December 2004), *Electric Power Annual 2003*.

Table A.2: Summer installed capacity (MW/year), 1990 - 2003

	Electric generators: electric utilities, CHP & IPP	% Total	CHP commercial power	CHP industrial power	Total CHP Commercial & industrial	% Total	Total electric power industry
1990	709,477	96.86%	1,405	21,600	23,004	3.14%	732,481
1991	714,624	96.86%	1,339	21,804	23,143	3.14%	737,767
1992	720,474	96.78%	1,510	22,453	23,964	3.22%	744,437
1993	727,898	96.71%	1,637	23,116	24,752	3.29%	752,651
1994	735,826	96.58%	2,057	23,991	26,048	3.42%	761,873
1995	741,518	96.58%	2,131	24,154	26,285	3.42%	767,803
1996	747,595	96.56%	2,309	24,322	26,630	3.44%	774,225
1997	749,908	96.50%	2,333	24,883	27,216	3.50%	777,124
1998	747,513	96.53%	2,281	24,554	26,835	3.47%	774,348
1999	756,286	96.46%	2,302	25,430	27,732	3.54%	784,017
2000	781,813	96.59%	2,240	25,324	27,564	3.41%	809,378
2001	818,446	96.68%	2,912	25,225	28,138	3.32%	846,584
2002	875,822	96.74%	2,188	27,291	29,479	3.26%	905,301
2003	918,629	96.86%	2,077	27,740	29,817	3.14%	948,446

Source: United States, Department of Energy, Energy Information Administration - Office of Coal, Nuclear, Electric and Alternate Fuels (December 2004), *Electric Power Annual 2003*.

Notes:

¹ The EIA classifies power plants (both electricity-only and combined-heat-and-power plants) into energy-use sectors based on the North American Industry Classification System (NAICS). Plants with a NAICS code of 22 are assigned to the Electric Power Sector. Those with NAICS codes beginning with 11 (agriculture, forestry, fishing, and hunting); 21 (mining, including oil and gas extraction); 23 (construction); 31-33 (manufacturing); 2212 (natural gas distribution); and 22131 (water supply and irrigation systems) are assigned to the Industrial Sector. Those with all other codes are assigned to the Commercial Sector.

Table A.2b: Summer installed capacity electric generators (MW/year), 1990 - 2003

	CHP electric generators ²	Rate of increase	Electric generators: Electric utilities & IPP	Rate increase
1990	11,215		698,262	
1991	12,932	15.31%	701,692	0.49%
1992	15,183	17.41%	705,291	0.51%
1993	17,263	13.70%	710,635	0.76%
1994	21,540	24.77%	714,286	0.51%
1995	22,733	5.54%	718,784	0.63%
1996	24,625	8.32%	722,970	0.58%
1997	25,071	1.81%	724,837	0.26%
1998	26,202	4.51%	721,312	-0.49%
1999	26,459	0.98%	729,827	1.18%
2000	27,392	3.53%	754,422	3.37%
2001	26,269	-4.10%	792,177	5.00%
2002	36,610	39.37%	839,212	5.94%
2003	42,332	15.63%	876,297	4.42%

Source: United States, Department of Energy, Energy Information Administration - Office of Coal, Nuclear, Electric and Alternate Fuels (December 2004), *Electric Power Annual 2003*.

Notes:

² "CHP Electric Generators" category only includes independent power producers' combined heat and power facilities. Electric utility CHP plants are included in "Electric Generators: Electric Utilities".

Figure A.1: U.S. Henry Hub natural gas futures, 2005 - 2010

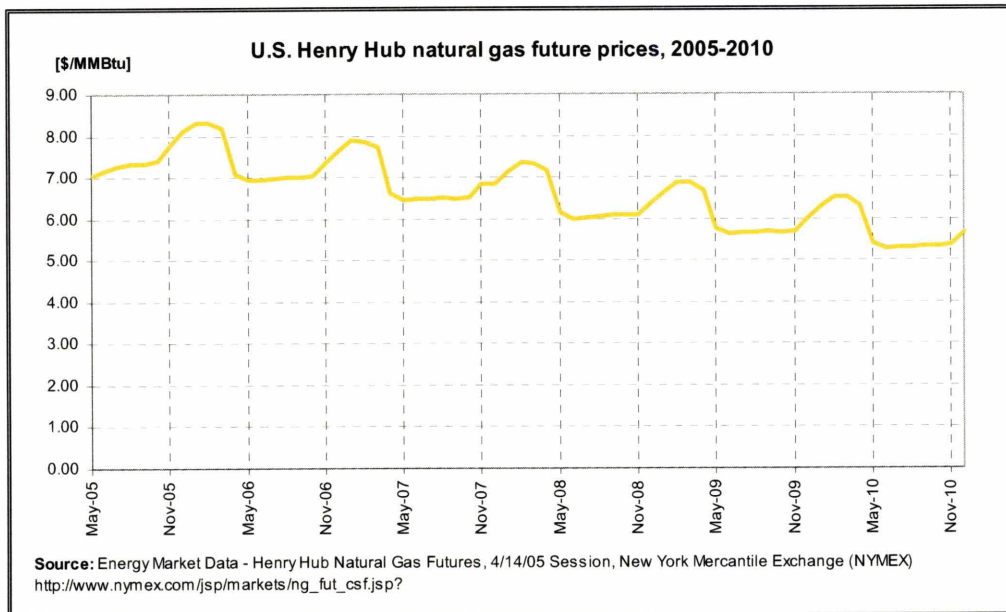
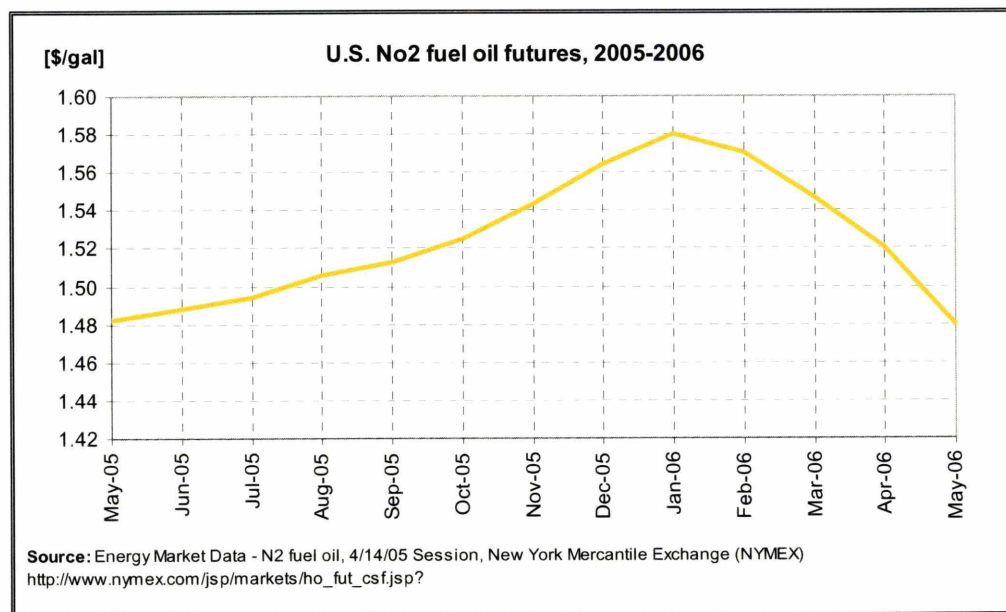


Figure A.2: U.S. heating oil futures, 2005 - 2006



APPENDIX B: UTILITY CASE-ELECTRICITY BOUGHT FROM NSTAR/STEAM GENERATED BY CUP

Utility Case

**All electricity purchased to NSTAR - Steam generated by the CUP
2005 USD**

Quantities		2005	2006	2007	2008	2009	2010	2011	2012
Electricity									
Peak electrical demand		28,967	29,981	31,030	32,116	32,598	33,087	33,584	38,588
Total Campus Electrical Load	MW/h	198,999	205,964	213,173	220,834	223,944	227,303	230,712	265,094
Fuel - Boilers 3,4,5 and Temp 7,8									
3,4,5 total fuel		1,934,521	2,002,229	2,072,307	2,144,838	2,177,010	2,209,666	2,242,811	2,577,040
7 total fuel	80.00%eff	-	-	-	-	-	-	-	-
8 total fuel	82.00%eff	-	-	-	-	-	-	-	-
Total BTU fuels	82.00%eff	-	-	-	-	-	-	-	-
3,4,5 Natural gas	9.26%	1,934,521	2,002,229	2,072,307	2,144,838	2,177,010	2,209,666	2,242,811	2,577,040
3,4,5 No. 6 oil	90.74%	179,043	185,310	191,795	198,508	201,486	204,508	207,576	238,509
7 Natural gas	9.26%	1,755,478	1,816,919	1,880,512	1,946,330	1,975,524	2,005,157	2,035,235	2,338,530
7 No. 2 oil	90.74%	-	-	-	-	-	-	-	-
8 Natural gas	100.00%	-	-	-	-	-	-	-	-
Notes: Max GAS contracted per day 7,000MMBtu/day									
Steam Quantities - Boilers 3,4,5 and Temp 7,8									
Peak steam demand (in year 2011, peak steam > 380kpph)	kpph	329	74%	77%	80%	81%	82%	83%	96%
Total campus steam load	MMBtu	1,547,617	1,601,783	1,657,846	1,715,870	1,741,608	1,767,732	1,794,248	438
3,4,5 --> max 2,153,115MMBtu/yr @ 90.2%	MMBtu	1,547,617	1,601,783	1,657,846	1,715,870	1,741,608	1,767,732	1,794,248	2,061,632
7 --> max 496,873MMBtu/yr @ 90.2%	MMBtu	-	-	-	-	-	-	-	2,061,632
8 --> max 496,873MMBtu/yr @ 90.2%	MMBtu	-	-	-	-	-	-	-	-
Notes:									
- Total maximum boilers capacity 380kpph									
- If boilers 3,4,5 coacity factor >70%, then efficiency 80%									
- If 85 trips off, the system needs a back-up boiler of at least 100kpph starting in 2005									
- In 2011 the system will have capacity problems again, but the same will happen with the Cogeneration case (no incremental cost)									

