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Electric/Oil Hybrid Heating Systems

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ELECTRIC/OIL
HYBRID HEATING SYSTEMS

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ELECTRIC/OIL HYBRID HEATING SYSTEMS

EXECUTIVE SUMMARY

Off-oil Strategy[1]

In 1980, the federal government's National Energy Program (NEP) established an "off-oil" conversion program designed to promote a rapid and effective shift from oil towards gas, electricity, renewable energy and coal. Unfortunately, unless unforeseen technological breakthroughs alter the situation, these potential alternatives are not as versatile as oil. Accordingly, a practical energy strategy for Canada should require that substitutes for oil be used wherever possible, and oil itself be retained for those applications where alternative energy sources are not readily adaptable, notably in transportation. A goal of the NEP, therefore, is to reduce the use of oil in the residential, commercial and industrial sectors to no more than 10 per cent of the total energy used in those sectors.

Alternatives to Oil for Space Heating[2]

One logical substitute for oil in space heating is natural gas. There is a very large domestic supply and, in many parts of Canada, the gas production and distribution infrastructure is already in place. However, while current prices will continue to encourage exploration for natural gas and its use in markets now served by oil, the technical opportunities for substantially improving the efficiency of Canada's total energy system by using gas to replace oil for space heating are limited. Transportation losses will figure more prominently in the future as the gas pipeline network is extended across the country and as the balance of new reserves come increasingly from frontier areas. In addition, as space heating demand is seasonal, the increased use of natural gas in this area will result in efficiency losses for the total Canadian gas transmission and distribution network (which includes industrial gas use). If the space heating market for natural gas were to grow relatively faster than the non-seasonal industrial market, the overall capacity utilization of the gas facilities would decline.

Whereas natural gas is not yet available in some areas of Canada, virtually every building in the country is wired for electricity. However, as electricity has been relatively expensive using current practices and as it is considered to be a "high quality" form of energy, it is generally seen as playing only a subsidiary role in space heating. To satisfy customer needs for all-electric space heating, utilities would have to have enough capacity at the generating plant (including adequate reserve), and in their transmission and distribution grids, to meet the highest possible demand, even if it occurs only once per year. In other words, all-electric space heating has a very poor load factor (the ratio of average kilowatts demanded to peak demand).

As the name suggests, "baseload" generating capacity is that which is in operation virtually all the time; it represents approximately 55 per cent of all generating plant in Canada. Intermediate plant (about 35 per cent of all capacity, generally coal-fired) is in operation some of the time, and peaking plant (about 10 per cent of capacity, generally oil- or gas-fired) comes into operation only infrequently. The distribution of load determines the appropriate types of equipment a utility requires; this will, in turn, affect the cost of electricity. In the long-run, baseload equipment gives the cheapest electricity, providing there is a large and assured market. From a cost standpoint, electric utilities would derive greater benefit from an improving capacity factor obtained from continuous stable loads. Such loads are not provided by all-electric space heating.

If oil were to be massively displaced by all-electric heating, using current practices and without compensating growth in other areas of use, the immense size of the market, particularly in Quebec and Ontario, would overburden the electric grid and intensify the peaking problems of utilities. The poor load factor of space heating would become characteristic of electricity as a whole and the uneven seasonal demand for space heating would cause severe deterioration of the overall efficiency of Canada's electricity generating plant. Additionally, the need for new generation, transmission and distribution facilities — much of which would stand idle most of the year — would put a strain on capital markets. In short, it would be more economical for utilities to sell greater amounts of off-peak electricity, than to add to their generating, transmission and distribution capacity to enable them to meet higher peak demands.

From the above, it should be clear that natural gas and all-electric systems for space heating both contribute to reducing oil consumption, but neither significantly improves the efficiency of Canada's total energy system.

Electric/Oil Hybrid Heating (Dual-Energy Heating)

There is another system that would reduce Canada's dependence on oil and, at the same time, increase the country's overall energy efficiency. The hybrid heating system (or "dual energy" heating system) involves the adoption not of a new technology but of a

[1] See Chapter One, *Canada's Energy Issues*, in main body of the report.
[2] See Chapter Two, *Canadian Options for Oil Substitution*.

new operational technique — the use of electricity for space heating during periods of off-peak electric demand, and the use of oil when the demand for electricity is peaking — thereby filling in the valleys in the demand curve for electricity. Using this method, maximum end-use efficiency is wrung out of the electric grid, and less expensive baseload generating plant and intermediate plant, where necessary, are substituted for oil. The main focus of this study is on the electric/oil hybrid in the residential sector, although this system could be adapted to space heating in the commercial and industrial sectors as well.

The Ministry of State for Science and Technology, with the support of Energy, Mines and Resources Canada, undertook this study to examine the potential benefits of hybrid heating and to answer technical questions on its impact and use. Also, an objective of this study was to involve federal and provincial governments, electric utilities and interested firms in an examination of hybrid heating which would lead them to further explore its benefits and, if appropriate, to initiate action to cause its widespread adoption.

Description of Hybrid System[3]

Approximately 35 per cent of all Canadian buildings already have an oil furnace. Converting them to hybrid heating systems can be achieved most simply by installing an electric heater in the furnace's plenum. Furthermore, with the exception of the coldest periods in Canadian winters, only a moderate amount of power is required to keep most buildings warm — the type of power that the existing electric grid can easily provide. In a hybrid system, the back-up oil furnace can be made to operate only at times when there is peak demand on the electric grid. Actual tests by Ontario Hydro, AECL and Hydro-Québec, and the implementation of hybrid heating by the Minnkota Power Co-operative in the northern United States, have shown that this system results in a significant improvement in the capacity factor of the electric grid.

There are two types of hybrid systems technically available. Most of the effort in Canada has concentrated on the "Hybrid I" system. In this method, electricity provides baseload heat from September to June, except when the outside temperature drops below a pre-set value or at a designated time of day. Below the specified temperature and/or during diurnal peak demand, a storable source of heat, such as oil, is used instead of electricity. In a Hybrid I system the control over the switching between the electric and oil heating sources is located within the building itself. Equipment for use in single family dwellings is now available. Appropriate equipment for use in large buildings has been developed, but is not yet available on a mass-production basis. Control systems for such equipment have not yet been developed in detail, although they would be able to use most of the same circuitry as in smaller plenum heaters.

Hybrid I contributes to a measure of stabilization in electrical demand and in the costs of electricity. Eventually, however, it will add to peaking problems — although not nearly as much as all-electric systems — because there is no error-free mechanism to shut the electric heater down when the grid is heavily burdened from other uses. The Hybrid I system, therefore, should be regarded as an introduction to a far more sophisticated control system which can be labelled "Hybrid II".

The Hybrid II system is superior to Hybrid I in that it provides the bulk of the space heating requirements of a building, but does not add at all to the peak demands of the utility. Capacity is allocated to heating only when it is not needed for other purposes; i.e., when it is "off-peak". When total electricity demand approaches capacity, the utility switches off a sufficient number of heaters by remote control, so as to provide enough electricity to satisfy this increasing demand. The heaters can then be reconnected progressively in the same way, as the demand declines.

The immediate and widespread implementation of Hybrid II would not be difficult to achieve in Ontario and Quebec. It would involve the installation of up to 15 Kw of electric heating capacity in those single-family houses presently heated with oil. This would not, even at maximum usage, overload the existing grid, and yet it would displace up to 95 per cent of all oil used for space heating in a given building.

Although the two central Canadian provinces have the greatest potential for the conversion of oil-based space heating to electric/oil hybrid heating, significant gains could be made in Newfoundland, New Brunswick, Manitoba, Saskatchewan, Alberta and British Columbia (especially on Vancouver Island). Nova Scotia might be able to benefit from hybrid heating in the future, but at present it lacks the appropriate amount of surplus baseload electricity.

Economic Benefits of Hybrid Heating[4]

By comparing projected heat demand with the surplus electric capacity of several provinces, this study has determined that for the 1979-80 heating season about 80 per cent of Canada's total oil space heat could theoretically have been provided electrically if all oil-heated buildings (residential, commercial and industrial) had been connected in a Hybrid II network. Displacement of the equivalent of 250,000 barrels of crude oil per day, or 91.3 million barrels a year, could have been realized in Ontario and Quebec alone. Such a reduction would represent savings to the federal government of $1.33 bil-

[3] See Chapter Three, *The Potential of the Electric Hybrid System.*

[4] See Chapter Four, *The Economic and Technological Benefits of Hybrids to Canada*, Sections (a) and (b).

lion in oil compensation payments for 1983, $1.43 billion for 1984 and $1.70 billion for 1985 (based on EMR projections for oil import subsidies), and would also make a major contribution to achieving oil self-sufficiency in this country.

As well, by increasing overall energy efficiency, hybrid heating would help in keeping down Canadian energy prices, relative to other countries. This would contribute to the industrial sector's competitive stance and enhance its ability to penetrate foreign markets. Such an advantage is largely possible because of the availability in Canada of substantial amounts of cheap, baseload electricity.

The use of electric/oil hybrid systems for space heating would provide an industrial opportunity for Canadian electrical products manufacturers. Five designs for residential hybrid heating equipment have so far been accepted by the Canadian Standards Association. Based on 1,280,000 potential installations, the estimated wholesale market value of plenum heaters for the residential sector in Ontario and Quebec using a Hybrid I system is $640 million. The market value for remote switching equipment necessary for a Hybrid II system in these provinces is approximately $768 million. If electric utilities were to offer differentiated rates for space heating in a hybrid system (i.e., lower rates for off-peak electricity), the electric heaters could be metered separately. The wholesale market value of these meters is estimated to be $384 million.

The adoption of hybrid heating would not place a strain on Canadian capital markets. Hybrid heating uses existing generation, transmission and distribution plant, and the costs to a utility of providing marginal power from existing facilities is extremely low. Accordingly, these expenses do not involve recourse to capital markets. Moreover, the hybrid system's use of surplus off-peak power would not necessitate the investment in new generating plant which would be required by the adoption of all-electric systems. In the case of Hybrid II systems, the utility would have to incur some capital expenditures for appropriate remote control equipment. However, these costs would be lower than those of expanding generating plant and upgrading transmission and distribution facilities. Based upon available data, the capital expenditures needed for the widespread implementation of hybrid heating would be at most ten per cent of that required for all-electric heating.

Natural gas, by contrast, requires a substantial investment in pipeline construction before it can be effectively used as an oil substitute. If one calculates the additional call on capital markets required for a Hybrid II system, as compared with the capital needed for the proposed eastward extension of the natural gas pipeline (including local installation costs), the latter exceeds the former by between $1.3 billion and $1.9 billion.

Benefits to Electric Utilities[5]

The adoption of electric/oil hybrid heating would result in significant advantages to electric utilities. The demand placed on the utility's generating plant throughout the heating season by the adoption of hybrid systems in otherwise oil-heated homes would raise the annual load factor to 85 per cent from its present value of 65 per cent and improve the capacity factor to 75 per cent from the present 46 per cent. Most of the load would thus be "base", with a small amount of "intermediate" and no "peaking" load.

In Canada, existing baseload and intermediate systems could theoretically have been called upon in the 1982-83 heating season to supply about 60 per cent more electricity than they now generate for space heating purposes, without significantly increasing operating costs. An additional total of about 145 billion kWH of baseload electricity could be generated and distributed off-peak at a marginal cost to the utilities of about 2.3¢/kWH or less, much lower than the current average rate. Under ideal conditions, a utility with optimum plant could charge as low as 0.5¢/kWH for off-peak power in a hybrid system. These figures are, of course, theoretical, and the full use of off-peak capacity would take several years to achieve. The potential is, however, very large and most of it could be realized.

If a Hybrid II system were adopted, the back-up heating system could be brought immediately into service by the utility when power is needed for reallocation to other uses, thus rendering the system self-adjusting. Hybrid II can also provide strong protection against the dangers of a system breakdown by enabling the utilities to shut down heaters over a wide area by remote control.

Until very recently, the two largest Canadian utilities, Ontario Hydro and Hydro-Québec, had been reluctant to embark upon large-scale promotion of hybrid heating as they believed they had enough peak generating capacity to permit the widespread adoption of all-electric space heating. Now, however, they are showing active interest in hybrid heating systems. Within the past year, each has announced non-taxable grants, over and above the federal government's Canadian Oil Substitution Program (COSP) grant, to encourage subscribers with oil furnaces to convert to electric/oil hybrid heating.

Benefits to Consumer[6]

The achievement of the government's off-oil objective will depend not only on the number of conversions away from oil but also on the swiftness of such conversions. Paradoxically, more rapid progress could be made

[5] See Chapter Four, Sections (c) and (d).
[6] See Chapter Four, Sections (e) to (h).

by the adoption of hybrid heating (in which a small amount of oil plays a back-up role) than by the adoption of all-electric systems (which would be restricted to a relatively small number of dwellings because of present limitations in transmission and distribution and eventual limits in generating capacity).

Based on fuel costs alone (1982-83 figures representative of Ontario and Quebec), the consumer has little or no incentive to purchase a hybrid heating system. If capital expenditures for conversion are introduced into the analysis, however, hybrid heating systems become more attractive. Such systems are less expensive to retrofit than all other alternatives except the conversion gas burner, but more expensive to install as a new system than all-electric furnaces and bottom-of-the-line natural gas furnaces. They are, however, even as new systems cheaper than either electric baseboards or high efficiency natural gas condensing furnaces.

Summarizing all costs for the consumer in choosing alternatives to oil in space heating, presently the least expensive substitute is natural gas, followed by hybrid heating, with all-electric heating the most costly. If, however, the savings resulting from the increased efficiency of hybrid heating systems were to be passed on to consumers in the form of differentiated rate structures which reward the purchase of off-peak electricity and penalize its purchase of peak demand, electric utilities could make it less expensive than natural gas and thus encourage consumers to adopt hybrid heating systems. Hydro-Québec is already developing a differentiated rate structure for hybrid systems.

Depending on how the relationship between the prices and rate structures of electricity and natural gas evolves in the years ahead, hybrid electric/oil heating systems could become economically much more attractive to the potential consumer of natural gas. While existing data suggest that this is likely to be the case, changes in prices and rate structures are impossible to forecast with certainty.

Implications for Natural Gas[7]

The adoption of preferential rates for off-peak electricity for space heating, unless it were countered by a significant revision in residential gas pricing policies, could very well result in the widespread penetration of the space heating market by electric/oil hybrid systems and thereby limit the expansion of natural gas sales. This would result in the loss of substantial royalties by the gas producing provinces and in a slow-down of their economic development. Accordingly, if electric/oil hybrid systems were introduced on a wide scale, it would become important to open alternative markets for natural gas so as to ease the hardships associated with the loss of the space heating market, on the utilities and the producing provinces.

One market with great potential for natural gas is found in the process heat requirements of Canadian industries. The federal government has announced measures to ensure the penetration of natural gas into this area. These measures include grants to meet half the cost of conversion to gas by industrial, commercial and private institutions, as well as restrictions on the licencing of the import of residual oils (which are undercutting the price of gas for industrial use) and the facilitation of exports of residual oil.

Another opportunity for the use of natural gas is its conversion into methanol, a high-octane unleaded motor fuel, for use in both gasoline and diesel engines. The market value of natural gas would be much higher as a transportation fuel than it would be in space heating. As well, since natural gas is the cheapest feedstock for producing methanol, synthetic transport fuels made from natural gas would likely be cheaper than U.S. synfuels made from coal. There could be a large export market for Canadian natural gas, not only in its primary form but also converted to higher-value energy products, and this could be very important to Canada's petrochemical industry.

However, it must be recognized that vast amounts of natural gas, which could be converted into methanol, are at present being flared in the world's major oil fields. As well, a significant drop in the price of natural gas would encourage its conversion into methanol even where it is not being flared.

Conclusions[8]

The early and widespread adoption of electric/oil hybrid space heating for Canadian homes would: (a) help achieve national energy security and self-sufficiency by rapidly reducing Canada's dependence on imported oil; (b) relieve the federal treasury of the burden of substantial oil import compensation payments; (c) enable electric utilities to increase sales significantly from existing plant; (d) delay the need for investment in new electricity generation, transmission and distribution facilities; (e) help keep down the cost of space heating to consumers, while still allowing utilities to achieve reasonable profits, if off-peak rates are set at appropriate levels; (f) provide industrial opportunities for Canadian electric products manufacturers; and (g) give Canadian industry a comparative advantage in the competition for world trade through the lower energy prices that would accompany the more efficient use of electrical generation systems.

[7] See Chapter Five, *Hybrid Systems and Natural Gas.*

[8] See Chapter Six, *A Federal Approach to Hybrid Heating.*

It should be noted as well that hybrid heating would increase the competition with natural gas in the residential heating market and might result in the need for natural gas utilities to either reassess their pricing or accept lower market shares.

In summary, given present conditions, and based on the best available cost projections, experimental data and actual tests, it is the conclusion of this study that electric/oil hybrid heating systems offer the greatest efficiency and financial benefits of the various space heating alternatives.

CHAPTER ONE: CANADA'S ENERGY ISSUES

(a) Energy Supply and Demand

In 1979, about 57 percent of Canada's secondary[1] or end-use energy came from oil (Figure 1)[2]. This is almost the same proportion as five years earlier. But while Canada was, on balance, still self-sufficient in oil in 1974, by 1979 it had become dependent on net imports for 20 per cent of its needs. At $40 (Cdn). per barrel — sixteen times the price of oil in the last years of Canadian self-sufficiency (1973-74) — the net oil import bill had reached $6 billion annually by 1981 and that year the federal government was spending over $3 billion a year on domestic oil equalization payments.[3]

More recently, owing to conservation, substitution and a general slowdown in economic activity, net imports have dropped considerably and it is expected that in 1983 they will be negligible. All the same, unless some new factor changes the supply/demand balance permanently, Canada's dependence on imported oil is bound to become serious again in the future. This is illustrated in Figures 2 and 3 for 1990 and 2000 respectively. These figures provide a general idea of Canada's energy supply and of its future requirements. The projections in Figures 2 and 3 are based on a forecasted overall energy consumption growth rate of 2 percent a year for the period 1980-2000, a substantial drop from the 1975 rate of 3.5 percent.

