CO_2 Emission Reduction in Canada: Results from an Energy System Model

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Canada is committed to stabilizing emissions of greenhouse gases at 1990 levels by the year 2000. This paper examines the costs and benefits of meeting the key component of this commitment: energy-related carbon dioxide (CO_2) emissions. The analysis uses a dynamic linear programming methodology to produce a process-oriented, techno-economic model of the Canadian energy system for the period 1990-2030. Three scenarios are analyzed to investigate the effects of sectoral vs. overall limits on CO_2 emissions compared to a "business-as-usual" (BAU) base case. The results from this work point to least-cost routes to CO_2 emission reduction, as well as addressing the issue of "equity vs. efficiency" in achieving the reductions. Potential collateral benefits to emission reduction are also discussed.

Le Canada s'est engagé à ramener les émissions de gaz à effet de serre à leur niveau de 1990 avant l'an 2000. Cet article examine les coûts et les avantages en jeu pour concrétiser la composante clé cet engagement: les émissions énergétiques de dioxyde de carbone (CO_2). L'analyse utilise une méthodologie de programmation linéaire dynamique afin de produire un modèle techno-économique, axé sur le processus, du système énergétique canadien pour la période 1990-2030. Trois scénarios sont analysés pour étudier les effets des limites sectorielles et, à l'inverse, celles globales, des émissions de CO_2 par rapport à un scénario de référence "maintien du statuquo" (MSQ). Les résultats de ce travail indiquent l'existence de circuits moins coûteux pour réduire les émissions de CO_2; ils abordent aussi la question d'"égalité par opposition à efficacité" pour parvenir à ces réductions. Les avantages collatéraux potentiels liés à la réduction des émissions font également l'objet d'une discussion.

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Introduction

Canada has committed to stabilizing emissions of carbon dioxide (CO_2) and other greenhouse gases (GHGs) at 1990 levels by the year 2000. Approximately 70% of total GHG emissions, and over 95% of CO_2 emissions come from the nation's energy system (i.e., from the extraction or harnessing of energy sources through to consumers' utilization of energy services). Thus, the search for cost-effective emission reduction measures must inevitably focus on changes to the energy system, with energy system models playing a key role in the evaluation of the potential impacts of such measures.

Published results from national energy models have taken a macroeconomic approach to the problem, in which the energy system is but one part of the national economy, and in which economic agents, rules and transactions are represented. Examples include NRCan (1993) and DRI/Marbek (1993). A valuable characteristic of macroeconomic models is their ability to explore interactions between the economy and the energy system, for example, the impact of rising energy prices on economic activity and on the demand for energy services, or the impact of a carbon or energy tax on other sectors of the economy and on the reallocation of resources that affect capital formation and economic growth. However, this ability is achieved at the expense of technological detail, especially concerning the evolution of technologies over time. Most macroeconomic-oriented energy models view technological performance as static, or, at best, with all technical and non-technical changes rolled into a single parameter reflecting an overall rate of autonomous energy efficiency improvement. The effect of such simplifications is to underestimate the potential role for technological change in, for example, meeting emission reduction targets.

An alternative approach views the energy system in terms of physical, rather than economic, agents and flows — in energy rather than monetary terms. The resulting technology-oriented energy system models (often referred to as process, engineering, bottom-up or techno-economic models) represent current and future technologies and infrastructures explicitly, in physical terms. To the extent that their techno-economic parameters are allowed to change over time, such models can provide a much clearer picture of the cumulative potential of projected technological change. However, this ability to capture long-range and fundamental technology change in the energy system occurs at the expense of representing feedbacks into the macroeconomy (i.e., investment behaviour or consumer utility). In the absence of alternative representations of the macroeconomic, behavioral and other constraints on technology change, techno-economic models will tend to be optimistic with respect to the impacts of such change. Techno-economic energy models have been applied to individual provinces and sectors in Canada (see, for example, Berger, Dubois et al., 1992; Margolick et al., 1992), but not as yet to the nation as a whole. We have attempted to fill this analytic gap by creating a technology-oriented model of the Canadian energy system — a Canadian Energy System Model (CESM) — with a particular focus on CO_2 and other energy-system emissions (Wells, 1993). Below, we present results from the model for different future scenarios of energy system development, focussing on the impacts and costs of meeting Canada's CO_2 emission stabilization target.

Modelling Approach

CESM is based on MESSAGE (a Model for Energy Supply Strategy Alternatives and their General Environmental impact), which was first developed in the late 1970s by the Energy Systems Group at the International Institute for Applied Systems Analysis (Häfele, 1981). MESSAGE continues to be developed, and has been used in recent years for regional, national and international energy studies (Messner and Strubegger, 1991; Rogner et al., 1990; EcoPlan International, 1990; Rogner, 1989).

MESSAGE, in common with similar modelling systems such as MARKAL,[1] provides a framework for representing an energy system in terms of physical energy stocks and flows linked by energy conversion technologies. Figure 1 represents such a structure schematically. Energy flows begin with the extraction or utilization of energy resources, and continue with their successive transformation by conversion technologies at the levels of primary, secondary, final and, lastly, useful energy — the useful energy services which people actually want, such as light, heat, cooling, transport, etc.

In such a system, conversion technologies are described in terms of both physical parameters (conversion efficiency, availability, lifetime) and economic parameters (investment cost, operating and maintenance (O&M) costs). The system is assumed to be driven by the demands for useful energy services, which must be specified exogenously.

As the examples in Figure 1 suggest, there may exist many different pathways through the energy system leading to a particular useful energy demand, each with different costs and impacts, and in particular, with different

1/ The standard version of MARKAL is described in Fishbone and Abilcock (1981). Many regionalized versions of MARKAL exist as well, for example, Canadian MARKAL (Berger, Dubois et al., 1992).