Efficiency									
Total steam energy load									
Steam energy load Boilers	MMBtu	1,547,617	1,601,783	1,657,846	1,715,870	1,741,608	1,767,732	1,794,248	2,061,632
Total fuel input	MMBtu	1,547,617	1,601,783	1,657,846	1,715,870	1,741,608	1,767,732	1,794,248	2,061,632
Fuel input Boilers	MMBtu	1,934,521	2,002,229	2,072,307	2,144,838	2,177,010	2,209,666	2,242,811	2,577,040
Efficiency CUP (Total_Steam/Total_Fuel)	%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Chilled Water Quantities									
CHW average demand	tons-hrs	45,587,421	47,182,980	48,834,385	50,543,588	51,301,742	52,071,268	52,852,337	60,728,521
Note: Assuming same quantities as in Cogeneration case -- Closed circuit									

Costs										
Electricity purchase, G-3										
Customer charge for G-3 rate		\$	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Distribution demand charge	over 100KVA	\$	508,218	549,658	592,308	617,275	630,385	643,325	660,841	828,556
Transition demand charge	1st 100	\$	1,462	1,525	1,588	1,598	1,608	1,617	1,636	1,785
	over 100KVA	\$	422,616	456,179	491,576	512,296	523,177	533,916	548,453	687,645
Transmission demand charge	1st 100	\$	3,876	4,042	4,208	4,236	4,262	4,285	4,337	4,730
	over 100KVA	\$	2,140,794	2,310,807	2,490,112	2,595,075	2,650,191	2,704,593	2,778,228	3,483,318
Distribution Energy		\$	242,779	262,029	282,329	294,198	300,432	306,585	314,918	394,689
Transition energy peak load		\$	-	-	-	-	-	-	-	-
Transition energy low load A		\$	-	-	-	-	-	-	-	-
Transition energy low load B		\$	-	-	-	-	-	-	-	-
Renewable energy		\$	99,500	107,389	115,709	120,573	123,128	125,650	129,065	161,758
Energy conservation		\$	497,498	536,945	578,543	602,864	615,640	628,249	645,324	808,789
Supplier-Default service		\$	15,117,652	16,316,325	17,580,387	18,319,431	18,707,648	19,090,799	19,609,887	24,576,934
Total electric purchase		\$	19,036,475	20,545,979	22,137,839	23,068,627	23,557,551	24,040,099	24,693,569	30,949,284
Fuel purchase - Boilers										
Natural gas Boilers 3,4,5,7,8		\$	1,474,007	1,441,032	1,403,943	1,387,692	1,345,125	1,303,863	1,296,953	1,242,474
No.6 oil Boilers 3,4,5		\$	10,602,682	11,529,202	12,507,589	12,362,814	11,983,584	11,615,988	11,554,423	11,069,078
No.2 oil Boiler 7		\$	-	-	-	-	-	-	-	-
Total fuel purchase		\$	12,076,689	12,970,233	13,911,532	13,750,506	13,328,709	12,919,851	12,851,376	12,311,552
Production without fuels										
O&M labor		\$	2,575,071	2,575,071	2,575,071	2,575,071	2,575,071	2,575,071	2,575,071	2,575,071
O&M materials		\$	1,546,325	1,546,325	1,546,325	1,546,325	1,546,325	1,546,325	1,546,325	1,546,325
Others: Water & Sewage (10% less than Cogeneration Case)		\$	4,036,356	4,036,356	4,036,356	4,036,356	4,036,356	4,036,356	4,036,356	4,036,356
Total O&M		\$	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752
			73,117,031							
Total operational costs		\$	39,270,916	41,673,965	44,207,124	44,976,886	45,044,012	45,117,702	45,702,697	51,418,589

Investment Costs

Tax rate = 0%
Initial investment (\$) = 6,000,000
Equity = 0%
Debt = 100%
Return on Equity = n/a
Return on Debt (real) = 7.125%
Economic life [yr] = 15
Discount rate (real) = 7.125%

Note: Investment on an existing building of 1 backup boiler with a capacity of 100kpph, stating 2005

	2005	2006	2007	2008	2009	2010	2011	2020
Investment backup boiler(s)								
(1) Operational cost	\$ 6,000,000	41,673,965	44,207,124	44,976,886	45,044,012	45,117,702	45,702,697	51,418,589
(2) Depreciation (SL)		400,000	400,000	400,000	400,000	400,000	400,000	400,000
(3) Interest payment		427,500	410,651	392,601	373,266	352,552	330,363	44,162
(4) Taxable income (1-2-3)		(42,501,465)	(45,017,775)	(45,769,487)	(45,817,278)	(45,870,255)	(46,433,060)	(51,862,751)
(5) Taxes								
(6) After tax cash-flow (1-3-5)		(42,101,465)	(44,617,775)	(45,369,487)	(45,417,278)	(45,470,255)	(46,033,060)	(51,462,751)
(7) Principal payment (sum=6,000,000)		236,478	253,327	271,377	290,713	311,426	333,615	619,816
(8) Principal remaining		5,763,522	5,510,194	5,238,817	4,948,105	4,636,679	4,303,064	0
(9) Total debt payment (princ + int -> cte)		663,978	663,978	663,978	663,978	663,978	663,978	663,978
(10) Net cash-flow (6-7)	\$ -	(42,337,943)	(44,871,102)	(45,640,864)	(45,707,991)	(45,781,681)	(46,366,675)	(52,082,567)

Emissions

		Total 06-20	2006	2007	2008	2009	2010	2011	2020
Emissions from boilers									
CO2 from Gas Boilers 3,4,5,7,8	[Metric ton CO2]	170,479	9,832	10,176	10,532	10,690	10,851	11,013	12,655
CO2 from No.6 FO Boilers 3,4,5	[Metric ton CO2]	2,482,431	143,167	148,178	153,364	155,665	158,000	160,370	184,268
CO2 from No.2 FO Boiler 7	[Metric ton CO2]	-	-	-	-	-	-	-	-
Total CO2	[Metric ton CO2]	2,652,911	152,999	158,354	163,896	166,355	168,850	171,383	196,923
Total C	[Metric ton C]	723,521	41,727	43,187	44,699	45,370	46,050	46,741	53,706
Emissions from purchased electricity (MWh-->%Nstar-->EnergyRate-->Losses-->Efficiency-->CO2 emission factor)									
CO2 from Gas	[Metric ton CO2]	735,558	42,421	43,906	45,443	46,124	46,816	47,518	54,600
CO2 from Oil (assuming No.6 FO)	[Metric ton CO2]	390,967	22,548	23,337	24,154	24,516	24,884	25,257	29,021
CO2 from Coal	[Metric ton CO2]	557,538	32,154	33,280	34,445	34,961	35,486	36,018	41,385
Total CO2	[Metric ton CO2]	1,684,064	97,124	100,523	104,041	105,602	107,186	108,794	125,006
Total C	[Metric ton C]	459,290	26,488	27,415	28,375	28,801	29,233	29,671	34,083
Total CO2 per year Boilers+NSTAR	[Metric ton CO2]	4,336,975	250,123	258,877	267,938	271,957	276,036	280,177	321,929
Total C per year Boilers+NSTAR	[Metric ton C]	1,182,811	68,215	70,603	73,074	74,170	75,283	76,412	87,799
Total CO2 emissions (2006 - 2020)	[Metric ton CO2]	4,336,975							
Total C emissions (2006 - 2020)	[Metric ton C]	1,182,811							

APPENDIX C: NEW ENGLAND NET GENERATION BY ENERGY SOURCE, 2004

Source	%
Coal	14.87%
Natural gas	38.16%
Oil	8.81%
Fossil	61.84%
Nuclear	28.51%
Hydro	4.84%
Other renewables	5.18%
Others sources	-0.38%
"Carbon-free"	38.15%

Table C.1: NE generation by energy sources

Source: United States, Department of Energy, Energy Information Administration (data through December 2004), *Electric Power Monthly Summary: Monthly information on net generation, fuel consumption, fuel stocks, fuel receipts, sales, and revenues at U.S. electric utilities* (http://www.eia.doe.gov/cneaf/electricity/epm/epm_h_tabs.html).

APPENDIX D: COGENERATION CASE - STEAM AND MOST ELECTRICITY GENERATED BY CUP

Cogeneration Case Steam and most electricity generated by the CUP 2005 USD		2005	2006	2007	2008	2009	2010	2011	2020
Quantities									
Electricity									
12 month average demand	KVA-month	28,967	29,981	31,030	32,116	32,598	33,087	33,584	38,588
Total Campus Electrical Load	MWh	198,999	205,964	213,173	220,634	223,944	227,303	230,712	265,094
Electricity generated CGT	MWh	154,087	154,087	154,087	154,087	154,087	154,087	154,087	154,087
Total energy purchase	MWh	44,912	51,877	59,086	66,547	69,856	73,215	76,625	111,006
Supplemental purchase (>19.5MW)									
Supplemental average demand (demand load-19,500)	kW-month	9,467	9,799	10,142	10,496	10,654	10,814	10,976	12,612
Total supplemental energy (load-100%CGT)	MWh	28,179	36,144	42,353	49,346	53,124	56,483	59,892	93,806
Maintenance purchase									
Transmission capacity (19500kW)	kW-month	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500
Total maintenance energy	MWh	16,380	16,380	16,380	16,425	16,380	16,380	16,380	16,425
Standby purchase (<19.5MW)									
Transmission capacity	kW-month	-	-	-	-	-	-	-	-
Peak Transmission capacity	kW-month	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500
Transmission capacity reserve	kW-month	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500
Total emergency energy (purchase-supplemental)	MWh	390	390	390	391	390	390	390	391
Fuel - Boilers 3,4,5, Temp 7,8 and Cogen									
Gas CGT	MMBtu	1,972,319	1,972,319	1,972,319	1,972,319	1,972,319	1,972,319	1,972,319	1,972,319
Gas HRSG	MMBtu	552,081	552,081	552,081	552,081	552,081	552,081	552,081	552,081
Total gas cogen	MMBtu	2,524,399	2,524,399	2,524,399	2,524,399	2,524,399	2,524,399	2,524,399	2,524,399
3,4,5 total fuel	MMBtu	278,279	345,987	416,065	488,596	520,768	553,424	586,569	920,798
7 total fuel	MMBtu	-	-	-	-	-	-	-	-
8 total fuel	MMBtu	-	-	-	-	-	-	-	-
3,4,5 Natural gas --> 9.26% or gas restriction	MMBtu	25,755	30,601	30,601	30,601	30,601	30,601	30,601	30,601
3,4,5 No. 6 oil --> 90.74% or gas restriction	MMBtu	252,524	315,386	385,464	457,995	490,168	522,823	555,968	890,197
7 Natural gas	MMBtu	-	-	-	-	-	-	-	-
7 No. 2 oil	MMBtu	-	-	-	-	-	-	-	-
8 Natural gas	MMBtu	-	-	-	-	-	-	-	-
% No. 6 oil burned in 3,4,5 because restriction of gas contracts		90.74%	91.16%	92.65%	93.74%	94.12%	94.47%	94.78%	96.68%
TOTAL GAS Cogen + boilers	MMBtu	2,550,155	2,555,000	2,555,000	2,555,000	2,555,000	2,555,000	2,555,000	2,555,000