No physical constraints are expected to prevent natural gas, coal, and electric generating resources from supplying their projected shares of energy requirements in the years ahead. However, Canada's domestic oil reserves are not likely to be adequate to supply the country's oil requirements.

In 1979, Canada produced 250,000m^3 (1,700,000 barrels)/day of crude oil. But according to recent projections by the National Energy Board,[4] even an optimistic forecast (the N.E.B.'s "modified base case") suggests that in 1985 only 200,000 m^3 (1,300,000 barrels/day will be available from domestic production. Under the best circumstances, a return to 1980 production levels could not be achieved until 1995, and then only if enough additional tar sand projects came on stream. The N.E.B.'s more conservative "base case" forecast predicts that only 192,000 m^3 (1,250,000 barrels)/day will be produced in 1985, and that production will continue to drop to 157,000 m^3 (900,000 barrels)/day by 1995. The N.E.B.'s more optimistic forecast is predicated on an oil-pricing regime structured to encourage private development of new and frontier resources on a wide scale. No new tar sand development has occurred to date; indeed, private capital has withdrawn from near-term projects.

The projections displayed in Figures 2 and 3 show that even using the N.E.B.'s "modified base case" of domestic oil availability, there is likely to be quite a gap in 1990 and 2000 between domestic supply and domestic requirements — labelled "POTENTIAL UNFILLED SUPPLY REQUIREMENTS" on the charts.

(b) Alternatives

Natural gas and electricity are the most obvious alternatives to oil in the space-heating and industrial sectors. Technically, both can be used to replace oil in a number of applications. However, if they continue to be substituted for oil only in the traditional manner, the overall efficiency of Canada's energy system will not be improved, even though efficiency will become increasingly important owing to rising costs.

Aside from the fact that there is a secure domestic supply of both natural gas and electricity, the reason for using these fuels instead of oil is that they are currently cheaper. But the real costs of gas and electricity are also growing, with deleterious economic effects. If greater efficiency could be achieved, real energy costs could be actually reduced.

Considerable potential exists for improving the utilization of Canada's energy system and, hence the country's overall economic efficiency. This is particularly true of the electrical sector. In 1979, the most recent year for which comprehensive energy statistics are available, Canada had a national electric generating capacity of 72,000 megawatts, which could generate 631 billion kilowatt-hours (kWH) a year if run continuously. Indeed, from August 1979 to July 1980, this capacity was drawn upon for only 293 billion kWH for an overall capacity factor of 46 percent (49 percent during the heating season). This means that, on average, the equipment stands idle more than half the time.

A few calculations will serve to illustrate the potential benefits which would be achieved as a result of improved efficiency in Canada's electric grid. If (say) half of the 388 billion kWH hours of electricity theoretically available (but not used) from Canada's generating plant could be put to work, and if consumers were charged two-thirds of the normal price (2.4/kWH rather than 3.6/kWH) for this "off-peak" electricity, this would:

(i) return $4.7 billion a year to Canadian electrical utilities without increasing their physical plant requirements, thus easing their debt service and amortization burdens significantly, to the ultimate benefit of consumers, while limiting utilities expenses to the marginal cost of fuelling existing plant at "off-peak" times;

(ii) delay the need to build much new generating plant, thus reducing utilities' demand for scarce capital on the money market; and

FIGURE 1

CANADA'S SECONDARY (END-USE) ENERGY SUPPLY AND DEMAND BALANCE 1979

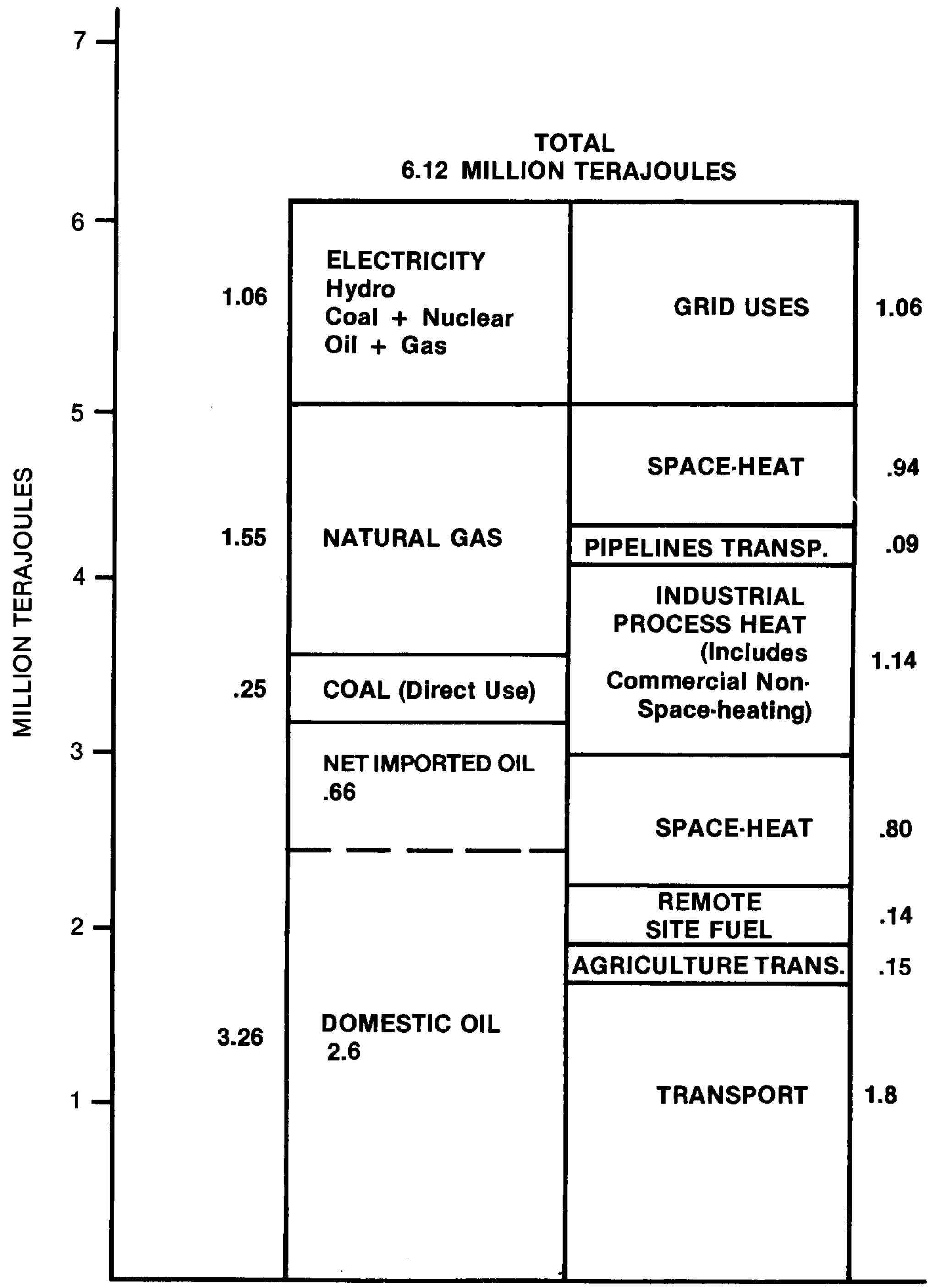


FIGURE 2

CANADA'S PROJECTED SECONDARY (END-USE) ENERGY SUPPLY AND DEMAND BALANCE, 1990

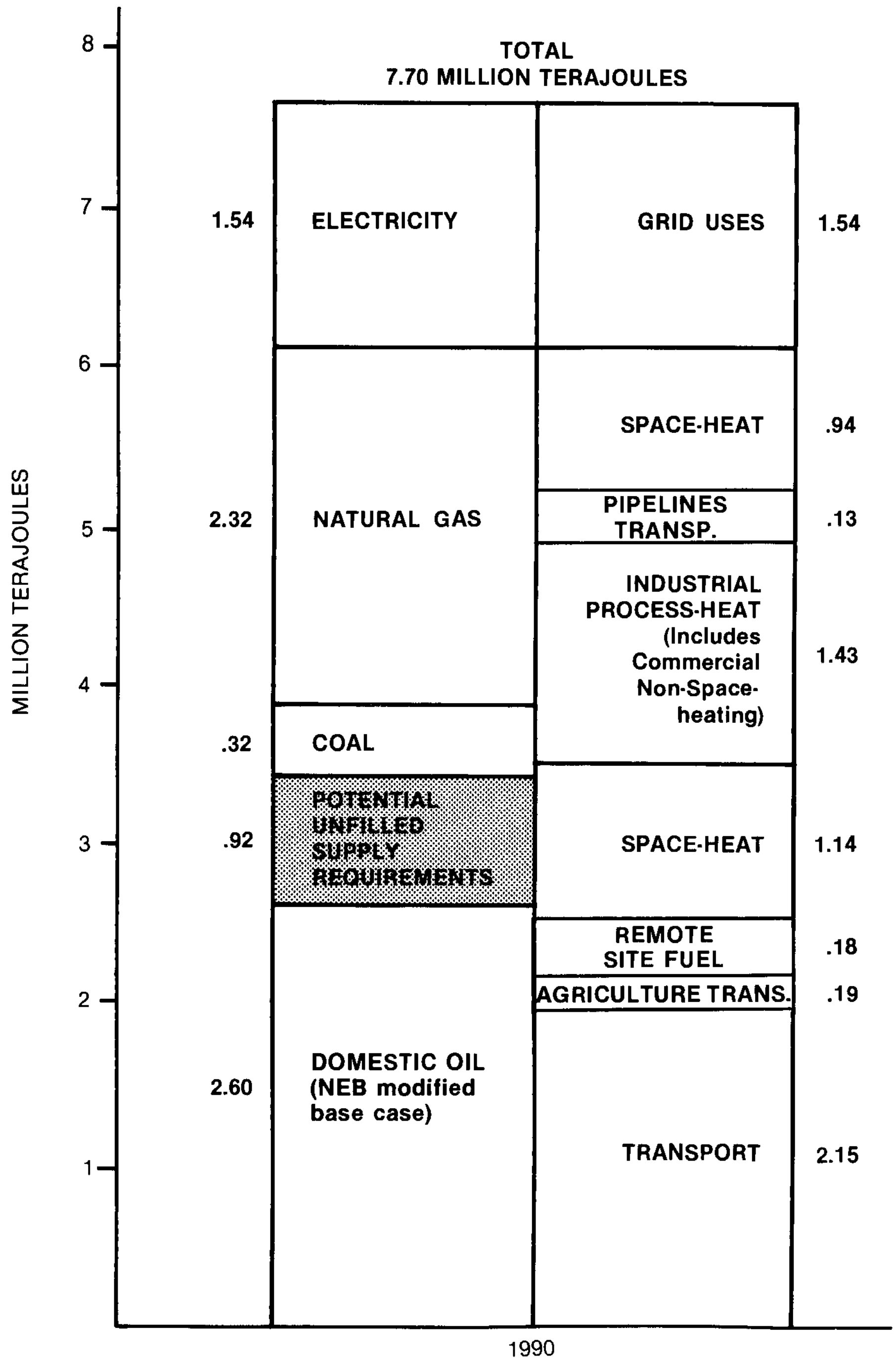
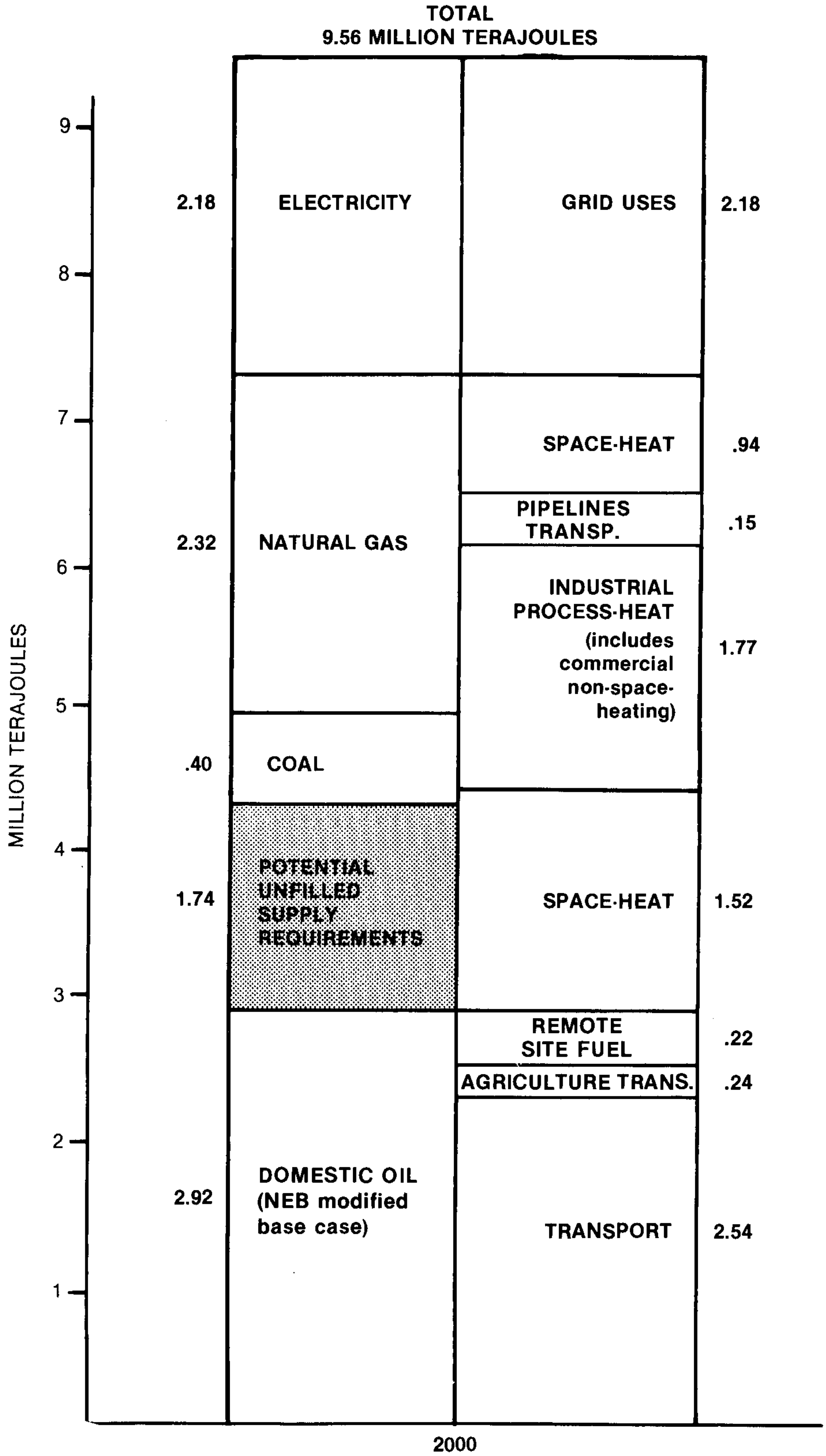


FIGURE 3

CANADA'S PROJECTED SECONDARY (END-USE) ENERGY SUPPLY AND DEMAND BALANCE, 2000



(iii) provide considerable amounts of energy to business and consumers at lower average prices than would be the case at lower capacity utilization.

Hybrid heating is a technique that would make it possible to draw heavily upon electric capacity that stands idle much of the time. The use of electricity in hybrid heating systems is designed specifically to increase the load on Canada's electric generating capacity without increasing the need to build more plant. If implemented in those regions where baseload electricity is cheap, it would improve the overall efficiency of Canada's energy system at competitive prices. It is a relatively simple and well-tested technique, ideally suited to Canada's energy resource base.

The mechanics, benefits, and conditions of widespread implementation of hybrid heating are the subjects of this report.

NOTES ON CHAPTER ONE: CANADA'S ENERGY ISSUES

1. The report will refer to three levels of energy, namely:

   PRIMARY ENERGY

   — crude oil at the wellhead
   — natural gas entering the Trans-Canada Pipeline
   — coal or uranium at a thermal generating plant or water falling over a dam

   SECONDARY ENERGY

   — oil delivered to a building's tank
   — natural gas going through a building's meter
   — electricity at a building's entrance

   TERTIARY ENERGY

   — space heat in a building

   For oil, there is approximately a 20 percent energy loss in refinery transformation between the primary and secondary stages, and an additional 40 percent loss of the oil delivered (at a furnace efficiency of 60 percent) between secondary and tertiary. There are losses for natural gas as well, mostly in transportation pipelines. However, while the primary/secondary loss for gas may be similar to, or greater than, the loss in oil refining (depending on pipeline transportation distances) secondary/tertiary losses are in general similar — roughly 40 percent (furnace efficiency of 60 percent). For electricity, there is a primary/secondary loss of about 65-70 percent in the case of thermal generation. Hydraulic generation losses are usually 5-10 percent but they are often calculated as if they were the same as thermal. (This is due to a statistical convention adopted to accommodate the energy accounting convenience of countries with electricity mostly generated by thermal plants. This convention distorts the primary energy efficiency of countries such as Canada with large amounts of hydraulic electricity, in order to ensure comparability at the more significant secondary level.) In either case there is a further 10 percent loss in primary/secondary transformation in the transmission and distribution network. However, the secondary and tertiary energy figures are identical — electricity is virtually 100 percent efficient at point of use.

2. Figure 1 is drawn from *Detailed Energy Supply and Demand in Canada*, Statistics Canada, 1979, Ottawa, series 57-207. It must be emphasized that this is a picture of the system in 1979. Certain essential features of supply and application will remain steady over time, but details change year to year. The height of the bars is proportional to the quantities of energy supply and use. The diagram does not include energy derived from wood and used mainly by the forest industries or other self-supplied sources of energy. All energy is shown here at the secondary stage (i.e., refined energy products available to the consumers, e.g., light fuel oil or gasoline) but it is before its use by the equipment involved (e.g., the furnace or automobile). Hence, in the case of fossil fuels, a further adjustment for thermal efficiency must be made to obtain a truly comparable "index" of final output, i.e., tertiary energy.