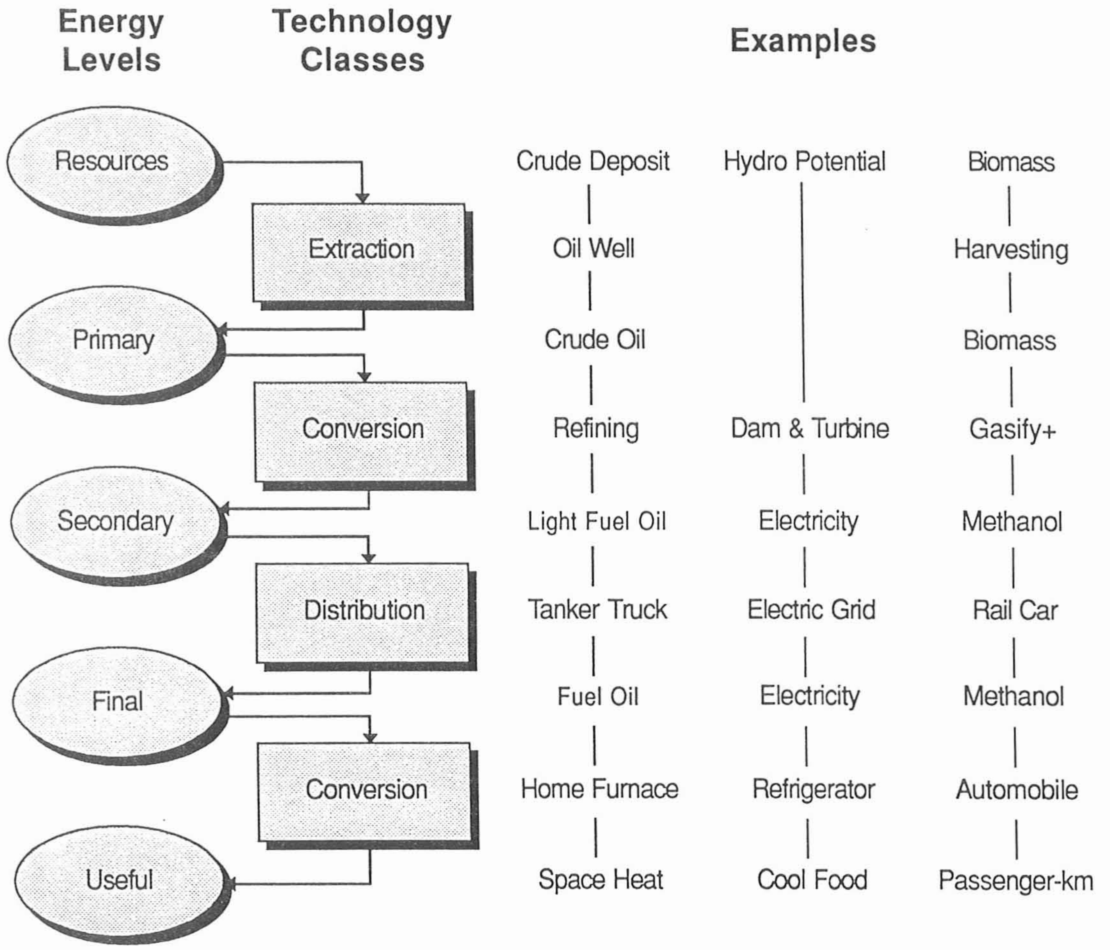

Figure 1: A physical view of the energy system

CO_2 emissions. To select among competing pathways, CESM takes a dynamic linear programming approach. The time horizon of interest is subdivided into time steps, and for each of these a set of linear equations is formulated, representing the physical constraints at each point in the system.

These equations ensure that installed capacity is sufficient to meet demand, that energy inflows to a technology are consistent with outflows, and that resource extraction limits are not exceeded. Additional constraints are included to reflect the realities of real-world energy systems (e.g., to limit the rate of change of technology capacities, energy flows, and resources consumption).

The sets of equations for all time steps are combined and solved jointly to optimize (i.e., minimize or maximize) the energy system according to some criterion, represented by an objective function. The criterion used in CESM is the minimization of the total system cost, calculated as the present value of the sum of all discounted costs in the system. This leads to a system in which the energy service demands are provided at the lowest overall cost, subject to the imposed constraints.

Note that because the equations for all time steps are optimized jointly, the results for later periods can influence those for earlier periods, leading to choices made as if by someone having "perfect foresight." While such decision-making is not possible in the real world, the resulting solutions are, in principle, what we would choose to do if it were possible.

CESM Description

CESM, following Figure 1, is primarily specified in terms of: (i) resources; (ii) primary, secondary and final forms of energy, or energy carriers; (iii) useful energy demands; and (iv) the technologies linking these together. The constraints on the system, plus global parameters such as the discount rate and the time steps to be examined, complete CESM's energy system description.

ENERGY RESOURCES

In CESM, energy resources are stocks of fossil fuels (coal, crude oil and bitumen, and natural gas), as well as uranium. Each resource is subdivided first by category (e.g., onshore, offshore and non-conventional in the case of crude oil), and second by grade, according to the difficulty and cost of discovery, development and extraction. Overall fossil resource estimates in CESM are from the NEB (1991), with subdivisions and cost data coming from Rogner et al. (1990).

Although commonly referred to as "renewable resources," hydropower, solar, wind and biomass are less resources or stocks to be depleted than they are annual flows with the potential to be harnessed. In CESM, limits on these potentials are represented as system constraints.

ENERGY FORMS

Reflecting the dominance of fossil resources in today's energy system, the primary-level energy carriers in CESM are coal, both "hard" (bituminous) and "soft" (sub-bituminous and lignite), crude oil, natural gas and associated liquids, and uranium. Derived from these are the secondary and final energy carriers coal, coke, gasoline, aviation fuel, diesel and light oil, residual or heavy oil, natural gas, and natural gas liquids. Of course, there is also secondary and final electricity. The inclusion of the remaining energy carriers in CESM reflects more their future potential than their importance today. These carriers are biomass,[2] municipal waste, hot and chilled water and steam (for district energy systems), methanol, and hydrogen.

USEFUL ENERGY DEMANDS

CESM is driven by 27 exogenously specified useful energy demands, serving nine economic sectors:

1. metals – metals smelting and processing;
2. pulp and paper – pulp, paper and sawmills;
3. chemicals;
4. forestry and agriculture;
5. other industry;
6. commerce – commerce and administration;
7. residential;
8. transport;
9. feedstocks – industrial feedstocks and related non-substitutables.

The first seven economic sectors are subdivided into thermal demands, which can be satisfied by many energy carriers (through interfuel and technology substitution), plus one or more non-substitutable demands, which can be realistically met by only a single energy carrier (typically electricity). Demands are specified in units of useful energy where possible.[3]

The transport demands are divided into three freight modes (road and rail, marine, and air) and two passenger services (intercity and urban). Unlike the other demands, these are specified in actual units of service: billion tonne-kilometres (t-km) of freight and billion passenger-kilometres (p-km), respectively.

