The Potential of Distributed Cogeneration in Commercial Sites in the Greater Vancouver Regional District

By

Jeremy Higham

B.Sc. (Agr), University of Guelph, 1992

RESEARCH PROJECT SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF MASTER OF NATURAL RESOURCE MANAGEMENT

in the School of Resource and Environmental Management
Report No. 240

SIMON FRASER UNIVERSITY

December, 1999

Approval

NAME: Jeremy Higham

DEGREE: Master of Resource Management

PROJECT TITLE: The Potential of Distributed Cogeneration in Commercial Sites in the Greater Vancouver Regional District

PROJECT: 240

SUPERVISORY COMMITTEE:

Mark Jaccard, Associate Professor
School of Resource and Environmental Management
Senior Supervisor

Trent Berry, Principal
Compass Resource Management Ltd.
Supervisory Committee Member

Date Approved: December 10, 1999

ABSTRACT

The Canadian government is evaluating options to reduce CO_2 emissions in order to honor commitments under the Kyoto Protocol, an international agreement to reduce greenhouse gas emissions. Significant technological advances in small-scale, electricity generation technologies and a worldwide trend toward competition and deregulation in the electricity sector may lead to new market opportunities for systems that cogenerate useful heat and electricity. This form of distributed generation (production of electricity at the point of use) may reduce CO_2 emissions relative to the most likely alternative system, that being one combustion technology to produce heat within buildings (a standard, on-site, heating boiler) and another combustion technology to produce electricity (an off-site, combined cycle gas turbine - CCGT).

This study examines one possibility from these recent trends in technological development and electricity market reform: the economic potential and environmental implications of on-site, cogeneration systems in commercial buildings in greater Vancouver. The research involved: (1) identifying all candidate buildings, (2) categorizing these by building type, (3) developing a profile of their baseload thermal demands by building type, (4) identifying the best technology options for on-site cogeneration of heat and electricity by building type, and (5) computing the levelized unit cost of electricity from these technologies (including a credit for the value of the useful heat). These cogeneration technologies were then compared to the conventional approach of on-site thermal boilers and off-site CCGT's, both in terms of levelized unit costs of electricity and CO_2 emissions.

The results showed that while greater energy efficiency is achieved with cogeneration in commercial buildings, and thus lower net CO_2 emissions, the cogeneration option is generally more expensive than the conventional alternative. However, while the cost difference is still significant for smaller units, applications that would allow larger cogeneration units (a 25 MW system that provides district heating for several buildings for example) may be economically viable, even without earning a credit for reducing CO_2 emissions. If the cogeneration units were universally applied (for new buildings and some retrofit), regardless of their higher cost, CO_2 emissions would be reduced by about 135 000 t. CO_2/year by the year 2010. The cost of the CO_2 reduction (based on the additional cost of

the cogeneration technologies) ranged from \$7-117 t. CO_2 for the selected cogeneration units.

Sensitivity analysis tested differences in amortization periods, capital cost estimates, capacity factors and heat rates, finding that under certain assumptions smaller scale cogeneration systems may be competitive. Cogeneration units may also defer the need for some transmission and distribution investments, and the sensitivity analysis included a critical value assessment to determine at what value of T&D savings the cogeneration units would become economic.

ACKNOWLEDGEMENTS

My sincere thanks to Mark Jaccard for his guidance and encouragement. My thanks also to Trent Berry for his expert advice and perceptive critiques, and to Paul Willis for generously providing his engineering expertise.

Thanks to members of the Energy Research Group, particularly Andrew Pape and Alison Bailie, for their patient assistance. Also, many thanks to REM students and staff, to my family, and to my good friends Nick and Rob, for their invaluable support.

Thanks to BC Hydro, Malatest and Associates Ltd., and BC Gas Inc. for providing critical data, and to Westcoast Energy Inc. and Vancity for their financial assistance.

Finally, thanks to Colette for her encouragement, and for caring for Pascale while I was immersed in work. And thanks to Pascale for reminding me to make time to play.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF EQUATIONS

1. INTRODUCTION

The British Columbia (BC) government is currently evaluating technologies to reduce CO_2 emissions in order to honor commitments under the Kyoto Protocol.[1] Adoption of distributed cogeneration, to provide heat and power in Greater Vancouver Regional District (GVRD) commercial buildings, could reduce net CO_2 production and may cost less than other supply options. Cogeneration is the combined production of heat and power. With this technology, heat from electrical generation is used for various thermal applications including space heating, water heating, and cooling. It is not economical to transport heat over long distances. Therefore, cogeneration units need to be located close to thermal users and would be distributed throughout the electrical grid in or near commercial buildings.

When heat and power are produced separately (which is the norm), heat from electrical generation is vented off and wasted. Technological evolution has lead to greater efficiency in small-scale electrical generators, such as those that could be employed in cogeneration applications in commercial buildings. Consequently, cogeneration is likely more fuel-efficient and less CO_2 polluting than separate heat and power systems.

Because cogeneration is more fuel-efficient, it may ultimately cost less than other technologies that will likely be considered as new electrical generation supply options. In North America, electricity markets are transforming from utility based monopolies into competitive markets where numerous generators sell into an organized marketplace or power pool. The advent of unrestricted competition will force utilities and independent power producers to adopt least cost technologies to generate new supply. Competitive markets will nonetheless be subject to environmental regulation and quite possibly some form of CO_2 emission control. Ultimately, electricity generators will pay for regulated environmental costs and winners in a new electricity market will be those with the lowest total costs.

Natural gas is an inexpensive and abundant, low greenhouse gas (GHG) emissions fuel. On a cost basis, natural gas-fired electricity generation technologies are very competitive in meeting new capacity demand. Currently, electric utilities consider electrical generation from

[1] As a signatories to the new legally binding Kyoto Protocol to the United Nations Framework Convention on Climate Change, Canada, along with the other industrialized countries, have collectively committed to reducing GHG emissions by 5.2% below 1990 levels between 2008 - 2012. Canada has agreed to reduce its GHG emissions by 6% below 1990 levels for this period. (http://climatechange.nrcan.gc.ca/english/html/addressi.html).

natural gas-fired combined cycle gas turbines[2] (CCGT's) to be the most likely option to provide incremental increases in electrical generation to electricity markets. However, small-scale, natural gas-fired cogeneration can produce even less CO_2 than CCGT's, and this may be particularly economical in serving commercial buildings in urban centres like the GVRD.

1.1. Study Objectives

The purpose of this study is to assess the market competitiveness and greenhouse gas reduction potential of distributed cogeneration of heat and power in the commercial building sector in the GVRD in a competitive electricity market structure. The primary objectives of this study are to determine:

1. if small-scale natural gas cogeneration in commercial buildings in the GVRD is a cost-effective technology under competitive market conditions, and

2. if adoption of these cogeneration systems, in lieu of investment in a new, large scale, combined cycle generating station, will reduce atmospheric emissions and help to attain provincial GHG emission reduction targets.

1.2. Report Structure

Chapter One provides background information on changes in the electricity sector and describes cogeneration technology and its potential role in meeting GHG emission commitments as electricity markets evolve. Chapter Two describes the methodology used to conduct a market assessment of cogeneration and to estimate potential CO_2 emission reduction for commercial buildings in the GVRD. Chapter Three identifies the inputs required for the study and provides intermediate calculations. Chapter Four presents the results in order to evaluate the viability of cogeneration as a low CO_2 emission technology in a competitive electricity market. Finally, Chapter Five summarizes the study and makes suggestions for further research.

[2] Typically, in a combined cycle power plant the exhaust from a gas combustion turbine is routed through a heat recovery steam generator. Steam from the steam generator is then used to turn a steam turbine. Both the steam and gas turbines generate electricity. Using previously wasted heat to fire the steam turbine increases overall fuel efficiency.

1.3. GHG Emission Reduction

The greenhouse effect is a natural process whereby GHG's such as carbon dioxide (CO_2), methane, water vapour, and nitrous oxide (NO_x) trap solar energy within the atmosphere, warming the planet and making life possible. However, dramatic increases of emissions of GHGs from human activities since the Industrial Revolution have increased atmospheric concentrations of these gases. The Intergovernmental Panel on Climate Change[3] predicts that unabated, continued emissions will cause global warming and climate change with potentially catastrophic consequences. To limit GHG emissions, it is conceivable that in the near future GHG emitters will be subject to some form of emission charges, such as tradable emission permits, taxes, or stricter regulations. To limit costs associated with emission charges or taxes, building owners with a natural gas infrastructure will likely seek affordable technologies that conserve energy (and reduce emissions) without compromising the supply of energy for end use services. Cogeneration is one such technology. This study will help determine if cogeneration is an affordable and suitable technology for application in commercial buildings in the GVRD.

1.4. Cogeneration

Cogeneration is the production of electricity and useable heat from a single fuel source. Cogeneration is currently more fuel efficient than generating electricity and heat separately, due to the waste heat produced in electrical generation. Fuel savings associated with implementing cogeneration could potentially reduce GHG emissions and help Canada meet international CO_2 reduction targets agreed to under the Kyoto Protocol. Before 1980, the most fuel efficient electrical generators were increasing in size. Many of these facilities, in turn, were located far away from most thermal users such as process heating industries, and residential and commercial buildings with heating and cooling demand. Until recently the cost for distributed[4] cogeneration was prohibitive; however, technological advances in small scale generation have made smaller sized cogeneration more affordable for commercial customers. Onsite cogeneration plants can supply thermal and electrical energy for

[3] The World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) established the Intergovernmental Panel on Climate Change (IPCC) in 1988 to address international concerns about global climate change. The role of the IPCC is to assess the scientific, technical and socio-economic information relevant for the understanding of the risk of human-induced climate change.

[4] Distributed electricity resources are technologies that are spread throughout the electricity grid and produce electricity at a scale suited to demand in an individual building or complex. Photovoltaic solar arrays and micro-hydro electricity generators are other examples of distributed resources.

individual buildings or district energy systems. Compared to new combined-cycle generating turbines (the most likely alternative for the electricity sector), investing in numerous distributed micro-cogeneration plants[5] could potentially reduce energy costs and GHG emissions. This study evaluates the viability of distributed micro-cogeneration to compete in an unrestricted electricity market[6] in British Columbia to provide heat and power to commercial buildings in the GVRD and reduce GHG emissions.

Cogeneration plants can be fired by many fuels including: natural gas, peat, coal, coke, oil, landfill gas, wood waste, pulping liquors, sewage sludge, and municipal solid waste. This study evaluates the potential of distributed natural gas-fired cogeneration in commercial buildings. Natural gas is an inexpensive, clean, and readily available fuel for this market.

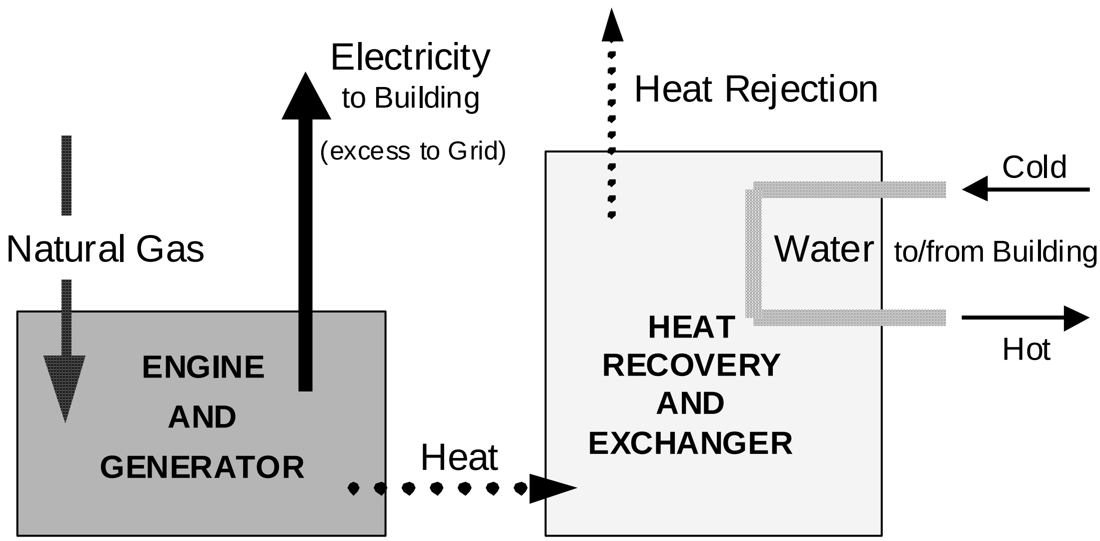
Electricity generation from natural gas combustion produces heat as a by-product. Unlike simple generators, cogeneration plants recover 'waste' heat for thermal applications like space and hot water heating. Almost any facility with a significant thermal load can make use of a cogeneration system. Cogeneration systems consist of several components: 1) an engine where fuel is converted to mechanical power and heat by a reciprocating engine or a gas turbine, 2) a heat recovery and exchange system, 3) a generator connected to the engine, 4) a heat rejection system in the event that thermal production exceeds demand, 5) electrical and mechanical interconnections to deliver heat and power, and, 6) a control system (Figure 1) (Waukesha Engine Division, 1986).

The electrical energy produced in a generator only represents a portion of the energy contained in the fuel. The average efficiency of existing electrical generators in Canada is approximately 30% before transmission line losses (Public Works Canada, 1993)**,** because a significant portion of thermal energy is lost through the cooling system. Adding a second cycle (a heat exchanger) to capture the waste heat typically increases electrical generation efficiency up to about 50%. The efficiency of the new CCGT used in this study is 52.5% (BC Hydro, 1995). Combustion of natural gas for thermal heating is more efficient at around 70-90+%, but no electricity is generated (Marbek Resource Consultants, 1999). Although cogeneration systems produce less electricity per unit fuel than generators alone, they are more efficient over all, because much of the heat is saved for thermal applications.

[5] For the purposes of this study cogeneration systems under 100 MW are considered 'micro-cogeneration'.
[6] Market competition generally takes two forms. Under wholesale competition monopoly control over transmission, distribution, and retail sales is retained. However, supply is open to competition. Under retail competition consumers either purchase electricity

Efficiency levels for cogeneration are up to 60% higher than conventional generating technologies (single cycle gas or steam turbines) and range from 65-93% depending on fuel type, facility size, process steam temperature, and various design features (Clayton and Wieringa, 1995).

Figure 1: Cogeneration System



1.4.1. Changing Economic Climate for Micro-Cogeneration

For most of the 20th century, economies of scale in the electricity sector have favoured large scale, stand-alone generation facilities. Consequently, the electricity market has been dominated by monopolies. Up until the 1980's, the most fuel-efficient generators were becoming progressively larger, reaching sizes of about 1000 MW. In the 1980's, engineering advances in smaller sized combined-cycle turbines began receiving recognition (Casten, 1995). By 1990, the trend had reversed and the most fuel-efficient generators were under 100 MW. One thousand MW simple cycle generators are about 35 - 40% fuel efficient, but the more sophisticated 100 MW generators are 55 - 60% efficient (Pfiefenberger et al, 1997). Efficiency gains in even smaller generators are expected in the future: the most fuel efficient generators may soon be in the range of 1 - 10 MW (Casten, 1995). Cogeneration units designed for this scale could further reduce energy demands by capturing waste heat.

directly from generators or market intermediaries. However, the T+D lines remain controlled by a regulated natural monopoly (Pape, 1997).

Falling capital costs and increased efficiency were the cause of falling economies of scale. At the same time, the natural gas market was deregulated, increasing availability of this low cost, clean fuel. The result is an improved economic climate for micro generators and an erosion of the monopoly rationale now that large-scale, centralized power plants are no longer the most fuel efficient or cost effective. In 1978, the United States (US) Congress passed the Public Utility Regulatory Policy Act (PURPA), legislating the inclusion of independent power production within utilities' power mixes (Pfiefenberger et al, 1997). Several states, particularly California, have progressed further in restructuring the power industry by dismantling monopoly control and developing competitive markets for the sale and purchase of electricity.

In Canada, Alberta and Ontario are at the forefront of electricity market reform. The province of Alberta opened up its wholesale electricity markets for competition and created the Power Pool of Alberta in 1996. Now, they are opening part of the market to retail competition, allowing large retail consumers to choose their electricity supplier. The entire market will be opened to retail competition by 2001. Ontario has a similar plan.

In BC, the provincially owned utility, BC Hydro, has created separate entities for generation, transmission, and distribution, but these remain in the control of the same corporation. The provincial government has also directed BC Hydro to purchase a limited amount of independently generated power. BC has on paper a competitive wholesale market. But this market is not really competitive, as BC Hydro is virtually a monopoly wholesale purchaser, with the exception of West Kootenay Power and a few municipal utilities. The BC Task Force on Electricity Market Reform recommended in 1998 to establish a competitive retail market, although, to date, the provincial government has not adopted the recommendations.

Jurisdictions in North America appear to be moving away from monopoly control in the electricity sector. Technical evolution, combined with affordable natural gas prices, and increased competition, has favoured smaller scale generators at the expense of large scale, centralized power plants and their corresponding transmission requirements. If these trends continue, and the BC government deregulates the electricity industry, the market may ultimately decide that micro-cogeneration is more economical than large scale plants.