   Statistics on secondary energy use are published for economic sectors such as residential and farming, industrial and commercial. However, the important factor in energy demand is the application to practical purposes such as space heating, lighting, movement of goods; it is in this way that we present secondary demand in Figures 1, 2 and 3. It is necessary to make certain assumptions in order to translate the Statistics Canada data on energy use by sector into energy use by purpose. Our figures have been constructed within the following calculations.

a) Space heating in the "Residential and Farm" and the "Commercial" sectors includes consumption for that purpose of all fuels except electricity. The space heating now provided by electricity is included in the "grid uses" component.

b) In the "Industrial" sector, it is calculated that one-quarter of natural gas consumption and all light fuel oil are used to provide low grade heat, which we include in the "space heat" component. Industrial heat — heat for industrial processes — consumes all of the coal, coke, liquefied petroleum gas, still gas, heavy fuel oil, and three-quarters of the natural gas in the Industrial sector.

c) Remote site fuel for on-site electricity generation and operation of remote mobile equipment is supplied by all diesel fuel oil and kerosene that Statistics Canada assigns to the Industrial sector.

d) Electricity is defined solely as "Grid Uses", that is, electricity generated by utilities and large commercial firms.

For the MOSST project, similar charts were prepared for all the provinces for 1979. The Ontario and Quebec charts are given in Chapter Four. All other provinces are included as appendices.

3. In 1981, Canada's net oil imports were 132,765,000 barrels. On an annual basis, this is equivalent to 364,000 barrels/day. The average price paid for these imports was (U.S.) $35.40/barrel and the domestic equalization payments for oil amounted to $3.4 billion.

4. National Energy Board, *Canadian Energy Supply and Demand: 1980-2000.* Ottawa, June 1981.

CHAPTER TWO: CANADIAN OPTIONS FOR OIL SUBSTITUTION

(a) The Versatility of Oil

The great advantages of oil are that it is well suited to a wide variety of applications and that it can be stored and transported with relative ease. However, because of its chemical complexity and the economics of refining it, crude petroleum must be transformed into a series of products[1]; it cannot be used to manufacture only one product, such as gasoline. Furthermore, there are limits to flexibility in the "mix" of fractions a refinery can yield from crude. Heretofore, oil refiners have managed to apply oil products to a wide spectrum of uses: gasoline for cars, kerosene for aircraft, diesel for trucks, light fuel oil for space heat, residuals for generating electricity. This versatility is one main reason why oil has been the world's dominant energy source since 1945.

Unfortunately, unless there is an unforeseen technological breakthrough, the potential substitutes for oil are not as well adapted to this multitude of roles. Accordingly, a practical energy strategy requires that oil be reserved, as much as possible, for those applications where substitutes are not yet readily available — notably transportation and providing the fuel needs of remote and isolated sites. Increasing the output of higher quality products, like transportation fuels, would require refinery upgrading. This would be technically possible, particularly if hydrogen from an external source were to become available. Canada is fortunate in having in its substantial natural gas reserves an excellent source of cheap external hydrogen. In time, electrolysis may provide an additional source. Higher real prices for oil products provide an economic incentive for developing the technologies of refinery upgrading.

Space-heating needs, while no less important than transportation needs, can be met by using any of several alternatives as well-suited as oil for the provision of relatively low-grade heat. Among the leading candidates are natural gas and electricity.

(b) Natural Gas

At first glance, the logical substitute for oil in the space heating sector would appear to be natural gas. The National Energy Board (N.E.B.) estimates[2] that, at current price levels, Canada's established reserves are 76.2 million terajoules (approximately 72 trillion cubic feet). At current rates of domestic use and export, this represents a 28-year supply. Furthermore, there are large additional deposits in frontier areas, "tight sands" formations, etc., that cannot be included in reserves owing to inadequate infrastructures and/or insufficient exploration or cost-recovery data. In many parts of Canada, the infrastructure required for the transmission and distribution of gas is already in place and producing provinces and companies are anxious to expand their markets.

In 1979, natural gas provided 1.55 million terajoules of end-use energy in Canada, second only to the 3.26 million terajoules from oil products. For space heating, it was actually used more than oil — 0.937 million compared with 0.795 million terajoules. However, the technical opportunities for substantially improving the efficiency of Canada's total energy system by using natural gas to replace oil for space heating are limited. Moreover, the bulk of Canada's developed natural gas reserves are in the western part of the land and frontier sources are in the Arctic and the Atlantic. Transportation and geography therefore become important economic considerations in the cost of delivering natural gas — and hence its competitiveness — in much of Canada's markets.

(c) All Electric Systems

Because electricity is relatively expensive under present conditions of use and considered to be a high quality form of energy, it is generally judged suitable only for a subsidiary role in space heating. Indeed, using current techniques, it is a relatively poor substitute for oil in Canada, owing to the seasonal concentration of space heating demand. If all-electric space heating were to be widely adopted using current practices, and without compensating growth in other markets, the load factor[3] on the electric grid would rapidly deteriorate to the point where it would have no reasonable prospect of cost-competitiveness beyond a relatively modest penetration level. A considerable amount of additional generating capacity would be required to meet peak demand during the space heating season.

At present, it is estimated that approximately 15 percent of space heating in Canada is provided by electricity[4]. Although in some provinces there is virtually no electric space heating, this is offset by a relatively larger proportion in others. Alberta, Saskatchewan and Nova Scotia have little or no electric space heating; Quebec, Manitoba and Newfoundland have significant amounts. However, in no province is much more than 25 percent of all space heating provided by electricity although, according to Hydro-Québec's surveys, about 29 percent of all residential space heating in Quebec is electric.

Electric space heating techniques vary; they include individual room resistor grids, electric furnaces connected to forced-air ducting, and heat pumps with resistance heating back-up. From the point of view of the user, electric space heating has the advantage of being cleaner and allowing more precise temperature-control. Until recently, however, it has not turned out to be cheaper, despite remarkably low-cost generating capacity in Canada, and this has been a major constraint on market penetration. Moreover, the characteristics of Canada's winter climate are likely to limit all-electric space heating because it could actually be more costly than oil on account of the associated need for additional generating capacity.

(d) The High Cost of All-Electric Heating

The high cost of all-electric systems arises from the severity of Canadian winters. Wide and intense cold fronts can extend across half the country for several days at a time. Local temperatures can drop to −30°C and even −40°C, or 20-30° lower than the January norm. Figure 4 shows a typical degree-day plot for Ottawa, which is illustrative of the Canadian climate. The gap between the lowest temperature (giving the peak heating demand) and the average temperature represented of even the coldest month (January) is noteworthy. This is the nub of the problem with all-electric space heating systems: to satisfy their customers' needs, utilities have to have enough capacity at the generating plant (including adequate reserve) and in their transmission and distribution grids to meet the worst possible situation, even if it occurs only once a year. In other words, all-electric space heating has a very poor load factor and this, as will be seen, is extremely costly in the long-run. Existing data on the climate show that, in Canada, all forms of space heating equipment work, on average 27 per cent of the time (i.e., under Canadian conditions of climate, space heating demand has a 27 per cent load factor). This compares with the overall diversified residential load on electricity generating plant which is 30 per cent — 35 per cent, and the average load factor which is 65 per cent[5].

Until now, Canadian utilities have offset this irregular space heating demand to some extent through load diversity. When only a very small proportion of the total space heating demand is met by electricity, load diversity can help smooth the diurnal load variations on the utility. For example, although it is generally colder at night, which means that more electricity is needed for space heating, night-time demand from other uses is less. This load diversity serves to flatten the diurnal load curve. In fact, most Canadian utilities have a flat January load now. But it should be stressed that the load is flat at a high level of use, and this means that if more all-electric space heating were attempted in the future, there would be little opportunity for load diversity to offset the new space heating demand peak.

Because Canadian utilities are already operating at a high level in winter, heavy additional electrical demand for space heating would add new peaks onto an already high level of demand and would result in a synchronized, as distinct from a diversified, load. As a result, utilities would be forced to buy considerably more equipment just to meet a higher January peak without a corresponding market at other times of the year, and the annual capacity factor of the total electric system would decline steeply. This would translate directly into much higher average generating costs which would have to be passed on to consumers in the form of higher rates.

According to Ontario Hydro, even after allowing for opportunities in load differentiation, an average-sized house in southern Ontario heated only by electricity requires over 9 kilowatts of dedicated power at point of use just for space heating during "peak" demand (i.e., coldest) conditions. This represents the diversified load of space heating (i.e., *after* making allowance for offsetting electrical demands from within the house that may improve the effective load factor from space heating); it is more than three times greater than the existing diversified load demand (3 kilowatts) from a non-electrically heated house. It is also worth bearing in mind that electrically heated houses are typically newer and better insulated than average. Furthermore, southern Ontario has a relatively mild climate by Canadian standards. Colder locations would place heavier demands on the electric grid. Additionally, a power demand of approximately 9 kilowatts may not represent the full requirement from the electric system. An electric utility has to be prepared to lose up to 10 per cent of its power in transmission and distribution, and also to retain an additional 20 per cent reserve margin of generation in case of equipment breakdown or other unscheduled outage. While there may be sufficient climatic diversity over a large area to reduce average diversified demand by 20 per cent, large stationary cold fronts often extend beyond the service area of one utility, a fact which limits its ability to use climatic diversity to reduce peak power demand.

Taking all these factors together, if it is operating at capacity under climatic conditions such as those prevailing in most of Ontario, a utility has normally to dedicate 10 or more kilowatts of electricity at the generating plant for each totally electrically heated house[6]. By contrast, without electric space heating, the average residential diversified peak demand (which establishes the utility's requirement for dedicated generating plant) is only 3 kilowatts or less — just one-quarter as great.

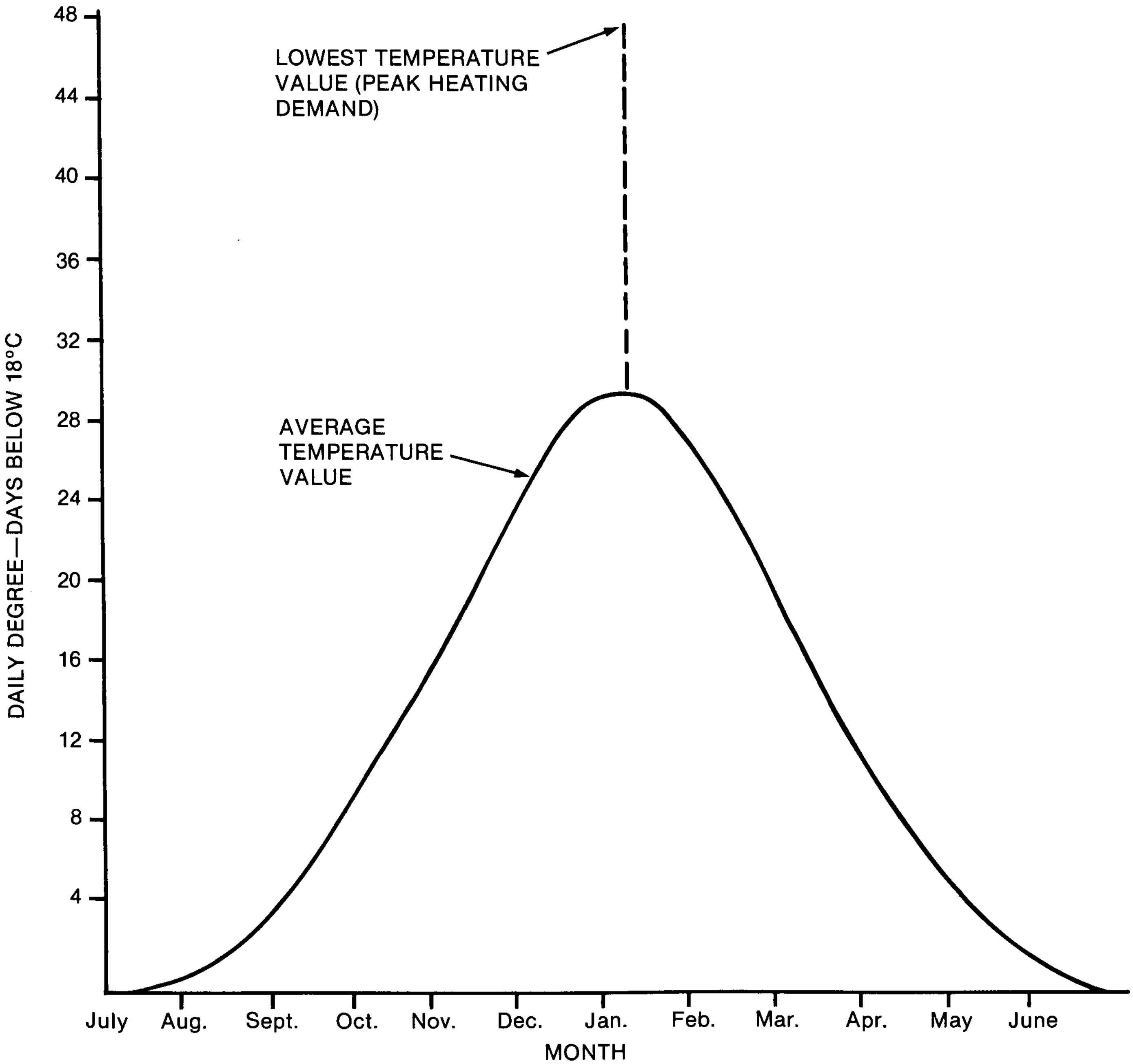
(e) Load Factor and Generating Mix

A utility has to provide adequate capacity to meet demand at all times, including peaks, however brief and infrequent. This leads to elaborate generation mixes calculated from the "load duration" curve, which expresses the proportion of total load that is sustained at any moment throughout the year.

As the name suggests, baseload generating capacity is that which is in operation virtually all the time. Probably 55 per cent of all generating plant in Canada can be characterized as baseload. Intermediate plant (about 35 per cent of all capacity, generally coal-fired) is in operation some of the time, and peaking plant (about 10 per cent of capacity, generally oil- or gas-fired) comes into operation only infrequently. The distribution of its load (among baseload, intermediate and peaking) deter-

FIGURE 4

A REPRESENTATIVE CANADIAN DEGREE-DAY PLOT



mines the appropriate mix of types of equipment a utility requires. Not all generating capacity has the same cost structure. For example, if there is a high constant demand for power, the most cost-effective equipment in the long run will be that which has a high capital and low fuel/operating costs. This type of equipment is ideal for "baseload" power. By comparison, intermediate and peaking equipment may actually have a higher cost per unit of output; however, as the capital costs of such equipment are lower, the utility will find it the most cost-effective for relatively infrequent use. In other words, it is uneconomical to let a large hydro site or a reactor stand idle because they are so capital-intensive, and the fuel to run them comparatively inexpensive. This is not, however, the case for relatively less capital-intensive coal boilers or combustion turbines (typical intermediate or peaking generators respectively). The "mix" of equipment utilities choose depends on their load characteristics and will, in turn, affect the cost of electricity. In the long-run, baseload equipment gives the cheapest electricity, providing, of course, there is a large and assured market. The question of the consistency over time of electrical load and generation is critical.

(f) Generating Mix and Electricity Costs

Figure 5 attempts to illustrate what different load and capacity factors imply for a utility's costs when a decision has to be made concerning the acquisition of new equipment. One system is characterized as an "all-baseload" system; it is meant to represent a very efficient system running at 75 per cent capacity factor. By contrast the other is more typical of current load factors; in fact, it assumes a system running at (by current load standards) only average efficiency — the 46% capacity factor that Canadian electric utilities achieved in the 12-month period from July, 1979 to June, 1980. These figures are meant to be representative of two hypothetical systems coming "on stream" in 1982 at current costs.

System "A" — the high efficiency system — uses equipment that operates most economically in the long-run; these are large hydro developments with annual water storage or nuclear (CANDU) reactors. The major expense of this system is capital carrying charges. Each kilowatt of generating capacity requires an investment of $1,200 and an additional $1,000 for transmission and distribution equipment[7]. These capital charges have been annualized using a factor for "real use of capital" of 10 per cent. Real use of capital is more than just real interest rate as it also includes amortization of principal. For a twenty-year amortization, which is representative of utility investments, it would correspond to an 8 per cent real interest rate. This figure is higher than that used by utilities themselves; they typically use a discount rate of 6 per cent real interest. However, the figure of 10 per cent for real use of capital has been used in cost/benefit studies in the federal government on several occasions in the past in an effort to represent a credible real annual cost of capital investment[8]. Moreover, some equipment (e.g., transmission and distribution facilities) may not last as long as generating plant and should therefore be amortized over a shorter period of time, 15 years for example. This would imply a real interest rate of about 6 per cent. Hence, these figures are meant to be taken here as reasonable, not definitive, cost accounting[7]. Accordingly, the yearly cost of the standing investment of $2,200 per kilowatt would be $220. But this is a high efficiency system running at 70 per cent capacity factor; as shown in Figure 5, 1 kilowatt of generating, transmission and distribution plant would provide 6,132 kWH per annum at an average cost of 3.59 cents per kWH. The costs for fuel, operations and maintenance are a relatively small proportion of the calculated "all-in" cost of 4.13 cents/kWH.

Every electric utility in Canada uses a slightly different accounting system to assign costs, and it would also be possible to use a different capital carrying charge factor to assess real charges. Nevertheless, a figure of 4.13 cents/kWH is a reasonable estimate of the cost of running new baseload plant in 1982.