All base year useful energy demands are

2/ The model distinguishes between biomass used within the forestry, and pulp and paper industries, and that used for residential heating, electricity generation, etc. The former use is considered non-substitutable, with the level of activity determined only by industry requirements. The latter uses are potentially substitutable by other energy carriers, and are modeled explicitly.

3/ For some demands (e.g., electricity in manufacturing), it is very difficult to determine the actual useful energy services provided. In such cases, the CESM demands are specified in terms of final energy, with an implicit end-use, or final-to-useful conversion efficiency of unity.

calibrated to Statistics Canada's *Quarterly Report on Energy Supply-Demand in Canada* (StatsCan, 1991), using assumptions regarding end-use or final-to-useful conversion efficiencies, fuel shares, energy intensities, etc. Future useful demands are estimated by combining population and GDP projections with assumptions regarding future changes in sectoral energy intensities.

Industrial energy demands (for the metals, pulp and paper, chemicals, other industry, forestry and agriculture, and feedstocks sectors), as well as commerce and administration energy demands are tied to total GDP via projected changes in both energy intensities and relative GDP shares. In the scenarios presented here, equal declines in intensity are assumed for all of these sectors. Increasing shares of GDP are assumed for the chemicals, and, especially, the commerce and administration sectors, with the remaining sectors having various declines in share.

Demands in the residential sector are calculated based on projected growth rates in per capita electricity and thermal energy use. Modal freight demands are tied to growth rates of GDP for various industrial sectors, while passenger transport demands are calculated using projected GDP per capita growth rates. Per-capita GDP is assumed to fall through 1995, followed by a 4% per year recovery through to 2000. From 2005 onwards, per capita growth is assumed constant at 1.25% per year. (Sensitivity scenarios, including those for lower per-capita GDP growth rates (1.00% per year from 2005 on), have also been analyzed, but are not presented here due to lack of space.)

Per capita demand growth rates are converted into total demands using assumed increases in population. For all scenarios, population growth is assumed to follow Statistics Canada's "medium 2" scenario, with increases of 1.46% per year in 1990 falling to 0.90% per year in 1995, and gradually declining from there to -0.10% per year in 2030 (Perreault, 1990).

ENERGY CONSERVATION TECHNOLOGIES

The current version of CESM includes approximately 230 technologies. Most fall naturally into one of the four technology classes shown in Figure 1:

- *Resource extraction* – includes coal and uranium mining, oil and gas development, and biomass harvesting;
- *Primary-secondary conversion* – currently dominated by electricity generation and oil refining, but with future options such as hydrogen production and methanol synthesis;
- *Transmission and distribution* – applies to all energy carriers, but particularly those based on fixed grids (i.e., natural gas, electricity, and district heat/district cooling);
- *Final-to-useful conversion* – includes everything from residential space heating and cooling, to industrial boilers and furnaces, to private automobiles and railway locomotives.

The remaining technologies fall into three broad categories:

- those serving an energy accounting, rather than conversion role, such as energy imports and exports;
- those satisfying energy service demands by non-energy means, through capital-energy substitution (i.e., demand reduction – what is often referred to as "energy conservation");[4]
- those representing the reduction or disposal of material emissions, particularly SO_2, NO_X, and CO_2.

Technologies in CESM are described in terms of their techno-economic parameters, including conversion efficiency, availability, lifetime, investment and O&M costs, and emissions. Each parameter can vary over time, to reflect expected performance improvements and cost reductions. Both the production of, and the new investment in, each technology can be separately constrained.

In addition to CO_2, CESM currently ac-

4/ Model limitations in CESM preclude separate representation of all possible demand-reduction options. Instead, each useful energy demand has two or more associated generic demand-reduction "technologies," each representing those demand reduction options falling into a particular techno-economic category.

counts for emissions of methane (CH_4), sulphur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOCs). However, of these all but SO_2 are strongly process dependent; only results for SO_2 are reported here.

SYSTEM CONSTRAINTS

Beyond the physical constraints inherent in the system (e.g., the requirement that energy flows balance at each point), most technologies require additional explicit constraints to reflect the inertia in real world energy systems. These constraints may limit absolute activity or capacity additions, or the rate of change in activity or capacity additions, or some combination of all of these.

Constraints are also used in CESM to reflect other realities of Canada's energy system. These include:

- limits on the fraction of useful demands which can be met by natural gas and district energy, simulating different energy-density regions to reflect the economics of grid-based transmission and distribution systems;
- constraints which force electricity and natural gas flows to conform to specified patterns of energy use (i.e., load curves);
- constraints which link otherwise separate technologies (e.g., to limit the share of public transit in all personal transportation);
- constraints to reflect the 1985 agreement between the federal government and the provincial governments from Manitoba east through to Newfoundland, to reduce emissions of SO_2 (Government of Canada, 1991, p. 12.17).

GLOBAL PARAMETERS

Time Frame – The CESM time frame begins with a base year of 1990 and extends through to 2030, divided into seven time steps with lengths of 1, 4, 5, 5, 5, 10, and 10 years.[5] While most of the attention is currently focussed on emission targets for the years 2000 and 2005, two points suggest a need to look beyond immediate goals and take a longer view of energy system development. First, implicit in an emission stabilization target is the assumption that stabilization will be maintained in the future; we should be at least as concerned about maintaining the target as we are about reaching it. Second, much of the capital stocks in the energy system have lifetimes measured in decades, and decisions taken in the next few years will have impacts well into the next century.

Discount Rate – To account for the time value of money, all investments and expenses in the model are discounted back to a base year using a chosen discount rate. In the scenarios presented here, a real discount rate of 5% has been used; this is within the range of Ontario Hydro's cost of capital (ONCI, 1989, p. 14), and is in keeping with discount rates commonly used in utility analysis (OECD-NEA, 1989).

Load Curves – Load curves are imposed on space heating and electricity demands, as well as on electricity and natural gas energy flows. While different curves are used for each of these, the underlying principle is the same: grid-dependent energy carriers can be stored only with great difficulty; thus, their production and distribution require sufficient investment in capacity to handle peak rather than average energy flows.

