IMPLEMENTING SUSTAINABLE ENERGY IN COMPETITIVE ELECTRICITY MARKETS

by

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ABSTRACT

The purpose of this study is to assess mechanisms to foster sustainable electricity generation technologies (Sustainables) under competitive electricity markets. Sustainables are those technologies which have environmentally desirable attributes when compared to conventional market-driven electricity generation technologies. The electricity sector is undergoing fundamental restructuring from direct government intervention and control to a more market-oriented approach. In particular, governments are introducing competition in electricity generation and, in some jurisdictions, retail supply, and imposing functional or corporate separation of vertically-integrated utilities to enhance competition and transparency. Some of the traditional mechanisms which governments have used to foster Sustainables may no longer be compatible, or may have to be supplemented, in this new market environment.

This study has identified and evaluated market-oriented policy mechanisms for fostering Sustainables under competitive electricity markets. These policies include: (1) a sustainable energy portfolio standard (SPS), which guarantees that a minimum share of electricity generated by Sustainables be included in the wholesale supply of electricity; (2) the collection of a non-bypassable System Benefits Charge (SBC) on electricity sales to establish a fund which subsidizes the development of Sustainables; and (3) the application of revenue-neutral environmental adders (EA) to generator bids into the electricity market which will affect their competitiveness.

The policy mechanisms were compared under several evaluative criteria in a simulation model called the Competitive Electricity Market Policy Analysis (CEMPA) model. Simulations were conducted of electricity dispatch and investment behavior in B.C. and Alberta from 1995 - 2025 assuming implementation of those mechanisms.

The results indicate that the SPS mechanism tends to maximize the installed capacity of Sustainables because it is designed to support the most cost-effective technologies or resources. The SBC mechanism, by design, enhances the diversity of Sustainables supported, and maximizes the cost reduction of emerging Sustainables. The SPS minimizes financial impacts due to a phasing-in of the requirement, and a continuous cost-minimization pressure on the market. The EA minimizes the CO_2 abatement cost because the policy mechanism is set-up as a CO_2 tax, thus driving the market to reduce emissions at the least cost. Finally, the SPS is the most simple to operate and administer because it relies on the market to achieve the policy objectives.

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1. INTRODUCTION

The purpose of this study is to assess mechanisms to foster environmentally desirable electricity generation technologies under competitive electricity markets. This study quantitatively analyzes three energy policy mechanisms which foster those technologies under competitive markets.

1.1 Background on the Study

This section includes a description of a current energy policy issue, framed as a problem statement for the study, a description of the study purpose which is an attempt to address the policy issue, and a brief overview of the methodology undertaken to demonstrate the application of policy mechanisms to respond to the problem/issue.

Problem Statement

Sustainable electricity generation technologies, referred to as *Sustainables* throughout this study, are those technologies which have environmentally desirable attributes when compared to conventional market-driven electricity generation technologies. The term *renewables* is often used to describe these technologies because they are mostly powered by renewable resources such as flowing water, solar radiation, wind, or biomass matter.

The electricity sector is undergoing fundamental restructuring from direct government intervention and control to a more market-oriented approach. In particular, governments are introducing competition in electricity generation and, in some jurisdictions, retail supply, and imposing functional or corporate separation of vertically-integrated utilities to enhance competition and transparency.

Some of the traditional mechanisms which governments have used to foster *Sustainables* may no longer be compatible, or may have to be supplemented, in this new market environment. These mechanisms include government regulation of electricity resource acquisition by distributors or direct government or public investment in sustainable energy.

Purpose of Study

This study has identified and evaluated market-oriented policy mechanisms for fostering *Sustainables* under competitive electricity markets. Several evaluative criteria were applied for comparing the policy mechanisms, including cost, market development, and environmental criteria.

Methodology of Study

The hypothesis of the study is that environmentally desirable electricity generation technologies (*Sustainables*) can be effectively fostered in competitive electricity markets. The hypothesis is demonstrated and tested through the following steps:

- Simulations were conducted of electricity dispatch and investment behavior in B.C. and Alberta from 1995 - 2025 assuming implementation of different policy mechanisms for fostering *Sustainables*.
- For the purposes of the study, *Sustainables* were defined as: wind generation systems, solar photovoltaic cells, small run-of-river hydroelectric and tidal generators, biomass and waste-fuel thermal generators, and biomass cogeneration systems.
- Three market-oriented policy mechanisms were tested, including a tradable *Sustainables* portfolio standard or market purchase requirement, a wire charge with subsidized support for *Sustainables*, and the establishment of a revenue-neutral environmental cost adder which gives *Sustainables* a competitive advantage over less environmentally desirable resources.
- The policy mechanisms were compared according to the following evaluative criteria:
    1. Market share of Sustainables (MW capacity and GWh production).
    2. Degree of diversity of Sustainables (number of technologies fostered).
    3. Impact on the reduction of the unit cost of Sustainables ($/kWh).
    4. Total expenditure on electricity production ($), and wholesale spot prices ($/GWh).
    5. Annual carbon dioxide emission abatement cost ($ / tonne CO_2 reduced).
    6. Administrative and operational simplicity.

  The first criterion was selected to demonstrate the achievement of the primary objective of the study, which is to analyze policy mechanisms to foster Sustainables. The capacity development and energy production are the most obvious ways of demonstrating that. The second and third criteria illustrate specific impacts of policies on the sustainable energy industry itself, the diversity of technologies developed, and the cost reduction achieved through economies of scale and manufacture. Technological diversity has a benefit of minimizing resource risk - so that if one resource (i.e. natural gas) is short in supply or high in price, then other resources will have a sufficient market share to partially replace thier loads. With sufficient cost reduction, the industry may be able to compete without any preferential policies driving it. The fourth criterion demonstrates the impacts of the sustainability policies on the financial health of the electricity sector, both in terms of price impacts (spot price) and the total cost of operating the electrical system. The fifth is a measure of environmental impacts of the electricity and the financial performance of various policies to meet an environmental objective (CO_2 reduction). The sixth is a qualitative assessment of the relative administrative burden of the various policies.

1.2 Competitive Electricity Markets

The electricity industry in Canada is facing a transformation that will foster greater competition for electricity supply and potentially modify the structure of current regulated vertically-integrated utilities. This transformation is often called *electricity market reform* or *electricity market restructuring*. Policymakers around the world are investigating or undertaking electricity market reform initiatives.

One restructuring outcome is the adoption of a *wholesale competition* market which maintains regulated, natural monopoly control over the transmission and distribution of power and retail sales to consumers, but the supply of electricity is opened to competition. The short-term wholesale price of electricity is determined like a commodity, according to the supply and wholesale demand for electricity in a spot market[1], rather than through regulatory mechanisms. The toll for regulated transmission and distribution (T&D) services is determined through rate hearings, encompassing the cost of providing those services and allowing the T&D utility a fair rate of return. In some cases, T&D tolls vary by the location of the generator and/or consumer, to provide an incentive for generators to locate in areas with high marginal transmission or distribution costs. Also, the cost of ancillary services[2] is often bundled in T&D tolls, although in some jurisdictions a separate competitive ancillary services market has been created.

Beyond *wholesale competition*, *retail competition* allows end-use consumers to contract directly with producers or marketer intermediaries for the electricity commodity, which is delivered by a

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1 A dynamic commodity market structure whereby the "spot price" of electricity is determined at regular intervals based on available supply and instantaneous demand. The "spot price" is set from the highest bid of the selected least-cost generators required to meet demand for that period.

2 Transmission support services necessary to ensure integrity of the transmission network, including voltage control, reactive power, load following, loss compensation, energy imbalance, scheduling and dispatch services, and system protection (operating reserves).

regulated natural monopoly through T&D lines. In some jurisdictions, those customers who turn to alternative suppliers may have to pay an "exit fee" to pay for their share of any *stranded costs* in generation facilities, those costs which result from the devaluation of utility generation assets as the market is opened to competition.

The main objective of fostering *wholesale competition* in the electricity generation market is to maximize the economic efficiency of investment and operation decisions so that electricity is provided at the least cost to consumers. With *retail competition*, a further objective is to provide greater choice to consumers in the types of pricing and services they receive. Additional objectives for both models may include streamlining or eliminating redundant regulatory mechanisms and diversifying the electricity sector by involving more players, such as independent power producers on the supply side and power marketers and brokers on the retail side.

Several factors are contributing to the momentum of electricity market restructuring in British Columbia and elsewhere (BCUC, 1995).

- U.S. trade requirements which dictate market access reciprocity - if Canadian producers want market access into the U.S., then U.S. producers have to have the same rights in Canada.
- Technological change and limitations of large-scale centralized generation technologies have contributed to the erosion of the rationale for maintaining vertically-integrated utilities, which control the generation, transmission and distribution of electricity within one organization.
- Increased global competition is forcing industrial electricity consumers to cut costs to the level that their competitors pay, hence pushing for a North-America wide competitive market.
- Public policy is emphasizing economic efficiency more than before - also favoring free markets and private ownership.

Alberta was the first jurisdiction in North America to restructure its electricity market by establishing a mandatory *power pool* in January, 1996, and appointing an independent *transmission administrator* (TA) in late-1997. The former is an independent, non-profit entity which coordinates all electricity trading in the province; and determines the short-term market price of electricity. An Irish company has been selected as the TA, as it has no financial interest in the Alberta electricity market as a buyer or seller. The role of the TA is to determine how transmission facilities are operated and developed. Eventually, when pre-restructuring contracts between generators and purchasers are phased-out, a full *wholesale competition* market will develop and the *power pool* will act as a *spot market* for short-term electricity trading in the province.

A small number of jurisdictions have adopted the *retail competition* model, including the United Kingdom, New Zealand, Chile, and parts of Australia. Several U.S. states will adopt a *retail competition* market model in 1998. It is expected that many other jurisdictions will adopt this model over the next decade. The *retail competition* market model is the one that is considered in this study.

1.3 Environmental Threats under Retail Competition

The development and utilization of electricity generation technologies and resources can have a significant impact on environmental quality. The investment behavior of electricity generators affects environmental quality through their choice of energy resources. The mode of operation of existing generation facilities can also enhance or reduce the environmental impacts of the sector.

Existing environmental regulations or regulatory mechanisms which foster Sustainables, or cause generators to operate their facilities in a manner that is environmentally desirable, may be affected by electricity market reforms, as outlined in the following sections.

1.3.1 Changes in Regulation Over Investment in New Generation Technologies

In certain jurisdictions with regulated electricity markets, generators have been required by regulators or government to include environmental considerations in their investment decisions through such mechanisms as Integrated Resource Planning (IRP) and Social Costing. IRP is a utility planning process which requires the consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional supply sources, and those which focus on the conservation and management of demand, referred to as Demand-Side Management (DSM) (BCUC, 1993). In some cases, regulators have required generators to quantify non-monetary environmental and social impacts of electricity generation through Social Costing policies, attaching a monetary or index value to impacts such as air emissions, job creation potential, or changes in land-use. Both IRP and Social Costing have potential environmental benefits through the promotion of DSM which reduces the consumption of electricity or delays the construction of new capacity plants, or by fostering new environmentally desirable electricity generation technologies that would not have been competitive without the inclusion of environmental considerations.

These types of mechanisms require regulatory oversight by governments or utility commissions over the sales of electricity from generators to consumers as has been the case in many electricity markets composed of vertically-integrated utilities. Under electricity market reforms which establish *wholesale competition*, whereby the electricity generation sector is deregulated, regulatory oversight is still maintained, as resource acquisition decisions of electricity distribution companies are scrutinized. However, under market reforms which establish *retail competition*, whereby a consumer has the ability to contract directly with a generator for power acquisition under a deregulated market, the ability of the regulator to require IRP or Social Costing ceases (BCUC, 1995). Thus, in order to maintain the inclusion of environmental considerations in resource acquisition decisions of generators under *retail competition*, current IRP or Social Costing mechanisms designed for regulated monopoly markets will need to be replaced by other policy measures which foster Sustainables.

The reform of electricity markets towards greater competition in North America is expected to increase investment in natural gas generating technologies, because of their low capital costs, forecasted low resource costs, and short development lead-times relative to other technologies (Jaccard, 1996). Natural gas combustion has several environmental impacts including greenhouse gas emissions, emissions of nitrous oxides and volatile organic compounds which can contribute to the creation of ground level ozone (smog), emissions of particulate matter which affects human health, and land and water impacts associated with the extraction and transportation of natural gas.

The impact of increased natural gas utilization on the environment can be positive if it is replacing coal-thermal facilities as they retire, resulting in smaller levels of greenhouse gas and smog causing emissions. However, in those jurisdictions that currently generate a large proportion of their electricity from non carbon based resources such as hydroelectricity, increased natural gas consumption can exacerbate environmental impacts, particularly with respect to air quality and greenhouse gases emissions.

In summary, under *retail competition* electricity markets, electricity regulators are unable to require generators to incorporate environmental considerations into their technology investment decisions, resulting in potential negative environmental impacts, particularly in those jurisdictions where a large proportion of the existing electricity supply is hydro based, and where natural gas technologies are gaining market share through new investments in supply.

1.3.2 Changes in Regulation Over the Operation of Generation Facilities

Electric utilities are currently subject to environmental regulation. The operation of any power plant in British Columbia requires an air emission permit as set out under the provincial environmental assessment process and the Waste Management Act, in addition to any municipal requirements. The Burrard Thermal (natural gas) plant in Vancouver has strict guidelines to follow with respect to local air quality impacting pollutants. These requirements will not change under competitive markets.

However, greenhouse gas emissions are currently not regulated, and they are directly related to the operation of fossil fuel facilities. Greenhouse gas emissions from existing facilities are expected to increase in some jurisdictions due to the introduction of competition into the market. For example, excess capacity will be exported on the open market throughout North America, and those competitive facilities that currently operate at less than their full capacity due to limitations in domestic demand will eventually find new markets for that power, resulting in increased utilization. This argument is particularly persuasive with respect to coal facilities, which have low operating costs, and are currently operating at less than full capacity in many U.S. jurisdictions, and in Alberta and Ontario. The 1991 average capacity factor for coal facilities in the U.S. was 44% (NARUC, 1995), and under competitive markets it is expected that their utilization could almost double, depending on other environmental constraints.

1.4 Sustainable Electricity Generation Technologies

Sustainable electricity generation technologies (Sustainables) have environmentally-desirable characteristics when compared to conventional market-driven electricity generation technologies. The focalpoint of this research project is the assess the costs and benefits of fostering Sustainables in *retail competition* electricity markets. It is assumed that Sustainables are not sufficiently cost-effective to be competitive with conventional technologies (i.e. combined cycle natural gas turbines), and as such an explicit policy mechanism is required to facilitate their market penetration.

The definition of what constitutes Sustainables is a value-based judgment, although certain technologies clearly fit into that category and others clearly do not. The definition also changes over time as different environmental and social priorities dictate the bounds of the definition. Current environmental priorities in B.C. and elsewhere point towards those technologies which have low net greenhouse gas emissions, minimal locally-impacting air emissions, minor impacts on watersheds or landscapes, and no contribution to toxic waste buildup. Those technologies are generally based on renewable resources, and are relatively small in scale.

The definition of Sustainables used throughout this study assumes those attributes. The specific technologies which fit into those bounds include: wind generation systems (including wind farms), solar thermal collectors and photovoltaic cells, small run-of-river hydroelectric and tidal generators, biomass and waste-fuel thermal generators, and waste fuel cogeneration systems.

Biomass technologies produce greenhouse gas and other emissions, but are assumed to be connected with a forestry or agricultural operation which grows an equivalent amount of biomass resources as it consumes, hence mitigating the CO_2 emissions. Also, it is assumed that the location of those facilities is outside of urban areas due to the nature of the resource, such that local air quality impacting emissions such as particulates, NO_X, and volatile organic compounds (VOCs) do not have a significant environmental impact on communities[3].

Waste fuel cogeneration systems have minimal net CO_2 emissions because the heat rate[4] of producing both steam and electricity from a cogenerator is similar to the heat rate of producing steam from a boiler (for water, space, or process heating), hence providing electricity with a minimal increment of fuel consumption. As a result, the conversion of an existing boiler in a commercial or industrial facility is environmentally desirable.

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3 Although the Lower Mainland region (Greater Vancouver) has a substantial agricultural resource, local air quality considerations would preclude the development of new biomass plants.

4 The amount of fuel required to produce a GJ of heat, or a kWh of electricity, indicative of the first-law efficiency of energy conversion from chemical energy to thermal, electrical or mechanical energy.

1.4.1 Costs and Benefits of Sustainables

The private cost of generating electricity from Sustainables is typically higher than from conventional technologies (i.e. natural gas turbines), despite the fact that their social cost[5] may be lower. Sustainables are capital intensive, with relatively low operation, maintenance, and fuel costs.

However, Sustainables offer several environmental, technical and economic benefits which have often been ignored within competitive electricity markets despite their recognition by energy policymakers and regulators.

Sustainables are environmentally benign, a characteristic which may become significant in the future if environmental legislation requires energy companies to pay for environmental externalities[6] through taxes, emissions caps or marketable emissions permits. Although the perceived threat of future environmental regulations is causing some electricity companies to develop Sustainables capacity, the majority still do not recognize their environmental benefits.

Conventional energy systems are generally based on large-scale centralized technologies characterized by long development lead times. The small scale of Sustainables also makes the time required from design to operation short, so that needed improvements can be identified by field testing and quickly incorporated into modified designs. Sustainables can advance at a faster pace than conventional technologies, and it is easier to apply modern manufacturing techniques that facilitate capital cost reduction. The dynamics of Sustainables development will have more in common with the rapid technological process and sharp price reductions that are characteristic of microprocessor-based technologies, pharmaceuticals, than with the experience for conventional energy technologies (Williams, 1993). The fact that many of these technologies are relatively new means that the potential for capital cost reduction is still great relative to many conventional technologies which have already exhausted many cost reduction opportunities.

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5 Social cost is defined as the private financial cost plus the monetized value of environmental and social externalities.

6 Impacts that occur whenever a third party receives, benefits or bears costs arising from an economic transaction in which she or he is not a direct participant (McGuigan and Moyer, 1989). An example would be the effects of pollution from a coal plant on area residents.

Sustainables are increasingly marketed as technologies which have low financial risk because they are based on abundant renewable resources, resulting in low or zero fuel costs, and not subject to global price volatility. In contrast, a large proportion of the cost of gas turbines is based directly on fuel prices, and resource price volatility substantially affects the operating costs of those technologies. An important caveat to this argument is that volatility in interest rates will affect capital intensive technologies such as Sustainables greater than gas turbines.

Finally, Sustainables can increase the reliability of electrical systems, leading to technical and financial benefits. Some of these benefits have been recognized by utilities to a limited extent, although they are often not sufficient to offset the high capital costs of Sustainables. Many of these benefits also apply for other distributed technologies.

- Distributed Sustainables can help to provide power to a region that has been cut-off from the main grid in time of failure (due to weather, vandalism, etc.), giving transmission and distribution (T&D) control systems more options to route power through distributed generation paths (Ibid.).
- Distributed Sustainables have cost advantages over centralized technologies due to avoided T&D capital and maintenance costs. A Pacific Gas & Electric company study priced the value of distributed technologies at $89US per kilowatt-year of avoided T&D development (Ibid.).
- Supply of electricity from Sustainables is sometimes correlated with peaks in customer electricity demand at certain times of the day or year. For example, PV generation peaks at a time when air conditioning loads are greatest. This simplifies system control functions, and can help to reduce the marginal costs of meeting increasing capacity requirements by "shaving" peaks in electricity demand.
- The excess capacity needed to maintain a given level of electricity supply reliability declines as size of individual units declines. A system made-up of plants which have a capacity of 100MW or less, require only an 11% safety margin capacity to maintain system reliability, while one with 1000MW plants needs a margin of 25% - 33% (Johannson et.al., 1993). However, this argument has become partly outmoded because of increased electricity trading between utilities, which inherently gives more options to system controllers during system failure periods.

1.5 Traditional Mechanisms to foster Sustainables

This section describes several traditional mechanisms to support Sustainables.

1.5.1 Set-Asides or Purchase Requirements

In some jurisdictions, the government has provided explicit support for Sustainables through legislation that requires electricity distributors to purchase Sustainables' generated electricity.

The Alberta *Small Power Research and Development Act* (1988) established a *renewable set-aside* of up to 125MW of capacity through the promotion of a variety of technologies, including: wind, biomass, small-hydro, each with a capacity of less than 2.5MW. The Act required that investor-owned utilities purchase this electricity at a guaranteed rate of 5.2 cents / kWh, and recover those revenues from their ratepayers. The initiative resulted in the development of 22MW of wind capacity, the only significant wind generation facilities in Canada today, in addition to several small-hydro and biomass plants.

In recent years, Germany has been a very active supporter of wind power and other Sustainables with its 1990 *Electricity Feed Law* (Stomeinspeisungsgesetz) which demands that any electricity generated from wind, solar, hydro, waste fuels or biomass be bought by the public electricity utility at fixed rates equivalent to 80% (90% for wind and solar) of utility rates (Groscurth, 1996). This mechanism is designed to foster the development of Sustainables without seriously impacting on consumer rates, although utilities in one State have been allowed to increase rates by up to 1% as a result of this law. Germany recently surpassed the U.S. for total installed wind energy capacity at 1,675 MW (Wind Power Monthly, 1997).

1.5.2 Utility and Market Based Initiatives

A variety of electric utility and market-based initiatives have supported Sustainables.

In some jurisdictions, government owned electric utilities have undertaken initiatives to support Sustainables, leveraging funds from ratepayers to cover any cost premium required. For example, Hydro Québec is planning to develop up to 150MW of wind capacity over the next decade under this type of arrangement.

A more common approach has been to initiate green marketing initiatives where a portion of the customer base voluntarily pays a cost premium to sustain a small amount Sustainables development and operation.

Reverse metering[7] is the practice of using a single meter to measure the difference between the total generation and total consumption of electricity by customers with on-site generation facilities by allowing the meter to run backwards. Reverse metering can increase the economic value of investing in Sustainables. It allows the customers to use the utility grid to "bank" self-generated electricity for later consumption. By using the existing meter, the utility is in essence buying Sustainables-generated electricity at full retail rates. Several utilities also buy power in excess of the total consumption of the customer in a billing period at the utility avoided cost. Currently 17 U.S. States have reverse metering programs and Toronto Hydro has a small trial program. These initiatives have not had many subscribers to date, possibly due to the high capital costs of many Sustainables.

Other mechanisms include tax rebates, such as those established under the U.S. Energy Policy Act of 1992 for wind power, or accelerated capital cost allowances for Sustainables, as was recently implemented in the Canadian taxation system, including the special CCA Class 34.1, and the Canadian Renewable Energy and Conservation Expenses (CRCE) write-off category. Advocates of sustainable energy in Canada have welcomed these recent changes in the Canadian taxation laws, but have cautioned policymakers that tax incentives are not sufficient to foster additional investment in the majority of Sustainables, as current electricity rates are too low to make sufficient profits to gain the taxation benefits.

1.6 Market Instruments to Foster Sustainables under Retail Competition

Some of the policy mechanisms presented in the previous section are only suitable under monopolistic electricity markets, particularly the ones that entail government intervention in the electricity market. They would not be appropriate for application under competitive markets, as traditional monopolies will be broken and government intervention in the electricity generation sector will be kept to a minimum to avoid stifling the free market. The green marketing, reverse metering and tax rebate mechanisms are compatible with competitive electricity markets, but are

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7 Sometimes referred to as Net Metering or Net Billing.

not expected to have a significant impact on increasing the market share of Sustainables. On green marketing programs, Nancy Rader, a renewable energy advocate in the U.S., stated that, "... utility-sponsored programs have not been very successful, supporting very small installations that would not sustain existing renewable energy producers, even if repeated by many utilities" (Rader, 1996). As such, this study excludes an analysis of green marketing initiatives because they will not satisfy the policy evaluative criterion of "enhancing the market share of Sustainables".

Several policy mechanisms have been proposed and implemented which provide substantial support for Sustainables under competitive electricity markets. Three of these mechanisms form the foundation of the analysis for this study. They are presented below.

1.6.1 Tradable Portfolio Standard or Market-based Set-Aside

A Renewables Portfolio Standard (RPS), advocated in several jurisdictions in the U.S., requires that every retail power supplier acquire renewable energy *credits* equivalent to some percentage of its total annual energy sales (Rader et.al., 1996). The *credits* are created for kWhs of electricity generated from renewable energy resources or Sustainables. Power retailers could generate Sustainables power through their own facilities or purchase it from separate companies to then resell. The government or regulator must pre-determine the level of portfolio requirement in the market based on a variety of economic, environmental and social criteria. The RPS mechanism is ideally suited for competitive market conditions, as it is sufficiently flexible to enable investment in the most cost-effective Sustainables. If the mechanism is applied across several jurisdictions and trading of *credits* is enabled, then further cost-effectiveness gains may be possible.

The U.S. Congressman Schaefer's proposed "Consumers Power to Choose Act" of 1996 would establish a national Renewables Portfolio Standard of 4% of all GWh sold by the year 2010, excluding large hydro. A recent Tellus Institute study (Bernow et.al., 1997) estimates the electricity rate impact of the Schaefer proposal to be about 0.03 ¢/kWh in 2010, with an increase in generation from Sustainables of 56 TWh/yr, and resultant CO_2 emissions reductions of about 9 million tonnes/year. The data are outlined in Figure 1.1.

Two U.S. Senate bills, "The Electric Consumers' Protection Act of 1997" (Sen. Bumper), and the "Electric System Public Benefits Protection Act of 1997" (Sen. Jeffords), include larger portfolio standards (the latter has a requirement of 20% by 2020), and the former includes large hydro as an eligible source to meet the requirement.

Figure 1.1 - Costs and Benefits of a Renewable Portfolio Standard in the U.S.

(Source: Bernow et.al., *Quantifying the Impacts of a National, Tradable Renewables Portfolio Standard.* In *The Electricity Journal*, May, 1997, pp.42-52)

Table 1: Summary Results for the MRGR (for non-hydro renewables)

	2000		2005		2010	
	Base Case	RPS Case	Base Case	RPS Case	Base Case	RPS C
Renewable Generation (TWh)	62	64	72	102	87	144
Renewable Percentage of Total Generation	1.9 %	2.0 %	2.1 %	3.0 %	2.4 %	4.0 [illegible]
Additional Renewable Generation from MRGR (TWh)	N/A	2	N/A	30	N/A	56
Change in Electricity Price (1995 ¢/kWh)	N/A	0.00	N/A	0.01	N/A	0.0[illegible]
Credit Trading Price (1995 ¢/kWh)	N/A	1.03	N/A	1.20	N/A	1.0[illegible]
Carbon Emissions Saved from Electric Sector (MMT)	N/A	0	N/A	3	N/A	9

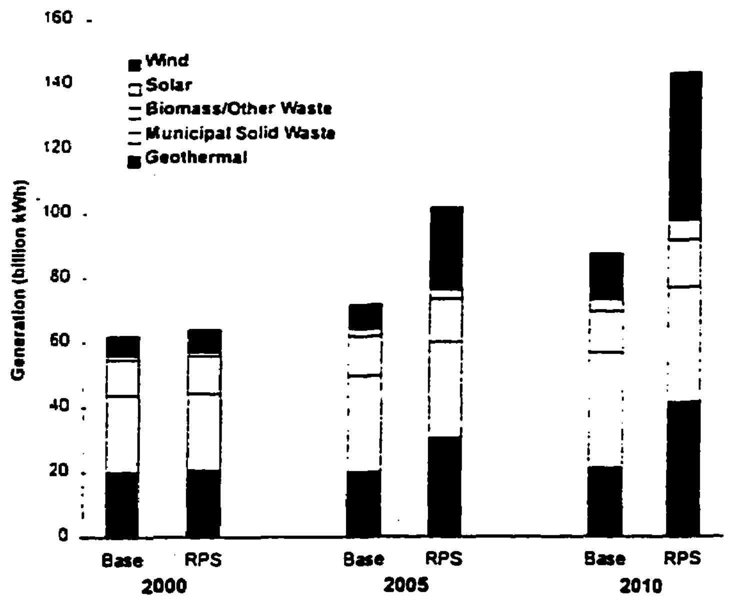


Figure 1: Breakdown of Total Non-Hydro Renewables with and without the RPS

1.6.2 Non-Bypassable System Benefits Charge with Subsidy

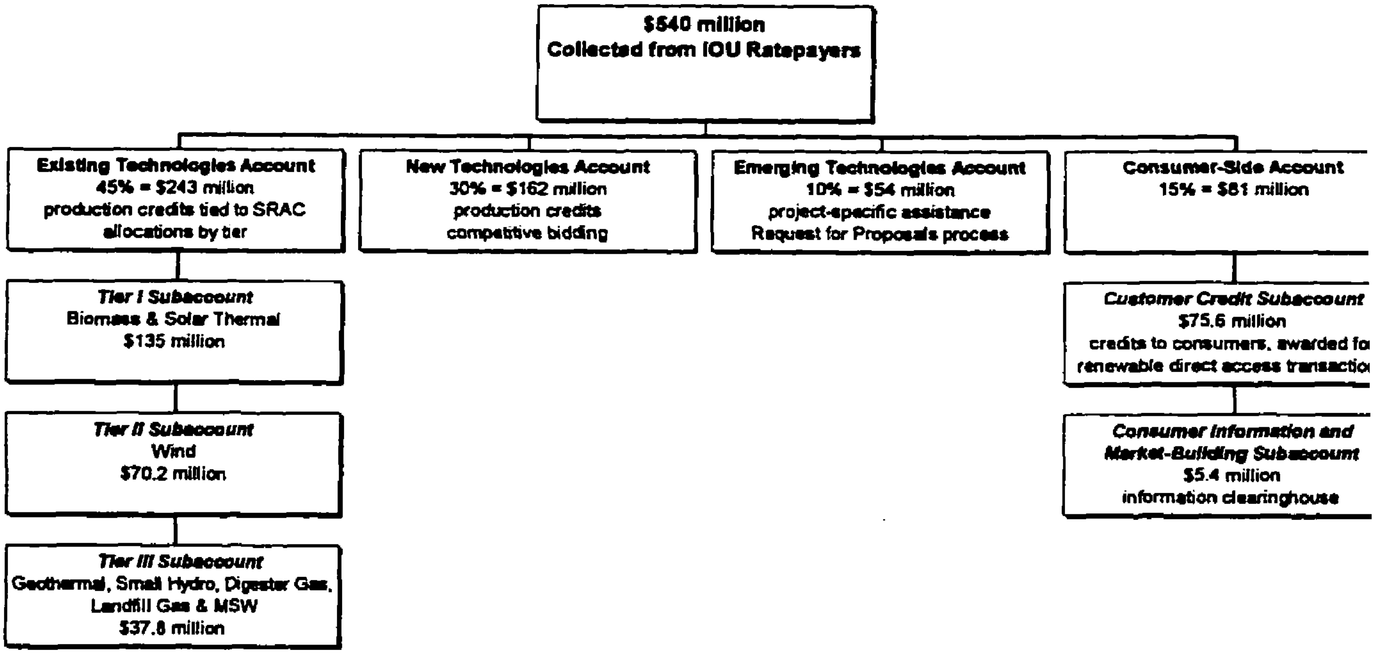
Another mechanism for fostering Sustainables under competitive markets is to subsidize their costs through the collection of a non-bypassable *wires charge* on all sales of electricity in the jurisdiction, also referred to as a "System Benefits Charge". The *wires charge* is collected over a period of time to build a pool of funds used to support the development of Sustainables. The funds could be distributed as direct subsidies to existing or new Sustainables facilities on a per-kWh basis (contracts-for-differences) or through capital grants via a competitive bidding system for new facilities.

The State of California, in its restructuring bill (AB1890), directs retailers to collect funds through wires charges for a variety of "public purpose programs", including a minimum of $540 million between 1998 and 2001 for Sustainables. The *wires charge* for energy efficiency, renewable energy development, and low-income services is estimated to be about 3% of revenues for investor owned utilities. The allocation of the $540 million for Sustainables was determined by the California Energy Commission through a public consultation process, resulting in a decision in March, 1997 to distribute 45% of the fund among existing Sustainables developed under the PURPA program, 30% to new technologies through production credits, 15% for customer rebates for green power purchased and public education programs, and 10% for "emerging technologies". See Figure 1.2 for a more detailed description of the allocation of AB1890 sustainable energy funds in California.

A similar proposal has been made in the Final Report of the "Comprehensive Review of the Northwest Energy System" calling for a 3% non-bypassable *wires charge* to facilitate the development of cost-effective conservation and appropriate renewable resource options, and sustaining appropriate low-income energy services.

Figure 1.2 - Allocation of AB1890 Renewables Funds in California from Wires Charge

(Source: California Energy Commission. *Policy Report on AB1890 Renewables Funding - Report to the Legislature*. March, 1997. pg.13)



In the U.K., the restructuring of the electricity sector in 1990 included a minimum 1.3% *wires charge* on the retail rate under the Non-Fossil Fuel Obligation (NFFO) to subsidize Sustainables (Wind Power Monthly, 1997). A series of five "Renewables Orders" have been made by the government whereby the local distribution companies signed fixed-term contracts with competitive Sustainables' companies to provide electricity from a variety of technologies, including wind power facilities, small hydro, municipal wastes and biomass. The program has a development target of 1500MW of Sustainables capacity by the year 2000, and has contributed to the development of a robust Sustainables industry that was virtually non-existent prior to restructuring. In addition, Sustainables producers in the U.K. are planning to establish a "green power pool" to market their non-NFFO power.

1.6.3 Revenue-Neutral Environmental Adders on Power Pool Bids

The Environmental Adder (EA) mechanism affects the dispatch order of technologies as directed by the electricity system operator, by adding a charge to the bid/offer price of generation facilities into the market that is reflective of environmental impacts. Environmentally-undesirable technologies will be at a competitive disadvantage, and the mechanism may lower their dispatch ranking[8] in the market. The mechanism favors Sustainables by potentially improving their dispatch ranking and by increasing the spot price of electricity. In order to minimize consumer rate impacts of the mechanism, it could be designed to be "revenue-neutral", meaning the funds equivalent to the total value of the EAs are transferred to consumers through a reduction in the wholesale price of electricity.

The actual value of the EA is determined by a policymaker or regulator, reflective of the environmental impacts of the operation of a particular technology.

1.7 Report Outline

This chapter has outlined the study objectives and methodology, provided background information on competitive electricity markets, potential environmental implications of adopting competitive structures, opportunities and constraints for sustainable electricity generation technologies

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[8] The dispatch ranking is used to determine which technologies will operate within a given time period (usually one hour), with the least cost resources operating first, and gradually more expensive technologies being dispatched as the cheaper ones reach capacity.

(Sustainables), and policy mechanisms to foster Sustainables. Chapter two provides detail on the methodology for the quantitative analysis (modelling). Chapter three outlines the modelling inputs and information on the scenarios. Chapter four outlines the modelling results, and Chapter five provides an overview analysis and evaluation of the policy alternatives tested within the modelling framework. Finally, Chapter six concludes on the effectiveness of the study and on the preferred policy alternatives for application in British Columbia and Alberta.

All financial figures in this report are in real 1995 dollars.

2. MODELLING METHODOLOGY

This chapter outlines the methodology for the development and execution of the simulation model which is used to meet the research objective outlined in Chapter 1. Section 2.1 provides an overview of simulation models which have been used for electricity market forecasting in the U.S., and compares them with the approach taken in this study. Section 2.2 introduces the model used for this study. Section 2.3 provides detail on the technology investment sub-model. Section 2.4 outlines the technology operation sub-model. Finally, Section 2.5 outlines the methodology for simulating three sustainability policy mechanisms.

Assumptions associated with each sub-model are outlined in this chapter, along with a description of parameters that are specific to the actual model. Chapter 4 outlines the assumptions and parameters that are exogenous to the model (provided as inputs): that is fuel prices, energy demand forecasts, discount rates, and details on competing technologies. Many of these assumptions have implications on the analysis of the modelling results provided in Chapter 6.

2.1 Overview of Simulation Models for Electricity Supply

Simulation modelling has been used as a tool by electricity planners and policymakers to forecast future market conditions and predict outcomes of policy reforms, allowing them to make informed policy decisions based on a variety of technical, economic, social or environmental considerations. A variety of simulation models have been developed for electricity markets, including specific "resource planning models" that are used by electric utilities. For example, BC Hydro uses a "Stochastic Resource Planning Model" (Drannan and Spafford, 1987) which incorporates uncertainty on a variety of levels in order to plan on generation expansion, DSM, and optimization of in-service dates for new projects. A probabilistic model of this type is useful for representing a variety of hydro reservoir streamflow conditions and variations in demand and fuel prices.

The United States Department of Energy, through its Energy Information Administration, has developed an electricity market model (EMM) for its National Energy Modelling System (NEMS), incorporating a demand forecast sub-model, an electricity capacity planning sub-module, a electricity fuel dispatch sub-model, and finally an electricity finance and pricing sub-model. The electricity capacity planning sub-module determines how best to meet expected growth in electricity demand, given available resources, expected load curves, demands, fuel prices, environmental constraints, and costs for utility and non-utility technologies (EIA, 1994). This type of modelling approach has been adapted into the technology "investment" methodology described in Section 2.3.

Simulation models of the dispatch of generation facilities and pricing of power are typically based on either optimizing the operation of existing generation facilities based on minimum system cost criteria, or optimizing the power flow through transmission lines, based on technical and financial criteria. The former are called "Unit Commitment Models" which decide which generation units to turn on and off based on least system cost criteria, and when to do it, considering significant time lags in start-up and shut-down and future values of electricity (Kahn et. al., 1996). The latter are called "Optimal Power Flow" models which solve for the least cost set of power injections on a transmission system, given a fixed demand and network parameters. Both of these types of models are computationally complex, and require a significant amount of data, far beyond the scope of this study.

In contrast, "Single Area Production Cost" (SAPC) models treat all facilities of a certain type as having the same financial characteristics, and neglect explicit representation of the electricity network. If they treat unit commitment, it is through a heuristic approach, rather than an explicit optimization. SAPC models are useful for analyzing economic and policy problems over long time frames, and are computation simple. This type of model has been applied for this study. A shortcoming of SAPC models which rely on the *load duration curve* model of demand (as in this study - Section 2.3.1) is that significant generation facility operational economies and constraints are not represented, and regional representation is lacking. One response to this has been to adapt the SAPC model to include transmission network limits, which has important implication on electricity trade, transmission congestion costs, and potential market power. However, this detailed level of analysis is beyond the scope of this study.

2.2 Introduction to the Competitive Market Policy Analysis Model (CEMPA)

The Competitive Electricity Market Policy Analysis model (CEMPA) used in this study was designed to simulate a competitive electricity market in Alberta and B.C., assuming that both jurisdictions have adopted a U.K. style *retail competition* market. The ultimate objective of CEMPA is to assess the potential for fostering sustainable electricity generation technologies (Sustainables) under *retail competition* electricity markets, and to identify the benefits and shortcomings of alternative market policies which achieve this. These policies include: (1) a sustainable energy portfolio standard, which guarantees that a minimum share of electricity generated by Sustainables be included in the wholesale supply of electricity; (2) the collection of a non-bypassable *wires charge* on electricity sales to establish a fund which subsidizes the development of Sustainables; and (3) the application of revenue-neutral environmental adders to generator bids into the *power pool* which will affect their dispatch rank order.

CEMPA assumes that all power is dispatched through a *power pool*, a hypothetical point of delivery where all electricity trades occur in a jurisdiction, and the short-term market price of electricity (spot price) is adjusted according to the instantaneous electricity supply and demand. Under a *retail competition* market, consumers can contract with any power supplier or marketer to guarantee a long-term electricity price, but they receive all their power through the *power pool*. Formally, purchasers and suppliers enter into *contracts for differences*, which provide a financial hedge against short-term variations in the spot electricity price from the *power pool*. Consumers can enter into such contracts directly with producers, or deal with a broker, marketer, or local distribution company (existing utility).

The CEMPA model is applied separately to the jurisdictions of Alberta and British Columbia, both markets which currently have some form of competition proposed or adopted, but neither of which have adopted full *retail competition*. The simulation period is from 1995 to 2025.

CEMPA is implemented in several spreadsheets with all of the market parameters and data included, and a series of Visual Basic macros that implement the market structure and policies associated with it. CEMPA is comprised of several sub-models, an *Investment Sub-Model* which determines the annual investment in generating capacity in each of those jurisdictions, a *Spot Market Sub-Model* which determines the wholesale price of electricity and the dispatch / operation of each technology, and three *Sustainability Policy Sub-Models* which simulate each of the previously mentioned sustainable energy policies on the market. The latter sub-models are actually applications of the first two, but with additional features (macros and parameters) which mimic the policies being simulated.

2.3 - Investment Sub-Model

Investment in new generating technologies occurs on an annual basis in CEMPA, following standard principles of economic supply and demand. New generation facilities are developed when the capacity of all existing generating units, including a reserve margin, falls below the expected peak capacity demand for the year. The selection of new generating technologies is based on the annualized capital and other fixed costs, operating and maintenance costs, and incremental fuel costs associated with that technology over its expected life.

2.3.1 Load Duration Curve and Screening Curve Investment Algorithm

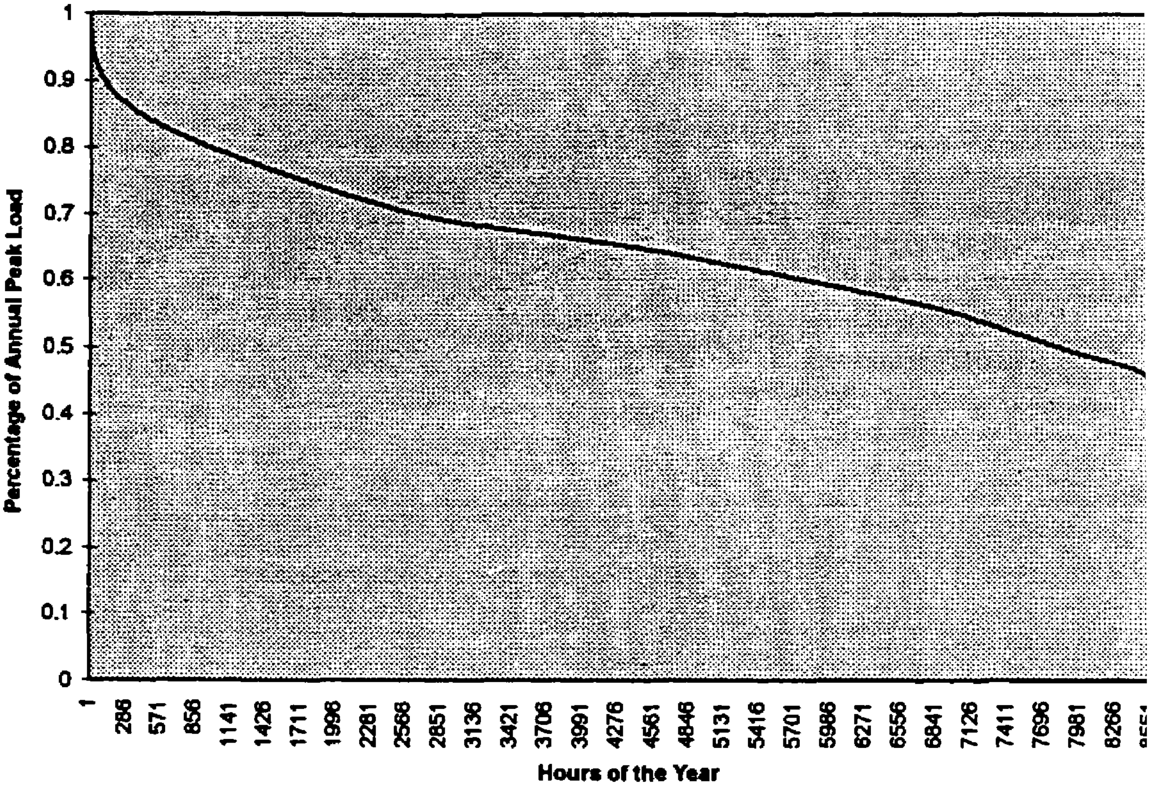
An annual *load-duration curve* (LDC) is utilized by CEMPA to represent the expected electricity demand, as illustrated in Figure 2.1, showing the number of operating hours required during the year (x-axis) for each proportion of peak capacity demand (y-axis). The peak capacity changes each year in CEMPA, but the shape of the LDC does not. The area under the LDC curve represents the annual energy demand (MWh).

The LDC data were provided from BC Hydro, and it is assumed that those data hold in non-BC Hydro service areas and in Alberta. This type of data was not available from Alberta due to confidentiality constraints.

The time segments on the far left portion of the LDC curve exemplify *peak* demand periods of the year, typically corresponding to winter evenings in B.C. and Alberta, while those on the right half represent *off-peak* (or *baseload*) periods such as summer nights, with *shoulder* periods in between. A *baseload* electricity plant provides power on a continuous basis, but cannot significantly modify its power output on short notice. Hence, it is best suited to the *off-peak* demand segments. A *peaking* plant provides additional electricity most economically for those hours associated with *peak* demand hours on the left side of the LDC.