1.4.2. Electrical and Thermal Demand

The key advantage of cogeneration over CCGT's is energy efficiency. In many cases, cogeneration is more energy efficient than separate electrical and heat production. Sites with sufficient thermal demand may be well suited to take advantage of these potential efficiency gains. Thermal energy from cogeneration could meet in-building heating and cooling requirements or thermal demand for district heating schemes. Anything larger and more spread out than a district heating system would be unable to take advantage of cogeneration's higher energy efficiency. This is because it is expensive and inefficient to transport heat even short distances (Pfiefenberger et al., 1997).

Many buildings in Greater Vancouver have natural gas-fired space heating systems and are already equipped with a boiler. Consequently, natural gas heating is essentially a sunk cost for many building owners considering a cogeneration retrofit.

Generally, stand-alone cogeneration is most economical at sites where thermal and electrical demands are continuous and correlated with one another (Pfiefenberger et al., 1997), but correlated loads are not necessarily common. Nevertheless, cogeneration plants which are designed to provide baseload thermal energy with a peaking boiler (to make up for heating shortfalls) and are connected to the electrical grid (to make up for electricity deficits or surpluses), as in this study, do not depend on a perfectly matched load. In commercial facilities, demand for electricity varies seasonally and with market forces. Therefore, cogeneration plants may periodically purchase or sell electricity to the grid in order to deal with shortfalls or excesses in electricity production. Creation of an unrestricted access spot market to absorb extra electrical production or meet shortfalls could enhance cogeneration adoption in the commercial building sector by improving financial performance. In this kind of market a clearing 'spot price' based on the bid price of the marginal producer, would set the hourly price for all transactions. Producers, consumers, and marketers would be able to buy or sell at the fluctuating price to meet their specific operational requirements. Cogeneration facilities able to co-ordinate power sales with high market demand periods could profit from elevated prices.

1.4.3. Role of Distributed Power Generation

Greater investment in cogeneration and other distributed generation resources is expected as electricity markets in North America become more competitive. Initially, distributed resources may serve only niche markets, but as constraints on existing transmission and distribution networks become increasingly costly to electricity consumers, distributed resources may comprise a larger component of generation capacity.

The predominance of central power stations in the electricity sector is based on several assumptions. It is generally accepted that large centralized stations have benefited from scale economies with respect to systems control, operations, and maintenance. Large plants have also benefited from economies in plant development such as siting, permit acquisition, and fuel contract negotiations (Pfiefenberger et al., 1997). With the emergence of large energy service corporations, with sufficient financial clout to negotiate on behalf of a wide customer base, cheap fuel may no longer be restricted to utilities and their large facilities. The economies of scale once exclusive to mega-generating stations may shift to mega-manufacture of many micro and mid-sized natural gas turbines and reciprocating engines, thereby greatly reducing the capital cost of highly efficient on-site technology (Flavin and Lenssen, 1994). Also, due to environmental and other public concerns, siting large-scale energy projects has become increasingly difficult, even outside urban areas. Numerous smaller, distributed facilities may be more palatable to the public and environmental regulators. Also, by siting energy generation at or near the point of consumption, cogeneration limits expensive long-term investment in the transmission and distribution infrastructure often required with utility mega-power projects.

Modular design and short lead times associated with distributed resources can make them more attractive than long lead time, large scale T+D investments. For example, Allied Signal plans to market microturbine packages from 75 - 450 kW_e that will be multiples of the basic 75 kW_e turbine[7]. To meet rising demand, capacity can be increased by 75 kW_e increments; small enough to avoid large capital investment and over supply. Larger T+D investments will take a long time to build and may cost more than anticipated (Hoff, 1997). There is management flexibility inherent in distributed resources in that they allow planners to change directions as the future unfolds.

[7] Personal Communication. Howard Bell, Mercury Electric Corporation, Calgary, AB.

Despite the apparent advantages of cogeneration and other distributed resources, existing distribution systems were not designed for widespread deployment of micro-generators. Because of high impedance in the distribution system, connection between customers and the transmission system can cause high line losses. Therefore, higher voltage or lower impedence interconnections may be required. Also, control frameworks for system stability are not as extensive as in the transmission system. Some form of centralized coordination is required to ensure that individual distributed generators conform to standards that reinforce system synchronicity. Individual generators would be required to carefully monitor generator controls and their settings, operating within system control designs (Cardell and Tabors, 1997).

2. METHODOLOGY

Cogeneration is more fuel efficient than CCGT's because waste heat is captured and used for thermal applications such as space heating and cooling, in such a manner as to consume less fuel than providing heat and electricity separately. Consequently, less CO_2 is emitted. However, cogeneration may cost more than CCGT's. This study was undertaken to determine the cost of distributed cogeneration and how much CO_2 it emits relative to CCGT's.

First, I estimated the technical potential for cogeneration. To do this, I developed an estimate of current and future baseload thermal demands among commercial buildings in the GVRD. Then, I selected representative commercial generators for different thermal load size categories. I used data from manufacturers on operating characteristics such as electrical to thermal output to determine the optimum size of cogeneration units to serve baseload thermal demand and to determine the associated electrical output of each size class.

I then computed the levelized unit cost of electrical output from these units, using capital and operating costs for each type of generator from manufacturers. In calculating levelized costs, I deducted credits for the value of heat, avoided back-up generation, non-fuel operating and capital costs for avoided heating boilers. To compute the levelized unit costs I used a weighted average cost of capital representing typical debt:equity ratios for private generation and representative costs of debt and equity.

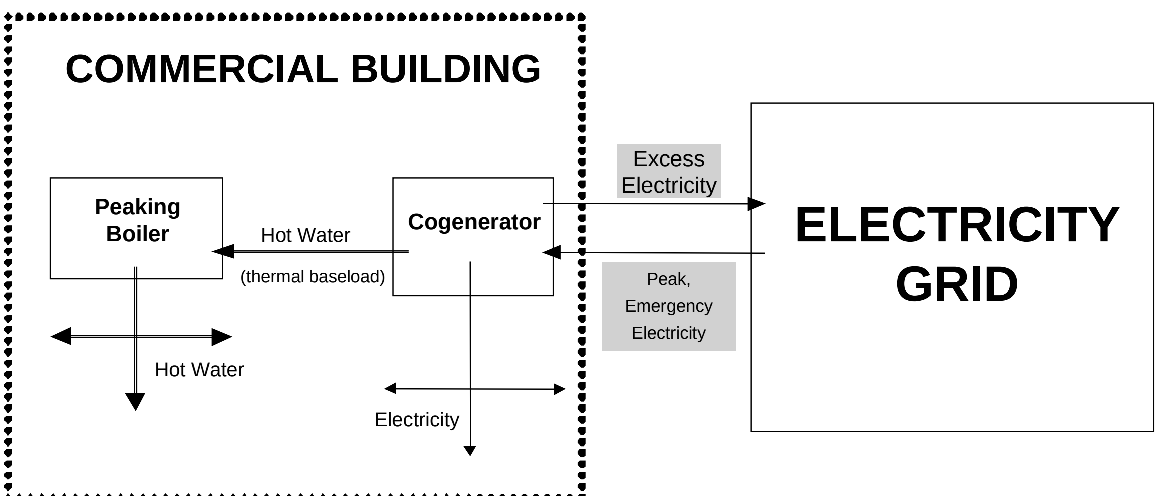
I then estimated the economic potential of cogeneration by comparing these levelized unit costs to estimates of the value of electricity: a forecast of bulk electricity prices in a competitive market and the levelized cost of new CCGT's (considered the marginal resource for the region). Finally, I estimated the reduction in CO_2 emissions as a result of installing cogeneration compared to a base case of on-site heating provided by stand-alone boilers and electricity generated centrally through CCGT's.

2.1. Typical Building Type Energy Use Profiles

In order to determine the appropriate generator for different sized buildings, typical energy use profiles for different building types were required. Characteristic energy use profiles for each building type were taken from the Commercial Base Building Reports (CBBR) (ERG International, 1993). Both electricity and thermal demand were reported in kW/square foot. Normally, kW is a measurement of electrical capacity, however, for the purposes of this study it is also used to report thermal demand. I have distinguished between the two with the common designators of kW_e for electricity and kW_t for thermal energy.

The most economical configuration for commercial building scale cogeneration would be one that supplies baseload thermal demand (Figure 2) (Willis, 1997). A peaking boiler in each building would make up for shortfalls in thermal energy. Cogeneration would work in concert with the existing electrical grid. In general, cogeneration would supply baseload electrical loads. The grid would supply peak and emergency electricity. Buildings generating excess electricity would export power to the grid at the wholesale/spot price.

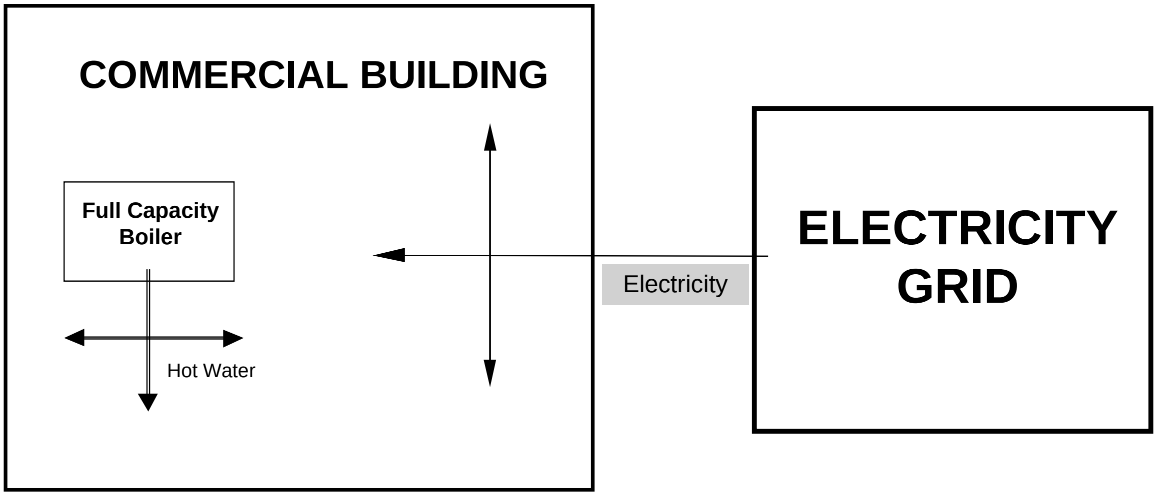
Figure 2: Distributed Cogeneration for a Commercial Building



In the conventional electricity system, the grid supplies all electricity demand (Figure 3). In the event of a black out, on-site generators are sized to supply only essential needs. All thermal energy in commercial buildings is produced on-site with full capacity boilers.[8]

[8] The exception is the district heating system (Central Heat Ltd.) serving most commercial buildings in the Vancouver downtown core.

Figure 3: Conventional Heat and Power Supply for Commercial Buildings



To estimate thermal baseload, I used an industry rule of thumb for the Vancouver area (Willis, 1997) which suggests that half of annual space heating, refrigeration, and cooling and all of annual hot water energy demand should be considered when calculating thermal baseload.[9] Cogeneration units, and specifically the generators, can be sized based on the thermal load. The CBBR's differentiate between energy demand in existing buildings and both ASHRAE (Association of Heating, Refrigeration, and Air Conditioning Engineers) and non-ASHRAE approved future buildings. For the purposes of this study, I assumed that all future buildings would be built to ASHRAE standards, as this is the standing policy for the City of Vancouver according to building bylaws. For existing buildings, calculation of baseload thermal demand was based just on space heating and hot water heating with the assumption that retrofit to absorption chillers[10] would not be economical, whereas installation of absorption chillers in future buildings would be. Cooling and refrigeration energy use in CBBR is based on electrical end use technologies. Absorption chillers use twice as much energy as electrical chillers; therefore, CBBR figures for cooling and refrigeration were doubled to more accurately reflect energy demand from a thermal source.

[9]Because thermal demand is relatively constant throughout the year in food stores and refrigerated warehouses, generator size was based on 100% of thermal loads.
[10] Absorption chillers provide space cooling and are well suited for cogeneration systems as they can be powered by heat from the generator.

2.2. Technical Feasibility

For the purposes of this economic analysis, the principal factor governing the technical feasibility of cogeneration installation in different buildings is the size of the thermal load and whether it is sufficient to warrant purchase of cost effective generation technology. A detailed feasibility study to determine the suitability of cogeneration for a specific building would contain a more thorough analysis to evaluate compatibility with existing building features or new building architectural design. Early discussions with industry experts[11] indicated that large cogeneration installations are more cost effective than small projects and the smallest cost effective cogeneration package is the 75 kW_e Allied Signal microturbine. I initially estimated that no cogeneration plant in GVRD commercial buildings would exceed 50 MW. Therefore, cogeneration packages for this study range in size from 75 kW_e to 50 MW_e. For buildings to qualify for cogeneration they had to have at least sufficient thermal baseload to warrant a microturbine. Therefore, buildings with an electrical demand of at least 56 kW_e (75 kW_t) were included in the study. To determine what the minimum building size is for each building type, I simply divided 75 kW_t by each building type's baseload thermal demand (in kW_t /square foot). To simplify calculations, thermal demand was measured in the kW_t equivalent to GJ.

2.2.1. Building Stock

A database of GVRD commercial building stock, identifying the number of buildings in different size (square feet) classes, was required for this study. With the exception of warehouses and food stores (R. A. Malatest and Associates Ltd., 1997) this information was not readily available; therefore, for most building types I contacted building owners, managers, or engineers directly. A comprehensive list of residential complexes and apartment buildings does not exist. As a result, potential installations in these building types are not represented in this study.

In downtown Vancouver, a district heating network run by Central Heat Ltd. already supplies steam to most buildings. Buildings currently connected to this central district heating steam network are not individually assessed for cogeneration as I assumed that cogeneration for these downtown hotels, office buildings, and schools could be amalgamated into a larger

[11] Howard Bell, Mercury Electric Corporation, Calgary, AB; Paul Willis, Willis Energy Services Ltd., Vancouver, BC; Roy Hewitt, Pamco Enerflex Ltd., Calgary, AB; Paul Gauguin, Alberta Power, Edmonton, AB; Doug Cullen, International Energy Systems Ltd.,

(and more cost effective) central district heating and power plant. Similarly, several hospitals and other medical and research facilities, as well as an RCMP administrative building on the West Side of Vancouver are linked together as they are linked by a steam grid which is not currently being used. For this study, I collectively refer to these amalgamated buildings as the Shaughnessy Steam Grid. I have grouped this potential cogeneration site in the hospital building designation (Business in Vancouver, 1997a).

Other building types represented in this study include: hotels (Tourism Vancouver - The Greater Vancouver Convention & Visitor's Bureau , 1997), offices (Building Owners and Managers Association, 1997), high schools (Vancouver Public School Board, 1998), shopping malls (Business in Vancouver, 1997b), colleges (Business in Vancouver, 1998), universities, food stores, and refrigerated warehouses (Malatest and Associates Ltd., 1997). Most hotels were unwilling to discuss the size of their buildings, so I estimated squarefootage based on the number of rooms. Similarly, squarefootage for some shopping malls was unavailable and I estimated total size from gross leasable area. Data for food stores and refrigerated warehouses were obtained from the Malatest report (Malatest and Associates Ltd., 1997). Because data from the Malatest report were grouped into size categories and not separated into individual buildings like other building types, I took the median square footage in each size category to calculate generator sizes and to estimate the number of buildings in each category.

2.2.2. Generator Sizing

Thermal baseload for each building type (kW_t /sqft) was then multiplied by square footage of each building to determine total thermal capacity. Depending on the generator required to meet baseload thermal demand, different electrical:thermal ratios were used to determine the size of the electrical generator. To ensure that thermal baseload estimates from annual thermal demand were in fact baseloads, I graphed monthly baseload thermal demand with thermal output from the cogeneration unit to ensure that heat is not produced beyond the requirements of the building and to check if any building types could use more heat because of the nature of their baseload thermal demand profile. Baseload thermal demand for food stores and refrigerated warehouses is approximately 100% of total thermal demand.

Delta, BC; David Fernandez, Cummins-Wartsila, Maple Ridge, BC; Mark Axford, Stewart and Stevenson International, Inc., Houston, TX.

2.3. Cogeneration Costs

I calculated the total levelized[12] unit costs for cogeneration using capital and operating costs for each type of generator (Equation 1). In calculating levelized costs I also deducted credits for the value of the heat, avoided backup generation, and non-fuel operating and maintenance (O+M) and capital costs for avoided heating boiler capacity).

Equation 1: Levelized Cogeneration Unit Cost

Levelized Cogeneration Unit Cost ($/kWh$_e$) =

Levelized Unit(Capital + non-fuel O+M + Fuel + Grid backup) Costs –

Levelized Unit (Heat/Steam + avoided Boiler O+M + avoided Boiler Capital + avoided Back up Generator) Credits

The design of some locations may not be well suited to cogeneration retrofit, and adapting a new technology to fit an old building may add substantially to costs.

To calculate the levelized costs ($/kWh$_e$) for each cogeneration package I used a real discount rate based on the weighted average cost of capital (Equation 2):

Equation 2: Weighted Average Cost of Capital

Weighted Average Cost of Capital =

% debt financing * real cost of debt + % equity financing * real pre-tax rate of return on equity.