Scenario Development

Energy system models necessarily contain many assumptions, and most can be reasoned by reference to the techno-economic reality of the energy system. Other assumptions and projections, however, are more uncertain, and can be considered as defining a particular view of the future — a scenario. This does not mean that a scenario is a prediction of *the* future; rather, it is a description of one *possible* future.

5/ The model actually has two additional steps of length 20 years, for which results have been calculated but not reported. Because dynamic optimizing models such as CESM solve for all time steps simultaneously, they tend to under-invest in the final step — the model "knows" that the energy system requires no capacity beyond the last time step, and thus has no reason to build it.

CESM has been used to analyze the effects of a number of scenario variables, including different types and levels of CO_2 emission limits, varying CO_2 emission charges, and varying developments of useful energy demands. This paper focusses on just one of these variables: the way in which CO_2 limits are imposed.

Three scenarios are considered, based on three possible courses of action regarding CO_2 emissions:

1. *Business-as-usual (BAU)* – This is the reference case against which scenarios involving emission reduction are compared. There are no CO_2 emission limits, and no other policy measures aimed at CO_2 emission reductions. This, however, is a not a static scenario, as the energy system continues to evolve over time.
2. *Stabilization* – This is the national emission reduction target applied directly to the country as a whole: total national CO_2 emissions limited at 1990 levels from 2000 onwards. Note that since CESM does not distinguish between sub-regions of the country, it implicitly allows emissions trading among regions and sectors.
3. *Sectoral Stabilization* – This is the same as the Stabilization limit, but without the option of sectoral emissions trading. The CO_2 emission limit is applied individually to emissions from each of the eight energy system sectors considered in CESM: resource extraction, primary energy processing and refining, electricity generation, energy transmission and distribution, industry, residences, commerce and public administration, and freight and personal transportation.

Other Scenario Variables

The following variables are held constant for all the scenarios reported here, although any or all might be varied to produce alternate scenario runs.

Oil Prices – International oil market prices (in 1990 US dollars) start at \$21 per barrel (/bbl) in 1990 and fall to \$18/bbl in 1991, before rising gradually to \$35/bbl by 2030. It is important to note that while projections of future oil prices play a central role in macroeconomic models, in a techno-economic model such as CESM oil prices serve only as reference points against which the prices of imported and exported energy carriers (including crude oil) may be set.[6] Moreover, constraints on import and export levels are typically specified which further reduce the importance of international oil market price projections.

Hydropower Potential – To reflect the public's increasing resistance to large scale hydroelectric development, hydroelectricity capacity additions are limited to 50% of the potential identified by NEB (1991), StatsCan (1992a), and NRCan (1993).

Biomass Potential – Two key issues relate to the future use of biomass for energy (i.e., bioenergy). First is the degree to which CO_2 emissions from bioenergy are balanced by CO_2 taken up by newly growing biomass, a question which can not be answered unequivocally. Here, we have accepted Jaques's (1992) arguments for treating moderate biomass utilization as CO_2-neutral. The second issue is the degree to which extensive expansion of bioenergy production in Canada is both environmentally sustainable and socially acceptable. As an initial way of incorporating this uncertainty, we have imposed a limit of 5% per year on the potential growth of non-industrial biomass utilization (i.e., apart from that determined indirectly by forest products and pulp and paper requirements).

Nuclear Electricity Potential – There exists considerable social resistance to further expansion of Canada's nuclear generating capacity. Here, this resistance is reflected by limiting such capacity additions to the replacement of

6/ In CESM, the import and export prices of crude oil, natural gas, coal, and refined oil products are set for each time step relative to the projected international crude oil price. The domestic production costs of these energy carriers, however, are determined by the techno-economic parameters of the related extraction, conversion, and distribution technologies. For any given time step, the model will import a particular energy carrier if domestic sources are insufficient to meet domestic requirements, or to substitute for more expensive domestic production. Conversely, an energy carrier will be exported to the extent that capacity is available and domestic production costs are less than the export price.

retired capacity.

Energy Import/Export Levels – In general, imports and exports of energy carriers are constrained to base year values, with these constraints loosening over time to allow prices and availability to increasingly determine trade levels.

Public vs. Private Passenger Transport – For both intercity and intracity useful demands, public and private transit technologies are linked to reflect the general preference for private travel. This preference reflects the non-monetary, service-related advantages attributed by most people to the private automobile, in spite of its greater monetary costs. In the BAU case, this link restricts the total share of public transport modes within each service to historical values; slightly greater shares of public transport are allowed in the other scenarios, to reflect potential behavioral change.

Road vs. Rail Freight Transport – A process similar to that of public/private passenger transport is also at work in the competition between trucks and trains for freight. Rail has a definite cost advantage, and must be constrained within the model to reasonable modal splits (reflecting the greater flexibility of truck transport). In all scenarios, this split reflects historical mode shares.

Results and Discussion

The primary CESM results for a particular scenario are the average annual values, for each time step, of all energy and material (emission) flows and of all technology capacity additions, plus the value of the overall objective function (i.e., the total discounted system cost).

Energy Trends

Figures 2 through 4 summarize energy flow results for two scenarios (BAU and Stabilization), presenting different views of the evolution of the Canadian energy system over the period 1990-2030.[7] (For brevity, the figures do not show results for the Sectoral Stabilization scenarios; except where otherwise noted, these are qualitatively very similar to the results for the Stabilization target.)

PRIMARY ENERGY

Figure 2 shows the evolution of total primary energy as well as its breakdown by source. The stabilization of CO_2 emissions beginning in the year 2000 causes a reduction in total primary energy use starting at 5% in 2000 and increasing to 12% by the year 2030. This decrease is the combined result of interfuel substitution, technology change, and efficiency improvements throughout the energy system, as well as price-induced demand reduction.

Regarding the structure of primary energy use, most significant is the decline in the demand for coal associated with the imposition of CO_2 emission limits. While primary coal demand over 1990-2030 grows by a factor of 2.6 under BAU, in the Stabilization scenario coal demand falls by more than 50%. (This decline, while significant, comes as no surprise given coal's high ratio of carbon/energy content.)