The *screening curve* method of selecting generation technologies for meeting new capacity demand minimizes the total cost of generation in the system by optimizing generation resources according to the characteristics of the LDC. Technologies which have low operating costs, and often higher fixed costs, are most appropriate for meeting *baseload* capacity, while technologies with low capital costs, but higher operating and fuel costs, are appropriate for meeting *peak* demand. The CEMPA investment sub-model utilizes the *screening curve* method to select the least capital cost option for the *peak* operating hours, and successively higher capital cost technologies with lower operational costs for *shoulder* and *baseload* conditions. This process is detailed in Section 2.3.5.

Figure 2.1 - Annual Load Duration Curve Applied in CEMPA



Source: BC Hydro

2.3.2 Variation in Investment Behavior

The sub-model allows for a pre-determined amount of investment in *baseload* generating technologies which are slightly more expensive than the least-cost technology, provided their *levelized-costs*[9] are within a threshold cost premium over the cheapest technology. This is intended to mimic the variation in the installed costs of the technologies due to geographic or technical constraints, and the variation in investment behavior that occurs due to other factors. Specific factors which could contribute to this variation in investment include the following.

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9 The cost per kWh of electricity from a technology, including operating and amortized capital costs.

- companies selecting electricity purchases based on an established relationship with a supplier that may not offer the cheapest resource.
- specific needs at a consumer site where an IPP project is being developed, or preference for or against specific technologies (e.g. woodwaste cogeneration facilities at forestry operations).
- preference towards technologies which have transmission or distribution benefits to the utility (e.g. small scale distributed technologies which help to avoid transmission bottlenecks).
- development of generation technologies at sites that are not integrated on the utility network, and where the least cost technology is not available (remote locations with no gas).
- geographically caused variation in operation expenses (e.g. different gas prices, or variation in reliability associated with climatic conditions).

An assumption is made that 20% of the new capacity developed each year will be met by those technologies that are within the specified price threshold. This market share is allocated equally among those technologies to keep the modelling simple. The 20% market share figure was selected to be representative of the combined effects of all the factors above that would induce an investor to purchase technologies that on-average are more expensive than the cheapest technology.

CEMPA assumes that the variation in investment occurs for those technologies which have costs no greater than 20% over the *levelized-cost* of the least-cost technology. This figure is representative of the willingness-to-pay for the criteria listed above, some of which have financial implications, and others which do not. The ISTUM modelling framework utilized at SFU applies a similar investment variation rule, whereby industrial end-use technologies (e.g. boilers) that have a life-cycle cost within 15% of the least cost technology will take up to 20% of the market share (ISTUM manual, 1996). Non-financial criteria are treated separately in ISTUM through minimum or maximum market shares for certain technologies. Based on this information, and assuming that non-price criteria are worth up to a 5% financial cost premium, it was decided to select a 20% price threshold in CEMPA as the basis for variation in investment behavior.

2.3.3 Development Limits for Particular Technologies

CEMPA applies a development limit for certain technologies, given that the resources required for their operation may be limited (e.g. wood waste), or due to political or social conditions that dictate a limitation on their development (e.g. large hydro developments). The development limits applied are specified in Chapter 3.

2.3.4 Investment Issues for Sustainables

Sustainable electricity generation technologies (Sustainables) are treated equally with other technologies in the CEMPA investment model. The economic characteristics of these technologies dictate that they be utilized for *baseload* operation, due to their high capital cost and low operating costs (no fuel costs).

2.3.4.1 Dispatchability

CEMPA applies development limits to certain Sustainables, reflective of their resource limitations within the jurisdiction, and for the purpose of maintaining the power quality of the electric grid. The latter objective is achieved by maintaining a minimum proportion of *dispatchable* technologies on the system grid. Those technologies are available for operation on command (short notice), allowing the grid operator to track variations in electricity demand. In contrast, *non-dispatchable* generation technologies, such as wind, tidal, and solar, are limited in their ability to produce electricity on short notice. They are powered by renewable resources which are intermittent, typically dependent on weather conditions. Research indicates that in order to maintain electricity system integrity, the total development of *non-dispatchable* technologies should not exceed 30-50% (Johansson et.al., 1993) of the total electrical system peak capacity. If several types of *non-dispatchable* technologies are developed, and there is diversity in both resource type and geographic location, then their total market share could be brought up to the 50% level without affecting power quality. In contrast, if the development occurs in one location with a single resource, then the maximum market share of that class of technology should be reduced to the 30% level.

2.3.4.2 Economies of Manufacture and Capital Cost Reduction of Emerging Technologies

CEMPA incorporates expected reductions in the capital cost of certain emerging Sustainables. Capital cost reduction results from the achievement of economies of manufacture in the factory production and innovations in the design of the technology. The capital cost of a new technology in a competitive marketplace often decreases as the sales of the technology increase because industry realizes efficiencies through increased experience with the technology and with mass production.

Eventually, the cost of the technology stabilizes, due to a stasis in technological innovation, similar to what has happened over the last century with steam turbines and hydraulic generators.

Robert Williams applies an "experience curve" in his assessment of the cost reduction potential of photovoltaic solar technologies. His thesis is that, ".. per unit production costs decline as a direct, estimable proportion of cumulative production" (Williams, 1993). This type of approach is adopted for certain Sustainables in CEMPA, including solar technologies, wind generators, tidal generators and fuel cells.

An assumption is made that the cumulative investment in Sustainables in B.C. or Alberta reflects investment patterns across North America, and cost reductions occur in the model that are reflective of a market-wide cost reduction. For example, if 10MW of photovoltaic capacity is developed in B.C., it is assumed that a proportionate amount of capacity is developed across North America, resulting in approximately 100 times the B.C. capacity. Thus, the anticipated capital cost reduction associated with 1000MW of cumulative capacity investment across North America is applied into the model.

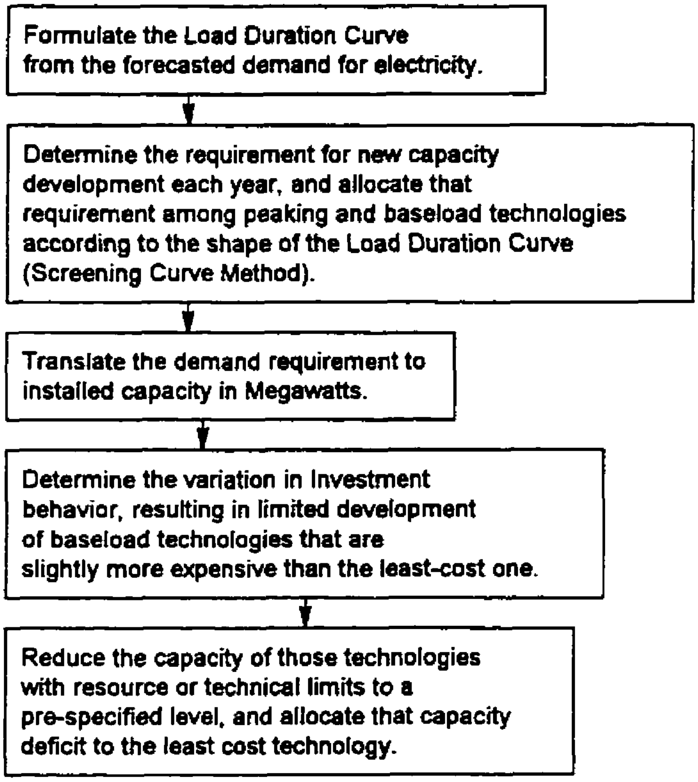
The capital cost of these emerging technologies is determined by an exponential formula which is a function of the starting cost of the technology in year one of the simulation, its cumulative capacity in the jurisdiction, and a specific exponent which is reflective of the rate of cost reduction and the specified limit of the cost reduction. This formula is calibrated against predicted cost reductions specified in the BC Hydro *Integrated Electricity Plan*, in Appendix E, *Resource Options* (1995). Specific details on the formula are presented in Section 2.3.5.4.

Also, CEMPA simulates some autonomous capital cost reduction as a function of time, not dependent on the cumulative capacity in the jurisdiction. It is assumed that investment in other jurisdictions will support this, as well as innovations in research and development in laboratories and universities which is not a function of market share.

2.3.5 Methodology for Modelling

The CEMPA investment sub-model determines the investment in new generation technologies on an annual basis. Investment is determined in megawatts of dependable capacity. The sub-model methodology is illustrated in Figure 2.2. First, the *Load Duration Curve* (LDC) is assembled from the forecast demand for electricity and the daily load profile of consumers. Second, CEMPA calculates the requirement for new capacity to meet that demand and determines the economically optimal mix of technologies based on the characteristics of the LDC. Third, the mix is converted to megawatts of installed new capacity. Fourth, the investment model allocates a small amount of capacity to investment in technologies which are more expensive than the most competitive *baseload* technology, but within a threshold price premium, intended to mimic variation in investment behavior. Finally, the model determines if the capacity development limit has been exceeded for any technologies, and adjusts their investment level accordingly.

Figure 2.2 - Overview of the Investment Sub-Model Methodology



2.3.5.1 Load Duration Curve and Screening Curve

The *Load Duration Curve* (LDC), as outlined in Figure 2.1, is used to determine investment in new generation technologies. The *Screening Curve* routine selects the technologies which are least cost for meeting the LDC. See Figure 2.3 for an illustration. The total annual cost[10] for each

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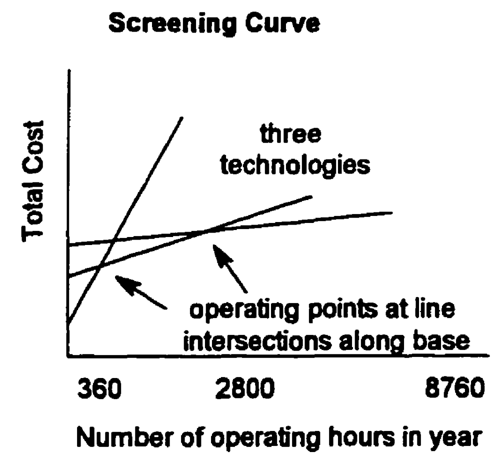
10 The annualized capital cost, as well as the accumulation of all variable costs is represented.

technology is represented on the y-axis of the *screening curve*, and the range of annual operating hours along the x-axis (0 to 8760 hours). Each technology is represented by a line on the graph. The least cost technologies for all operating hours of the year are selected as those that minimize the total annual cost, switching technologies at line intersection points. In the example illustrated below, all three technologies are selected for a segment of the market, because all of them are the least cost technology for a particular operating hour range. However, in the CEMPA model with up to 20 competing technologies, not all are selected, as several technologies have significantly higher capital costs.

The *screening curve* routine is executed for every year of the simulation (30 years). The specific model employed is illustrated in Appendix A.1. The fixed and variable costs of technologies change over the course of the simulation with the shape of the *screening curve* changing as well. The capital costs of certain emerging technologies declines over time as explained previously. In other investment routines, CEMPA further accelerates the decline of capital costs of technologies when their market penetration increases (See Sections 2.3.4.2 and 2.3.5.4 for details).

The result of this routine is an indication of the number of operating hours of each new technology for each year of the simulation. With the example in Figure 2.3, the first technology would operate for 360 hours of the year, corresponding with *peak* hours only (e.g. simple cycle gas), the second for 2800 (e.g. combined cycle gas), and the third for a full 8760 hours (e.g. hydroelectricity or cogeneration), the latter being *baseload*.

Figure 2.3 - Overview of the Screening Curve Routine



2.3.5.2 Installed Capacity for Each new Technology

The CEMPA investment sub-model, in a separate routine, next allocates a specific capacity to each technology that has been selected by the *screening curve*, based on their number of operating hours. It utilizes the *load duration curve* to determine the specific capacities associated with each operating hour. For example, if the three technologies selected in the *screening curve* in Figure 2.3 were applied to the LDC on Figure 2.1, and the 100% mark on the LDC was 1000MW, then about 150MW of technology 1 would be developed (corresponding with *peak* loads), 150MW of technology 2 (*shoulder*), and about 700MW of technology 3 (*baseload*).

It is assumed that the new capacity will come on line every year with no lead times required. In other words, if a certain technology is required in a particular year, CEMPA assumes the construction of that facility would have commenced a number of years earlier, as required.

2.3.5.3 Calculation of Levelized Cost, Other CEMPA investment functions

The CEMPA investment sub-model next simulates the variation in investment behavior for reasons specified in Section 2.3.2. It applies only to *baseload* technologies. The key parameter for this routine is the *levelized-cost* function, which is the expected average cost of electricity production from a technology per kWh when all investment and operating costs are included. This *levelized-cost* calculation only applies to *baseload* technologies because it assumes full operation of the technology for the entire year, unlike *peaking* plants which operate a lot less than their capability.

In calculating the *levelized-cost*, it is assumed that the financing conditions for all technologies is identical, that the discount rate is the same, and that the amortization period is 25 years. Under regulated utility markets (such as B.C.), projects are financed on terms linked to the anticipated life of the project, with debt guarantees in place from provincial governments or purchasing contracts. Under competitive markets, financing terms for new generation facilities will vary according to the policies of the investor, although discount rates will probably increase as a result of a higher cost of capital and reduced risk tolerance compared with regulated markets (see Section 3.1.1). It is assumed there that the higher cost of capital will lead generators to seek a financing life of 25 years or more in order to minimize their debt payments.

CEMPA calculates the *levelized-cost* for each technology for each year of the simulation period. This is the cost in real 1995$ of building and operating a technology as if it were built in that year and the operating, maintenance and fuel costs over a 25 year period are included. Those technologies with longer than 25 year lives are treated in a similar fashion, as the costs/benefits associated with those years beyond the 25th are sufficiently small when discounted to 1995 dollars. The equation used for *levelized cost* is outlined below. The *capacity factor* is specified exogenously, equivalent to the proportion of year that a technology is operating at its maximum output, assuming that it is operating as a *baseload* technology.

Equation 2.1 - Levelized Cost Equation

$$Levelized\,Cost_{year\,x} = \frac{Annuity\,of\left[CapCost_{year\,x}\right]}{8760 * CapacityFactor} + Annuity\,of\left[NPV(O\&M + Fuel)\right]$$

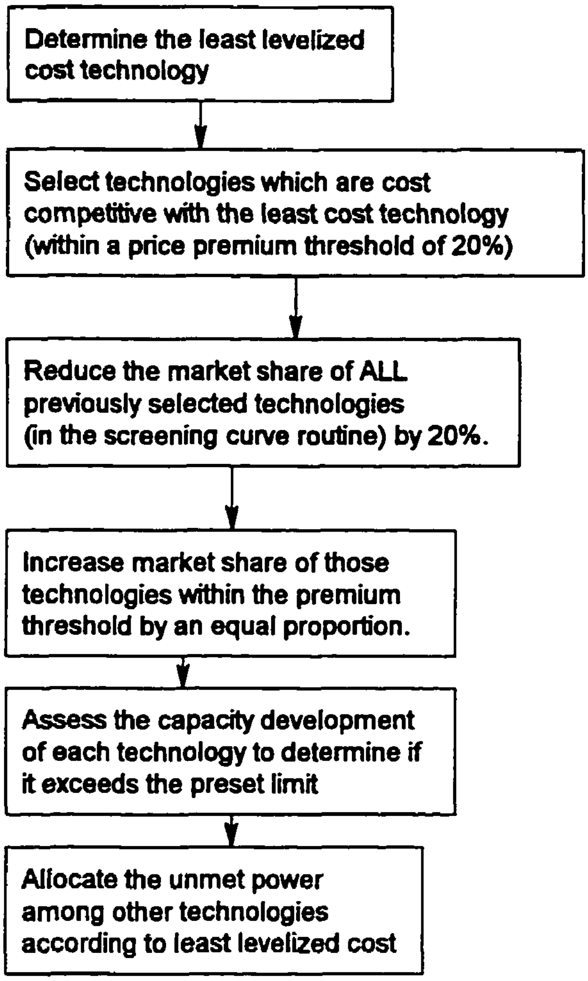
$$units = \frac{\$/MW\cdot year}{hours/year * \eta} + \$/MWh \Rightarrow cents/kWh$$

CapCost = capital cost for year X of the simulation
Capacity Factor (η) = the proportion of kWH produced per kW capacity
Annuity of [...] = an annual payment for an investment
NPV(O& M + Fuel) = Net Present Value of operating and maintenance costs

In order to determine variations in market investment behavior (Figure 2.4), CEMPA first identifies the least cost technology for each simulation year. It then assesses technologies to determine if their *levelized costs* are within the price "threshold" which investors would accept - a 20% *levelized-cost* premium over the least cost technology. The proportion of the market share of new developments that is met by those technologies is pre-set at 20%, and is allocated equally among them, adjusting other technologies' market share to avoid overcapacity. The result is a greater diversity in new technology developments than would be the case if only the strict *screening curve* method is followed.

CEMPA also limits the capacity development of technologies according to their resource limitations or other reasons. Specific details of those development limits is listed in Chapter 4.

Figure 2.4 - Overview of the Investment Variation and Development Limit Routines



2.3.5.4 Reduction of the Capital Costs of Emerging Technologies

As outlined in Section 2.3.4.2, CEMPA simulates declining capital costs of emerging technologies according to a time-based function and as a function of cumulative market penetration. There are two levels of implementation of this function in CEMPA, with the latter applied by both the routine that determines the variation in investment behavior in the market (Section 2.3.5.3) and the Sustainability sub-model mechanisms (Section 2.5).

1. A time-based declining capital cost function is applied into the *screening curve* function, as well as into the calculation of *levelized-cost*. This time-based function calculates the annual capital cost reduction based on a linear function that bridges the current *levelized costs* with

the BC Hydro estimate of *levelized costs* in the year 2015 (BCH IEP, Appendix E). Those BC Hydro estimates assume a certain market penetration of the technology, and hence declining capital costs resulting from economies of manufacture.

The specific cost reduction formula applied in CEMPA is based on BC Hydro forecasts of unit production cost reduction for emerging technologies (BCH IEP, 1995) and assumes that about half of the cost reduction occurs due to innovations through technology R&D. The specific reductions applied are listed in the first column of Table 2.1

2. A declining capital cost function that is based on the market penetration of Sustainables, applied into the calculation of the *levelized-cost* only (utilized by several CEMPA routines).

The specific cost reduction formula is based on a simple exponential function outlined in Equation 2.2. The capital cost at year zero is the starting point of the equation (assuming zero market share in the first year). These values were given in the BC Hydro IEP (Appendix E). The cumulative market share is the key variable driving the capital cost reduction. That variable is raised to the power of a negative exponent that scales the impact on capital cost reduction according to the extent of the market penetration of the technology. This causes steep capital cost reductions in early phases of the technological implementation, and gradually less impact as the share is proportionately increased.

The key parameters for this methodology are listed in Table 2.1. The capital costs in year zero are listed in the second column of Table 2.1 The exponent, listed in the third column of Table 2.1, was determined through a calibration process that utilized a target capital cost, and a market penetration level that would result in that target capital cost being reached. The target capital costs listed in the fourth column of the table, were determined based on the figures in the BC Hydro IEP. The required market penetration levels also made use of the BC Hydro source, but scaled down by a factor of 100 to convert those North America market penetration levels to a scale appropriate to B.C. or Alberta.

Equation 2.2 - Market -Share Based Capital Cost Reduction of Emerging Sustainables

$$\text{Cost} = \text{Cost}_{\text{year } 0} \bullet (\text{CMS})^{-E}$$

$Cost_{year\,0}$ = the capital cost in \$/kW at the start of the simulation (listed in Table 2.1)

CMS = cumulative market share

E = exponent (listed in Table 2.1)

Table 2.1 - Factors Applied for Declining Capital Costs of Emerging Sustainables

	Time Based Annual Reduction	Market Share Based Reduction Year zero capital cost (real \$1995)	Exponent value	Target Capital Cost (real \$1995)	Required M Share to Re Target Reduction I
Wind Generators	0.7% / year	\$557 / kW	0.09	\$368 / kW	100MW
Fuel Cell Cogenerators	0.8% / year	\$672 / kW	0.11	\$405 / kW	100MW
Solar PV	1.7% / year	\$2621 / kW	0.46	\$909 / kW	10MW
Solar Thermal - Parabolic Trough	1.4% / year	\$2036 / kW	0.23	\$828 / kW	50MW
Tidal Power	1.4 % / year	\$850 / kW	0.19	\$354 / kW	100MW

2.4 Electricity Dispatch - Spot Market Sub-Model

The purpose of the CEMPA spot market sub-model is to illustrate the patterns of technology operation in the market, to forecast the wholesale price of electricity over the 30 year simulation period, and to keep track of the revenue that generators receive through market transactions.

The business functions within a competitive electricity market are typically coordinated through an unlimited-access *power pool*, which is a clearinghouse for all power trading, and the location of an electricity spot market. The spot price of electricity varies according to the instantaneous electricity supply and demand, typically peaking during periods of high demand or due to electricity supply shortages or transmission overloading periods. The spot market is closely tied to a *forward market* for electricity which is described in the next section. Also, many buyers and sellers establish long-term contracts to guarantee the price of electricity for their transactions and hedge against uncertainty in the spot market. A *contract for differences* between two parties typically includes an agreed-upon price for electricity (the *strike price*) and a provision that the buyer or seller of power compensates the other party for the difference between the contracted price and the hourly spot price of electricity.

The CEMPA model mimics the *power pool* structure that is established in the United Kingdom. Although the Alberta electricity market also has a *power pool* structure, it is more difficult to model because of the existence of both demand and supply-side bids, and a variety of *forward market* options.

This section begins by describing the electricity market structure in the United Kingdom, then discusses some of the issues associated with running Sustainables under a *power pool* structure, and finally outlines the methodology that is followed by CEMPA in simulating the dispatch and business aspects of the competitive electricity market in Alberta and a hypothetical competitive market in British Columbia.

2.4.1 Background on U.K. System

In the U.K., three parallel markets operate for trading electricity - the forward market, options market and spot market. Only the forward and spot markets are relevant for the CEMPA model. The price of electricity that is published in newspapers for half-hour intervals of every day is based on the day-ahead forward market, while the price that is actually paid to generators is the spot price.

The U.K. market is one of the few in the world with *retail access*, meaning that some customers can contract directly with outside utilities or electricity marketers, and their local distribution utility is required to wheel/transmit power to them. Currently, only industrial customers (100kW+ transmission customers) have *retail access*, but in 1998 the whole market will be opened up.

2.4.1.1 Forward Market - Generation Supply Bidding

In the U.K., electricity generators make *offers* to the *Electricity Pool* (synonymous with *power pool*) one day in advance through a forward market, indicating their ability to produce power for each half-hour of the next day and the price they would be willing to produce it for. The *Electricity Pool* authority selects the least-cost electricity generation units sufficient to meet the forecast demand for each period, and establishes a *U-schedule* or "unconstrained schedule" for the dispatch of those units (Hunt & Shuttleworth, 1996). The most expensive unit that has been selected to run for each half-hour of the next day (*marginal unit*) sets the *system marginal price* (SMP) for the market. In the U.K., the SMP in peak periods has exceeded that in off-peak periods by as much as 20 times over the past six years (Hamrin, 1994).

The SMP is reflective of the marginal cost of generation and does not encompass the amortized capital costs of generating technologies, but rather only the variable operating, maintenance and fuel costs. The variable costs of operating a generation facility are directly proportional to the energy output of the facility (kWh), while the fixed or capital costs of the facility are often proportional to its power capacity (kW). As such, the SMP rewards generators for the energy they produce, but not for their production capacity. In the U.K., a capacity element is included in the price paid to generators, the *pool purchase price* (PPP), allowing utilities to recover some of their fixed costs. The PPP is a function of the SMP, the *loss-of-load probability* (LOLP), and the *value of lost load* (VOLL). The LOLP is defined as, "the probability that demand will exceed capacity" (Ibid.), which would occur on failure of a large generation technology which has been scheduled to operate. Alternatively, this could occur when the demand for electricity suddenly increases, but the system *reserve margin* is designed to protect against short-term changes in demand. The VOLL is reflective of customers' willingness to pay for un-interruptible or firm electricity. In the U.K., the average VOLL has been about £2,500/MWh (Dunn & Rossi, 1996), equivalent to about $5/kWh. The LOLP / VOLL component of the PPP is reflective of the reliability of a unit to provide firm capacity into the system. The PPP has risen to £1,000/MWh during periods when the reserve margin on the system is low (Ibid.), giving generators a premium for reliable power production. The average PPP in the 1995/96 year was equivalent to $0.0477/kWh (Canadian), consisting of an average SMP of $0.0388/kWh and a capacity adder of $0.009/kWh (U.K. Stats).

2.4.1.2 Spot Market and Uplift Fees

The spot market is characterized by immediate delivery of the product, with the price varying to equalize supply and demand at half-hour intervals. The spot market is also used by generators and purchasers to cancel or modify their contractual arrangements - if a generator isn't able to produce what it offered in the forward market due to physical or economic constraints, then it has to buy back an amount equivalent to the missing component through the spot market at the spot price of electricity which fluctuates throughout the day.

The *pool selling price* (PSP) that wholesale customers or retailers pay for electricity bought through the *electricity pool* is equivalent to the PPP plus a component called *uplift* which is the difference between the *U-schedule* price of electricity and the spot price during the day, reflecting physical constraints on the system and changes in demand (Scott, 1996). The *uplift* includes the transmission related costs that the *electric pool* administrator has to incur to maintain system integrity such as, "reactive power, frequency response and reserve generation capacity" (Ibid.). *Uplift* amounts have doubled between 1991 and 1995, particularly due to transmission constraints, but an initiative in 1994 worked towards reducing those expenses by giving the transmission company an incentive to improve transmission outage management, to encourage competition from the demand side for reserve services and to install new transmission equipment (Ibid.). The average PSP in 1995/96 was $0.0512/kWh, including an average *uplift* of $0.004/kWh (U.K. Stats).

2.4.2 Dispatch Issues for Sustainables

Typically, a Sustainables facility will bid into the market at a zero or near-zero price, as the marginal cost of operating such facilities is virtually zero. The renewable resource driving the facility is a free good (wind, sun, water), and many of the technologies have low operating and maintenance expenses. This is a significant advantage for Sustainables under a competitive market because they are always going to be dispatched when they are able to produce power.

However, *non-dispatchable* Sustainables could suffer a significant market disadvantage under competitive electricity markets if the *power pool* authority required them to provide firm electricity for the full period in which they bid into the market (half-hour). They are only able to provide electricity when the resource is available, unless they contract with other *dispatchable* generation facilities to back them up which will affect their cost-effectiveness. In practice, electricity supply into a spot market frequently fluctuates, and the *power pool* authority is charged with the task of providing backup for those fluctuations. Dispatchable facilities, with an ability to load follow or provide backup, will earn a return that reflects the value they provide to the market.

In Alberta, the *power pool* authority recognizes non-dispatchable Sustainables as a unique resource type, and grants them a *standing bid* which means that they don't have to make financial offers into the *power pool* on a daily basis as other facilities do. When Sustainables facilities are producing power, they are automatically included in the *power pool* and the power is utilized.

For the purposes of modelling Sustainables in the CEMPA *power pool*, it is assumed that non-dispatchable Sustainables will not be penalized if they don't produce.

2.4.3 Methodology for Modelling

The purpose of the CEMPA spot-market sub-model is to: (1) compute the market price of electricity for each year of the simulation and under a variety of market conditions; (2) simulate the patterns of technology dispatch, including which technologies operate and for how many hours; and finally (3) calculate the GWh's produced and revenue received by generators under each simulation condition and for each year.

2.4.3.1 Energy Demand

The CEMPA spot-market sub-model simulates the market outcome under 24 different levels of energy demand within a year, each representative of a <u>single hour</u> of electricity system operation. The energy demands are specified by 24 different positions along the annual load duration curve (see Figure 2.1). The LDC indicates the time duration for various levels of capacity demand (GW), but this can easily be converted to energy consumption (GWh) by multiplying the capacity by the number of hours required. For example, according to the LDC in Figure 2.1, if the total system peak capacity demand is 10GW, then the one hour energy demand would range from 10 GWh under peak operating hours to about 4 GWh for the baseload hours.

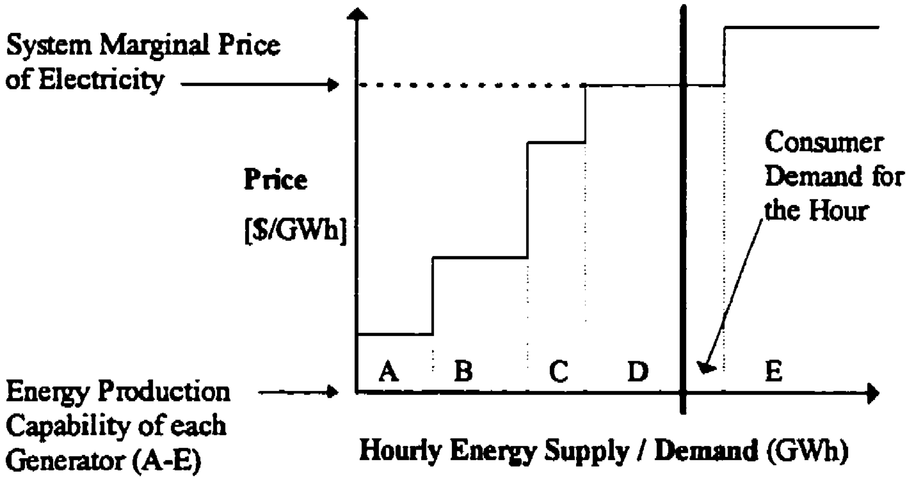
By dividing the LDC into 24 segments, determining the one hour energy demand for each of those segments, multiplying each of those demands by 365 hours (equivalent to about 15.2 days of the year), and finally summing those values together, an estimate of annual energy demand can be determined. In fact, the area under the LDC times the annual peak capacity, is equal to the annual system energy requirement, and CEMPA computes that area by breaking the LDC into 24 rectangular segments with the top left corner of each rectangle intersecting the LDC.

2.4.3.2 System Marginal Price (SMP) of Electricity

CEMPA calculates the electricity System Marginal Price (SMP) of electricity for each of the 24 segments along the annual load duration curve, and for each year of the simulation, amounting to a total of 720 different SMPs for the entire simulation. The SMP, provided in units of dollars per GWh, is defined as the operating cost of the most expensive technology among all those required to meet the electricity demand for one hour. In periods of peak demand, the SMP is higher than in periods of average demand because peaking technologies typically have higher operating, maintenance and fuel costs than baseload technologies.

Figure 2.5 illustrates how the SMP is calculated in CEMPA: four technologies are required to operate within that hour, and the SMP is equivalent to the variable cost (in $/GWh) of technology D. In that hour, technology E is not required and will not operate.

Figure 2.5 - System Marginal Price Calculation



CEMPA calculates the SMP by sorting the variable costs of the new and existing technologies operating in the jurisdiction, and then dispatching them in order of their cost (from least to most expensive) until the demand for the simulation period is met. Up to 23 technologies are included in the competition, including hydro, oil, natural gas, coal, and biomass for existing technologies, and up to 18 new technologies (see Chapter 4).

2.4.3.3 The Price Received by Generators (Pool Purchase Price - PPP)

The *model* assumes that a capacity value is added to the SMP for the price paid to generators, similar to that in the U.K. *Pool Purchase Price* (PPP) (Section 2.4.1.1). The capacity adder is a function of the *Loss of Load Probability* (LOLP) of the system which is a measure of the rate of unplanned system failure, and the *Value of Lost Load* (VOLL) or the expected losses by consumers is the power were to be cut without notice. The combination of LOLP and VOLL results in a capacity adder that reflects the importance of firm or reliable capacity on the system - when the LOLP is high, then firm capacity should be valued greater than when the LOLP is low.

The capacity adder has varied in the U.K. between £0.0001/kWh and £0.0105/kWh between 1990 and 1996, translating to about \$0.0002/kWh to \$0.021/kWh in Canadian currency.

Loss of Load Probability (LOLP)

Accurate determination of the system LOLP would require a specific knowledge of the number of generation units operating within an hour, the probability of failure for each one, and the availability of *spinning reserve* on the system which provides immediate backup. The LOLP would be equivalent to the probability that total electricity plant failures would exceed the capacity of the *spinning reserve*, and that could occur by any combination of individual plant failures. For example, if 10 equal-sized plants were operating, and the failure of any 2 of those plants would cause the system capacity to fall below demand, then the LOLP would be equal to the maximum of the resulting probability of multiplying individual plant LOLPs in groups of 2 units. In the U.K., the LOLP has varied between 0.002% and 0.21% over the past 5 years (U.K. Stats, 1996).

CEMPA applies a simplified routine for determining the hourly LOLP, making the assumption that the capacity value added to the SMP is reflective of the probability of any one plant failing within one hour of the simulation year. If the failure is longer than an hour, then the *power pool* authority can arrange to purchase electricity from other generators with only one hour notice. It is assumed that a sudden increase in demand is met by the *spinning reserve*, but a failure in supply of any magnitude will be accounted for in the value of the LOLP.

Each hour, the LOLP is calculated by calculating an energy-weighted average LOLP from all the generating technologies required within that hour. CEMPA utilizes the following formula:

Equation 2.3 - Hourly Average System Loss of Load Probability

$$Average\ LOLP = \frac{\sum_{all\ technologies} LOLP \bullet Energy\ Supplied\ by\ each\ Tech.}{Total\ Hourly\ Energy\ Supply}$$

The Canadian Electrical Association, in their annual Canadian electricity market report (1995), publishes data on the "number of forced outages" of electricity generation units defined as, "... the occurrence of a component failure or other condition which requires that the generating unit be removed from service immediately or up to and including the very next weekend". (CEA, 1995). CEMPA utilizes those numbers, divides them by the number of units included in those statistics, and then divides by 8760 hours/year, because only sub-one hour failures are important for the spot market. The resulting LOLPs for generating units is provided below:

Table 2.2 - Loss of Load Probabilities

Technology Name	LOLP
Combustion Turbine Units	0.0444%
Fossil Generating Units	0.1002%
Hydraulic Generating Units	0.0393%
Wind Generators	1%
Solar Converters	1%
Tidal Generators	0.0393%
Fuel Cells	0.01%

The numbers for the final four technologies are estimates. It is assumed that the LOLP of tidal generators is the same as hydraulic turbines, as tide tables can be read in advance, and bidding behavior will reflect that. Fuel Cells are very reliable due to few moving parts, so a 0.01% LOLP is applied as an estimate.

Solar and wind conversion units have high LOLPs because of the inherent variation in their energy resources - the sun and wind. On an annual basis, solar collectors produce an equivalent amount of energy as if their peak generation capacity was being reached 20% of the time (higher in some regions), while wind generators are at the 30-40% level (BC Hydro, 1995 and NRCan, 1996). Solar technologies only produce power during the daytime, and their output varies according to the amount of cloud cover as well. Wind generators are even less predictable. The major constraint for including large quantities of solar or wind energy in the *power pool* is that sudden changes in weather could cause them to lose a significant portion of their production capacity, and possibly put the entire electricity system at risk of falling below the required electricity supply. The LOLP should represent that risk, but determining an accurate LOLP would require specific site information and installation sizes, neither of which is easily included in the CEMPA spot-market model. The LOLP should reflect the variation of solar collectors or wind generators within one hour, which is much less than the annual variation in output. The assumed LOLP value for solar and wind technologies was set at 1% through a sensitivity analysis of spot electricity price impacts resulting from raising their market shares to the development limits.

Value of Lost Load (VOLL)

The VOLL is a value selected by the *Power Pool* authority which represents the cost of an electricity brownout or blackout to customers. This value is somewhat arbitrary in that it is not based on detailed empirical analysis. It is in the interest of the *Power Pool* authority to ensure that reliable power is always provided, however a market value for lost load is necessary for calculating the capacity value which contributes to the PPP. CEMPA applies the VOLL that is typically applied in the U.K., valued at £2,000/MWh in 1991 (Newbery, 1995) or about $4.3/kWh in 1995 dollars.

Pool Purchase Price (PPP)

Equation 2.4 illustrates the formula that is applied by CEMPA for determining the electricity *pool purchase price* (PPP), the price that generators receive for the electricity they actually produce, including an adder for the value of firm capacity.

Equation 2.4 - Pool Purchase Price of Electricity

$$PPP = [\ (1 - LOLP) \times SMP\ ] + [\ LOLP \times VOLL\ ]$$

$LOLP$ = Average(technology $LOLP$s)

SMP = *Offer* price of the *marginal* operating unit

$VOLL$ = \$4 / kWh (1991 dollars)

The revenue that electricity generators receive on a short-term basis is equivalent to the product of the PPP and the amount of energy they actually produce and sell into the spot market. Some generators operate exclusively in the spot market, receiving only the PPP, and do not sign any long-term agreements with buyers for the electricity they produce. However, the majority of generators will sign long-term contracts with electricity purchasers - retailers, distribution utilities, or brokers - to provide some security for their investments in generation technologies, and to hedge the volatile spot price of electricity (PPP).

2.4.3.4 The Wholesale Cost of Electricity (Pool Selling Price - PSP)

In the U.K. and Alberta, there are separate forward markets which determine a day-ahead forecast SMP based on the forecast demand, but the actual SMP and PPP (in the U.K.) are based on the instantaneous supply and demand both of which vary. In the U.K., the difference between the day-ahead forecast SMP and the actual SMP contributes to the *uplift* charge which also includes the costs of operating the *power pool* and transmission facilities (Dunn, 1996). CEMPA also applies an *uplift* to determine the *pool selling price* (PSP), which is the price that wholesale customers pay for electricity purchases through the *power pool*, including *power pool* expenses and some transmission costs.

CEMPA does not determine a specific value for the *uplift* in each period, rather an average system value is determined based on transmission expenses, typical *power pool* operating expenses, and anticipated variations between day-ahead forecast and actual SMP based on U.K. data. A single *uplift* value is applied for both B.C. and Alberta. In B.C., the transmission charges under the BC Hydro *Wholesale Transmission Services Application* (1996) to the B.C. Utilities Commission varied between \$0.001 and \$0.00753 per kWh (BCH, 1996). The average is in the \$0.002 - \$0.004/kWh range. The charges for operating the *power pool* in Alberta are currently set at \$0.00007/kWh (Power Pool of Alberta), including all necessary system stability and backup services. The CEMPA *uplift* of \$0.004/kWh attempts to reflect those costs.

The equation applied by CEMPA for calculating the PSP, or the wholesale price of electricity in the jurisdiction, is detailed below:

Equation 2.5 - Pool Selling Price

Pool Selling Price = Spot Price + Uplift

Uplift = \$0.004/kWh

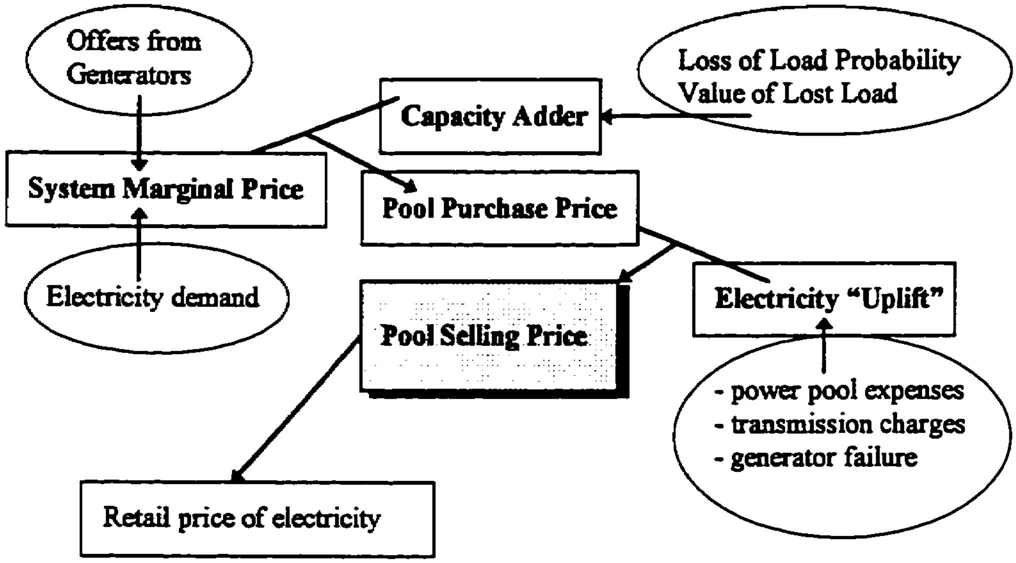
2.4.3.5 Annual Electricity Production, Revenue Generated and CO_2 Emissions

The annual electricity production from each technology is tracked by CEMPA. This value is compared with the CEA/NRCan electricity forecast to determine how closely the *load duration* *curve* electricity demand estimate is to the actual forecast. Also, the annual revenue generated for each technology from electricity sales is determined, as well as the annual CO_2 emissions.

2.4.3.6 Summary of Spot Market Sub-Model

The CEMPA spot market sub-model achieves the tasks illustrated in Figure 2.6.

Figure 2.6 - Overview Diagram of CEMPA Spot Market Sub-Model



2.5 Sustainability Policy Implementations

2.5.1 Introduction

The purpose of the sustainability policy components in CEMPA is to forecast the economic, market, and environmental impacts of three alternative policies which are designed to enhance the market penetration of Sustainables.

The three sustainability policies are those outlined in Chapter 1 and in Section 2.2. Each is intended to be compatible with retail competition electricity markets and *power pool* market trading mechanisms. The implementation of these policies in CEMPA is achieved by modifying the Investment and Spot Market Sub-Models that were outlined in Sections 2.3 and 2.4.

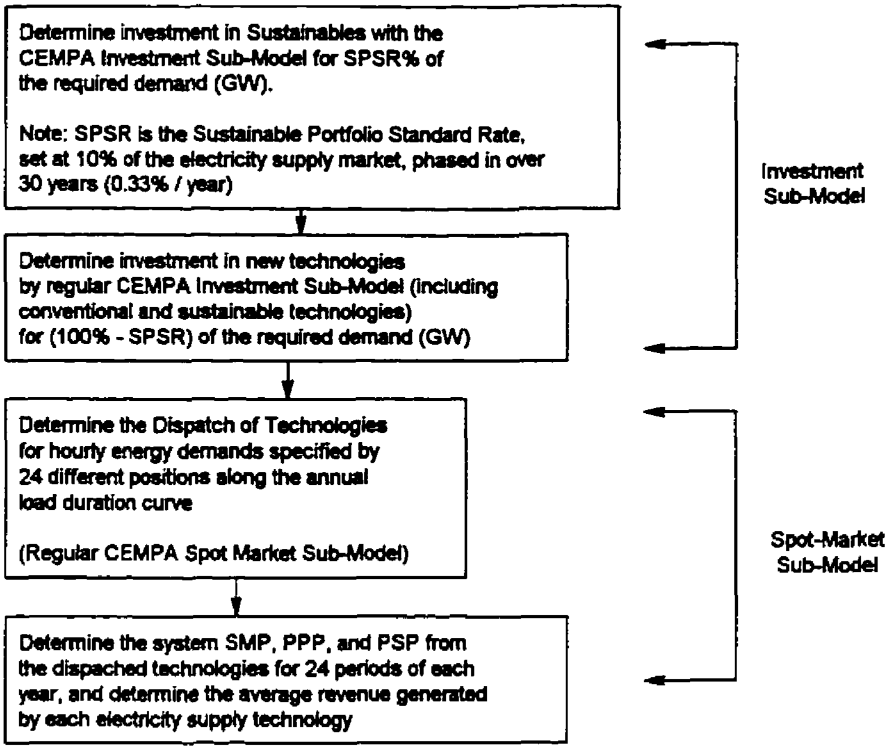
2.5.2 Sustainables Portfolio Standard (SPS)

CEMPA adopts an SPS of 10% of annual electricity sales (kWh) by 2025, phased in annually over the 30 year simulation, with a 1/3% increase in the share each year. That means that by 2025, 10% of the electricity (in kWh) generated and sold must be derived from sustainable electricity generation technologies. It assumes that the market share specified by the SPS is met during all periods of the year, whether the demand is close to the system *peak* capacity or if the system is operating at *baseload* capacity.

The SPS mechanism, as defined, controls the way electricity is dispatched to meet retail <u>energy</u> demand, hence it is a spot market function. However, CEMPA controls the mechanism from the investment sub-model, as sufficient investment in new Sustainables <u>capacity</u> is necessary to meet retail sales standards. Modifications are made to the investment sub-model methodology described in Section 2.3. An assumption is made that once generating units are developed, the *power pool* structure is conducive to the full dispatch of Sustainables facilities. As such, no modification of the CEMPA spot-market model is necessary to ensure that the SPS energy requirement is met.

Figure 2.7 provides an overview of the implementation of the SPS mechanism in CEMPA, and a description follows.

Figure 2.7 - CEMPA Implementation of Sustainables Portfolio Standard



Investment Sub-Model Issues and Modifications

The challenge of implementing an SPS mechanism is ensuring that adequate investment in Sustainables takes place so that the requirement can be met. Therefore the CEMPA SPS routine focuses exclusively on investment, rather than operating requirements. CEMPA determines technology investment under the SPS mechanism in a similar manner to the methodology described in Section 2.3, but based exclusively on the *levelized-costs*.

The SPS routine applies the following methodology.

1. run the regular CEMPA investment sub-model (without SPS requirement).
2. determine the SPS requirement in GWh.
3. check if any Sustainables capacity was developed based on financial merit (in step #1), and convert that to annual GWh production with the capacity factor.
4. select the least *levelized cost* Sustainable, determine its maximum capacity, convert that capacity to annual GWh production.