2.3.1. Capital Cost

Levelized capital cost represents the installed cost of a new cogeneration plant and is a function of the cost of fixed system components ($/kW$_e$) divided by the present value of the energy (total lifetime operating hours). Capital cost represents installed cost and includes extra costs associated with advanced grid inter-connection equipment (approximately $50/kW$_e$), enabling the cogeneration system to run in parallel with the grid.

[12] Levelizing involves the conversion of non-uniform cost and energy streams into a present value equivalent uniform unit cost series. In other words, it is a way of obtaining an average unit cost while incorporating the rental value of the resource.

2.3.2. Operating and Maintenance Cost

Levelized O+M costs equal annual O+M costs ($/yr) divided by annual electricity generation (kWh_e /yr).

2.3.3. Fuel Cost

Levelized fuel cost is a function of the fuel price, fuel consumption, and plant capacity (kW_e).

A fuel conversion from lower heating value (LHV) to higher heating value (HHV) is necessary as generator performance is measured with LHV, whereas fuel requirements are measured with HHV. HHV measures total heat given off by a fuel, but some fuel bound hydrogen forms water in combustion. Therefore, to determine natural gas consumption from generator heat rate, fuel consumption must be increased by 11% (Equation 3) (Waukesha Engine Division, 1986). Fuel consumption is estimated from heat rates for all generators except for the Microturbine. Microturbine fuel consumption was estimated directly by the manufacturer, Allied Signal.

Equation 3: Fuel Consumption

Fuel Consumption (GJ/h) =

heat rate (Btu/kWh_e) * LHV to HHV conv. * Btu to GJ conv. * generator size (kW_e) * capacity factor (85%)

Due to heat loss in larger scale district energy systems (25MW and 50MW) I increased fuel consumption by 5% for these sites.[13]

Equation 4 for fuel cost calculation is as follows:

Equation 4: Fuel Cost

Fuel Cost =

fuel price ($/GJ) * fuel consumption (GJ/h) / plant capacity (kW_e)

[13] This district energy heat loss estimate was based on discussions with industry experts from Willis Energy Services Ltd. and Central Heat Distribution Ltd., both in Vancouver, BC.

2.3.4. Standby Fee for Peak and Backup Requirements

Cogeneration facilities will pay a standby fee for grid hook-up for peak and emergency backup electricity requirements. However, provided that T+D capacity is sufficient it would probably not be a substantial cost. For the purposes of this study, electricity produced by cogeneration will approximate baseload requirements under normal operating conditions. The grid provides excess demand for peak and shoulder requirements. However, under emergency conditions full electrical load would be taken from the grid. Existing buildings have sufficient T+D capacity to provide full electrical load. Full T+D capacity for new buildings would also be required in the event of an emergency. However, distributed resources like cogeneration would probably not all fail simultaneously. Consequently, individual T+D capacity requirements to deliver baseload power under backup situations would be incidental. Nevertheless, there is currently no explicit backup or standby tariff for small generators. Instead of estimating the standby fee in this study, I conduct a critical value analysis later which gives an indication of how high a standby fee could be without affecting the profitability of cogeneration. To prevent too many distributed generators from simultaneously drawing on backup power, a central system power pool operator would have to schedule routine downtime between generators.

2.3.5. Absorption Chilling Cost in New Buildings

The cost of absorption chilling in a cogeneration system is essentially equivalent to the cost of an electrical chilling system, the most likely technology used in conjunction with grid supplied electricity. Therefore, I assumed that addition of absorption chilling to cogeneration systems in new buildings would add no net cost.

2.3.6. Steam / Heat Credit

Steam or heat is a byproduct of cogenerated electricity. The steam (or heat) credit represents the cost to produce an equivalent amount of steam or hot water in a conventional system with a boiler, thereby giving a dollar value to cogenerated thermal energy. The levelized steam credit is equivalent to the unit value for replaced fuel, the amount of fuel necessary to produce an equivalent amount of heat or steam in a conventional boiler.

2.3.7. Operating and Maintenance and Boiler Credits

O+M and boiler credits represent the incremental difference in costs associated with a conventional full load boiler normally used to heat a building and a smaller, peaking boiler used in conjunction with cogeneration. Therefore, I have applied a credit to the over all cogeneration cost representative of the decreased capital cost of purchasing a smaller boiler and maintaining it. A retrofit is undertaken when the boiler is due for retirement, consequently both greenfield and retrofit installations require cogeneration equipment and peaking boilers. Unit cost for the O+M credit equals the annual cost divided by the annual electricity production. Levelized unit cost for the boiler credit equals the differential cost between full load and peaking boilers divided by the present worth of energy (kWh_e) over the lifetime of the plant.

2.3.8. Backup Generator Credit

The levelized credit for the backup generator is based on the present value of the cost of an inexpensive generator estimated to last as long as the cogeneration package which is replacing it. Currently, large commercial builidings are required to install and maintain back-up generators. However, with cogeneration a backup generator would not be required as the electrical grid could provide backup service. Greenfield installations would forgo the need to purchase a backup generator and existing backup generators in existing buildings could be sold. Relative to other costs and credits, the background generator credit is small. The cost difference between new and used backup generators is not significant. Therefore, I assumed that this credit has the same value for both retrofit and greenfield installations.

2.4. Cost Comparisons

To determine if cogeneration is a prudent economic investment, I compared total levelized costs of the selected cogeneration packages to average electricity market price and levelized CCGT costs (Berry, 1997).[14] CCGT's are generally considered the marginal resource for new investment in electrical generation technology. Consequently, it can serve as a point of comparison for an alternate new resource, such as small-scale cogeneration. If cogeneration is competitive with the marginal resource, it would probably be a good

[14] The market price and CCGT cost forecasts used in this study are out of date (1997), but they do illustrate the type of analysis an investor may undertake to determine if cogeneration is economically viable.

investment. In an efficient market, electricity prices would tend to oscillate around the long term cost of supply. However, if the market price of electricity is not high enough to recoup investment costs and garner an acceptable profit, investment in cogeneration, and CCGT, for that matter, is unlikely.

Consequently, I conducted two analyses. The first compares the cost of various sizes of cogeneration units to the cost of a 240 MW CCGT plant to determine if cogeneration is an economic investment from a social perspective. The second compares the cost of cogeneration to a projected market price to determine if cogeneration is a profitable investment for the private sector. I took the average market price from a publicly available forecast (Berry, 1997). I also took CCGT costs from the same report (Berry, 1997).

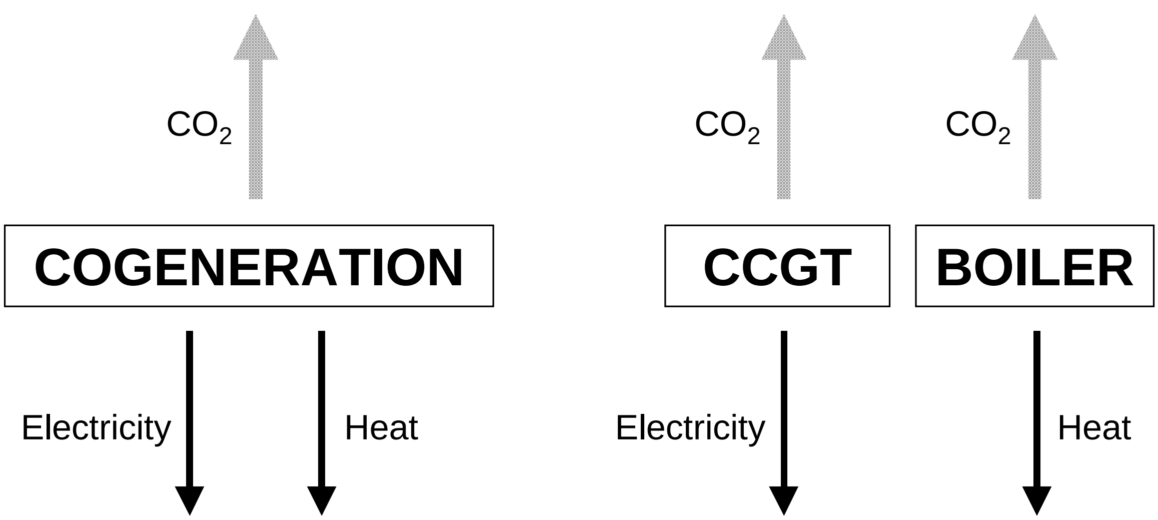
Incorporating a T+D cost for CCGT's and a standby fee for cogeneration directly into these analyses is not straightforward. Instead, I conducted a critical value assessment for these costs. That is, I computed the difference between the costs of these two technologies. For example, if my calculations show that CCGT is less expensive than cogeneration, then cogeneration would only be competitive if the CCGT T+D cost is greater than the cogeneration grid backup cost by at least the critical value. If cogeneration is less expensive, then CCGT would only be competitive if the cogeneration grid backup cost is greater than the CCGT T+D cost. Unlike cogeneration, large electricity generation facilities like CCGT's require the grid to transport all power to customers. Some argue that T+D is effectively a sunk cost and should be ignored. Also, baseload cogeneration systems require the grid for backup and peak periods, and to export excess electricity. Nevertheless, cogeneration owners can expect to pay a grid standby fee. Both cogeneration and CCGT systems depend on the grid. However, in the long run, cogeneration may reduce grid loads, and, ultimately, may delay some T+D investments. In this study I do not determine precise values for T+D costs and grid standby fees. Instead, I use a critical value assessment to determine how much net of T+D costs and standby fees would have to be to make cogeneration economic.

A typical commercial building today uses the grid for all its power needs and uses a small generator for backup. The distributed cogeneration installations I have modeled in this study use the grid for intermediate and peak loads, and for backup. Therefore I am measuring the difference between baseload costs. In previous sections I explained how I calculated the costs for distributed cogeneration. Costs for a grid supported building are represented by average market price, or alternatively, combined cycle gas turbine cost. Transmission line losses (estimated at 5%) are included in CCGT and electricity market rates. Some cogeneration installations are large enough to power a district heat network. Heat losses for these systems are reflected in total levelized costs.

2.5. CO_2 Emission Difference Between Cogeneration and CCGT

Relative to a heat and power system in which a centralized CCGT plant generates electricity for buildings which get their heat from gas fired boilers, a distributed cogeneration system may emit less CO_2. Cogeneration uses less natural gas to produce heat and electricity because heat from power generation is used as thermal energy, not wasted. In the cogeneration system, heat and power are produced from the same source. In the CCGT system, buildings receive electricity from the grid and generate thermal energy internally with boilers, both producing CO_2 (Figure 4).

Figure 4: CO_2 Sources from Buildings using Cogeneration and CCGT's



Combustion of 0.0497 GJ of natural gas produces one tonne of CO_2. In order to determine the CO_2 emission difference between a cogeneration heat and power system and a CCGT and boiler heat and power system, I first calculated the difference in natural gas consumption between the two systems. To do this I computed the quantity of natural gas required in a cogeneration unit to produce sufficient heat to meet annual thermal demand (Equation 5).

Equation 5: Annual Cogeneration Natural Gas Consumption

Cogeneration fuel consumption (GJ/yr) =

Hourly fuel consumption (GJ/h) * 8760 h/yr * capacity factor (85%)

Associated with this cogeneration heat production is an electrical output. I then calculated how much natural gas is necessary for a CCGT to generate the same amount of electricity (Equation 6) and a boiler to generate the same amount of heat (Equation 7).

Equation 6: Annual CCGT Natural Gas Consumption

CCGT fuel consumption (GJ/yr) =

Electricity (kW_e) * gridline losses (5%) * 8760 h/yr * capacity factor (85%) * kWhe to GJ conv. ***/*** efficiency (52.5%)

Equation 7: Annual Boiler Natural Gas Consumption

Boiler fuel consumption (GJ/yr) =

Thermal demand (kW_t) * 8760 h/yr * capacity factor (85%) * kWh_t to GJ conv. ***/*** efficiency (75%)

From the difference in natural gas consumption, I then calculated the difference in CO_2 emissions.

2.6. Annual CO_2 Reduction Cost/Benefit ($/t CO_2)

To calculate the costs or savings associated with reducing CO_2 by installing distributed cogeneration, I compared the price/ year and t CO_2/ year for cogeneration systems to the CCGT plus boiler system. The cost of reducing CO_2 was calculated for each cogeneration package by dividing the annual cost differential between the cogeneration system and the CCGT plus boiler system by the annual CO_2 emissions differential. For this calculation I used the 1998 CCGT cost.

2.7. Cogeneration Potential

This section of the methodology estimates potential retrofit and greenfield cogeneration installations up to and at the year 2010 in order to calculate the total cost of implementation and the net reduction in CO_2 emissions relative to CCGT investment. Retrofit installations occur when old boilers are retired. For the purposes of this analysis I have made a simplifying assumption that all boilers in the current commercial building stock will have been retired by 2010. Specifically, I assumed that half of the boiler stock is retired in 1998 and the other half in 2004. Greenfield installations are based on the expected building stock growth for each building type. Mostly because of gains in energy efficiency, thermal demand generally decreases for new buildings relative to existing stock. Future thermal energy demand (kW_t /sq.ft.), in conjunction with the current stock of buildings, was used to calculate a capacity average for each generator type in new buildings. When growth in the building stock reached the appropriate level, another suite of average capacity cogeneration plants was constructed. CO_2 reduction and cost differences between cogeneration and CCGT's were identified by generator size for each building type.

I assumed that half the boiler stock is retired in 1998 and the rest is retired 6 years later. To determine potential CO_2 reduction to 2010 for retrofits, I incorporated this assumption into the model by taking half the annual CO_2 reduction for 12 years plus the other half for 6 years for each generator size in each building type. Total cost/benefit for cogeneration retrofit potential amounts to the present value of 12 years of the first half of retrofits plus 6 years (from 2004-2010) of the second half of the retrofits. For greenfield installations, the total emission reduction to 2010 is the annual CO_2 reduction corresponding to new plants multiplied by the number of years they are in operation between now and 2010. Total cost/benefit for greenfield installations for this period is calculated by taking the present value for each year that a plant is running.

Totals for CO_2 reduction and cost differences for retrofit and greenfield installations were calculated independently. Then, CO_2 and cost differences were combined to calculate totals for each generator size in each building type. These totals were then summed for all buildings.

Specific fuel consumption and thermal efficiency values for the microturbine had yet to be determined by the manufacturer. For this study, I used a high thermal efficiency and low fuel consumption estimate provided by the manufacturer. If the microturbine proves to have lower thermal efficiency and higher fuel consumption it will be a net CO_2 producer relative to CCGT's and of no value as a CO_2 reduction technology in the scope of this study.

Combined retrofit and greenfield capacity by the end of year 2010 was determined to calculate the annual cost difference and CO_2 reductions for cogeneration relative to CCGT's at 2010 for each generator in each building type. Finally, the sum total for both cost and CO_2

differentials was calculated for all generators in all building types to estimate the potential annual reduction in CO_2 and the corresponding annual costs or savings.

2.8. Sensitivity Analyses

I conducted three sensitivity analyses. In the first two, I tested the sensitivity of the CCGT-cogeneration cost difference to ranges in key variables including: capacity factor, capital costs, fuel prices, heat rate, amortization period, and components of the weighted average cost of capital, specifically: % debt financing, real cost of debt, and pre-tax rate of return on equity. For each variable I selected a low, base, and high value. Rather than developing scenarios, each variable was tested individually while other variables were held constant at the base value. In the first analysis, I varied cogeneration cost variables and kept all CCGT cost variables, with the exception of fuel price and real cost of debt, at their base values. In the second analysis I varied CCGT variables along with cogeneration variables. From these analyses I determined which variables had the greatest impact on cogeneration market competitiveness. In the third analyses I tested the sensitivity of cogeneration and CCGT costs to variability in the weighted average cost of capital.

2.9. Barriers to Adoption

Finally, I examined barriers other than equipment and maintenance costs which could impede the adoption of distributed cogeneration. I discussed the legal, political, and perceptual obstacles this new technology faces in a changing marketplace and suggested possible remedies.

3. INPUTS AND INTERMEDIATE CALCULATIONS

3.1. Building Archetype Baseload Thermal Demand

Based on the calculations discussed in the Methodology section, the baseload thermal demands for each building type are listed in Table 1 for both existing and future buildings. Food stores and refrigerated warehouses do not have sufficient thermal demand without absorption chilling to warrant cogeneration installation and retrofit to absorption chilling is not economical. Therefore, only future building installations were calculated for this building type. Advances in energy conservation have generally led to decreased thermal demand in future building types, but future offices and hotels exhibit an increase due to greater energy intensification in these commercial activities. As the Vancouver downtown core is primarily composed of office buildings, I have also used the office energy demand profile for the central district heat and power system. Energy savings in future high schools are significant enough that there will no longer be sufficient baseload thermal demand to justify cogeneration. Baseload thermal demand is used to calculate the appropriate generator size for each building. In turn, generator sizing allows a minimum size standard to be set for each building type.