Notes:
- 20 years gas contract with COMGAS (left 12years starting 2005): 5,500 MMBtu/day
- 12 years gas contract with DISTRIGAS (starting 2005): 1,500 MMBtu/day
- Assuming 365days and 7,000MMBtu/day --> Max GAS consumption:2,555,000MMBtu/yr

Steam Quantities - Bollers 3,4,5, Temp 7,8 and CGT+HRSG (total max. capacity 540kpph)

Peak steam demand	MMBtu/hr
Total campus steam load	MMBtu/hr
CGT --> max 828,121MMBtu/yr @ 90.2%	MMBtu/hr
HRSG--> max 496,873MMBtu/yr @ 90.2%	MMBtu/hr
Total hydrogen production (GT10 + HRSG)	MMBtu/hr
3,4,5 --> max 2,153,115MMBtu/yr @ 90.2%	MMBtu/hr
7 --> max 496,873MMBtu/yr @ 90.2%	MMBtu/hr
8 --> max 496,873MMBtu/yr @ 90.2%	MMBtu/hr

Notes:

- CGT unfired --> waste heat = base load @ 90.20% Cap. Factor
- HRSG supplemental --> HRSG = steam load-waste (max 496,873MMBtu/yr)
- Total Cogen production = waste+HRSG (max 1,324,994MMBtu/yr)
- Boilers3,4,5 --> rest steam = steam load-cogen (max 2,153,115MMBtu/yr)
- Boiler Temp 7 --> rest steam = steam load-cogen-3,4,5 boilers (max 496,873MMBtu/yr)
- Boiler Temp 8 --> rest steam = steam load-cogen-3,4,5,7 boilers (max 496,873MMBtu/yr)
- If Coen trips off there is back up until year 2010 (540-160=380kppht)
- but in 2011 the system will have problems again = same scenario with Utility Case (no incremental cost)

Efficiency

[illegible]

Chilled Water Quantities

CHW average demand

CHW average demand
Note: Assuming same quantities as in Utility case -- Closed circuit

Costs											
Supplemental purchase, G-3 rate											
Customer charge for supplemental/maintenance/standby											
Distribution demand charge											
Transition demand charge											
Transmission demand charge											
Distribution Energy											
Transition energy peak load											
Transition energy low load A											
Transition energy low load B											
Renewable energy											
Energy conservation											
Supplier-Default service											
Total electric supplemental purchase											
Maintenance purchase, G-3 rate											
Transmission capacity charge											
Distribution Energy											
Transition energy charge											
Renewable energy											
Energy conservation											
Supplier-Default service var rate (DTE)											
Total electric maintenance purchase											
Standby service purchase											
Transmission capacity charge											
Greater of --> Peak transmission capacity charge											
or --> Transmission capacity reserve charge											
Distribution Energy											
Transition energy charge											
Renewable energy											
Energy conservation											
Supplier-Default service var rate (DTE)											
Total electric emergency purchase											
Fuel purchase, CGT + HRSG + 3,4,5,7,8 Boilers											
Natural gas 3,4,5,7,8 + Cogen											
No 6 oil 3,4,5											
No 2 oil 7											
Total fuel purchase											
Production without fuels											
O&M labor											
O&M materials											
Others - Water & Sewage											
Total O&M											
Total operational costs											

Carrying capital costs cogeneration plant since 1996

Source: Finance and Accounting, MIT's Facilities Department

1996 Investment Costs

Tax rate =	0%
Initial investment (\$) =	48,477,265
Equity =	0%
Debt =	100%
Return on Equity =	n/a
Return on Debt (real) =	7.125%
Economic life (yr) =	25
Discount rate (real) =	7.125%
Indirect Cost Recovery (ICR) on interests =	45%

30 years taxable-bonds sold by MIT in 11/05/96
Depreciation for 25 year and straight line method

@ 1996

Total Project capitalization \$	51,803,522	Cogeneration plant, deferred maintenance, contingency, interests during construction, others
Deferred Maintenance \$	3,326,257	2.3kV substation, boilers controls upgrade, flame safety upgrade, chiller control upgrade, fuel tank removal
Cogeneration plant \$	48,477,265	Including interests during construction (\$3,103,603)

	1995	1996	Base 2005	2006	2007	2008	2009	2010	2011	2020
Investment in 1995	48,477,265									
(1) Operating Income		1,939,091	1,939,091	1,939,091	1,939,091	1,939,091	1,939,091	1,939,091	1,939,091	1,939,091
(2) Depreciation (SL)		3,454,005	2,808,190	2,708,538	2,601,787	2,487,429	2,364,923	2,233,689	2,093,104	279,799
(3) Interest payment		(5,393,096)	(4,747,281)	(4,647,629)	(4,540,877)	(4,426,519)	(4,304,014)	(4,172,779)	(4,032,194)	(2,218,890)
(4) Taxable Income (1-2-3)										
(5) Taxes										
(6) After tax cash-flow (1-3-5)		(3,454,005)	(2,808,190)	(2,708,538)	(2,601,787)	(2,487,429)	(2,364,923)	(2,233,689)	(2,093,104)	(279,799)
(7) Principal payment (sum=48,477,265)		752,804	1,398,619	1,498,271	1,605,022	1,719,380	1,841,886	1,973,121	2,113,705	3,927,010
(8) Principal remaining		47,724,461	38,014,575	36,516,304	34,911,282	33,191,901	31,350,015	29,376,895	27,263,189	-
(9) Total debt payment (princ + Int = cte)		4,206,809	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809
(10) Net cash-flow (6-7)		(4,206,809)	(4,206,809)	(4,206,809)	(4,206,809)	(4,206,809)	(4,206,809)	(4,206,809)	(4,206,809)	(4,206,809)
(11) Indirect Cost Recovery (ICR)		1,554,302	1,263,686	1,218,842	1,170,804	1,119,343	1,064,215	1,005,160	941,897	125,910
Total Net cash-flow with ICR (10+11)		(2,652,507)	(2,943,124)	(2,987,967)	(3,036,005)	(3,087,466)	(3,142,594)	(3,201,649)	(3,264,912)	(4,080,899)

Emissions

		Total 06-20	2006	2007	2008	2009	2010	2011	2020
Emissions from purchased fuel									
CO2 from Gas 3,4,5,7,8 + Cogen	[Metric ton CO2]	2,033,397	135,560	135,560	135,560	135,560	135,560	135,560	135,560
CO2 from No6FO 3,4,5	[Metric ton CO2]	741,854	24,851	30,373	36,088	38,624	41,197	43,808	70,145
CO2 from No2FO 7	[Metric ton CO2]	-	-	-	-	-	-	-	-
Total CO2	[Metric ton CO2]	2,775,251	160,411	165,933	171,648	174,183	176,756	179,368	205,704
Total C	[Metric ton C]	756,887	43,749	45,254	46,813	47,505	48,206	48,919	56,101
Emissions from purchased electricity (MWh-->%Nstar-->EnergyRate-->Losses-->CO2 emission factor)									
CO2 from Gas	[Metric ton CO2]	259,512	10,685	12,170	13,706	14,388	15,080	15,782	22,863
CO2 from Oil (assuming No6 FO)	[Metric ton CO2]	137,937	5,679	6,468	7,285	7,648	8,015	8,389	12,152
CO2 from Coal	[Metric ton CO2]	196,704	8,099	9,224	10,389	10,906	11,430	11,962	17,330
Total CO2	[Metric ton CO2]	594,153	24,463	27,862	31,380	32,941	34,525	36,133	52,346
Total C	[Metric ton C]	162,042	6,672	7,599	8,558	8,984	9,416	9,854	14,276
Total CO2 per year CUP+NSTAR	[Metric ton CO2]	3,369,403	184,874	193,795	203,029	207,124	211,282	215,501	258,050
Total C per year CUP+NSTAR	[Metric ton C]	918,928	50,420	52,853	55,371	56,488	57,622	58,773	70,377
Total CO2 emissions (2006 - 2020)	[Metric ton CO2]	3,369,403							
Total C emissions (2006 - 2020)	[Metric ton C]	918,928							