By contrast, system "B", running at 46 per cent capacity factor, has significantly higher unit costs. The type of generating plant is different from system "A". It contains three elements — a baseload component, an intermediate component and a peaking component. The baseload component is the same capital-intensive type of plant as in system "A". However, it represents only 55 per cent of the weighted kilowatt of generating capacity in this system. The intermediate plant (35 per cent) and peaking plant (10 per cent) represent significantly lower weighted capital investment costs. Being technically much simple, a kilowatt of coal-fired intermediate plant requires much less investment than a kilowatt of nuclear or large hydro — a representative estimate is $500/kWH — and, at 35 per cent of the weighted mix, only $165 need be assigned to its share in this hypothetical kilowatt of generating plant investment. Peaking plant is even less capital-intensive; at 10 per cent of the weighted total, only $30 need be assigned to it in standing investment.

Overall the mixed system "B" has lower standing capital costs. Including transmission and distribution capital (same as for system "A"), the total capital investment is assessed at $1,855/per kilowatt, and using a consistent 10 per cent real "use-of-capital" factor, annual carrying charges would be $185.

However, this system runs at much lower efficiency — only 46 per cent capacity factor — and, hence, all these costs have to be amortized against much less total output than was projected for system "A" — only 4030 kWH per annum, or 4.59 cents/kWH. Although the actual capital cost component is lower for the mixed than for the baseload system, the difference is not nearly enough to offset the operational decline in efficient use as determined by the poorer capacity factor.

FIGURE 5

A REPRESENTATIVE COST STRUCTURE COMPARISON PER KWH (EXISTING AVERAGE)

System "A"
An "All-baseload"
(High Efficiency) System
Running at 70% Capacity Factor

I. CAPITAL COSTS
PER KILOWATT
OF GENERATING PLANT

$1,200 (nuclear or large hydro)

II. CAPITAL COSTS
TRANSMISSION & DISTRIBUTION

$1,000

TOTAL CAPITAL COSTS: $2,200

III.
(a) ESTIMATED ANNUAL REAL
"USE-OF-CAPITAL" COSTS (10%)

$220

At 70% capacity factor, this has to be amortized against 6132 kWH
= 3.59¢/kWH

(b) FUEL/OPERATING COSTS
Uranium at $100/KG
.8% burn-up and 30% efficiency
= .19¢/kWH

(c) Maintenance at 10% of capital costs
= .35¢/kWH

IV. GRAND TOTAL COSTS: 4.13¢/kWH

System "B"
An Illustrated Current (1979)
System Using Typical "Mix" of
Equipment Running at 46% Capacity Factor

I. CAPITAL COSTS
PER WEIGHTED KILOWATT
OF GENERATING PLANT

55% $660 — BASELOAD COMPONENT (nuclear or large hydro)
35% $165 — INTERMEDIATE COMPONENT (coal, hydro)
10% $ 30 — PEAKING COMPONENT (turbines)
$855 — TOTAL

II. CAPITAL COSTS
TRANSMISSION & DISTRIBUTION

$1,000

TOTAL CAPITAL COSTS: $1,855

III.
(a) ESTIMATED ANNUAL REAL
"USE-OF-CAPITAL" COSTS (10%)

$185

At 46% capacity factor, this has to be amortized against 4030 kWH
= 4.59¢/kWH

(b) FUEL/OPERATING COSTS (Weighted kWH)
Uranium (55%) = .1¢/kWH

Coal at $30/ton (35%) = .47¢/kWH

(c) Turbines (oil at $30/barrel) (10%)
= .58¢/kWH

IV. GRAND TOTAL COSTS: 5.74¢/kWH

Furthermore the fuel and maintenance costs are higher. Thus, while this plant is cheaper from a capital investment point of view, its operating expenses per kWH of output are greater than those for hydro or nuclear plants. Overall it is reckoned that system "B" produces power at about 5.74 cents/kWH.

These figures represent the costs of output from plant coming on stream in 1982. In actual practice, 1982 electricity costs were lower than either of these two figures, because electric utilities "roll in" all their costs to obtain an average figure. Recently commissioned new plant is likely to cost more than older equipment owing to inflation. Nevertheless, these figures, which might be viewed as appropriate replacement cost estimates, show the implications and trends apparent to utilities in assessing their need for capital renewal and expansion in light of their forecasted loads.

The high-efficiency system "A" was postulated to run at 70 per cent capacity factor. To achieve this kind of utilization, the characteristics of the load placed on this plant would have to be remarkably uniform. An electric utility normally ensures it has reserve capacity to meet unscheduled outages of equipment. Since this plant is likely to stay idle most of the time, to obtain an overall capacity factor of 70 per cent, the load factor of the demands placed upon the equipment must be even higher — probably 80-85 per cent. By contrast, a 46 per cent capacity factor, typical of the current Canadian average, would imply a load factor of about 65 per cent. But a great deal of equipment — not just in the reserve — is inevitably going to stand idle a large portion of the time.

It is clearly in the interests of electric utilities, from a cost standpoint, to have an improving capacity factor derived from continuous stable loads. Such loads are not provided by all-electric space heating systems.

(g) The Characteristics of Hydraulic Systems

Although inherently flexible, hydraulic systems are used less and less to meet peak demand. Recent major additions to generating capacity have all been designed to sustain their rated capacity continuously, i.e., they are baseload. The reasons for this are the cost and transmission constraints arising from the scarcity and remoteness of remaining hydraulic power sites.

As a generalization, the cheapest hydraulic electricity is that generated by large scale water streamflows. This is why large bodies of moving water which are relatively close to electricity demand centers are the first to be dammed. Smaller and more remote streamflows are costlier to harness and, as a result, are brought into use later. Another consideration favouring larger hydro sites, from an engineering standpoint, is that they provide an assured flow of water despite droughts and other natural phenomena. In sum, Canadian hydraulic resources yield maximum economies of scale and provide a high sustained output of electricity. There are, of course, many smaller hydro sites that have limited use (i.e., for the generation of intermediate or even peaking power), but they account for a relatively small share of Canada's hydraulic generating capacity.

The fact that the remaining large potential hydro sites are far removed from demand centers does not necessarily destroy their usefulness, but it does make them subject to transmission constraints. Where, as in the case of long distances, transmission has to be run at very high voltages (i.e., over 400 kilovolts), carriers must be kept at a fairly constant electrical tension. This, in turn, makes these distant hydro sites suitable chiefly for baseload. An excellent example is Hydro-Québec's James Bay project. Economics and technical limitations make this baseload plant. Its break-even point occurs at 68 per cent capacity factor, and it can run at virtually 100 per cent capacity factor. Currently about 2 million kW of power is available from the first of four major power sources. The second generating unit, soon to come on stream, is rated at over 5 million kW. In all, about 10 million kW will be developed, and the power will be carried over several hundred miles at 750 kV tension to the major population centers of Quebec. And this is merely the beginning of the development of the water draining into the eastern half of James Bay. There is much additional potential. The great Churchill Falls capacity is similarly enormous, but constrained. These massive hydraulic sites, when developed, are outstanding technical achievements, but they are economical only if a corresponding baseload demand can be found.

In sum, there is no doubt that, for economic reasons, future large-scale hydro developments will have to be geared to the needs of baseload markets. Because of its seasonality and poor load factor, all-electric space heating is not such a market.

(h) The Limited Possibilities of Other Offsetting Factors

It can be argued that electrical utilities in Canada could offset the enormous potential winter market with new summertime sales and, thus, improve the annual load factor. It is noted that U.S. utilities often have a summertime peak from air-conditioning loads. This, however, does not take into account the fact that U.S. utilities within practical transmission range are either winter-peaking (New England, northern plains States) — and therefore have the necessary capacity for summer air-conditioning — or that their summer peaks are not significantly higher than their winter peaks (New York, Mid-West States). More Canadian homes could, of course, be air-conditioned, but cooling a home by 10°C below outdoor temperature requires 8 to 14 times less energy than heating it by 50°C above outdoors. Electric utilities could, as well, improve their interties so that the one facing the coldest weather could get additional power from its neighbours, but large stationary cold fronts usually extend beyond reasonable transmission distances.

In an earlier study[10], opportunities for offsetting the poor load characteristics of current electric heating systems by selling off-peak electricity to alternative markets, both new and traditional (such as hot water heating and thermal storage), were examined and none was found that solved the problem.

(i) Peak Demand Problems: Hydro-Québec and Ontario Hydro

Hydro-Québec's highest recorded demand peak occurred on January 4, 1981. Approximately 18,600 megawatts out of a total installed generating capacity of 20,500 megawatts had to be committed. The sequence of events is illuminating.

January 2 had been an exceptionally cold day throughout the province. However, total load did not rise immediately on the utility's grid because buildings have a considerable heat inertia. In this instance, however, the cold wave persisted over three days and, on January 4, Hydro-Québec reached a peak in demand which was 8.08 per cent higher than the previous year's. It is not unusual at all for such a situation to occur in January, but this peak was unprecedented because January 4, 1981, was a Sunday; never before had a peak occurred on a weekend. That it did so indicates clearly that it was a space heating peak.

Ontario Hydro's highest peak to date occurred on January 11, 1982, when 18,600 megawatts out of 25,000 megawatts total installed capacity was committed. This was 6.3 per cent higher than the previous year's peak and in excess of the December 1983 load forecast. January 11 was a Monday, which is not the usual peak day. Normally the peak occurs towards the middle or end of the working week when industry is producing at full capacity. One possible explanation of the January 11 peak is that Ontario Hydro is in an "intermediate" stage — space heating does not cause the peak by itself, but is a substantial contributing factor. At the very least, the occurrence of the peak on a Monday indicates that a large part of Ontario Hydro's load is temperature-sensitive.

The rapid growth in the peak demand for electricity faced by Hydro-Québec and Ontario Hydro is worth comparing with growth in energy use as a whole, which was 3.5 per cent annually for the period 1975-79. Peak (as distinct from total) electrical demand has been growing almost twice as fast as electrical energy use and twice as fast as energy use generally.

Another indication of space heating becoming a major load on utilities is the time of day at which the peak demand develops. Without space heating, the diurnal peak load usually occurs between 4:00 and 7:00 P.M. The space heating peak usually occurs earlier, however, between 7:00 and 10:00 A.M. (at 45° latitude) since it is often coldest an hour or two after dawn. A shift in the daily peak from evening to morning is therefore a reliable sign of space heating concentrations. In this context, it should be noted that Toronto Hydro now has a morning peak.

The "setting back" of thermostats at night and raising of them in the morning is perfectly sensible from a conservation point of view. Where electric heat is used, however, it causes serious problems to the utility. Electric heating systems become a synchronized load and exacerbate the morning space heating peaks.

Furthermore, space heating peaks are unpredictable and uncontrollable. Weather forecasting is still an inexact science, and an electric utility may not know from one day to the next when and where demand will peak. This creates serious complications in electricity generation. It puts a premium on quick-reaction plant that can be brought into action on immediate notice — so called "peaking" plant. This is the most expensive type of plant to operate, and is usually fired with oil or gas.

(j) The Problems Associated with Large Space Heating Markets

The fact that an electric utility effectively has to dedicate five times as much generating capacity for a home heated entirely by electricity as for one heated otherwise gives some idea of the large size of the space heating market. Figure 1, already referred to, shows that much more oil and gas is being used in Canada for space heating than is electricity for all purposes. Approximately 1.75 million terajoules of oil and gas are used for identifiable space heating purposes. By contrast, only 1.06 million terajoules of electricity are used for all purposes, and around 10 per cent of this energy is used for space heating. Oil space heating alone presently uses approximately the same amount of energy as do the non-space heating uses of electricity. The fact space heating is such a large market for energy creates a significant possibility for both the more efficient use of the electric system and the more inefficient use of it. If the space heating is done by traditional all-electric techniques, it will mean less efficiency because the opportunities for utilities to offset the poor load factor through the existing load diversity will become steadily more limited, and the effective overall electric load factor will deteriorate.

If oil were to be massively displaced by all-electric heating, the immense size of the market would overburden the electric grid. The poor load factor of space heating would become characteristic of electricity as a whole and the uneven seasonal demand for space heating would cause severe deterioration in overall efficiency of use of Canada's electricity generating plant.

NOTES ON CHAPTER TWO: CANADIAN OPTIONS FOR OIL SUBSTITUTION

1. Broadly, there are three families of oil products. Gasoline is typical of the "lighter fractions" which are the highest quality products — they have the highest hydrogen-to-carbon ratio. "Middle distillates" are intermediate products exemplified by diesel fuel and kerosene. Finally, the "residuals" have the poorest hydrogen/carbon ratio.

2. National Energy Board, *Canadian Energy Supply and Demand: 1980-2000*, Ottawa, June 1981, p. 7.

3. The reader may be interested in some technical terms relating to the equipment and operations of an electric utility. The most important of these are also included in the main body of the text, or related footnotes.

   a) *Installed capacity:* The sum total of the rated capacities of all generating equipment. Since 1950 installed capacity has expanded at an average rate of 8 per cent annually (but actual output has grown at only 7 per cent reflecting a declining capacity factor).

   b) *Load:* The actual kilowatts demanded at any given time. This fluctuates from hour to hour, day to day and over the year. Typically it is highest, at 80 per cent of installed capacity, at 5:30 p.m. on the coldest working day in the winter and lowest, at about 20 per cent of installed capacity, at 4:00 a.m. on Labour Day.

   c) *Peak Load:* The highest load demanded over a period of time. The annual peak load in Canada has been at about 80 per cent of installed capacity.

   d) *Base Load:* The part of the load that is in continuous demand over the year, currently 30-40 per cent of installed capacity.

   e) *Peaking Load:* The part of the load that is in demand for only a few days or weeks during the year.

   f) *Intermediate Load:* The part of the load that is neither base nor peaking.

   g) *Reserve:* The difference between installed capacity and peak load, i.e., the unused capacity. This consists of the ready reserve (10 per cent of peak load) which can be switched on, at short notice, and the reserve under repair or unavailable for any reason (10-15 per cent of peak) which is not available for use on short notice. The availability of plant is the installed capacity minus the latter reserve.

   h) *Load Factor:* This is the ratio of average load over peak load during a period of time. The load factor is a measure of the uniformity of the electricity demand. The higher the load factor, the more uniform the use. The annual load factor in Canada (including electricity exports to U.S.A.) is now about 65 per cent. It was over 75 per cent during 1952-53.

   i) *Load Duration Curve:* A curve that shows the amount of operating capacity versus per cent of total time.

4. Source: Statistics Canada, *Residential Survey of Household Equipment*, Ottawa.

5. *Load factor:*

   $\frac{\textit{average load}}{\text{peak load}} \times 100\%$. It is an index of load.

   By contrast, *capacity factor* is an index of capacity utilization:

   $$\frac{\text{actual output}}{\text{theoretical output}} \times 100\%$$

   Load factor is always higher in practice than capacity factor. This is essentially because utilities have reserve equipment which operates only in case of breakdown or other unscheduled outage. Of course, if all goes well, it will stand idle. Although this reserve component has no bearing on demand load characteristics, it does get included in the capacity utilization calculations. Since it is designed to stand idle — and usually does — it produces very little output and this statistically drags down the capacity factor. Moreover, a utility may have surplus plant above and beyond reserve (most in Canada do). This further depresses the capacity factor relative to the load factor.

6. Although a utility has to dedicate 10kW per building for peak space heating, the capacity of the electric space heating equipment in the same building would have to be much greater — 20 or 25 kW. This is to ensure that there is always enough capacity to keep the house warm under different circumstances, e.g., if people are entering or leaving the building and, hence, opening doors or windows, etc., and creating unusually high heat loss conditions. Essentially the utility is counting on differences in timing between houses for these sorts of activities to reduce its average (i.e., diversified) load, and in practice this assumption seems to turn out to be reasonable. But 10 kW would not always be enough to keep one particular building warm.

7. Source: Ontario Hydro and Hydro-Québec.

8. In the course of their research for the MOSST project, Ontario Hydro used a "real interest rate" of 4.5 per cent, and Hydro-Québec 6 per cent. However, this "real interest rate" does not capture all the elements included here. A more detailed discussion of capital is included in Footnote 9.

9. An electric utility would use a far more complex accounting system. Essentially the problem for an electric utility is to calculate a fair price schedule at a time of general price inflation while maintaining a smooth progression of price changes. The utility will normally develop an accounting model designed to give the "present day annualized capital cost per kW". This model will start with a very low figure: for example, if the actual capital cost for generating is $1,000, then the present day annualized cost might be only $50 (5 per cent).

   Of course, while an electric utility can borrow money at a very favourable rate relative to many other borrowers, it cannot really obtain funds at an interest rate as low as 5 per cent. But the utility can raise its rates in line with inflation. The $50 can be escalated at a certain rate for the entire life of the equipment. To illustrate, if one assumed inflation at 10 per cent annually, then the rates will double every seven years. If the life of the equipment was 30 years, then the revenue from the given kilowatt would be eight times higher the 30th year than at present, i.e., in this example $400, which is 40 per cent of the original principal. This, of course, is higher than the utility would actually have to pay but, taken in conjunction with the low start-up figure, gives an overall revenue flow that amortizes the cost of the equipment at the actual interest rates the utility must pay.

   By taking 10 percent for "use-of-capital", we are in effect capturing approximately the mid-point of this sequence and, hence, approximating the real cost a utility eventually pays for its capital investments.

10. Clayton, R.H., et al., *Canadian Energy: The Next Twenty Years and Beyond.* Institute for Research on Public Policy, Montreal, 1980, pp. 214-223.