Table 1: Building Archetype Baseload Thermal Demand

	Existing (kW_t/sqft)	Future (kW_t/sqft)
Food Store	n/a	0.009175
Refrigerated Warehouse	n/a	0.000662
College	0.001258	0.000845
University	0.001258	0.000845
Hotel	0.001231	0.001360
Hospital	0.000977	0.000911
High School	0.000593	n/a
Shopping Mall	0.000333	0.000311
Office	0.000332	0.000410
Central Heat	0.000332	0.000410

3.2. Technical Feasibility

3.2.1. Generators

I have selected generator sizes for cogeneration units ranging from 75 kW_e to 50 MW_e. In an effort to use the least-cost technology, I chose a suite of generators (Table 2) comprised of microturbines for thermal demands <500 kW_t, reciprocating engines for demands in the 500-4000 kW_t range, and turbines in the 4-50+ MW_t range. Industry experts had indicated to me that reciprocating engines generally outperform turbines below 10MW_e. Therefore, I have not included turbines for applications less than 10MW_e, other than the 75 kW_e microturbine that I selected for use up to 375 kW_e (or 500 kW_t).

Table 2: Cogeneration Units

Cogeneration Units		Electrical Capacity (kW_e)	electricity: thermal ratio	Thermal Output (kW_t)
Microturbine	Allied Signal Prototype	75	0.75	100
Recip 500	Waukesha 7100G	575	0.67	863
Recip 2000	Wartsila Nohab 25	2100	1.03	2045
10MW Turbine	Allied Signal ASE120	9580	0.67	14370
25MW Turbine	GE LM 2500+	26350	0.67	39525
50 MW Turbine	Rolls Royce / Westinghouse Trent	49602	0.67	74403

The microturbine is a 75 kW_e modular prototype developed by Allied Signal (Bell et al, 1998) and designed for various configurations up to 450 kW_e. Allied Signal expects that a commercial model will be available late 1999. Because the unit is still undergoing testing and calibration, factors such as heat rate, fuel consumption, and the electrical:thermal ratio are not as strictly defined as the other generators chosen for this study. Estimates of electrical efficiency are as high as 30%, with a thermal efficiency as high as 40%, for an overall efficiency of 70%. However, thermal efficiency may end up being closer to 30%, giving an overall efficiency of 60%. The significance of uncertainty in this variable will be discussed in the Discussion section.

The Waukesha 7100G (Waukesha Engine Division, 1987) represents the 500 kW_e sized generator referred to as Recip 500. This reciprocating engine actually has an electrical output of 575 kW_e, with an electrical:thermal efficiency ratio of 30:45 and overall efficiency of

67%, producing the equivalent of 863 kW_t of thermal energy. Buildings with the equivalent of 500-1500 kW_t of baseload thermal demand have been allocated this generator.

Buildings requiring the equivalent of 1500-6000 kW_t of thermal power have been allotted the Recip 2000 cogeneration package for which I chose the Wartsila Nohab 25 Diesel (Wartsila Diesel Power News Customer Journal, 1997). This engine generates 2100 kW_e of electricity and 2045 kW_t of thermal power with an electrical:thermal efficiency ratio of 38:37 and an overall efficiency of 75%.

To represent the 10 MW turbine, I selected the Allied Signal ASE120 (Gas Turbine World 1997 Handbook, 1997, pp. 133). This turbine generates 9580 kW_e of electricity and 14 370 kW_t of thermal power. The 25 MW turbine is represented by the General Electric LM 2500+ (Gas Turbine World 1996 Handbook, 1996, pp. 5-12), generating 26 350 kW_e of electricity and 39 525 kW_t of thermal power. The Rolls Royce / Westinghouse Trent (Gas Turbine World 1996 Handbook, 1996, pp. 5-16) generates 49 602 kW_e of electricity and 74 403 kW_t of thermal power, representing the 50 MW turbine. All turbines have an electrical:thermal efficiency ratio of 30:45 and an overall efficiency of 75%.

These generators are all designed to run at high capacity factors, important for this application of meeting baseload thermal demand. In this study, all generators are assumed to run for 7446 hours per year (85% capacity factor), although the impact of higher and lower capacity factors on cogeneration prices were assessed in the Sensitivity Analysis. The industry standard is 85% which leaves sufficient down time for regular maintenance. The turbines are assumed to have a lifetime of 20 years, the reciprocating engines 12 years, and the microturbine 10 years. The expected lifetime of some turbines may be longer, but for accounting purposes, 20 years appears to be the standard.

3.2.2. Minimum Building Size

As noted earlier buildings have to have at least sufficient baseload thermal demand to warrant purchase of a 75 kW_e generator. Table 3 lists the approximate minimum sizes for each building type.

Table 3: Minimum Building Size

	(sqft)
Hotel	60 000
Office	250 000
High School	120 000
Shopping Mall	250 000
College	60 000
University	60 000
Hospital	75 000
Central Heat	250 000
Food Store	20 000
Refrigerated Warehouse	60 000

3.3. Building Type Stock

Buildings exceeding the minimum building size criteria were included in the study and are listed by building type in Appendix A.

3.4. Generator Sizing

Based on building size and typical baseload thermal demand, generators were chosen for each building and are also included in Appendix A.

3.5. Cogeneration Package Cost Calculations ($/kWh$_e$)

3.5.1. Weighted Average Cost of Capital

For the weighted average cost of capital I have assumed that the project is 50% debt financed and 50% equity financed (Berry, 1997). The real cost of debt is 5.25% and real pre-tax rate of return on equity (ROE) is 17% (Berry, 1997).[15]

[15] Using a real pre-tax rate of return on equity allows me to ignore income taxes in this preliminary analysis.

3.5.2. Costs

3.5.2.1 Capital Cost

Table 4 shows the levelized capital costs for the different cogeneration packages, a function of unit capital cost ($/kW$_e$) divided by the present value of energy which is represented by the present value of the lifetime hours of the plant.

Table 4: Capital Costs

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Capital Cost ($/kW)	1067	1050	1250	1320	1197	1120
Hours of Operation (h/yr)	7446	7446	7446	7446	7446	7446
Life of Project (yr)	10	12	12	15	15	15
Present Value of Energy (h)	43622	48056	48056	53176	53176	53176
Levelized Cost ($/kWh$_e$)	**0.0245**	**0.0218**	**0.0260**	**0.0248**	**0.0225**	**0.0211**

3.5.2.2 Non-fuel Operating and Maintenance Cost

The levelized non-fuel O+M cost of the microturbine is $0.0118/ kWh$_e$ (Table 5). The costs are comprised of a levelized recuperator replacement cost of $10 000 every 40 000 hours and basic costs (operating) associated with the turbine and the heat recovery system of $0.008/ kWh$_e$ and $0.002/ kWh$_e$ ($6000/yr) (Bell, 1998), respectively. O+M costs for the Recip 500 are $55 000/yr and $5000/yr, respectively, yielding a levelized cost of $.014/ kWh$_e$ (Willis, 1998). O+M costs for the Recip 2000 are $83 000/yr and $20 000/yr respectively, yielding a levelized cost of $.0066/ kWh$_e$ (Willis, 1998). O+M costs for the 10MW, 25MW, and 50 MW turbines ($0.0088/ kWh$_e$, $0.0077/ kWh$_e$, $0.0059/ kWh$_e$, respectively) were pre-calculated estimates from a large turbine distributor.[16] Other industry sources have reported higher and lower turbine O+M costs. For example, expert estimates for the 10 MW turbine range from $0.0035 - $0.02/ kWh$_e$, however, the $0.0088/ kWh$_e$ value was generally more accepted by more industry people.

Table 5: O+M Costs

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Maintenance ($/yr)	1007	55000	83000			
Operating ($/yr)	5585	5000	20000			
Electricity ('000 000's kWh$_e$)	0.56	4.28	15.64	71.33	196.20	369.34
Levelized Cost ($/kWh$_e$)	**0.0118**	**0.0140**	**0.0066**	**0.0088**	**0.0077**	**0.0059**

[16] Personal communication. Mark Axford, Stewart and Stevenson International, Inc., Houston, TX.

3.5.2.3 Fuel Cost

Cogeneration fuel prices were calculated using BC Gas Rate 22 (Makinen, 1998) and a price index consistent with that used to calculate CCGT fuel costs (Berry, 1997) (Table 6). I used the Recip 2000 price as a proxy for the microturbine and Recip 500 prices.

Table 6: Fuel Costs

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Plant Capacity (kWe)	75	575	2100	9580	26350	49602
Fuel Price ($/GJ)	2.40	2.40	2.40	2.22	2.19	2.18
Heat Rate		10278	8191	9813	9330	8354
Fuel Consumption (GJ/h)	0.9	6.9	20	110	302	509
Annual Consumption ('000's GJ/yr)	6.70	51.52	149.96	818.94	2248.73	3790.27
Levelized Cost ($/kWh$_e$)	**0.0288**	**0.0289**	**0.0230**	**0.0254**	**0.0251**	**0.0224**

Rate 22 is the sum of the basic index ($1.68/GJ) less 5%, total variable cost ($0.58), and a basic charge that varies with size of operation. With the exception of the microturbine, fuel consumption is based on generator heat rate, following the formula discussed in the methodology section. Allied Signal (the manufacturer) could not provide a specific heat rate for the microturbine yet. However, they estimate fuel use at approximately 0.90 GJ/h.[17] Levelized fuel costs are as follows: microturbine $0.0288/ kWh$_e$, Recip 500 $0.0289/ kWh$_e$, reicp 2000 $0.0230/ kWh$_e$, 10 MW turbine $0.0254/ kWh$_e$, 25 MW turbine $0.0251/ kWh$_e$, and 50 MW turbine $0.0224/ kWh$_e$.

3.5.3. Credits

3.5.3.1 Steam / Heat Credit

Using the calculations outlined in the Methodology section, and the BC Gas rates discussed above, levelized steam/heat credits were $0.0153 for the microturbine (Table 7), $0.0173/ kWh$_e$ for the Recip 500, $0.0112/ kWh$_e$ for the Recip 2000, $0.0160/ kWh$_e$ for the 10MW turbine, $0.0158/ kWh$_e$ for the 25MW turbine, and $0.0157/ kWh$_e$ for the 50 MW turbine.

[17] Allied Signal, in conjunction with its Western Canadian distributor, Mercury Electric, and Natural Resources Canada are testing microturbine prototypes to determine optimum efficiency, specific heat rates, and fuel consumption. Final results are expected in 1999. Fuel consumption is estimated to range between 0.9 - 0.93 GJ/hr and overall efficiency of the cogeneration unit is expected to be in the range of 60 - 70%. Ultimately, the microturbines position as a net reducer of CO2 emissions is sensitive to both values, as I will explain in greater depth in the Discussion Section.

Table 7: Steam/Heat Credits

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Fuel Replaced (GJ/h)	0.48	4.1	10	69	190	357
Value of Replaced Fuel ($/GJ)	2.40	2.40	2.40	2.22	2.19	2.18
Annual Value of Fuel Replaced ('000's $)	8.57	73.93	175.28	1138.49	3094.84	5809.87
Levelized Cost ($/kWh$_e$)	**0.0153**	**0.0173**	**0.0112**	**0.0160**	**0.0158**	**0.0157**

3.5.3.2 Boiler Operating and Maintenance Credit

The O+M credits for the different cogeneration packages were as follows: $0.0013/ kWh$_e$ for the microturbine (Table 8), $0.0012/ kWh$_e$ for the Recip 500, $0.0005/ kWh$_e$ for the Recip 2000, $0.0007/ kWh$_e$ for the 10MW turbine, $0.0003/ kWh$_e$ for the 25MW turbine, and $0.0002/ kWh$_e$ for the 50MW turbine.

Table 8: Boiler O+M Credits

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
O+M Credits ($/yr)	750	5000	8000	50000	65000	90000
Levelized Cost ($/kWh$_e$)	**0.0013**	**0.0012**	**0.0005**	**0.0007**	**0.0003**	**0.0002**

3.5.3.3 Boiler Credit

The differential costs for the boilers were $1875 for the microturbine (Table 9), $16 008 for the Recip 500, $40 317 for the Recip 2000, $279 390 for the 10MW turbine, $650 000 for the 25MW turbine, and $1 120 848 for the 50MW turbine. Levelized cost for the differential was $0.0006/ kWh$_e$ for the microturbine and the Recip 500, $0.0004/ kWh$_e$ for the Recip 2000 and 50MW turbines, and $0.0005/ kWh$_e$ for the 10 MW and 25 MW turbines.

Table 9: Boiler Credits

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Boiler Capital Cost ($)	1875	16008	40317	279390	650000	1120848
PV of electricity ('000 000's kWh$_e$)	3.27	27.63	100.92	509.42	1401.18	2637.63
Levelized Cost ($/kWh$_e$)	**0.0006**	**0.0006**	**0.0004**	**0.0005**	**0.0005**	**0.0004**

3.5.3.4 Backup Generator Credit

I asssumed a unit cost of \$200/ kW_e for backup generators for all cogeneration plants (Table 10). This is a typical cost for an inexpensive generator which is used occasionally on an intermittent basis. Levelized costs for the backup generator credit are \$0.0046/ kWh_e for the microturbine, \$0.0042 for the Recip 500 and Recip 2000, and \$0.0038 for the turbines.

Table10: Backup Generator Credits

	Micro TB	R 500	R 2000	10MW TB	25MW TB	50MW TB
Capital Cost of Backup Generator($/kW)	200	200	200	200	200	200
PV of Energy (h)	43622	48056	48056	53176	53176	53176
Levelized Cost ($/kWh$_e$)	**0.0046**	**0.0042**	**0.0042**	**0.0038**	**0.0038**	**0.0038**

3.6. Greenfield Installations

New cogeneration installations were estimated from projected building stock growth and average generator capacity. Growth in building stock ranged from 1.01% in food stores and warehouses to 1.03% in offices and malls (R. A. Malatest and Associates Ltd., 1997) (Table 11). In this study simulation, for simplicity, when stock (and consequently capacity) in each building type increased sufficiently to match average capacity (from existing building stock), a ‘suite’ of new cogeneration units was installed. Depending on the building type, a ‘suite’ can consist of one, two, or several generators and is based on the average size of generators used in the existing building stock and future baseload thermal demand. Cumulative installations of new suites are also displayed in Table 11. Building types with a high growth rate and a significant number of units, such as shopping malls, will consequently have more suites.

Table 11: Estimated Greenfield Cogeneration

	Food Store	Hotel	Shop Mall	Hospital	College	Ref. Warehse	Office	Uni-versity	Central Heat	High School
Growth (%)	1.01	1.02	1.03	1.02	1.02	1.01	1.03	1.02	1.03	n/a
1999	0	0	0	0	0	0	0	0	0	n/a
2000	0	0	0	0	0	0	0	0	0	n/a
2001	0	0	0	0	0	0	0	0	0	n/a
2002	0	1	1	0	0	0	0	0	0	n/a
2003	1	0	0	0	0	0	0	0	0	n/a
2004	0	1	1	0	0	1	0	0	0	n/a
2005	1	1	1	1	0	0	0	0	0	n/a
2006	1	1	2	0	1	1	0	0	0	n/a
2007	1	2	2	1	0	0	1	0	0	n/a
2008	1	2	2	0	1	1	0	0	0	n/a
2009	2	2	2	1	0	1	0	0	0	n/a
2010	2	3	3	1	1	1	1	1	1	n/a

4. RESULTS

The purpose of this study is to determine the economic viability and GHG (specifically CO_2) reduction potential of distributed cogeneration of heat and power in the GVRD commercial building sector. This chapter is a discussion of the results of a simulation of cogeneration costs and CO_2 emissions to the year 2010.

Section 4.1 estimates the potential number of installations and associated electrical capacity for retrofit and greenfield cogeneration. Also, in this section the methodology for sizing cogeneration units for individual buildings is assessed. Section 4.2 estimates potential CO_2 reduction associated with cogeneration. Section 4.3 provides a breakdown of costs and credits for the cogeneration units used in this study. Section 4.4 identifies the costs and potential capacity associated with different cogeneration units on a cogeneration supply curve. Section 4.5 assesses cogeneration economic competitiveness from a social perspective and that of a private investor. Section 4.6 estimates cogeneration CO_2 reduction costs (in \$/t CO_2) relative to CCGT cost and emissions. Section 4.7 outlines potential capacity, annual CO_2 reduction and the annual cost of distributed cogeneration relative to CCGT's in the year 2010. Section 4.8 tests the sensitivity of cogeneration costs to input variability. Section 4.9 further discusses barriers to cogeneration implementation.

4.1. Distributed Cogeneration Technical Potential

Table 3 of the Inputs and Intermediate Results section identifies the minimum building size necessary in each building type to house a cogeneration plant. From this basic criterion I determined the potential number of retrofit and greenfield cogeneration installations for the commercial building sector and the corresponding electricity capacity.

4.1.1. Retrofit Installations

For the study period 1998–2010, there are 93 potential commercial building sites suited for cogeneration retrofit (Table 12): 34 hotels, 12 shopping malls, 16 hospitals, 14 colleges, 2 universities, 1 central district heat and power system, and 12 high schools.

Table 12: Retrofit Installations

Sites	Hotel	Shop Mall	Hosp.	College	Office	University	Central Heat	High School	Totals
Microturbine	31	12	11	9	2			12	77
Recip 500	3		4	4					11
Recip 2000			1	1		1			3
10MW Turbine						1			1
25MW Turbine							1		1
	34	12	16	14	2	2	1	12	93

As noted earlier, without absorption chilling in food stores and refrigerated warehouses, there is insufficient baseload thermal demand to warrant cogeneration retrofit. Because absorption chilling is not an economical part of a retrofit package, food stores and refrigerated warehouses were only considered for greenfield cogeneration sites. Generators for retrofit sites include 77 microturbine packages, 11 Recip 500's, 3 Recip 2000's, 1 10MW turbine, and 1 25MW turbine.