APPENDIX E: COMPARISON COGENERATION AND UTILITY CASES

Costs

Utility Case	2005	2006	2007	2008	2009	2010	2011	2020
Total electric purchase	\$	20,545,979	22,137,839	23,068,627	23,557,551	24,040,099	24,693,569	30,949,284
Total fuel purchase	\$	12,970,233	13,911,532	13,750,506	13,328,709	12,919,851	12,851,376	12,311,552
Total O&M water services	\$	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752	8,157,752
Total costs with capacity investment (1A)	\$	42,337,943	44,871,102	45,640,884	45,707,991	45,781,681	46,366,675	52,082,567
Cogeneration Case								
Efficiency Cogen plant	%	73.32%	73.32%	73.32%	73.32%	73.32%	73.32%	73.32%
Efficiency CUP	%	74.12%	74.26%	74.40%	74.46%	74.52%	74.58%	75.10%
PURPA QF efficiency	%	47.08%	47.08%	47.08%	47.08%	47.08%	47.08%	47.08%
Total electric supplemental purchase	\$	4,030,194	4,862,350	5,549,537	5,934,853	6,283,459	6,683,961	10,820,975
Total electric maintenance purchase	\$	1,691,789	1,761,213	1,777,123	1,784,006	1,793,640	1,815,163	1,984,296
Total electric emergency purchase	\$	481,190	500,936	504,436	507,418	510,158	516,280	563,242
Total fuel purchase	\$	21,869,835	21,266,387	20,770,105	20,030,610	19,318,406	19,120,208	17,523,453
Total O&M water services	\$	10,069,116	10,069,116	10,069,116	10,069,116	10,069,116	10,069,116	10,069,116
Total operational costs (2)	\$	38,142,123	38,460,002	38,670,317	38,326,004	37,974,779	38,204,729	40,961,082
Operational savings (1A-2)	\$	4,195,820	6,411,100	6,970,547	7,381,987	7,806,902	8,161,946	11,121,485
NPV 2006-2020 @ 7.13%	\$	73,318,511						
Operational Savings - Carrying Capital Costs Cogeneration Case								
(1) Operational savings	\$	-	6,411,100	6,970,547	7,381,987	7,806,902	8,161,946	11,121,485
(2) Depreciation (SL)	\$	4,195,820	1,939,091	1,939,091	1,939,091	1,939,091	1,939,091	1,939,091
(3) Interest payment	\$	2,708,538	2,601,787	2,487,429	2,364,923	2,233,689	2,093,104	279,799
(4) Taxable Income (1-2-3)	\$	(451,809)	1,870,223	2,544,028	3,077,973	3,634,123	4,129,751	8,902,595
(5) Taxes	\$	-	-	-	-	-	-	-
(6) After tax cash-flow (1-3-5)	\$	1,487,281	3,809,313	4,483,119	5,017,064	5,573,213	6,068,842	10,841,685
(7) Principal payment	\$	1,498,271	1,605,022	1,719,380	1,841,886	1,973,121	2,113,705	3,927,010
(8) Principal remaining	\$	36,516,304	34,911,282	33,191,901	31,350,015	29,376,895	27,263,189	-
(9) Total debt payment (princ + int -> cte)	\$	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809	4,206,809
(10) Net cash-flow (6-7)	\$	(10,990)	2,204,291	2,763,738	3,175,178	3,600,093	3,955,137	6,914,676
(11) Indirect Cost Recovery (ICR)	\$	1,218,842	1,170,804	1,119,343	1,064,215	1,005,160	941,897	125,910
Total Net cash-flow with ICR (10+11)	\$	-	3,375,095	3,883,081	4,239,393	4,605,253	4,897,033	7,040,585
NPV @ 7.13%	\$	42,969,816						

CO2 Emissions

Utility Case	Total 06-20	2006	2007	2008	2009	2010	2011	2020
From boilers	2,652,911	152,999	158,354	163,896	166,355	168,850	171,383	196,923
From purchased electricity	1,684,064	97,124	100,523	104,041	105,602	107,186	108,794	125,006
Total CO2 emissions (1)	4,336,975	250,123	258,877	267,938	271,957	276,036	280,177	321,929
Cogeneration Case	Total 06-20	2006	2007	2008	2009	2010	2011	2020
From fuel_CGT_HRSG_Boilers	2,775,251	160,411	165,933	171,648	174,183	176,756	179,368	205,704
From purchased electricity	594,153	24,463	27,862	31,380	32,941	34,525	36,133	52,346
Total CO2 emissions (2)	3,369,403	184,874	193,795	203,029	207,124	211,282	215,501	258,050
CO2 benefit (1-2)		65,249	65,082	64,909	64,832	64,754	64,676	63,879
CO2 benefit 2006-2020	967,571							

APPENDIX F: DESCRIPTION OF PRIME MOVER TECHNOLOGIES

F.1. INTERNAL COMBUSTION ENGINE

Also known as reciprocating internal combustion (IC) engines, they are mostly used for small size applications because of their good performance and the already existing production capability. Some of the applications include backup power during emergency situations or power outages, peak shaving, and CHP in commercial, institutional, and light industrial applications less than 10MW.

IC engines can use gasoline, diesel, natural gas, or propane/methane fuel to power the piston engine based on the “Otto cycle”. This cycle consists of four strokes (see Diagram F.1 for an illustration of the Otto cycle) , where the “intake” stroke takes air mixed with fuel into the cylinder, then the “compression” stroke compresses the cylinder content where combustion takes place producing pressure and heat to move the piston in the “power” stroke, and finally in the “exhaust” stroke the exhaust of the combustion process is removed from the engine (Willis et al, 2000, pp. 156).

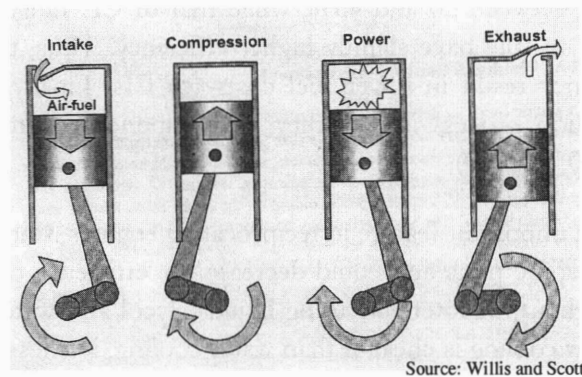


Diagram F.1: Otto cycle

For power generation, there are two main IC engine types used in the process:

a. Four-Cycle Spark-Ignition Engines (SI).

SI engines ignite the fuel through an electrical spark located inside the cylinder at a specific time, close to the end of the compression stroke. Natural gas is mostly preferred, although gasoline can also be used. Both fuels are easy to ignite, and work best when used with SI engines at lower compression ratios. This type of engine has lower fuel costs and lower emissions than diesel engines, although they need more maintenance and the efficiency levels are extremely low when not operating at full-load conditions.

b. Compression-Ignition Reciprocating Engines (CI).

CI engines compress the fuel-air mixture inside the piston cylinder, increasing the temperature until the combination explodes spontaneously. This process works best with slow-burning fuels like diesel fuels instead of gasoline, since a high compression rate is required before the spontaneous combustion occurs. It can also use natural gas, although there is some loss in efficiency.

Within this category, the diesel engine is a very common technology. It combines fuel injection and compression ignition in a process where the fuel and air are mixed inside the cylinder. The air is drawn into the cylinder through the intake stroke, and the fuel is injected into the cylinder after the compression stroke has started, when the combustion is to occur. This difference in the process makes it possible to increase the compression ratio, simultaneously increasing the temperature and the efficiency.

When compared to SI engines, CIs are bigger and heavier because the higher compression ratio of diesels requires heavier components to resist the pressures and temperatures. CIs generally burn lower cost, heavier liquid fuels, while SI can burn gasoline, methane or natural gas. The efficiency of SIs ranges between 20 and 43%, while that of CIs ranges between 28 and 40%, although the latter ones usually have slightly higher efficiency. Thus, the use of less expensive fuels and higher efficiency result in lower fuel costs for CIs. Finally, because of the precise control of the combustion process in SIs, they have superior control of emissions than CI engines (Willis et al, 2000, pp. 170).

The cooling system is an important feature in reciprocating engines, since the heat of the internal combustion could melt some parts and could decrease the efficiency of the engine. ICs can be cooled externally through air, or internally using liquid (glycol and water mixture) pumped into the radiator. Although air cooling is cheaper than water cooling, it is less efficient and works well with small engines. On the other hand, liquid cooling permits a more precise control of the combustion process, both enhancing the efficiency and the control of exhaust emissions.

Among the benefits of using IC engines we can mention (Aspen, 2000, pp. 3):

- Low installation costs, ranging between \$500 and \$1,200/kW.
- Low start-up and operating costs.
- Reliable generation.
- Ease of maintenance.
- Higher efficiency levels.

Issues of concern are noise and vibration, exhaust emissions, and the poor quality of the waste heat for cogeneration applications. Even though the noise can be reduced through multi-cylinder engines, where the motion of one piston will oppose that of another, the engines still remain very noisy. Also, large amounts of particulates⁶⁹ are released especially when IC engines use diesel fuel; getting the permit for continuous operation in non-attainment areas is difficult.

Finally, new developments are being focused in small packaged IC engines, aimed at small to medium sized building applications. These engines are being designed to be quiet and clean, use natural gas, and have higher efficiency levels. Packaged natural-gas IC engine cogenerators can capture the waste heat and reach overall efficiencies of about 80% (Aspen, 2000, pp. 4). Also, among the latest emissions reduction technologies, we can mention lean NO_x catalytic converters, mechanical fuel injection, after cooling, advanced NO_x absorbers, and particulate traps.

F.2. COMBUSTION TURBINES

In combustion gas turbines (CTs), the combustion gases spin a turbine which rotates a generator to produce electricity. This technology ranges from 20kVA to hundreds of megawatts, using different type of fuels, with various efficiency levels and operating characteristics. Broadly speaking there are three categories of gas turbine generators depending on the size (Willis et al, 2000, pp. 176). The traditional "utility gas turbines" range from 10,000kVA to more than 150,000kVA, with typical values of about 70,000kVA⁷⁰ and designed specifically for power generation applications. The "mini-gas turbine generators" range from 800kVA up to about 10,000kVA mostly produced for military designs, but when used for DG they tend to be less efficient. The third category, the "micro-turbine generator", ranges from less than 20kVA up to 750kVA and has been increasing its uses for power applications. The best efficiency levels for each of them is about 37%, 30% and 32% respectively.

A gas turbine's operation consists of four stages (Willis et al, 2000, pp. 182). First, the air is drawn into the turbine at the compressor inlet and compressed in the compressor, where the air is pulled at high speed and pressure into the engine. Second, the high temperature compressed air is mixed with fuel in the combustion chamber or burner, where it is ignited under controlled conditions to promote fuel efficiency and low emissions. Third, the hot gases are discharged through the expansion turbine to produce work used to spin the compressor and the electric generator, while the temperature and pressure of the gases drop. Finally, the waste gases are discharged from the turbine outlet into the atmosphere (see Diagram F.2).

⁶⁹ Depending on the fuel, NO_x emissions for SI engines range from 2-28lb/MWh and for CI engines from 3-33lb/MWh.

⁷⁰ Greater sizes are distinctive for large central power plants.