5. allocates the remaining GWh in a similar fashion among other Sustainables if necessary.

Spot Market Sub-Model Issues and Modifications

The marginal cost of electricity production from Sustainables is equivalent to their operating and maintenance costs and additional expenses such as water license fees for small hydro or land-use fees. Fuel costs are typically zero or negative for biomass cogenerators (due to a financial credit for steam generation). In order to simulate the SPS policy mechanism, CEMPA applies the spot-market sub-model described in Section 2.4 to determine the dispatch of technologies and the market price of electricity. It is assumed that the SPS is met automatically by electricity retailers provided sufficient capacity is available, because the Sustainables are often the cheapest technologies to operate on a marginal kWh basis.

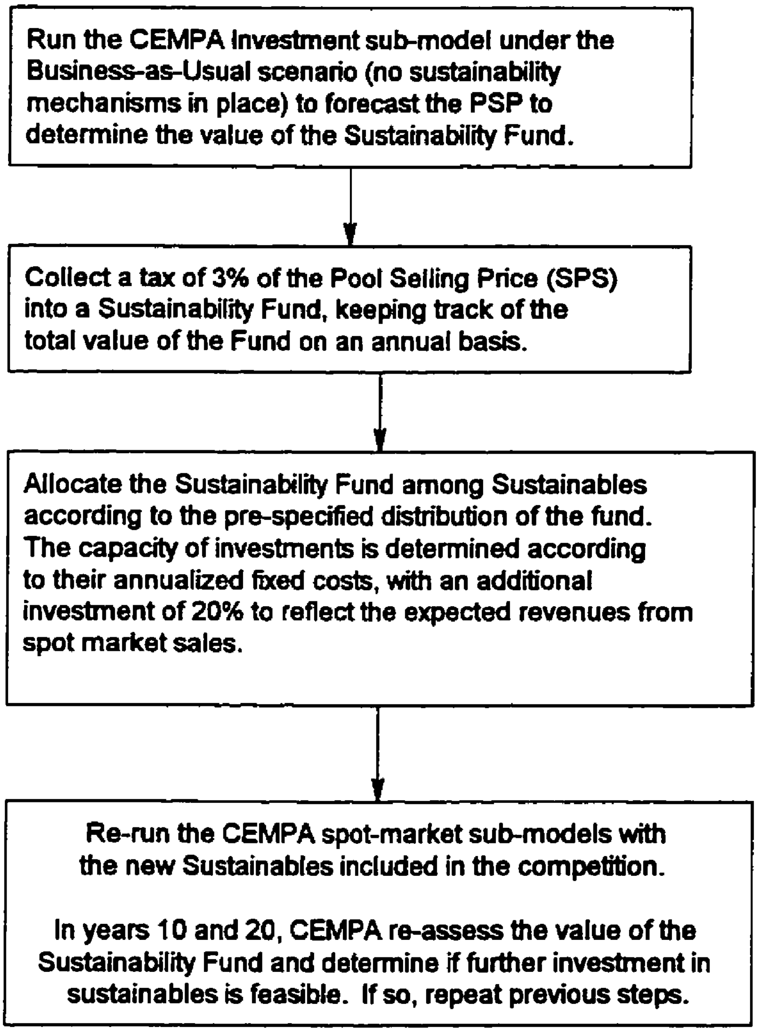
2.5.3 Non-Bypassable System Benefits Charge with Sustainability Fund

CEMPA assumes that a System Benefits Charge (SBC) is collected on all electricity sales equivalent to 3% of the Pool Selling Price (PSP). This charge is deposited into a *Sustainability Fund* which is used to subsidize Sustainables by an amount equivalent to the difference between their levelized-cost of production and the Pool Purchase Price (PPP) of electricity, which is paid to generators. In British Columbia, the wholesale price of electricity is equivalent to about one-half of the retail price for residential consumers. As such, the SBC is on the order of 1.5% of the retail price of electricity.

The mechanism relies upon separate electricity price and demand forecasts (from the "business-as-usual" scenario) to determine in advance the amount of money available for investment in Sustainables on an annual basis. In year one, collection of the SBC commences. In that year, the fund administrator signs *contracts-for-differences* with producers of sustainable electricity to guarantee the price they will be paid for their electricity production over the financing terms of the plant (25 years). Once they are developed, the Sustainables compete with all existing technologies in the *Power Pool*. In years 10 and 20, the value of the *Sustainability Fund* is re-assessed to determine if there is a surplus of funds available to fund additional Sustainables development. This surplus could be created by rising electricity prices (relative to the "business-as-usual" forecast) in CEMPA which reduces the gap between the market price of electricity and their levelized costs, or due to an over-assessment of the magnitude of the subsidy required by Sustainables in year 0.

The funds are distributed to a variety of technology types, in order to promote diversity of supply options. This causes the cost of the mechanism to be higher than others (SPS, EA), although it was designed in this manner to reflect what is being done in other jurisdictions such as the U.K. and California.

Figure 2.8 - CEMPA implementation of the Non-Bypassable System Benefits Charge



Investment Sub-Model Issues and Modifications

The approach undertaken for implementing the SBC is as follows.

1. the CEMPA Investment and Spot Market Sub-models are run to forecast the PPP and PSP of electricity over the simulation period.
2. the present value ($1995) of the *Sustainability Fund* is determined, and then is annualized to determine the annual subsidy to Sustainables.
3. the *Fund* is allocated among various classes of technologies (See Table 2.3) to foster investment in each of those technologies.
4. the level of investment in new Sustainables is calculated by taking the available *Fund* dollars for each technology class, and determining how many megawatts can be developed based on the annualized capital costs. An additional 20% of that capacity is developed to reflect the fact that electricity sales into the spot market will partially compensate the capital costs given the low marginal costs of operating Sustainables facilities relative to the PPP.
5. the CEMPA Spot Market Sub-Model is re-run to determine the operation of Sustainables and the change in PSP (to see if the amount of fund collected is different).
6. the surplus of *Fund* dollars is calculated by re-assessing the value of the *Fund*, allocating the subsidy to existing Sustainables, and calculating the remainder.
7. in years 10 and 20, the surplus *Fund* dollars are allocated to Sustainables.

Table 2.3 - Allocation of Sustainability Fund among Sustainables

	British Columbia	Alberta
Wind Power	25%	50%
Solar PV	15%	20%
Tidal Power	20%	0%
Small Hydro (lower grade sites)	20%	0%
Biomass Gasifier	10%	15%
Waste Fuels Cogenerator	10%	15%

Spot Market Sub-Model Issues and Modifications

The CEMPA spot-market sub-model is executed as described in Section 2.3, but the PSP includes the System Benefits Charge, and additional Sustainables technologies are included as a result of the investment via the *Sustainability Fund* outlined above.

2.5.4 Revenue-Neutral Environmental Cost Adder

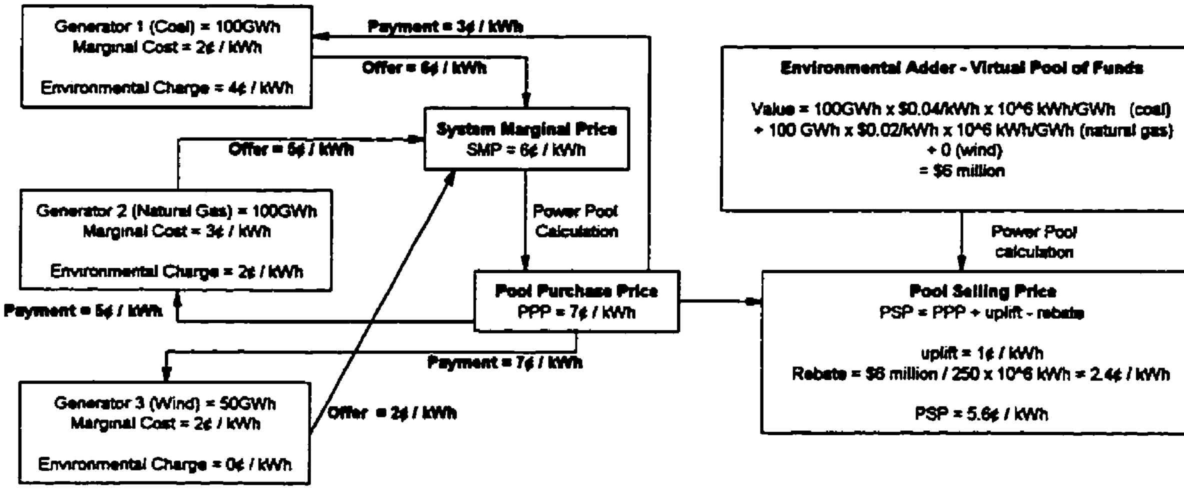
2.5.4.1 Introduction

The EA mechanism subtracts a monetary value from the price that is paid to generators (PPP), reflective of the environmental impacts of the utilization of that technology. In order for electricity generators to adequately cover their costs, they would treat the charge as an "Environmental Adder" to their "offer" price. The mechanism is designed to be "revenue-neutral", meaning that the total value of the "adders" is subtracted from the wholesale price of electricity (PSP).

Figure 2.9 illustrates the mechanics of an EA mechanism, showing that the wholesale price of electricity (PSP) is only slightly higher than if the mechanism were not in place. Without the EA mechanism in place, the PSP would have been approximately 5¢ / kWh (SMP=3¢ for natural gas, PPP=4¢, PSP=5¢). With the EA mechanism in place the PSP is 5.6¢/kWh in the example illustrated below. In this case, wind gets 3¢ / kWh more, a gas generator 1¢/kWh more, and a coal generator 1¢/kWh less than if the EA mechanism were not in place.

Figure 2.9 - Financial Calculations for a Revenue-Neutral Environmental Charge Mechanism

(real 1995 dollars and cents)



The EC mechanism favors sustainable electricity generation technologies, translating into long-term revenue gains for their producers. There is a financial disincentive for investors to fund the development of new facilities which incur large EA expenses (e.g. coal power), and an incentive for investment in Sustainables because the PPP is higher, and Sustainables are able to receive the full extent of that increase.

2.5.4.2 *Methodology for Modelling*

This incentive is difficult to represent in CEMPA because the magnitude of the financial benefit is only measurable after several years of system operation. As such it was decided to treat the EA mechanism in CEMPA like a carbon dioxide tax of $20/tonne. It is assumed that carbon dioxide emissions are generally indicative of other pollutants such as SO_2, NO_x, CH_4, CO, Particulates, VOCs, and N_2O. The specific carbon taxes applied for various technologies are as follows:

Table 2.4 - Carbon Taxes Applied for Technologies under the Environmental Adder Mechanism

Technology Name	Carbon Tax ($/kWh) resulting from tax of $20/tonne of CO_2 emissions
Simple Cycle Gas	$0.0106
Combined Cycle Gas	$0.0079
Coal - Pressurized Fluidized Bed Combustion	$0.0201
Coal Gasifier Turbine	$0.0173
Simple Cycle Oil	$0.0176
Combined Cycle Oil	$0.0125
Gas Cogeneration Retrofits (with steam credit)	$0.002

Investment and Spot Market Sub-Model Issues and Modifications

The CEMPA parameters are adjusted to reflect the Environmental Charge in the operating costs of each technology. The CEMPA Investment and Spot Market Sub-models are then executed to determine investment and operation of new technologies based on the inclusion of the additional charge. Following that, an EC refund routine is executed to subtract the value of the EC collected from the PSP.

3. MODELLING INPUTS AND SCENARIOS

3.1 Modelling Input Parameters

3.1.1 Discount Rate

The real discount rate applied in the simulation is 12%, attempting to balance a public utility cost of capital of 6-9%, and a private power producer's costs of capital of 5-12%. The real discount rate used by BC Hydro in its economic analysis is set by the Crown Corporations Secretariat typically at 8%. In contrast, IPP developers that were surveyed indicated a much wider range of discount rates. A developer of small-hydro projects in the province of B.C. applied a real discount rate of 12% in their assessment of small hydro resources in the province (Sigma Engineering), although that study was completed over 10 years ago. A combined-cycle gas turbine developer suggested applying an 80-20 debt-equity ratio (Westcoast Power), with discount rates as low as 5% real, given the current low lending rates. Another developer suggested using a long term bond rate for a typical industrial customer (e.g. Timber West), and adding 20% to that rate to reflect the equity component (Inland Pacific). This leads to rates in the 9-11% range, depending on the company. Corporate taxation should be reflected in the discount rate, something that Crown-owned are not required to pay, but IPPs and private utilities do, pointing towards the application of a discount rate on the upper end of the spectrum mentioned above.

It was decided to go on the conservative end for the CEMPA analysis, applying a 12% real discount rate, to ensure that those parties assessing the results from a cost-effectiveness standpoint would be satisfied with the representation of costs of Sustainables. Had a 5% discount rate been applied, the costs of certain Sustainables would have been significantly lower because they are capital intensive. Also, there are no guarantees that the current low lending rates will be maintained. Applying a low discount rate would work against the conservative approach undertaken. This issue is briefly investigated in Chapter 6 through a sensitivity analysis.

The CEMPA model utilizes an inflation rate of 2%, which was used to adjust all historical costs to Real 1995 dollars.

3.1.2 Commodity Prices

The energy resource price inputs that are utilized by CEMPA include.

- natural gas price forecasts.
- coal price forecasts.
- oil price forecasts.
- biomass resource prices.
- hydroelectricity water usage fees (water license).
- steam output values for cogeneration facilities.

Natural gas prices are sourced from the recent NRCan document, "Canada's Energy Outlook 1996-2020" which indicates the anticipated "Domestic Price at the Alberta Border" in real $1995 per million cubic feet. Those values are converted to $/GJ by multiplying the costs by a factor of 1.055. In the province of B.C., the Alberta border price is utilized, but in Alberta, a 5% reduction is applied to reflect reduced transportation costs. The values are listed in Table 3.1, with the lower price being the Alberta price.

Coal prices are derived from Liu (1995). See Table 3.1.

Oil prices are similarly derived from Liu (1995), but inflated by 30% to ensure that existing oil facilities are not operated under CEMPA except for exceptional peaking purposes. This decision was made to reflect the fact that most oil facilities (diesel) are in non-integrated areas, and would not compete on the open market anyway. As far as new technologies are concerned, there is a general consensus in the industry that the *levelized costs* of oil based technologies are not cost competitive with natural gas ones. See Table 3.1.

Biomass resource prices reflect the opportunity cost of those resources, given that they could be used to offset natural gas in existing pulp and paper operations, or for other uses. The numbers illustrated in Table 3.1 are directly proportional to natural gas prices, but are scaled to reflect the fact that a biomass boiler is less efficient than a natural gas one. The specific scaling factor of 0.89 is derived from the ISTUM model for the pulp and paper sector by taking the ratio of steam production from a biomass cogenerator versus a natural gas cogenerator. The Alberta biomass price is raised by 25% to reflect transportation costs, so its value is actually higher than the natural gas price.

Fuel costs for hydroelectricity production depend on the water license fee of the provincial water or environment ministry. In B.C., large hydroelectric operations pay slightly more than small hydro producers (conversation with Bob Mathews). See Table 3.1.

Cogeneration technologies jointly produce electricity and steam from an input fuel such as biomass or natural gas, and the steam can be used for other uses, which adds additional value to the technology. As such a "steam credit" is granted to those technologies, proportional to the fuel price of natural gas, and based on the efficiency of the technology. Data from ISTUM are used to come up with that scaling factors that lead to the net fuel costs listed in Table 3.1 (Simon Fraser University, Energy Research Group, 1997). CEMPA applies a negative fuel cost for cogeneration technologies, which helps offset the higher capital costs.

Table 3.1 - Energy Price Forecasts (real $1995 per Gigajoule)

Fuel Type	1995 Price	2000 Forecast	2005	2010	2015	2020
Natural Gas (AB, BC)	$1.67, $1.76	$1.96, $2.07	$2.03, $2.13	$2.09, $2.19	$2.07, $2.18	$2.06, $2.17
Coal	$0.97	$0.99	$1.02	$1.04	$1.15	$1.27
Oil	$2.30	$3.61	$4.62	$4.98	$5.50	$6.07
Biomass (BC, AB)	$1.58, $1.87	$1.85, $2.20	$1.91, $2.26	$1.96, $2.33	$1.95, $2.32	$1.94, $2.31
Hydro water rental (¢/kWh)	0.46, 0.48	0.46, 0.48	0.46, 0.48	0.46, 0.48	0.46, 0.48	0.46, 0
Gas Cogen Net Fuel Cost (AB, BC, ¢/kWh)	-0.157, -0.165	-0.184, -0.194	-0.190, -0.200	-0.196, -0.206	-0.195, -0.205	-0.194, -0.204
Biomass Cogen. Net Fuel Cost (AB,BC,¢/kWh)	-0.235, -0.248	-0.276, -0.291	-0.285, -0.300	-0.293, -0.309	-0.292, -0.307	-0.290, -0.306

3.1.3 Load Forecast

The Canadian Electricity Association / Natural Resources Canada annual report entitled, "Electric Power in Canada" (1996) contains a load and energy forecast for each province. Table 3.2 outlines those forecasts. The capacity demand values do not include the *reserve margin*. The energy demand values include a 7% transmission line loss factor.

The forecasted capacity demand is scaled-up in CEMPA by a *reserve margin* to ensure that peak demand and annual energy requirements are met, given that most generation technologies have limited capacity factors. CEMPA applies *reserve margins* that are reflective of the capacity factors of the dominant existing generation technologies and transmission losses. The capacity factor for B.C. hydroelectric resources assumes an average water reservoir condition. In Alberta a 15% margin is added to reflect the energy shortfall of fossil fuel technologies with capacity factors of 85%. In B.C. where hydroelectricity is the dominant generation source and the systems are "energy critical", a large *energy reserve margin* is required to meet annual energy requirements, although this can also be met by trading with other jurisdictions. CEMPA assumes a 70% capacity factor for existing hydroelectric facilities which means that the facility can only produce its full capacity for 70% of the year, requiring a *reserve margin* of 30%. This margin is decreased in proportion to the retirement rate of existing hydroelectric facilities, about 1% / year. In summary, a 22% reserve margin is applied to Alberta (consistent with CEA stat's), and a 30% margin is applied in B.C., reduced to about 22% by the year 2025, assuming that trading or DSM during energy critical periods will make up for the 7% transmission losses.

For energy demand, CEMPA utilizes the *Load Duration Curve* (LDC) illustrated in Figure 2.1, and converts the demand segments to energy demand. The LDC is divided into 24 segments, each representing a characteristic point of demand for the year, and the area of each segment (under the curve) represents the demand. The sum of those quantities specifies the annual GWh demand. Table 3.2 outlines these values, including 7% line losses.

The difference between the CEA/NRCan forecasted demands, and the CEMPA LDC forecasts, range from 18-21% in Alberta (with CEMPA underpredicting demand), and 0-7% in B.C. The explanation for the large divergence in the Alberta model is that a B.C. *Load Duration Curve* was applied in the Alberta model due to the unavailability of that data. Other explanations include differences in the assessment of line losses (CEMPA assumes 7%), the lack of precision by which CEMPA determines the annual demand, or a different assumption about the shape of the LDC.

Table 3.2 - Load and Energy Forecasts (MW and GWh)

Forecast	1995	2000	2005	2010	2015	2020
BC Demand (MW)	10,504	11,906	12,684	13,936	15,311	16,82
AB Demand (MW)	6,924	7,644	8,409	9,284	10,250	11,31
BC Energy (CEA, GWh)	64,660	78,017	84,063	89,987	99,841	110,7
AB Energy (CEA, GWh)	54,931	60,687	66,752	73,335	80,177	87.65
BC Energy (CEMPA, GWh)	64,712	73,464	78,312	86,100	94,633	104,0
AB Energy (CEMPA, GWh)	43,104	47,465	52,224	57,667	63,678	70,31

3.1.4 Competing Electricity Generation Technologies

The technologies selected for this analysis include the following.

- Combustion turbine technologies - Simple and combined cycle gas and oil technologies. The combined cycle technologies operate at a higher efficiency but with a higher capital cost. The data source for these technologies is from Liu (1995), and the BC Hydro IEP.
- Coal pressurized fluidized bed, and coal gasifier plants, are the latest generation of coal combustion technologies, offering advantages of higher efficiency and lower local-airshed emissions (SO_x, NO_x, Particulates), but at a higher cost than the conventional coal steam plants used in Alberta. Data source: BC Hydro IEP and Liu (1995).
- Biomass steam and gasifier turbines utilize a variety of biomass or waste products to produce electricity through a thermal steam cycle. The gasifier converts biomass into methanol or ethanol before combustion. Data source: Liu (1995).
- Small hydro - typically under 20MW in capacity, they operate as run-of-river plants, without storage reservoirs. The "Optimal" technologies are those that are cost-competitive with the

cheapest conventional technologies (natural gas), while those that are "lower grade" are more expensive due to higher capital costs, lower capacity factors, or long distance from transmission corridors. Data source: Canadian Hydro Developers and Sigma Engineering.

- Waste Fuel Cogen - this technology co-generates steam and electricity from waste fuels, typically at industrial facilities such as pulp & paper plants (using mill waste). This technology was characterized with information from Stothert Engineering, the developers of the proposed Purcell Power project in the East Kootenays. Because it is a cogenerator, it is given a steam credit of about 0.2 cent/kWh which offsets its variable costs. The fuel cost of the waste fuel waste fuel used (wood waste) has an *opportunity cost* proportional to the value of natural gas, as waste fuels are often consumed in the place of natural gas. The resource potential information was derived from Jaccard and Makinen (1993).
- Gas Cogen Retrofits - this technology involves retrofitting or replacing an existing natural gas boiler in an industrial, commercial or institutional facility with a cogenerator. CEMPA also applies a steam credit equivalent to the technology fuel costs. It turns out that the steam credit exceeds the cost of the natural gas fuel, because cogenerators are more efficient at producing steam than a steam boiler is, and therefore it has a negative net fuel cost. Data source: BC Government study and Willis Energy.
- Fuel Cell cogenerators convert natural gas, methanol or hydrogen into electricity and heat without combustion, at a higher efficiency than an equivalent combustion turbine. Data source: BC Hydro IEP.
- Large hydro are those plants with capacities greater than 100MW, usually in remote areas, requiring long transmission line extensions. The technology represented by CEMPA mimics the financial characteristics of the Peace Site C proposal (Data source: BC Hydro IEP).
- Solar technologies, PV and Parabolic-through - both convert solar radiation into electricity. PV cells produce electricity directly from radiation through a semiconductor device, and the Parabolic collector produces steam which drives a turbine. Data source: BC Hydro IEP and Johansson et.al. (1993).
- Wind - Wind generators produce electricity directly from the wind using a airfoil and turbine. Data source: BC Hydro IEP, and VisionQuest Wind Electric.
- Tidal Power - Tidal generators use a vertical-axis hydraulic turbine to generate electricity from tidal flows. Data source: BC Hydro IEP and BC Government Energy Resources Map.

The development of new technologies is simulated by the CEMPA Investment Sub-Model, and competition between new and existing technologies is simulated in the Spot Market Sub-Model. Table 3.3 outlines several technical and financial characteristics of each technology, and Table 3.4 outlines those characteristics for existing technologies. Tables 3.3, and 3.4 only present technology parameters from the CEMPA B.C. model, because they are virtually identical for the Alberta model, and any differences are explained in the notes below the tables. The parameters include the following.

- fixed costs (capital and fixed operating costs) in year 1 of the simulation, annualized over a 25 year period at 12% discount rate (dollars per kW).
- non-fuel variable costs - operating and maintenance costs (dollars per kWh).
- fuel-costs in the first year of the simulation in cents per kWh.
- capacity factors of each technology (%).
- operating life of each technology (years).
- the loss of load probability of each technology (% - used in CEMPA Spot Market Sub-Model).
- the CO_2 emissions from the technology (tonnes per GWh).
- the annual retirement rate of existing technologies (%/year).

The sources of data for individual technologies is listed above with the technologies. The loss of load probability figures came from the Canadian Electricity Association annual report on reliability statistics (See Table 2.2). CO_2 emissions came from BC Hydro and Liu (1995).

Table 3.3 - Technology Parameters

Technology Parameters - British Columbia							
Name	Annualized Costs Fixed Costs $/kW	O&M $/kWh	Fuel Costs In year 1 ¢/kWh	Capacity Factor percent	Operating Life years	oss of Load Probability percent	on Dioxide Emissions es per GWh
Simple cycle gas	70	0.60	1.88	85.0%	25	0.0444%	530.00
Combined cycle gas	103	0.59	1.41	85.0%	25	0.0444%	396.94
Coal - Pressurized Fluidized Bed	228	0.43	1.13	85.0%	25	0.1002%	1,007.00
Coal gasifier turbine	297	0.54	0.97	85.0%	25	0.0444%	865.00
Simple cycle oil (b)	91	0.57	2.73	85.0%	25	0.1002%	878.38
Combined cycle oil	132	0.32	1.94	85.0%	25	0.0444%	624.56
Biomass steam	207	0.21	1.48	85.0%	25	0.1002%	-
Biomass gasifier turbine	235	0.14	1.25	85.0%	25	0.0444%	-
Small hydro - Optimal	206	0.66	0.00	65.0%	50	0.0393%	-
Waste fuels cogen	443	0.64	-0.25	90.0%	25	0.1002%	-
Gas cogen retrofits	251	0.64	-0.17	76.5%	25	0.0444%	100.00
Fuel Cell Cogenerator	769	0.01	1.01	85.0%	25	0.0100%	100.00
Large Hydro	285	0.69	0.00	62.5%	50	0.0393%	-
Solar PV	3033	0.00	0.00	99.0%	40	1.0000%	-
Parabolic-Trough Solar-Power Plan	2350	0.00	0.00	95.0%	40	1.0000%	-
Wind Generators	641	0.01	0.00	90.0%	25	1.0000%	-
Tidal Power	978	0.01	0.00	90.0%	40	0.0393%	-
Small Hydro - lower grade	384	0.58	0.00	70.1%	50	0.0393%	-

Notes: In the Alberta model, all the fuel costs in year one are lower for those technologies based on natural gas (with the negative fuel cost for cogeneration technologies closer to zero, indicating less benefit), and higher for biomass technologies. Solar PV technologies are $2424/kW because of better solar resources in Alberta, Parabolic-Trough Solar is $1846/kW (same justification), and wind technologies are cheaper at $531/kW because of better wind conditions in S-W Alberta.

Table 3.4 - Parameters for Existing Technologies

Technology Parameters - Existing Technologies - B.C.					
Name	Variable Costs In year 1 ¢/kWh	Capacity Factor percent	Annual Retirement Rate %/year	Loss of Load Probability percent	Carbon Dioxide Emissions tonnes per GWh
Natural Gas	2.48	85.0%	1%	0.1002%	530.00
Coal	1.61	85.0%	1%	0.1002%	1,007.00
Oil	3.44	85.0%	5%	0.1002%	878.38
Hydro	1.00	70.0%	1%	0.0393%	-
Nuclear	2.20	85.0%	0%	0.0488%	-
Biomass	3.02	85.0%	1%	0.1002%	-

Note: In the Alberta model, the variable costs for natural gas are lower, and those for biomass are higher. Also the annual retirement rates are higher in Alberta, 2.5% / year for all thermal technologies.

The annual retirement rate of existing technologies was selected based on information from BC Hydro, with the selection of the retirement rate of oil facilities arbitrarily set high to phase them out and ensure that they don't overly contribute to peak demand in CEMPA. The Alberta figures

(2.5%/year) are representative of the typical life of generation plants and information provided from the Alberta Power Pool. It should be noted that such a straight-line retirement rate is unrealistic, as plants are typically retired entirely at one time, and the capacity of exiting technologies is reduced in a stepwise fashion. However, it is beyond the scope of this study to undertake a detailed assessment of individual generation facilities.

Table 3.5 outlines the development limits for particular technologies, specified by province, given that some technologies have limited resources or limited available sites for certain technologies. Those technologies not listed have no specified development limits.

Table 3.5 - Development Limits for Technologies (MW)

Technology Name	B.C. Development Limit	Alberta Development Limit
Biomass steam	500 MW	200 MW
Biomass gasifier	500 MW	200 MW
Large hydro	500 MW	0 MW
Optimal small hydro	300 MW	200 MW
Waste-fuel cogenerator	444 MW	100 MW
Less-Optimal small hydro	1,026 MW	0 MW
Gas cogen retrofits	1000 MW	500 MW
Wind Farm	3,257 MW	2,509- 18,561 MW
Tidal Generator	3,186 MW	0 MW
Solar technologies	1,000 MW	1,000 MW

CEMPA calculates the *levelized-costs* of all the technologies on an annual basis, integrating the annualized capital cost data with variable costs and expected generation of energy. See Equation 2.1 for a description of that calculation. The *levelized cost* information for the B.C. simulation model is listed in Table 3.6, and that information for Alberta is listed in Table 3.7.

Table 3.6 - Levelized Costs of New Technologies in B.C. ($1995/kWh)

(assuming all technologies operate as baseload technologies - at full capacity factor)

Annual Levelized Costs - B.C. Model - BAU

Technology Name	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	$0.0369	$0.0373	$0.0376	$0.0379	$0.0381	$0.0383	$0.0384	$0.0385	$0.0386	$0.0387	$0.0388	$0.0390	$0.0391	$0.0392	$0.0393	$0.0395
Simple cycle oil (b)	$0.0620	$0.0644	$0.0666	$0.0688	$0.0708	$0.0726	$0.0743	$0.0759	$0.0774	$0.0788	$0.0800	$0.0811	$0.0823	$0.0835	$0.0847	$0.0860
Combined cycle gas	$0.0358	$0.0361	$0.0363	$0.0365	$0.0367	$0.0368	$0.0369	$0.0370	$0.0371	$0.0372	$0.0372	$0.0373	$0.0374	$0.0375	$0.0376	$0.0377
Combined cycle oil	$0.0522	$0.0539	$0.0555	$0.0570	$0.0584	$0.0597	$0.0609	$0.0620	$0.0631	$0.0641	$0.0650	$0.0658	$0.0666	$0.0675	$0.0684	$0.0693
Small hydro - Optimal	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427
Biomass steam	$0.0465	$0.0468	$0.0470	$0.0472	$0.0474	$0.0475	$0.0476	$0.0477	$0.0478	$0.0479	$0.0480	$0.0481	$0.0482	$0.0483	$0.0484	$0.0485
Coal - Pressurized Fluidi	$0.0467	$0.0468	$0.0469	$0.0470	$0.0471	$0.0472	$0.0473	$0.0474	$0.0476	$0.0477	$0.0479	$0.0480	$0.0482	$0.0484	$0.0487	$0.0489
Biomass gasifier turbine	$0.0472	$0.0474	$0.0476	$0.0478	$0.0480	$0.0481	$0.0481	$0.0482	$0.0483	$0.0484	$0.0485	$0.0485	$0.0486	$0.0487	$0.0488	$0.0489
Gas cogen retrofits	$0.0419	$0.0419	$0.0418	$0.0418	$0.0418	$0.0418	$0.0418	$0.0418	$0.0418	$0.0417	$0.0417	$0.0417	$0.0417	$0.0417	$0.0417	$0.0417
Large Hydro	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590
Coal gasifier turbine	$0.0555	$0.0555	$0.0556	$0.0557	$0.0558	$0.0559	$0.0560	$0.0561	$0.0562	$0.0563	$0.0565	$0.0566	$0.0568	$0.0570	$0.0572	$0.0574
Small Hydro - lower grad	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682
Waste fuels cogen	$0.0598	$0.0597	$0.0597	$0.0597	$0.0596	$0.0596	$0 0596	$0 0596	$0.0596	$0.0596	$0.0595	$0.0595	$0.0595	$0.0595	$0.0595	$0.0595
Wind Generators	$0.0814	$0.0809	$0.0803	$0.0798	$0.0793	$0.0787	$0.0782	$0.0777	$0.0772	$0.0767	$0.0761	$0.0756	$0.0751	$0.0746	$0.0741	$0.0736
Fuel Cell Cogenerator	$0.1149	$0.1143	$0.1136	$0.1130	$0.1123	$0.1116	$0.1109	$0.1102	$0.1095	$0.1088	$0.1081	$0.1074	$0.1068	$0.1061	$0.1054	$0.1048
Tidal Power	$0.1241	$0.1224	$0.1207	$0.1190	$0.1173	$0.1157	$0.1140	$0.1124	$0.1109	$0.1093	$0.1078	$0.1063	$0.1048	$0.1033	$0.1018	$0.1004
Parabolic-Trough Solar-	$0.2824	$0.2783	$0.2744	$0.2705	$0.2666	$0.2628	$0.2590	$0.2553	$0.2517	$0.2481	$0.2445	$0.2410	$0.2376	$0.2342	$0.2309	$0.2276
Solar PV	$0.3498	$0.3438	$0.3380	$0.3322	$0.3265	$0.3210	$0.3155	$0 3101	$0.3048	$0.2996	$0.2945	$0.2895	$0.2846	$0.2797	$0.2750	$0.2703

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	$0.0396	$0.0397	$0.0399	$0.0401	$0 0403	$0 0406	$0.0409	$0.0413	$0.0417	$0.0422	$0.0427	$0.0433	$0.0438	$0.0444	$0.0450
Simple cycle oil (b)	$0.0874	$0.0888	$0.0902	$0.0917	$0.0931	$0.0946	$0.0962	$0.0977	$0.0993	$0.1010	$0.1026	$0.1043	$0.1060	$0.1078	$0.1096
Combined cycle gas	$0.0378	$0.0379	$0.0380	$0.0382	$0.0384	$0.0386	$0.0388	$0 0391	$0.0394	$0.0397	$0.0401	$0.0406	$0.0410	$0.0414	$0.0418
Combined cycle oil	$0 0702	$0.0712	$0 0722	$0.0733	$0.0743	$0.0754	$0.0765	$0 0776	$0.0787	$0.0799	$0.0811	$0.0823	$0.0835	$0.0847	$0.0860
Small hydro - Optimal	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0 0427	$0.0427	$0 0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427
Biomass steam	$0.0486	$0.0487	$0.0488	$0.0490	$0.0492	$0.0494	$0.0496	$0 0499	$0.0502	$0.0506	$0.0510	$0.0514	$0.0519	$0.0523	$0.0527
Coal - Pressurized Fluidi	$0.0492	$0.0495	$0.0498	$0.0501	$0.0504	$0.0507	$0.0510	$0 0513	$0.0517	$0.0520	$0.0523	$0.0527	$0.0530	$0.0534	$0.0538
Biomass gasifier turbine	$0.0489	$0.0490	$0.0492	$0.0493	$0.0495	$0.0496	$0.0499	$0 0501	$0.0504	$0.0507	$0.0510	$0.0514	$0.0518	$0.0521	$0.0525
Gas cogen retrofits	$0.0417	$0.0417	$0.0416	$0.0416	$0.0416	$0.0416	$0.0415	$0.0415	$0.0415	$0.0414	$0.0414	$0.0413	$0.0413	$0.0412	$0.0412
Large Hydro	$0.0590	$0.0590	$0.0590	$0.0590	$0 0590	$0.0590	$0.0590	$0 0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590
Coal gasifier turbine	$0.0576	$0.0579	$0.0581	$0.0584	$0.0586	$0 0589	$0.0592	$0.0594	$0.0597	$0.0600	$0.0603	$0.0606	$0.0609	$0.0612	$0.0615
Small Hydro - lower grad	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0 0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682	$0.0682
Waste fuels cogen	$0.0594	$0.0594	$0.0594	$0.0594	$0 0593	$0.0593	$0.0593	$0 0592	$0.0592	$0.0591	$0.0590	$0.0590	$0.0589	$0.0588	$0.0587
Wind Generators	$0.0731	$0.0727	$0.0722	$0.0717	$0.0712	$0.0707	$0.0703	$0 0698	$0.0693	$0.0689	$0.0684	$0.0679	$0.0675	$0.0670	$0.0666
Fuel Cell Cogenerator	$0.1041	$0.1035	$0.1029	$0.1023	$0.1017	$0.1012	$0 1006	$0 1002	$0.0997	$0.0993	$0 0989	$0.0985	$0.0982	$0.0978	$0.0975
Tidal Power	$0.0990	$0.0976	$0.0962	$0.0949	$0.0935	$0.0922	$0 0909	$0 0897	$0 0884	$0.0872	$0.0859	$0.0847	$0.0835	$0.0824	$0.0812
Parabolic-Trough Solar-	$0.2243	$0.2211	$0.2180	$0.2148	$0.2118	$0.2087	$0.2058	$0 2028	$0.1999	$0.1971	$0.1943	$0.1915	$0.1887	$0.1860	$0.1834
Solar PV	$0.2657	$0.2611	$0.2567	$0.2523	$0.2480	$0.2438	$0.2396	$0.2355	$0.2315	$0.2276	$0.2237	$0.2199	$0.2161	$0.2125	$0.2088

Table 3.7 - Levelized Costs of New Technologies in Alberta ($1995/kWh)

(assuming all technologies operate as baseload technologies - at full capacity factor)

Annual Levelized Costs - Alberta Model - BAU

Technology Name	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	$0.0359	$0.0362	$0.0365	$0.0367	$0.0370	$0.0371	$0.0372	$0.0373	$0.0375	$0.0376	$0.0377	$0.0378	$0.0379	$0.0380	$0.0381	$0.0383
Simple cycle oil (b)	$0.0620	$0.0644	$0.0666	$0.0688	$0.0706	$0.0726	$0.0743	$0.0759	$0.0774	$0.0788	$0.0800	$0.0811	$0.0823	$0.0835	$0.0847	$0.0860
Combined cycle gas	$0.0350	$0.0353	$0.0356	$0.0357	$0.0358	$0.0360	$0.0360	$0.0361	$0.0362	$0.0363	$0.0364	$0.0365	$0.0365	$0.0366	$0.0367	$0.0368
Combined cycle oil	$0.0522	$0.0539	$0.0555	$0.0570	$0.0584	$0.0597	$0.0609	$0.0620	$0.0631	$0.0641	$0.0650	$0.0658	$0.0666	$0.0675	$0.0684	$0.0693
Small hydro	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427
Biomass steam	$0.0520	$0.0524	$0.0527	$0.0530	$0.0532	$0.0534	$0.0535	$0.0536	$0.0537	$0.0539	$0.0540	$0.0541	$0.0542	$0.0544	$0.0545	$0.0546
Coal - Pressurized Fluidz	$0.0467	$0.0468	$0.0469	$0.0470	$0.0471	$0.0472	$0.0473	$0.0474	$0.0476	$0.0477	$0.0479	$0.0480	$0.0482	$0.0484	$0.0487	$0.0489
Biomass gasifier turbine	$0.0499	$0.0501	$0.0504	$0.0506	$0.0508	$0.0509	$0.0510	$0.0511	$0.0512	$0.0513	$0.0514	$0.0515	$0.0516	$0.0517	$0.0518	$0.0519
Gas cogen retrofits	$0.0420	$0.0420	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0419	$0.0418	$0.0418	$0.0418	$0.0418	$0.0418	$0.0418	$0.0418
Large Hydro	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590
Coal gasifier turbine	$0.0544	$0.0544	$0.0545	$0.0546	$0.0547	$0.0548	$0.0549	$0.0550	$0.0551	$0.0552	$0.0553	$0.0554	$0.0556	$0.0557	$0.0559	$0.0561
Waste fuels cogen	$0.0599	$0.0599	$0.0598	$0.0598	$0.0598	$0.0598	$0.0597	$0.0597	$0.0597	$0.0597	$0.0597	$0.0597	$0.0597	$0.0596	$0.0596	$0.0596
Wind Generators	$0.0702	$0.0697	$0.0693	$0.0688	$0.0683	$0.0679	$0.0674	$0.0670	$0.0665	$0.0661	$0.0656	$0.0652	$0.0648	$0.0643	$0.0639	$0.0635
Fuel Cell Cogenerator	$0.1143	$0.1137	$0.1131	$0.1124	$0.1117	$0.1110	$0.1103	$0.1096	$0.1089	$0.1082	$0.1075	$0.1068	$0.1061	$0.1054	$0.1048	$0.1041
Tidal Power	$0.1241	$0.1224	$0.1207	$0.1190	$0.1173	$0.1157	$0.1140	$0.1124	$0.1109	$0.1093	$0.1078	$0.1063	$0.1048	$0.1033	$0.1018	$0.1004
Parabolic-Trough Solar-P	$0.2269	$0.2237	$0.2206	$0.2173	$0.2142	$0.2112	$0.2082	$0.2052	$0.2023	$0.1994	$0.1965	$0.1937	$0.1909	$0.1882	$0.1856	$0.1829
Solar PV	$0.2799	$0.2751	$0.2704	$0.2658	$0.2613	$0.2568	$0.2525	$0.2482	$0.2439	$0.2398	$0.2357	$0.2317	$0.2277	$0.2238	$0.2200	$0.2163

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	$0.0384	$0.0385	$0.0387	$0.0389	$0.0391	$0.0394	$0.0397	$0.0400	$0.0404	$0.0408	$0.0413	$0.0419	$0.0424	$0.0429	$0.0435
Simple cycle oil (b)	$0.0874	$0.0888	$0.0902	$0.0917	$0.0931	$0.0946	$0.0962	$0.0977	$0.0993	$0.1010	$0.1026	$0.1043	$0.1060	$0.1078	$0.1096
Combined cycle gas	$0.0369	$0.0370	$0.0371	$0.0373	$0.0374	$0.0376	$0.0379	$0.0381	$0.0384	$0.0387	$0.0391	$0.0395	$0.0399	$0.0403	$0.0407
Combined cycle oil	$0.0702	$0.0712	$0.0722	$0.0733	$0.0743	$0.0754	$0.0765	$0.0776	$0.0787	$0.0799	$0.0811	$0.0823	$0.0835	$0.0847	$0.0860
Small hydro	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427	$0.0427
Biomass steam	$0.0547	$0.0549	$0.0551	$0.0553	$0.0555	$0.0558	$0.0561	$0.0565	$0.0569	$0.0574	$0.0580	$0.0585	$0.0591	$0.0597	$0.0603
Coal - Pressurized Fluidz	$0.0492	$0.0495	$0.0498	$0.0501	$0.0504	$0.0507	$0.0510	$0.0513	$0.0517	$0.0520	$0.0523	$0.0527	$0.0530	$0.0534	$0.0538
Biomass gasifier turbine	$0.0520	$0.0521	$0.0522	$0.0524	$0.0526	$0.0528	$0.0530	$0.0533	$0.0536	$0.0540	$0.0544	$0.0549	$0.0553	$0.0558	$0.0562
Gas cogen retrofits	$0.0418	$0.0418	$0.0417	$0.0417	$0.0417	$0.0417	$0.0417	$0.0416	$0.0416	$0.0416	$0.0415	$0.0415	$0.0414	$0.0414	$0.0413
Large Hydro	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590	$0.0590
Coal gasifier turbine	$0.0563	$0.0565	$0.0568	$0.0570	$0.0572	$0.0575	$0.0577	$0.0579	$0.0582	$0.0585	$0.0587	$0.0590	$0.0593	$0.0595	$0.0598
Waste fuels cogen	$0.0596	$0.0596	$0.0596	$0.0595	$0.0595	$0.0595	$0.0594	$0.0594	$0.0593	$0.0593	$0.0592	$0.0591	$0.0591	$0.0590	$0.0589
Wind Generators	$0.0631	$0.0626	$0.0622	$0.0618	$0.0614	$0.0610	$0.0606	$0.0602	$0.0598	$0.0594	$0.0590	$0.0586	$0.0582	$0.0578	$0.0574
Fuel Cell Cogenerator	$0.1035	$0.1028	$0.1022	$0.1016	$0.1010	$0.1005	$0.1000	$0.0995	$0.0990	$0.0986	$0.0982	$0.0978	$0.0974	$0.0971	$0.0967
Tidal Power	$0.0990	$0.0976	$0.0962	$0.0949	$0.0935	$0.0922	$0.0909	$0.0897	$0.0884	$0.0872	$0.0859	$0.0847	$0.0835	$0.0824	$0.0812
Parabolic-Trough Solar-P	$0.1803	$0.1777	$0.1752	$0.1726	$0.1702	$0.1678	$0.1654	$0.1630	$0.1607	$0.1584	$0.1561	$0.1539	$0.1517	$0.1495	$0.1474
Solar PV	$0.2126	$0.2090	$0.2054	$0.2019	$0.1985	$0.1951	$0.1918	$0.1885	$0.1853	$0.1821	$0.1790	$0.1760	$0.1730	$0.1700	$0.1671

3.2 Policy Scenarios

There are four modelling scenarios that were applied under CEMPA for this analysis.

1. Business-as-usual (BAU). This scenario is the base case under a competitive electricity market, that is the outcome that could be expected if no explicit policies to promote Sustainables are implemented. Under this scenario, the CEMPA Investment and Spot-Market Sub-Models are executed under the methodology outlined in Sections 2.3 and 2.4.
2. Sustainables Portfolio Standard (SPS). This scenario illustrates the forecasted outcome of a 10% Sustainables portfolio requirement, phased in over the next 30 years. Under this scenario, the CEMPA SPS Sub-Model is executed under the methodology outlined in Section 2.5.2.
3. A Non-Bypassable System Benefits Charge (SBC) with Sustainability Fund. This scenario illustrates the outcome of subsidizing Sustainables with a 3% charge on electricity sales, with the subsidy being divided among different classes of Sustainables according to a pre-determined allocation. Under this scenario, the CEMPA SBC Sub-Model is executed under the methodology outlined in Section 2.5.3.
4. A Revenue-neutral Environmental Adder (EA) Scenario, whereby a $20/tonne CO_2 charge is added to the variable costs of all technologies (representative of a broad range of environmental externalities), and the extra funds that are collected are redistributed to customers through reduced rates. Under this scenario, the CEMPA EA Sub-Model is executed under the methodology outlined in Section 2.5.4.