These 93 cogeneration plants would generate 61.5 MW of electricity (Table 13). The Microturbine sites would include individual units, as well as, multiple microturbine configurations. Microturbines would produce 10.7 MW, Recip 500's 4.3 MW, Recip 2000's 10.6 MW, 10MW turbines 10.9 MW, and 25MW turbines 25 MW. Capacity by building type is as follows: hotels 5.4 MW, shopping malls 2.2 MW, hospitals 9.2 MW, colleges 5 MW, offices 0.3 MW, universities 13.4 MW, a central district heat and power system 25 MW, and high schools 1 MW.

Table 13: Retrofit Capacity (kW$_e$)

Sites	Hotel	Shop Mall	Hosp.	College	Office	University	Central Heat	High School	Totals
Microturbine	4073	2154	1720	1420	315			1021	10703
Recip 500	1336		1466	1511					4312
Recip 2000			6015	2112		2503			10630
10MW Turbine						10903			10903
25MW Turbine							25000		25000
	5408	2154	9201	5043	315	13405	25000	1021	61548

4.1.2. Greenfield Installations

By 2010, cogeneration would be installed at 95 greenfield sites (Table 14). Some building types, such as food stores, have a range of building sizes requiring different generators and consequently have more overall new installations. Most potential greenfield installations exist in the food stores (27) and hotels (26). There are also a sizable number of potential installations for new shopping malls (14) and hospitals (12), fewer for colleges (6) and refrigerated warehouses (5), and very few for offices (2), universities (2), and a central district heat and power system (1).

Table 14: Greenfield Installations (at 2010)

Sites	Food Store	Hotel	Shop Mall	Hosp.	College	Ref. Warehse	Office	University	Central Heat	Totals
Microturbine	9	13	14	4	3	5	2			50
Recip 500	9	13		4	3					29
Recip 2000	9			4				1		14
10MW Turbine								1		1
25MW Turbine									1	1
	27	26	14	12	6	5	2	2	1	95

Because of the sheer size of universities and a central district heat and power system, growth in thermal demand for these two building types would not result in new installations until the last year of the simulation, 2010. Given expected energy conservation measures, future high schools will no longer have sufficient baseload thermal demand to warrant distributed cogeneration. Most potential installations would be in smaller generator size classes. I have forecasted 50 microturbine installations, 29 Recip 500's, 14 Recip 2000's, 1 10MW turbine, and 1 25MW turbine.

Distributed cogeneration in new GVRD commercial buildings could provide 83.3 MW of electricity capacity (Table 15). The most significant source of power (25 MW) would come from a new central district heat and power system to meet the needs of a larger and more energy intensive downtown. Food stores alone could generate 21.9 MW of power. New hospital development could provide 13.8 MW, universities 9 MW, hotels 7 MW, colleges 3.2, shopping malls 2.3 MW, refrigerated warehouses 0.6 MW, and offices 0.4 MW.

Table 15: Greenfield Capacity (kW_e) at 2010

Sites	Food Store	Hotel	Shop Mall	Hosp.	College	Ref. Warehse	Office	University	Central Heat	Totals
Microturbine	2174	1550	2347	712	483	636	393			8296
Recip 500	4266	5433		1471	2763					13933
Recip 2000	15434			11590				1681		28706
10MW Turbine								7323		7323
25MW Turbine									25000	25000
	21874	6983	2347	13774	3246	636	393	9004	25000	83258

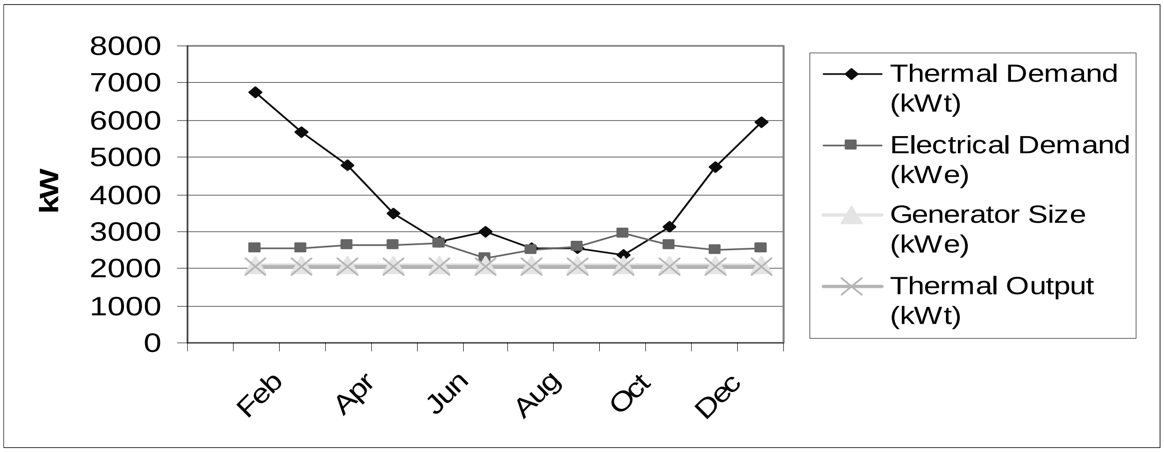
Of the different generator size classes, Recip 2000's would provide the most power (28.7). 25MW turbines would be next with 25 MW, followed by Recip 500's (13.9), microturbines (8.3), and 10MW turbines (7.3).

4.1.3. Energy Use Profiles

In the Methodology section I discussed how I used the engineering rule of thumb that half of annual space heating, refrigeration, and cooling and all of annual hot water energy demand should be added to calculate thermal baseload demand. To determine the accuracy of this technique I constructed monthly load profiles for each building type. Load profiles showed that the rule of thumb generally worked well, although better for some building types than others. For example, thermal baseload for 2000 kW_e reciprocating engines in colleges and universities (Figure 5) was accurately calculated such that heat is not wasted. Also, generator size is well correlated to electrical demand. Cogeneration units would import and export electricity to the grid when needed, so exact correlation is not necessary. However, if generators are closely matched with building requirements, they will be less dependent on the grid, and could potentially defer future T+D investment. Still, individual building cogeneration correlation would not affect T+D deferment if all cogeneration facilities were collectively correlated under some type of centralized management.

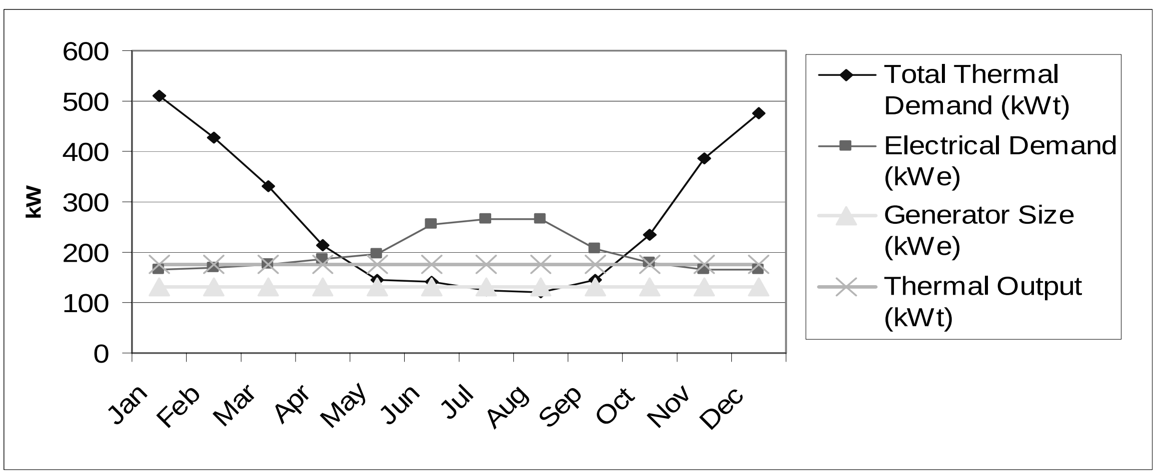
The electrical: thermal ratio is different for each generator. However, baseload thermal requirements are well correlated for each type of college and university.

Figure 5: Existing College (Recip 2000) Load Profile



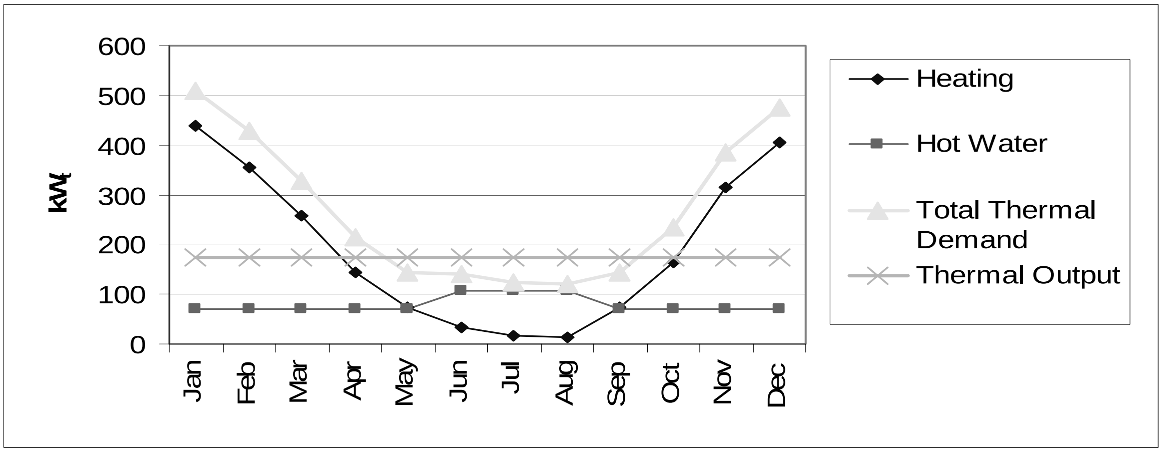
For other building types, thermal baseload is not necessarily as accurately correlated. Figure 6 illustrates that in existing hotels microturbines would produce excess heat from May to October. This is also the case for Recip 500 installations.

Figure 6: Existing Hotel (Microturbine) Load Profile



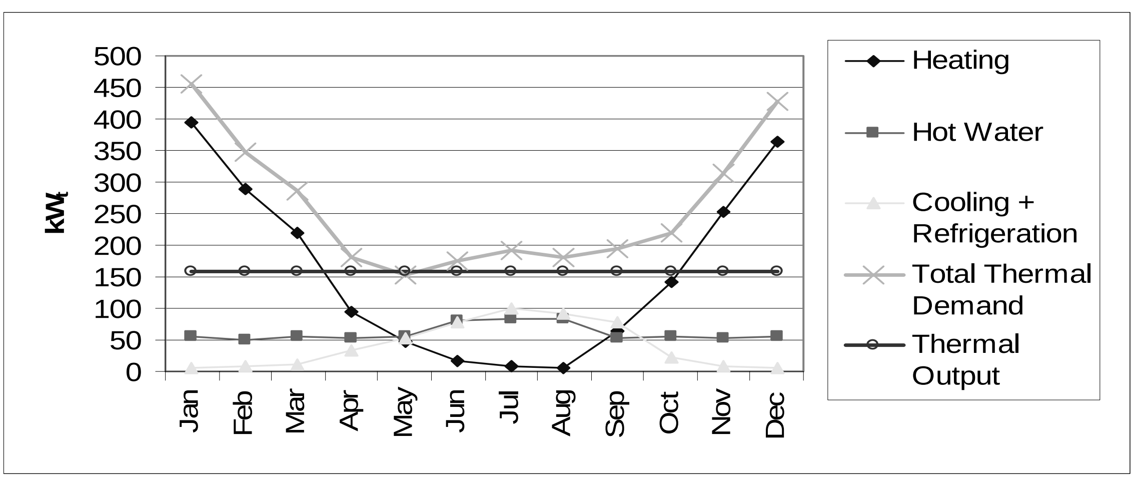
For existing buildings, baseload thermal demand is comprised of hot water heating and space heating. Although hot water heating in hotels rises slightly in the summer, it is fairly constant throughout the year (Figure 7). Seasonal variability in baseload thermal demand is largely due to seasonal variation in space heating. Through the year, average monthly baseload thermal demand for microturbine installations varies from a low of 121 kW_t in August to a high of 509 kW_t in January.

Figure 7: Existing Hotel (Microturbine) Thermal Load (kW_t)



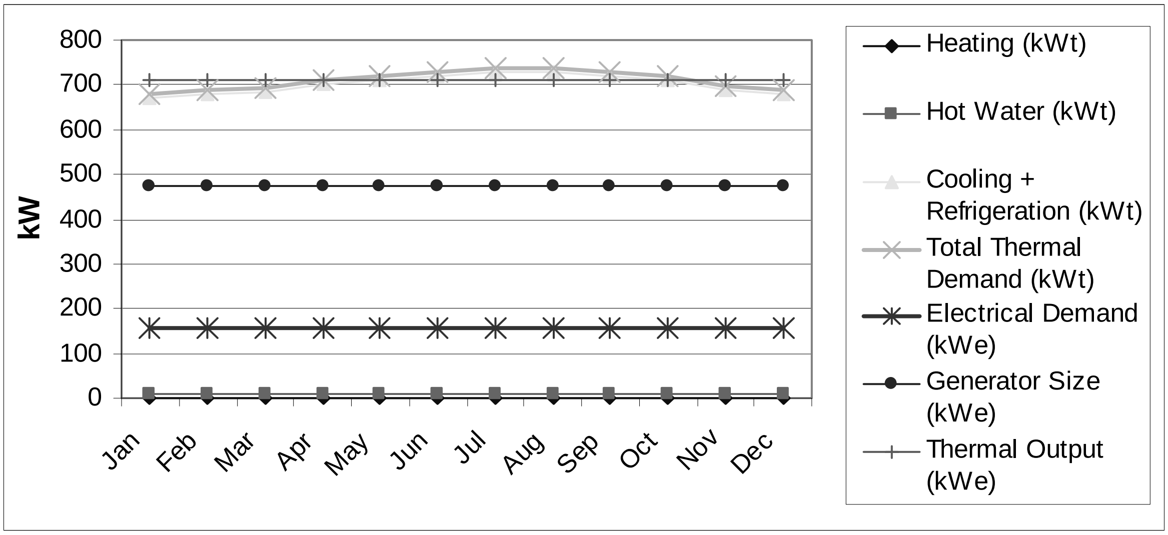
For optimal sizing, cogeneration would be set to the lowest monthly baseload. Buildings with high seasonal variability may have a high annual thermal demand, but cogeneration could efficiently only provide a limited portion of the total demand. Greenfield installations typically have more stable thermal load profiles, as the addition of absorption chilling for cooling and refrigeration somewhat offsets low summer space heating demand (Figure 8). In the case of microturbine installations in future hotels, absorption chilling for summertime cooling and refrigeration would increase demand sufficiently to use up all thermal output from a baseload facility.

Figure 8: Future Hotel (Microturbine) Thermal Load (kW_t)



Unlike other building types, baseload thermal demand in future food stores and refrigerated warehouses would principally be comprised of refrigeration, not space heating (Figure 9). Because refrigeration demand is fairly constant year round, thermal baseload for these building types was determined using 100% of cooling and refrigeration, not 50%.

Figure 9: Future Food Stores (Recip 500) Load Profile

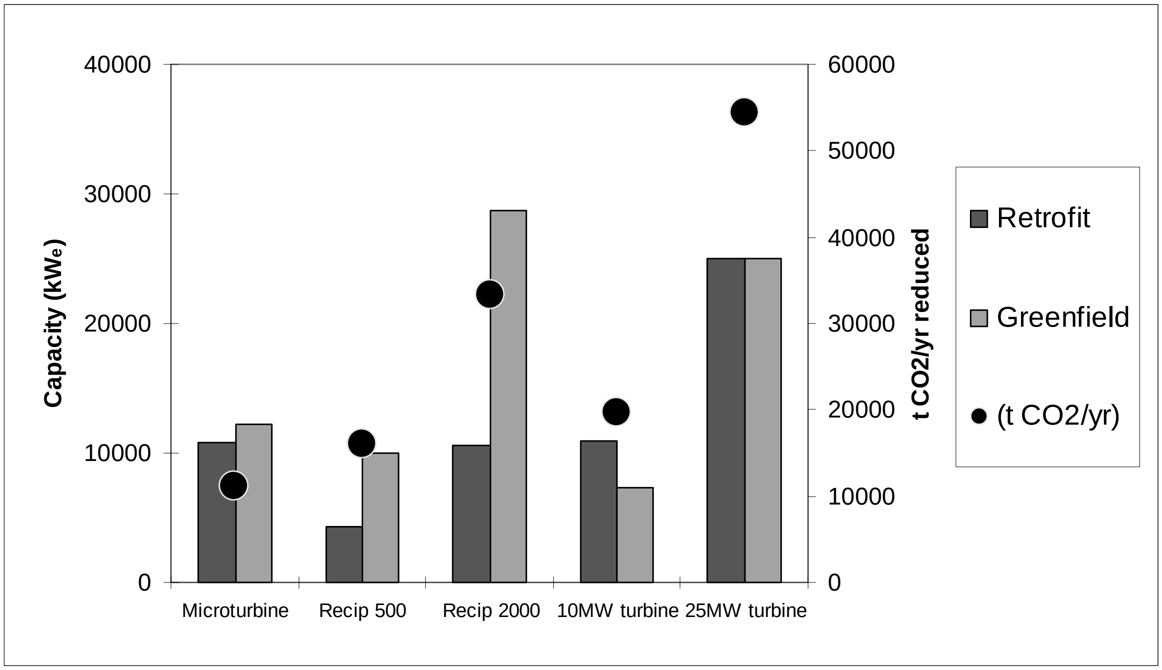


Also, electrical generation in food stores and refrigerated warehouses would greatly exceed on-site demand. Consequently, a significant portion of cogenerated electricity would be exported back to the grid. Other building types use the bulk of their electricity on-site.