In absolute terms, annual coal use declines by 2,300 petajoules (PJ), which is more than the drop in total primary energy (1,800 PJ). Thus, the overall primary energy system embarks on a fundamentally different trajectory having less dependence on coal and oil and a larger reliance on natural gas, especially in the short run, and, over the longer term, on renewable energy sources. As expected, natural gas, the fossil fuel with the lowest carbon content per unit of energy, expands its market share significantly (from about 32% to 38%). This increase in market share, however, translates to only 230 PJ in absolute terms due to the drop in overall primary energy use.

In the Stabilization scenario, and unlike under BAU, wind and solar energy sources make a small but growing contribution by 2030 — about 300 PJ of solar photovoltaic and about 200 PJ of wind power. This is in addition to the large contributions of the traditional re-

7/ The results are presented as annual averages for the model periods ending in the indicated years. To simplify the presentation, the figures show data only for those periods ending on even decades.

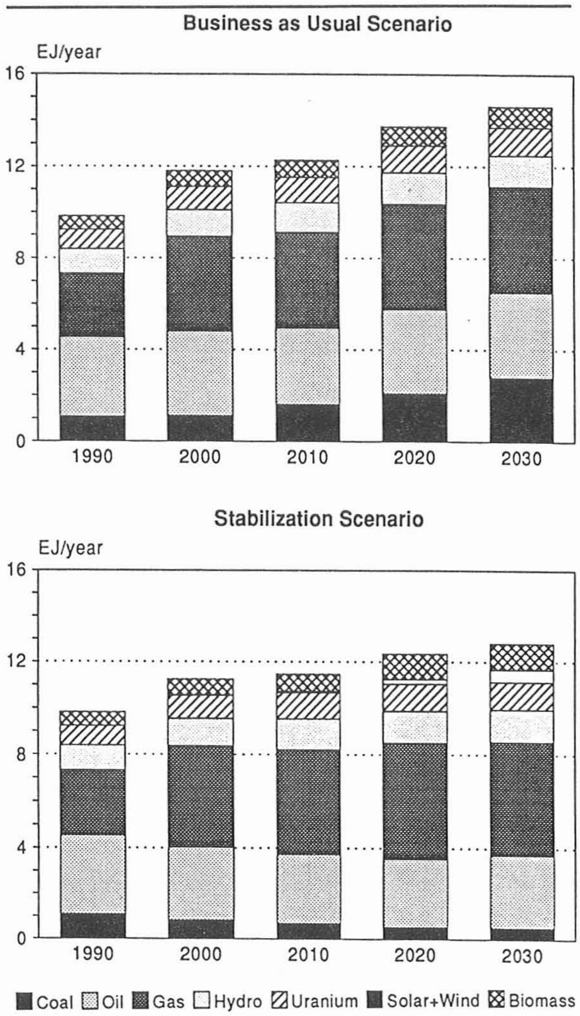

Figure 2: Total primary energy demand, by source
Note: "Biomass" also includes municipal waste

newables biomass and hydropower. Utilization of biomass increases, but remains below the sustainability/acceptability-related limit. New hydropower capacity, however, is added at the maximum rate, indicating that its economic feasibility may exceed its socio-political acceptability. By the end of the model time frame, renewable energy sources account for almost 24% of primary energy supply, compared to slightly less than 16% under BAU.

The use of nuclear energy is essentially unchanged between BAU and Stabilization; in both cases, retired generating capacity is replaced up to the imposed scenario limit.

In the short run (i.e., for the year 2000), oil — not coal — experiences the largest absolute cut (490 PJ versus 300 PJ for coal) due to Stabilization, although its relative decline compared to BAU is smaller (-13% versus -27% for coal). From 2000 through to the end of the model time horizon, oil use hovers around the year 2000 level of 3,200 PJ. In terms of market share, however, oil's long-term contribution is not affected significantly by the Stabilization scenario.

In both scenarios, natural gas production and transmission infrastructures expand rapidly during the second part of the 1990s. Here the question arises whether growth rates in the order of 8-10% annually over a period of five years are economically feasible, especially from the viewpoint of capital formation. To put things into perspective, this increase in domestic gas use represents the current total volume of gas exports.

FINAL ENERGY

Figure 3 shows a breakdown of final energy demand by energy carrier/fuel. Compared to the changes in primary energy demand, both the breakdown and growth of final energy demand are relatively unaffected by CO_2 emission limits; total final demand in 2030 under Stabilization is only 2% lower than for BAU,[8] and at a first glance, the breakdown displays no significant shifts among fuels. Coal, which at the primary level assumes most of the burden under Stabilization, contributes less than 1% to final energy supply in 1990; even under BAU the relative share of coal is declining, and a CO_2 limit cannot have any significant additional impact. Three major changes, however, do impact the structure of final energy demand.

8/ With specified useful energy demands equal in all scenarios, any decline in final energy must be the result of two competing processes: improvements in final-to-useful energy conversion, and price-induced investment in demand reduction (i.e., "energy conservation"). In the case of residential thermal demands, an example of the first would be the use of higher-efficiency heating systems, while the second could be represented by thermal envelope improvements.

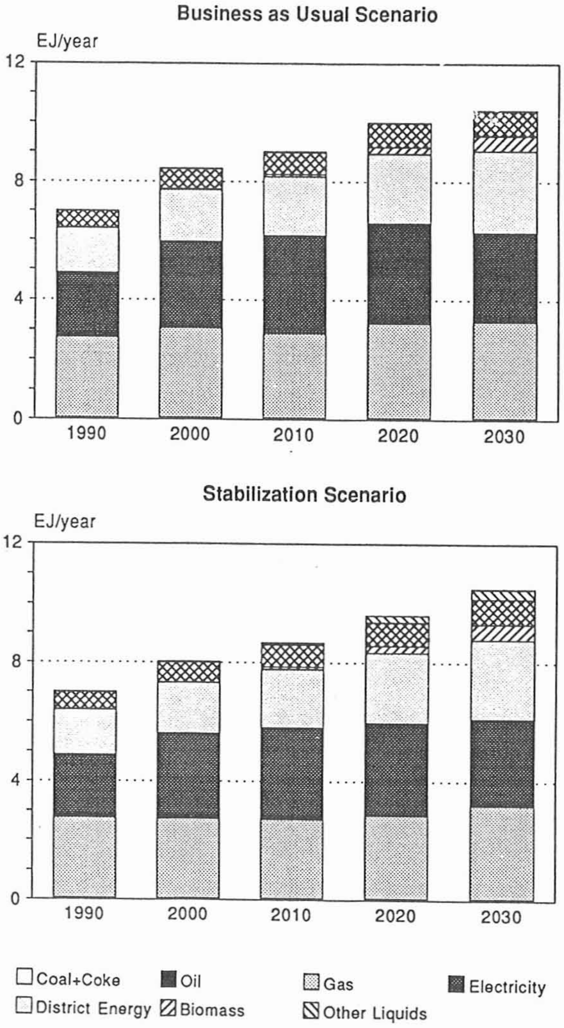

Figure 3: Total final energy, by fuel

Note: "Other Liquids" is methanol and liquid hydrogen (LH_2). Note that "Coal+Coke" is near zero in most cases.