4. SIMULATION RESULTS

Based on the methodology presented in Chapter 2, and the model parameters described in Chapter 3, the results from the CEMPA model are presented in this chapter in a sequential fashion for British Columbia and Alberta over a simulation period of 30 years, from 1995 to 2025. The results which are presented include the following outputs.

Electricity Generation

- Total generation capacity (MW) by technology type.
- Annual energy generation (GWh) by technology type (in appendix).
- Investment in Sustainables Capacity.
- Generation by Sustainables.
- Generation Share by Sustainables.

Rates and Cost

- Peak wholesale electricity rates ($/GWh).
- Baseload wholesale electricity rates ($/GWh).
- Total expenditures on electricity (million $).

Emissions

- Carbon Dioxide Emissions (tonnes).

For each of the results, the specific scenario associated with the output is also specified. The scenarios are distinguished by an acronym. Details on the scenarios are included in Section 3.2 and Chapter 2.

- Business-as-usual - BAU.
- Sustainables Portfolio Standard (Sustain. Port. Stand.) - SPS.
- Non-Bypassable System Benefits Charge with Sustainability Fund (Sys. Benefits Charge) - SBC.
- Revenue-neutral Environmental Adder (Environmental Adders) - EA.

4.1 British Columbia Model

Table 4.1 outlines the market penetration of technologies under the four scenarios. The full data is contained in Appendix B in Tables B.1 through B.4.

Under the BAU scenario, other than 300MW of the most cost-effective small hydro, the entire remainder of new technologies is met by natural gas technologies, with combined-cycle turbines dominating, followed by simple-cycle turbines for peaking purposes and gas cogeneration retrofits for baseload operation. Under the SPS scenario, Sustainables take a greater market share, with less investment in natural gas technologies than under the BAU scenario. Biomass technologies are the predominant Sustainables developed as they are the most cost-effective after Optimal Small Hydro resources are used-up. Under the SBC scenario, a diversity of Sustainables are developed, including wind, tidal, solar, hydro and biomass technologies. The EA scenario shows an outcome similar to that of the SPS scenario, again only the most cost-effective Sustainables being developed.

Table 4.1 - Market Penetration (MW of capacity) of Technologies in 2025 - B.C.

Tech. Name	BAU	SPS	SBC	EA
Small Hydro	300	300	353	300
S.C. Gas	4583	4517	4583	3682
C.C. Gas	6552	5171	6355	6336
Gas Cogen.	1000	1000	1000	1000
Biomass	0	1444	67	1038
Other Sustain.	0	0	77	0
Existing Hydro	8301	8301	8301	8301
Existing Gas	763	763	763	763
Existing Biomass	394	394	394	394

The expected energy production in GWh of various technologies under the BAU scenario is outlined in Table B.5 of Appendix B. This is also reflective of operations in other scenarios except for the EA which maximizes the operation of non-carbon based resources. Hydroelectricity dominates the low cost generation with variable costs at 1cent/kWh, and other technologies are used during higher demand periods. Combined-cycle gas plants dominate new technologies, producing 43,817 GWh in 2025. Gas cogeneration technologies operate at nearly full capacity (6700 GWh in 2025) because of their low operating costs. Simple-cycle gas turbines, are used predominantly as peaking plants (9057 GWh in 2025), as they have higher fuel costs than both combined cycle plants and cogeneration units. These results also indicate that existing natural gas facilities (Burrard Thermal) are run at well below capacity under a competitive market. The annual production capability of those technologies is about 5681 GWh in 2025, and yet the plants only produced 355 GWh in that year (6% of the capability). Their variable costs are higher than those of hydroelectricity or new technologies, so they are used predominantly as peaking plants under competitive markets.

The EA scenario generating statistics, listed in Table B.6 (Appendix B), illustrate a 36% reduction in the operation of simple cycle gas turbines, a smaller reduction in the operation of combined cycle gas turbines, with all of the shortfall being met by biomass technologies. This is due to the fact that net carbon dioxide emissions from biomass are zero, and therefore their operating costs remain unaffected by the "environmental adder".

Figure 4.1 illustrates the percentage share of generation met from Sustainables. Figure B.1 in the Appendix illustrates the market penetration of Sustainables in MW and Figure B.2 illustrates the annual electricity generation from Sustainables in GWh's. Under the BAU case, the level of investment in Sustainables is very limited, with an exception of a small amount of small hydro development (300 MW). This is brought on line all at once, enabled by the introduction of competitive markets. The investment in Sustainables is highest under the SPS scenario, at 1750 MW in 2025. In-turn, their generation accounts for about 11% of the total generation in the year 2025. The EA mechanism fosters the development of 1340 MW of Sustainables capacity by 2025, or about 8% of the generation. Finally, the SBC mechanism fosters the development of about 497 MW of Sustainables capacity, resulting in a generation share of only 3%, compared with about 1.5% under the BAU scenario. The factors leading to these differences are discussed in Chapter 5.

Figure 4.1 - Generation Share by Sustainables (percent)- all scenarios

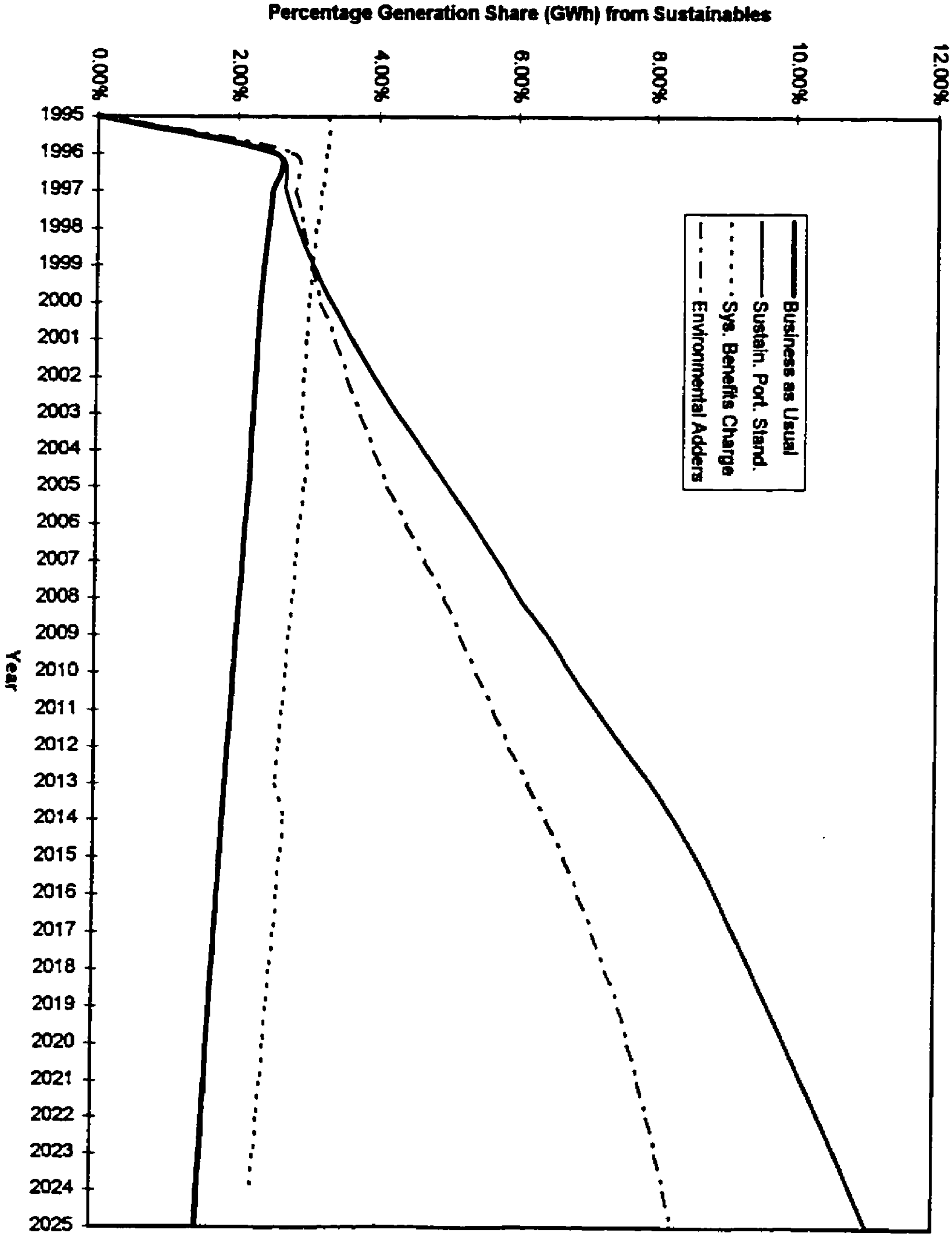


Table 4.2 illustrates the wholesale spot price of electricity in the years 1995 and 2025 for each of the scenarios. The wholesale spot price (the PSP) includes capacity adders, transmission expenses, and administrative charges. CEMPA characterizes the spot electricity price for 24 different positions on the *load duration curve*, with the first 5-10 representing *peaking* periods, and the remainder being *shoulder* and *baseload* conditions. The "peaking" spot price listed is representative of those hours of the year where the demand for electricity is between 75% and 77% of the peak demand for the year. This is representative of 365 non-consecutive hours of the year. The "baseload" spot price is representative of those periods were demand is between 53 % and 56% of the peak. The data are also included in Appendix B, Figures B.3 and B.4.

Table 4.2 - Peaking and Baseload Wholesale Spot Prices of Electricity (PSP) (1995$/MWh)

Scenario	1995 Peak	2025 Peak	1995 Baseload	2025 Baseload
BAU	$29	$36	$16	$29
SPS	$29	$36	$16	$29
SBC	$30	$37	$17	$30
EA	$39	$43	$16	$34

Under all conditions, the spot price under the BAU scenario is the same as that under the SPS. The SBC scenario includes a $1 / MWh price premium to fund the subsidy for Sustainables. The EA spot prices are higher because of the inclusion of an "environmental adder" on all spot market transactions, minus the refund to customers. However, the refund is not sufficient to completely counteract the cost of the adder to each generator's operation. Thus, a price premium of up to $10 is paid. Figure B.3 illustrates a flat spot price profile over the simulation period. In contrast, Figure B.4 indicates a sudden jump in the spot price around 2005, due to the retirement of existing low cost generation facilities (see assumptions in Chapter 3, Table 3.4) that are met with more expensive combined-cycle gas turbines. Most consumers will not feel this price jump directly, as their purchase price would reflect an average of spot prices.

Table 4.3 lists the forecasted cost of electricity in 2025, equivalent to the *levelized-cost* of production from each technology, times the actual energy it produces over the year. This information is also illustrated in Figure B.5 in Appendix B. The wires charge associated with the

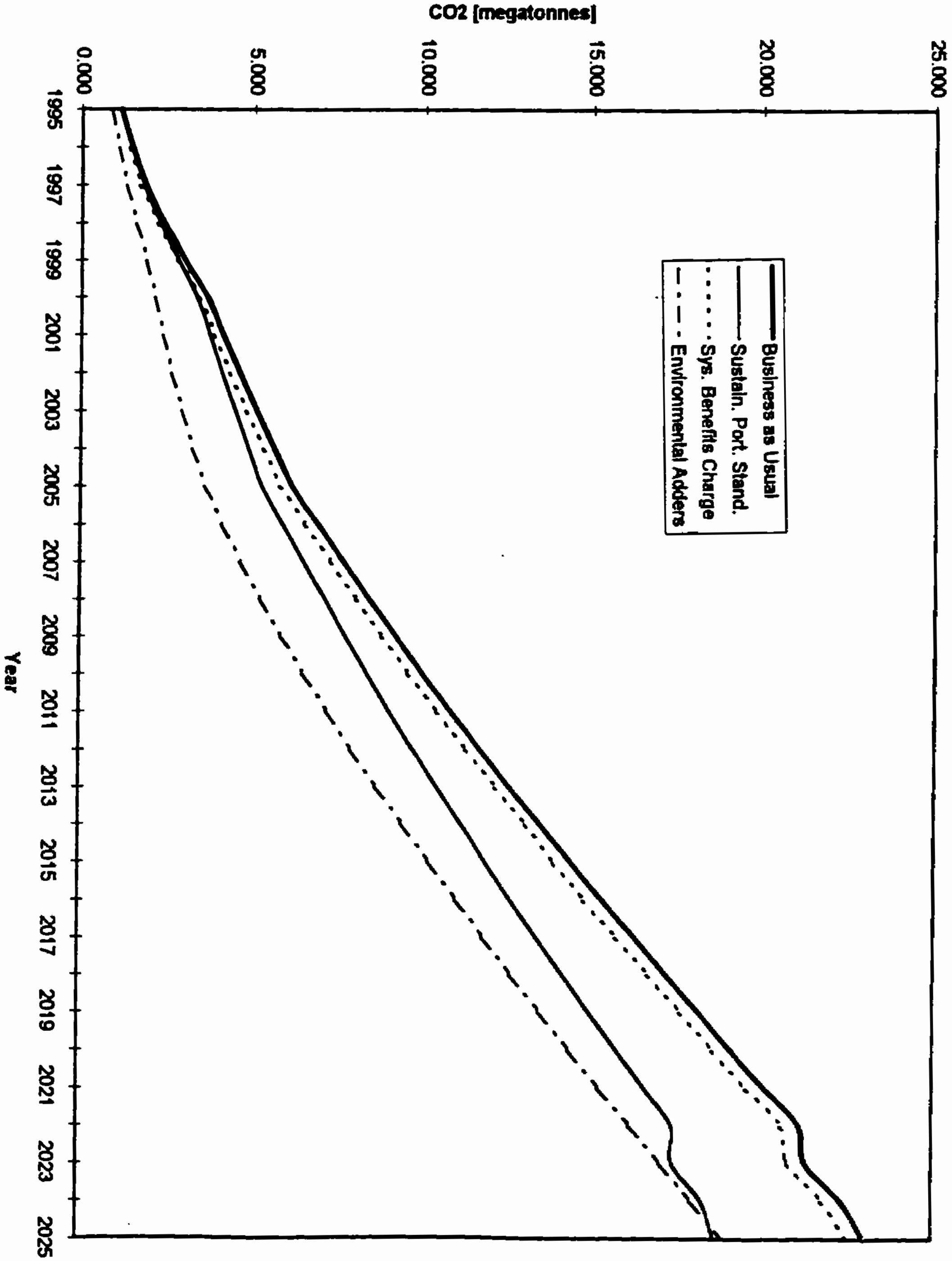
SBC scenario is not added to this cost figure because that money is directed towards the capital costs of Sustainables which is reflected in the *levelized-cost*. Also, the environmental charge associated with the EA scenario is not added, because it is refunded to customers. Chapter 5 includes an illustration of the incremental costs of adopting a policy measure over and above the costs of the BAU.

Table 4.3 - Cost of Electricity in the Year 2025 (Millon $1995)

Scenario	Cost (Millions of Dollars)
BAU	4,217
SPS	4,348
SBC	4,240
EA	4,307

Carbon dioxide emissions in B.C. are illustrated in Figure 4.2. They rise sharply under the BAU scenario, from about 1Mt in 1995 to 23Mt in 2025. This is due to significant investment in new natural gas technologies and retirement of existing hydroelectric facilities. Emissions are 3.5 MT less (in 2010) with the EA scenario, and about 1.7MT and 0.5MT less under the SPS and SBC scenarios respectively. In the long term, the SPS is the optimal scenario for minimizing CO_2 emissions, with 4.4MT less emissions in 2025 than under the BAU.

Figure 4.2 - Carbon Dioxide Emissions (tonnes) - all scenarios



4.2 Alberta Model

Table 4.4 outlines the market penetration of technologies under the four scenarios. The full data is contained in Appendix C in Tables C.1 through C.4.

Under the BAU scenario, other than 200MW of the most cost-effective small hydro, the entire remainder of new technologies is met by natural gas technologies, with combined-cycle turbines dominating, followed by simple-cycle and gas cogeneration retrofit technologies. Under the SPS scenario, Sustainables take a greater market share. Biomass technologies are the predominant Sustainables developed as they are the most cost-effective after Small Hydro resources are used-up. However, in 2022, wind technologies are developed, reaching 149 MW by 2025. Under the SBC scenario, a diversity of Sustainables are developed, including wind, biomass, solar and small hydro. The EA scenario shows an outcome similar to that of the SPS scenario, again only the most cost-effective Sustainables being developed.

Existing technologies include coal, natural gas, hydro and biomass. The coal resources, equivalent to about 5850 MW in 1996, are retired at a rate of 2.5% / year, thus reducing the capacity significantly by the end of the simulation.

Table 4.4 - Market Penetration (MW of capacity) of Technologies in 2025 - Alberta.

Tech. Name	BAU	SPS	SBC	EA
Small Hydro	200	200	200	200
S.C. Gas	4034	4034	4034	2931
C.C. Gas	6001	4870	5851	6205
Gas Cogen.	500	500	500	500
Biomass	0	1000	69	867
Other Sustain.	0	149 (wind)	81 (wind and PV)	30 (wind)
Existing Hydro	609	609	609	609
Existing Gas	859	859	859	859
Existing Biomass	95	95	95	95
Existing Coal	2935	2935	2935	2935

The expected GWh production of various technologies under the BAU scenario is illustrated in Table C.5 (Appendix C, two parts). Coal dominates the low cost generation (21,857 GWh in 2025) with variable costs at 1.5 cents/kWh. New combined cycle gas turbines make up the remaining *baseload* and *shoulder* loads (40,859 GWh in 2025), and new simple-cycle gas technologies supplement the supply for *peak* demand (6561 GWh in 2025). Gas cogeneration technologies operate at nearly full capacity (3351 GWh in 2025) because of their low operating costs. Existing gas and biomass technologies operate below capacity because of high operating costs relative to new combined-cycle gas turbines. Existing hydroelectric resources operate at full capacity because of their low operating costs, generating 3200 GWh in 2025.

The EA scenario generating statistics, listed in Table C.6 (Appendix C), illustrate a 53% reduction in the operation of simple cycle gas turbines, a 38% reduction in the operation of coal facilities, and a 10% reduction in the operation of combined cycle gas turbines. The shortfall is mostly met by biomass technologies. This is due to the fact that net carbon dioxide emissions from biomass, and therefore their operating costs remain unaffected by the "environmental adder".

Figure 4.3 illustrates the percentage share of generation met from Sustainables. Figure C.1 in the Appendix illustrates the market penetration of Sustainables in MW and Figure C.2 illustrates the annual electricity generation from Sustainables in GWh's. Under the BAU case, the level of investment in Sustainables is very limited, with an exception of a small amount of small hydro development (200 MW). The investment in Sustainables is highest under the SPS scenario, at 1349 MW in 2025. In-turn, their generation accounts for about 11% of the total generation in the year 2025. The EA mechanism fosters the development of 1098 MW of Sustainables capacity by 2025, about 10% of the generation. Finally, the SBC mechanism fosters the development of about 350 MW of Sustainables capacity, resulting in a generation share of only 3%, compared with about 1.5% under the BAU scenario.

Figure 4.3 - Generation Share by Sustainables (percent)- all scenarios

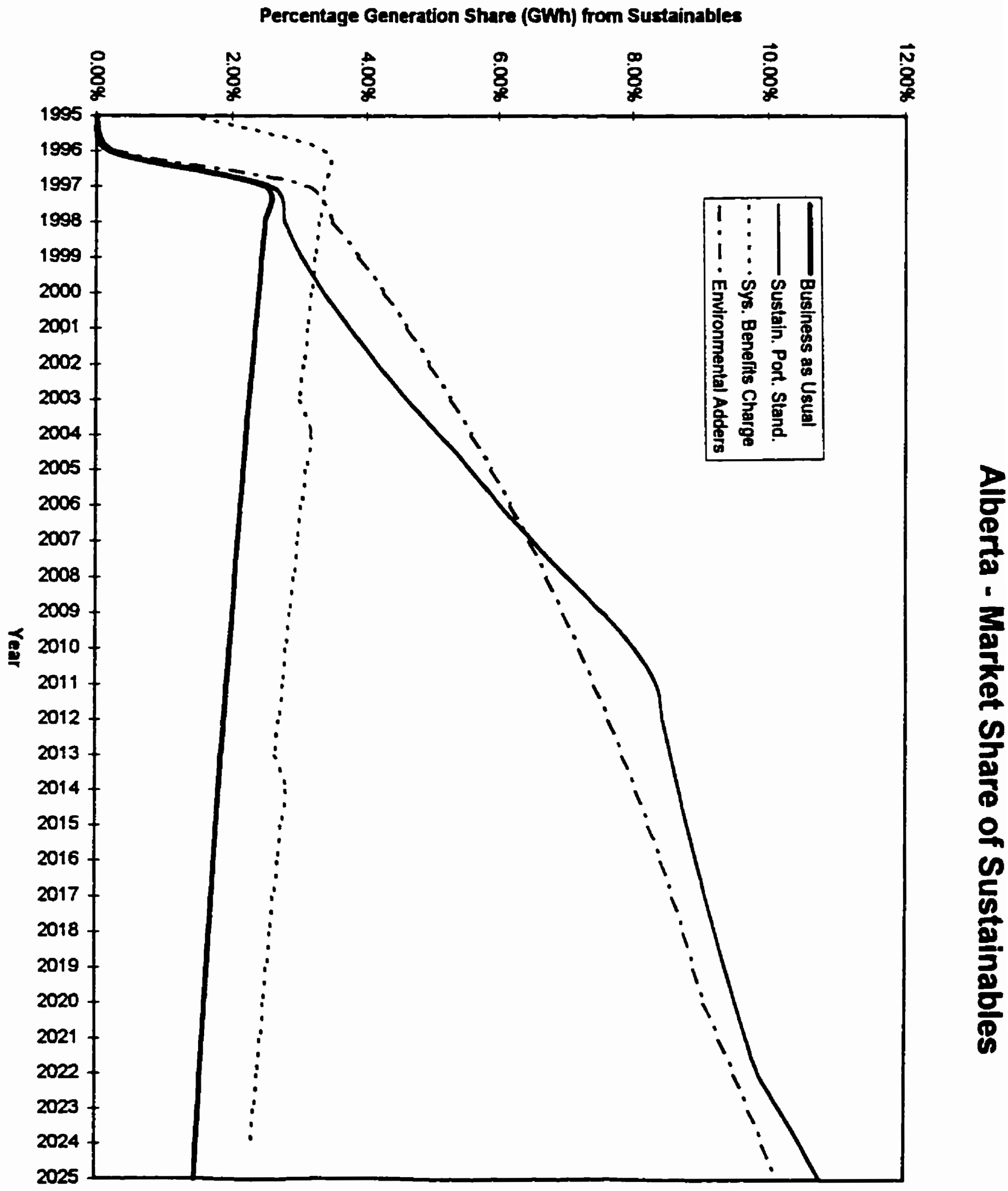


Table 4.5 illustrates the wholesale spot price of electricity in the years 1995 and 2025 for each of the scenarios. The data are also included in Appendix C, Figures C.3 and C.4.

Table 4.5 - Peaking and Baseload Wholesale Spot Prices of Electricity (PSP) (1995$/MWh)

Scenario	1995 Peak	2025 Peak	1995 Baseload	2025 Baseload
BAU	$28	$34	$22	$28
SPS	$28	$34	$22	$28
SBC	$29	$35	$23	$29
EA	$24	$39	$24	$36

Under all conditions, the spot price under the BAU scenario is the same as that under the SPS. The SBC scenario includes a $1 / MWh price premium to fund the subsidy for Sustainables. The EA spot prices are higher because of the inclusion of an "environmental adder" on all spot market transactions, minus the refund to customers. This price premium increases over time as the demand for electricity increases, and more carbon intensive resources are required to meet the demand. In 2025, the spot price under the EA scenario exceeds the spot price under BAU by $5 or $6 per megawatt-hour.

An anomaly is evident for the peak wholesale price in 1995 for the EA scenario, indicating that the EA is cheaper than the BAU, extending through to the year 2003 (see Figure C.3). In this case, the consumer rebate against the PSP, equivalent to the total financial value of the "environmental adders", exceeds the impact of the policy on the SMP, or the cost of operating the marginal resource.

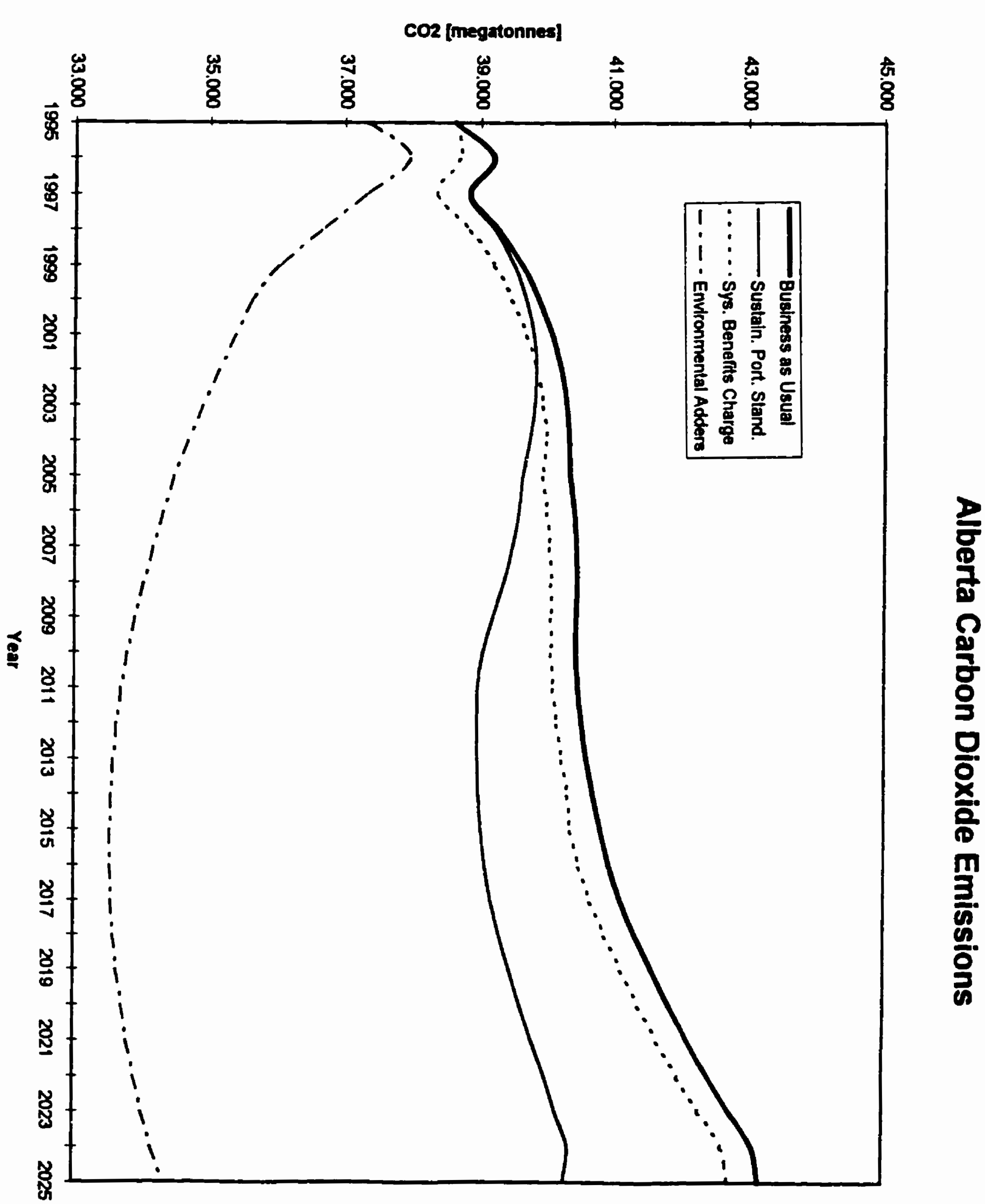
Table 4.6 lists the forecasted cost of electricity in 2025, equivalent to the *levelized-cost* of production from each technology, times the actual energy it produces over the year. This information is also illustrated in Figure C.5 in Appendix C. The wires charge associated with the SBC scenario is not added to this cost figure because that money is directed towards the capital costs of Sustainables which is reflected in the *levelized-cost*. Also, the environmental charge associated with the EA scenario is not added, because it is refunded to customers. Chapter 5 includes an illustration of the incremental costs of adopting a policy measure compared with the BAU.

Table 4.6 - Cost of Electricity in the Year 2025 (Million $1995)

Scenario	Cost (Millions of Dollars)
BAU	2,919
SPS	3,027
SBC	2,931
EA	3,119

Carbon dioxide emissions in B.C. are illustrated in Figure 4.4. They rise moderately under the BAU scenario in early years, are flat in mid-years, and rise in later years, from about 39Mt in 1995 to 40.5MT in 2010 and 43Mt in 2025. This is due to significant investment in new natural gas technologies and retirement of existing coal facilities. Emissions are 0.5 Mt less with the SBC scenario, 3Mt less with the SPS, and almost 9Mt less with the EA scenario. In the long term, the SPS stabilizes emissions, while the EA scenario significantly reduces them.

Figure 4.4 - Carbon Dioxide Emissions (tonnes) - all scenarios



5. SIMULATION ANALYSIS AND EVALUATION

The purpose of this study is to compare the level of development of Sustainables under different electricity market policy scenarios, each including full *retail competition*. The scenarios include: Business as Usual (BAU), Sustainables Portfolio Standard (SPS), System Benefits Charge (SBC), and Revenue-neutral Environmental Adders (EA). The first scenario is the expected outcome without any explicit policy to foster Sustainables, which is currently the case in both Alberta and B.C. The other three scenarios encompass specific policy objectives to foster Sustainables.

This chapter expands on the results provided in Chapter 4 by analyzing them according to specific evaluative criteria or policy objectives. The criteria allow for an analysis of the merits of the three sustainability policies relative to the BAU scenario. The results of both the Alberta and B.C. models are merged in this chapter.

1. Maximization of the market penetration of Sustainables in terms of investment and operation (MW installed and GWh per year operation).
2. Maximization of a diversity of Sustainables (number of technologies fostered).
3. Reduction of unit costs of Sustainables ($/kWh).
4. Minimization of financial impacts - peak and baseload wholesale electricity rates ($/GWh) and total expenditure on electricity (million $).
5. Minimization of the annual carbon dioxide emission abatement cost ($ / tonne CO_2 reduced).
6. Administrative and operational simplicity.

The significance of each evaluative crieterion is outlined in Section 1.1.

An important distinction in this analysis is to separate those impacts related to the choice of policy parameters from those impacts which result from specific merits of each policy. For example, the market penetration of Sustainables can be influenced by the level of portfolio requirement under SPS, the size of the environmental charge under EA, or the quantity of the wires charge under the SBC. In order to assess the cost-effectiveness of the policies in their support for Sustainables, those parameters should be adjusted so that the market penetration of Sustainables is approximately the same for all policies, and then a relative financial comparison is possible. On the other hand, if the analysis focuses on issues such as the timing of development of Sustainables, administrative and political feasibility, the diversity of Sustainables developed, or impacts on the reduction of Sustainables' unit cost, then this is not necessary.

In order to capture the different analysis priorities, this chapter is divided into three sections.

First, in Section 5.1 the policies presented in Chapters 2 through 4 are analyzed according to the six criteria listed above. These policies were designed in such a manner as to be consistent with what other jurisdictions are proposing, so as to be political feasible.

Second, section 5.2 provides an analysis of the cost-effectiveness of the policies to foster Sustainables. In this case, each policy was adjusted to result in approximately the same market penetration of Sustainables. The size of the SBC and the EA were increased from those levels presented in previous chapters so that each results in a similar market share of Sustainables as was the case for the SPS scenario. The results from these simulation runs are not presented elsewhere in this study because they diverge from the magnitude of mechanisms that have been proposed or implemented in other jurisdictions.

Section 5.3 provides an overview of the policy analysis in the form of a summary matrix on the extent to which each of the policy mechanisms satisfy the six evaluative criteria.

Section 5.4 includes a general discussion on uncertainty and the accuracy of the CEMPA model.

5.1 Analysis of Policy Mechanisms

In this section, each of the policy mechanisms presented in Chapters 2 through 4 is analyzed according to the six evaluative criteria listed above. These policies were designed in a manner that is comparable with policies implemented or proposed in other jurisdictions.

The size of the SPS portfolio standard is set at 10% by 2025, the magnitude of the SBC is 3% of the wholesale price (PSP), and the size of the carbon tax for the EA is $20/tonne. This results in different levels of financial support for Sustainables and hence a different market penetration for Sustainables.

5.1.1 Market Penetration of Sustainables

Under the business-as-usual (BAU) scenario, the market penetration of Sustainables remains flat in both B.C. and Alberta after all of the low-cost small hydro resources are tapped. The market penetration of Sustainables under all scenarios for both provinces is presented in Table 5.1. The SPS policy results in the highest market penetration of Sustainables, reaching 1750 MW and 1350 MW by the year 2025 in B.C. and Alberta respectively. The other policies (SBC and EA) could also be designed in a manner which maximizes market penetration per unit cost and those results are presented in Section 5.2.

Table 5.1 - Market Penetration of Sustainables (MW) in 2025

Scenario	B.C. Market Penetration	Alberta Market Penetration
BAU	300 MW	200 MW
SPS	1750 MW	1350 MW
SBC	500 MW	350 MW
EA	1340 MW	1100 MW

The energy production from Sustainables (see Figures B.2 and C.2), in GWh production per year, has similar results, with the SPS and EA maximizing production.

5.1.2 Diversity of Sustainables Developed

The issue of technological diversity is illustrated in Table 5.2, showing how many different types of Sustainables are developed and operated under each policy mechanism. The SBC scenario achieves the highest diversity for Sustainables because it was designed in a manner which prioritizes diversity.

Table 5.2 - Capacity of New Sustainables Developed (MW) in 2025

Tech. Type	SPS B.C.	SPS Alberta	SBC B.C.	SBC Alberta	EA B.C.	EA Alberta
Biomass	1444	1000	67	69	1037	868
Small Hydro	300	200	353.4	200	300	200
Wind	2.51	149	44.2	73	0	30
SolarPV	0	0	6.61	8.04	0	0
Tidal	0	0	25.82	0	0	0

5.1.3 Reduction of Unit Costs of Sustainables

Tables 5.3 and 5.4 outline how the *levelized-costs* of those technologies are reduced as a result of their increased participation in the market. Only the wind, solar PV and tidal technologies demonstrate substantial cost reductions because they are relatively new technologies. Large gains in unit cost reduction occur under those policies which result in some amount of market penetration of the technology whereby economies of manufacture are reached. Only the SBC policy fully stimulates a diversity of Sustainables, and hence it results in the highest unit cost reduction for emerging technologies. In contrast, the SPS and EA mechanisms tend to foster low-cost biomass technologies which do not realize economies of manufacture due to the technological stasis with boiler technologies (See Section 2.3.5.4).

An anomaly in the results from the Alberta model indicates that the unit cost reduction under the SPS scenario is less than that under the SBC, even though the SPS results in a higher market penetration of Sustainables by 2025 than the SBC. This is due to the fact that the market penetration under the SPS is in the last five years of the simulation, while those under the SBC occur over the entire duration of the simulation, realizing significant unit cost reductions on three occasions over the 30 year simulation period.

Table 5.3 - Reduction in the Unit Cost of Sustainables ($1995/kWh) - British Columbia

Tech. Type	SPS	1995	2025	SBC	1995	2025	EA	1995	2025
Biomass		0.0598 (cogen)	0.0587		0.0598 (cogen)	0.0587		0.0598 (cogen)	0.0587
Small Hydro		0.043 - 0.068	0.043 - 0.068		0.043 - 0.068	0.043 - 0.068		0.043 - 0.068	0.043 - 0.068
Wind		0.0814	0.0666		0.0814	0.0492		0.0814	0.0666
SolarPV		0.3498	0.2088		0.3498	0.1426		0.3498	0.2088
Tidal		0.1241	0.0812		0.1241	0.0483		0.1241	0.0812

Table 5.4 - Reduction in the Unit Cost of Sustainables ($1995/kWh) - Alberta

Tech. Type	SPS	1995	2025	SBC	1995	2025	EA	1995	2025
Biomass		0.0599 (cogen)	0.0589		0.0599 (cogen)	0.0589		0.0599 (cogen)	0.0589
Small Hydro		0.043	0.043		0.043	0.043		0.043	0.043
Wind		0.0702	0.0448		0.0702	0.0409		0.0702	0.0518
SolarPV		0.2799	0.1671		0.2799	0.1111		0.2799	0.1671

5.1.4 Financial Impacts - Total Expenditure on Electricity Sales and Impacts on Spot Price

Figures 5.1 and 5.2 illustrate the incremental costs associated with the adoption of different policy scenarios relative to the BAU scenario, in essence the cost premium required to implement a policy. In Alberta, the EA mechanism is the most costly because of the large installed capacity of carbon-intensive coal resources which are offset with more expensive natural gas and biomass technologies. In B.C., the SPS policy has the highest cost premium. In both cases, the expensive policy mechanism also results in a high market penetration of Sustainables and reduction in CO_2 emissions. An analysis of the cost-effectiveness of each policy in fostering Sustainables and reducing CO_2 emissions is presented in Section 5.2.

The SPS demonstrates a gradual increase in the cost premium, while the SBC applies the majority of costs in the first year, with a reduction in costs in 2020 after the original 25-year contract with the Sustainables facilities is expired and they are forced to compete at the market rate. The EA mechanism causes rapid cost increases due to the rapid development of less carbon intensive resources. In B.C., the rapid cost increases subside after the year 2000, while in Alberta, costs increase steadily over the entire simulation period.

Spot electricity prices are expected to climb slightly over the years, with sharper increases in *baseload* prices as existing low cost hydroelectric and coal generation sources are retired. The data are illustrated in Figures B.3, B.4 and C.3 and C.4 in the appendices. The difference in prices between the BAU and SPS are minor, due to the fact that sustainable technologies have relatively low operating costs and zero fuels costs, allowing them to make low "offers" in to the power pool provided their fixed costs are covered through external contracts. The wholesale electricity price under the SBC scenario shows a small premium, due to the fact that a 3% wires charge is being added to customers' bills. The EA scenario indicates a larger premium, resulting from changes in the generation mix and from the environmental charge, even though the charge is redistributed to customers through reduced rates. This premium is higher under *peaking* conditions than *baseload* conditions because less efficient natural gas and coal plants are operated to meet the peak load with resulting increases in emissions and the value of the environmental charge.

Figure 5.1 - Policy Cost Premium over BAU (Million $1995) - British Columbia

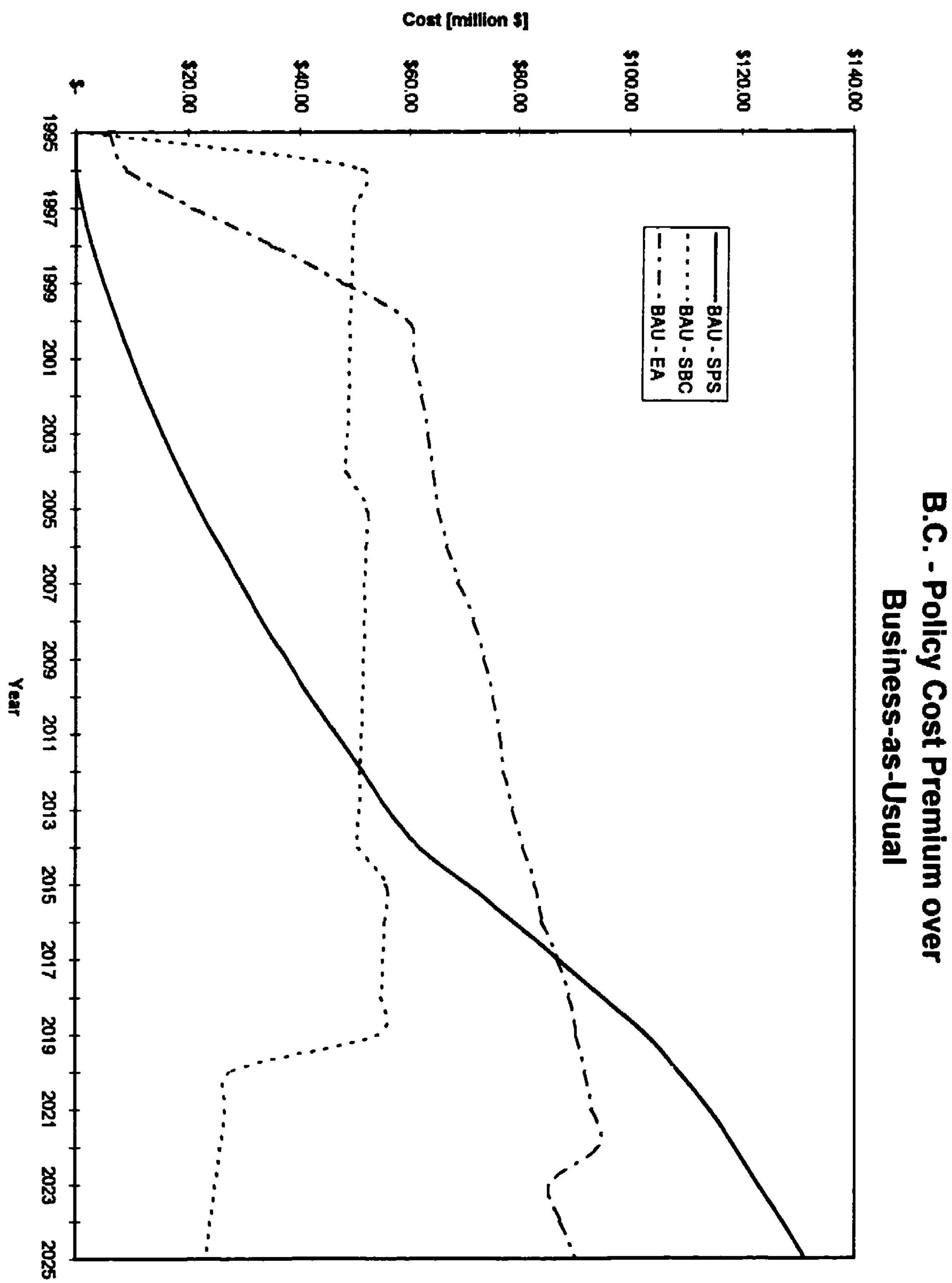
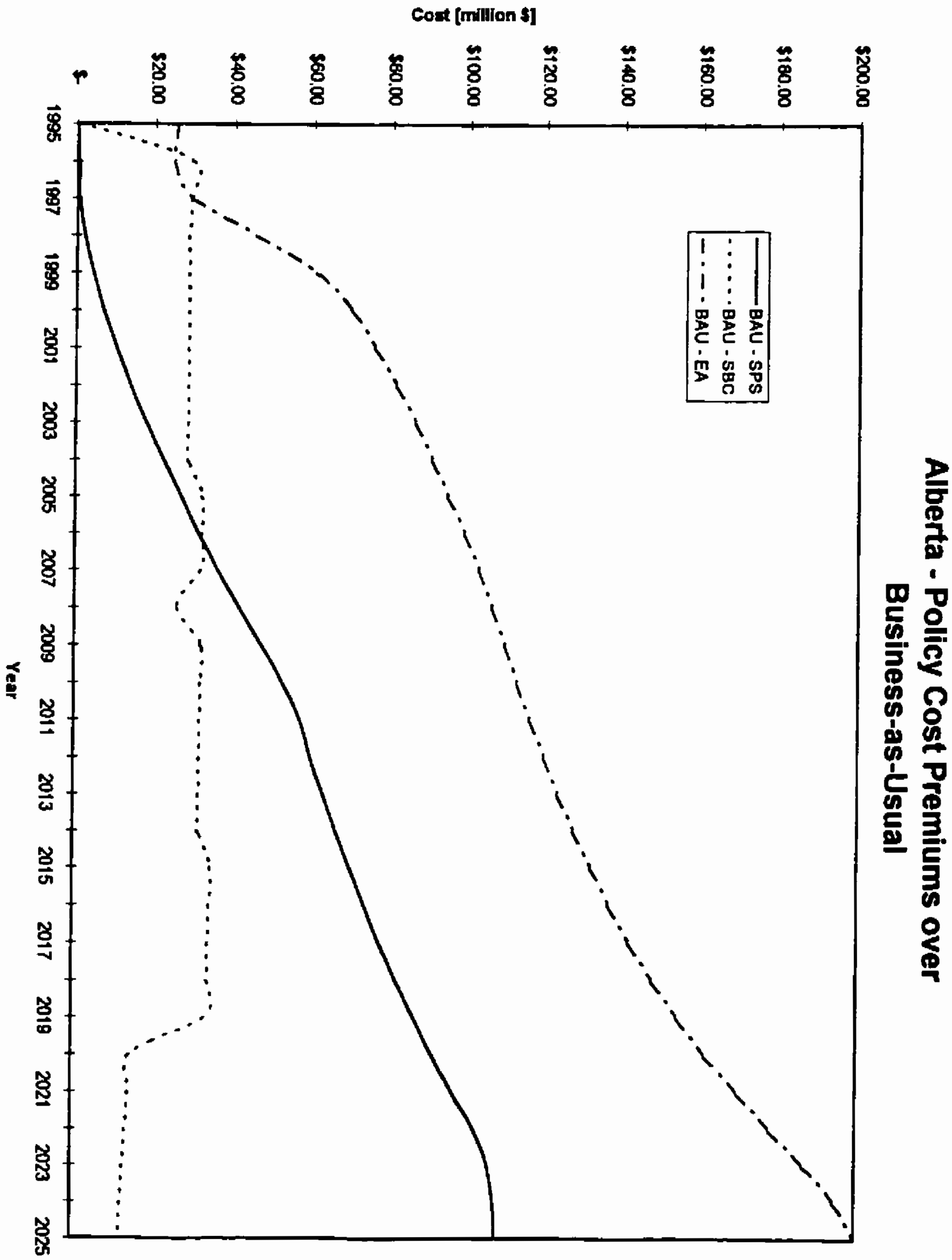


Figure 5.2 - Policy Cost Premium Over BAU (Million $1995) - Alberta



5.1.5 Annual Carbon Dioxide Emissions and Abatement Costs

CO_2 emissions are expected to increase dramatically in B.C. under BAU (Figure 4.2) because of increased growth in natural gas generation, and a strong increase in demand for electricity in the province. Emissions are expected to more-or-less stabilize in Alberta (Figure 4.4) due to declining coal consumption in favor of natural gas, despite a steady increase in demand for electricity in the province. The EA scenario demonstrates sharp reductions in CO_2 emissions in Alberta through reduced operation of coal facilities and the increased market share of gas cogenerators, combined cycle gas turbines, biomass technologies, and small hydro technologies, which are developed at a faster rate under this scenario than under the BAU. The results of this scenario indicate a possible early retirement of some coal capacity facilities, as their production (GWh) is reduced by 11% in the year 2000, and 22.5% in 2010, relative to the BAU scenario.