4.2. CO_2 Reduction

Adoption of cogeneration by the commercial building sector could reduce CO_2 emissions in the GVRD by about 135 000 t/year in the year 2010 relative to CCGT powered buildings with full capacity boilers (Figure 10). The 25MW turbines alone in one greenfield and one retrofitted central heat and power network would reduce CO_2 emissions by about 55 000 t/yr. The 10 MW turbine facilities would reduce emissions by about 20 000 t/yr. Recip 2000 facilities would reduce emissions by about 33 000 t/yr. Recip 500 facilities would reduce emissions by about 16 000 t/yr. Microturbine facilities would reduce emissions by about 11 000 t/yr.

Figure 10: **CO_2 Reduction with Adoption of Cogeneration (Relative to CCGT's and Boilers) in 2010**



4.3. Cogeneration Costs and Credits

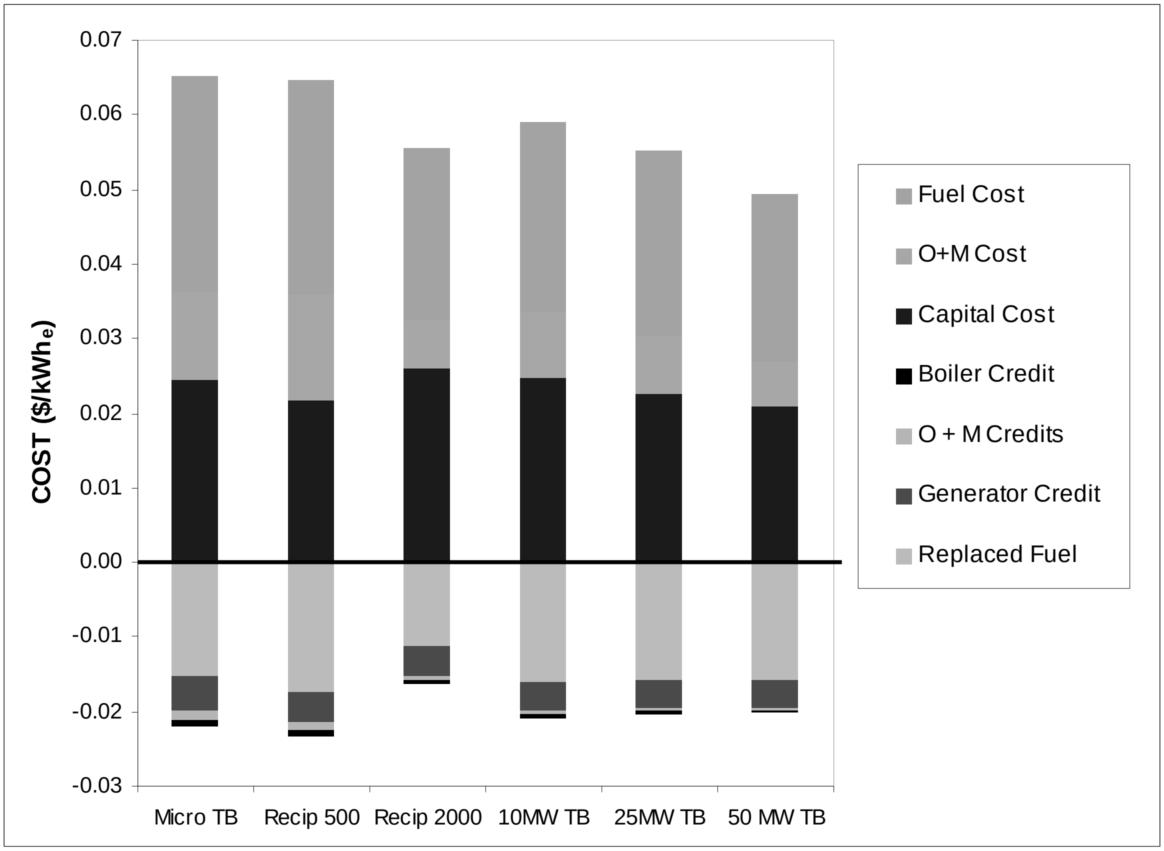
Table 16 displays total cogeneration unit costs (including credits). Total cost decreases with generator size and varies from \$0.0432/ kWh_e for the microturbine to \$0.0292/ kWh_e for the 50MW turbine, showing a pattern of declining cost with increased generator size.

Table 16: Total Cogeneration Costs (\$/kWh_e)

	Microturbine	Recip 500	Recip 2000	10MW Turbine	25MW Turbine	50 MW Turbine
Total Cost	**0.0432**	**0.0415**	**0.0393**	**0.0381**	**0.0350**	**0.0292**

At first glance (Figure 11) fuel would appear to be the most significant component of total cogeneration costs, yet when fuel credits are taken into account, net fuel costs are roughly half of capital costs, and roughly equivalent to O+M costs. Variables affecting capital costs are particularly important in determining cogeneration affordability relative to other generation options. The remaining credits are not particularly significant to total cogeneration cost. The generator credit is worth slightly more than a third of a cent and displaced boiler capital and boiler O+M, are almost insignificant to total cost, at less than a tenth of a penny.

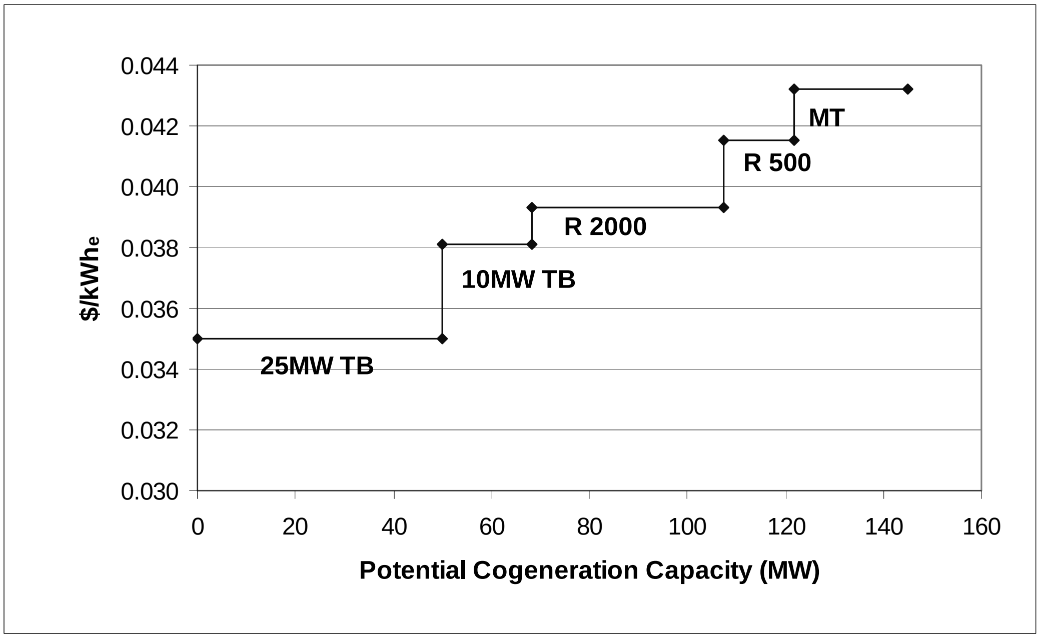
Figure 11: Breakdown of Cogeneration Costs and Credits



4.4. Cogeneration Supply Curve

I created a supply curve illustrating the unit cost and technical potential for cogeneration in commercial buildings in the GVRD. Combined retrofit and greenfield cogeneration capacity in the year 2010 is 144.9 MW (Figure 12) with 25MW and Recip 2000 installations comprising the bulk of new capacity, 35% and 27%, respectively. The remaining 38% of capacity is supplied by microturbines (16%), Recip 500's (10%), and 10MW turbines (13%). As discussed earlier, the cost is inversely related to size.

Figure 12: Potential Cogeneration Supply Curve for GVRD Commercial Buildings



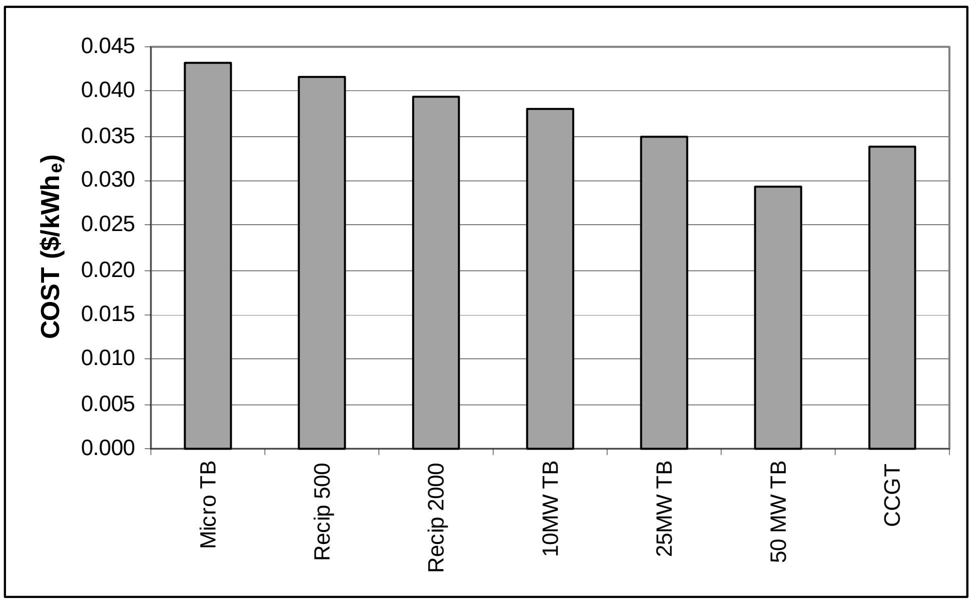
4.5. Cogeneration Competitiveness

To determine if cogeneration is an economic investment from a social perspective, I compared cogeneration costs to CCGT costs. To determine if private investors would finance cogeneration, I compared cogeneration costs to the predicted average electricity price for a competitive market. For both analyses I conducted a critical value assessment to determine what is the difference in cost between the various cogeneration units and a CCGT. This difference represents the cost shortfall between the two technologies which would have to be bridged by the right combination of CCGT T+D cost and cogeneration grid backup cost. If the initial analysis shows that CCGT is less expensive than cogeneration, then a high CCGT T+D cost and a low cogeneration backup cost might make up the difference. If the initial analysis shows that cogeneration is less expensive than CCGT, then a low CCGT T+D cost and a high cogeneration backup cost might make up the difference.

4.5.1. Social Perspective

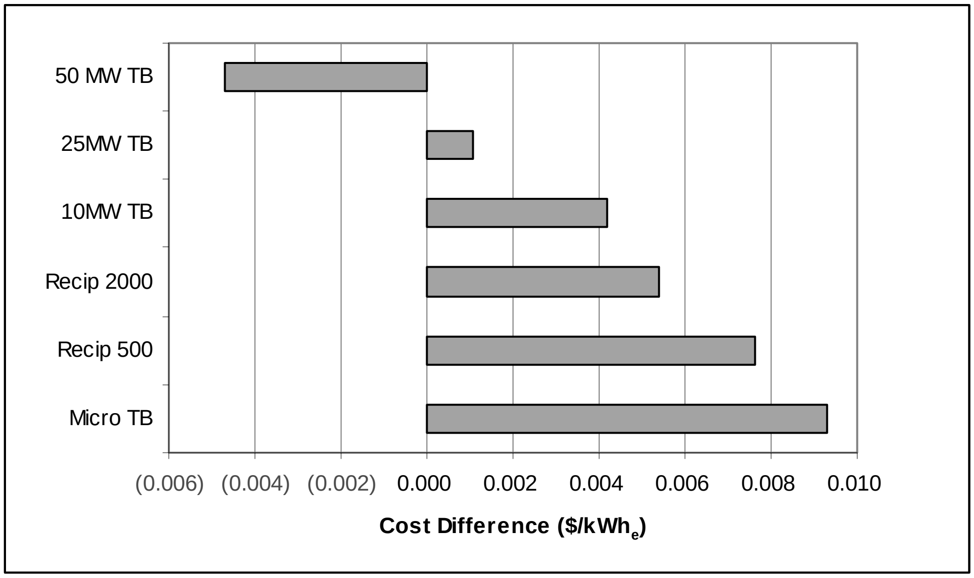
The most likely alternative to distributed cogeneration is a combined cycle generating station (CCGT). With a projected levelized cost of \$0.0339/ kWh_e (Berry, 1997), CCGT's are generally considered the least cost source of new electrical supply. Figure 13 shows CCGT cost relative to cogeneration costs. Without T+D costs or a grid backup cost, only 50MW cogeneration would be more economical than CCGT's. However, I have estimated that the largest potential cogeneration installation in the GVRD would only be 25MW. Given this information, distributed cogeneration in commercial buildings in the GVRD does not appear cost competitive with CCGT's, and, from a purely financial perspective, is not an investment in the social interest. Nevertheless, the cost difference between CCGT's and the larger cogeneration units is not enormous. On-site generation of electricity should eliminate some of the T+D costs associated with centralized plants such as CCGT's. If T+D costs are significant, and the grid backup cost is not high, some cogeneration units, particularly the larger turbines might be competitive.

Figure 13: CCGT and Cogeneration Costs



A critical value assessment (Figure 14) indicates that for cogeneration to be socially economical the combined positive impact of CCGT T+D costs and negative impact of cogeneration grid backup costs must improve cogeneration's financial standing by amounts according to the type of generator: microturbine - \$0.009/ kWh$_e$, Recip 500 - \$0.008/ kWh$_e$, Recip 2000 - \$0.005/ kWh$_e$, 10MW turbine - \$0.004/ kWh$_e$, and the 25MW turbine - \$0.001/ kWh$_e$. For example, if the CCGT T+D cost proves to be more than \$0.004/ kWh$_e$ greater than the grid backup cost for the 10MW turbine, then the 10MW turbine will be more economical than CCGT's.

Figure 14: Critical Value Assessment: CCGT and Cogeneration Cost Differences

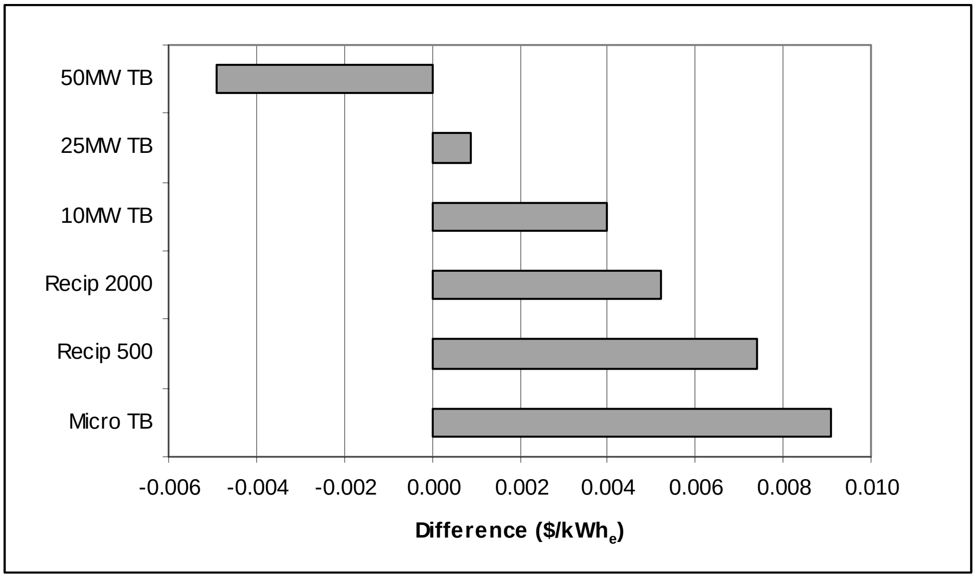


4.5.2. Private Perspective

The predicted average electricity price (plus an allowance for grid line losses of 5%) in a competitive market in BC is \$0.0341/kWh$_e$ (Berry, 1997). Similar to the cost comparison with CCGT's, only the 50MW cogeneration unit is less expensive than the average price of electricity in a competitive market (Figure 15).

Critical value analysis indicates that for cogeneration to be competitive with CCGT's, the CCGT T+D cost would have to be greater than grid backup costs by the following amounts: microturbine - \$0.009/ kWh$_e$, Recip 500 - \$0.007/ kWh$_e$, Recip 2000 - \$0.005/ kWh$_e$, 10MW turbine - \$0.004/ kWh$_e$, and the 25MW turbine - \$0.001/ kWh$_e$. It is not unusual that the CCGT cost and the average market price is similar. In a competitive and efficient market, price would generally fluctuate around the long-term cost of new supply. As demand for new capacity increases, so would market price. If market price increases more than the cost of new supply, new generation would be constructed. Market price indicates when new investment is required.