CHAPTER THREE: THE POTENTIAL OF THE ELECTRIC HYBRID SYSTEM

(a) Description of the Hybrid (Dual Energy) System

While natural gas and all-electrical space heating systems both contribute to reducing oil consumption, neither offers improvement in the efficiency of Canada's total energy system. There is, however, another type of approach which can reduce Canada's dependence on oil and, at the same time, increase the overall efficiency of the country's energy system. It involves the adoption not so much of new technology as that of a new operational technique: the use of electricity for space heating during periods of off-peak electric demand, and the use of oil when the demand for electricity is peaking — thereby filling in the valleys in the electrical demand curve for space heating. This technique would improve the system load factor and raise the level of *baseload* demand. For the sake of brevity, this approach will be called hybrid heating.[1]

As has been shown, current all-electric systems intensify the peaking problems of electric utilities and, in the long-term, they work against the most efficient and, hence, economical use of baseload generating plant. If, however, the capacity factor of the electric grid could be improved, it would reduce considerably the cost of generating electricity, and this consideration is very important to Canada owing to the large number of its hydro sites and enormous reserves of uranium and coal. The technology to exploit these resources is well developed. It includes the CANDU natural uranium system for electricity generation, and long-range transmission and distribution systems to tap large and distant hydro sites. Canada's electrical system is technically highly advanced and its sources of power are virtually inexhaustible.[2]

The hybrid or dual-energy approach to space heating involves the use of both electricity and a back-up hydrocarbon fuel (oil or gas) furnace. (The focus of this study, however, is the electric/oil hybrid in the residential sector, as this has been better developed than any other). In this way, maximum end-use efficiency is wrung out of the grid, with more economical baseload generating plant, (and intermediate plant where necessary) providing heat instead of oil.

Two facts make it possible to implement hybrid heating economically in Canada. First, approximately 35 per cent of all Canadian buildings already have an oil furnace; converting them to hybrid heating systems can be achieved most simply by installing an electric heater in the furnace's plenum[3]. Second, throughout much of the Canadian autumn, winter and spring heating seasons (despite a few sharp demand peaks), only a modest amount of power is required to keep the great majority of buildings warm — the sort of power that the existing electric grid can easily provide. This point is illustrated in Figure 6 for the single detached housing sector.

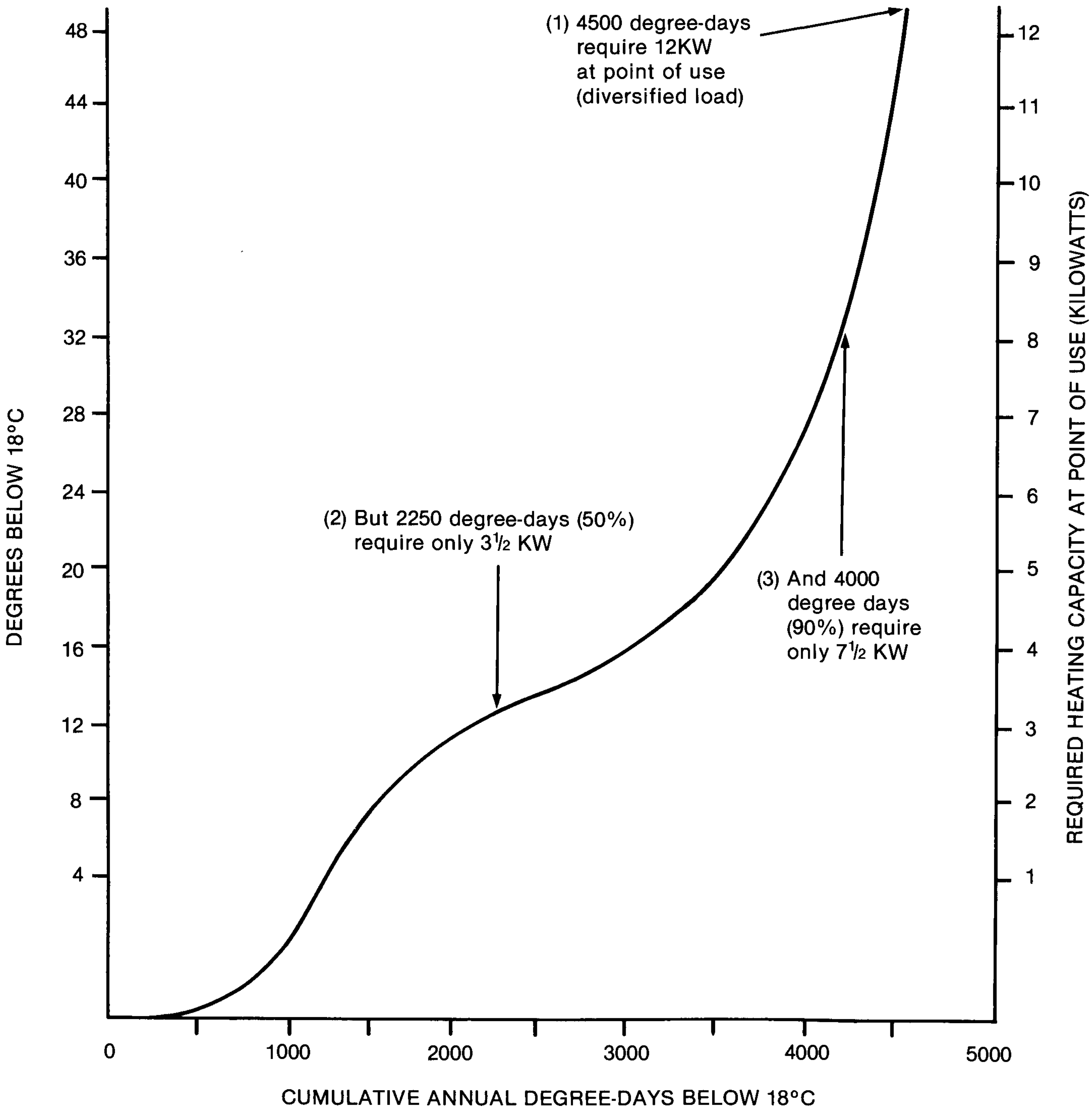
Figure 6 plots cumulative degree-days[4] for Ottawa against the theoretical heating capacity required from September to June to heat a 1200 square foot well-insulated average-sized house. If the electric system has to provide all the heat for the 4500 Celsius degree-days typical of Ottawa, then sooner or later it has to meet the lowest temperature in the heating season. In the case of Ottawa, which is colder than Southern Ontario, this would require up to 12 kilowatts at point of use, and up to 14 kilowatts at the generating station after allowing for transmission losses and reserve. But, significantly, if the electric heating needs were designed to satisfy only 80 per cent of heating needs, the 3,600 Celsius degree-days could be accommodated with only 5 kilowatts electrical capacity at point of use. Meeting half of the demand, or 2,250 Celsius degree-days, with an electric system, would require only 3.5 kW. The difference between these two values and 12-14 kW is considerable: they suggest that 80 per cent (50 per cent) of the heating requirements could be met with 42 per cent (29 per cent) of the heating capacity needed for an all-electric system, provided the remaining 20 per cent (50 per cent) were met by the fossil fuel furnace. In fact, these improvements are critical. As will be seen, they represent the difference between the capability of using the existing electrical grid to supply much more space heat and the need for an enormous electrical expansion to supply the same amount of extra power — at heavy additional cost.

In a hybrid system, the back-up oil furnace can be made to operate only at time of peak demand on the electric grid, so as to avoid coincidence with other demands. Such an approach would result in a significant improvement in the capacity factor of the electrical system. Actual tests by Ontario Hydro (throughout Ontario), AECL (in Deep River, Ontario), and Hydro-Québec (in various parts of the province, including Montreal and Bagotville), and the deployment of hybrid heating by Minnkota Power to 7,000 homes in the northern United States have confirmed these figures in practice. Such is the value of the hybrid system: a very high proportion of Canada's space heating requirements could be satisfied at superior capacity factors, provided the electric system were not required to do all the work.

There are two technical options for making such a system work in practice. Up until now, most of the efforts in Canada has been concentrated on the first — it will be labelled "Hybrid I". This is a worthwhile first step but the second, "Hybrid II", which is used by Minnkota Power, is much superior in the long run.

FIGURE 6

CUMULATIVE DEGREE-DAYS FOR OTTAWA AND HEATING CAPACITY REQUIRED FOR THE AVERAGE MODERN HOME



(b) "Hybrid I": A Hybrid Heating System with Fixed Temperature or Time-of-Day Controls

In this system, electricity would provide baseload heat — for example — four-fifths the annual requirement — with 5-8 (diversified) kilowatts at point of use for the average home[5], as shown in Figure 6. The electric heater would be in operation from September to June and would provide all heating needs, except when the outside temperature dropped below a pre-set value, say −15°C, or at a pre-specified time of day, e.g., 4-7 P.M.; below the specified temperature, and/or at times other than diurnal peak demand, a storable source of heat, such as oil, would be used instead of electricity. A Hybrid I system is characterized by the fact that the control over the switching between the two heating sources is contained within the building itself. The initial area of application would be in single family dwellings, although larger buildings could be included when the appropriate equipment becomes available. Control systems for such equipment have not yet been fully developed, although they would be capable of using essentially the same circuitry as do the smaller plenum heaters.

In Hybrid I, control of the two heat sources can be accomplished through a dual system, with one element controlling the electric heater and the other back-up furnace. There are two basic arrangements around which variations are possible:

(i) A sensing element (commonly called a thermister) is placed outside the dwelling or building, and controls the operation of the electric heater. During colder weather, the thermister automatically shuts down the electric heater when a predetermined temperature is reached. An indoor thermostat, which controls the back-up furnace, will automatically switch it on as the house temperature drops as a result of the electric heater being off.

This particular Hybrid I approach is typical of the method of installation of the plenum heaters being marketed at the present time by various private firms in the oil and electric sectors, and is the one used in most Ontario Hydro experiments. Depending on the temperature at which the external thermister is set to cut off the electric heater, between 50 per cent and 90 percent of all oil used can be displaced.

Control by outdoor temperature is the cheapest means to avoid *temperature*-related peaking problems for the utility. The obvious drawback of thermister controls is the oscillation between night and day temperatures. In the Canadian autumn and spring, even sometimes in winter, temperatures often fluctuate around the plenum heater shut-off point. Because days are milder than nights, the thermister will cause the oil furnace to turn on at night, leaving the electric heater to work during the day. This is not necessarily helpful to the utility. Because of other domestic and industrial demands, loads are usually higher during the day, and some accumulation of peaks will still take place. Yet another problem is determining the exact temperature at which the oil furnace cuts in. Electric plenum heaters are often set to come into operation at points which do not allow them to work anywhere near their potential (e.g., −2°C rather than −15°C). Oil is thus consumed at times when the utility still has spare capacity to supply electricity for space heating purposes.

(ii) The second arrangement involves a two-stage indoor thermostat. The thermostat for the electric heater is set a few degrees above that for the furnace so that the heater is always triggered first with the furnace coming on only when needed,that is, in colder weather, when the heater is insufficient.

A two-stage indoor thermostat gives a better performance than the external thermister in some respects, but still does not optimize load diversity. Indoor temperature trends follow those outdoors, but with a lag because of the heat inertia in buildings. Accordingly, if the back-up fossil-fuel furnace is controlled by variations in indoor temperature, it will usually not enter into service until one to four hours later than it would if it were controlled by an outdoor thermister. As well, because of the operation of household appliances and the body heat generated by occupants, a further heat cushion is created at the lower end of the control range, allowing the electric heating system to work even longer.

There is another advantage to the two-stage indoor control. When the electric heater is inadequate and the temperature drops, the oil furnace is switched on; however, as temperature rises as a result of oil-fuelled heat, the indoor thermostat will eventually set off the electric heater, albeit only temporarily, even in very cold weather (e.g., during the night). As a result, there would be some use of capacity during otherwise off-peak periods. But against this benefit is the problem that in very cold weather, the electric heater, not being off all the time, could add to peaks.

Ontario Hydro has used some two-stage indoor thermostat controls in its various experiments with hybrids in Ontario. These have shown that a small 5.5 kW heater fitted to an averaged-sized house can displace 87 per cent of the oil normally consumed.

It is possible, of course, to combine a thermister with a two stage indoor thermostat. With such an arrangement, the external cut-off point could be set lower and, if the electric heater failed to generate sufficient heat to keep the house comfortable under such circumstances, the second stage of the indoor thermostat would trigger the oil furnace into operation.

In summary, temperature-controlled Hybrid I offers a significant, if limited, opportunity for improving the overall load factor on the utility's grid. Although in every utility an important part of the load is temperature-sensitive, some of it is not and, hence, load diversity is not optimized with this type of Hybrid I system.

A somewhat more refined Hybrid I-type system was developed by AECL and tested in Deep River, Ontario. In this arrangement, the electric heaters in a number of houses were equipped with a timer to shut them down, regardless of temperature, between 4:00 and 6:00 P.M., the peak demand period on the municipal electric utility. Time-of-day controlled Hybrid I showed considerable load factor improvement, but it did not have all the advantages of Hybrid II systems. The Hydro-Québec Sunday peak (usually an "off-peak" time) described above shows how difficult it is to predict when peaks will occur.

Nevertheless, Hybrid I has advantages over all-electric systems: it can be installed easily on the decision of the homeowner; it is not expensive from a control or installation viewpoint; and it helps the utility's capacity factor to a certain degree. It thus contributes to a measure of stabilization in electrical demand and to reducing the average cost of electricity. Eventually, however, it will add to peaking problems — because there is no fool-proof mechanism to shut the electric heater down when the grid is heavily burdened from other uses. In short, Hybrid I systems of all types are really introductions to a far more sophisticated control system for using off-peak electricity: Hybrid II.

(c) "Hybrid II": A Hybrid Heating System with Control by the Utility

This system is superior to Hybrid I; it can provide the bulk of the space heating requirements of a building without adding at all to the peak demands on the utility. It allocates capacity to heating only when it is not needed for other purposes. There are large amounts of temporary surplus capacity in those provinces with a suitable mix of generating plant. In Hybrid II, control is exercised remotely by the electric utility itself. Like the Hybrid I, the Hybrid II system also requires an oil (or other storable fuel) furnace as a source of back-up heat.

In practice, the Hybrid II system works as follows: when the system-wide demand for electricity is less than the available capacity, surplus capacity is assigned to heating in hybrid systems. When total electricity demand approaches capacity, the electric utility progressively disconnects heaters by remote control to make demand manageable. The heaters can subsequently be reconnected, progressively and again by remote control, as the demand declines. By this technique, a large part of the capacity available can be used full-time during the 6 or 7 coldest months of the year.

By matching the surplus capacity known to be available with the heat demand shown by the degree-day curves, it can be determined that, theoretically, for the 1979-80 heating season, about 80 per cent of Canada's total oil space heat could have been provided electrically from existing capacity if all oil-heated buildings (residential, commercial and industrial) had been connected in a Hybrid II network. This would have "backed-off" oil in amounts equivalent to more than four-fifths (350,000 barrels of oil per day) of Canada's net oil imports in that period. Figure 7 illustrates the potential for electric space heating in Hybrid II systems[6].

The Hybrid II system relies on the utilities having a remote control load-shedding capability. Power is assigned to space heating as available. (This is the technique used by Minnkota Power in Minnesota and North Dakota to achieve the remarkable capacity factor of 72 per cent during the 1981-82 heating season. It is also the technique used by Hydro-Québec in its Rate "E" experiments). Existing data[7] show that up to 96 per cent of all oil used for space heating in any given building can be displaced by the Hybrid II system.

Figure 7 shows the potential for major gains in the electric grid's efficiency of use if baseload generating plant is run continuously throughout the heating season. The ability to shed heating load could even serve as a reserve, and thus eliminate the idle standby capacity required today. In lieu of standby, the electric utility would simply disconnect, by remote control, enough heating capacity to make up any capacity required elsewhere, and would reconnect it when the non-heating demand decreased. While the electric heating capacity is off, the back-up oil furnace would provide all the heat required.

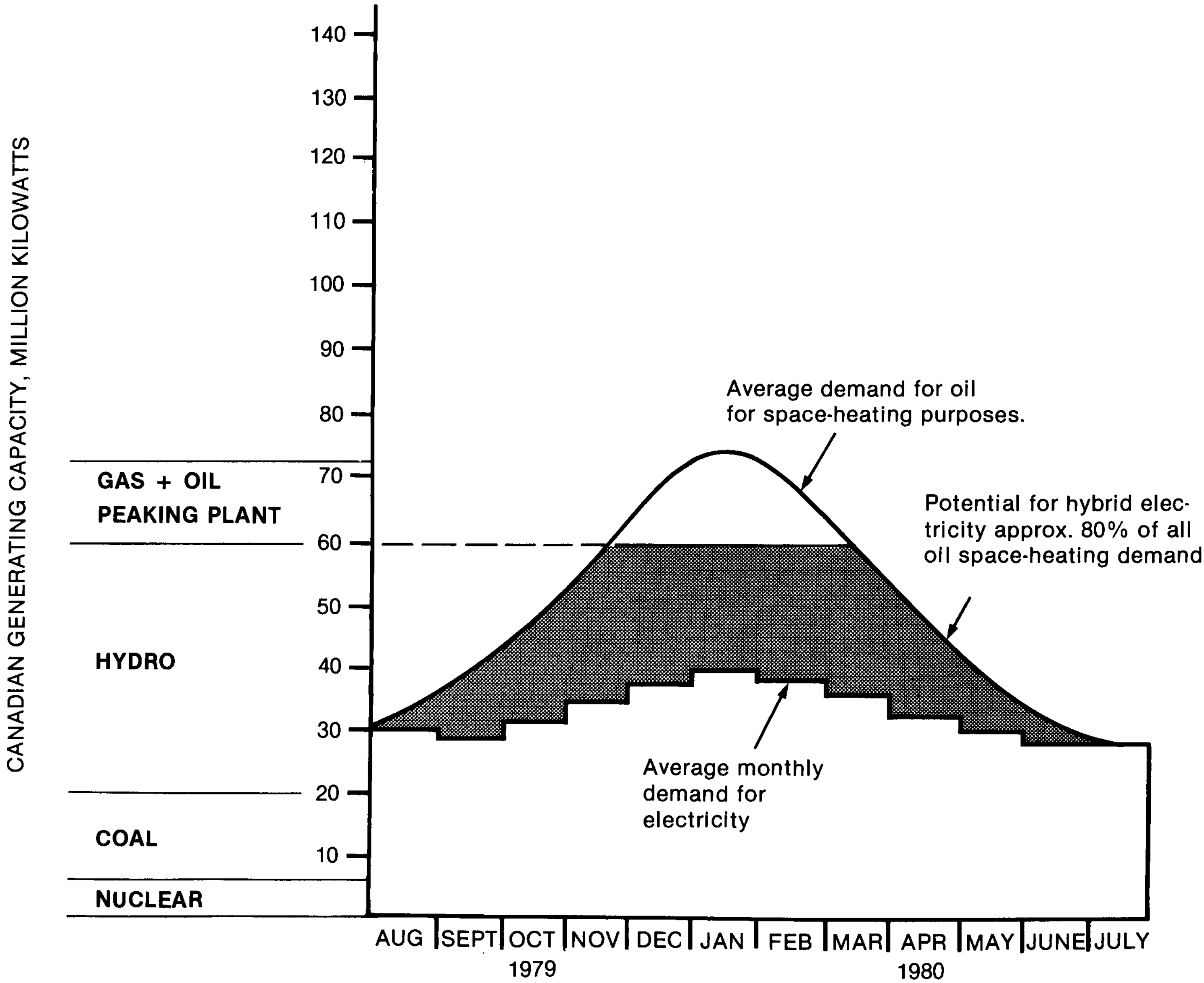
The immediate and widespread implementation of Hybrid II in the oil-heated residential sector would not be difficult to achieve in Ontario and Quebec. What would be needed is the installation of seven to fifteen kilowatts of remote (utility) controlled electric heating capacity[8] in those single-family houses presently heated with oil; such a capacity would not, at maximum draw, overload the existing grid. Based on equipment available now, and projected new designs, the heating equipment could be offered initially at a one-time (installed) cost of $900-$1,400 to the average homeowner (such an installation is eligible for a COSP grant). The equipment is not complex, and large production runs and competition should bring the price down in the future. In the spring and fall, when temperatures are relatively mild, houses could be heated electrically. During most of the winter, they could also be heated electrically, but would use oil when generating capacity was required for other (e.g., industrial) uses. If necessary, during the coldest weather, electric heat and the auxiliary furnace could be used in combination. At all times, however, the availability and use of electricity for space heating would be determined by the extent of the other demands placed on the utility's generating capacity.