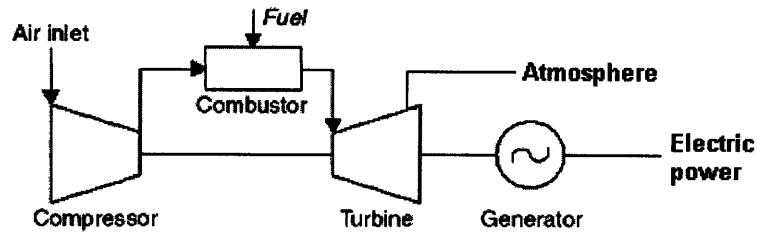


Diagram F.2: Operation gas turbine

Gas turbines generally use either natural gas or fuel oil, with the first one providing better efficiency and higher maximum output ratings. It is common that the turbines be built to burn two or more fuels, providing the system flexibility and reliability in cases where some of the fuels is not available.

CTs produce large volumes of hot exhaust gas which can be converted or not to produce additional thermal energy or electricity. Depending on how the waste heat of the process is used, two configurations can be adopted:

a. Simple-Cycle CTs.

A simple-cycle CTs has only one gas turbine that operates as we explained above (see Diagram F.2). The high quality of the waste heat makes this technology attractive for commercial or institutional CHP applications. As with MIT's case, the exhaust flow from the turbine can be captured to produce useful steam for heating and cooling purposes in a simple-cycle configuration in combination with a heat recovery steam generator (HRSG).

This technology is widely used in industrial applications between 5 to 30MW range. Among the main advantages of this technology are low capital and maintenance costs, and easy dispatchability suitable for peaking operations.

b. Combined-Cycle Gas CTs (CCGT).

In CCGTs, the CT exhaust heat is used to boil water to produce steam. This steam runs a steam turbine which will be used to spin a second electrical generator for additional electrical power. A HRSG links the cycles from the gas turbine and steam turbine generators, which through supplemental firing can increase the temperature of the exhaust gas and optimize the operations of the steam turbine (see Diagram F.3). Usually, in gas turbine-based combined-cycle systems, the ratio of power output of the gas turbine to the steam turbine is 2:1 (Petchers, 2003, pp. 255). CCGT turbines have one of the highest efficiencies in commercial use among all types of power generation technologies, some of them up to 44% (Willis et al, 2000, pp. 180).

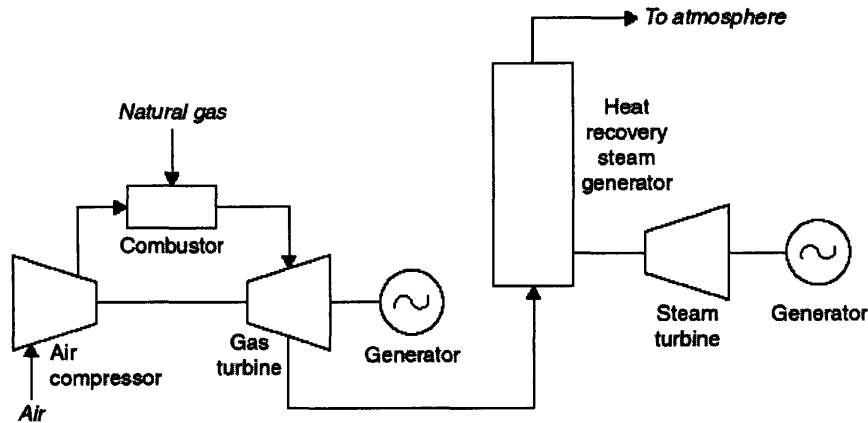


Diagram F.3: Combined-cycle combustion gas turbine

When the electrical and thermal loads are variable over time, combined-cycle configuration may be preferred. This system will give more flexibility to the operation by varying the flow of the steam and the electrical output to the conditions at a particular moment. Thus, during periods of high electrical demand, the steam sent to the steam turbine can be used to generate the additional requirements and, during periods of high thermal demand, the steam generated at the HRSG can be used for meeting that need.

However, CCGTs increase the size of the facility because of the additional turbine and generators. Therefore, CCGTs are mostly used for large size applications, and because of the low efficiency at part-load operations, they are mostly used in sizes above 50MW not suitable for DG.

Among the benefits of the combustion gas turbines are (Aspen, 2000, pp. 5-6):

- High reliability, with long times between major overhauls.
- Low maintenance and maintenance costs, because there is no liquid cooling systems and minor contamination of the lubricating systems.
- Large volumes and high quality of waste heat, which can be used in a combined cycle or cogeneration applications.
- Low emissions, because the combustion process is oxygen rich. NO_x emissions vary from 0.25 to 4lb/MWh, a much lower level than those for IC engines. Additionally, the emissions can be lowered using dry combustion techniques, water or steam injection, or exhaust treatment.
- Electric efficiencies can reach beyond 40% when used as combined-cycle unit.
- Low CHP capital costs especially for large units, ranging between \$650 and \$900/kW (CECA, 2001, pp. 27).

However, some disadvantages of this technology are the specialized skill and knowledge necessary for maintenance requirements; degradation of maximum output and efficiency with changes in site ambient conditions⁷¹ for simple-cycle systems; efficiencies between 28 and 32% for small gas turbine generators which is lower than that of IC engines; and low efficiency levels if CTs are operated under partial load mode⁷² (CECA, 2001, pp. 33).

Finally, current research and development of gas turbines are centered in emission control technologies, and in material strength and operating temperature tolerance of turbine components (Petchers, 2003, pp. 211). Material and cooling technology are key to endure long-term operational stresses, with enhanced efficiency and power capacity. Research is being focused on superalloys with great strength and resistance to oxidation at high temperatures, also high-temperature ceramics for components, among other materials.

F.3. FUEL CELLS

Fuel cells use an electrochemical process that converts hydrogen-rich fuels into electricity and heat. This technology consumes oxygen obtained from air, and hydrogen contained in fossil fuels, such as natural gas, petroleum, liquefied petroleum gas (LPG), petroleum, methanol, or coal gas.

In general, a hydrogen fuel cell has an anode and a cathode and contain an electrolyte material that allows ions to pass, blocking the electrons (see Diagram F.4). A hydrogen reformer extracts hydrogen from the hydrocarbon fuel such as natural gas and then it is pumped through a cleaner and filter into the fuel cell. The hydrogen flows to the anode where the pulled off electrons, that can not pass through the electrolyte membrane to the cathode, travel around it in an external circuit to generate DC power. At the cathode, the hydrogen is oxidized when the electrons combine with the hydrogen ions and oxygen to form water or steam. The exhaust heat is steam with few pollutants that exceeds 530°C, and can be used for cogeneration purposes using a heat recovery system. Finally, since the oxidation of hydrogen produces a charge that will create a direct current (DC) flow from the anode to the cathode, an inverter will be required to convert the DC power into alternating current (AC).

⁷¹ Factors that affect the overall performance are increase altitude, and increase ambient temperature and humidity.

⁷² Below 25kW, efficiency ranges from 4% to 10%.

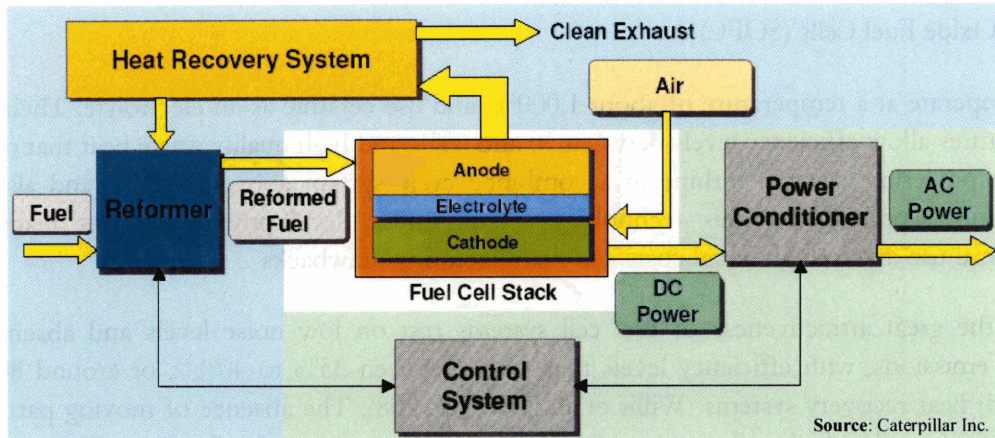


Diagram F.4: Fuel cell basic operation

Fuel cells are classified depending on the type of chemical used as electrolyte. We will focus our analysis in those high temperature fuel cells, where the heat can be used for other applications. Particularly, we will review⁷³:

a. Phosphoric Acid Electrolyte Fuel Cells (PAFC).

PAFCs are the most mature technology of this type suitable for DG applications, with some plants commercially available but limited to niche markets. They use phosphoric acid as an electrolyte and platinum as a catalyst. This technology can be operated at internal temperatures of 175 - 225°C, with almost 40% efficiency. Even though they are currently produced in 200kW modules⁷⁴, they have been used to build power plants as large as 11MW (CECA, 2001, pp. 36). PAFCs are mostly configured as CHP applications, where the heat is used for space heating or hot water.

b. Molten Carbonate Fuel Cells (MCFC).

MCFCs use molten carbonates as an electrolyte and operate between 600 and 750°C requiring long start-up time. Because they do not require an external hydrogen reformer, and the high operating temperatures, their efficiency levels are about 50%. The high temperature exhaust gases can be used in a combined cycle system increasing the overall efficiency of the system, but also requiring more supporting equipment (rendering this technology not suitable for small modular systems). This technology is still under development, being tested in DG demonstration plants. Some manufacturers are developing MCFCs systems targeted at 250kW, 1MW and 2MW power plants⁷⁵.

⁷³ Most information extracted from (Willis et al, 2000, pp. 213-220).

⁷⁴ Some units have been built in sizes as small as 50kW of capacity.

⁷⁵ Manufacturers such as Energy Research Corporation (ERC) and M-C Power (MCP).

c. Solid Oxide Fuel Cells (SOFC).

SOFCs operate at a temperature of about 1,000°C and use ceramic as an electrolyte. Their high temperatures allow efficiency levels between 50 and 60%, and high quality waste heat that can be used for powering a steam turbine in a combined cycle system above 25MVA, and also for cogeneration applications. This technology is still under development and not ready for commercial use due to high initial costs and manufacturing drawbacks.