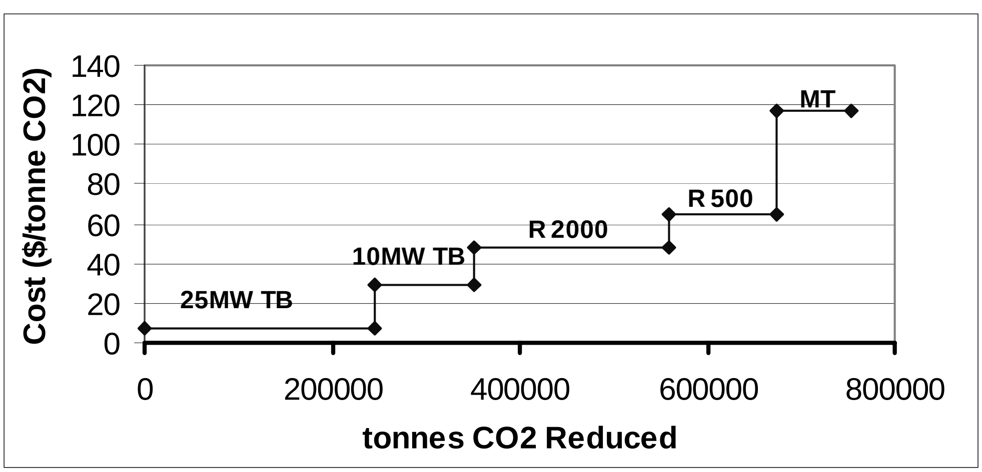
Figure 15: Critical Value Analysis: Difference Between Cogeneration Cost and Avg. Electricity Price



4.6. CO_2 Reduction Costs

Overall, adoption of distributed cogeneration by the commercial building sector in the GVRD would reduce cumulative CO_2 emissions by more than 750 000 t over the study period (1998-2010) relative to the separate incremental generation of electricity by CCGT's combined with regular boilers to meet thermal needs (Figure 16). 25MW turbines would diminish emissions by about 250 000t, 10MW turbines by about 110 000t, Recip 2000 engines by about 210 000t, Recip 500 engines by about 115 000t, and microturbines by about 80 000t.

Figure 16: Cost Curve for Potential CO_2 Reductions with Cogeneration



The cost of reducing a tonne of CO_2 emissions is a good measure to compare different emission reduction strategies and technologies or to indicate an appropriate CO_2 taxation or credit rate. The cost for reducing a tonne of CO_2 varies for the different cogeneration systems. Before including a CCGT T+D cost or a cogeneration grid backup fee into the analysis, all the cogeneration systems represented in this study have a net CO_2 reduction cost relative to CCGT's. The 25MW installation is the least costly at \$7/t CO_2, followed by the 10MW turbine (\$29/t), Recip 2000 (\$48/t), Recip 500 (\$65/t), and microturbine (\$117/t). In order to determine the relative merit of cogeneration as a CO_2 reduction tool, these CO_2 reduction costs should be compared to other options currently being examined by governments in various provincial (GHG Forum) and national (National Climate Change Initiative) processes.

Research conducted by Taylor (1999) suggests an increasing taxation rate of \$7/t CO_2 to \$22.5/t CO_2 from the year 2000 to 2010 for a tentative approach to CO_2 taxation and an increasing rate of \$13.75/t CO_2 to \$41.25/t CO_2 for the same period for an ambitious approach. With the tentative CO_2 taxation approach only the 25MW turbine would be competitive with CCGT. With the ambitious approach, the 25MW and 10MW turbines would be competitive.

4.7. Cogeneration Implementation Costs

To illustrate the potential impact of different cogeneration systems I have listed annual CO_2 reduction, and cost of CO_2 in the year 2010 before accounting for a CCGT T+D cost or a cogeneration grid backup fee (Table 17). Of all the generators, the 25MW turbine has the greatest potential capacity (50.0 MW) and CO_2 reduction (54 375 t CO_2/yr) with both a retrofit and greenfield installation at a central district heat and power site. However, it is slightly more expensive (\$0.001/ kWh_e on average) than CCGT's and would ultimately cost about \$400 000/yr more.

Without accounting for a CCGT T+D cost or a cogeneration grid backup fee no cogeneration installations are economical relative to CCGT's. Total cogeneration capacity of 145MW would reduce CO_2 emissions by 134 528 t /yr at a cost \$4.7 million per year.

Table 17: Cogeneration Potential at 2010

		Capacity (kW_e)	CO2 Reduced (t CO2/yr)	Cost ($/yr)
Hotel	Recip 500	2886	5926	384706
Hotel	Microturbine	9505	3329	388782
Office	Microturbine	786	419	48975
High School	Microturbine	1021	605	70604
Mall	Microturbine	4502	2666	148975
College	Recip 2000	2112	1785	84977
College	Recip 500	4274	3742	242909
College	Microturbine	1903	1127	131603
University	10MW turbine	18226	19691	568179
University	Recip 2000	4184	3535	168308
Hospital	Recip 2000	17605	14876	708270
Hospital	Recip 500	2937	2572	166967
Hospital	Microturbine	2432	1440	168183
Central Heat	25MW turbine	50000	54375	398690
Food Store	Recip 2000	15434	13041	620924
Food Store	Recip 500	4266	3735	242494
Food Store	Microturbine	2174	1287	150305
Fridge Warehouse	Microturbine	636	377	43986
TOTAL:		144884	134528	4737837
TOTAL (without Microturbines):		121924	123278	3586424

Because the microturbine is still in the prototype stage, a specific thermal efficiency has not yet been determined. The manufacturer estimated a range of 30 - 40%. A thermal efficiency as low as 30% would produce the same CO_2/ kWh_e as CCGT's. I used a thermal efficiency of 40% to calculate the microturbine's optimum potential. If the thermal efficiency of the microturbine proves to be 30% or less, then it would have little value as a CO_2 reduction tool in the commercial building sector. Total cogeneration capacity at 2010 without microturbines would be about 122MW with an estimated CO2 reduction of 123 278 t/yr at a cost of about $3.5 million per year, relative to CCGT's.

4.8. Sensitivity Analysis

4.8.1. Key Cost Variables

To test the sensitivity of the CCGT-cogeneration cost difference I chose a low, base, and high value for each of eight key cogeneration cost variables (Table 18) and individually tested the range of each cogeneration cost value while keeping the other values at base levels. Initially, I assumed that the CCGT cost would only be affected by changes in % debt financing and fuel price, and I varied these CCGT values accordingly. All other CCGT values were held constant at base values.

Table 18: Variable Range

	Low	Base	High
% debt financing	40%	50%	60%
real cost of debt	4%	5.25%	8%
ROE	15%	17%	19%
capacity factor	75%	85%	90%
capital cost	0.9	1	1.1
fuel price	0.9	1	1.1
heat rate	0.9	1	1.1
amortization	0.66	1	1.33

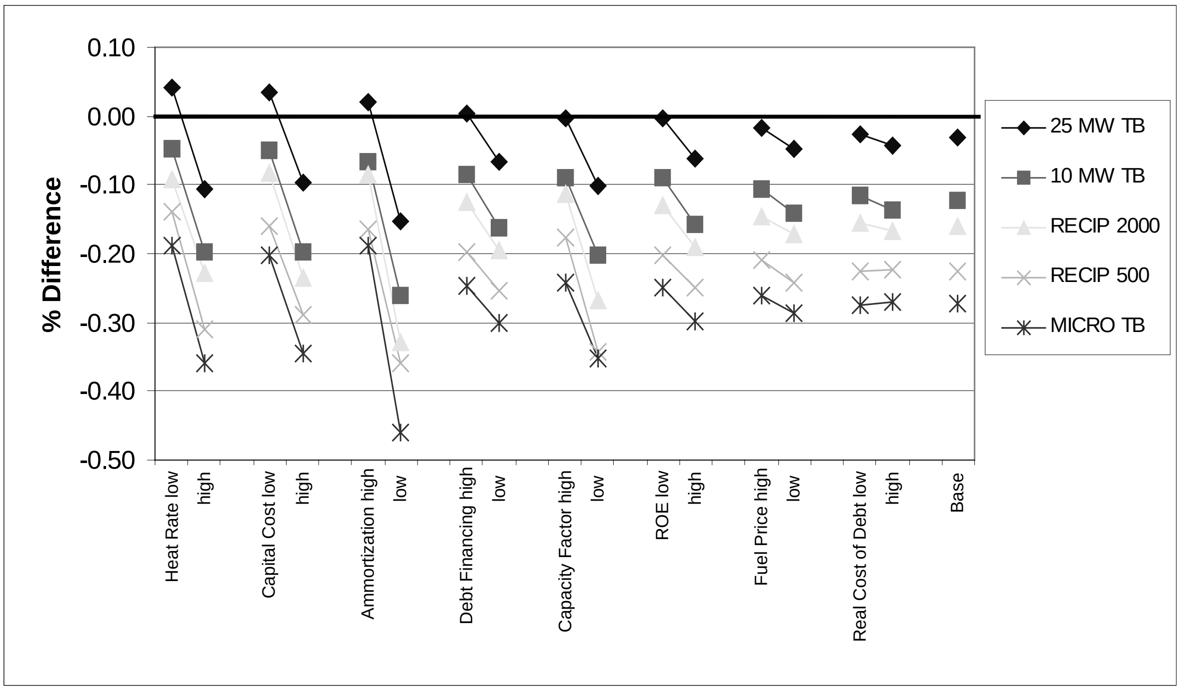
For the second sensitivity analysis, I again tested each cogeneration cost value individually while holding the other values at base levels. However, this time I also varied all corresponding CCGT cost values, not just % debt financing and fuel price. The range in CCGT values is listed in Table 19 and is proportional to that of cogeneration. For example, CCGT heat rate ranges from 6390 – 7810 Btu/kWh, from a factor of 0.9 to 1.1 of the base value, 7100 Btu/kWh.

Table 19: CCGT Variable Range

	Low	Base	High
% debt financing	40%	50%	60%
real cost of debt	4%	5.25%	8%
ROE	15%	17%	19%
capacity factor	75%	85%	90%
capital cost ($US/kW)	464	515	567
fuel price ($US/mmBtu)	1.18	1.31	1.44
heat rate (Btu/kWh)	6390	7100	7810
amortization (years)	10	15	20

The first sensitivity analysis assessed the cost relationship between CCGT's and cogeneration by testing assumptions about cogeneration cost (Figure 17), and reveals that CCGT cost exceeds or is equal to the 25MW turbine cost under several cogeneration variable assumptions (low heat rate, low capital cost, high amortization period, high debt financing, high capacity factor, and low expected return on equity). The cost of the 25MW turbine is greater than CCGT cost for the remaining variable assumptions (high and low fuel price, high and low real cost of debt, base values, high heat rate, high capital cost, low amortization period, low debt financing, low capacity factor, and high expected return on equity). CCGT cost is less than the other cogeneration units' costs for all variable ranges explored in this study. In other words, the CCGT is less expensive than all cogeneration units under all variable ranges, except the 25MW turbine under some assumptions.

Figure 17: % Difference: CCGT Cost vs. Cogeneration Cost (CCGT Base Values)

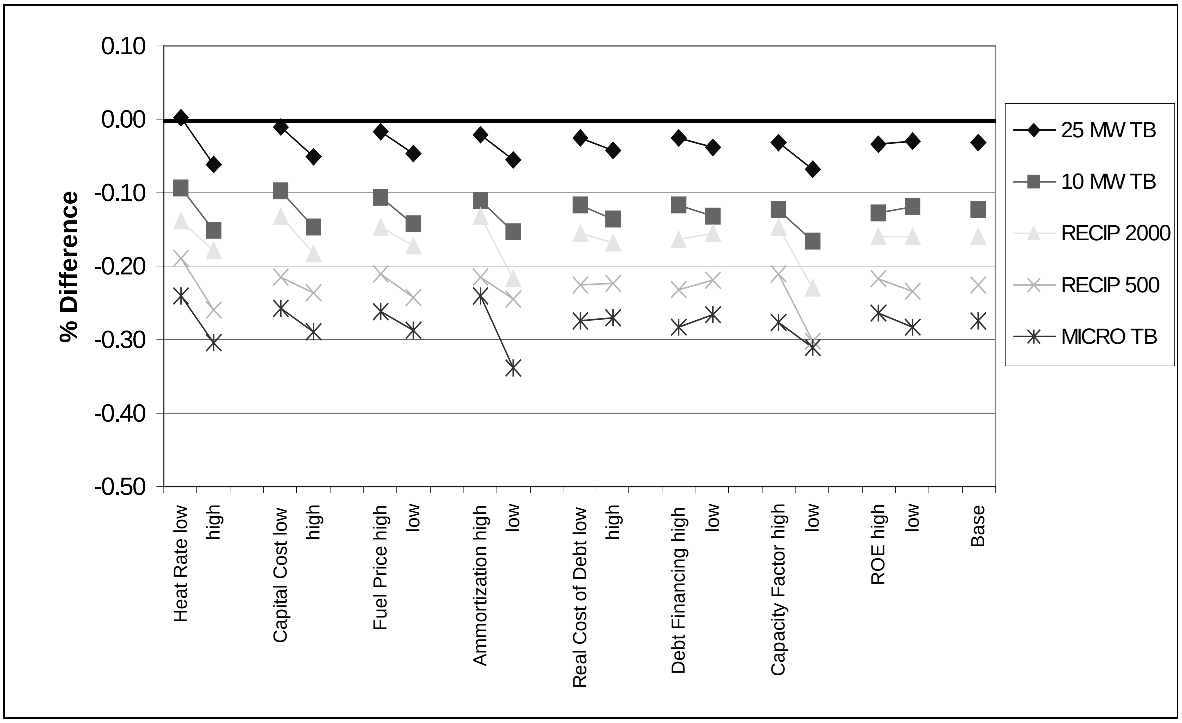


Of the range of variables explored in this analysis, the % difference in cost is most sensitive to variability in length of amortization periods, heat rate, capital cost and capacity factor, in that order. Capital cost is a significant variable because it is the largest component of total cogeneration cost. Consequently, variability in this value will have a proportionally greater impact on the cogeneration-CCGT cost difference than other cost components such as fuel and non-fuel O+M costs. Capital is also a fixed cost. When the amortization period is longer, more energy is produced with the same fixed costs. Therefore, as Figure 17 illustrates, increasing the lifetime of a cogeneration unit will have a considerable impact on total cogeneration cost, and, as a result, the cost difference. Variability in amortization periods is greatest with respect to the microturbine because it has the shortest lifetime of all the selected generators and the highest $/kWh$_e$ cost. Consequently, change in amortization period will have a disproportionately greater impact on this cogeneration unit. Like amortization period, capacity factor is also a key variable because increased production (now on an annual basis) on a fixed cost asset will reduce total cogeneration cost. The range of variability for capacity factor is likely, slightly larger than Figure 17 indicates. If cogeneration capacity factor were to increase, building owners could use a smaller and less expensive peaking boiler and the difference between cogeneration and CCGT cost would diminish slightly more than indicated. Conversely, a reduction in cogeneration capacity factor would necessitate purchase of a slightly larger peaking boiler, and would increase the cogeneration-CCGT cost difference slightly more than indicated. Finally, heat rate is also a significant variable, because a lower heat rate produces more electricity relative to heat.

Consequently, cogeneration competitiveness would be enhanced by factors which improve technical performance (heat rate) and length of operation (capacity factor and amortization period), such as optimal maintenance and improved engineering. Also, capital cost is the most important total cost component. Cogeneration capital cost reduction would greatly improve cogeneration competitiveness with CCGT. Other North American jurisdictions like Ontario and California have higher electricity prices, partly due to costly stranded generation assets. If the market for cogeneration investment improves, and capital costs decrease with economies of scale of production, future cogeneration competitiveness may be greatly enhanced.

The second sensitivity analysis assesses the cost relationship between CCGT's and cogeneration by testing assumptions about both cogeneration and CCGT costs (Figure 18). This analysis reveals that CCGT cost is less than all cogeneration units under all of this study's assumptions except for the 25MW turbine with a low heat rate value. Also, when values are varied for both cogeneration and CCGT, much less variability is apparent in the cogeneration-CCGT cost difference relative to the first sensitivity analysis. For example, cogeneration uses fuel more efficiently than CCGT, and fares better when fuel prices increase, however the 20% range in fuel prices tested in this analysis only amounts to a roughly 3% variability in cost difference between cogeneration and CCGT.