On the basis of a detailed survey of Canadian manufacturers of hybrid heating equipment[9], all of the hybrid

FIGURE 7

THE OIL/ELECTRIC HYBRID (1979/80)

THE SPACE-HEATING POTENTIAL OF ELECTRICITY IN HYBRID SYSTEMS IN 1979-80 USING ONLY OIL AS BACK-UP



heaters now produced in Canada can be adapted to Hybrid II use. Over the longer-term, hybrid heating systems for larger buildings could be developed and marketed, and brought into the Hybrid II system.

(d) Hybrid Heating in Any Given Building

The calculations in Figure 7 are based on the conversion of all oil-based structures. That is, if every oil-heated building used an electric/oil hybrid, it follows (based on the 1979 electric utilities' generating plant) that the electric component would provide 80 per cent of the space heating and the oil back-up about 20 per cent. However, it is unlikely in practice that all owners would want to fit their buildings with hybrid heating equipment. Some buildings, particularly those scheduled for demolition, might be too expensive to retrofit, given their life expectancy. Nevertheless, a large proportion of buildings would be suitable for conversion.

Moreover, it has been shown in empirical tests that any given building can usefully absorb electricity (in a hybrid space heating system) equivalent to well over 80 per cent of its total needs. Accordingly, it follows that, if some oil-heated buildings were not equipped with hybrid systems, the available electric generating capacity could provide a higher proportion of electric heat to those which were so equipped.

From the standpoint of any given building — for example, the average-sized home — the oil component of the hybrid system is required under three types of circumstances: first, when the electrical system is inadequate to maintain comfortable indoor temperatures owing to severe cold temperatures outdoors; secondly, when the operation of electrical appliances, most notably the stove or electric clothes-dryer, requires that power for the electric heater be reduced because of potential house wiring overloads (it is worth noting, however, that the electricity consumed by such appliances is ultimately released into the environment in the form of heat); thirdly, when the occupants of the building, for their own comfort, require a rise of internal temperature, demanding a warm air output from the heating system which the electric component is unable to supply (e.g., when a building's indoor thermostat is turned up in the morning). However, only a small part of the total heat is affected by these limitations — 500 hours or less out of a total annual heating season of 5000 hours. This implies that any given house could meet approximately 90 per cent of its space heating needs from the electric component of a hybrid system. As part of the research for the MOSST project, this range of figures was confirmed in simulations and empirical tests carried out by Ontario Hydro and Hydro-Québec[10].

(e) Simulations of Hybrid Heating Loads and Impact on Ontario Hydro and Hydro-Québec Total Systems

According to computer simulations performed by Ontario Hydro and Hydro-Québec for the MOSST project, up to 96 per cent of all space heat in any given single family detached residence can be provided by "off-peak" electricity with a Hybrid II system, and up to 87 per cent with a Hybrid I-type — using existing wiring. The heating of a representative dwelling, fitted with a 9 kW or 15 kW heater (depending on whether the service entrance is for 60A or 100A) was simulated under different control and use configurations (both Hybrid I and Hybrid II). These simulations showed that beneficial effects on capacity characteristics were obtainable for hybrids under the climatic conditions of both Ontario and Quebec, using either hydraulic or thermal generation.

To test a Hybrid II configuration, Hydro-Québec, working with Montreal climatic data, projected a load simulation in which the plenum heater for a representative detached dwelling, having a (diversified) peak load of 6.6 kW, was remotely shut off when the total load on the utility reached 91.65 per cent of system capacity. This level was achieved by shedding the space heating load during the 100 peak hours of the winter. Using this constraint, approximately 95 per cent of all space heating could be provided by off-peak electricity leaving only 5 per cent to be supplied by the back-up heating system.

In a Hybrid I-type projection, Hydro-Québec simulated a 15 kW heater with a diversified peak of 6.6 kW shut off by an external thermister at −15°C. At this setting, 75 of the peak 100 hours of operation could be avoided by the thermister control. So long as the utility had a small degree of surplus power, this would not present a problem. At a thermister shut-off temperature of −12°C, 89 out of the peak 100 hours on the system were escaped. At a −15°C setting, electricity could provide 80 per cent of all space heat requirements with the back-up furnace supplying the other 20 per cent. At −12°C, approximately 70 per cent of the space heating could be supplied by electricity and 30 per cent by fossil fuels.

Similarly, in a Hybrid II-type simulation using 1977 data, Ontario Hydro showed that, if heater loads were 7 kW (diversified peak), and these were shut down when the overall system load rose to 14,000 MW (about 80 per cent of record peak demand), 93 per cent of all space heating in a given detached residence could be provided through electricity and, at the same time, all system generation, transmission and distribution peaks could be avoided.

Ontario Hydro also experimented with a Hybrid I-type system, controlled by a 2-stage indoor thermostat, for single detached residential dwellings. This experiment was based on empirical data obtained with 5.5 kW heaters designed for the purpose. The heaters were found to give a 4.6 kW diversified peak; however, because the relatively unsophisticated controls of Hybrid I do not shut the heater down automatically during the times of local or system peaks, this is not the most energy-efficient approach. In the short run, however, this factor is not crucial, nor will it become so as long as the utility has surplus generation, transmission and distribution capacity. At the moment, Ontario has such capacity. In the Ontario Hydro experiments, 87 per cent of the oil was displaced.

In all simulations and experiments, it is clear that relatively low-powered heaters in a variety of control system configurations can displace large quantities of oil — enough so that only one tank fill-up per year is necessary. Moreover, such oil fill-ups could be done through the year, avoiding peaks on the fuel refinery and delivery system.

(f) Hybrid II in Practice: The Minnkota Power Peak of Saturday, January 9, 1982

One U.S. utility, Minnkota Power, which supplies electricity in parts of Minnesota and North Dakota, has been operating a Hybrid II-type "dual energy" system since 1977[11]. Although the utility is a small one by comparison with Ontario Hydro or Hydro-Québec, it is representative on a local, small scale, of what hybrid systems could mean on a large scale.

Minnkota Power is a rural co-operative utility serving 70,000 customers over 35,000 square miles of the northern United States. It has approximately 400 MW of power available, of which 380 is taken as the maximum acceptable peak load. Minnkota Power has installed ripple controls on its interruptible loads to respond to signals from the utility itself, and this enables the utility to control these loads. About 7,000 hybrid heating systems had been installed by early 1982 and another 5,000 controlled loads of various kinds were operated by the utility. There are, accordingly, 12,000 ripple-controlled units in Minnkota's service area.

Minnkota Power has a total connected interruptible load of 248 MW which gives a diversified peak of 148 MW in practice. Accordingly, up to 100 MW can be shed as required. Of this total, 80 MW are taken up by dual energy (hybrid heating) systems.

The 1981-82 plan for load management was to set a target system load of 380 MW and manage the load to stay at or below that level for the winter season. If that level were ever to be exceeded, it would only be after the entire interruptible load had been shed; any new record peak would therefore only include non-interruptible loads.

On Saturday, January 9, 1982, Minnkota established the winter peak during the hours ending at 6:00 and 7:00 P.M., at a time when wind chill was −70°C. During those hours, the utility's entire interruptible load (100 MW) was shed, and the 380 MW target was maintained.

The load factor on this particular Saturday was 98.8 per cent and load was managed for 18 hours. The load management carried into Sunday and was continuous for over 42 hours. During that period, varying amounts of load were shed each hour to maintain the 380 MW target load.

For the 24-hour period beginning at 6:00 A.M. on Saturday, a 99.5 per cent load factor was achieved, 1268 MWH being shed during that period (the average hourly shed was 53 MW). If load had not been curtailed at peak, the uncontrolled peak would have been an estimated 490 MW (380 MW actual; 100 MW interruptible; and 10 MW losses on the interruptible).

For the seven-day period beginning January 5 and ending January 11, 1982 Minnkota's system load factor was 97 per cent. During that week, load was managed for 112 hours, and dual heating systems were on oil an average of 68 hours. During this same period, dual heating systems burned an estimated 79,000 gallons of oil. Of the 1268 MWH of energy shed, 1223 MWH (97 per cent) was due to dual heating loads and 45 MWH (3 per cent) was due to other loads such as water heaters and storage heating.

During the 1981-82 heating season, the oil backup furnaces in the 7,000 dual heating systems were used for an average of 145 hours each. Together, these furnaces burned an estimated total of 3,600 to 5,000 gallons of oil per hour (depending on prevailing wind and temperatures). Total oil consumption during the 1981-82 season was estimated at 725,000 gallons, or an average of 100 gallons per dual installation. Total oil savings per dual installation for that season were estimated to be around 1,200 gallons, for a total saving of 8.25 million gallons of oil during the winter. This represents 93 per cent of the space heating being met by electricity, and 7 per cent by fossil fuels.

The Minnkota Power experience is noteworthy in several respects. Like the above-mentioned Hydro-Québec experience, peak demand occurred on a weekend — in this case a Saturday; it was therefore a space heating peak. Minnkota Power, however, never exceeded its acceptable load and it operated at load factors much higher than normal. Above all, the Minnkota Power experience demonstrates the technical feasibility of hybrid systems. On the economic side of matters, it should be noted that Minnkota Power offers to its subscribers the lowest cost electricity in the entire United States.

NOTES ON CHAPTER THREE: THE POTENTIAL OF THE ELECTRIC HYBRID SYSTEM

1. Sometimes referred to as a "dual-fuel" or "dual-energy" system. In this report, the expression "hybrid heating" is used as shorthand way of referring to all systems in which space heating is met by electricity for most of the time, and a storable-fuel energy source otherwise. Examples of means to provide space heat by electricity in hybrid systems include the plenum heater and the add-on heat pump.

2. *Sources for Electricity*

   a) *Hydro:* Quebec and Labrador have an additional potential, beyond James Bay, of approximately 18 million kilowatts at costs comparable to nuclear. In addition, another 20 million kilowatts of higher cost capacity in small sites exists in Quebec, although there may be capacity factor limitations on its eventual use. Moreover, the western part of the country (e.g., British Columbia) has a comparable potential. The economic potential in the other regions is of less significance, except for Manitoba. Thus a total of 40 million kilowatts at costs comparable to nuclear, and perhaps an additional 30 million kilowatts at slightly higher cost may ultimately be developed. This is more than the existing installed hydro capacity (40 million kW in 1976). If developed, it would bring total installed hydro capacity to over 100 million kW (including plant presently under construction). This is in excess of the total Canadian 1982 generating plant of all types.

   b) *Nuclear:* Measured and indicated reserves of uranium are 190,000 tonnes while additional probable reserves are 320,000 tonnes. The former would produce 10,300 billion kWH and the latter 17,300 billion in CANDU reactors at .8 per cent burn-up (7,500 megawatt-days thermal per tonne) and 30 per cent efficiency. (For Canadian Uranium, see *1977 Assessment of Canada's Uranium Supply and Demand*, Department of Energy, Mines and Resources, Ottawa, 1978). The sum of these two quantities theoretically equals 100 years of supply of electricity at the 1975 rate of total Canadian output. The ultimate Canadian reserves may even be larger than this sum. The Thorium Breeder, which may be developed by the year 2000 or soon thereafter, will greatly extend these resources. (The world's reserve of uranium are estimated to be about 5 times larger than Canada's).

   c) *Coal:* Coal resources in western Canada are about 230 billion tonnes. If a quarter of this resource were mineable, it could generate 110,000 billion kWH of electricity. This is theoretically equal to about 400 years supply of electricity at the 1975 rate of total Canadian output.

3. It is recognized that the equipment used and the installation procedures followed must meet safety standards. If, for example, the electric service entrance is not adequate to handle the additional load arising from the use of the plenum heater, it needs to be upgraded to the appropriate level, otherwise there would be a fire hazard. As well, precautions have to be taken to ensure that there is no snow or ice accumulation on the top of the chimney, which would prevent the escape of smoke and combustion gases, otherwise there would be a serious hazard to health. That these problems can be solved effectively is evidence by the widespread use of electric/oil hybrid heating in the service area of the Minnkota Power Cooperative.

4. "Degree-days" are an index of temperature differentials between comfortable indoor temperatures and the outdoor climate. Specifically one degree-day would be 1 degree Celsius below a given comfort temperature sustained for 24 hours. In this case the given comfort temperature is 18°C (65°F), taken as the point below which supplementary heating is required within the building.

5. The actual electric heater itself might well be a more powerful unit than 5-8 kW. A 60A service entrance could accommodate a 9 kW unit and a 100A entrance, 15 kW. However, these "instantaneous peak" values are not reasonable "diversified peak" values. Simply put, any given piece of electric heating equipment is expected to work only half the time. It is important to remember from a previous footnote that although the diversified peak of an all-electric heated home is 10 kW, instantaneous peaks can be much more — 20 kW. This is why the typical baseboard system or electric furnace has a rating of 20-25 kW, and this level of power requirement, in turn, requires a 200A entrance.

6. The oil-equivalent saving is calculated as follows: the total 1979 oil-fired space heat demand for the country (from Figure 1) is distributed across time according to the shape of the degree-day curve for Ottawa (which is used to represent Canada as a whole). Energy demand for space heating is expressed in hypothetical kilowatts at the generating station, and allowance is made for furnace and transmission/distribution losses. In translating the oil energy into its electrical equivalent, a furnace efficiency in 1979 of 55 per cent is assumed, as are transmission/distribution losses of 10 per cent. Figure 7 shows installed electric capacity on December 31, 1979, assuming it remained

constant over the period August 1979 — July 1980. Any capacity that is not needed for other uses at any moment is assigned to space heating. All available capacity, including the ready reserve, is used. However, oil- and gas-fired "peaking" plant is not included in the hybrid heating calculations because it can not economically be run continuously.

7. Prepared in computer simulations by Hydro-Québec and confirmed by actual empirical tests by Minnkota Power Cooperative in the northern United States.

8. An electric heater with a rating of 7(15) kW would imply a diversified peak of 4-8 kW to the utility.

9. Clark, Thomas E., *The Hybrid Electric Heating Industry in Canada.* Report prepared for MOSST.

10. Hydro-Québec, *Rapport pour le Ministère d'État Sciences et Technologie Canada: Chauffage Bi-Énergie dans le Secteur Résidentiel*, Montreal, 1982.

11. Minnkota Power uses the term "dual energy" rather than "hybrid heating".

CHAPTER FOUR: THE ECONOMIC AND TECHNOLOGICAL BENEFITS OF HYBRIDS TO CANADA

If hybrid heating systems were adopted on a wide scale and existing electric generating plant employed much closer to full capacity, the benefits to Canada would be considerable. They would show up in improved national energy security and self-sufficiency, better returns on energy capital, and a greater market for Canadian electrical and new electronics technology. In the long-run, this would lead to steadily lower real electricity prices to consumers and business — because the existence of hybrid systems would encourage the gradual substitution of baseload generating capacity for intermediate plant which is more expensive to operate.

(a) Contribution to Security of Energy Supply and Energy Self-Sufficiency

If all buildings in Canada which currently use oil for space heat were to switch to electric/oil hybrid heating, and if the electric generating plant available to be drawn upon were the same as in 1979, 80 per cent of the oil now used for space heating would be displaced with a Hybrid II system. From Figure 1, it can be calculated that this represents 636,000 terajoules of secondary energy, or the equivalent of approximately 350,000 barrels of crude oil per day, on an annual basis. This is close to Canada's 1979 net oil imports of 400,000 barrels/day. In other words, use of the existing generating plant and transmission and distribution systems in hybrid heating systems would make a major contribution to helping Canada achieve self-sufficiency in heating fuels.

To illustrate the extent to which hybrid heating can reduce dependency on imported oil, the hypothetical contribution of this system in Quebec and Ontario in 1979 is shown in Figures 8 and 9, respectively. The figures show that the excess electrical capacity available for hybrid heating could have provided 70 per cent of the space heating supplied by oil in Quebec in 1979, and 90 per cent in Ontario.