Finally, the great attractiveness of fuel cell systems rest on low noise levels and absence of harmful emissions, with efficiency levels that range between 35% to 40%⁷⁶, or around 80% if used with heat recovery systems (Willis et al, 2000, pp. 208). The absence of moving parts and combustion in the fuel cell process helps to reduce noise and vibration. The catalytic combination of hydrogen and oxygen is the main reason of the high efficiency and almost emission-free operations of this technology. The combustion does not have the open flame characteristic of the IC engines and CTs systems, and the exhaust consists of almost pure steam and hot air. Other advantages are the high quality of the heat exhaust, and modular availability and quick installation.

However, the main barrier for a wider market deployment of this technology is the high capital costs ranging from \$3,000 to \$3,500/kW; great sensitivity to fuel impurities which makes necessary more effective filters and cleaners than for ICs and CTs; and low efficiency when power output fluctuates. Additionally, because fuel cells produce high-current/low-voltage DC power, they need a DC/AC converter and a filter system to transform it into AC. For maintenance and repair, they require specialists in this particular technology. Therefore, much of its development is being made under demonstration programs only.

⁷⁶ Few units under research and testing have efficiencies over 50%, and some researchers predict that they could reach up to 60%.

APPENDIX G: REGULATORY FRAMEWORK

G.1. PUBLIC UTILITIES REGULATORY POLICY ACT

In 1978 the passage of the Public Utilities Regulatory Policy Act (PURPA) brought into the electricity market a new player: the independent power producer who competed with the existing utilities for supplying electricity during the 1980s. PURPA's primary goal was to encourage a better use of energy through cogeneration and renewable resources through the conservation of electricity, fuel and energy efficiency, and equitable pricing for non-utility generated electricity.

PURPA made possible the development of non-utility generating companies and the introduction of competition into the generation sector through Qualifying Facilities (QFs). QFs could be small power production facilities using renewable resources or cogeneration facilities using oil, gas or coal under specific requirements regarding ownership, operating, and efficiency criteria established by the FERC (EIA, 2000).

FERC left PURPA's implementation to the individual decision of the states, and as a result, the legislation had wide support from states such as California, New York, Massachusetts, Maine, and New Jersey; and it was important also for stimulating the development of Gas Combined Cycle Generation Technology (CCGT) (Joskow, 2000). QFs represented a new source of supply in the electricity market, and there was an increasing demand for new generating technologies with lower capital costs and shorter lead times than the conventional ones.

PURPA defines two kinds of QFs: i) small power producers whose capacity does not exceed 80MW and receive at least 75% of energy input from renewable resources, ii) cogenerators that produce electric power as well as useful thermal energy through the sequential use of energy from one source of fuel. FERC is responsible for certifying QFs⁷⁷. To be recognized as such facility, it needs to meet the following criteria (Fluor, 1986, pp. 4-29):

- An electric utility may own no more than 50% equity in a cogeneration facility.
- Criteria for Cogeneration facilities⁷⁸:
 - Facility efficiency (η_{QF}^{PURPA}) defined as:

$$\eta_{QF}^{PURPA} = \frac{q_{electricity} + \frac{1}{2}q_{thermal}}{f_{electricity} + f_{thermal}}$$

⁷⁷ As of 1999, application fees were \$12,650 for small power producers and \$14,320 for cogeneration facilities.

⁷⁸ These criteria are applicable to topping-cycle facilities, such as MIT's cogeneration plant, where the energy input is first used to produce useful electricity, and part of the waste heat is then used to provide useful thermal energy. For bottoming-cycle facilities, where the energy input is first applied to a useful thermal energy process and then part of the rejected heat is used for electric generation, the annual power output must be at least 45% of the total energy input.

where,

$q_{electricity}$	= Energy content of the electricity generated,
$q_{thermal}$	= Energy content of the steam generated,
$f_{electricity} + f_{thermal}$	= Total energy input.

- If useful thermal output ($q_{electricity}$) is greater than 15% of the total energy output, then the facility efficiency (η_{QF}^{PURPA}) must be greater than or equal to 42.5%.
- If useful thermal output is between 5 and 15% of the total energy output, then the efficiency must be greater than or equal to 45%.
- Useful thermal energy output during any calendar year can be no less than 5% of the total energy output.
- Criteria for Small Power Production facilities:
 - Small power producers are facilities $\leq 80\text{MW}$ that use biomass, waste, geothermal, or renewable resources to produce electricity. These facilities include solar, wind, geothermal, hydroelectric, biomass, and municipal solid waste systems, with a maximum fossil fuel use of 25% of the total energy input during a twelve-month period.

In general, PURPA encourages non-discriminatory practices requiring utilities to purchase electricity from the QFs at a just and reasonable price, sell electricity to QFs at rates available to customers with similar load characteristics, and allow all QFs to interconnect to the electrical grid. Therefore, when QFs have excess capacity they can sell it back into the wholesale market or into the retail market depending on the state's regulations.

As we will explain below, the rate structure used by the utilities will depend mostly on the customer's load characteristic, but it will vary widely from state to state and from utility to utility. Some of them may include more restrictive options such as mandatory standby charges in case of outages (Petchers, 2003, pp. 404-405).

G.2. DE REGULATIONS

In Massachusetts, besides the two type of QFs – small power production facilities and cogeneration facilities – there is another type of small facility called “on-site generating facility (OSGF)” which is allowed to sell electricity back to the distribution companies through net metering⁷⁹. An OSGF includes any generator that has a capacity of 60kW or less, including QFs and non QFs such as natural gas microturbines that produce only electricity (DOER, 2001).

On December of 1999, the DTE promulgated regulations regarding the sale of electricity between QFs, OSGFs and distributions companies – 220 CMR 8.00 et seq – in the competitive market. Thus, DE producers are able to sell and buy power, through a standard contract, from

⁷⁹ An OSGF can receive credit for surplus generation against the retail cost of electricity. Thus, OSGFs can run their meter forward and backwards.

their local distribution company based on hourly wholesale market prices determined by the New England Independent System Operator (ISO-NE). Other options for selling power are either through the ISO-NE if the facility has a capacity greater than 5MW and it is metered by that organization, or a negotiated contract between the QF and the distribution company or other market participant – retail suppliers or brokers –, or net metering for the OSGF based on average monthly market rate. In the latter case, distribution companies are prohibited from imposing special fees on net metering customers, such as additional backup charges and demand charges, or other additional costs, as long as the OSGFs meet interconnection standards and safety and power quality requirements.

Selling and purchasing electricity entails DE facilities to interconnect to the electrical grid. Large generators may be able to connect directly to the bulk transmission system, but other DEs need to interconnect first to the distribution system of the local utility company. The DTE has set standards regarding interconnection and metering, and recently it issued a regulation requiring each distribution company to file interconnection standards for DE and renewable projects (more details below).

Technical requirements include equipment safety, systems reliability, and power quality. In particular they include the prevention of power backfeeding from the facilities to the utility system during power outages, synchronization with the utility's requirements regarding voltage and frequency, among others. The distribution company needs to make an initial on-site inspection to evaluate the interconnection equipment and the costs of that interconnection. A more complete estimation of the costs may be needed, where the costs of the additional studies must be paid by DE developers.

Under DTE's regulations, DE facilities have to provide the distribution company with a certification that protective devices and related equipment have been installed and tested before they can deliver power to the utility company. The distribution company has the right to inspect and test the physical interface.

Regarding the costs of interconnection, the DTE has determined that QFs and OSGFs are responsible for bearing them. They have to reimburse the utility for the incremental costs incurred when the facility has been interconnected, such as installation costs, and operations and maintenance costs. The DTE has the responsibility of defining the standard charges for interconnection equipment, meters, and meter reading costs. However, when these charges are not applicable, they need to be estimated on a case-by-case basis.

As we reviewed for MIT case, in some cases a distribution company may charge exit fees to on-site DE developers because of the impact on the company's overall revenues, and consequently on the rates applicable to its remaining customers. However, in Massachusetts distribution companies can not charge exit fees to distributed generation projects that give a six-month notice to the distribution company about the installation of on-site cogeneration equipment, renewable energy technologies, or fuel cells. Also, if a customer plans to buy electricity from DE

resources, he needs to provide the distribution company and the DTE a six-month notice and he will not be subject to exit charges⁸⁰.

As we mentioned, large-scale QFs need to interconnect with the transmission system through the ISO. On the other hand, OSGFs and small scale QFs will generally need their sales handled by the distribution company or rely on net metering in the case of OSGFs. Facilities larger than 5MW may become member of the New England Power Pool (NEPOOL)⁸¹ to interconnect into the system directly – option also available to facilities larger than 1MW. However, the interconnection costs⁸² to the NEPOOL system are high, the operation itself requires the facility to be dispatchable and respond to ISO instructions which requires the facility, among others, to have more personnel available.

Finally, Massachusetts has several programs that support the development of renewable and DE resources. The Massachusetts Renewable Energy Trust Fund is a fund currently administered by the Massachusetts Technology Collaborative (MTC), a state development agency that promotes clean energy technologies and sustainable market for renewable electricity generation⁸³. The mission of the fund is to increase the use and generation of renewable energy in the state and region, and enable Massachusetts companies to capture a greater share of the market for renewable energy technologies. Some of the technologies supported by this initiative include solar systems, wind, ocean thermal, wave or tidal, fuel cells, landfill gas, and advanced biomass power conversion technologies. Funds may also be used for joint energy efficiency and renewable projects.

⁸⁰ Other conditions regarding the total amount of generation leaving the grid need to be met.

⁸¹ Organization that represents traditional and competitive electric utilities. The ISO-NE has a service contract with it to operate the bulk power system and administers the wholesale marketplace.

⁸² As of 1999, participants who joined the NEPOOL were required to pay a \$5,000 application fee, a \$5,000 annual fee, and a variable monthly fee.