The key indicator for assessing the economic efficiency of CO_2 emission reduction is the emission abatement cost curve that is the cost associated with the adoption of a policy mechanism relative to BAU, and the subsequent emissions reduction that follows from the adoption of that mechanism. A detailed analysis of the abatement cost will be provided in Section 5.2 where those policies are adjusted in order to result in approximately the same market penetration of Sustainables by the year 2025.

5.1.6 Administrative and Operational Simplicity

The SPS mechanism puts the onus of developing Sustainables on the electricity retailer without the need for extensive administration. The requirement for purchasing Sustainables is imbedded in the resource acquisition decisions of the electricity retailer. One challenge will be for the electricity marketer to predict how much power will need to be purchased from Sustainables over the year, given that load forecasts are not always accurate. Presumably, the SPS mechanism would have some flexibility for those marketers who underpredict demand, and hence underpredict the amount of Sustainables generation that is required. Enforcement of the requirements is straightforward because all electricity sales are transferred through the *Power Pool* and records are kept of the amount of generation from each technology type. Fines might be established to penalize those entities which consistently underproduce their requirement.

The SBC mechanism is also administratively simple to set-up, because the wires charge is added to customer bills in a similar fashion to a tax, and the fund is distributed according to the contracted price and the spot price of electricity. It does however require that an external organization administer the funds. Enforcement of the operation of Sustainables facilities is not necessary because they only get paid when they operate.

The EA mechanism is complex from an administrative or operational perspective, as every hourly transaction in the *Power Pool* for every generator includes an environmental charge. It is possible to automate the operation of the EA mechanism within the *Power Pool* computer system, but each new market entrant needs to be assessed in order to determine the "environmental adder" for that plant. Enforcement is automatic, within the operations of the *Power Pool*.

In summary, under the SPS policy, administrators only need to characterize technologies on a generic basis, as compliant or not compliant within the definition of Sustainables. In contrast, under the EA, each facility needs to be characterized and assessed a charge. The SBC requires an administrative body to manage the funds collected from the wires charge, and coordinate

5.2 Cost Effectiveness of Policies for Fostering Sustainables

This section provides an analysis of the cost-effectiveness of the policies to foster Sustainables. In order to undertake this analysis, each policy was adjusted to result in approximately the same installed capacity of Sustainables. The assessment of the cost-effectiveness of policy options is made using the capacity of Sustainables as the unit of comparison. The capacity of Sustainables developed must be made consistent among all policies as they may have different cost impacts associated with different levels of support for Sustainables. Also, in order to compare the policies on their financial merit, they should have the same policy design criteria. In previous chapters the design of the SBC mechanism prioritized technological diversity, while the SPS and EA mechanisms prioritized cost-effectiveness.

The parameters driving the EA and SBC scenarios were modified such that their outcome resulted in the same market penetration of Sustainables as the SPS scenario, approximately 10% of the capacity by the year 2025. Also, the technology mix for the SBC mechanism was changed to adopt only the most cost-effective technologies and not focus on fostering a diversity of technologies.

A direct extension of the capacity of Sustainables is the annual energy production from Sustainables and the CO_2 emissions reduced as a result of the deployment of Sustainables. The cost-effectiveness of a policy to reduce CO_2 emissions is also included in this section.

The results from these simulation runs are not presented elsewhere in this study because they diverge from the magnitude of mechanisms that have been proposed or implemented in other jurisdictions. Thus, there is a tradeoff with the design of the policies between their cost-effectiveness and political feasibility.

5.2.1 Analysis of Scenario Parameters Adopted

As previously mentioned, the SBC and EA mechanisms were modified so that they result in the same installed capacity of Sustainables by 2025 as the SPS policy. Table 5.5 summarizes the policy parameters employed for this analysis.

Table 5.5 - Policy Parameters Employed for Cost-Effectiveness Analysis

Policy (and parameter name)	Parameter Value	B.C. Capacity of new Sustainables in 2025 (megawatts)	Alberta Capacity of new Sustainables in 2025 (megawatts)
SPS (portfolio requirement)	10% by 2025	1,746	1,349
SBC (wires charge)	10% of the PSP	1,755	1,114
EA (CO_2 tax)	$25 / tonne	1,596	1,312

The size of the System Benefits Charge, included on all wholesale purchases, was increased from 3% to 10%, the former being the value employed in the previous chapters. Also, the payout from the SBC fund to Sustainables was changed so that only the most cost-effective Sustainables are supported. In previous chapters, the policy supported solar, wind, tidal, small hydro and biomass technologies, whereas for this analysis, biomass was the predominant technology supported. Table 5.6 lists the revised technology portfolio.

Table 5.6 - Technology Portfolio for the Cost-Effective SBC Scenario

Technology Type	Share of Capacity in B.C.	Share of Capacity in Alberta
Biomass Gasifier Turbine	50%	50%
Wastefuel Cogeneration -biomass	25%	25%
Wind Farms	15%	25%
Small Hydro (high cost)	10%	0%

The EA mechanism was adjusted by increasing the CO_2 tax to a level that would raise the installed capacity of Sustainables to about 1,750 MW in B.C., and 1,350 MW in Alberta, to match the 10% SPS mechanism. Several different tax levels were simulated ($25,$30,$35,$40) and the results were varied. The $25/tonne level was selected because it resulted in the installed capacity of Sustainables reaching the target level in Alberta. In B.C., a $40/tonne CO_2 tax is necessary to raise the installed capacity of Sustainables to the 1750 MW level. By raising the tax to a higher level in Alberta, for example to the $30/tonne level, the installed capacity of Sustainables far exceeds the target value, resulting in 2,316 MW being developed.

5.2.2 Market Penetration of Sustainables

The market penetration of Sustainables in terms of installed capacity is approximately equal for all three policies, as their parameters were selected to achieve that objective. The values are shown in Figures 5.3 and 5.4.

Variation of the parameter for the EA mechanism (CO_2 tax in $/tonne) has some interesting results related to the installed capacity of Sustainables. As the value of the tax was raised from $20 / tonne (the value employed in previous chapters) to $25 / tonne, the installed capacity of Sustainables went up from 1337 MW to 1596 MW in B.C.. However, when the tax was raised to $30 / tonne, the installed capacity of Sustainables stayed approximately constant, reaching 1592 MW, showing a non-linearity between the level of CO_2 tax and the installed capacity of Sustainables. This is due to the fact that the additional $5 / tonne tax (from $25 to $30) does not sufficiently cover the financial premium required to bring on an additional share of Sustainables capacity, given that the most cost-effective Sustainables were already exhausted. When the tax was raised to $40 / tonne, the capacity exceeded the 1750 MW target.

Figures 5.3 through 5.7 illustrate the installed capacity and market share of Sustainables in B.C. and Alberta under the revised scenarios. The installed capacities reach about 1750 MW by 2025 for B.C., and 1350 MW for Alberta. The key difference between the scenarios is the timing of development. Both the SPS and EA scenarios result in a gradual increase in the market share of Sustainables. In fact, the SPS demonstrates a perfectly linear growth curve because it is designed to do that. In contrast, the SBC demonstrates a sharp increase in the first year, with subsequent increases in 2005 and 2015. The percentage market share of Sustainables generation is consistent with the installed capacity figures, except that the SBC has a lower than expected value because of the low capacity factor of the wind technologies which are fostered under the policy.

Figure 5.3 - B.C. Installed Capacity of Sustainables (MW)

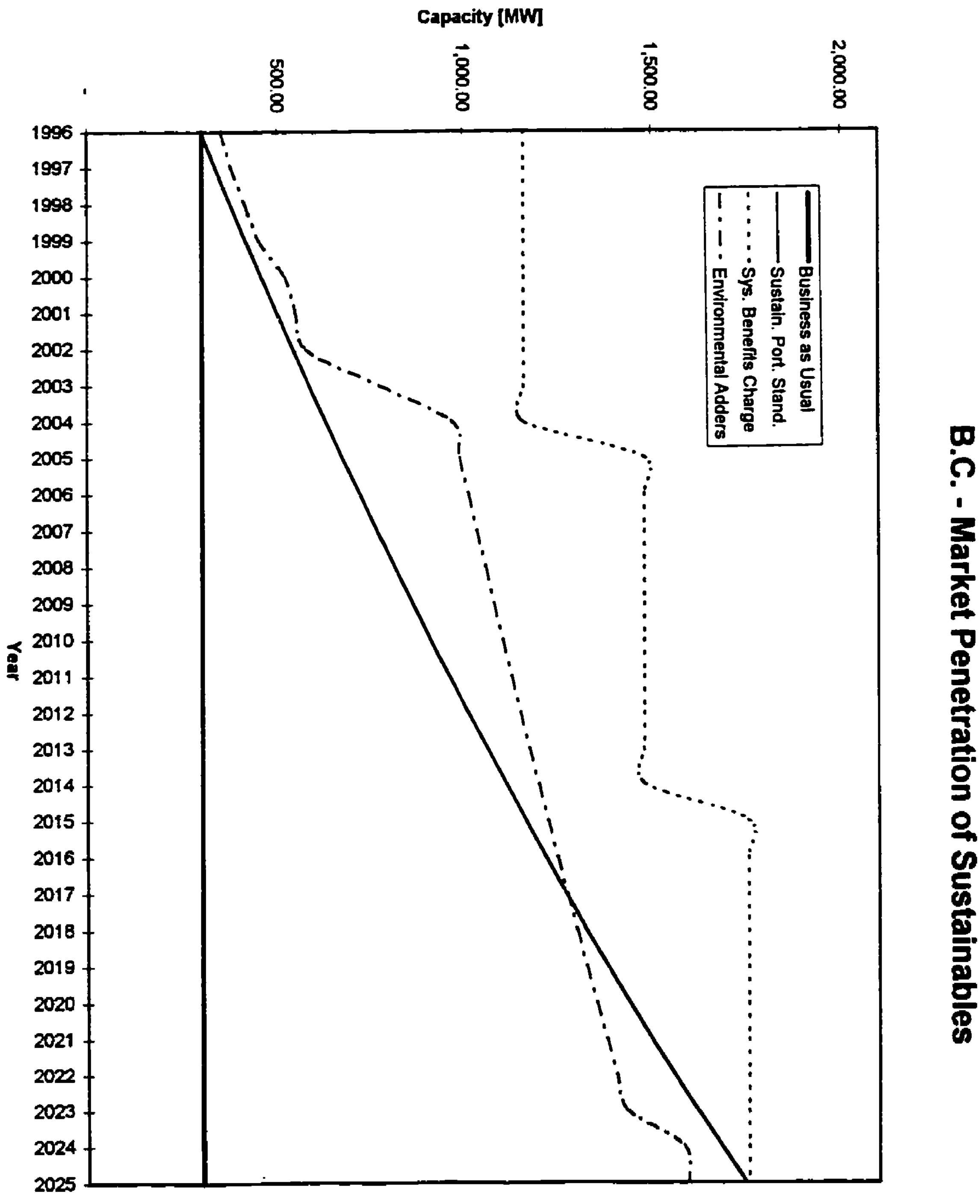


Figure 5.4 - Alberta Installed Capacity of Sustainables (MW)

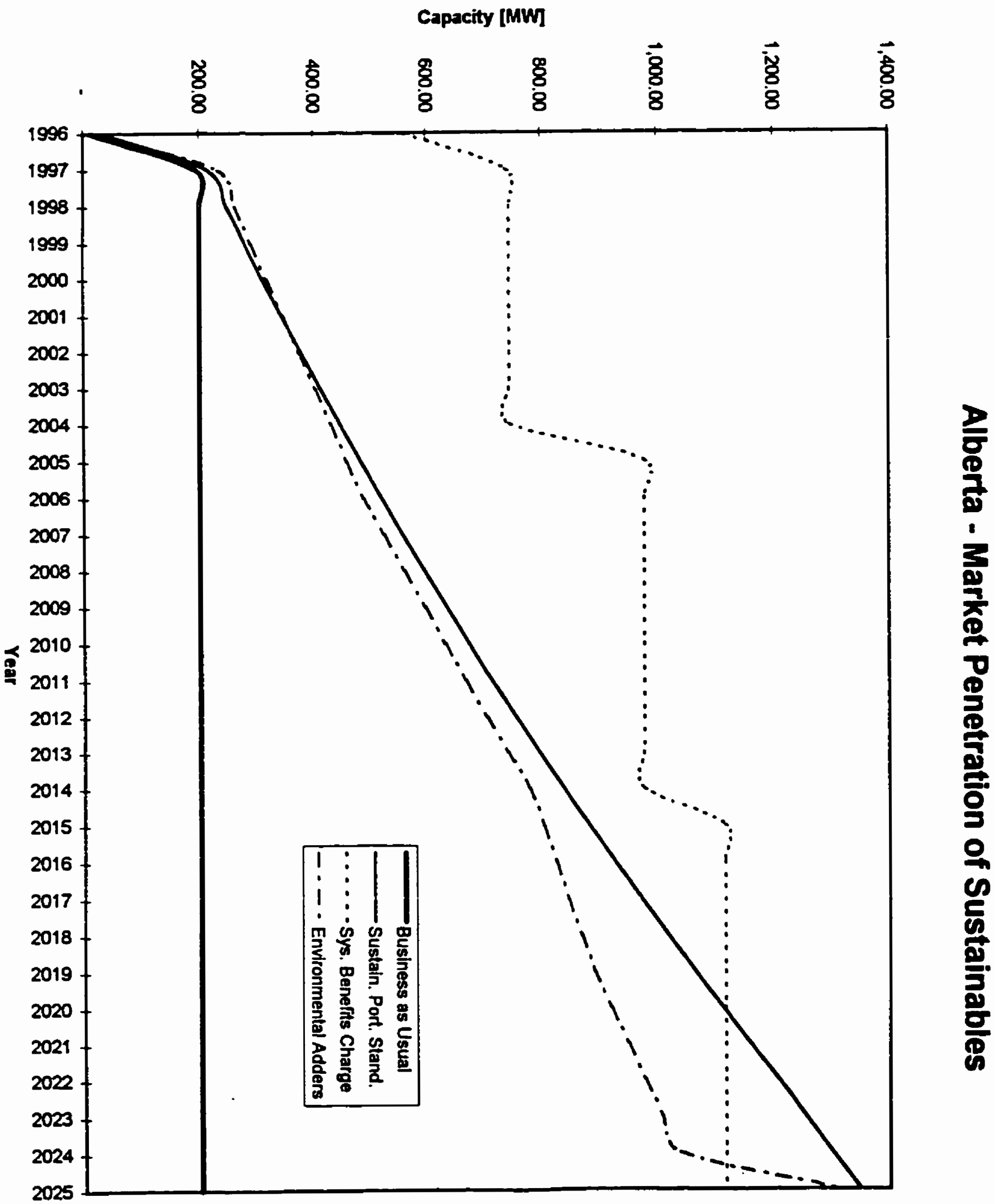


Figure 5.5 - B.C. Market Share of Generation from Sustainables (percent)

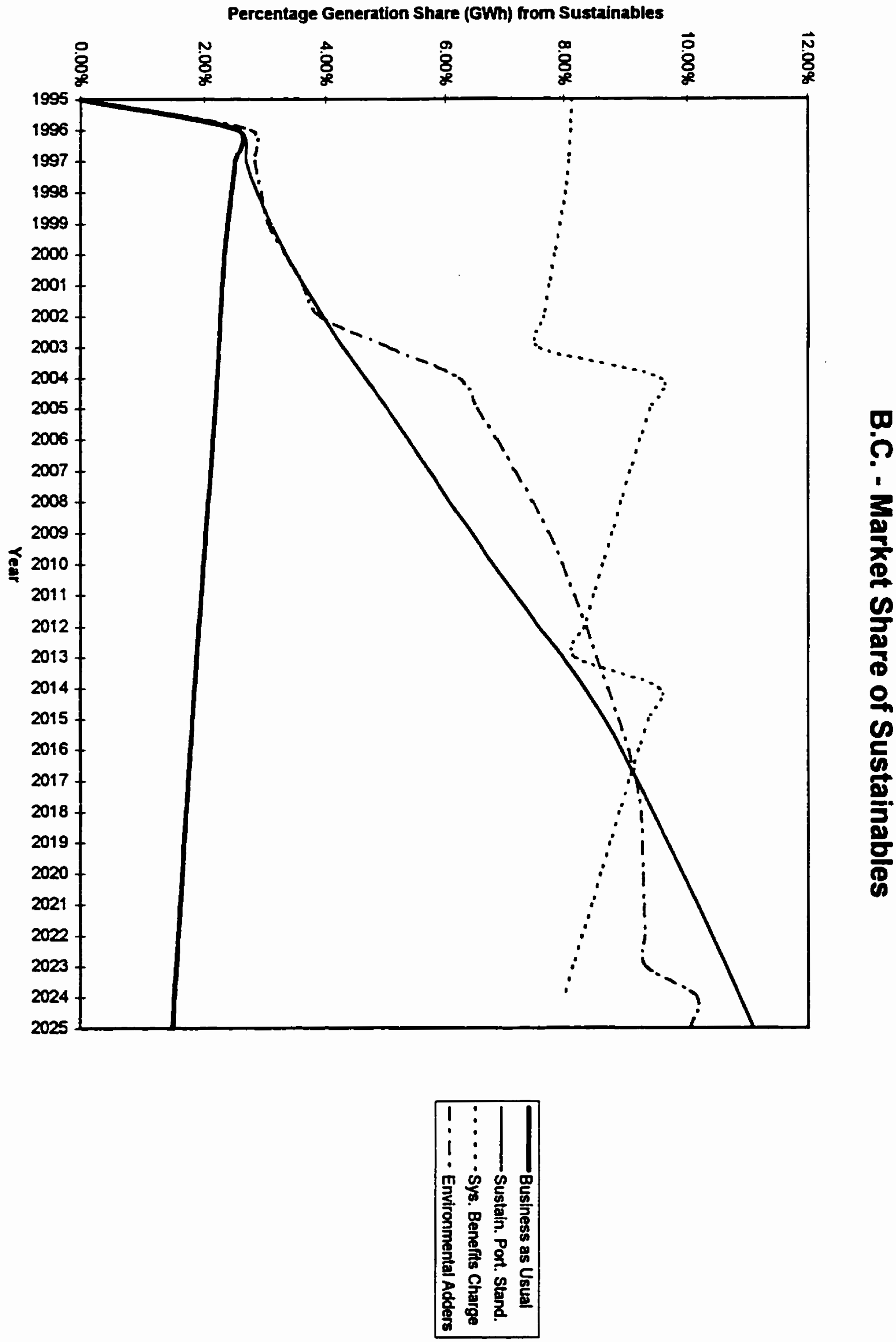
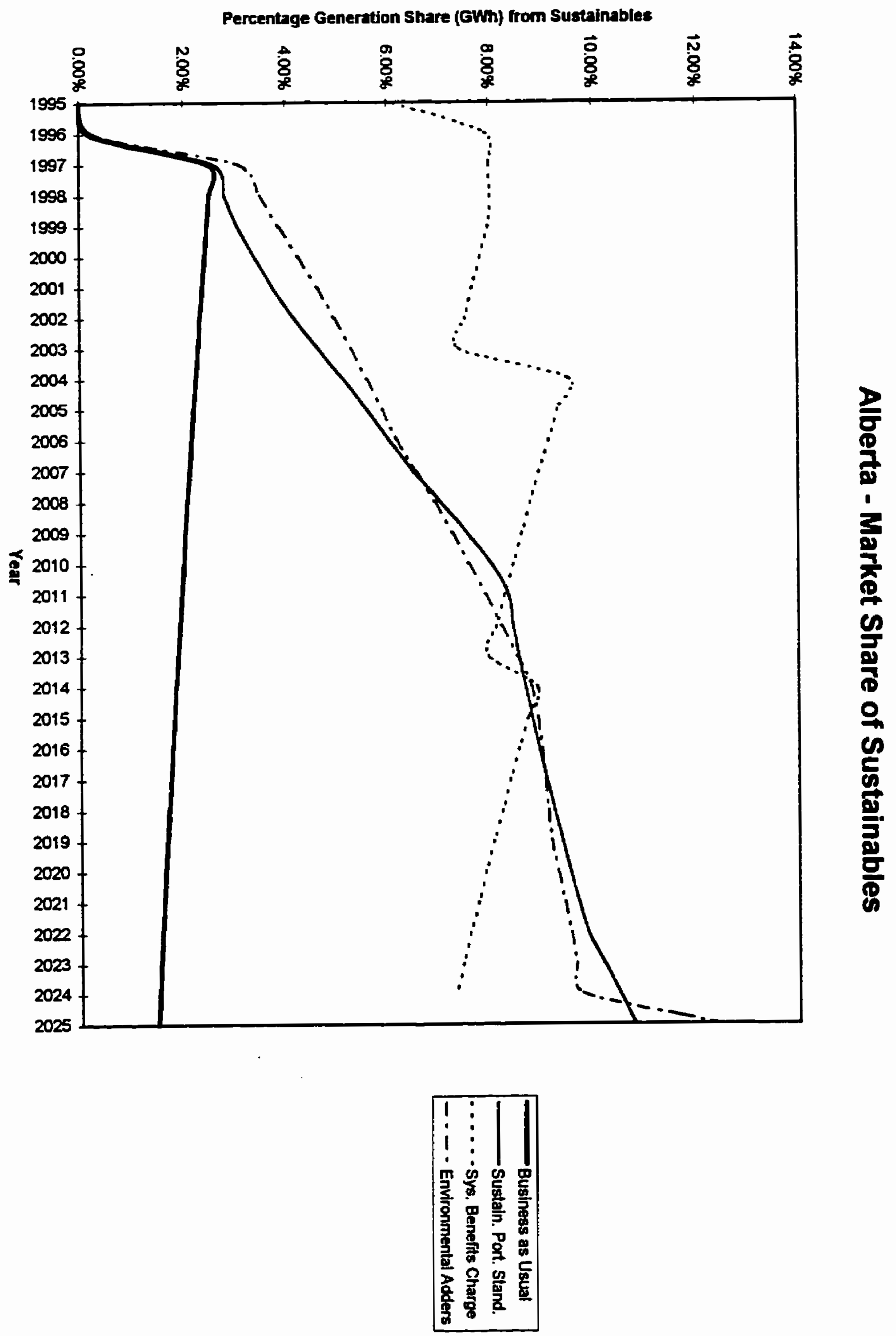


Figure 5.6 - Alberta Market Share of Generation from Sustainables (percent)



5.2.3 Financial Impacts - Total Expenditure on Electricity Sales and Impacts on Spot Price

The cost premium over BAU for each policy in millions of dollars is illustrated in Figures 5.7 and 5.8, for B.C. and Alberta respectively. Other than the costs of the EA mechanism for Alberta, all of the costs are approximately equal in 2025, as the level of support for Sustainables is approximately equal. The EA is more expensive in Alberta because of the large capacity of coal power in the province which produces a high environmental charge. The charge results in a change in the *Power Pool* generating mix, bringing in more expensive resources such as biomass instead of coal. The cost premium does not include the value of the environmental charge as it is rebated off of customers' bills. The cost premium of the more expensive resources exceeds the value of the rebate by about $200 million in 2025.

The SBC shows predictable cost increases as Sustainables capacity is brought on line, and a decrease in 2020 when the 25 year contract with Sustainables from 1996 expires[11]. It is important to note that the SBC costs on consumers are distributed equally over the entire simulation period through a wires charge that is collected on all electricity sales. However, the costs borne by society, the allocation of investment capital into the electricity market, occur in three distinct periods when the contracts are established with Sustainables producers.

The distribution of costs over the 30 year simulation period varies significantly, and this becomes the major point of comparison between the policies from a risk management perspective. The SBC, by design, forces a large proportion of the investment costs to the beginning of the simulation period, with all that investment capital subject to risk of future increases in the cost of capital. In contrast, the required capital for the SPS mechanism is gradually increased as the required market share from *Sustainables* increases.

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11 In the year 2020, a wind technology that was developed in 1996 has paid off all capital costs, and is outside of the original investment contract. As such, the facility would compete in an open market for renewables, with its value being equated to the value of a new wind facility in that year, including resultant capital cost reductions between those years.

Figure 5.7 - B.C. Policy Cost Premium over BAU for each Policy (million $1995)

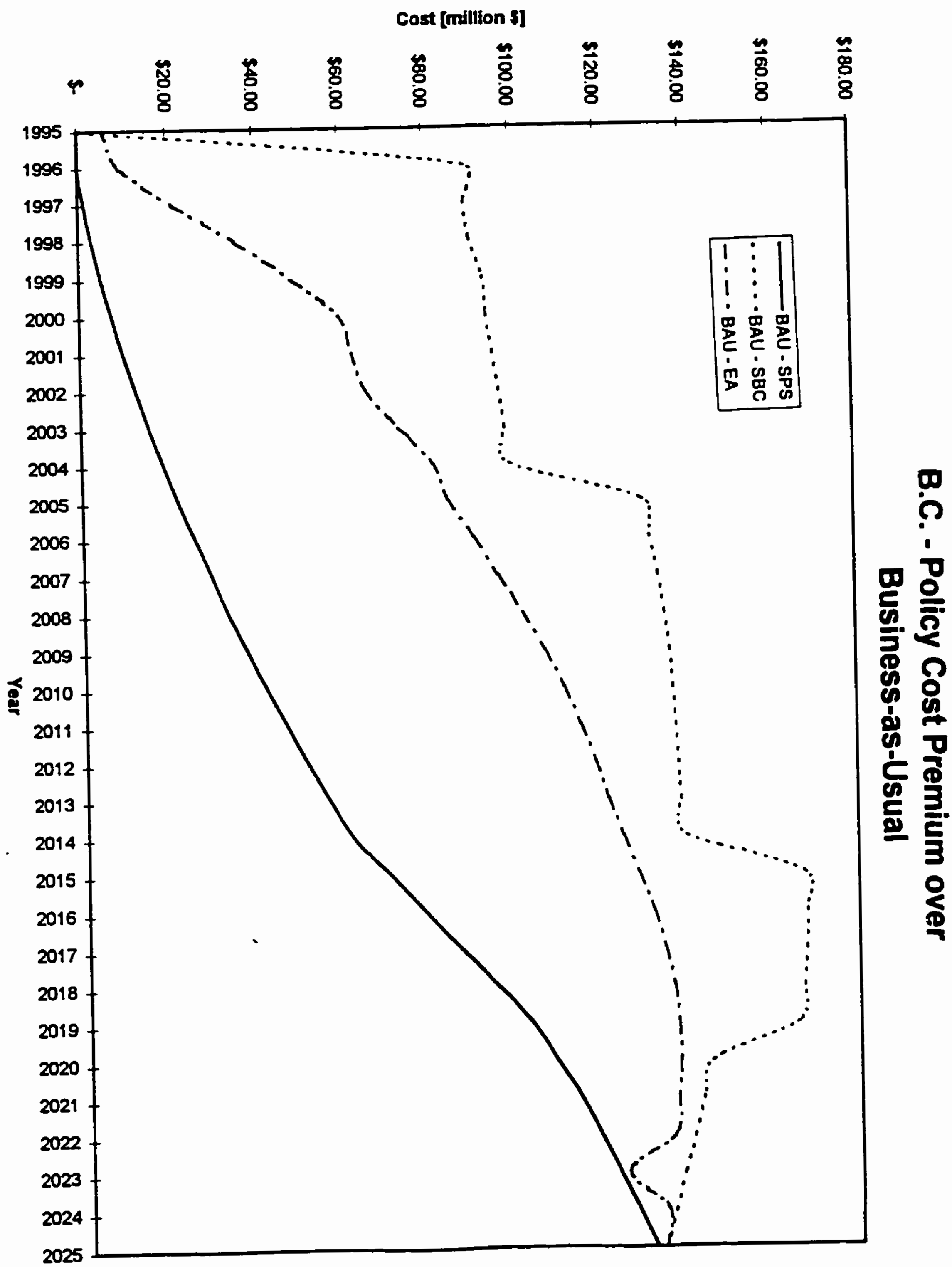
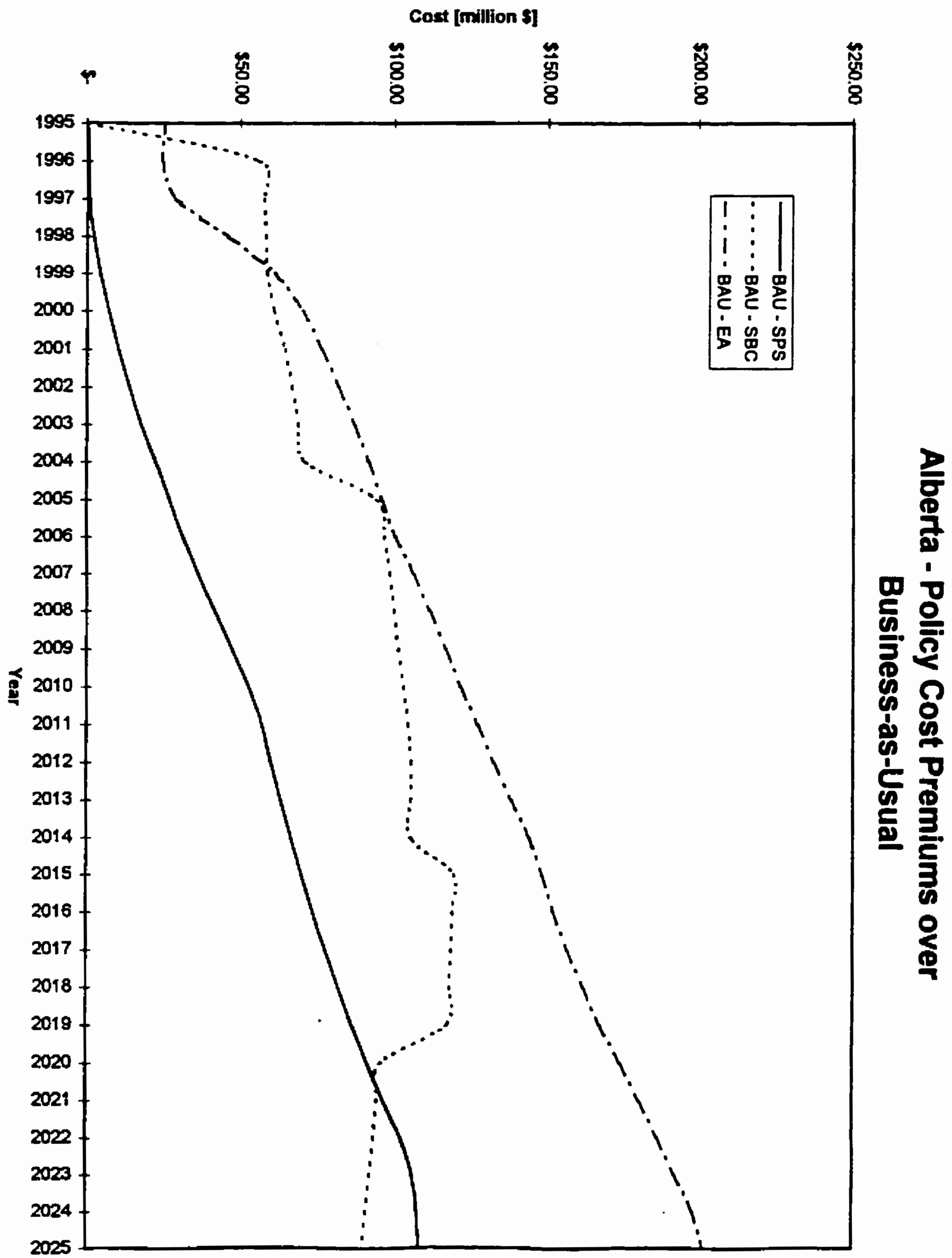


Figure 5.8 - Alberta Policy Cost Premium over BAU for each Policy (million $1995)



The costs of fostering Sustainables under each policy mechanism, relative to the BAU scenario, are outlined in Tables 5.7 and 5.8. These values were determined by dividing the policy cost premium by the total capacity of new Sustainables developed.

Table 5.7 - Cost Premium of Fostering Sustainables Development ($1995/MW of Sustainables) - B.C.

Scenario	2010	2025
SPS	$45,612	$75,101
SBC	$92,365	$75,969
EA	$100,686	$83,593

Table 5.8 - Cost Premium of Fostering Sustainables Development ($1995/MW of Sustainables) - Alberta

Scenario	2010	2025
SPS	$78,238	$80,104
SBC	$105,302	$80,587
EA	$192,093	$153,644

The results indicate that the SPS and SBC mechanisms have similar costs in the year 2025, but the SBC has a dramatically higher cost in 2010. This is because the policy fostered a large capacity of Sustainables in the first year of the simulation which has to be paid off. Also, the costs in 2025 do not include a large portion of the original capital costs for the facilities built in 1996 as it was paid off in the year 2020. In contrast, the SPS demonstrates a gradual cost increase as the capacity of Sustainables is increased. The costs of the EA mechanism are significantly higher because it affects the operation of existing generation facilities, in addition to the investment patterns of the market, with resultant reductions in CO_2 emissions.

A cost-effectiveness indicator for the energy production from Sustainables is presented in Tables 5.9 and 5.10, indicating the price premium for Sustainables production. These costs are reflective of the cost premium of Sustainables over the average electricity cost.

Table 5.9 - Cost Premium for Sustainables Production ($1995/kWh from Sustainables) - B.C.

Scenario	2010	2025
SPS	$ 0.007 / kWh	$ 0.010 / kWh
SBC	$ 0.014 / kWh	$ 0.011 / kWh
EA	$ 0.016 / kWh	$ 0.012 / kWh

Table 5.10 - Cost Premium for Sustainables Production ($1995/kWh of Sustainables) - Alberta

Scenario	2010	2025
SPS	$ 0.011 / kWh	$ 0.013 / kWh
SBC	$ 0.015 / kWh	$ 0.011 / kWh
EA	$ 0.028 / kWh	$ 0.021 / kWh

The cost premium over the BAU for every kilowatt-hour of Sustainable electricity ranges from 0.7 to 1.5 cents, except for the EA, which has costs as high as 2.8 cents. Both the SPS and SBC mechanisms demonstrate comparable costs in the year 2025, with the SBC incurring higher costs in 2010 because of the higher installed capacity of Sustainables in that year under the original 1996 development contract. The EA demonstrates higher costs for the same reasons previously mentioned.

The wholesale and peaking spot prices of electricity for B.C. and Alberta are illustrated in Figures 5.9 through 5.12.

Figure 5.9 - B.C. Wholesale Spot Price ($1995/kWh)

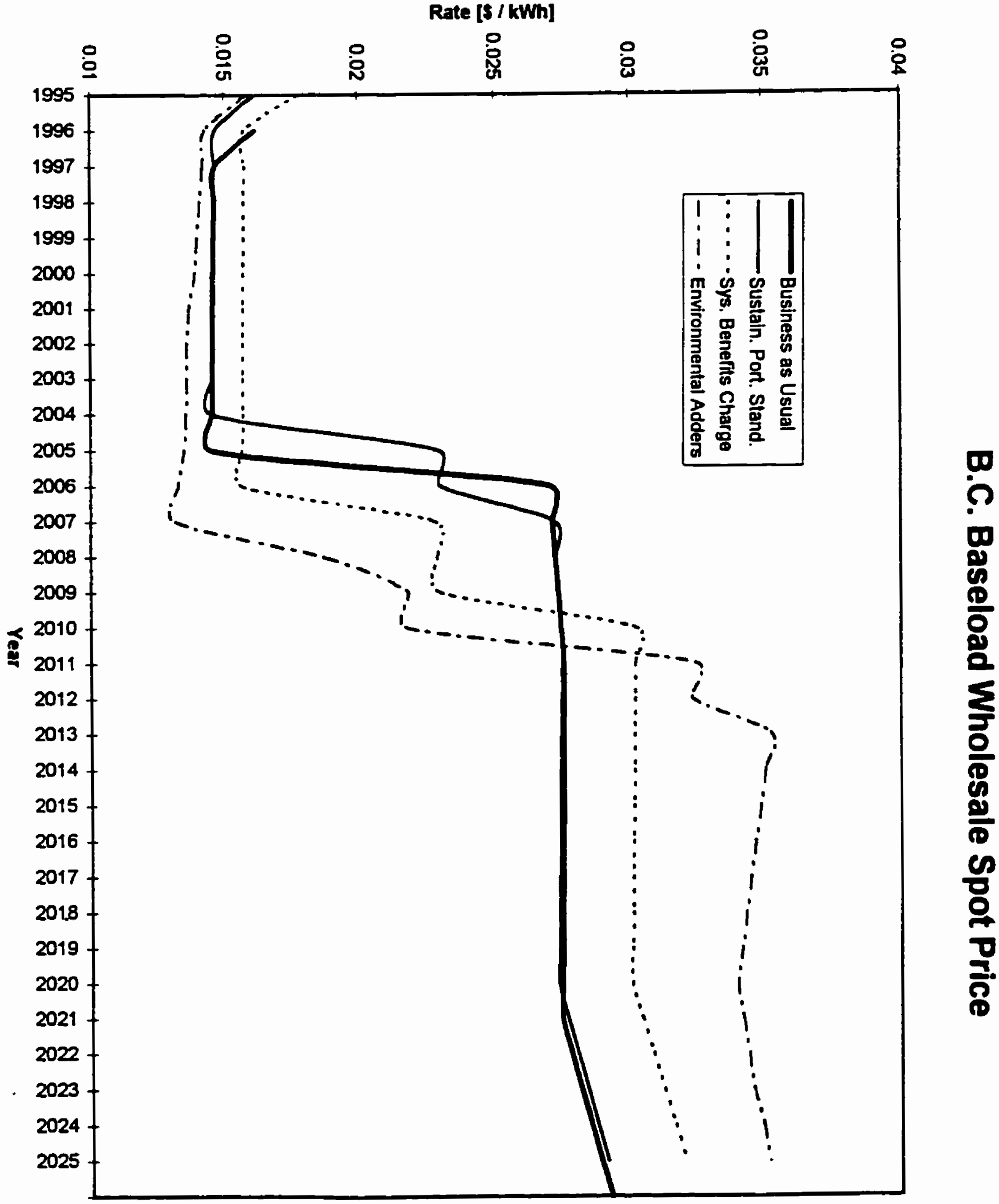


Figure 5.10 - B.C. Peaking Spot Price ($1995/kWh)

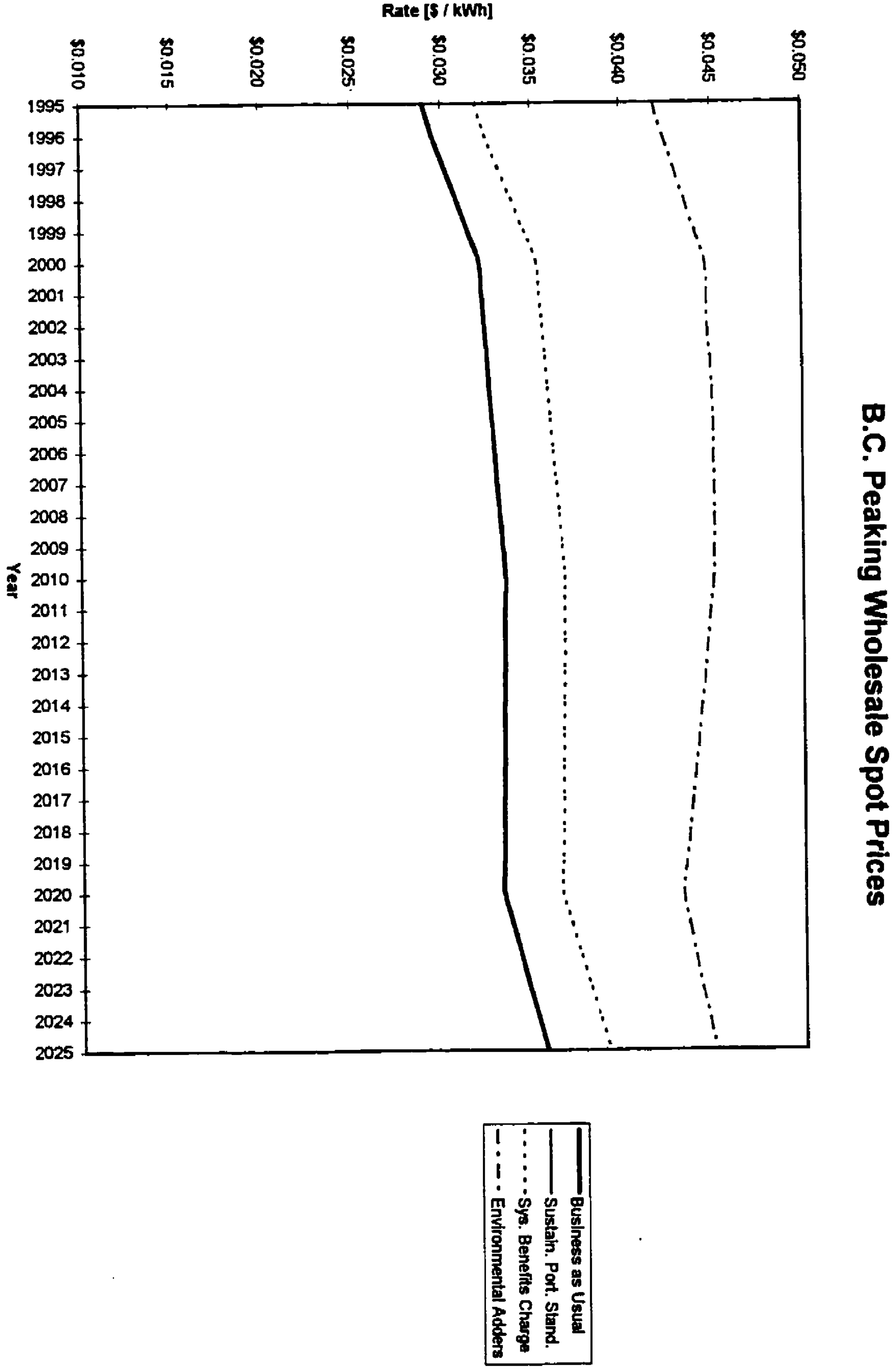


Figure 5.11 - Alberta Wholesale Spot Price ($1995/kWh)