For the MOSST project a secondary energy supply and demand balance was calculated for each province, and data for Quebec and Ontario are shown here in Figures 10 and 11. In Quebec, it can be seen that the oil used for space heating in 1979 was equivalent to 295,000 tejaroules. If the electric component of hybrid systems had provided 70 per cent of this, it would have supplied 207,000 terajoules. The corresponding figure for Ontario was 217,000 terajoules out of 241,000 terajoules, assuming 90 per cent of the oil space heating needs had been provided by electricity in hybrids.

Taking both together, the total back-out of oil in 1979 would have been 424,000 terajoules. Moreover, it has been demonstrated[1] that hybrid heating reduces oil consumption not just by displacing it but by improving the efficiency of the oil furnace on those occasions when it is called into action. As it operates only when the temperature is coldest, the furnace cycles less frequently and this improves its seasonal efficiency. This gain is equivalent to an additional 5 per cent of displaced fossil-fuel — another 21,000 terajoules — for a total of 445,000 terajoules in Ontario and Quebec alone (83 per cent of the space heating provided in both provinces by oil)[2].

The equivalent of all the oil used for space heating in Ontario and Quebec has, in effect, to be imported from outside Canada whereas their electricity is generated mostly from Canadian resources[3]. Based on these figures, a hybrid heating strategy would spare Canada the need to import approximately 120,000 barrels of crude oil per day for Quebec and 130,000 barrels for Ontario, for a total of 250,000 barrels per day on an annual basis.

(b) Impact on Capital Markets

The widespread adoption of hybrid heating would place no strain on Canadian capital markets and should help to ease the pressure on interest rates. This is one of its most important benefits.

Hybrid heating increases sales of electricity by using existing generation, transmission and distribution plant, and the costs to a utility of providing off-peak power from existing facilities is extremely low. Accordingly, no new plant needs to be built and recourse to capital markets is unnecessary. In other words, because the hybrid system is designed not to add to existing peaks arising from other demands, the building of new generating plant and transmission and distribution lines for purely space heating purposes — and the resulting need to borrow on capital markets — can be deferred for many years. In the case of Hybrid II systems, the utility would have to incur some capital for the appropriate remote control equipment. However, these costs would be lower than those of expanding generating plant and of upgrading transmission and distribution solely to supply a larger space heating market.

The sums involved can be illustrated by comparing the capital cost of generating plant and transmission and distribution facilities for all-electric heating with the capital cost of the remote switching equipment for a Hybrid II installation. At the present time, generating plant calls for a capital expenditure of $1,000 per kilowatt, and the average all-electric resident would require 10 kW at peak solely for space heating. This necessitates a dedicated investment by the utility of $10,000 for generating plant per average house. Transmission and distribution equipment requires capital costs in the same amount, for a total investment by the utility of $20,000 per average

FIGURE 8

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN QUEBEC, 1979-80

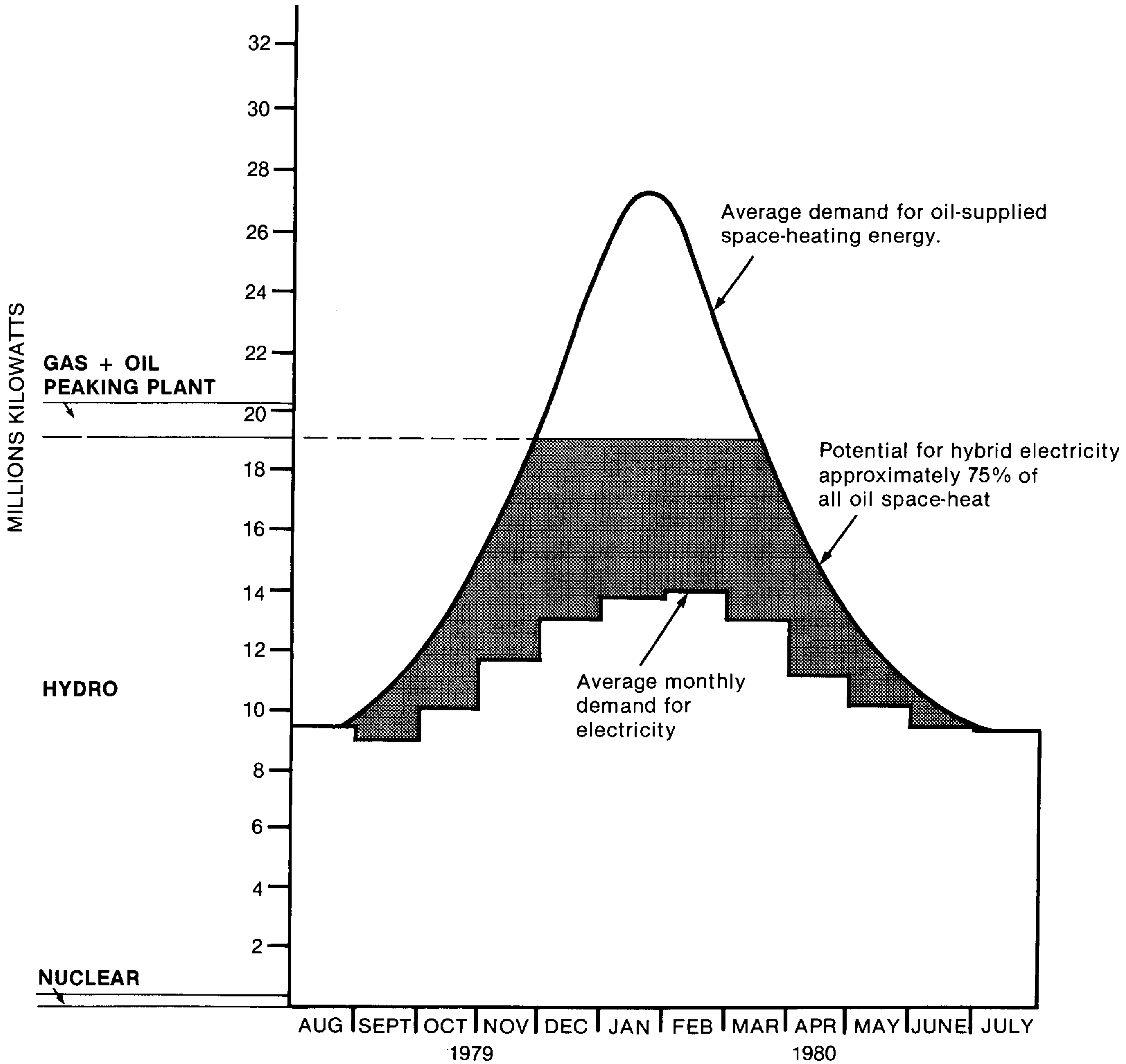


FIGURE 9

HEATING POTENTIAL OF OIL-ELECTRIC HYBRID IN ONTARIO, 1979-80

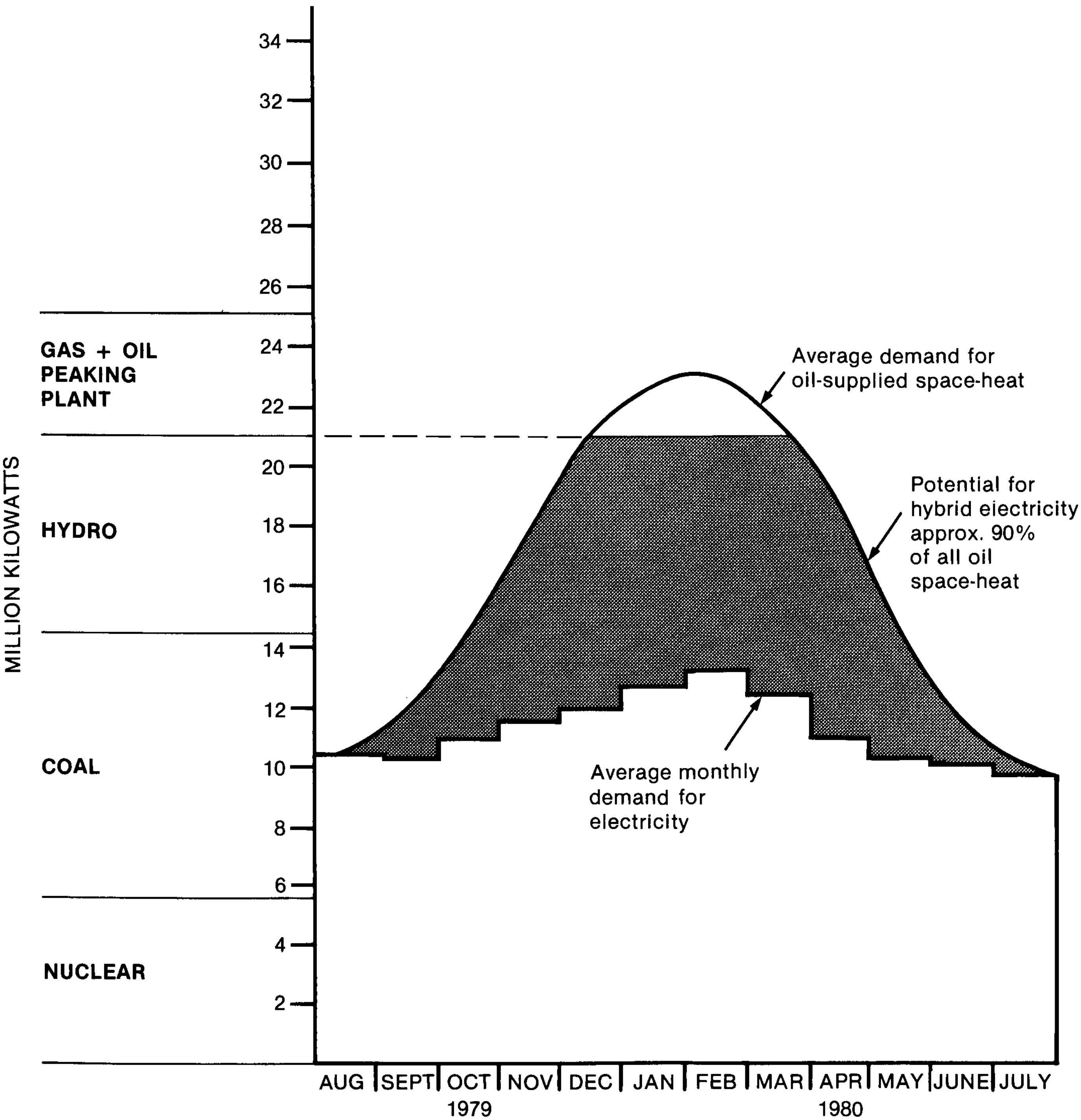


FIGURE 10

QUEBEC'S END-USE ENERGY SUPPLY AND DEMAND BALANCE, 1979

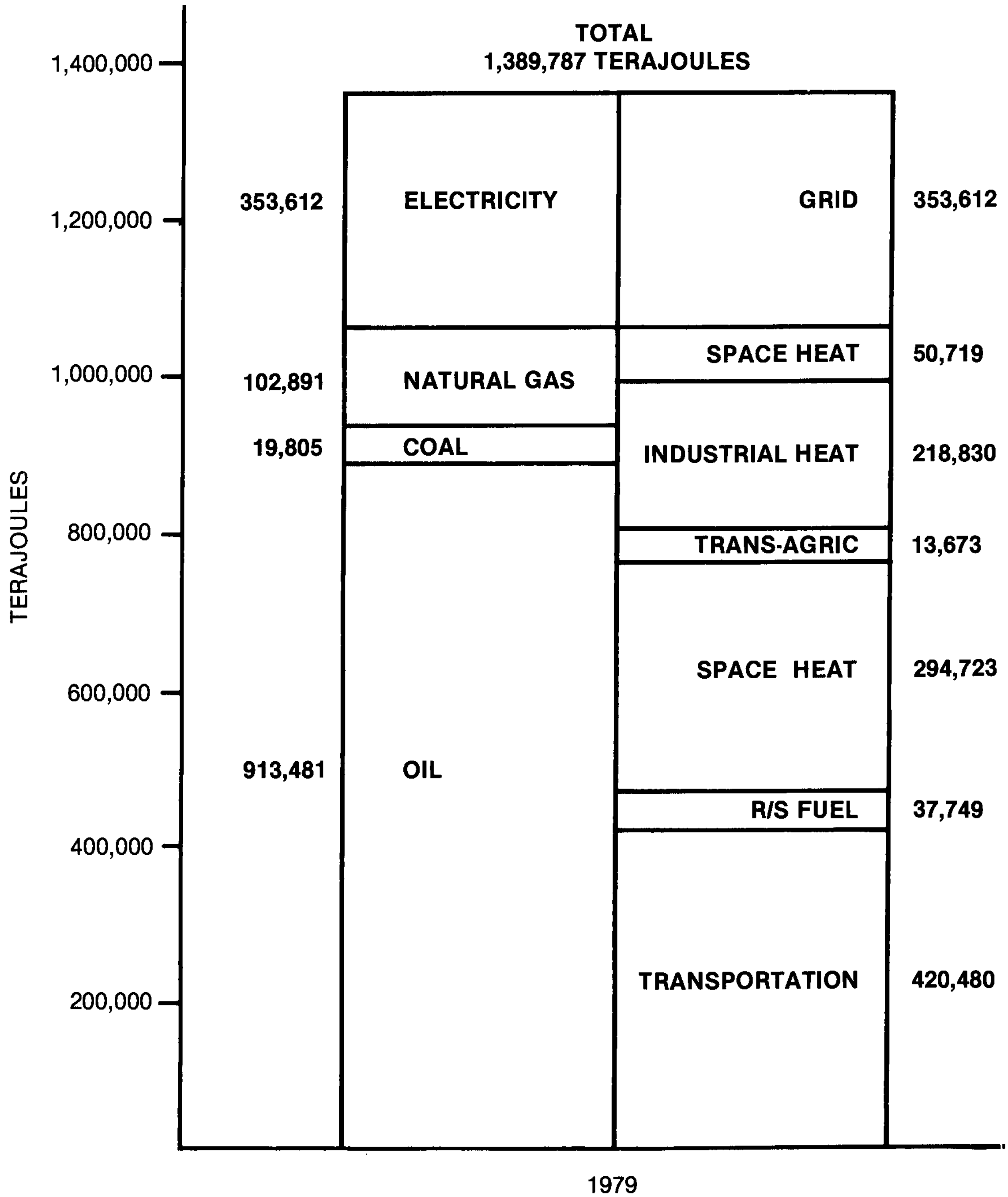
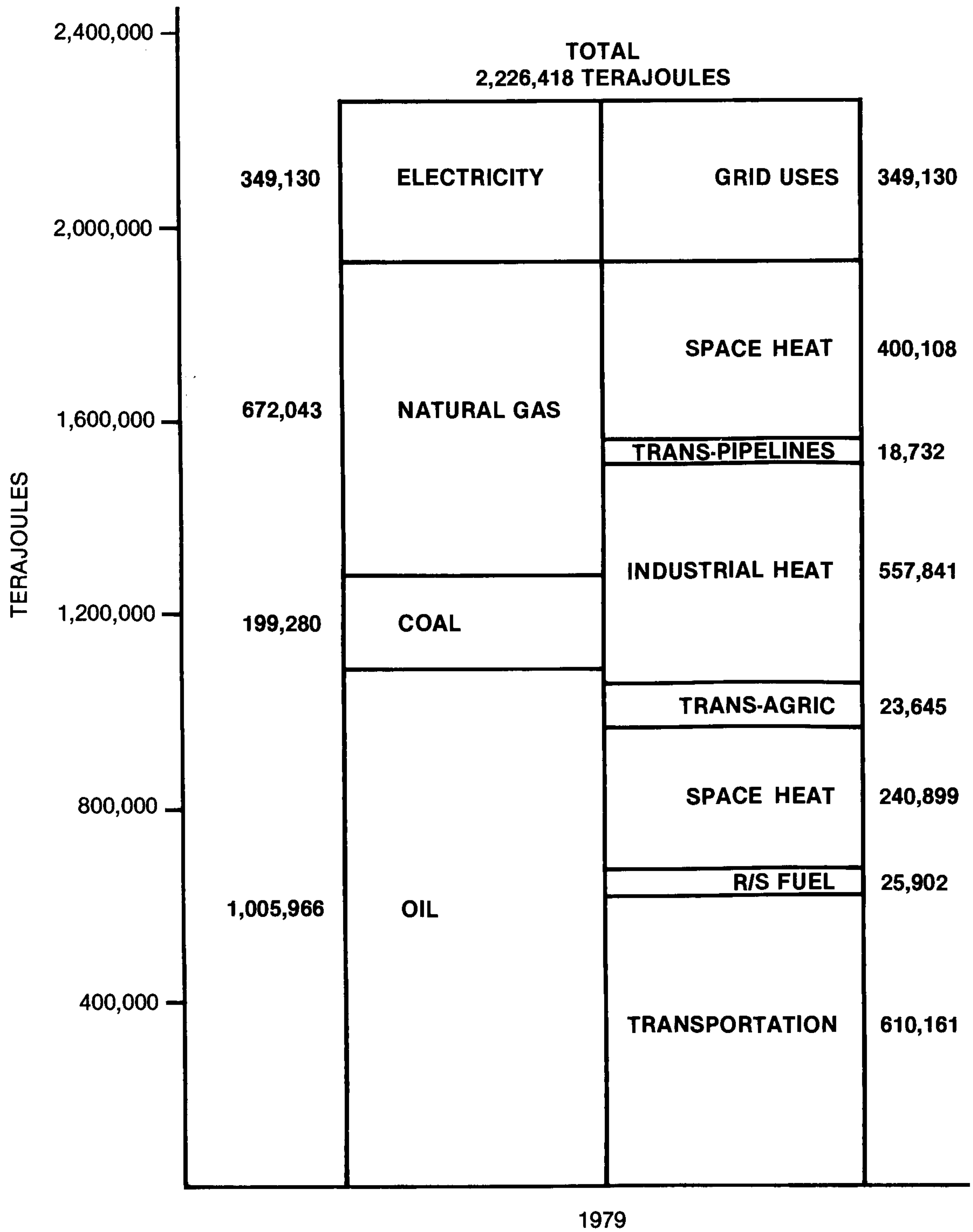


FIGURE 11

ONTARIO'S END-USE ENERGY SUPPLY AND DEMAND BALANCE, 1979



house. By contrast, according to figures developed by Hydro-Québec, the complete cost of controls for operating a Hybrid II system would be in the range of $682-$1264 per household, depending upon the specifications and design of the equipment[4]. These figures include the costs of equipment for the transmission of command signals from the central source, as well as for their reception and appropriate response by the residential heating system.