⁸³ Renewable Energy Trust, the Massachusetts Technology Collaborative
(<http://www.mtpc.org/RenewableEnergy/index.htm>)

Among Massachusetts' tax incentives we can mention:

- State income tax credit aimed at individuals who install solar thermal, solar water and space heat, photovoltaics, wind, and hydro systems.
- Individual state tax exemption applicable to the sales of equipment related to solar, wind, or heat pump system to be used in a person's principal residence in the state.
- Local property tax exemption applicable to a taxpayer who installs a solar or wind-powered system in his residence or business for 20 years.
- Hydropower-property tax exemption which exempts hydropower facilities from local property tax for a period of 20 years subject to particular conditions.
- Alternative energy and energy conservation patent exemption which exempts residents from state personal income or corporate tax whose patent has been approved and income has been received for the transfer of that patent.

Additional to these incentives, three Massachusetts policies try to incentivize the development of renewables and DE resources:

- A renewable energy portfolio standard requiring a minimum percentage of retail sales to come from renewable energy.
- An uniform generation performance standard providing a cap for certain emissions produced per unit of electric output.
- A mandatory disclosure requirement of electricity information, where suppliers must reveal information about the generation sources such as the specification of fuel mix and emissions, as well as information about generation prices, contract and labor information.

G.3. UTILITY RATES

Among the current pricing alternatives, we can mention at least three: real-time pricing (RTP), direct negotiated rate with the utility, and time of use rate (TOU) (Petchers, 2003, pp. 419-435). RTP allows the customers to buy during specific days, hours, or other interval on a dynamic and instantaneous basis. Negotiated pricing is a bilateral agreement between the utility and the customer, where pricing and supply conditions are established through a contract. TOU rests on peak and off-peak charges depending on the time of the day and season of the year. Since MIT cogeneration facility is subject to a TOU rate schedule, we will focus our discussion on this structure.

In general, a large general TOU service will be mostly applicable to large commercial, industrial and institutional customers depending upon the specific criteria that the non-residential customer has, such as the type of facility, equipments and size of load. This rate, approved by the Massachusetts Department of Telecommunications and Energy (DTE) typically includes monthly-fixed demand charges, and energy charges for peak load and low load periods according to the customer's usage. Peak loads occur during the periods where the utility must supply the maximum amount of energy, and uses the largest amount of system capacity with the subsequent stress of the system and the operation of less efficient peaking resources. Off-peak loads occur

during those periods when the utility uses less of its total system capacity, with subsequent low line losses and the use of more efficient plants. Therefore, large general TOU G-3 rate assigns higher costs to peak usage periods. It also includes minimum customer charges, and rate adjustments such as energy efficiency and renewable energy charges.

In Chapter 2, Section 2.3.2, we mentioned the rate structure MIT is subject to. For large customers whose metered load exceed 0.1MW for 12 consecutive months, NSTAR applies the so called Large General Time of Use – 13.8kV service – G-3 rate schedule. In Table 2.12 we listed the current applicable charges effective from January 2005, and from there we can observe that there are charges related to electricity demand and energy usage.

Customer charges are fixed and represent the cost of providing metering, billing and account maintenance⁸⁴. Distribution demand and energy charges, regulated by the DTE, allow the local utility company to recover the costs of providing the distribution service to the customers located in its franchised area.

Transition charges allow the distribution company to recover stranded costs such as generation-related fixed assets, nuclear decommissioning costs, removal and decommissioning for fossil-fuel generators, among others.

Transmission charges allow the distribution company to recover the costs of providing transmission service to its retail customers. Like distribution charges, this rate is regulated by the DTE⁸⁵.

Renewable energy rates are intended to increase the availability of renewable energy in Massachusetts, through the Massachusetts Renewable Energy Trust Fund.

Energy conservation charge covers the cost of supporting energy efficiency programs, required as part of the 1997 Massachusetts Electric Restructuring Act. These programs include (DOER, 2004):

- Retrofit programs that encourage the replacement of outdated and inefficient electrical and mechanical equipment.
- Lost Opportunity/New Construction programs that encourage investment in higher energy efficiency buildings or equipments.
- Regional Market Transformation programs that aim in transforming the market practices of manufacturers, builders, engineers, and retails over the long-term to promote purchases of higher energy efficiency products and services.
- Educational programs aimed mostly to residential customers.

⁸⁴ NSTAR, *Understanding your Electrical Bill*
(http://www.nstaronline.com/customer_service/electric_bill/bill.asp)

⁸⁵ Massachusetts, Department of Telecommunications and Energy, Electric Division, *Electric Restructuring in Massachusetts: Description of the Restructured Electric Industry*
(<http://www.mass.gov/dte/restruct/competition/index.htm#BACKGROUND>)

The supplier service charge represents the cost of supplying electricity either through a competitive supplier or the local distribution company. There are two service options available to consumers: competitive generation service and the default service. Until February 2005, a standard offer service was provided also by the local utility to some particular customers⁸⁶.

The competitive generation service is provided by competitive suppliers and electricity brokers licensed by the DTE. The first ones are entitled to sell electricity and related services to their customers, while the second one can facilitate the purchase and sale of electricity and related services to customers. The prices for this service are not regulated by the DTE, and they are determined competitively in the electricity marketplace.

The default service is the generation service provided by the local distribution company to those customers not receiving competitive service, and as of March 2005 it is the only service provided by the utility. The prices for this service are regulated by the DTE and may not exceed the average market price for electricity in New England. Default service customers has two options: a variable pricing option with monthly charges; and a fixed pricing option where the monthly price is averaged and kept constant for a specific period⁸⁷.

As we mentioned above, a standard offer service also provided by the distribution companies was available through February 2005. This charge was a transition generation service for those customers that did not choose the competitive generation service supplier as of March 1, 1998 and it was regulated by the DTE.

Finally, as we discussed in Chapter 2, since MIT's load is greater than the maximum capacity of its plant the Institute requires from NSTAR other services to make up for the remaining electricity needs – supplemental – and also for additional services such as maintenance and standby. In general, standby and maintenance rates are related to the supporting generating capacity and replacement energy that the utility makes available to the cogeneration facility to be used in case of emergency or maintenance schedules. These rates are based on a monthly charge of capacity reserve that it is always paid according to the contracted demand and depending on the period in which the plant is out of service. For MIT's particular case the provisions for each service are contained in rate G-3 and rate SS-1 for supplemental, rate MS-1 for maintenance, and rate SB-1 for stand by service (in section 2.3.3 we explained each of the main components, and in Table 2.23 we listed the current applicable charges for MIT).

⁸⁶ Most of this information was extracted from the Massachusetts Department of Telecommunications and Energy, Electric Division, *Description of the Restructured Electric Industry* (<http://www.mass.gov/dte/restruct/competition/index.htm#BACKGROUND>)

⁸⁷ Six months for residential, small commercial and industrial customers; and three months for medium and large commercial and industrial customers.

G.4. ENVIRONMENTAL REGULATIONS

In Chapter 2, we outlined the major barriers for the development of MIT's cogeneration project. Among them, we mentioned several permitting processes that the Institute had to comply with in order to operate its plant. In this section we will explain in more detail the regulations and entities involved during the process.

In Massachusetts an energy facility's permitting and regulation takes places mostly at the state and local levels. Within the first category, there are a series of state agencies involved such as the Executive Office of Environmental Affairs (EOEA), the Massachusetts Environmental Policy Act unit (MEPA), the Department of Environmental Protection (DEP), and the DTE. The approval from the municipality in which the facility will be constructed may also be needed (see Diagram G.1).

Broadly speaking, the EOEA is responsible for protecting and conserving natural resources in Massachusetts. The MEPA unit is in charge of evaluating the potential environmental impacts of proposed projects, providing the permitting agencies with the necessary information and requiring projects to avoid, minimize and mitigate adverse effects. QF developers need to verify whether the project is subject to MEPA and, if that is the case, an Environmental Notification Form (ENF) must be completed describing the proposed project. When needed, a more detailed analysis – an Environmental Impact Report (EIR) – may be required, and it should include a complete air, water, land, solid waste, and other environmental impacts that the project might potentially cause. MEPA certification is issued by the EOEA⁸⁸.

Additionally, the DEP has to protect human health and environment by ensuring, among others, clean air and water. DEP administers state laws and regulations aimed at this primary goal, enforces much of the U.S. Environmental Protection Agency (EPA)'s federal laws and regulations, and ultimately issues the energy facilities' emission permits depending upon whether the facility is in compliance with the regulations and a MEPA certification has been granted, when applicable.

The DTE, through the Energy Facilities Siting Board (EFSB) determines the feasibility of siting a plant in a particular location. The EFSB has the responsibility to ensure "reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost"⁸⁹. A petition for approval of construction of the facility needs to be approved by the Board in order to commence the construction. Although, we need to mention that most cogeneration projects will not be subject to the EFSB regulations unless they have a gross capacity larger than 100MW or meet any of the other criteria established by the EFSB.

⁸⁸ Some small projects may not to exceed MEPA thresholds, but still they will subject to local requirements.

⁸⁹ Massachusetts, Department of Environmental Protection, Energy Facilities, *State Permitting Agencies* (<http://www.mass.gov/dep/energy/permit.htm>)

The Massachusetts Coastal Zone Management (CZM) program advises the EOEA on state coastal policy issues and administer the state's coastal management program. CZM has jurisdiction on those projects that will affect coastal zones – land, water use or natural resources. It will issue general permits for those projects with minimal environmental impact.

Finally, federal permits will be mostly applicable to photovoltaic, wind, hydro, and waves-related technologies. The National Environmental Policy Act is concerned on those projects that potentially might have significant environmental impacts on or affecting federal lands or resources; the Army Corps of Engineers requires a permit for the construction of a structure and work under/in/over any navigable waters, or the discharge of filling materials into waters; the National Pollutant Discharge Elimination System permits are required for all point source discharges of pollutants into navigable waterways; the Federal Aviation Administration requires a notification for those structures that potentially can obstruct air navigation; and lastly the Federal Emergency Management Administration needs to identify those areas located in special flood hazard areas. At the local level, local permits and approvals for QFs vary considerable from town to town and may include, among others, building permits, construction in/near wetlands, orders from conservation commissions, sewer connections, water quality, and noise levels that will be applicable to the majority of technologies (DOER, 2001, pp. 66-73).