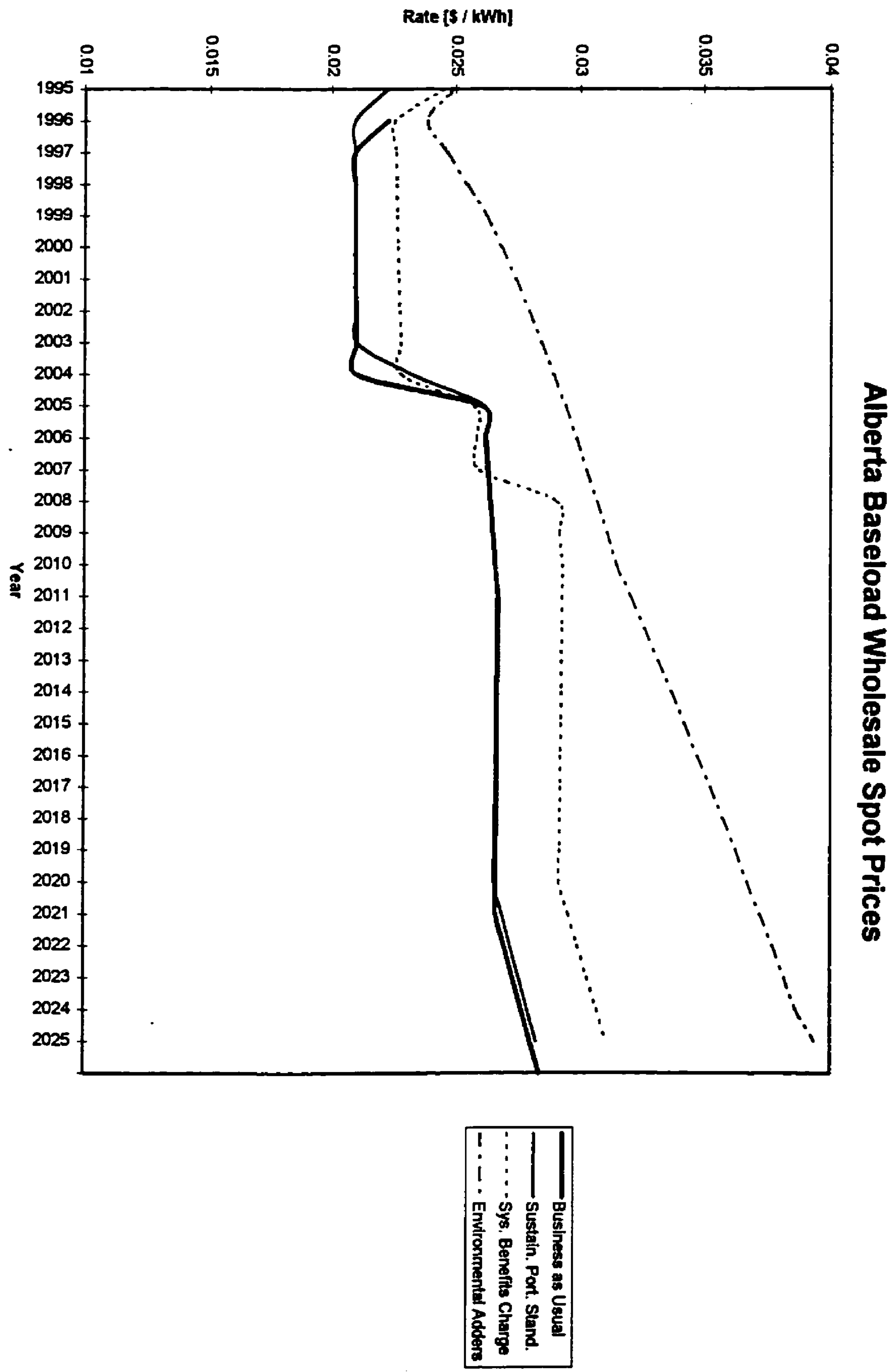
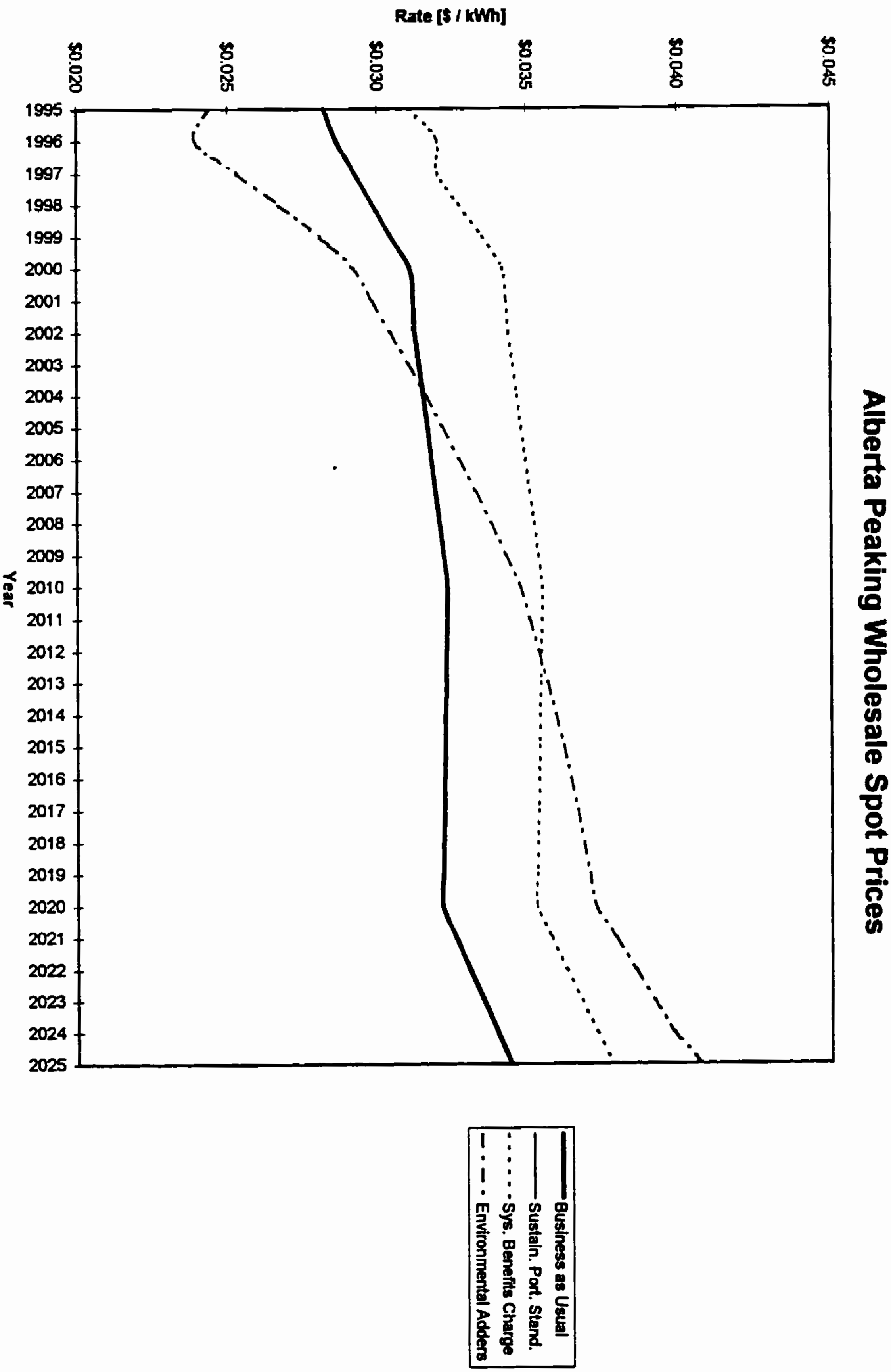


Figure 5.12 - Alberta Peaking Spot Price ($1995/kWh)



The spot prices differ from those in Appendices B and C (Figures B.3, B.4, C.3 and C.4) in a predictable fashion. The size of the SBC is higher for the analysis in this section, and as such, the gap between the BAU spot prices and the SBC spot prices is larger. Also, the size of the CO_2 tax is higher, and as such the spot price is higher. Again, the SPS and BAU demonstrate similar spot prices.

5.2.4 Annual Carbon Dioxide Emission Abatement Cost

CO_2 emissions associated with the four scenarios are listed in Table 5.11. The emissions associated with the SPS and SBC are approximately the same, as the policies equally foster Sustainables to play a role in the market. The EA has less emissions, due to the inclusion of a CO_2 tax in all electricity sales of $25/tonne, affecting not only investment decisions, which translates to increased investment in Sustainables, but also operating decisions, which affects existing technologies. In Alberta, the EA policy forces a reduction in emissions over the simulation period.

Table 5.11 - CO_2 Emissions in 2025 - B.C. and Alberta (megatonnes)

Scenario	B.C. Emissions (megatonnes)	Alberta Emissions (megatonnes)
BAU	23.065	43.196
SPS	18.687	40.303
SBC	18.760	40.425
EA	17.692	32.938

An important policy analysis indicator is the CO_2 abatement cost of a measure. This is the total cost associated with the reduction of one tonne of CO_2 emissions that results from the adoption of a policy measure. The costs are illustrated in Figures 5.13 and 5.14. In B.C. the abatement costs in 2025 are almost the same for all policies, ranging from $25 - $30/tonne. However, only the SPS mechanism kept the costs consistent over the simulation period. In Alberta, the SPS mechanism demonstrates an abatement cost of between $30 and $40/tonne, remaining more or less stable. The SBC costs range from $30 - $45/tonne, with a sharp decrease in 2020 when the technology costs are reduced. The EA mechanism stays flat at $20/tonne approximately at the level of the tax.

Figure 5.13 - CO_2 Emissions Abatement Cost Curve ($1995/tonne)- British Columbia

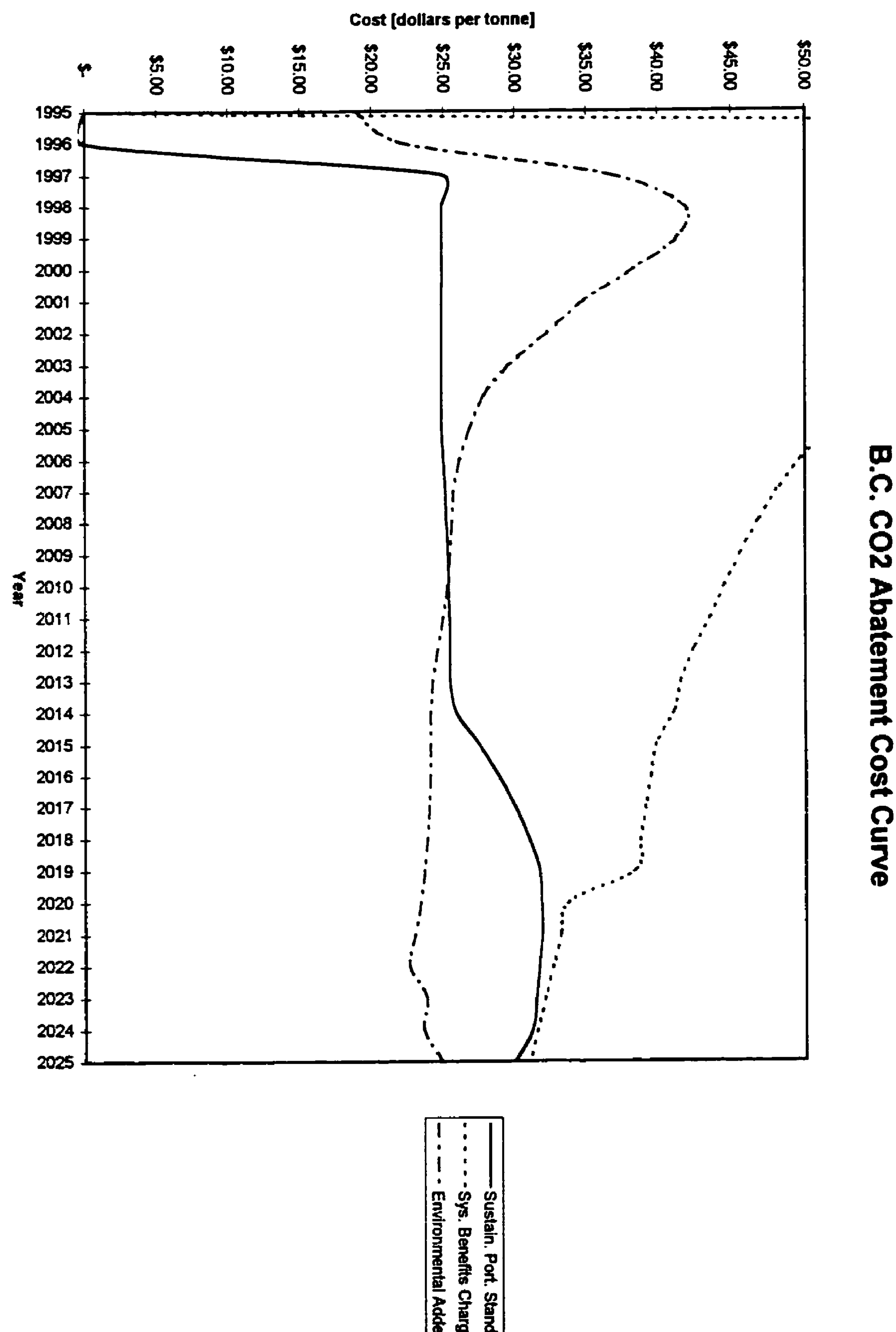
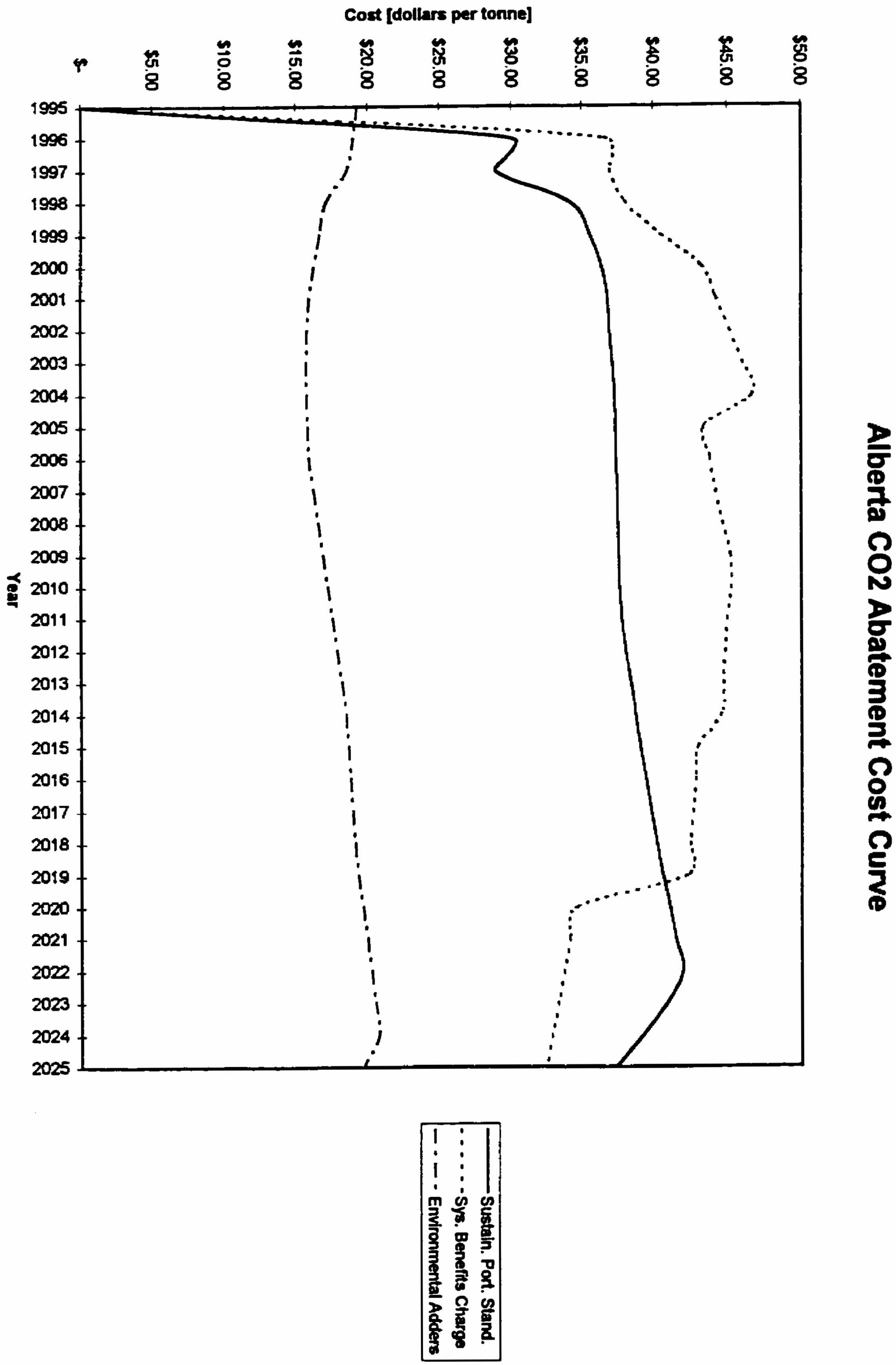


Figure 5.14 - CO_2 Emissions Abatement Cost Curve ($1995/tonne)- Alberta



5.3 Summary of Analysis

The following table provides an overview of the analysis results, organized according to the six evaluative criteria outlined at the beginning of this chapter. A numeric indicator is provided by each policy mechanisms for each of the evaluative criteria. The indicators are not intended to be added to determine the optimal mechanism, but rather are intended to provide a basis for comparison between mechanisms within one evaluative criterion. In some cases, the indicator differs between Alberta and B.C. due to differences in the electrical systems in those jurisdictions.

Table 5.12 - Summary Matrix of Policy Analysis

Criterion	Policy Mechanisms		
	SPS	SBC	EA
Maximize Installed Sustainables Capacity	1	4	2
Maximize Sustainables Technology Diversity	4 - B.C. 2 - Alberta	1 - B.C. 2 - Alberta	4 - B.C. 3 - Alberta
Maximize Sustainables Cost Reduction	5 - B.C. 2 - Alberta	1	5 - B.C. 3 - Alberta
Minimize Financial Impacts	1	4	2 - B.C. 5 - Alberta
Minimize CO_2 Abatement Cost	2	5	1
Administrative and Operational Simplicity	1	3	3

(1 is for high achievement, 5 for low achievement)

For detailed comments on the basis for each of the indicators listed above, see the text in Sections 5.1 and 5.2. In summary, the SPS approach tends to maximize the installed capacity of Sustainables because it is designed to support the most cost-effective technologies or resources. The SBC mechanism, by design, enhances the diversity of Sustainables supported, and maximizes the cost reduction of emerging Sustainables due to that diversity of support. The SPS minimizes financial impacts due to a phasing-in of the requirement, and a continuous cost-minimization pressure on the market. The EA minimizes the CO_2 abatement cost because the policy mechanism is set-up as a CO_2 tax, thus driving the market to reduce emissions at the least cost. Finally, the

SPS is the most simple to operate and administer because it relies on the market to achieve the policy objectives.

5.4 Analysis of Uncertainty and Accuracy of the CEMPA Model

5.4.1 Uncertainty Analysis

Simulation modelling involves uncertainty. The modelling exercise can attempt to minimize the impacts of that uncertainty through careful selection of model structure or parameters, and/or by doing a sensitivity analysis of key parameters, assessing the robustness of model results under a wide range of conditions. In this study, the former approach was undertaken - to attempt to minimize the impacts of uncertainty, rather than doing an extensive sensitivity analysis. However, the modelling results have been compared with published information from similar studies to demonstrate accuracy.

The explicit approach undertaken to minimize the impacts of uncertainty included the following:

- The utilization of a high discount rate - thus evaluating policy options from a conservative financial standpoint. By adopting a high discount rate, technology costs reach their upper limits, particularly among capital intensive technologies such as Sustainables.
- Application of generic technology parameters into the model, thus averaging out all the uncertainty associated with costs, capacity factors, heat rates, emissions, etc. Had an effort been made to characterize specific generation facilities, then uncertainty considerations would have been more prevalent.
- Using conservative estimates of fuel costs for competing technologies.
- Utilization of conservative resource potential parameters for emerging technologies.
- Defining driving policy parameters according to realistic levels being applied or proposed in other jurisdictions. The level of portfolio requirement under the SPS policy is on the lower-range of what is being proposed in the U.S., as is the carbon tax applied for the EA. The SBC is consistent with what is proposed in other jurisdictions. The parameters that were adopted for the EA and SBC mechanisms under the analysis in Section 5.2 are not necessarily realistic, but were selected in order to compare with the outcome of the SPS.

5.4.2 Accuracy of the Model

Three recent studies by the Canadian Electricity Association, the Tellus Institute, and BC Hydro, can be used to assess the accuracy of the CEMPA results, at least partially. Those studies include.

1. The Canadian Electricity Association study, *Greenhouse Gas Management and the Canadian Electric Utility Industry* (CEA, 1997).
2. The Tellus Institute study that looks at the costs and benefits of a national Renewable Portfolio Standard in the U.S., similar to the CEMPA SPS scenario (Bernow.et.al., 1997 & Figure 1.1).
3. An overview of CO_2 abatement costs, prepared by BC Hydro.

The first study demonstrates that B.C. CO_2 emissions will increase from 2.5 million tonnes in 1995 to 6MT in 2015 under the "base case" scenario. In comparison CEMPA predicts that emissions will rise from about 1MT to 10MT during that period (BAU). For Alberta, the CEA study predicts emissions will drop from 45MT to 39MT during that period, while CEMPA predicts they will remain flat at 39MT to 40.5 MT. There are 2 explanations for this divergence.

1. The production estimates in GWh are significantly different than those of the CEA, with the CEMPA B.C. production ranging from 65,000 to 86,000 GWh per year over the simulation, and the CEA study range from 48,000 to 67,000 GWh. CEMPA utilizes an NRCan estimate for capacity demand, and a BC Hydro *load duration curve* to estimate annual production, and is in-line with the NRCan energy forecasts. For the CEMPA Alberta model, the difference was not as great.
2. The utilization of a higher discount rate in CEMPA (12% in CEMPA, 8% in CEA) results in the greater deployment of low capital cost fossil fuel technologies. For example, CEMPA predicts a considerable market penetration of simple-cycle gas turbines, which have lower capital costs than combined-cycle turbines. The combined-cycle turbines are more efficient, resulting in reduced emissions if they are used as peaking plants instead of simple-cycle technologies.

The second study (Bernow et.al., 1997) quantifies the costs and benefits of a policy similar to the SPS, but for the entire U.S. market. The results of this study were illustrated in Figure 1.1, showing that the rate impact of an SPS is close to zero, which is consistent with the results from CEMPA (Figures 5.9, 5.10, 5.11, 5.12). The Tellus study shows that the cost of a renewable energy *credit* is about 1.03 to 1.2 US cents / kWh, and CEMPA results show a magnitude of 0.7 to 1 cent in B.C. (Table 5.9), and 1.1 to 1.3 cents in Alberta (Table 5.10), indicating a close resemblance between CEMPA and the Tellus Institute study (Ibid.).

Finally, BC Hydro produced a summary of CO_2 mitigation cost estimates which showed a range of about $1/tonne and $155/tonne, with the majority of values in the $10-$40 range. These figures are indicative of the cost of a policy to reduce CO_2 emissions and can be compared with the CO_2 emission abatement costs curves presented in Figures 5.13 and 5.14. CEMPA results indicate an average cost of $20-$40 per tonne for all scenarios, in-line with the estimates from BC Hydro.

5.4.3 Discussion on Limitations of Model

As briefly outlined in Chapter 2, CEMPA is only one of many different types of models, most of which are much more complex. Due to the scope of this study, and limitations on the modelling methodology, the results from CEMPA will inherently be less accurate than some other models. Those limitations include (including ones not related to those other models):

- CEMPA characterizes energy demand with the *load duration curve*, rather than a time-based function which provides real-time demand information to the model, representative of consumer demand. Also, there are price elasticity feedbacks between demand periods which are not represented - such as the impact of a high electricity price in one period on the demand in the same period on a future date. This impacts on the accuracy of CEMPA's representation of market trading functions.
- CEMPA does not characterize the limitations of the transmission network, or attach a time or congestion-based charge for transmission wheeling, but rather applies an average transmission cost for all transactions. However those expenses may become prevalent under competitive markets as the number of transactions increase, and transmission constraints will start to dictate the location and types of technologies that will be developed.
- CEMPA does not characterize electricity trade between jurisdictions, which is expected to increase under competitive markets.
- CEMPA assumes that all generation facilities fall under a generic class of technology, yet in reality there is a wide divergence of costs and performance of facilities that fall under the same

generic class. The CEMPA "variation in investment behavior" function partially meets this concern.

- The characterization of hydroelectric facilities in CEMPA is unrealistic. In reality, they are energy-poor and capacity-rich, able to meet peaking loads at almost all times. CEMPA applies an annual average capacity factor to hydro facilities, thus limiting their ability to meet annual peak loads. This results in CEMPA over-building capacity in B.C. to meet peak loads, in order to compensate for the low annual average capacity factor of existing hydro facilities.

- Under the three sustainability scenarios (SPS, SBC, EA), CEMPA first runs the business-as-usual scenario to determine cost-effective investment in technologies, and then characterizes the sustainability policy after the fact, adding Sustainables capacity to the mix. This is done to keep the model complexity to a minimum. As a result, the characterization of declining capital costs among emerging technologies in CEMPA resulting from the sustainability policies does not feed back to the regular investment model, thus possibly under-predicting the investment in Sustainables. For example, as a result of the SBC mechanism in Alberta, wind technologies become competitive with several natural gas technologies in later years of the simulation, and should offset some natural gas technology development, based on strict financial criteria. CEMPA does not capture that additional investment resulting from cost reductions. The model that captures the cost-effective investment was executed prior to the SBC mechanism model where the cost reductions occurred.

- Retirement of existing technologies is based on a straight-line function in percent retired per year, rather than reducing their capacity according to actual plant closures.

6. CONCLUSIONS

6.1 Overview

Sustainables will not be competitive under competitive electricity generation markets, and will essentially achieve zero market penetration if no specific instruments favoring them are applied in B.C. or Alberta. There are three reasons for the failure of Sustainables to achieve an increased market share: (1) the failure of governments to implement regulations or other mechanisms which reflect environmental externalities in decision making; (2) the low capital and operating costs of natural gas turbine technologies; and (3) the high capital cost / low operating cost characteristics of Sustainables which is especially problematic as the market becomes dominated by private investors with higher discount rates.

"Business as usual" market development is likely to result in negative environmental impacts through increased greenhouse gas and other emissions, which could have financial risk implications in the future if environmental standards are established for greenhouse gas emissions and other pollutants. The study demonstrates that greenhouse gas emission will climb from 1 to 23 Megatonnes over the next 20 years in B.C., and will increase slightly in Alberta from 39 to 43 Mt, currently the highest in Canada for the electricity sector.

Sustainables can be effectively fostered under competitive electricity markets. The three policy mechanisms that were analyzed in this study resulted in significant increases of Sustainables' capacity. Of the three. the Sustainables Portfolio Standard mechanism was most effective at fostering Sustainables within the policy objectives. The characteristics of this policy mechanism include.

- Large increases in installed capacity of Sustainables, reaching 1750 MW in B.C. and 1350 MW in Alberta by the year 2025.
- Zero impact on the spot price of electricity.
- Gradual electricity sector cost impacts as it is phased-in over the 30 year study period.
- Cost-effective support for Sustainables, averaging about one cent per kilowatt-hour of Sustainables electricity produced, and between $45 and $80 per kW of Sustainables capacity installed.

- Cost-effective CO_2 emission abatement costs, ranging from an average of $25 / tonne in B.C. to about $35/tonne in Alberta.
- Political acceptability and administrative simplicity.

The only failing of the SPS mechanism implemented in this study is that it does not result in a diversity of Sustainables technologies being developed, but rather only the most cost-effective ones - small hydro, biomass and in later years, wind. However, the policy could be set-up in such a way that requires electricity marketers to purchase a minimum share from various technology types, and hence a diversity of technologies would be fostered.

The SBC mechanism is cost-effective in the long run and can be easily designed to foster a diversity of technologies. Under the policy design implemented in this study, the majority of investment costs are borne in early years, and investments in Sustainables are made in block purchases. In order to reach the same market support for Sustainables as the SPS mechanism does, the wires charge needs to be at a politically unacceptable level of 10% of the PSP, or about 5% of the consumer rates for electricity. This far exceeds the magnitude that has been supported in other jurisdictions. For example, in the U.K., the wires charge is about 1.3%.

The EA mechanism results in cost-effective CO_2 emission abatement and good support for Sustainables, but has potentially significant impacts on the spot price of electricity, and has excessive financial implications in Alberta due to the large capacity of existing coal plants there. Also, the mechanism is administratively complex.

6.2 Future Work - What are the Next Steps?

Future modifications if similar analyses are to be undertaken include:

- The development of a more complex spot market sub-model, including trade between jurisdictions and a network analysis that assesses the costs of transmission line congestion.
- The inclusion of a greater number of competing technologies, to better represent the diversity of technologies available, and to specifically represent existing generation facilities.
- The development of a greater number of sustainability scenarios, to allow for a more detailed comparison of policy options, and to assess the sensitivity of the outcomes to a variety of factors.

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8. APPENDIX A - SPECIFIC METHODOLOGICAL DETAILS

8.1 Screening Curve Model

The specific equation that is applied to determine the intersection points of the least-cost technologies in the *screening curve* routine (Chapter 2, Section 2.3.5.1) is outlined in Equation A.1 below. Y is representative of the total cost of developing a technology, and is a function of X, the number of operating hours of that technology for a year. Intersection points are determined by equating the mathematical expressions for each of the two lines. Each intersection point translates to the number of operating hours for a technology.

Equation A.1 - Equation for the Optimization of Electricity Supply Resource Investment

$$Y = Intercept + (Slope * X)$$

X = the number of operating hours in a year

Y = cost of technology for a given number of operating hours (X)

Intercept = Fixed Cost

$$\text{Slope} = \left(\frac{(\text{Variable Cost} * X)}{X}\right)$$

$$Y = \left(\frac{(\text{Variable Cost} * X)}{X}\right) * X + \text{Fixed Cost}$$

$$Y = (\text{Variable Cost} * X) + \text{Fixed Cost}$$

Intersection at the Point where the line equations are equal

$$Y_1 = Y_2$$

$$X_{\text{Intersection}} = \frac{(fixed_1 - fixed_2)}{(\text{var}_2 - \text{var}_1)}$$

9. APPENDIX B - SIMULATION RESULTS FROM THE B.C. MODEL

Table B.1 - Total generation capacity (MW) by technology type - BAU

Total Cumulative Capacity from New and Existing Technologies - BC Model - BAU

Share of market for non-least cost t 20%   Price threshold over least cost for inv 20%

MegaWatts

Technology Name		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	*New*	251.75	385.96	560.34	730.97	898.12	1008.53	1117.83	1226.04	1333.20	1439.31	1586.69	1736.78	1883.60	2029.17	2173.51
Simple cycle oil (b)	*hnologies*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas		39.03	225.01	473.27	722.46	972.38	1138.20	1303.07	1467.03	1630.08	1792.24	2021.48	2249.70	2476.89	2703.08	2928.29
Combined cycle oil		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal		300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Be		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas cogen retrofits		42.20	65.07	95.26	125.25	155.04	174.77	194.35	213.79	233.09	252.25	279.30	306.18	332.89	359.45	385.84
Large Hydro		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	*Existing*	1020.69	1010.48	1000.38	990.37	980.47	970.67	960.96	951.35	941.84	932.42	923.09	913.86	904.72	895.68	886.72
Coal	*hnologies*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil		215.65	204.87	194.62	184.89	175.65	166.87	158.52	150.60	143.07	135.91	129.12	122.66	116.53	110.70	105.17
Hydro		11110.77	10999.66	10889.67	10780.77	10672.96	10566.23	10460.57	10355.96	10252.40	10149.88	10048.38	9947.90	9848.42	9749.93	9652.43
Nuclear		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass		526.68	521.41	516.20	511.04	505.93	500.87	495.86	490.90	485.99	481.13	476.32	471.56	466.84	462.17	457.55
Total Supply		**13,506.8**	**13,712.5**	**14,029.7**	**14,345.8**	**14,660.5**	**14,828.1**	**14,991.2**	**15,155.7**	**15,319.7**	**15,483.1**	**15,764.4**	**16,048.6**	**16,329.9**	**16,610.2**	**16,889.5**
Total New Sustainables		300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00

Technology Name		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	*New*	2323.66	2475.31	2628.50	2783.29	2939.73	3097.85	3257.71	3419.35	3582.83	3748.19	3913.99	4080.27	4247.08	4414.49	4582.68
Simple cycle oil (b)	*hnologies*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas		3162.38	3398.66	3637.19	3878.04	4121.27	4366.98	4615.16	4866.00	5119.49	5375.73	5636.28	5901.22	6170.64	6444.60	6552.03
Combined cycle oil		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal		300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Be		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas cogen retrofits		413.29	441.00	468.98	497.24	525.79	554.63	583.78	613.24	643.02	673.14	703.59	734.39	765.55	797.08	1000.00
Large Hydro		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	*Existing*	877.85	869.07	860.38	851.78	843.26	834.83	826.48	818.22	810.03	801.93	793.91	785.98	778.12	770.33	762.63
Coal	*hnologies*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil		99.91	94.91	90.17	85.66	81.38	77.31	73.44	69.77	66.28	62.97	59.82	56.83	53.99	51.29	48.72
Hydro		9555.91	9460.35	9365.75	9272.09	9179.37	9087.58	8996.70	8906.73	8817.67	8729.49	8642.19	8555.77	8470.21	8385.51	8301.66
Nuclear		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass		452.98	448.45	443.96	439.52	435.13	430.78	426.47	422.20	417.98	413.80	409.66	405.57	401.51	397.50	393.52
Total Supply		**17,186.0**	**17,487.8**	**17,794.9**	**18,107.6**	**18,425.9**	**18,749.9**	**19,079.8**	**19,415.5**	**19,757.3**	**20,105.2**	**20,459.4**	**20,820.0**	**21,187.1**	**21,560.8**	**21,941.2**
Total New Sustainables		300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00

Table B.2 - Total generation capacity (MW) by technology type - SPS

Total Cumulative Capacity from New and Existing Technologies - BC Model - SPS

Share of market for non-least cost technologies: 20%   Price threshold over least cost for investment: 20%

MegaWatts

Technology Name	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	251.75	385.80	560.34	730.87	880.12	1008.53	1117.83	1228.04	1333.20	1438.31	1588.88	1730.78	1883.80	2028.17	2173.51
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	38.03	187.78	387.21	808.04	814.05	837.30	1058.87	1178.07	1287.81	1414.81	1588.08	1778.84	1858.98	2138.45	2315.32
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam	0.00	37.28	78.08	118.42	158.33	200.88	244.10	287.88	332.47	377.83	379.34	379.34	379.34	379.34	379.34
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.08	88.52	137.58	185.28	233.83
Gas cogen retrofits	42.20	65.07	85.28	125.25	155.04	174.77	184.35	213.78	233.08	252.25	279.30	308.18	332.88	358.45	385.84
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1020.88	1010.48	1000.38	990.37	980.47	970.87	960.88	951.35	941.84	932.42	923.08	913.88	904.72	895.88	888.72
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	215.85	204.87	194.82	184.88	175.85	166.87	158.52	150.80	143.07	135.81	129.12	122.88	116.53	110.70	108.17
Hydro	11110.77	10998.98	10888.87	10780.77	10672.86	10568.23	10460.57	10355.86	10252.40	10148.88	10048.38	9947.80	9848.42	9748.93	9652.43
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	526.88	521.41	516.20	511.04	505.93	500.87	495.88	490.90	485.98	481.13	476.32	471.58	466.84	462.17	457.55
Total Supply	13,586.77	13,712.47	14,020.74	14,345.75	14,660.34	14,820.12	14,991.18	15,155.87	15,318.07	15,483.15	15,708.38	16,048.83	16,328.88	16,618.18	16,888.52
Total New Sustainables	300.00	337.28	378.08	418.42	458.33	500.88	544.10	587.88	632.47	677.83	723.45	768.88	818.83	864.83	912.87

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	2323.88	2475.31	2628.50	2783.28	2938.73	3097.85	3257.71	3418.35	3582.83	3740.88	3898.85	4052.81	4207.15	4361.85	4517.38
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2500.08	2685.84	2873.02	3062.03	3254.61	3448.58	3644.00	3840.80	4038.35	4253.10	4470.31	4688.25	4831.71	5167.71	5170.88
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam	379.34	379.34	379.34	379.34	379.34	379.34	379.34	379.34	379.34	401.83	434.77	443.25	481.84	480.88	500.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	282.88	333.38	384.83	424.77	424.77	424.77	424.77	424.77	424.77	424.77	424.77	443.25	481.84	480.88	500.00
Gas cogen retrofits	413.28	441.00	468.88	487.24	525.78	554.83	583.78	613.24	643.02	666.61	688.45	708.83	725.83	744.54	1000.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	11.80	62.56	114.27	167.07	220.88	278.03	310.81	348.72	370.38	394.80	420.24	443.84
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.51
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	877.85	868.07	860.38	851.78	843.28	834.83	826.48	818.22	810.03	801.93	793.91	785.98	778.12	770.33	782.83
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	98.91	94.81	90.17	85.66	81.38	77.31	73.44	69.77	66.28	62.97	59.82	56.83	53.98	51.28	48.72
Hydro	9655.91	9460.35	9365.75	9272.09	9179.37	9087.58	8996.70	8906.73	8817.67	8729.49	8642.18	8555.77	8470.21	8385.51	8301.66
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	452.88	448.45	443.96	439.52	435.13	430.78	426.47	422.20	417.98	413.80	409.66	405.57	401.51	397.50	393.52
Total Supply	17,185.88	17,487.75	17,794.93	18,107.62	18,425.92	18,740.93	19,070.70	19,415.31	19,757.31	20,105.25	20,450.46	20,828.83	21,187.18	21,560.70	21,841.22
Total New Sustainables	962.33	1012.72	1064.17	1118.00	1166.66	1218.38	1271.18	1325.10	1380.14	1437.80	1496.25	1558.88	1618.78	1681.88	1748.44

Table B.3 - Total generation capacity (MW) by technology type - SBC

Total Cumulative Capacity from New and Existing Technologies - BC Model - SBC

Share of market for non-least cost technologies: 20% Price threshold over least cost for investment: 20%

MegaWatts

Technology Name	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	251.75	385.98	580.34	730.87	898.12	1008.53	1117.83	1228.04	1333.20	1438.31	1588.88	1736.78	1883.80	2029.17	2173.51
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	0.00	77.56	325.80	675.00	824.81	990.73	1156.01	1319.54	1482.01	1620.40	1855.05	2083.88	2311.05	2537.24	2762.45
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	38.07	38.07	38.07	38.07	38.07	38.07
Gas cogen retrofits	42.20	65.07	85.28	125.25	155.04	174.77	194.35	213.70	233.08	252.25	279.30	306.10	332.88	358.46	385.84
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade	42.32	42.32	42.32	42.32	42.32	42.32	42.32	42.32	42.32	46.58	46.58	46.58	46.58	46.58	46.58
Waste fuels cogen	18.31	18.31	18.31	18.31	18.31	18.31	18.31	18.31	18.31	20.18	20.18	20.18	20.18	20.18	20.18
Wind Generators	31.85	31.85	31.85	31.85	31.85	31.85	31.85	31.85	31.85	38.27	38.27	38.27	38.27	38.27	38.27
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	18.80	18.80	18.80	18.80	18.80	18.80	18.80	18.80	18.80	19.84	19.84	19.84	19.84	19.84	19.84
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.81	4.81	4.81	4.81	4.81	4.81
Natural Gas	1020.89	1010.48	1000.38	990.37	980.47	970.67	960.98	951.35	941.84	932.42	923.08	913.88	904.72	895.68	886.72
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	215.86	204.87	194.82	184.88	175.85	166.87	158.52	150.80	143.07	135.81	129.12	122.88	116.53	110.70	105.17
Hydro	11110.77	10988.88	10889.87	10780.77	10672.98	10566.23	10460.57	10355.98	10252.40	10148.88	10046.38	9947.80	9848.42	9749.83	9652.43
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	526.89	521.41	516.20	511.04	505.93	500.87	495.90	490.90	485.98	481.13	476.32	471.58	466.84	462.17	457.55
Total Supply	13,615.21	13,712.47	14,029.74	14,345.75	14,688.64	14,820.12	14,991.16	15,155.67	15,318.87	15,483.15	15,780.38	16,048.83	16,320.88	16,616.10	16,888.62
Total New Sustainables	447.47	447.47	447.47	447.47	447.47	447.47	447.47	447.47	447.47	465.84	465.84	465.84	465.84	465.84	465.84

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	2323.88	2475.31	2628.50	2783.28	2938.73	3087.85	3257.71	3419.35	3582.83	3748.18	3913.88	4080.27	4247.08	4414.48	4582.88
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2988.56	3232.82	3471.35	3712.20	3924.44	4170.13	4418.35	4668.17	4922.86	5178.90	5438.45	5704.38	5973.81	6247.77	6356.20
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	38.07	38.07	38.07	38.07	43.88	43.88	43.88	43.88	43.88	43.88	43.88	43.88	43.88	43.88	43.88
Gas cogen retrofits	413.28	441.00	468.88	497.24	525.79	554.83	583.70	613.24	643.02	673.14	703.58	734.38	765.55	797.08	1000.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade	46.58	46.58	46.58	46.58	53.42	53.42	53.42	53.42	53.42	53.42	53.42	53.42	53.42	53.42	53.42
Waste fuels cogen	20.18	20.18	20.18	20.18	23.11	23.11	23.11	23.11	23.11	23.11	23.11	23.11	23.11	23.11	23.11
Wind Generators	38.27	38.27	38.27	38.27	44.20	44.20	44.20	44.20	44.20	44.20	44.20	44.20	44.20	44.20	44.20
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	19.84	19.84	19.84	19.84	25.82	25.82	25.82	25.82	25.82	25.82	25.82	25.82	25.82	25.82	25.82
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	4.81	4.81	4.81	4.81	8.81	8.81	8.81	8.81	8.81	8.81	8.81	8.81	8.81	8.81	8.81
Natural Gas	877.85	869.07	860.38	851.78	843.26	834.83	826.48	818.22	810.03	801.93	793.91	785.98	778.12	770.33	762.63
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	99.91	94.91	90.17	85.66	81.38	77.31	73.44	69.77	66.28	62.97	59.82	56.83	53.98	51.29	48.72
Hydro	9555.81	9460.35	9365.75	9272.09	9179.37	9087.58	8996.70	8906.73	8817.67	8729.48	8642.19	8555.77	8470.21	8385.51	8301.66
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	452.88	448.45	443.98	439.52	435.13	430.78	426.47	422.20	417.98	413.80	409.66	405.57	401.51	397.50	393.52
Total Supply	17,185.88	17,487.75	17,794.93	18,107.62	18,425.82	18,740.83	19,079.70	19,415.51	19,757.31	20,105.25	20,458.46	20,820.83	21,187.10	21,560.70	21,941.22
Total New Sustainables	465.84	465.84	465.84	465.84	496.83	496.83	496.83	496.83	496.83	496.83	496.83	496.83	496.83	496.83	496.83

Table B.4 - Total generation capacity (MW) by technology type - ADD

Total Cumulative Capacity from New and Existing Technologies - BC Model - EA

Share of market for non-least cost technologies: 20%   Price threshold over least cost for investment: 20%

MegaWatts

Technology Name	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	194.88	288.81	437.77	574.00	708.62	797.88	888.00	973.57	1060.42	1148.58	1288.02	1389.80	1508.32	1627.21	1745.27
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	31.34	48.14	70.08	91.85	130.87	314.08	468.03	678.74	858.24	1034.54	1288.30	1536.64	1785.58	2033.15	2279.38
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam	25.32	38.04	57.15	75.19	83.02	104.88	116.61	128.27	139.85	151.35	167.58	183.71	198.74	215.67	231.51
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	25.32	38.04	57.15	75.15	83.02	104.88	116.61	128.27	139.85	151.35	167.58	183.71	198.74	215.67	231.51
Gas cogen retrofits	56.12	248.81	506.71	782.73	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1020.88	1010.48	1000.38	990.37	980.47	970.67	960.96	951.35	941.84	932.42	923.08	913.88	904.72	895.68	886.72
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	215.85	204.87	194.62	184.89	175.65	166.87	158.52	150.60	143.07	135.91	129.12	122.66	116.53	110.70	105.17
Hydro	11110.77	10996.66	10888.67	10780.77	10672.96	10566.23	10460.57	10355.96	10252.40	10149.88	10048.38	9947.90	9848.42	9749.93	9652.43
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	526.88	521.41	516.20	511.04	505.93	500.87	495.86	490.90	485.99	481.13	476.32	471.56	466.84	462.17	457.55
Total Supply	13,566.77	13,712.47	14,029.74	14,345.78	14,666.54	14,826.12	14,991.16	15,155.67	15,316.67	15,483.16	15,760.50	16,046.63	16,328.90	16,618.18	16,906.52
Total New Sustainables	360.64	378.08	414.31	450.29	486.04	509.72	533.22	558.55	579.71	602.70	635.16	667.41	699.47	731.34	763.01

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	1869.05	1992.02	2117.23	2243.71	2371.50	2500.64	2629.25	2757.25	2887.08	3017.44	3148.19	3279.98	3412.00	3546.07	3681.01
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2535.34	2783.75	3054.08	3318.17	3584.34	3853.24	4119.14	4387.87	4658.51	4929.85	5203.88	5481.14	5762.20	6047.25	6336.14
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro - Optimal	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
Biomass steam	247.97	264.80	281.30	298.34	315.47	332.79	347.35	362.09	376.88	389.89	402.83	416.13	429.48	443.00	456.67
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	247.97	264.80	281.30	298.34	315.47	332.79	347.35	362.09	376.88	389.89	402.83	416.13	429.48	443.00	456.67
Gas cogen retrofits	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00	1000.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.81	25.98	39.18	52.51	66.02	79.70
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Hydro - lower grade	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	14.57	29.31	44.20	57.10	70.18	83.38	96.71	110.22	123.88
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	877.85	869.07	860.38	851.78	843.26	834.83	826.48	818.22	810.03	801.93	793.91	785.98	770.12	770.33	762.63
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	99.91	94.91	90.17	85.66	81.38	77.31	73.44	69.77	66.28	62.97	59.82	56.83	53.99	51.29	48.72
Hydro	9556.91	9460.35	9365.75	9272.09	9179.37	9087.58	8996.70	8906.73	8817.67	8729.49	8642.19	8555.77	8470.21	8385.51	8301.66
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	452.99	448.45	443.96	439.52	435.13	430.78	426.47	422.20	417.98	413.80	409.66	405.57	401.51	397.50	393.52
Total Supply	17,105.06	17,487.75	17,794.03	18,107.62	18,425.92	18,748.93	19,078.78	19,415.51	19,757.31	20,105.25	20,458.45	20,828.03	21,187.10	21,560.79	21,941.22
Total New Sustainables	795.95	828.20	862.77	896.69	930.94	965.58	1000.29	1053.47	1090.15	1130.87	1170.02	1215.42	1255.98	1296.22	1337.23

Table B.5 - Annual energy generation (GWh) by technology type - BAU

Generating Statistics - B.C. Model - BAU

Annual GWh production and Revenue Received for Electricity (million $)

	1995		1996		1997		1998		1999		2000		2001		2002		2003
	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh
Simple cycle gas	0.0	0.0	623.8	18.8	944.1	29.2	1355.8	43.6	1743.6	57.6	2118.0	72.8	2374.9	83.4	2630.0	94.3	2886.0
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	0.0	0.0	109.0	3.2	663.7	20.2	1632.2	48.2	2729.5	81.9	3943.1	119.9	4825.6	147.4	5759.1	176.6	6726.3
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro - Optimal	0.0	0.0	1708.2	30.1	1708.2	32.3	1708.2	34.6	1708.2	36.4	1708.2	39.0	1708.2	40.3	1708.2	40.8	1708.2
Biomass steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal - Pressurized Flui	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier turbin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas cogen retrofits	0.0	0.0	282.8	5.0	436.1	8.2	638.4	12.9	839.3	17.9	1039.0	23.7	1171.2	27.7	1302.4	31.1	1432.7
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro - lower gra	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	1884.5	57.9	1788.1	55.9	1684.2	55.9	1574.3	55.2	1489.3	53.5	1373.7	53.1	1312.9	52.8	1253.5	52.5	1203.7
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	148.3	5.1	133.8	5.0	127.1	5.2	120.8	5.3	114.7	5.5	109.0	5.5	103.5	5.5	98.4	5.5	93.4
Hydro	62120.4	1140.0	62054.5	1138.2	62284.6	1219.4	62587.6	1307.3	62741.4	1373.2	62777.1	1466.9	62556.3	1508.6	62284.9	1513.0	61969.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	558.5	19.0	534.9	18.8	499.1	18.6	449.8	18.1	419.9	18.2	396.3	18.4	382.1	18.7	368.2	19.0	354.7
Total (GWh, Millions)	64,712	$ 1,222	67,218	$ 1,273	68,367	$ 1,389	70,067	$ 1,525	71,766	$ 1,644	73,464	$ 1,799	74,435	$ 1,862	75,405	$ 1,933	76,374

	2011		2012		2013		2014		2015		2016		2017		2018		2019
	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh
Simple cycle gas	5338.7	186.3	5681.1	199.2	6028.8	212.4	6382.1	225.9	6725.3	239.3	7070.0	252.9	7430.3	267.1	7799.3	281.7	8174.7
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	18216.3	544.0	19990.6	595.4	21798.0	647.9	23623.6	701.0	25468.2	754.9	27332.3	809.5	29206.6	873.1	31099.1	929.4	33012.3
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro - Optimal	1708.2	47.7	1708.2	48.6	1708.2	48.7	1708.2	48.8	1708.2	48.9	1708.2	48.9	1708.2	49.4	1708.2	49.5	1708.2
Biomass steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal - Pressurized Flui	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier turbin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas cogen retrofits	2769.6	77.3	2955.3	84.2	3142.8	89.6	3332.2	95.2	3523.5	100.8	3716.8	106.5	3912.1	113.2	4109.6	119.1	4309.2
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro - lower gra	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	821.5	35.2	778.5	34.2	735.8	33.1	693.3	32.1	666.8	31.6	644.7	31.1	622.8	30.7	601.1	30.3	579.6
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	31.0	2.1	29.4	2.1	28.0	2.0	26.6	1.9	25.2	1.9	24.0	1.8	22.8	1.8	21.6	1.7	20.6
Hydro	58582.2	1634.4	58010.9	1652.1	57430.8	1637.9	56856.5	1623.9	56287.9	1610.1	55725.0	1596.4	55167.8	1596.4	54616.1	1582.9	54069.9
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	276.2	13.8	263.9	13.6	251.7	13.3	239.8	13.1	228.1	12.8	216.5	12.6	205.1	12.4	194.0	12.2	183.0
Total (GWh, Millions)	87,744	$ 2,541	89,419	$ 2,629	91,124	$ 2,685	92,862	$ 2,742	94,633	$ 2,800	96,438	$ 2,860	98,278	$ 2,944	100,149	$ 3,007	102,057

Table B.5 - Annual energy generation (GWh) by technology type - BAU (continued....)