• In the short run, efficiency improvements, "energy conservation" and lifestyle changes curb the use of liquid fuels in the transport sector, as well as electricity use in industries and households. The cut of one kWh of coal-fired electricity has the largest marginal effect on CO_2 emissions. On the other hand, electricity is the most efficient end-use fuel. Consequently, interfuel substitution away from electricity may well outweigh efficiency improvements and demand reductions associated with other fuels at the level of end-use energy conversion.

• In the longer run, biomass-derived methanol makes inroads as a transportation fuel, contributing some 320 PJ by the year 2030.

• There are shifts to more efficient technologies such as heat pumps, industrial co-generation and lower mileage vehicles, shifts which are not apparent from Figure 3.

What Figure 3 does *not* show also are the options the model chooses not to use (or to use to only a minor degree — less than 5 PJ per year), even under Stabilization in 2030:

• liquid hydrogen (LH_2), for vehicles;

• district cooling of commercial buildings;

• residential and commercial solar space heating.

ELECTRICITY GENERATION

The split in total electricity generation by source is given by Figure 4. As expected from the associated shifts in primary energy, coal-sourced electricity is greatly reduced under Stabilization. Under BAU, coal is responsible for 17% of electricity generation in 1990, rising to over 30% in 2030. However, under Stabilization, coal's share in 2030 has fallen to about 1%.

Much of this loss of coal-fired generation is balanced by increases in other generation sources and adjustments at the end-use level (see the previous section). By 2000, natural gas-fired electricity expands by almost 46% over and above an already appreciable increase under BAU during the 1990s.

Wind, solar photovoltaic, biomass, and municipal waste begin to make small but steadily growing contributions to electricity supply after 2000, and by 2030 are providing about 585 PJ or 165 terawatt-hours (TWh) per year (i.e., about 20% of the total supply). By the end of the study period, non-fossil sources account for 80% of total electricity generation under Stabilization, compared to some 57% under BAU. It appears that CO_2 stabilization pushes the electricity sector to the limit, and any further reductions in CO_2 emissions will require potentially far-reaching policy interventions with respect to the role of hydro, nu-

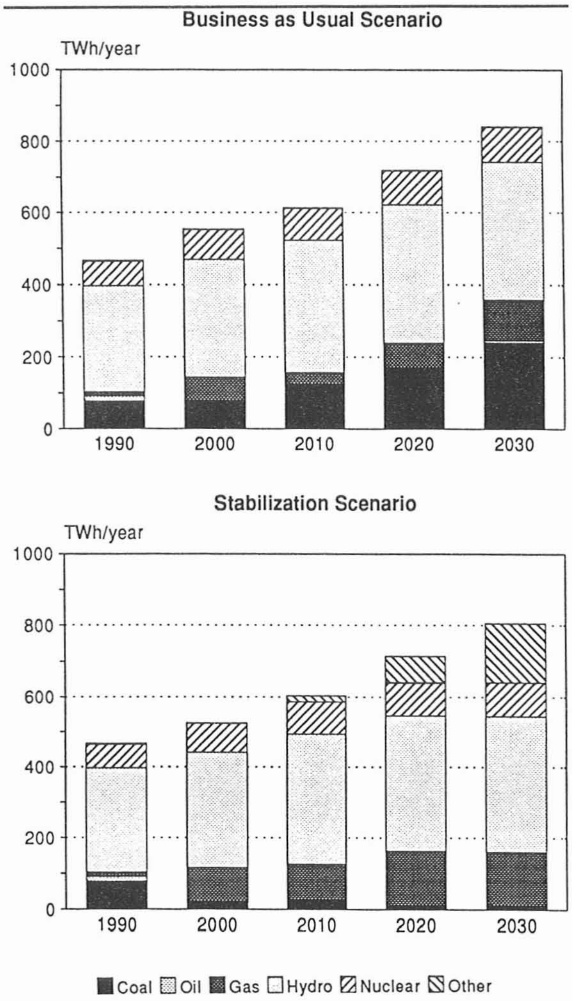

Figure 4: Total electricity generation by primary source

Note: "Other" is biomass, municipal waste, solar, and wind power.

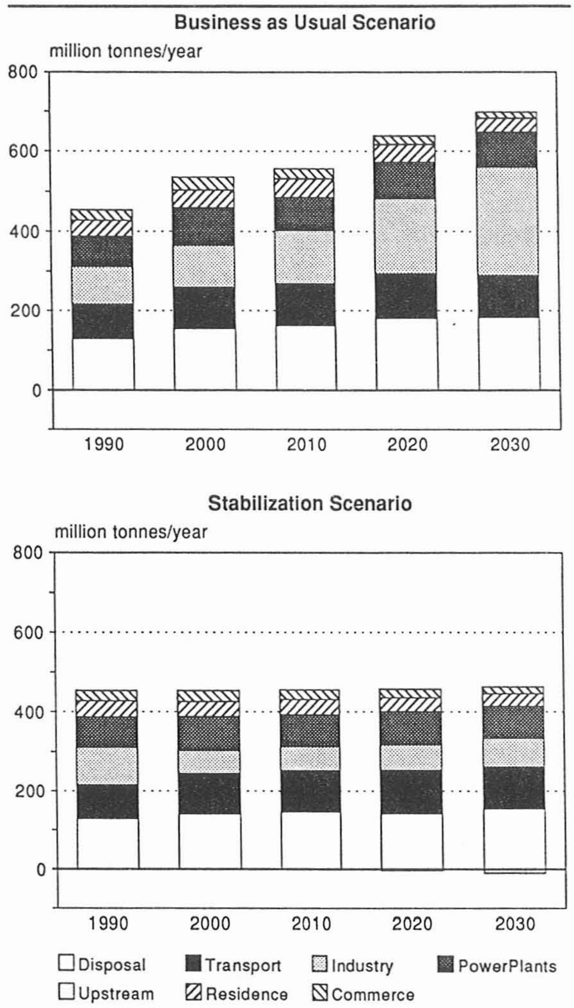

Figure 5: Total CO_2 emission, by sector

Note: "Disposal" is storage of CO_2 separated from IGCC (intercooled gasification/combined-cycle) power plants and from hydrogen production via steam-methane reforming (SMR), in nearby abandoned gas wells. "Upstream" includes emissions from energy extraction, production, transmission, and distribution.

clear, and solar technologies.