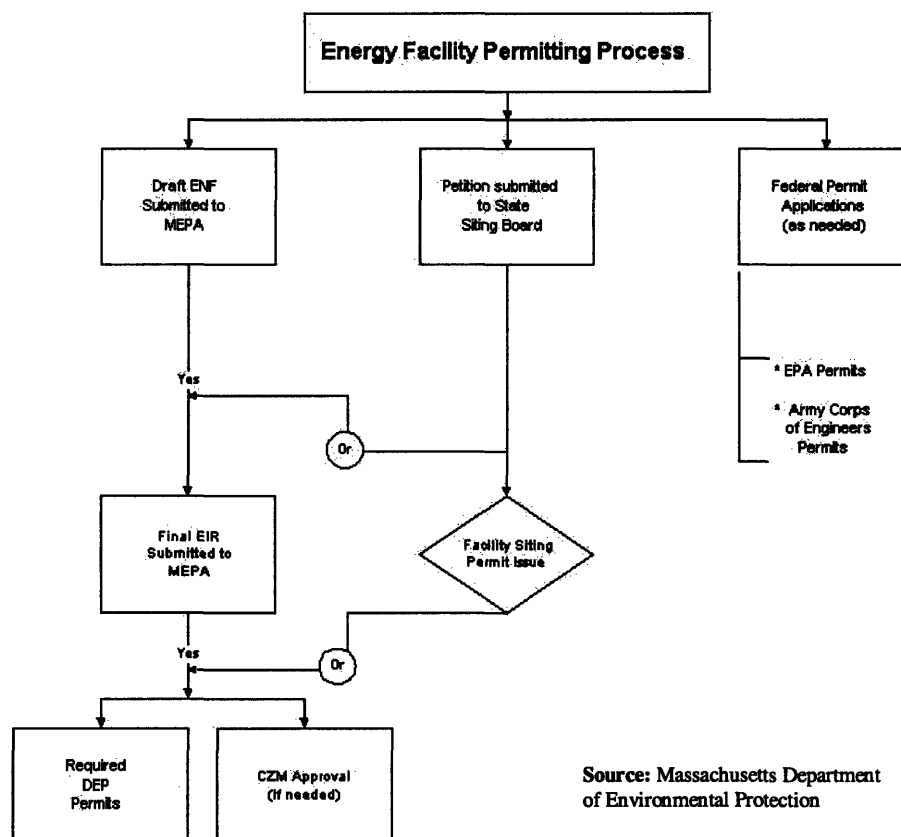


Diagram G.1: Permitting tree

As we mentioned for MIT's cogeneration plant, air permitting is a critical one for energy facilities since it is required in order to emit or discharge a regulated pollutant into the air. The air quality regulations that the DEP and the EPA promulgated are intended to establish "health based ambient air quality standards and emission limits", and they entail engineering design constraints and impact evaluations on the proposed projects. Compliance with these regulations is implemented through the DEP's "Air Plan Approval Process". Among the regulations we can mention⁹⁰:

- National Ambient Air Quality Standards (NAAQS).
- Prevention of Significant Deterioration (PSD).
- New Source Review (NSR) requirements.
- New Source Performance Standards (NSPS).

The NAAQS are targeted to six criteria pollutants: sulfur dioxide (SO₂), nitrogen dioxide (NO₂), carbon monoxide (CO), ozone (O₃), particulate matter with a diameter up to 10 microns (pm-10), and lead. The limits imposed for each pollutant were also adopted as Massachusetts Ambient Air Quality Standards (MAAQS) (see Table H.1 in Appendix H for current standards values).

Not only new sources, but also existing ones need to comply with these air ambient standards. Consequently, if an area is classified as in "attainment" or "unclassified" regarding these standards for a particular contaminant, the PSD review process will apply for new sources as well as demonstration of compliance with the NAAQS. In the case that an area is classified as "non-attainment" for a particular pollutant, the state needs to develop an attainment plan that include mandatory limits; application of non-attainment NSR procedures; impact assessment modeling that takes into consideration new and existing sources, and background levels (required by the DEP); enforceable emission limits and control measures; timetables for attainment of the NAAQS; and contingency measures.

In attainment areas, the focus is on maintaining good air quality through the PSD program. The PSD review process intends to assess not only new major sources of criteria pollutants but also "major modifications" to existing major sources to assure that emissions will not cause non-attainment. A "major" facility is one that has the potential to emit⁹¹ more than 100ton/yr of any pollutant and it is listed as one of the designated PSD/Stationary source categories in the Clean Air Act, or it is an unlisted stationary source that emits at least 250ton/yr of any pollutant regulated by the Clean Air Act⁹².

⁹⁰ Massachusetts, Department of Environmental Protection, Energy Facilities, *Applicable Air Quality Regulatory Requirements* (<http://www.mass.gov/dep/energy/air1.htm>)

⁹¹ The potential to emit is defined as the amount of pollution a source could generate if it were run all the time without any pollution control.

⁹² Massachusetts, Department of Environmental Protection, Energy Facilities, *Prevention of Significant Deterioration (PSD) Review* (<http://www.mass.gov/dep/energy/psd.htm>)

In non-attainment areas, the goal is restoring air quality. The NSR program limits emissions growth for a given pollutant from new major sources in those particular areas. For ozone, since Volatile organic compounds (VOCs) and oxides of nitrogen (NO_x) are the precursors of this pollutant, non-attainment NSR is required for major sources where the emissions exceed 50ton/yr in serious non-attainment areas for VOCs or NO_x, as it is the case for Commonwealth of Massachusetts. More stringent requirements for source control, such as the Lowest Achievable Emissions Reduction (LAER) technology⁹³, and the acquisition of emissions offsets are required⁹⁴. This last point may require either shutting down an existing source, or curtailing its operation, or applying more controls to the emission sources, or purchasing offsets from another source within the same non-attainment area or from another that meets some specific criteria⁹⁵.

The NSPS are established for various categories of new combustion sources such as stationary gas turbines. However, the NSPS NO_x standards are out of date and no longer used for combustion turbines, so instead the LAER is being used as a permitting standard under a NSR. The standard for SO₂ is limited to 0.015% by volume at 15% oxygen on a dry basis, with fuel sulfur content no greater than 0.8 percent by weight⁹⁶.

Finally, compliance of the facilities with these regulations are implemented through the Air Plan Approval Process required by the DEP in combination with the application of the Best Available Control Technology (BACT) for each regulated pollutant – which it is based on the maximum degree of emissions reductions for each contaminant technically and economically feasible, taking into account economic, energy, and environmental impacts. In addition, DEP has adopted a maximum hourly concentration of NO_x for new sources or modifications of the existing ones that would result in NO_x emissions above 250ton/yr. This policy requires that the air concentrations remain below 320ug/m³ per hour at locations where the facility has an impact of 32ug/m³ or greater⁹⁷.

The air permitting approval process for energy facilities⁹⁸ starts with the application being sent to the DEP where the data (such as emission rates, equipment, emissions control, and siting) is reviewed and assessed whether the project meets the state and federal regulatory requirements. A “draft conditional approval” is issued in case it meets all the requirements, and it is subject to a

⁹³ It does not take into account cost and other environmental impacts, and it is always more or as stringent as BACT.

⁹⁴ Massachusetts, Department of Environmental Protection, Energy Facilities, *Non-Attainment New Source Review* (<http://www.mass.gov/dep/energy/nsr.htm>)

⁹⁵ Offset ratio for major sources of NO_x in a serious O₃ non-attainment region is 1.26 to 1, which means that a facility with a potential to emit of 100ton/yr will need to reduce or purchase 126ton/yr of pollution offset.

⁹⁶ Massachusetts, Department of Environmental Protection, Energy Facilities, *New Source Performance Standards* (<http://www.mass.gov/dep/energy/nsps.htm>)

⁹⁷ Massachusetts, Department of Environmental Protection, Energy Facilities, *Air Plan Approval Process* (<http://www.mass.gov/dep/energy/apap.htm>)

⁹⁸ Massachusetts, Department of Environmental Protection, Energy Facilities, *Massachusetts Energy Facilities Air Permit Approval Process* (<http://www.mass.gov/dep/energy/provrw.htm>)

comment period. Then, the DEP will issue a “conditional approval” that will require additional data and will allow for the construction of the project to begin. The data should include facility plans, technical specifications of the equipment, emission and noise monitoring, and proof of offsets reductions. A “final approval” is issued by the DEP, which will allow the facility to begin operations. Finally, once the facility has started its operations, it should file with the DEP (within one year) for an “operating permit” that lasts for 5 years. This permit is required for any major source of air emissions, and new applications may be filed before the expiration – a process that can take the DEP one year or longer.

APPENDIX H: NAAQS, MAAQS AND PSD SIGNIFICANCE LEVELS

Pollutant	Average period	NAAQS primary [ug/m ³]	Secondary	MAAQS primary [ug/m ³]	Secondary	Significant impact levels [ug/m ³]
Nitrogen Dioxide	Annual ¹	100	same	100	same	1
	Annual ¹	80	–	80	–	1
	24-hour ² 3-hour ²	365 –	– 1,300	365 –	– 1,300	5 25
PM-10	Annual ⁴	50	–	50	–	1
	24-hour ³	150	–	150	–	5
Carbon Monoxide	8-hour ²	10,000	same	10,000	same	500
	1-hour ²	40,000	same	40,000	same	2,000
Ozone	1-hour ³	235	same	235	same	–
Lead	3-month ¹	1.5	–	1.5	–	–

Table H.1: National and Massachusetts Ambient Air Quality Standards and PSD Significance Levels

Source: Massachusetts, DEP - Energy Facilities, *National Ambient Air Quality Standards (NAAQS)* (<http://www.mass.gov/dep/energy/naaqs.htm>).

Notes:

¹ Not to be exceeded.

² Not to be exceeded more than once per year.

³ Not to be exceeded more than one day per year over three years.

⁴ Not to be exceeded by the arithmetic average of the annual arithmetic averages from three successive years.

⁵ Modeled impact level from a facility undergoing PSD review below which it is not necessary to undergo PSD increment consumption.

Primary standards: intended to protect human health.

Secondary standards: intended to protect public welfare from known or anticipated adverse effects associated with the presence of air pollutants, such as damage to property or vegetation.

Significant Impact Levels (SILs): for new sources that exceed these SILs, an interactive source modeling is required to consider the impact of the new source, existing sources, and measured background levels.