	2004		2005		2006		2007		2008		2009		2010	
Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $
105.6	3131.4	117.0	3375.5	128.6	3704.7	142.6	4043.1	156.3	4379.9	170.9	4693.4	185.0	5006.2	199.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
209.8	7735.0	242.4	8773.5	276.4	10258.1	325.9	11771.4	372.6	13304.5	421.1	14898.2	471.6	16505.7	523.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42.6	1708.2	43.9	1708.2	45.3	1708.2	46.0	1708.2	47.1	1708.2	47.4	1708.2	48.6	1708.2	49.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35.7	1562.0	40.2	1690.5	44.8	1871.7	50.4	2051.8	56.6	2230.8	61.9	2408.8	68.5	2585.7	75.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52.4	1164.2	52.6	1125.5	52.6	1071.3	51.6	1016.9	50.0	950.2	48.4	906.9	47.5	864.7	48.6
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.4	88.8	5.4	84.3	5.3	80.1	5.1	72.3	4.7	60.1	4.0	48.5	3.2	37.5	2.5
1586.2	61612.0	1603.5	61225.5	1640.1	60872.6	1651.3	60480.4	1676.1	60068.1	1671.8	59595.2	1699.0	59106.4	1725.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19.3	341.6	19.5	326.9	19.8	309.8	19.4	292.6	19.0	289.7	19.1	286.8	19.2	283.9	19.3
$ 2,037	77,343	$ 2,126	78,312	$ 2,213	79,877	$ 2,292	81,437	$ 2,382	82,992	$ 2,445	84,546	$ 2,543	86,100	$ 2,642

	2020		2021		2022		2023		2024		2025	
Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $	GWh	Million $
298.8	8556.6	312.2	8938.8	331.0	9321.1	350.3	8259.7	326.3	8628.4	346.3	9056.8	368.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
986.5	34946.9	1044.4	36910.0	1118.2	38902.1	1194.9	40923.9	1274.4	42972.5	1368.0	43818.6	1414.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49.6	1708.2	49.7	1708.2	50.4	1708.2	51.2	1708.2	52.0	1708.2	53.2	1708.2	53.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
125.1	4511.0	131.2	4715.1	139.2	4921.5	147.5	5130.3	156.1	5341.5	166.2	6701.4	211.6
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29.9	558.2	29.5	537.0	29.2	515.9	28.8	374.5	24.8	362.1	24.8	355.2	24.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.6	19.5	1.6	18.6	1.5	17.6	1.5	16.7	1.4	15.9	1.4	15.1	1.3
1569.6	53529.2	1556.4	52993.9	1564.3	52464.0	1572.4	51939.4	1580.2	51420.0	1600.0	50905.8	1607.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.0	172.2	11.6	161.5	11.6	151.1	11.4	1705.5	59.2	1705.0	60.0	1722.3	61.4
$ 3,071	104,002	$ 3,137	105,983	$ 3,245	106,001	$ 3,358	110,058	$ 3,474	112,154	$ 3,620	114,263	$ 3,744

Table B.6 - Annual energy generation (GWh) by technology type - EA

Generating Statistics — Annual GWh production and Revenue Received for Electricity (million $)

	1995 GWh	1995 Million Dollars	1996 GWh	1996 Million Dollars	1997 GWh	1997 Million Dollars	1998 GWh	1998 Million Dollars	1999 GWh	1999 Million Dollars	2000 GWh	2000 Million Dollars	2001 GWh	2001 Million Dollars	2002 GWh	2002 Million Dollars
Simple cycle gas	0.0	0.0	362.8	15.4	544.1	24.0	778.4	35.7	1025.5	48.6	1260.1	62.2	1425.9	71.2	1571.0	80.1
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	0.0	0.0	78.0	3.1	134.4	5.3	195.7	8.1	281.9	11.0	284.2	13.4	732.1	34.2	1238.4	57.4
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro - Optim	0.0	0.0	1708.2	35.8	1708.2	36.8	1708.2	38.2	1708.2	40.1	1708.2	41.4	1708.2	44.1	1708.2	45.8
Biomass steam	0.0	0.0	70.7	2.7	109.0	4.3	168.1	6.7	233.1	9.6	303.1	12.4	380.4	15.8	470.3	18.8
Coal - Pressurized Fl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier tur	0.0	0.0	70.7	2.7	109.0	4.3	177.3	6.9	244.2	8.7	318.4	12.7	412.0	16.2	501.4	18.4
Gas cogen retrofits	0.0	0.0	378.1	7.8	1874.8	35.9	3395.6	78.0	5111.4	120.0	6701.4	162.4	6701.4	172.9	6701.4	180.1
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro - lower	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Sol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	1325.2	62.8	1251.1	57.3	1202.0	57.8	1139.2	57.8	1078.3	57.6	1017.6	57.4	987.2	56.8	928.8	56.7
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	148.3	7.7	133.8	7.4	127.1	7.4	120.8	7.5	114.7	7.5	108.0	7.5	103.5	7.3	98.4	7.2
Hydro	62120.4	1397.0	61806.2	1363.9	61565.8	1382.6	61150.8	1434.5	60726.4	1484.8	60354.8	1532.4	60422.1	1625.4	60418.5	1684.4
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	1117.7	47.2	1168.6	47.3	1181.3	49.1	1209.4	52.4	1222.8	54.2	1344.8	59.3	1520.6	65.3	1722.2	72.2

	2011 GWh	2011 Million Dollars	2012 GWh	2012 Million Dollars	2013 GWh	2013 Million Dollars	2014 GWh	2014 Million Dollars	2015 GWh	2015 Million Dollars	2016 GWh	2016 Million Dollars	2017 GWh	2017 Million Dollars	2018 GWh	2018 Million Dollars
Simple cycle gas	3003.3	177.8	3278.1	180.3	3487.7	170.8	3659.4	181.4	3854.1	182.1	4051.6	203.0	4242.0	213.9	4429.6	224.6
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	11118.1	476.7	12738.1	542.8	14387.9	583.4	16118.2	628.4	17893.7	695.2	19734.0	784.3	21587.7	844.1	23452.4	915.7
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro - Optim	1708.2	61.0	1708.2	61.4	1708.2	58.4	1708.2	60.1	1708.2	61.2	1708.2	61.3	1708.2	62.8	1708.2	62.8
Biomass steam	1615.6	63.0	1758.8	68.2	1920.6	70.5	2095.7	78.0	2275.4	82.8	2470.5	88.8	2586.4	95.1	2696.1	98.3
Coal - Pressurized Fl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier tur	1655.2	63.7	1806.0	69.1	1995.0	71.7	2174.8	77.4	2349.0	84.2	2477.8	88.9	2586.4	95.1	2696.1	98.3
Gas cogen retrofits	6701.4	239.2	6701.4	241.0	6701.4	232.9	6701.4	235.6	6701.4	240.2	6701.4	240.5	6701.4	248.5	6701.4	248.8
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro - lower	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.8	4.2	231.0	8.5
Fuel Cell Cogenerat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Sol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	634.8	50.8	612.3	50.3	582.9	36.4	550.9	35.4	519.3	34.3	487.9	33.3	486.0	32.8	451.1	32.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	44.3	3.8	32.4	2.8	28.0	2.5	26.6	2.4	25.2	2.3	24.0	2.2	22.8	2.2	21.6	2.1
Hydro	58340.1	2089.0	57904.2	2085.5	57401.1	1995.6	56856.5	1999.2	56287.9	2017.3	55725.0	1998.5	55107.8	2029.0	54616.1	2011.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	2814.6	111.0	2861.4	112.7	2914.7	107.7	2955.0	108.8	3004.3	110.5	3043.0	111.8	3089.7	114.5	3133.8	115.5

Table B.6 - Annual energy generation (GWh) by technology type - EA (continued....)

2003 GWh	2003 Million Dollars	2004 GWh	2004 Million Dollars	2005 GWh	2005 Million Dollars	2006 GWh	2006 Million Dollars	2007 GWh	2007 Million Dollars	2008 GWh	2008 Million Dollars	2009 GWh	2009 Million Dollars	2010 GWh	2010 Million Dollars
1710.8	89.1	1849.8	98.3	1988.5	107.8	2175.8	119.2	2363.4	130.7	2558.6	142.7	2734.6	154.1	2910.5	165.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1829.5	83.9	2502.3	113.5	3242.8	145.8	4354.8	192.5	5558.8	246.4	6832.2	299.7	8175.0	355.8	9585.3	414.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1708.2	47.8	1708.2	49.7	1708.2	51.6	1708.2	53.2	1708.2	55.8	1708.2	57.3	1708.2	58.3	1708.2	58.6
557.2	22.3	650.9	25.8	751.3	29.8	883.9	34.8	1025.9	40.6	1177.4	46.3	1332.7	51.5	1447.4	58.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
580.9	22.8	682.5	28.4	775.5	30.2	920.4	35.4	1074.7	41.4	1226.2	47.1	1343.9	51.7	1508.3	57.9
8701.4	187.5	8701.4	194.8	8701.4	202.3	8701.4	208.9	8701.4	218.1	8701.4	224.9	8701.4	228.8	8701.4	234.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
898.4	58.7	864.8	56.8	833.9	56.8	798.9	55.4	744.8	53.9	701.9	52.5	670.0	51.8	657.0	51.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
93.4	7.1	88.8	7.0	84.3	6.8	80.1	6.5	76.1	6.3	72.3	6.0	68.4	5.8	58.5	4.8
60348.1	1743.2	60218.1	1798.8	60038.0	1855.2	59924.0	1902.5	58719.2	1972.0	58437.8	2016.6	58124.7	2032.9	58745.5	2061.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1801.5	78.1	2028.1	83.0	2141.8	87.3	2294.4	92.2	2425.2	97.8	2548.4	102.0	2650.2	105.8	2761.1	109.4

2019 GWh	2019 Million Dollars	2020 GWh	2020 Million Dollars	2021 GWh	2021 Million Dollars	2022 GWh	2022 Million Dollars	2023 GWh	2023 Million Dollars	2024 GWh	2024 Million Dollars	2025 GWh	2025 Million Dollars
4620.7	235.7	4817.1	247.2	5015.8	260.8	5218.9	275.0	5420.4	289.5	5628.6	304.6	5843.3	320.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25415.2	990.1	27384.9	1064.8	29378.0	1152.2	31397.9	1242.8	33442.3	1336.5	35512.7	1450.3	37801.8	1551.3
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1708.2	83.1	1708.2	83.1	1708.2	83.9	1708.2	84.6	1708.2	85.4	1708.2	86.8	1708.2	87.7
2807.0	103.8	2903.1	107.3	3000.2	112.2	3098.5	117.2	3198.0	122.4	3298.6	129.1	3400.4	134.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2807.0	103.8	2903.1	107.3	3000.2	112.2	3098.5	117.2	3198.0	122.4	3298.6	129.1	3400.4	134.7
8701.4	247.4	8701.4	247.8	8701.4	250.8	8701.4	253.5	8701.4	256.6	8701.4	262.2	8701.4	265.4
0.0	0.0	70.7	2.8	142.1	5.3	214.4	8.1	287.5	11.0	361.5	14.1	438.3	17.3
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
348.4	12.9	450.2	16.8	553.1	20.7	657.2	24.9	762.5	29.2	869.0	34.0	978.8	38.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
438.5	31.9	423.2	31.8	410.0	31.3	397.1	31.1	384.3	30.9	371.8	30.7	350.4	30.5
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20.8	2.0	19.5	1.9	18.8	1.9	17.6	1.8	16.7	1.7	15.9	1.7	15.1	1.6
54088.8	1995.9	53529.2	1978.0	52993.8	1981.3	52464.0	1984.9	51938.4	1988.6	51420.0	2011.9	50805.8	2018.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3112.3	114.9	3081.2	113.8	3050.4	114.0	3019.8	114.3	2989.6	114.5	2959.8	115.8	2930.2	118.0

Figure B.1 - Investment in Sustainables Capacity (MW) - all scenarios

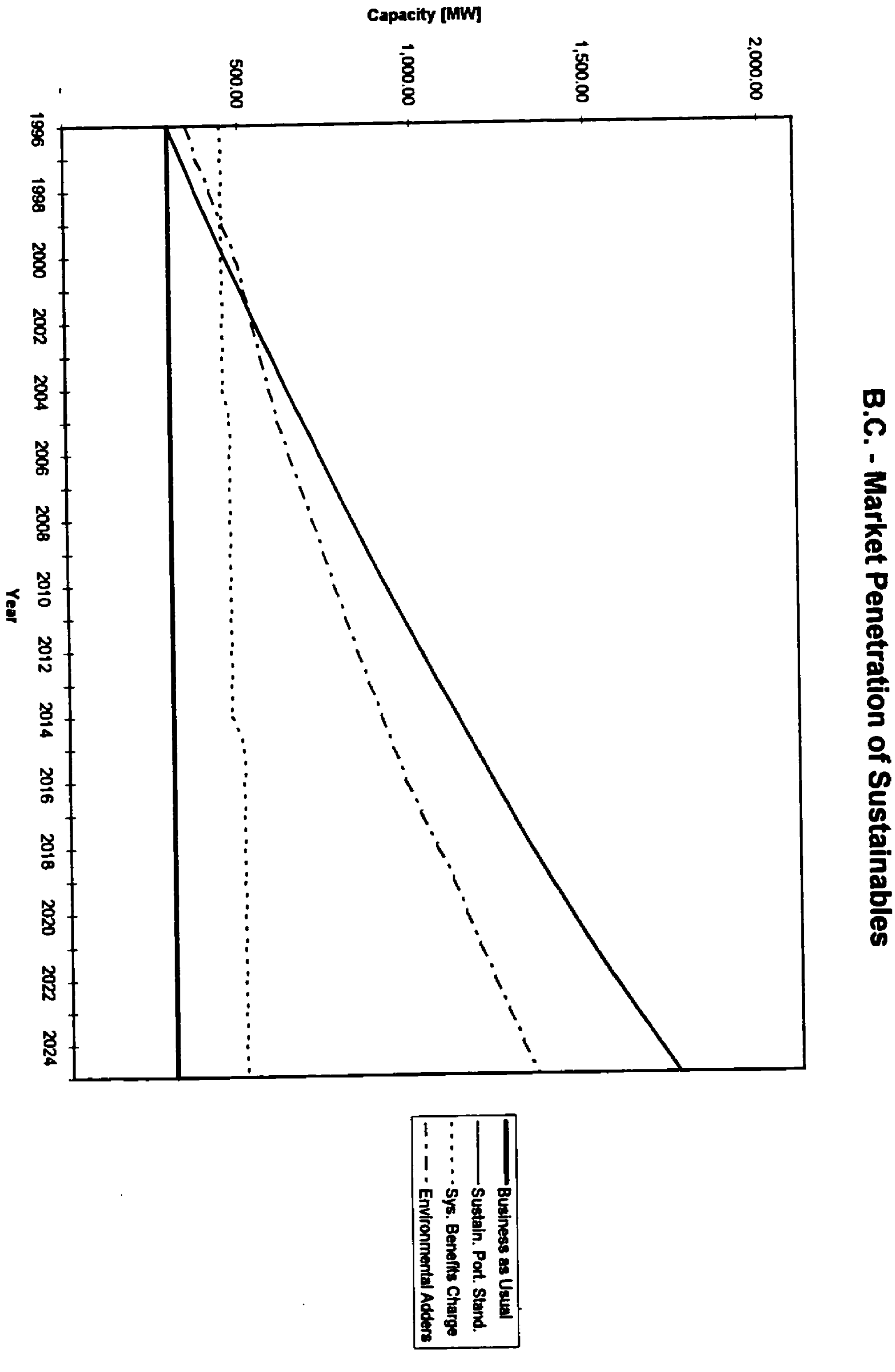


Figure B.2 - Generation by Sustainables (GWh) - all scenarios

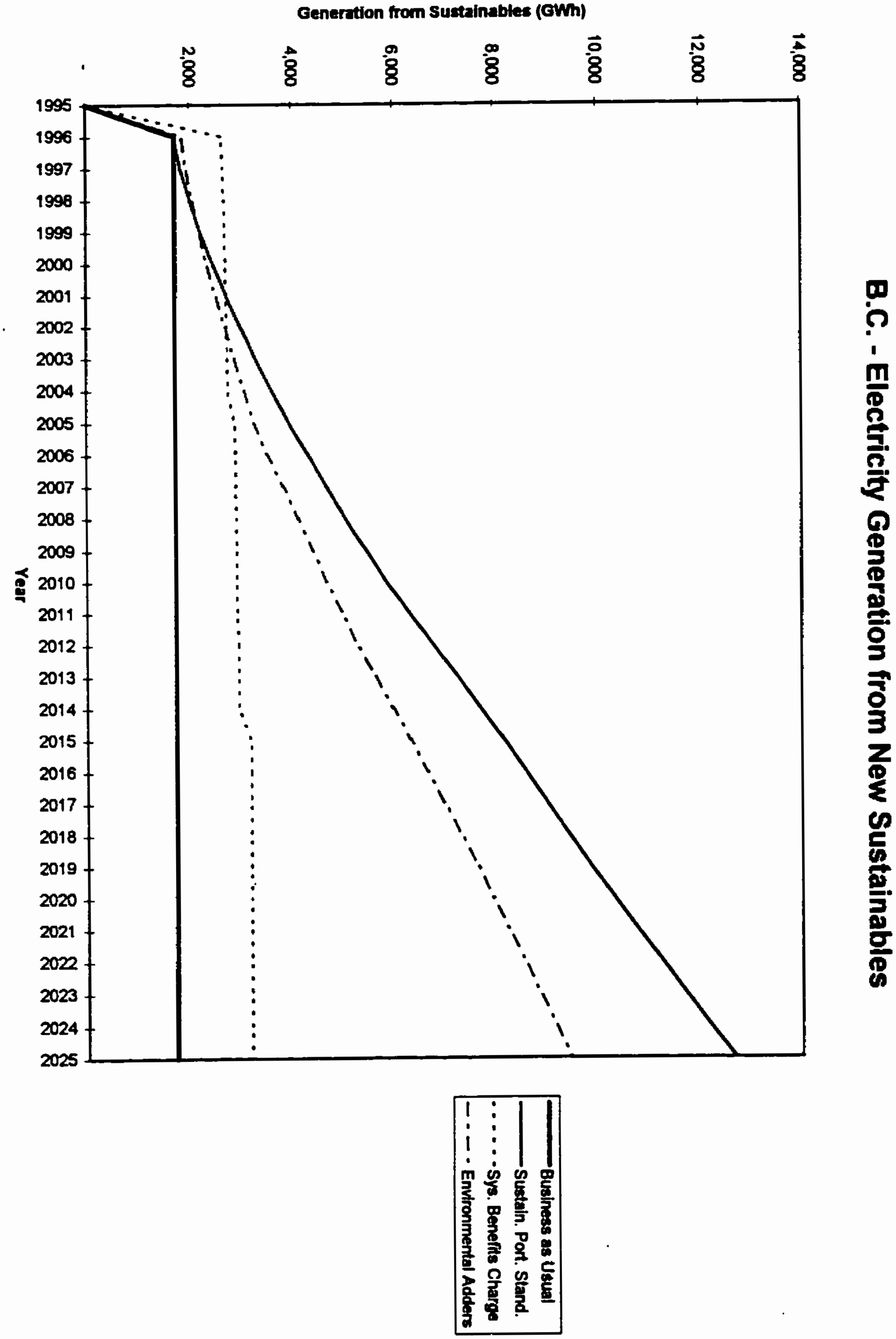


Figure B.3 - Peak wholesale electricity rates ($1995/kWh) - all scenarios

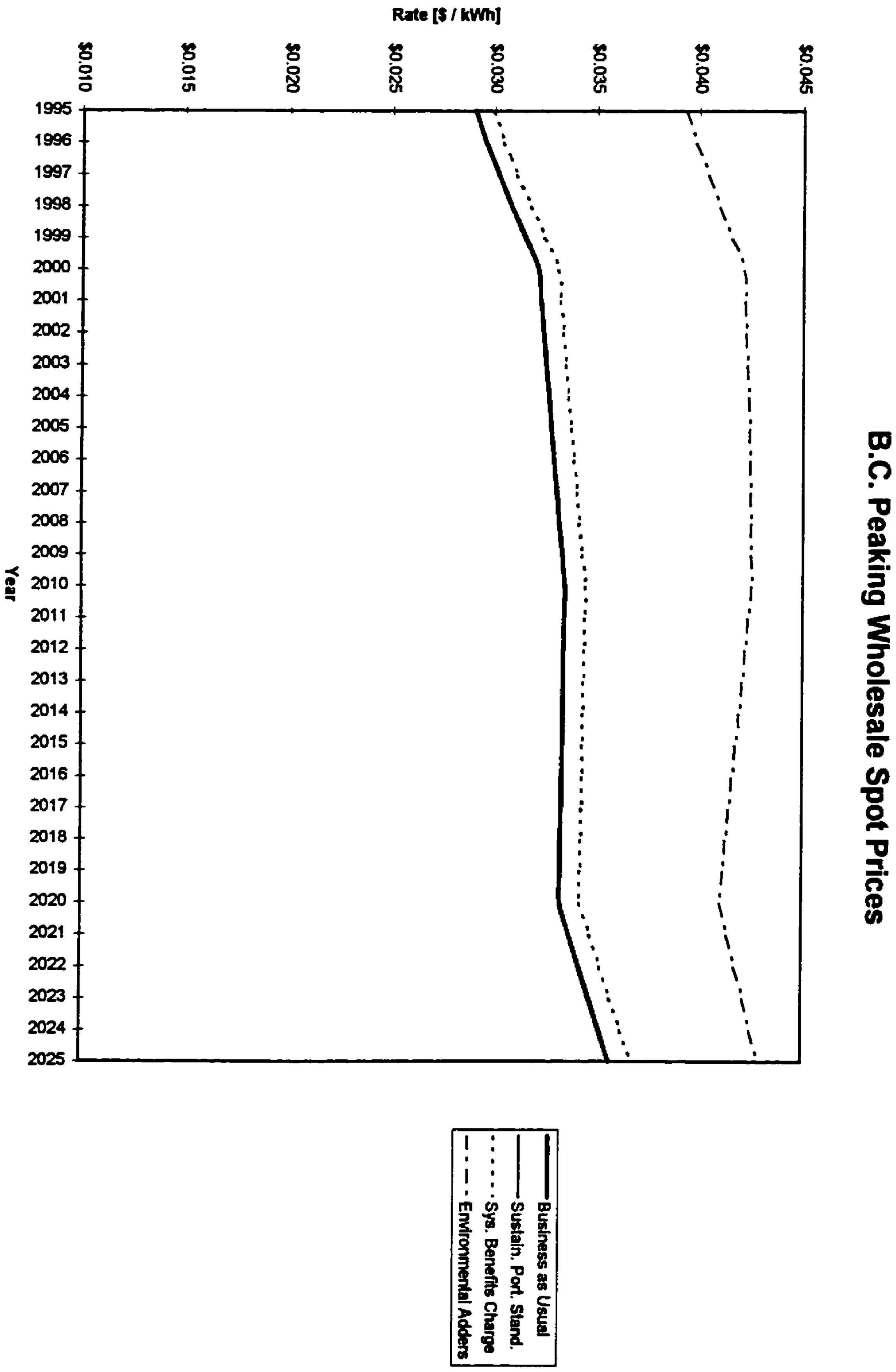


Figure B.4 - Baseload wholesale electricity rates ($1995/kWh) - all scenarios

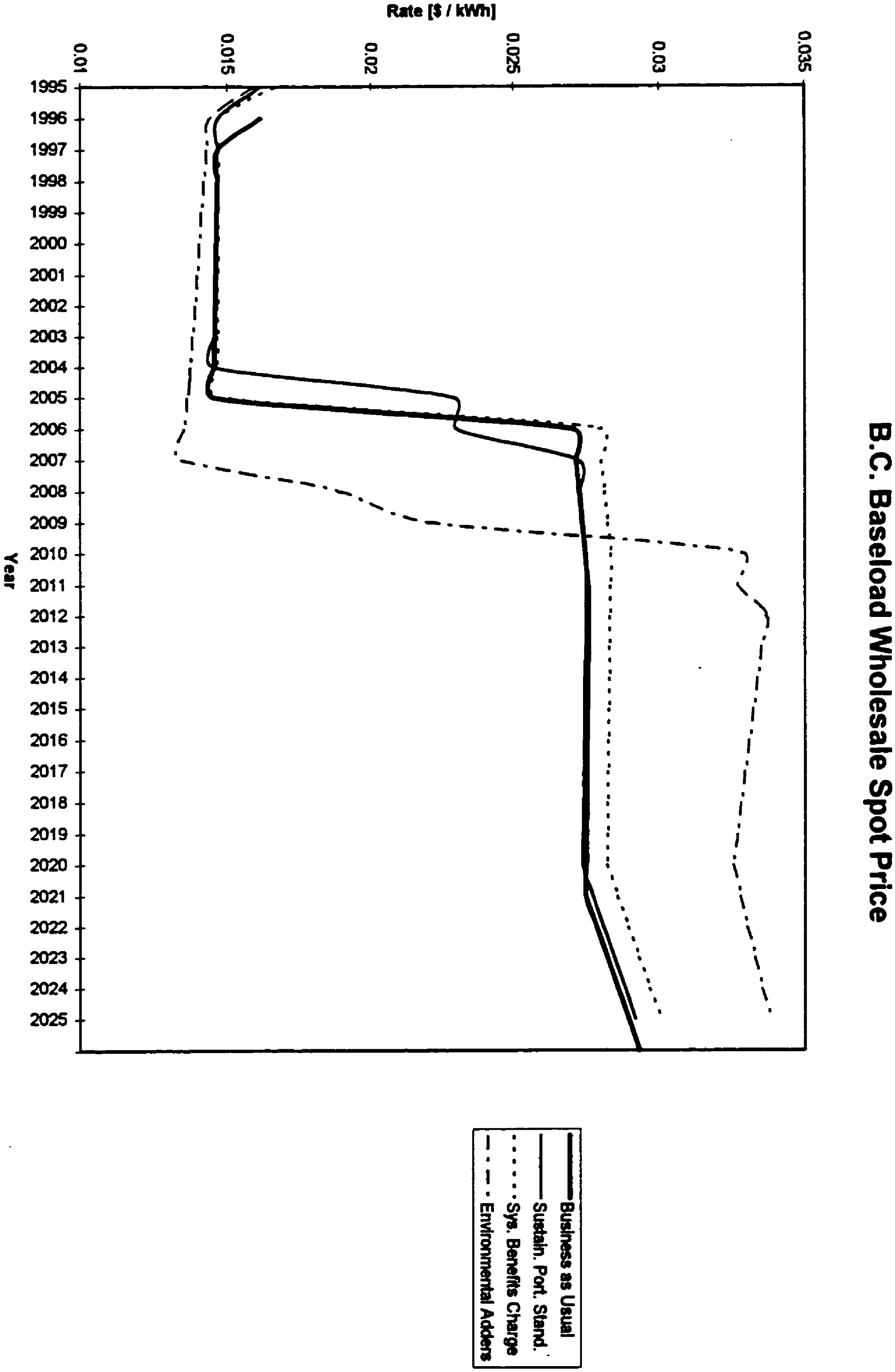


Figure B.5 - Total cost of electricity (million $1995) - all scenarios

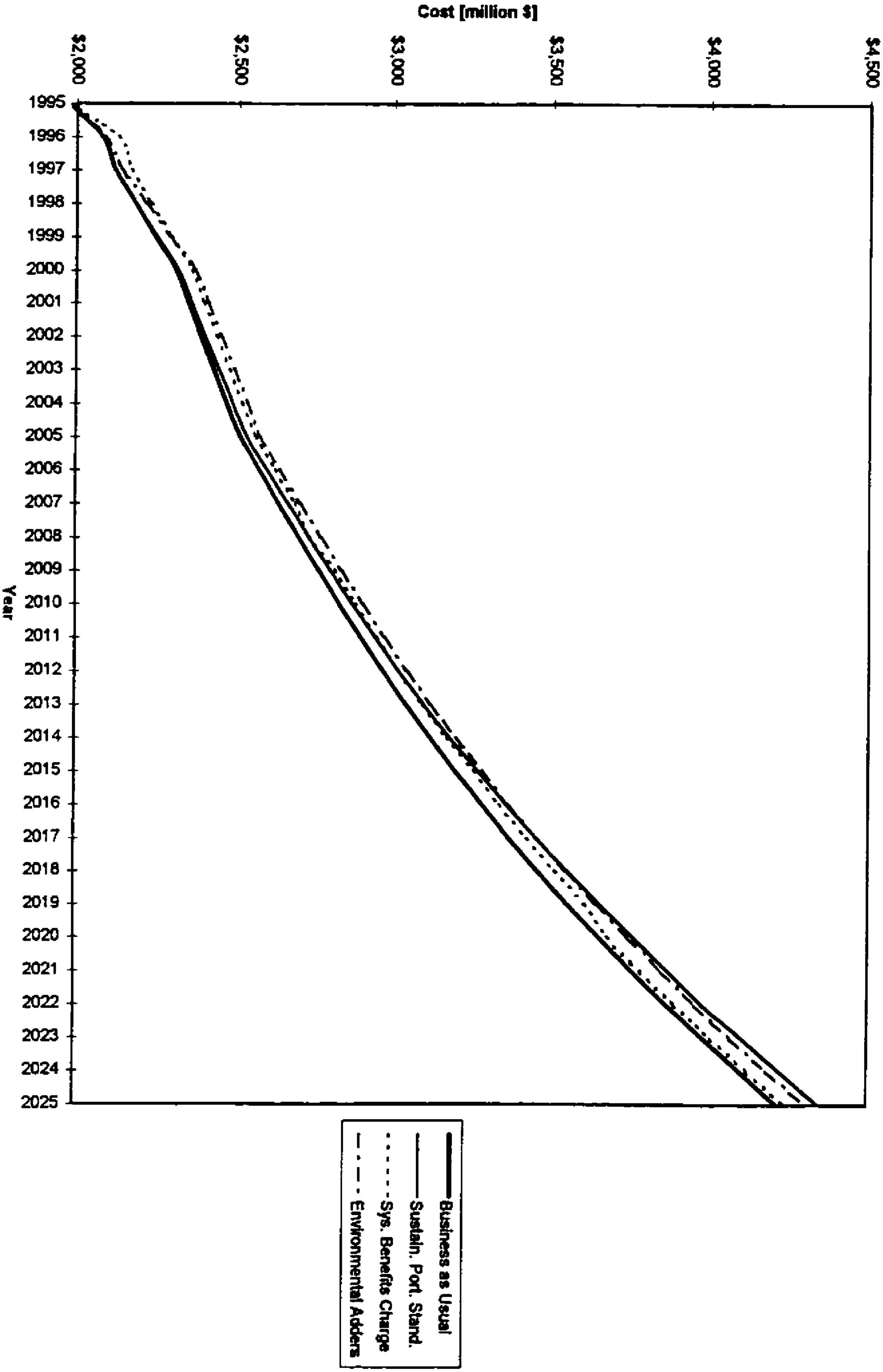


Table C.1 - Total generation capacity (MW) by technology type - BAU

Total Cumulative Capacity from New and Existing Technologies - Alberta Model - BAU

Share of market for non-least cost technol 20%   Price threshold over least cost for invest 20%

MegaWatts

Technology Name		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	ew	11.39	157.00	301.48	442.10	579.05	716.84	852.70	986.69	1118.85	1249.24	1387.99	1525.04	1660.44	1794.23	1926.45
Simple cycle oil (b)	es	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas		1.09	12.58	204.62	401.41	597.96	796.71	993.87	1188.87	1382.36	1574.16	1779.25	1982.75	2184.67	2385.05	2583.92
Combined cycle oil		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro		13.58	194.83	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidi		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas cogen retrofits		1.86	26.05	50.44	74.54	98.36	122.40	146.17	169.68	192.94	215.96	240.52	264.84	288.94	312.81	336.48
Large Hydro		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	ng	1712.78	1672.53	1633.23	1594.85	1557.37	1520.77	1485.03	1450.13	1416.05	1382.78	1350.28	1318.55	1287.56	1257.31	1227.76
Coal	es	5850.21	5712.73	5578.48	5447.39	5319.37	5194.37	5072.30	4953.10	4836.70	4723.04	4612.05	4503.67	4397.83	4294.48	4193.56
Oil		21.48	20.98	20.49	20.00	19.53	19.07	18.63	18.19	17.76	17.34	16.94	16.54	16.15	15.77	15.40
Hydro		814.77	806.62	798.56	790.57	782.66	774.84	767.09	759.42	751.82	744.31	736.86	729.49	722.20	714.98	707.83
Nuclear		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass		188.46	184.04	179.71	175.49	171.36	167.34	163.40	159.56	155.81	152.15	148.56	145.09	141.68	138.35	135.10
Total Supply		**8,615.64**	**8,787.66**	**8,967.00**	**9,146.34**	**9,325.68**	**9,512.34**	**9,696.99**	**9,885.65**	**10,072.31**	**10,258.97**	**10,472.47**	**10,685.97**	**10,899.47**	**11,112.97**	**11,326.47**
Total Sustainables		13.58	194.83	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00

Technology Name		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	ew	2062.38	2198.89	2336.03	2473.87	2612.46	2751.88	2892.18	3033.42	3175.68	3319.00	3462.15	3605.20	3748.20	3891.20	4034.27
Simple cycle oil (b)	es	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas		2788.23	2993.25	3199.09	3405.82	3613.55	3822.35	4041.23	4277.65	4515.60	4755.17	4997.79	5243.54	5492.54	5744.90	6000.74
Combined cycle oil		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro		200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidi		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas cogen retrofits		360.76	385.15	409.65	434.26	459.00	483.88	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Large Hydro		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	ng	1198.91	1170.73	1143.22	1116.35	1090.12	1064.50	1039.49	1015.06	991.21	967.91	945.17	922.95	901.27	880.09	859.40
Coal	es	4095.01	3998.78	3904.61	3813.05	3723.44	3635.94	3550.49	3467.06	3385.58	3306.02	3228.33	3152.46	3078.38	3006.04	2935.40
Oil		15.04	14.68	14.34	14.00	13.67	13.35	13.04	12.73	12.43	12.14	11.85	11.56	11.30	11.04	10.78
Hydro		700.75	693.74	686.80	679.94	673.14	666.41	659.74	653.14	646.61	640.15	633.75	627.41	621.13	614.92	608.77
Nuclear		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass		131.92	128.82	125.79	122.84	119.95	117.13	114.38	111.69	109.07	106.50	104.00	101.56	99.17	96.84	94.56
Total Supply		**11,553.00**	**11,784.06**	**12,019.74**	**12,260.13**	**12,505.33**	**12,755.44**	**13,010.65**	**13,270.76**	**13,536.17**	**13,806.90**	**14,083.03**	**14,364.89**	**14,651.99**	**14,945.03**	**15,243.93**
Total Sustainables		200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00

Table C.2 - Total generation capacity (MW) by technology type - SPS

Total Cumulative Capacity from New and Existing Technologies - Alberta Model - SPS

Share of market for non-least cost technologies: 20%   Price threshold over least cost for investment: 20%

MegaWatts

Technology Name	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	11.38	197.00	301.48	442.10	578.05	718.84	852.70	988.88	1118.85	1248.24	1387.88	1525.04	1660.44	1794.23	1928.45
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	0.00	11.76	176.13	340.85	504.80	670.40	833.45	994.10	1152.37	1308.31	1478.84	1643.07	1807.01	1968.70	2128.17
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro	13.58	184.83	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	18.73	18.73	47.13	78.10	111.70	144.88	178.84	213.42	248.63	284.40	321.05	358.32	388.31	434.88	474.38
Gas cogen retrofits	1.86	28.05	50.44	74.54	98.38	122.40	146.17	168.88	192.84	215.88	240.52	264.84	288.84	312.81	336.48
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1712.78	1872.53	1833.23	1584.85	1557.37	1520.77	1485.03	1450.13	1416.05	1382.78	1350.28	1318.55	1287.58	1257.31	1227.78
Coal	5850.21	5712.73	5578.48	5447.38	5318.37	5184.37	5072.30	4953.10	4836.70	4723.04	4612.05	4503.87	4387.83	4294.48	4183.58
Oil	21.40	20.88	20.48	20.00	19.53	19.07	18.63	18.19	17.78	17.34	16.84	16.54	16.15	15.77	15.40
Hydro	814.77	806.82	798.58	790.67	782.88	774.84	767.08	758.42	751.82	744.31	736.88	729.40	722.20	714.98	707.83
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	188.48	184.04	179.71	175.48	171.38	167.34	163.40	159.58	155.81	152.15	148.58	145.08	141.68	138.35	135.10
Total Supply	8,034.29	8,888.30	8,985.84	9,164.88	9,344.32	9,530.88	9,717.64	9,904.30	10,088.95	10,277.01	10,481.11	10,704.01	10,918.11	11,131.01	11,388.11
Total Sustainables	33.32	214.56	347.13	279.10	311.70	344.98	378.88	413.42	448.83	484.48	521.05	558.32	588.31	634.88	674.38

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	2082.38	2198.88	2336.03	2473.87	2612.48	2751.88	2882.18	3033.42	3175.88	3318.00	3462.15	3605.20	3748.20	3891.20	4034.27
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2292.38	2458.58	2620.85	2788.27	2948.93	3114.88	3288.13	3480.11	3671.80	3864.28	4058.88	4258.28	4458.34	4662.84	4870.18
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam	14.48	55.32	98.88	138.18	182.28	228.11	270.74	318.18	362.44	408.53	457.47	500.00	500.00	500.00	500.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Gas cogen retrofits	380.78	385.15	408.85	434.26	458.00	483.88	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.82	52.84	100.60	148.22
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1198.91	1170.73	1143.22	1118.35	1090.12	1064.50	1039.48	1015.08	991.21	967.81	945.17	922.95	901.27	880.08	858.40
Coal	4085.01	3988.78	3894.81	3813.05	3723.44	3635.94	3550.48	3467.08	3385.58	3306.02	3228.33	3152.48	3078.38	3006.04	2935.40
Oil	15.04	14.68	14.34	14.00	13.67	13.35	13.04	12.73	12.43	12.14	11.85	11.58	11.30	11.04	10.78
Hydro	700.75	693.74	686.80	679.94	673.14	666.41	659.74	653.14	646.61	640.15	633.75	627.41	621.13	614.92	608.77
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	131.92	128.82	125.79	122.84	119.95	117.13	114.38	111.68	109.07	106.50	104.00	101.56	99.17	96.84	94.58
Total Supply	11,571.64	11,902.76	12,036.38	12,278.77	12,523.97	12,774.88	13,028.10	13,288.40	13,554.91	13,825.54	14,101.88	14,383.34	14,670.83	14,963.67	15,262.57
Total Sustainables	714.48	755.32	798.88	838.18	882.28	926.11	970.74	1016.18	1062.44	1108.53	1157.47	1205.92	1252.84	1300.80	1348.22

Table C.3 - Total generation capacity (MW) by technology type - SBC

Total Cumulative Capacity from New and Existing Technologies - Alberta Model - SBC

Share of market for non-least cost technologies: 20% Price threshold over least cost for investment: 20%