Figure 18: % Difference: CCGT Cost vs. Cogeneration Cost (CCGT Variable Values)



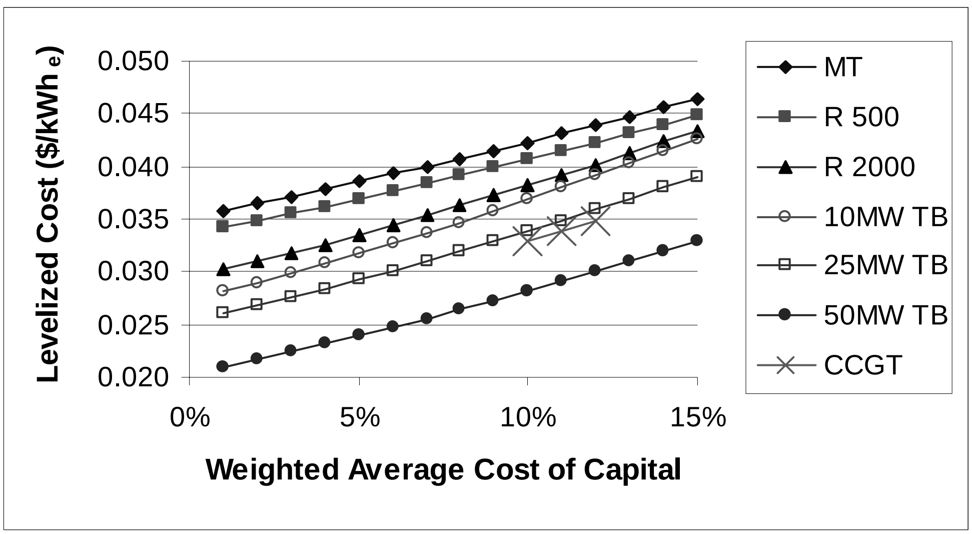
Consequently, if CCGT's keep pace with cogeneration technological improvements and optimum maintenance, there would be limited opportunities for improving cogeneration competitiveness. Overall industry increase in amortization periods by 33% or capacity factors by 5% would improve microturbine, Recip 500, and Recip 2000 competitiveness by about 10%. In general, most financial or technical changes that would reduce cogeneration costs, would also reduce CCGT costs, although, to a slightly lesser degree. In order for cogeneration to improve its market competitiveness, it must distinguish itself by outperforming its main competitor, CCGT, in technological improvements, enhanced maintenance systems, and capital cost reduction.

The other way to make up for the shortfall between CCGT and cogeneration costs would be to introduce a carbon credit system for CO_2 reduction technologies such as cogeneration, or, a carbon tax on CO_2 emitting fuels. Because CCGT's use more natural gas per kWh_e than cogeneration, they would be disproportionately impacted by any carbon penalty. As discussed earlier, an ambitious carbon tax could increase the market potential of the 25MW and 10MW turbines enough to successfully compete with CCGT's.

4.8.2. Weighted Average Cost of Capital

As shown in the above analyses, relative to other cogeneration and CCGT cost values, components of the weighted average cost capital calculation, such as debt financing, real cost of debt, and expected return on equity (ROE), do not have a great impact on cogeneration cost or the cogeneration-CCGT cost difference. As Figure 19 shows, cogeneration and CCGT costs are similarly affected by changes in the weighted average cost of capital, but are not highly sensitive to them. For example, an increase in the interest rate from 10% to 12% increases the cost of a 25MW cogeneration system by \$0.002/ kWh_e. Costs for CCGT's and other cogeneration systems also display similar sensitivity to the weighted average cost of capital, although microturbine and Recip 500 costs are slightly less sensitive to changes in the weighted average cost of capital.

Figure 19: Sensitivity of Cogeneration and CCGT Costs to Weighted Average Cost of Capital



From a social perspective, all electricity investments should have the same the weighted average cost of capital. Nevertheless, because the government absorbs much of the risk for public projects, cost of capital is essentially subsidized. Consequently, private investment is often subject to higher the weighted average cost of capital because the rate includes a risk premium. In the existing market structure, lower public costs of capital could favour cogeneration or CCGT's, if BC Hydro was interested in investing in these technologies. In a competitive electricity market, all electricity suppliers would be competing as private investors and would probably be subject to similar costs of capital.

4.9. Barriers to Implementation

4.9.1. Existing Market Structure

Independently financed generation can not currently compete with the low BC Hydro electricity tariff. Much of BC Hydro's generating capacity comes from low cost hydro power. Investment in new capacity costs more than the tariffs, in part because a considerable amount of the debt from the development of earlier hydro projects has been amortized. BC Hydro supports its own new supply by averaging it with the low costs of existing assets. The new average price is still less than what private investors require to finance independent power projects. Thus, under the current market and tariff structure, it is unlikely that distributed cogeneration will be adopted unless it is by BC Hydro.

In a competitive market, electricity prices would likely oscillate around the long run cost of new supply (probably CCGT's). Even if there were a competitive market for electricity, cogeneration would need some type of help, such as CO_2 emission credits or a carbon tax, to make up for its higher cost relative to CCGT. Only the 25MW and 10MW turbines, and possibly the Recip 2000, with favourable value assumptions (high amortization period and capacity factor and low cost of capital and heat rate), would be competitive with CCGT's. Simply put, high capital costs could price many cogeneration systems out of consideration.

A perfect match between cogeneration electricity and thermal output and building demands are highly unlikely. A cogeneration system can be matched to a building's thermal demand; however, either too much or too little electricity will be produced. Therefore, in order for cogeneration to benefit economically from its higher fuel efficiency, small generators, like cogeneration must be able to import and export electricity to and from the grid. The current electricity market structure does permit IPP's to wheel electricity[18]; however, they are required to pay high fixed costs for transmission under the current tariff and they may have to find a purchaser outside the province. Also, there is currently no explicit backup or standby tariff for small generators. Without regulatory protection for independent operators, these economic barriers could limit investment in cogeneration, even if electricity market rates were higher. Although some independent power production is contracted for by BC

[18] To use the grid to supply power to a third party.

Hydro in the current monopoly market, IPP's often face higher costs of capital than BC Hydro. Ultimately, high capital cost, financing, bureaucratic hurdles, and cheaper investments like CCGT's discourage IPP's from considering distributed cogeneration.

4.9.2. Technical

From a technical perspective, some buildings are not well suited to cogeneration. Modifications required to retrofit cogeneration into existing sites may, in some cases, prove prohibitively expensive. Also, buildings with low or highly variable thermal demand are not good candidates for the baseload cogeneration options examined in this paper. With grid connection for import and export of electricity shortfalls or excesses, electricity to thermal demand does not have to be perfectly matched. However, if cogeneration units are less dependent on the grid, then future T+D investment will more likely be deferred, ultimately reducing net cogeneration costs relative to larger scale investments such as CCGT's.

5. CONCLUSIONS

The first objective of this study was to determine if small-scale cogeneration would be a cost competitive technology under competitive market conditions. CCGT is generally considered the marginal resource for new investment in electrical generation technology, so I used CCGT cost as a proxy for electricity price in a competitive market. If cogeneration proved to be less expensive than CCGT's then it would be cost competitive. However, there is not a straightforward answer. At first blush, the answer is no. The 25 MW turbine is almost competitive, only \$0.0011/kWh_e more expensive than CCGT. Cost difference for the remainder of the cogeneration systems varies from \$0.0042/kWh_e for the 10MW turbine to \$0.0093/kWh_e for the microturbine. The main driver for the cost difference between these technologies and CCGT is cogeneration capital cost. Capital is the largest component of total cogeneration cost, and on a unit cost basis, it is high relative to other potentially competitive generation technologies.

Nevertheless, sensitivity analysis indicates that the 25MW turbine is competitive under many value assumptions (high amortization period and capacity factor and low capital cost and heat rate). Also, costs for all cogeneration units are highly variable when subject to a range of amortization period, capacity factor, capital cost, and heat rate values. Consequently, cogeneration competitiveness would be enhanced by factors that improve technical performance (heat rate) and length of operation (capacity factor and amortization period), such as optimal maintenance and improved engineering.

Further, CCGT T+D cost and cogeneration grid backup costs were not directly considered in the analysis. If distributed cogeneration installations throughout the grid lead to significant deferral of future T+D investments and grid backup costs prove to be low, cogeneration competitiveness would also be enhanced. Critical value assessment indicated that cogeneration would be competitive if CCGT T+D cost exceeds grid backup costs by \$0.001/ kWh_e for the 25MW turbine, \$0.004/ kWh_e for the10MW turbine, \$0.005/ kWh_e for the Recip 2000, \$0.008/ kWh_e for the Recip 500, and \$0.009/ kWh_e for the microturbine.

The second study objective was to determine if adoption of selected cogeneration systems, in lieu of investment in a CCGT powered generating station would reduce CO_2 emissions. From an environmental perspective, cogeneration is a more attractive technology than

CCGT's, for it produces less CO_2 on a per kW_e basis. Reductions in the order of 135 000 t/yr in CO_2 emissions are possible in 2010 with about 145MW capacity of retrofit and greenfield distributed cogeneration in the GVRD commercial building sector. Cogeneration could be an important CO_2 reduction tool, but convincing private investors that it is an economically viable technology may require financial incentives like CO_2 reduction credits, or penalties in the form of a carbon tax.

Without including T+D costs and grid back-up costs, cogeneration would cost about $4.7 million more annually in the year 2010 relative to CCGT's. This cost is equivalent to $7/t - $117/t of CO_2 reduced, depending on the size of the cogeneration system. With a tentative CO_2 tax the 25MW turbine would be competitive with CCGT's. With an ambitious tax, the 25MW and 10MW turbines, and possibly the Recip 2000 would be competitive. Combining an ambitious CO_2 tax with a high T+D cost and/or technological improvements in amortization period, capacity factor, and heat rate might also make the smaller cogeneration units economically viable generation technologies in a competitive market.

6. REFERENCES

BC Hydro, 1995. Integrated Electricity Plan: Appendix E. Vancouver, BC.

Bell, Howard (1998). Mercury Electric Corporation. Personal communication.

Bell, Howard, Bob Williams, and Vern Mantey (1998). Mercury Electric Corporation, Calgary, AB. Personal communication.

Berry, Trent (1997). BC Taskforce on Electricity Market Reform: Final Report to the Pricing & Entitlements Technical Subcommittee, Rates and Regulatory Affairs, BC Hydro, Vancouver, BC.

Building Owners and Managers Association (1997). Greater Vancouver Leasing Guide ‘97. A supplement to Business in Vancouver, BIV Publications, Vancouver, BC.

Business in Vancouver (1998). January 6-12, BIV Publications Ltd., Vancouver, BC.

Business in Vancouver (1997a). Dec 16-22, BIV Publications Ltd., Vancouver, BC.

Business in Vancouver (1997b). Dec 2-8, BIV Publications Ltd., Vancouver, BC.

Cardell, Judith and Richard Tabors (1997). “What’s in the Cards for Distributed Resources?” *The Energy Journal,* Special Issue: Distributed Resources: Toward a New Paradigm of the Electricity Business.

Casten, Thomas R. (1995). “Electricity Generation: Smaller is Better”, The Force of Technology. December, 1995, p. 65-73.

Clayton, Sarah and Paul Wieringa (1995). Natural Gas-fired Cogeneration Study: Staff Discussion Paper. Victoria, BC: Province of British Columbia.

Dresser Industries Inc. (1986) Cogeneration Handbook, Form 7030, Waukesha Power Systems, Waukesha Engine Division, Dresser Industries Inc., Waukesha, WI

ERG International (1993). Commercial Base Building Reports. Prepared for BC Hydro, Vancouver, BC.

Feinstein, Charles D. and Jonathan A. Lesser (1997). “What’s in the Cards for Distributed Resources?” *The Energy Journal,* Special Issue: Distributed Resources: Toward a New Paradigm of the Electricity Business.

Flavin, Christopher and Nicholas Lenssen (1994). Power Surge: Guide to the Coming Energy Revolution. Worldwatch Institute, Washington, D.C.

Gas Turbine World 1997 Handbook (1997). Volume 18. p. 133. Peaquot Publishing Inc. Fairfield, CT. Robert Farmer, Chief Editor.

Hoff, Thomas E. (1997). “What’s in the Cards for Distributed Resources?” *The Energy Journal,* Special Issue: Distributed Resources: Toward a New Paradigm of the Electricity Business.

Makinen, Timo (1998). BC Gas, Vancouver, BC. Personal communication.

Marbek Resource Consultants, Sheltaire Scientific, and SAR Engineering Ltd. (1999). Commercial/Institutional and Residential Sector Action/Opportunity Cost Curves – Buildings Table: Final Report. Volume 1. Ottawa, ON.

Pape, Andrew (1997). Implementing Sustainable Energy in Competitive Markets. M.R.M. Research Project, Simon Fraser University, Burnaby, BC.

Pfiefenberger, Johannes P., Philip Q. Hauser, and Paul Ammann (1997). “What’s in the Cards for Distributed Resources?” *The Energy Journal,* Special Issue: Distributed Resources: Toward a New Paradigm of the Electricity Business.

Public Works Canada (1993). Micro-Cogeneration Assessment Guide for Federally Owned Buildings, Ottawa, ON.

R.A. Malatest and Associates Ltd. (1997). Summary Report: Commercial Floor Stock. Prepared for BC Gas, Victoria, BC.

Taylor, Amy (1999). Ecological Tax Reform: Estimated Environmental and Employment Effects in British Columbia. M.R.M. Research Project, Simon Fraser University, Burnaby, BC.

Tourism Vancouver - The Greater Vancouver Convention & Visitor's Bureau (1997). Key Pacific Publishers, Victoria, BC. The Vancouver Book: a Visitor's Guide to Greater Vancouver.

Vancouver Public School Board. (1998) Personal communication.

Waukesha Engine Division, Dresser Industries Inc. (1987). Cogeneration Handbook - Bulletin 8009B. Waukesha, WI.

Waukesha Engine Division, Dresser Industries Inc. (1986). Form 7030. Waukesha, WI.

Wartsila Diesel Power News Customer Journal (1997). 1/97. Operational Experience. Editor Anci Sandas. Wartsila Diesel Int. Ltd. Oy, Vaasa, Finland.

Willis (1997). Paul Willis, Willis, Energy Services Ltd. Personal communication.

Willis (1998). Paul Willis, Willis, Energy Services Ltd. Personal communication.

7. APPENDIX A - Existing Building Stock And Corresponding Generators

Building Type	Generator
Hotel	
Westin Bayshore	recip 500
Pan Pacific	recip 500
Waterfront Centre	microturbine
Delta Pacific	microturbine
Delta Vancouver Airport	microturbine
Best Western Richmond	microturbine
Sheraton Guildford	microturbine
Clarion Villa	microturbine
Coast Plaza Stanley Park	recip 500
Stay'n Save Vancouver Airport	microturbine
Holiday Inn Vancouver Centre	microturbine
Radisson President	microturbine
Best Western Tsawassen	microturbine
Plaza Hotel	microturbine
Best Western Pacific Inn	microturbine
Best Western King's Inn	microturbine
Coast Vancouver Airport	microturbine
Stay'n Save Motor Inn Burnaby	microturbine
Ramada Vancouver Centre	microturbine
Best Western Coquitlam	microturbine
Atrium Inn	microturbine
Quality Inn Airport	microturbine
Holiday Inn Metrotown	microturbine
Abercorn Best Western	microturbine
Biltmore	microturbine
Ramada Limited	microturbine
Holiday Inn Coquitlam	microturbine
Grouse Inn	microturbine
Quality Inn Metrotown	microturbine
Tropicana Motor Inn	microturbine
Holiday Inn Express (North Shore)	microturbine
Lonsdale Quay Hotel	microturbine
Kingsway Lodge	microturbine
2400 Motel	microturbine
Office	
Canada Way Business Park	microturbine
Metrotown:	microturbine
Place III	
Place I	
Metropointe	
Roger's Cantel Tower	
Metrotower II - Eaton Centre	
Malls	
Park Royal	microturbine
Metrotown Centre	microturbine
Guildford Tn Ctre	microturbine
Richmond Centre	microturbine
Coquitlam Centre	microturbine
Oakridge Centre	microturbine
Surrey Place	microturbine
Lansdowne Park	microturbine
Eaton's Ctre Metro.	microturbine
Willowbrook Mall	microturbine
Lougheed Mall	microturbine
Brentwood Mall	microturbine
Central Heat	10MW turbine

Building Type	Generator
Hospital	
Shaughnessy Steam Grid:	recip 2000
VGH	
Children's and Women's	
RCMP	
Vancouver Cancer Centre	
GF Strong	
St. Vincent (Heather)	
Red Cross	
Riverview	recip 2000
Royal Columbian	recip 500
Lion's Gate	recip 500
Surrey Memorial	recip 500
Burnaby	recip 500
Langley	microturbine
Peace Arch	microturbine
Eagle Ridge	microturbine
MSA General	microturbine
Mount St. Joseph's	microturbine
Ridge Meadows	microturbine
George Pearson	microturbine
Queen's Park	microturbine
Holy Family	microturbine
Delta	microturbine
St. Vincent (Langara)	microturbine
Colleges	
Trinity Western University	recip 500
Capilano	recip 500
Douglas:	
New West	recip 500
Coquitlam	microturbine
BCIT:	
Burnaby	recip 2000
North Van	microturbine
Airport	microturbine
Langara	recip 500
VCC (King Edward)	microturbine
Kwantlen:	
Richmond	microturbine
Langley	microturbine
Surrey	microturbine
Newton	microturbine
Emily Carr	microturbine
Universities	
UBC	10MW turbine
SFU	recip 2000
High Schools	
Vancouver Technical	microturbine
Templeton	microturbine
John Oliver	microturbine
Britannia	microturbine
Tupper	microturbine
Windermere	microturbine
Killarney	microturbine
Prince of Wales	microturbine
Point Grey	microturbine
David Thompson	microturbine
Gladstone	microturbine
Magee	microturbine