CO_2 Emission Trends

Figure 5 shows the sectoral distribution of today's CO_2 emissions, as well as their differing development through to 2030 under all three future scenarios: BAU, Stabilization, and Sectoral Stabilization.

The results for BAU show that much of the growth in CO_2 emissions between 1990 and 2030 is in the electricity generation sector, due to the increase in coal-fired electricity generation. It is not surprising, then, that the necessary emission cuts for Stabilization are made mostly in electricity generation, with other sectors seeing much smaller impacts.

The Sectoral Stabilization scenario requires all energy system sectors to reduce emissions by an equal proportion. As discussed below, while the overall effect of the two Stabilization

Table 1: Incremental System Costs and CO_2 Emission Reduction Costs, for Stabilization Scenarios

Scenarios:	Stabilization	Sectoral Stabilization
Increase in Total Discounted System Cost		
Relative increase (%)	2.3	6.3
Increment ($\$10^9$)	72	196
Cumulative CO_2 Emission Reduction (megatonnes (Mt) CO_2)		
Nominal	5640	6120
Discounted [1]	1730	1870
Average CO_2 Reduction Cost ($/tonne CO_2)	42	105

Note: Costs are in 1990 Canadian dollars.

1/ Emissions reductions must be discounted if they are to be allocated equal shares of cumulative discounted costs. While this may appear counter-intuitive, the effect is to *undiscount* the reduction *costs*, to assign the same nominal cost to each unit of reduction regardless of when it occurs.

scenarios is the same–emissions no higher than 1990 levels through to 2030–they have one key difference: the cost of meeting the target.

CO_2 Emission Reduction Costs

The total system cost of a particular scenario is, by itself, not especially important. However, it serves as a benchmark against which the cost of other scenarios can be compared, and thus from which their *incremental* costs can be determined. Table 1 shows the incremental cost, the cumulative CO_2 emission reduction, and the resulting average unit emission reduction cost for the Stabilization and Sectoral Stabilization scenarios.

These CO_2 emission reduction costs can be given some context through expression in terms of the equivalent costs of common fuels, based on their carbon contents. Table 2 lists costs equivalent to $100 per tonne of CO_2 (/t CO_2) for common units of natural gas, gasoline, and coal.

Using these values and assuming that all reduction costs are paid out of levies on energy carriers in proportion to their carbon content (however unlikely such a scenario might be in reality), the average reduction cost for the Stabilization scenario ($42/t CO_2) is equivalent to a surcharge of about $2.10 per gigajoule of natural gas or about $0.10 per litre of gasoline. Coal sees a much greater impact: for the hard coal used in central and eastern Canada, a $42/t CO_2 levy is equivalent to a near-tripling of the average $62 per tonne (/t) utility price, while for the soft coal used in the West the same levy leads to an over sevenfold increase in the $11/t average price (StatsCan, 1992b). It must be stressed that this is *not* to say that a carbon tax of $42/t CO_2 would achieve the emission reduction target, but only that the corresponding surcharges on carbon-based fuels would be sufficient to fund the required technical changes in an optimal energy system.

Table 2: Energy Carrier Values Equivalent to $100 per Tonne of CO_2

Energy Carrier	Cost equivalent to $100/t CO_2
Natural gas	$5.0 per gigajoule
Gasoline	$0.24 per litre
Hard coal	$240 per tonne
Soft coal	$160 per tonne

Note: These are the cost of common energy carriers, per physical unit, which is equivalent to $100 per tonne of CO_2 (i.e., the value of each fuel if the CO_2 produced by it is valued at $100 per tonne). Based on emission factors in Jaques (1992).

Table 3 is similar to Table 1, but shows results for variants of the two Stabilization scenarios (referred to as Reduction scenarios), in which emissions must be reduced to 1990 levels by the year 2000 but are unconstrained from that point on. There are both Reduction and Sectoral Reduction scenarios, corresponding to the Stabilization and Sectoral Stabilization scenarios.

Comparing Tables 1 and 3 shows the effect of time on the cost of emission reduction: in terms of average unit reduction costs, it is more expensive to reach the emission target in 2000 than it is to stabilize emissions at the target through to 2030, despite the considerable increase in overall useful energy demand between 2000 and 2030 (seen, in part, in the increase in final energy demands in Figure 3). This simply reflects the realities of Canada's energy system, which is highly capital inten-

Table 3: Incremental System Costs and CO_2 Emission Reduction Costs, for Reduction Scenarios

Scenarios:	Reduction	Sectoral Reduction
Increase in Total Discounted System Cost from BAU		
Relative Increase (%)	1.9	4.6
Increment ($\$10^9$)	58	144
Cumulative CO_2 Emission Reduction (megatonnes (Mt) CO_2)		
Nominal	3180	3460
Discounted	1090	1170
Average CO_2 Reduction Cost ($/t CO_2)	53	123

Note: Reduction scenarios differ from Stabilization scenarios only in that CO_2 emissions must be cut to 1990 levels by 2000, but are unconstrained thereafter. Costs are in 1990 Canadian dollars.

sive, and in which much of the capital stocks have lifetimes measured in decades. Longer-term emissions reduction is greatly eased by natural technological improvement and cost reductions, and the benefits can be captured at the end of the existing capital's natural life.