MegaWatts

Technology Name	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	11.38	157.00	301.48	442.10	579.05	718.84	852.70	986.88	1118.85	1248.24	1387.88	1525.04	1680.44	1794.23	1828.45
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	0.00	0.00	102.52	288.31	485.87	684.82	881.58	1086.78	1280.28	1448.54	1654.83	1858.13	2080.05	2280.43	2458.30
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro	13.58	184.83	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	33.21	33.21	33.21	33.21	33.21	33.21	33.21	33.21	33.21	38.82	38.82	38.82	38.82	38.82	38.82
Gas cogen retrofits	1.88	28.05	50.44	74.54	98.36	122.40	148.17	168.88	192.84	215.86	240.52	264.84	288.84	312.81	336.48
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58	20.80	20.80	20.80	20.80	20.80	20.80
Wind Generators	47.02	47.02	47.02	47.02	47.02	47.02	47.02	47.02	47.02	58.14	58.14	58.14	58.14	58.14	58.14
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	5.98	5.98	5.98	5.98	5.98	5.98
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1712.78	1672.53	1633.23	1594.85	1557.37	1520.77	1485.03	1450.13	1416.05	1382.78	1350.28	1318.55	1287.58	1257.31	1227.78
Coal	5850.21	5712.73	5578.48	5447.38	5319.37	5194.37	5072.30	4953.10	4836.70	4723.04	4612.05	4503.87	4397.83	4294.48	4193.58
Oil	21.48	20.98	20.48	20.00	19.53	19.07	18.63	18.19	17.76	17.34	16.94	16.54	16.15	15.77	15.40
Hydro	814.77	806.02	798.58	790.57	782.66	774.84	767.09	759.42	751.82	744.31	736.86	729.48	722.20	714.98	707.83
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	188.48	184.04	179.71	175.48	171.36	167.34	163.40	159.56	155.81	152.15	148.58	145.08	141.68	138.35	135.10
Total Supply	8,718.64	8,878.88	8,987.88	9,148.34	9,325.68	9,512.34	9,698.98	9,885.85	10,072.31	10,258.87	10,472.47	10,685.97	10,898.47	11,112.97	11,326.47
Total Sustainables	115.88	298.83	302.08	302.08	302.08	302.08	302.08	302.08	302.08	324.82	324.82	324.82	324.82	324.82	324.82

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	2062.38	2198.88	2336.03	2473.87	2612.48	2751.88	2892.18	3033.42	3175.68	3318.00	3462.15	3605.20	3748.20	3891.20	4034.27
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2683.81	2868.83	3074.47	3261.20	3464.03	3672.83	3881.71	4120.13	4368.08	4605.85	4848.27	5094.02	5343.02	5595.38	5851.22
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	38.82	38.82	38.82	38.82	44.81	44.81	44.81	44.81	44.81	44.81	44.81	44.81	44.81	44.81	44.81
Gas cogen retrofits	360.70	385.15	409.65	434.20	458.00	483.88	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	20.80	20.80	20.80	20.80	23.70	23.70	23.70	23.70	23.70	23.70	23.70	23.70	23.70	23.70	23.70
Wind Generators	58.14	58.14	58.14	58.14	72.70	72.70	72.70	72.70	72.70	72.70	72.70	72.70	72.70	72.70	72.70
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	5.98	5.98	5.98	5.98	8.04	8.04	8.04	8.04	8.04	8.04	8.04	8.04	8.04	8.04	8.04
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1198.91	1170.73	1143.22	1116.35	1090.12	1064.50	1038.49	1015.06	991.21	967.81	945.17	922.95	901.27	880.08	859.40
Coal	4095.01	3998.78	3904.81	3813.05	3723.44	3635.94	3550.49	3467.06	3385.58	3306.02	3228.33	3152.48	3078.38	3006.04	2935.40
Oil	15.04	14.68	14.34	14.00	13.67	13.35	13.04	12.73	12.43	12.14	11.85	11.58	11.30	11.04	10.78
Hydro	700.75	693.74	686.80	679.94	673.14	666.41	659.74	653.14	646.61	640.15	633.75	627.41	621.13	614.92	608.77
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	131.92	128.82	125.79	122.84	119.95	117.13	114.38	111.69	109.07	106.50	104.00	101.56	99.17	96.84	94.56
Total Supply	11,553.88	11,784.06	12,018.74	12,260.13	12,505.33	12,755.44	13,010.55	13,270.78	13,536.17	13,806.98	14,083.83	14,364.88	14,651.88	14,945.03	15,243.83
Total Sustainables	324.82	324.82	324.82	324.82	349.52	349.52	349.52	349.52	349.52	349.52	349.52	349.52	349.52	349.52	349.52

Table C.4 - Total generation capacity (MW) by technology type - ADD

Total Cumulative Capacity from New and Existing Technologies - Alberta Model - EA

Share of market for non-least cost technologies: 20% Price threshold over least cost for investment: 20%

MegaWatts

Technology Name	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Simple cycle gas	7.81	110.12	212.84	313.45	412.82	512.80	611.37	708.97	805.42	900.75	1002.38	1102.80	1202.34	1300.72	1388.08
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2.19	30.14	58.00	85.28	244.72	478.48	705.77	832.88	1157.20	1378.45	1618.78	1851.93	2084.88	2318.00	2545.00
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.00
Small hydro	14.48	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam	1.12	15.63	30.28	44.72	58.02	73.44	87.70	101.81	115.77	128.57	144.31	158.81	173.38	187.88	201.87
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	1.12	15.63	30.28	44.72	58.02	73.44	87.70	101.81	115.77	128.57	144.31	158.81	173.38	187.88	201.87
Gas cogen retrofits	1.12	19.24	225.38	429.88	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1712.78	1672.53	1633.23	1594.85	1557.37	1520.77	1485.03	1450.13	1418.05	1382.78	1350.28	1318.56	1287.88	1257.31	1227.78
Coal	5850.21	5712.73	5578.48	5447.38	5318.37	5184.37	5072.30	4953.10	4836.70	4723.04	4612.05	4503.87	4397.83	4294.40	4193.56
Oil	21.48	20.88	20.48	20.00	19.53	19.07	18.63	18.19	17.78	17.34	16.94	16.54	16.15	15.77	15.40
Hydro	814.77	808.62	798.58	790.57	782.88	774.84	767.08	758.42	751.82	744.31	738.88	728.48	722.20	714.88	707.83
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	100.46	104.04	178.71	175.48	171.38	167.34	163.40	159.56	155.81	152.15	148.58	145.09	141.68	138.36	135.10
Total Supply	8,618.64	8,787.88	8,987.08	9,146.34	9,325.58	9,512.34	9,688.98	9,883.85	10,072.31	10,258.97	10,472.47	10,685.07	10,888.47	11,112.07	11,328.47
Total Sustainables	18.72	231.28	260.52	289.44	318.03	348.88	375.40	403.82	431.53	458.15	488.82	517.81	548.72	575.37	603.75

Technology Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Simple cycle gas	1400.15	1500.82	1600.53	1800.84	1902.88	2005.40	2100.55	2212.38	2318.82	2422.22	2525.28	2628.70	2728.23	2830.15	2801.51
Simple cycle oil (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combined cycle gas	2780.31	3018.50	3253.88	3481.80	3731.33	3972.08	4214.18	4457.81	4703.06	4850.01	5104.14	5440.84	5682.81	5947.82	6205.48
Combined cycle oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small hydro	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Biomass steam	216.48	231.08	245.78	260.58	275.40	290.33	305.34	320.44	335.65	350.87	363.83	376.78	388.58	398.47	408.44
Coal - Pressurized Fluidized Bed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass gasifier turbine	216.48	231.08	245.78	260.58	275.40	290.33	305.34	320.44	335.65	350.87	363.83	376.78	388.58	398.47	408.44
Gas cogen retrofits	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Large Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal gasifier turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste fuels cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.88	25.82	35.82	45.50	55.48
Wind Generators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.88	18.88	29.88
Fuel Cell Cogenerator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tidal Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parabolic-Trough Solar-Power Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar PV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	1198.81	1170.73	1143.22	1116.35	1090.12	1064.50	1039.46	1015.08	991.21	967.81	945.17	922.85	901.27	880.08	859.40
Coal	4085.01	3988.78	3904.81	3813.05	3723.44	3635.84	3550.49	3467.08	3385.58	3308.02	3228.33	3152.48	3078.38	3008.04	2935.40
Oil	15.04	14.68	14.34	14.00	13.67	13.35	13.04	12.73	12.43	12.14	11.85	11.58	11.30	11.04	10.78
Hydro	700.75	693.74	686.80	679.94	673.14	666.41	659.74	653.14	646.61	640.15	633.75	627.41	621.13	614.92	608.77
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	131.92	128.82	125.79	122.84	119.95	117.13	114.38	111.69	109.07	106.50	104.00	101.56	99.17	96.84	94.56
Total Supply	11,553.88	11,784.88	12,018.74	12,268.13	12,505.33	12,755.44	13,010.55	13,270.78	13,538.17	13,808.88	14,083.83	14,384.88	14,651.88	14,945.83	15,243.83
Total Sustainables	632.81	662.18	691.58	721.12	750.80	780.85	810.87	840.88	871.30	901.84	940.51	978.38	1018.58	1058.13	1098.02

Table C.5 - Annual energy generation (GWh) by technology type - BAU

Generating Statistics - Alberta Model - BAU

Annual GWh production and Revenue Received for Electricity (million $)

	1995 GWh	1995 Million $	1996 GWh	1996 Million $	1997 GWh	1997 Million $	1998 GWh	1998 Million $	1999 GWh	1999 Million $	2000 GWh	2000 Million $	2001 GWh	2001 Million $	2002 GWh
Simple cycle gas	0.0	0.0	21.2	0.6	322.9	8.9	609.3	17.5	885.7	26.3	1144.4	35.2	1404.5	44.0	1649.7
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	0.0	0.0	2.1	0.1	28.0	0.8	515.4	14.1	1187.9	33.0	2034.5	56.4	3019.8	82.8	4109.7
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro	0.0	0.0	77.4	1.5	1109.4	22.1	1138.8	23.4	1138.8	24.7	1138.8	25.6	1138.8	26.3	1138.8
Biomass steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal - Pressurized Flui	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier turbin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas cogen retrofits	0.0	0.0	12.5	0.2	174.6	3.5	338.0	7.0	499.5	10.8	659.1	14.8	820.2	18.9	979.5
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	1134.5	33.0	1503.4	44.0	1439.4	44.5	1311.0	43.2	1192.1	42.0	1091.5	41.0	990.9	39.3	908.2
Coal	37577.1	752.7	37894.0	751.3	37344.7	760.2	37464.3	785.1	37430.7	825.5	37223.8	849.4	36912.3	861.6	36494.4
Oil	6.8	0.2	6.7	0.3	6.5	0.3	6.4	0.3	6.2	0.3	6.1	0.3	5.9	0.3	5.8
Hydro	4325.7	85.4	4282.4	83.3	4239.6	84.5	4197.2	86.3	4155.2	90.0	4113.7	92.4	4072.5	93.9	4031.8
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	59.9	2.1	58.5	2.2	57.1	2.3	55.8	2.5	54.4	2.6	53.2	2.7	51.9	2.8	50.7
Total (GWh, Millions)	43,104	$ 873	43,858	$ 883	44,722	$ 927	45,636	$ 979	46,851	$ 1,065	47,465	$ 1,118	48,417	$ 1,170	49,369

	2011 GWh	2011 Million $	2012 GWh	2012 Million $	2013 GWh	2013 Million $	2014 GWh	2014 Million $	2015 GWh	2015 Million $	2016 GWh	2016 Million $	2017 GWh	2017 Million $	2018 GWh
Simple cycle gas	3754.2	132.3	3985.6	141.4	4218.1	150.6	4453.8	160.0	4696.1	169.9	4936.1	179.7	5182.1	189.3	5383.9
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	16836.8	475.5	18401.5	518.8	19970.4	562.3	21542.2	612.1	23112.5	656.4	24689.1	701.1	26335.9	747.9	28106.1
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro	1138.8	31.0	1138.8	31.0	1138.8	31.1	1138.8	31.4	1138.8	31.4	1138.8	31.5	1138.8	31.5	1138.8
Biomass steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal - Pressurized Flui	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier turbin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas cogen retrofits	2417.6	65.7	2581.1	70.3	2745.2	74.9	2910.2	80.2	3076.0	84.9	3242.6	89.6	3350.7	92.8	3350.7
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	454.5	28.0	427.6	27.4	401.0	26.7	374.6	26.1	348.4	25.4	330.3	25.0	322.5	24.8	314.9
Coal	30491.5	829.2	29774.9	810.9	29075.2	793.1	28391.9	782.2	27724.7	765.0	27073.2	748.3	26437.0	731.9	25815.7
Oil	4.7	0.3	4.6	0.3	4.4	0.3	4.3	0.3	4.2	0.3	4.1	0.3	4.0	0.3	3.9
Hydro	3683.1	100.2	3646.3	99.3	3609.8	98.5	3573.7	98.5	3538.0	97.6	3502.6	96.8	3467.6	96.0	3432.9
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	40.9	2.8	40.0	2.8	39.0	2.8	38.1	2.8	37.2	2.8	36.3	2.7	35.5	2.7	34.7
Total (GWh, Millions)	58,822	$ 1,665	60,000	$ 1,702	61,202	$ 1,740	62,428	$ 1,794	63,678	$ 1,834	64,953	$ 1,876	66,254	$ 1,917	67,582

Table C.5 - Annual energy generation (GWh) by technology type - BAU (continued....)

Million $	2003 GWh	Million $	2004 GWh	Million $	2005 GWh	Million $	2006 GWh	Million $	2007 GWh	Million $	2008 GWh	Million $	2009 GWh	Million $	2010 GWh	Million $
52.8	1890.8	61.3	2128.2	70.2	2362.1	79.1	2599.3	87.9	2835.3	96.8	3076.7	105.9	3307.9	114.8	3524.0	123.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
113.6	5281.4	145.4	6536.0	179.6	7820.3	217.6	9241.1	256.4	10705.0	299.9	12202.9	341.6	13744.2	384.6	15275.6	432.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27.0	1138.8	27.6	1138.8	28.1	1138.8	28.8	1138.8	29.2	1138.8	29.7	1138.8	30.1	1138.8	30.5	1138.8	30.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23.2	1137.1	27.6	1293.0	31.9	1447.2	36.6	1611.8	41.4	1774.6	46.2	1936.3	51.1	2096.2	56.1	2254.7	61.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37.9	834.6	36.8	762.1	35.6	700.4	34.7	649.7	33.3	599.8	32.0	550.7	30.8	509.0	29.4	481.8	28.7
872.1	35991.1	879.9	35408.7	878.4	34790.7	883.9	34147.7	878.2	33463.2	872.0	32739.7	864.5	31976.7	856.0	31225.3	847.9
0.3	5.8	0.3	5.5	0.3	5.4	0.3	5.3	0.3	5.1	0.3	5.0	0.3	4.9	0.3	4.8	0.3
95.4	3991.5	96.9	3951.6	97.5	3912.1	99.0	3873.0	99.4	3834.2	99.8	3795.9	100.2	3757.9	100.6	3720.3	101.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.8	49.5	2.9	48.3	2.9	47.2	3.0	46.1	3.0	45.0	2.9	44.0	2.9	42.9	2.9	41.9	2.8
$ 1,225	60,321	$ 1,279	61,272	$ 1,325	62,224	$ 1,383	63,313	$ 1,429	64,401	$ 1,480	65,490	$ 1,527	66,579	$ 1,575	67,667	$ 1,629

Million $	2019 GWh	Million $	2020 GWh	Million $	2021 GWh	Million $	2022 GWh	Million $	2023 GWh	Million $	2024 GWh	Million $	2025 GWh	Million $
198.9	5607.4	206.8	5833.7	218.9	6062.6	231.5	6287.8	244.5	6509.6	257.6	6727.9	271.1	6561.4	273.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
798.4	29885.9	849.3	31675.2	908.9	33475.0	974.7	35292.6	1042.9	37128.5	1113.7	38983.8	1187.1	40859.1	1262.9
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31.6	1138.8	31.6	1138.8	32.0	1138.8	32.5	1138.8	33.0	1138.8	33.5	1138.8	34.0	1138.8	34.6
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92.9	3350.7	93.1	3350.7	94.0	3350.7	95.5	3350.7	97.0	3350.7	98.6	3350.7	100.1	3350.7	101.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24.7	307.5	24.6	300.3	24.4	293.2	24.3	286.3	24.2	279.6	24.1	273.0	23.9	266.6	23.8
715.9	25209.0	700.2	24816.6	690.7	24036.1	685.1	23473.2	679.6	22921.6	674.2	22383.0	668.8	21857.0	663.4
0.3	3.9	0.3	3.8	0.3	3.7	0.3	3.6	0.3	3.5	0.3	3.4	0.3	3.3	0.3
95.2	3398.6	94.4	3364.6	94.4	3331.0	94.9	3297.7	95.5	3264.7	96.0	3232.0	96.6	3199.7	97.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.7	33.8	2.7	33.0	2.7	32.3	2.7	31.5	2.7	30.8	2.6	30.0	2.6	410.7	14.2
$ 1,961	68,936	$ 2,005	70,317	$ 2,068	71,725	$ 2,141	73,162	$ 2,220	74,628	$ 2,301	76,123	$ 2,385	77,647	$ 2,471

Table C.6 - Annual energy generation (GWh) by technology type - EA

Generating Statistics - Alberta — Annual GWh production and Revenue Received for Electricity (million $)

	1995 GWh	1995 Million Dollars	1996 GWh	1996 Million Dollars	1997 GWh	1997 Million Dollars	1998 GWh	1998 Million Dollars	1999 GWh	1999 Million Dollars	2000 GWh	2000 Million Dollars	2001 GWh	2001 Million Dollars	2002 GWh	2002 Million Dollars
Simple cycle gas	0.0	0.0	12.3	0.5	190.8	8.1	382.2	15.7	530.8	23.7	864.1	31.3	820.4	38.2	855.1	45.2
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	0.0	0.0	18.3	0.8	224.4	8.5	431.8	18.5	634.8	24.4	1822.2	70.5	3547.8	137.8	5255.2	205.0
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro	0.0	0.0	82.5	3.1	1130.8	43.1	1130.8	43.4	1130.8	43.7	1130.8	44.0	1130.8	44.2	1130.8	44.4
Biomass steam	0.0	0.0	8.3	0.3	118.4	4.4	225.3	8.8	333.0	12.8	439.4	17.0	548.8	21.2	853.0	25.5
Coal - Pressurized Fl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier bur	0.0	0.0	8.3	0.3	118.4	4.4	225.3	8.8	333.0	12.8	439.4	17.0	548.8	21.2	853.0	25.5
Gas cogen retrofits	0.0	0.0	7.5	0.3	128.8	4.8	1510.3	57.5	2080.8	110.8	3350.7	128.6	3350.7	130.1	3350.7	130.7
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Sol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	815.5	42.3	1213.8	55.4	1188.8	55.6	1083.0	54.4	1018.4	53.1	838.7	51.4	882.3	48.3	788.0	47.2
Coal	36418.0	1387.8	36818.7	1385.8	36020.8	1370.7	35102.1	1347.8	34201.8	1324.7	33245.7	1288.1	32287.0	1287.5	31308.8	1238.4
Oil	8.8	0.4	8.7	0.4	8.5	0.4	8.4	0.4	8.2	0.4	8.1	0.4	5.8	0.4	5.8	0.4
Hydro	4325.7	184.3	4282.4	180.4	4238.6	180.3	4187.2	158.8	4155.2	158.5	4113.7	158.1	4072.5	158.2	4031.8	157.2
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	1437.1	54.8	1403.3	52.5	1370.3	51.8	1338.1	51.0	1308.7	50.2	1278.0	49.3	1248.0	48.4	1218.7	47.6

	2011 GWh	2011 Million Dollars	2012 GWh	2012 Million Dollars	2013 GWh	2013 Million Dollars	2014 GWh	2014 Million Dollars	2015 GWh	2015 Million Dollars	2016 GWh	2016 Million Dollars	2017 GWh	2017 Million Dollars	2018 GWh	2018 Million Dollars
Simple cycle gas	1924.0	101.3	2021.1	107.3	2118.7	113.5	2208.1	118.8	2290.2	125.1	2371.8	131.0	2454.5	138.8	2537.8	143.1
Simple cycle oil (b)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle gas	20702.2	838.1	22480.8	911.8	24228.7	988.9	26000.7	1067.1	27783.5	1148.8	29575.8	1227.5	31378.8	1308.8	33182.8	1383.7
Combined cycle oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small hydro	1130.8	48.0	1130.8	48.2	1130.8	48.5	1130.8	48.7	1130.8	47.0	1130.8	47.3	1130.8	47.5	1130.8	47.8
Biomass steam	1611.7	65.1	1720.7	68.8	1830.2	74.7	1940.1	78.8	2050.8	84.8	2161.8	88.7	2273.5	94.8	2386.0	100.2
Coal - Pressurized Fl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass gasifier bur	1611.7	65.1	1720.7	68.8	1830.2	74.7	1940.1	78.8	2050.8	84.8	2161.8	88.7	2273.5	94.8	2386.0	100.2
Gas cogen retrofits	3350.7	135.3	3350.7	136.0	3350.7	134.8	3350.7	137.5	3350.7	138.3	3350.7	138.1	3350.7	138.8	3350.7	140.7
Large Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal gasifier turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste fuels cogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell Cogenerat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tidal Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Parabolic-Trough Sol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	417.8	34.1	391.2	33.1	364.7	32.0	348.3	31.3	338.2	31.1	330.3	30.8	322.5	30.5	314.8	30.2
Coal	23380.7	987.4	22582.7	938.7	21788.2	912.4	21007.0	885.3	20238.8	858.6	19482.5	832.1	18738.5	805.8	18008.0	779.8
Oil	4.7	0.4	4.6	0.4	4.4	0.4	4.3	0.4	4.2	0.4	4.1	0.4	4.0	0.4	3.8	0.4
Hydro	3683.1	148.7	3648.3	148.0	3608.8	147.3	3573.7	148.7	3538.0	146.0	3502.8	145.4	3467.8	144.8	3432.8	144.1
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	982.3	39.7	950.2	38.8	938.7	38.2	914.8	37.5	893.2	36.8	872.2	36.2	851.7	35.6	831.7	34.8

Table C.6 - Annual energy generation (GWh) by technology type - EA (continued....)

2003 GWh	2003 Million Dollars	2004 GWh	2004 Million Dollars	2005 GWh	2005 Million Dollars	2006 GWh	2006 Million Dollars	2007 GWh	2007 Million Dollars	2008 GWh	2008 Million Dollars	2009 GWh	2009 Million Dollars	2010 GWh	2010 Million Dollars
1083.7	52.1	1188.5	58.5	1308.5	65.0	1427.8	71.8	1543.1	78.1	1838.0	83.8	1733.7	88.8	1827.4	85.3
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8844.8	272.0	8818.5	340.5	10271.4	407.7	12038.4	478.0	13788.4	550.0	15524.8	620.7	17244.8	681.2	18850.1	781.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1138.8	44.8	1138.8	45.0	1138.8	45.2	1138.8	45.3	1138.8	45.4	1138.8	45.5	1138.8	45.6	1138.8	45.8
758.1	29.7	862.0	34.1	864.8	38.3	1074.5	42.8	1183.2	47.2	1290.8	51.8	1387.5	56.0	1503.1	60.4
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
758.1	29.7	862.0	34.1	864.8	38.3	1074.5	42.8	1183.2	47.2	1290.8	51.8	1387.5	56.0	1503.1	60.4
3350.7	131.2	3350.7	132.4	3350.7	133.0	3350.7	133.3	3350.7	133.8	3350.7	134.0	3350.7	134.3	3350.7	134.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
721.2	45.2	872.0	44.0	823.8	42.7	573.8	40.8	527.1	38.7	488.3	37.5	471.8	38.4	444.8	35.2
30388.8	1205.7	28448.8	1182.1	28542.3	1152.3	27641.7	1118.8	28750.8	1087.8	25883.3	1058.5	25044.8	1025.7	24212.8	985.4
5.8	0.4	5.5	0.4	5.4	0.4	5.3	0.4	5.1	0.4	5.0	0.4	4.8	0.4	4.8	0.4
3881.5	158.3	3851.8	158.2	3812.1	153.3	3873.0	154.1	3834.2	152.8	3785.8	151.8	3757.8	150.8	3720.3	148.5
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1188.1	48.5	1180.2	45.8	1132.8	45.0	1108.3	44.0	1080.3	43.1	1054.8	42.2	1030.1	41.3	1005.8	40.4

2019 GWh	2019 Million Dollars	2020 GWh	2020 Million Dollars	2021 GWh	2021 Million Dollars	2022 GWh	2022 Million Dollars	2023 GWh	2023 Million Dollars	2024 GWh	2024 Million Dollars	2025 GWh	2025 Million Dollars
2621.9	149.3	2708.8	155.8	2784.8	162.8	2882.4	170.2	2932.2	177.3	3001.7	184.8	3071.0	182.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35018.8	1479.2	34828.8	1551.5	38600.4	1640.7	40355.5	1718.8	42144.8	1810.1	43831.8	1888.6	45718.3	1988.8
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1138.8	48.1	1138.8	48.0	1138.8	48.4	1138.8	48.4	1138.8	48.8	1138.8	48.9	1138.8	48.4
2489.3	105.8	2613.3	110.1	2708.1	115.1	2805.8	119.2	2878.5	123.4	2952.1	128.7	3028.4	131.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2489.3	105.8	2613.3	110.1	2708.1	115.1	2805.8	119.2	2878.5	123.4	2952.1	128.7	3028.4	131.2
3350.7	141.5	3350.7	141.1	3350.7	142.3	3350.7	142.4	3350.7	143.7	3350.7	143.8	3350.7	145.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	101.4	4.3	203.8	8.7	288.8	12.0	358.7	15.4	437.4	18.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	77.3	3.3	155.2	6.7	233.8	10.1
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
307.5	30.0	300.3	29.7	293.2	29.5	288.3	29.2	279.8	29.0	273.0	28.7	288.8	28.5
17284.7	754.1	16605.2	729.7	15829.2	707.8	15298.8	687.5	14660.7	668.7	14053.1	648.8	13471.4	627.7
3.8	0.4	3.8	0.4	3.7	0.4	3.6	0.4	3.5	0.4	3.4	0.4	3.3	0.4
3308.8	143.8	3384.8	141.7	3331.0	141.5	3287.7	140.1	3264.7	140.0	3232.0	138.7	3188.7	138.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
812.1	34.3	783.0	33.4	774.4	32.8	758.2	32.1	738.4	31.7	721.1	30.8	704.1	30.5

Figure C.1 - Investment in Sustainables Capacity (MW) - all scenarios

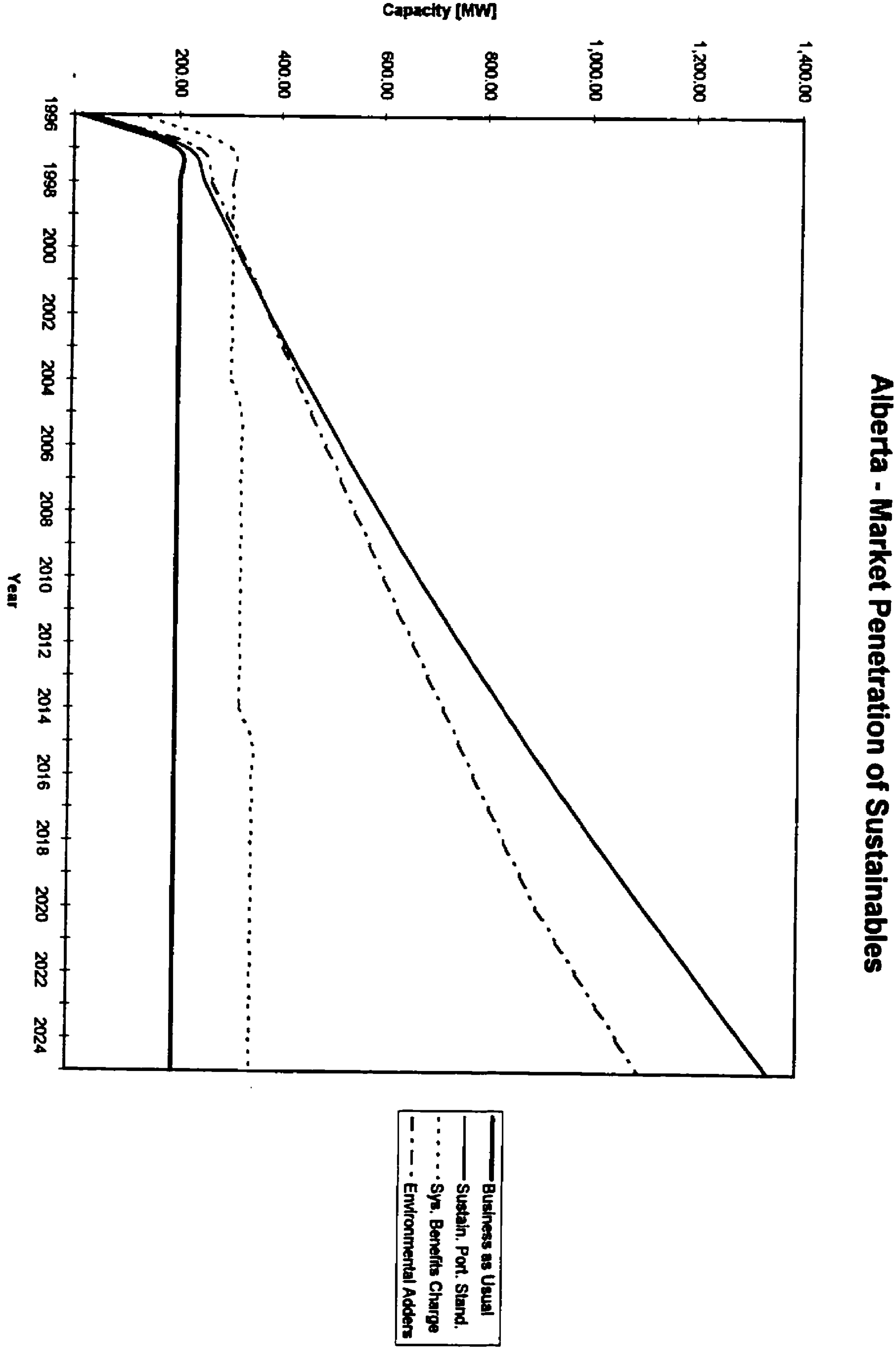


Figure C.2 - Generation by Sustainables (GWh) - all scenarios

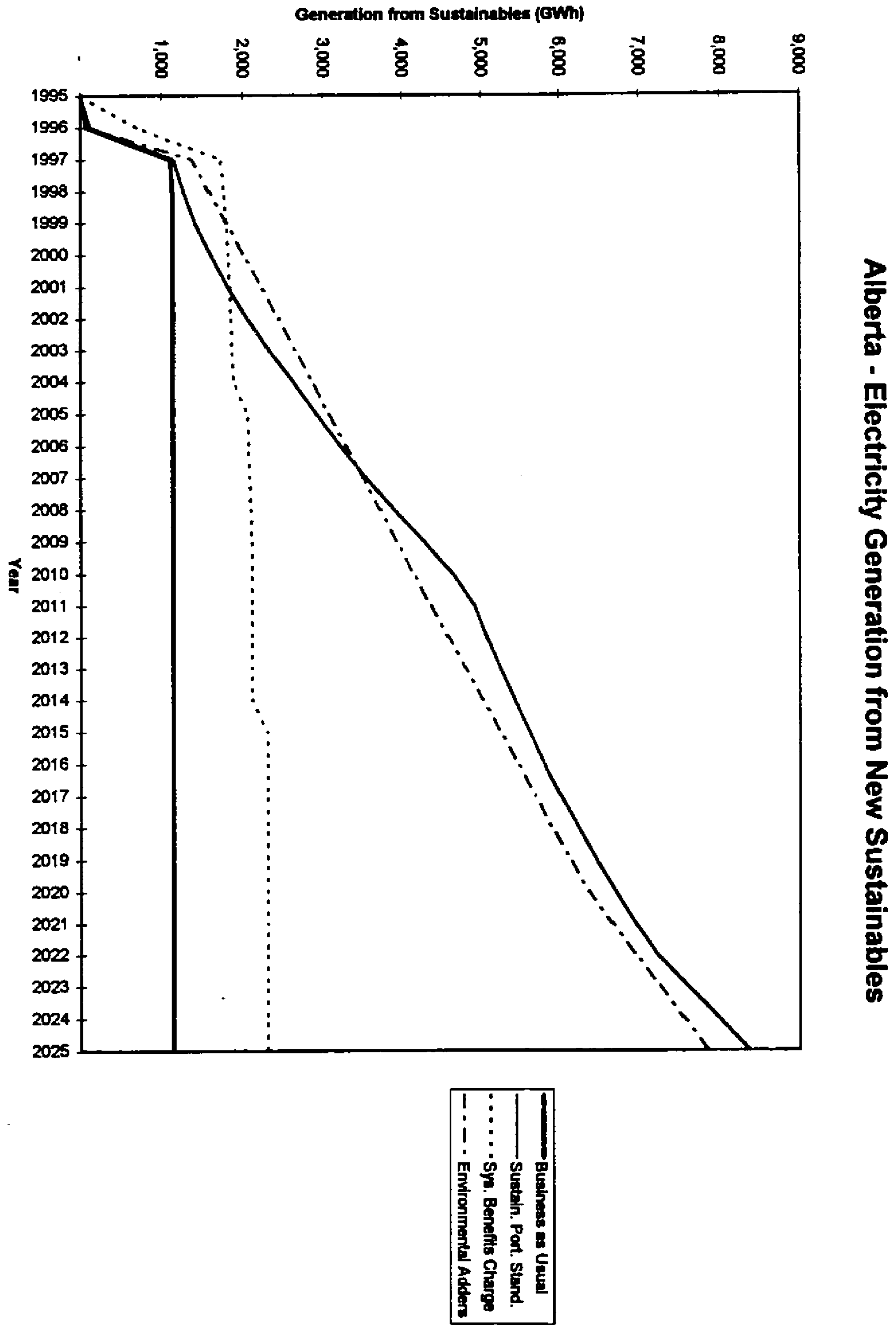


Figure C.3 - Peak wholesale electricity rates ($1995/kWh) - all scenarios

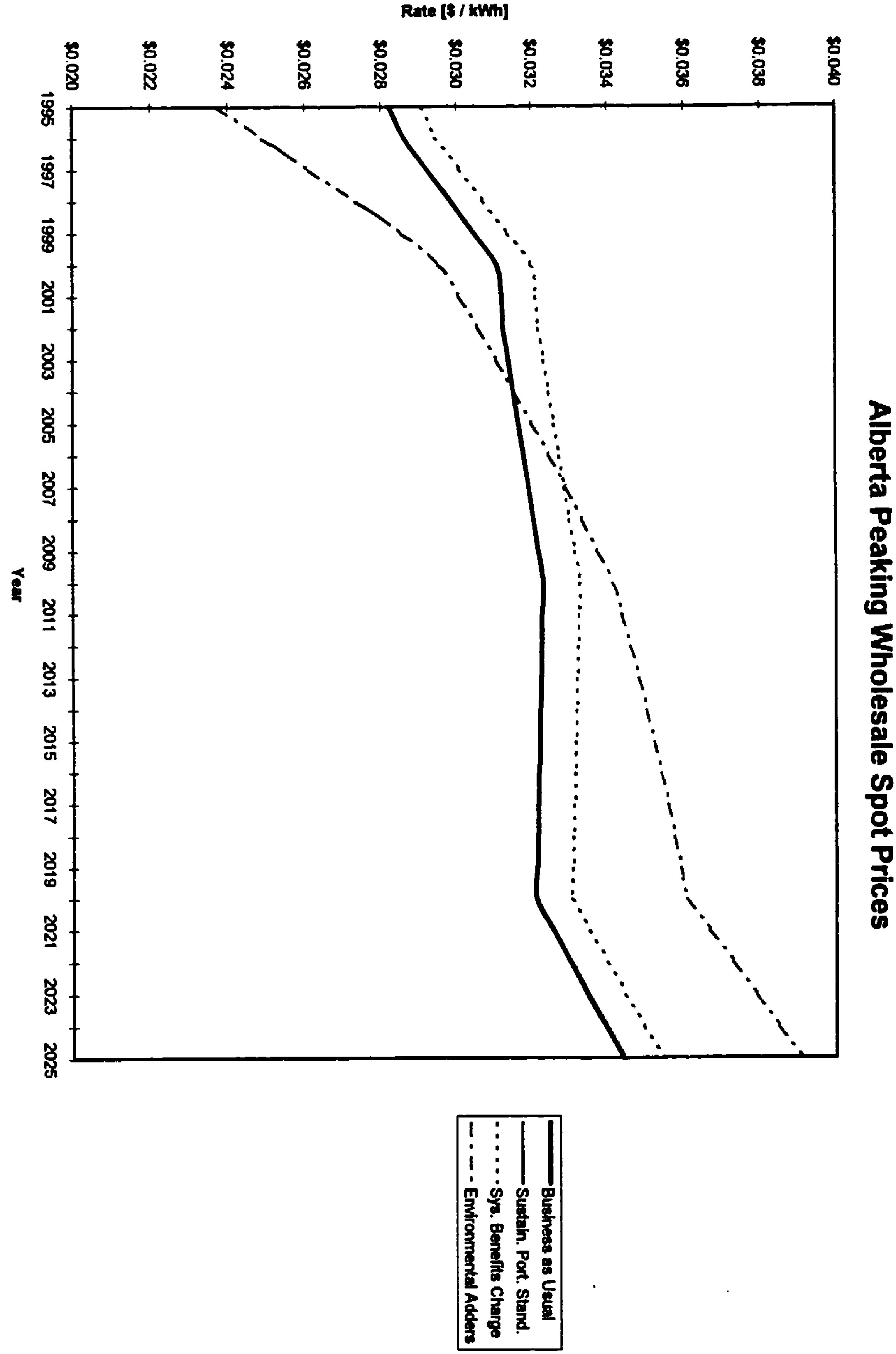


Figure C.4 - Baseload wholesale electricity rates ($1995/kWh) - all scenarios

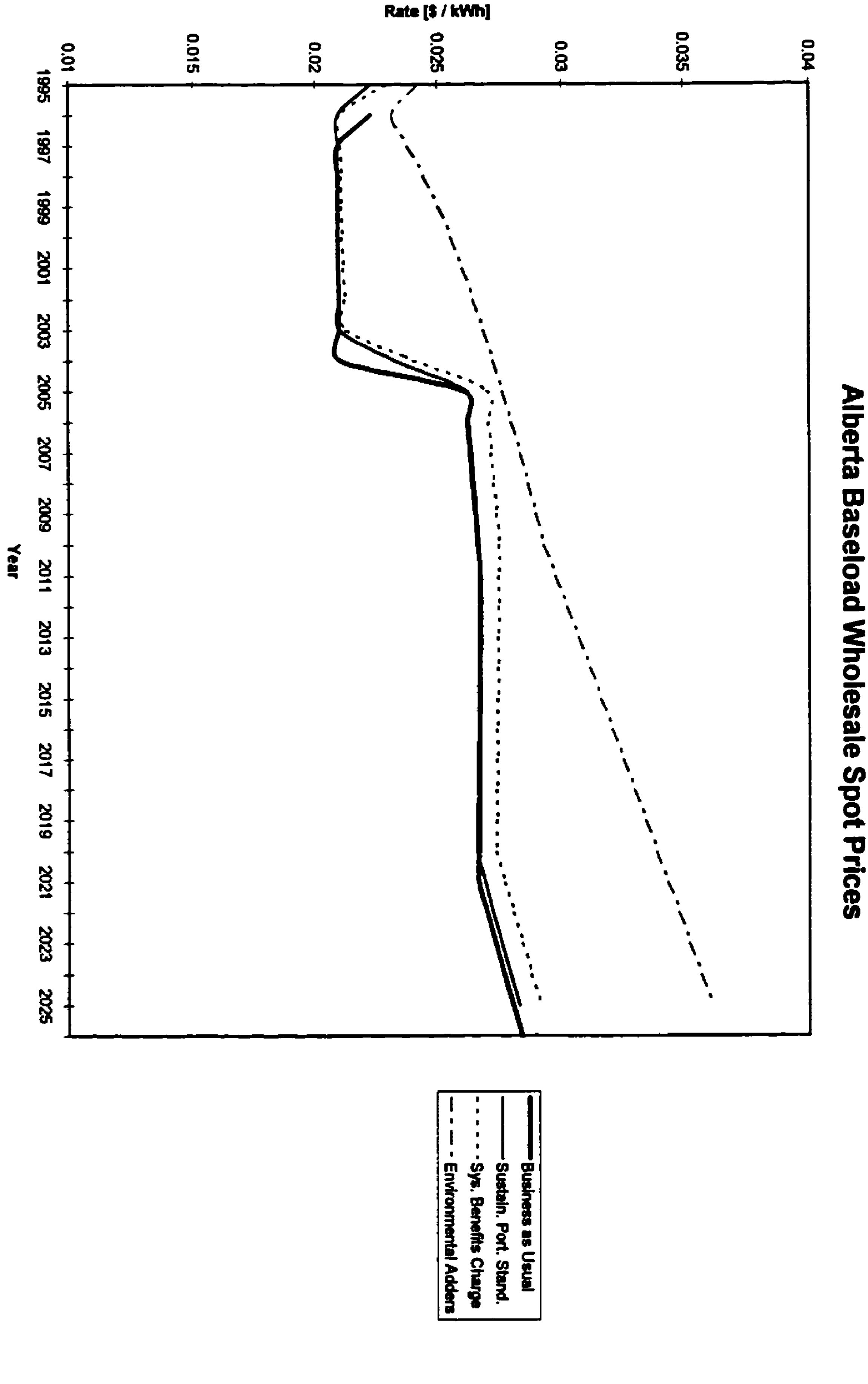


Figure C.5 - Total cost of electricity (million $1995) - all scenarios

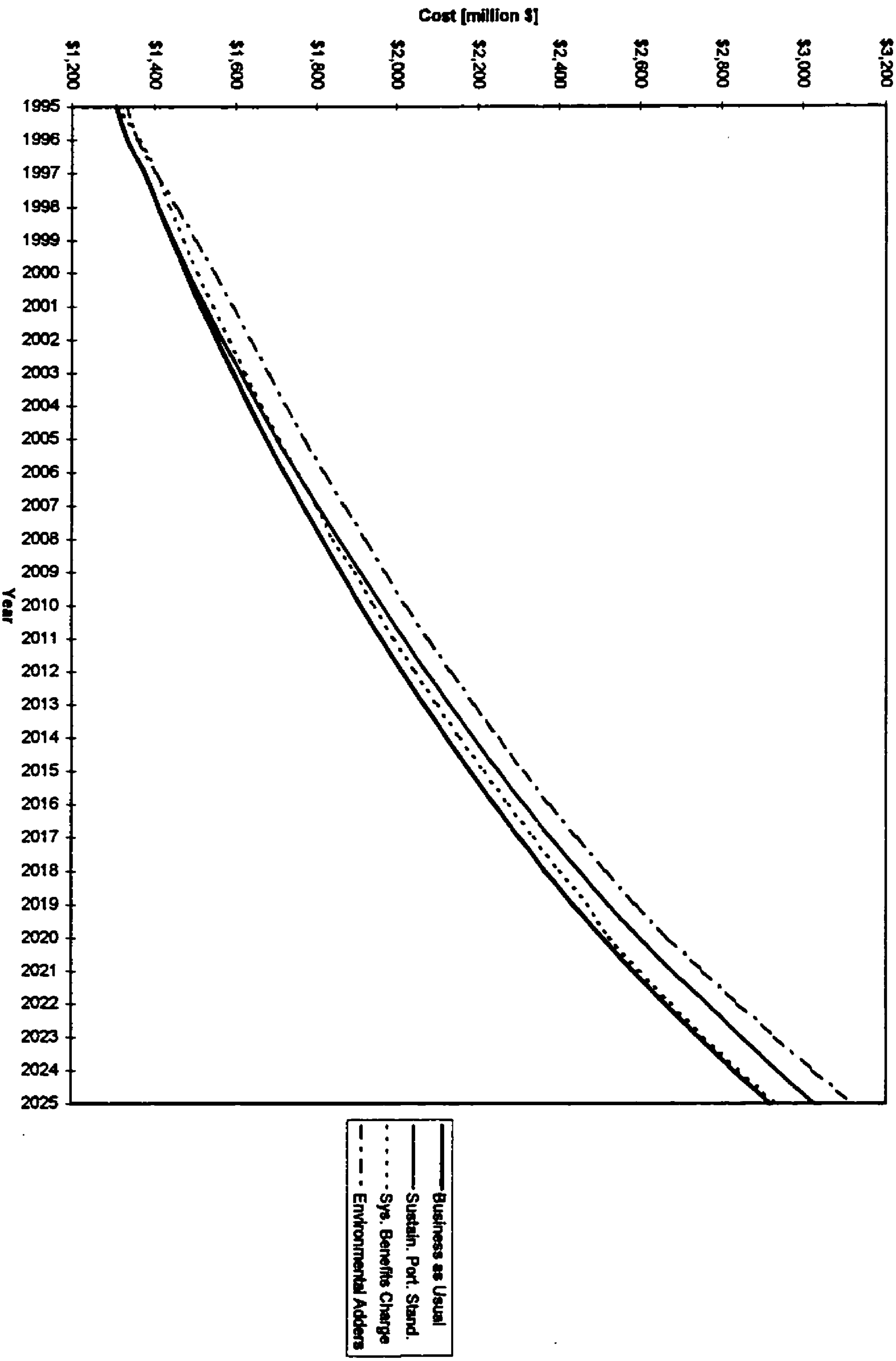
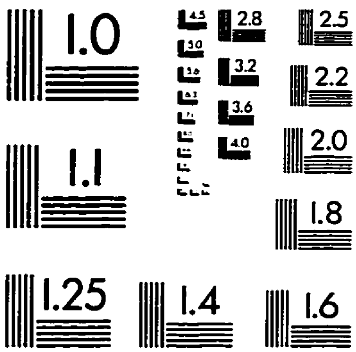


IMAGE EVALUATION
TEST TARGET (QA-3)



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