OVERALL VS. SECTORAL STABILIZATION

Tables 1 and 3 also highlight the penalties incurred by imposing restrictions on the means by which emission reductions are achieved. The unit cost of Sectoral Stabilization is over twice as high as for Stabilization at the same emission reduction target, reflecting the very high costs of emission reduction faced by some sectors.[9] In the Stabilization scenario, each sector reduces emissions only to the point where its marginal unit reduction cost equals the marginal unit cost of all other sectors — any other situation would imply a greater-than-optimal cost. In terms of implementation, this scenario could be interpreted as representing an ideal national tradable permits scheme, in which those who can most easily reduce emissions do so, paid in part by those who can not. (Whether such a system is, in practice, feasible is an open question.)

One attraction to sectoral limits is an appeal to (perceived) equity: that all parties should have to meet the same limit. However, the one clear result of this work is that such an approach is, in fact, very inequitable: under overall Stabilization everyone pays the same unit reduction cost, while under Sectoral Stabilization some pay much larger costs than others.[10]

Collateral Benefits

While discussion of CO_2 emission reduction is generally focussed on the associated costs, it is equally important to consider potential benefits (aside from the presumed, but unknown reduction in the threat of global climate change).[11]

One certain, but difficult-to-quantify collateral benefit is the reduction of other emissions to the atmosphere. As mentioned earlier, CESM currently accounts for emissions of:

- methane (CH_4), also a greenhouse gas;
- sulphur dioxide (SO_2), the major contributor to the problem of acid deposition or "acid rain;"
- nitrogen oxides (NO_X), a precursor to ground-level ozone as well as a source of acid deposition;
- carbon monoxide (CO), affecting local air quality;
- volatile organic compounds (VOCs), precursors to ground-level ozone.

However, as noted earlier, with the excep-

9/ While both Stabilization scenarios have the same emissions reduction target, Sectoral Stabilization has slightly lower overall emissions due, in particular, to the difficulty faced by the resource extraction sector in meeting its target. Achieving it requires restricting the available quantity of some final energy carriers, such that emissions in sectors consuming them actually fall below their respective targets.

10/ Berger, Loulou et al. (1992) comment on a similar effect in comparing the cost of CO_2 emission reductions in Ontario and Quebec with and without electricity trading. In their provincial MARKAL models, allowing Quebec to provide 3 GW of hydroelectric capacity to Ontario greatly reduces Ontario's cost in meeting its target, while increasing Quebec's costs only slightly.

11/ Of course, such reduction can only be possible as part of a global CO_2 reduction strategy.

tion of SO_2, these emissions are strongly process dependent; that is, small changes in combustion parameters can have significant effects on emissions. (See, for example, Alson et al. (1991) for the variation in emissions of alternate fuel vehicles.) For this reason, and because these emissions are not the focus of this work, they are not reported here. However, one value is worth noting: compared to the BAU scenario, the Stabilization scenario shows an average annual reduction of more than 590,000 tonnes of SO_2, or about 34% of total energy-system SO_2 emissions.

What is 590 kilotonnes of SO_2 per year worth? Putting a monetary value on any emission is an uncertain undertaking, yet as Ottinger et al. (1991, p. 14) put it in their extensive review of the field: "one always has to come back to the basic tenet that a 'crude approximation' of these damage costs is closer to an accurate accounting for resource costs than is a value of zero." Ottinger et al. (1991) estimate the damage cost of SO_2 at just over US$2 per pound, or about Cdn $5,200 per tonne,[12] leading to a value for a 590 kilotonne annual SO_2 emission reduction of more than $\$3.1 \times 10^9$ per year. The corresponding total discounted SO_2 emission reduction for the model time frame is approximately 7.9 megatonnes, which at $5,200 per tonne gives a present value on the order of $\$41 \times 10^9$.

Thus, the collateral SO_2 abatement associated with Canada's meeting its stabilization commitment could lead to a reduction in SO_2 damage costs of the same order of magnitude as the total CO_2 emission reduction cost. We recognize that this comparison ignores:

- whether there exist less costly means to reduce SO_2 emissions;
- whether the damage cost used is, in general, applicable to SO_2 emissions in Canada; and
- whether the damage cost used is applicable to all SO_2 emissions in Canada.

Nonetheless, SO_2 reduction is only one potential collateral benefit to CO_2 reduction; one can expect others.

Concluding Comments

When discussing CO_2 emission reductions, few question the physical feasibility of stabilizing emissions at 1990 levels by the year 2000. Rather, attention is usually focussed on the costs required to achieve the target. Our techno-economic modelling work suggests that, over the longer term, and assuming maximum flexibility in choosing where to cut, these costs could be on the order of $40 per tonne of CO_2. This is equivalent to a surcharge of about $2 per gigajoule of natural gas, $0.10 per litre of gasoline, or $100 per tonne of hard coal; such increases are non-trivial in relative terms, but would lead to energy prices still low by world standards. It is true, however, that over the shorter term costs would necessarily be much higher, perhaps by as much as a factor of three.

Another key issue around CO_2 emission cuts is determining who will be most affected. Given its underlying assumptions, our model suggests that the least expensive route to meeting the target is through reductions in coal-fired electricity generation, balanced by increases in other generation sources as well as adjustments at the end-use level.

Two lessons from this modelling work are essentially independent of the model's underlying assumptions. First, the benefits of CO_2 emission reduction must be considered in addition to the costs. One key collateral benefit is likely to be the reduction of other emissions, particular SO_2. Second, minimum cost emission reductions are a result of giving the system maximum flexibility in meeting the target. Forcing every sector, or every province, or every person to make the same cuts may appear to be equitable, but is, in fact, very inequitable: it imposes much larger costs on some agents than on others, and in doing so leads to a much higher overall cost.

12/ Any number of this type is necessarily an average, and is based on numerous assumptions including ones about the environment into which the SO_2 is emitted. Thus, separate from the issue of whether the value is reasonable given the underlying assumptions, there is the question of whether the value can be applied in a different environment (e.g., Western Canada versus the Northeastern United States).

Finally, the results reported here should be viewed as the first phase of a work in progress. While the CESM structure is complete, model refinement is an ongoing process, particularly concerning the technology resolution within the end-use sectors. Near-term improvements will be focussed on: (i) representation of the transport sector; and (ii) representation of the costs and benefits of capital-energy substitution (i.e., "energy conservation"). Longer-term model development will aim to integrate a macroeconomic module into the existing techno-economic framework, allowing the linking of cost, price and capital feedbacks from the energy system with the macroeconomy.

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