The Hybrid I system requires no expenditures on the part of the utility to put controls into place. However, it is a less effective system in that it does not automatically prevent demand peak coincidence. Nevertheless, so long as the utility has large amounts of surplus generating plant and adequate transmission and distribution facilities, this is not a severe drawback.

In short, the investment required on the part of the utilities for the implementation of hybrid heating is at most 10 per cent of that required for all-electric space heating. The impact on capital markets is of the same order.

Natural gas also requires substantial investments in pipeline infrastructure before it can be effectively substituted for oil. According to figures from Consumers' Gas, the investment per new residential customer in established areas is about $1,400. In areas of new construction, the investment is reckoned to be about $800 per customer. To these costs to the local gas utility have to be added those of any major eastern extension to the Trans-Canada Pipeline (e.g., TQM pipeline) and of any new laterals. The financing of such infrastructure would make heavy demands on capital markets: amounts of $1 billion and higher have been mentioned for the TQM pipeline.

From these figures, it is clear that the more efficient use of existing electrical facilities in hybrid heating systems would weigh the least heavily on capital markets in the short term, and in the long run as well.

(c) Technical Advantages to Electric Utilities

The adoption of electric hybrid heating would result in substantial advantages to electric utilities. First, it would provide them with the possibility of generating and usefully deploying much more energy with any given stock of electric generation, transmission and distribution equipment, thereby raising the load and capacity factors. If a constant demand were placed on the utility's generating plant throughout the heating season by the adoption of hybrid systems in otherwise oil-heated homes, it could easily raise the annual load factor for the country's total electric system to 85 per cent from its present value of 65 per cent and improve the capacity factor to 75 per cent from the present 46 per cent. Most of the load would thus be "base", with a small amount of "intermediate" and no "peaking" load. The most suitable generating plant to serve this load would be the type with high continuous availability and low fuel cost. Nuclear (CANDU), which is available 85 per cent of the year and has very low fuel costs, fits these conditions well. Hydro with annual water storage[5] (e.g., James Bay) would also be excellent. Coal-fired plant could also be used.

From a utility's point of view, the overall effect of adopting hybrid heating, particularly of the Hybrid II-type, would be to create a flattened load from September to June, leaving a convenient summer valley for necessary maintenance. Between the flat load derived from the complementarity of heating and non-heating uses, and the opportunity to put the reserve capacity to good use, the overall annual capacity factor would be at least 50 per cent higher than it is now; that is, 50 per cent more practical end-use energy could be generated from a given fixed capacity. This would have the effect of significantly reducing the unit costs of electricity. In a Hybrid I or II system with separate metering for off-peak electricity, these savings could be passed on to consumers in the form of substantially lower rates (as discussed below).

Hybrid II-type heating can also serve as a buffer for planning errors in electric capacity by absorbing them without serious harm to any of the interested parties. Space heating in such a system constitutes a buffer market. If a sufficient amount of electrical generation, transmission and distribution capacity has been allocated to hybrid heating purposes, the back-up system can serve as insurance, to be brought into service when power required elsewhere is withdrawn for re-allocation to other uses. By making it possible to accommodate larger demand forecast errors, Hybrid II renders the system self-adjusting.

Another advantage is that the hybrid is likely to improve the utilities' reliability of service. The widespread adoption of all-electric space heating would bring with it yet another problem aside from costs. While there is a risk of breakdown in any system, the extensive use of all-electric heat would increase that risk at the worst time, i.e., during very cold weather. Should a breakdown occur across a large geographical area during such conditions, and should it last for a long period, not only would this result in potential damage to life, health and property, but, as well, there would be substantial problems associated with the restoration of power. The grid would have to supply not only the peak heat demand but also additional power to bring the depressed building temperatures back to their normal level. Such additional power might not be available because of inadequate reserves and, if the entire network were to be reconnected, the resulting overload could cause yet another general failure[6]. To avoid the risk, power would have to be restored section by section. Even so, the danger of overloading local equipment would remain and could only be eliminated by building substantial and costly overcapacity into local distribution equipment. In any case, complete power restoration might be lengthy, with people and property exposed to the danger of serious harm in the meantime. Hybrid II can provide strong protection against these dangers. The possibility of shutting down the heaters over a wide geographic area by remote control serves as the system's reserve. Even under such shutdown conditions, power would remain available to ignite fossil-fuel furnaces and operate other vital equipment.

(d) Economic Benefits to Electric Utilities

The economic implications of hybrids are considerable. Only a very small revenue flow would be needed from the electricity supplied for off-peak heating to recover the marginal cost of running existing baseload and intermediate plant throughout the off-peak period.

This can be illustrated by the marginal costs of providing electric space heat in hybrid systems over the 12-month period including the 1979-80 winter season during which Canadian utilities generated 292 billion kWH at a capacity factor of 46 per cent. From Figure 7, it is possible to calculate that, theoretically, they could have usefully generated 437 billion kWH. The extra 145 billion kWH could therefore have been used to supply hybrid heating in currently oil-heated buildings, in which case the utilities would have been operating at 69 per cent capacity factor.

Although detailed data on all Canadian electric utilities' cost profiles is not available, a hypothetical but representative cost comparison for 1979-80 is shown in Figure 12.

First, an attempt has been made in Demand Profile "A" to capture the actual 1979-80 capital carrying costs (in 1980 dollars) of utilities by assuming a 35 per cent depreciation from replacement cost. Then, an attempt has been made in Demand Profile "B" to capture the hypothetical cost of a greater amount of electricity supplied from the same plant operating at a higher capacity factor. Of the total 6044 kilowatt-hours per year theoretically produced by each kilowatt of generating plant, most are shown to be produced by the intermediate (coal) component of the total generating mix. This represents the utilities' most likely short-term response to meeting the increased demand that would result from the adoption of hybrid heating: greater output from intermediate, or surplus baseload (if any), generating plant.

Based on the data contained in Figure 12, the average cost per kilowatt-hour to meet the actual load (Demand Profile "A") in 1979-80 would have been 4.15¢/kWH (in 1980 dollars). If, however, the same plant had produced the additional power to meet the hypothetical Demand Profile "B" (hybrid heating demand added), average unit costs would have been reduced to 3.5¢/kWH (in 1980 dollars).

To meet Demand Profile "A" (the actual load for 1979-80), it cost the system $12.12 billion (292 billion kWH at 4.15¢/kWH). To meet Demand Profile "B", it would have cost the system $15.30 billion (437 billion kWH at 3.50¢). The additional 45 billion kWH for the hybrid heaters would therefore have cost utilities an extra $3.18 billion, which would only have been 2.19¢/kWH, which is less than the average.

Although the figures for Demand Profile "B" are only a hypothetical representation of utilities' 1979-80 cost structures, in the course of their participation in the MOSST project, Ontario Hydro identified an off-peak fuel cost for coal-fired plant of approximately 2.1¢/kWH. This figure suggests that off-peak power for hybrid systems using existing plant would be in the range calculated in the MOSST examples.

Moreover, it can be seen from Figure 12 that the existing demand for electricity has not been disturbed in the theoretical Demand Profile "B". This profile makes allowance for the operation of peaking power combustion turbines. The 69 per cent capacity factor was chosen so that, even with some peak coincidence, the generation, transmission and distribution systems would not be over-loaded. Thus, the figures would be applicable to both Hybrid I and Hybrid II systems. Some extra operating costs have been factored into the calculations, to take account of the higher level of maintenance required for coal-fired plant used more continuously.

In the 1979-80 hypothetical representation of Figure 12, the off-peak incremental power for the hybrid heaters comes from intermediate coal-fired plant. If a utility knew beforehand that it could capture a large market at high load factors, it would steadily acquire more baseload plant (i.e., cheapest to operate in long run) in the course of renewing its equipment. The incremental cost of the off-peak power for the hybrid heaters would be correspondingly reduced. This can be seen by referring to Figure 5 — which showed the theoretical cost differences between generating plant running at high (70 per cent) and average (46 per cent) capacity factors. Figure 5 was based on replacement cost values but, in practice, utilities can not acquire high capacity systems overnight. All the same, the figures developed from Figure 5 show the costs (in 1982 dollars) for fuelling hybrid heating over the time period 1990-2010, provided in the meantime the utilities take steps to acquire optimum plant in the course of their capital expansion.

As was shown earlier in Figure 5, at 46 per cent capacity factor, and at current replacement costs, Canadian utilities, on average, would require future revenue of approximately 5.74¢ per kWH[7] to achieve total cost recovery over a generating mix that is representative of present installations. By contrast, were utilities to run their plant at 70 per cent capacity factor, average revenue would only need to be about 4.13¢/kWH for full cost recovery. In the latter case, total expenditures for electricity generation would not be much greater

FIGURE 12

HYBRID HEATING IN 1979-80: A REPRESENTATIVE COST COMPARISON*

Costs to Meet Demand Profile "A": The Actual 1979-80 Load	**Costs to Meet Demand Profile "B": If Hybrid Had Been Introduced Into The Actual 1979-80 Load**
I. CAPITAL COSTS PER WEIGHTED KILOWATT OF PARTLY (35%) DEPRECIATED GENERATING PLANT: 55% $429.00 — Baseload component (nuclear large hydro) 35% $107.25 — Intermediate component (coal, hydro) 10% $ 19.50 — Peaking component (turbines) $555.75 TOTAL	I. CAPITAL COSTS PER WEIGHTED KILOWATT OF PARTLY (35%) DEPRECIATED GENERATING PLANT: SAME AS FOR DEMAND "A" — ACTUAL 1979-80 $555.75 — TOTAL
II. CAPITAL COSTS TRANSMISSION AND DISTRIBUTION: $650.00 TOTAL CAPITAL COSTS: $1,205.75	II. CAPITAL COSTS TRANSMISSION AND DISTRIBUTION: SAME AS FOR DEMAND "A" — ACTUAL 1979-80 $650.00 TOTAL CAPITAL COSTS: $1,205.75
III. (a) ESTIMATED ANNUAL REAL "USE-OF-CAPITAL COSTS (10%): $120.57 AT 46% capacity factor (actual for 1979-80), this has to be amortized against 4030 kWH = 3.0¢/kWH	III. (a) ESTIMATED ANNUAL REAL "USE-OF-CAPITAL" COSTS (10%): $120.57 At 69% capacity factor (theoretically available through hybrid heating), this has to be amortized against 6044 kWH in 12 months = 2.0¢/kWH
(b) FUEL/OPERATING COSTS (weighted kWH) Uranium (55%) = .1¢/kWH Coal at $30/ton (35%) = .47¢/kWH Turbines (oil at $30/barrel) (10%) = .58¢/kWH	(b) FUEL/ORDINARY OPERATING COSTS (weighted kWH) Uranium (37%) = .07¢/kWH Coal at $30/ton (57%) = .77¢/kWH Turbines (oil at $30/barrel) (6%) = .45¢/kWH
	(c) EXTRA OPERATING EXPENSES (taken as 15% of all fuel costs) = .21¢/kWH
IV. GRAND TOTAL COSTS: = 4.15¢/kWH	IV. GRAND TOTAL COSTS: = 3.5¢/kWH

* See text for more detailed explanation.

because of the cost of the extra power. The difference between the implied total revenues for each case can be calculated, as in Figure 12, but based on the revenue requirements that were shown in Figure 5. The high-capacity (baseload) system would produce 437 billion kWH at 4.13¢/kWH for a total cost of $18.05 billion. The average capacity system (a mix of baseload, intermediate and peaking plant) would produce 292 billion kWH at 5.74¢/kWH for a total cost of $16.76 billion. The additional 145 billion kWH in the 69 per cent capacity system could be generated at a marginal cost of only $1.29 billion. This is approximately 1¢/kWH and four times cheaper than average current cost of electricity. Under ideal conditions, the rate a utility with optimum plant could charge for the off-peak power in a hybrid system could, in theory, be as low as this.

Moreover, the opportunity to reduce costs through higher load factors gives electric utilities numerous options in rate differentiation. A utility anticipating deteriorating load factors, possibly owing to increasing electric space heat penetration, might well project increasing real prices to consumers. If, however, the load and capacity factors improve through hybrid heating, actual costs would decline. If the utility held to its previously projected rates for firm power, there would be a considerable surplus of revenue. This surplus could be used to reduce the rate for off-peak power or to assist homeowners and building proprietors to install the appropriate hybrid heating equipment. The electric utilities would have many other options, as they would be working on a declining real cost curve. They could readily convert these options into beneficial incentives to the consumer.

(e) Incentives for Using Hybrids and the Potential Economic Gains to Consumers

There are several ways in which the savings which result from the increased efficiency of hybrid space heating systems can be passed on the consumers. For example, electricity used by heaters in Hybrid I or Hybrid II systems can be metered separately and charged at a preferential off-peak or interruptible (as the case may be) rate. This is the most direct method, and it is the one used by Minnkota Power. Another possibility is for the electric utility to supply a fixed volume of free or low-cost fuel oil per heating season to each subscriber who uses hybrid heating (this is cheaper for the utility than to build expensive additional plant for all-electric space heating, which stands idle much of the time). Utilities can also offer conversion grants to encourage subscribers to convert to electric hybrid heating systems, as Hydro-Québec and Ontario Hydro are doing.

On November 15, 1982, Hydro-Québec announced a program under which it began to offer a $650 non-taxable grant (over and above the COSP grant) to home owners who convert from oil to electric/oil hybrid systems. The target of the program is to cause 78,000 conversions by 1985 and it is reckoned that it can cost the utility up to $50 million when all expenses are taken into account. Initially, Hybrid I systems will be used, but plans call for their adaptation to Hybrid II with preferential rates for interruptible electricity when the required equipment becomes available. The main purpose of this program is to increase sales of electricity without adding to peak demand.

As well, on March 28, 1983, Ontario Hydro, together with the Ontario Municipal Electric Association and the Association of Municipal Electrical Utilities, announced a program under which it and participating utilities will cover the $200 cost of pre-service checks and electrical inspection for homeowners who have a 9 kilowatt plenum heater installed in the main air duct of existing furnaces.

To gain a perspective on possible incentives for hybrids and how much they would mean to business and consumers, it is necessary to consider the present and projected future costs of heating buildings in Canada. For simplicity's sake, all comparisons shown here will be for an "average" residence located in Ottawa. The "average" residence is a well insulated, detached building containing a normally-used living area of 121 sq. meters (1200 sq. ft), not including any basement. As Ottawa is fairly representative of the Canadian winter climate at about 4500 Celsius degree-days per year, it provides a convenient statistical baseline for making consistent comparisons.

Typically, the average residence consumes about 700 gallons (about 3,200 litres) of home heating oil per year. At 165,000 BTU/gallon (37,000 BTU per litre), this is approximately 115 million BTU of secondary energy. At a furnace efficiency of 60 per cent, this represents 70 million BTU of tertiary energy (warm air inside the home). Since secondary and tertiary energy are virtually identical in the case of electric heating, the average heating requirements per house of approximately 21,000 kWH given by Hydro-Québec and Ontario Hydro represent the same amount of end-use energy (70 million BTU). For natural gas, if furnace efficiency is 60 per cent, a tertiary requirement of 70 million BTU implies 115 million BTU or 115,000 MCF of gas delivered to the burner[8]. In practice, of course, differently insulated, larger or smaller buildings, or buildings in rows or other complexes, have quite different requirements. However, this does not change the ranking of costs of different fuels.

The particular "off-oil" strategy chosen by a consumer will be influenced by his or her assessment of several variables besides the current prices of different fuels. It will depend as well on an assessment of future fuel costs and also on the capital costs of conversion. The relative prices of fuel can change, and some systems are cheaper than others. Capital costs must therefore be factored into any decision. There are also maintenance costs to be taken into account.

(f) Heating Fuel Costs: 1982-83

For the 1982-83 heating season in Ottawa (using fuel prices in effect in March 1983), among the common alternatives for space heating, the costs of fuel alone were approximately as follows:

FIGURE 13-a

1982-83 FUEL COSTS (OTTAWA)

FUEL	QUANTITY CONSUMED	UNIT COST	TOTAL FUEL COST
Oil	700 gallons (3200 litres)	\$1.47/gal (33.7¢/litre)	\$1,099
Gas	110,000 MCF	\$6.63/MCF	\$ 762
Electricity (all-electric)	21,000 kWH	3.86¢/kWH	\$ 811

Source: Unies Ltd., *Costs of Residential Space Heating Alternatives in Major Canadian Cities Including Hybrid Heating Systems.* Winnipeg, 1983.

These figures show that natural gas is the cheapest fuel to heat an average-sized Ottawa home in particular, and any other building in general. Oil is the most expensive.

All these figures are based on current prices and rate structures — they assume or project no change in the way utilities or oil companies would charge for their products. Given the same prices and rate structures, how would the price of hybrids compare with traditional heating methods?

FIGURE 13-b

1982-83 HYBRID HEATING COSTS WITHOUT INCENTIVE (FUEL COSTS ONLY)

SYSTEM	QUANTITY	UNIT COST	TOTAL FUEL COST
Electric/Oil Hybrid (80% electric, 20% oil Hybrid II system or Hybrid I system with thermister set at −15°C or lower	16,800 kWH 553 litres (includes improvement in seasonal efficiency to 75%)*	3.88¢/kWH 33.7¢/litre	\$648 + 192 = \$834

* Oil furnaces show gains in seasonal efficiency in hybrid modes, as they only operate in colder weather, and hence cycle less frequently. Less heat loss through the chimney associated with start/stop operation is registered.

Based solely on present prices and rates in central Canada (i.e., Ontario and Quebec), the consumer has little or no incentive on the grounds of fuel costs to buy a hybrid system. This is logical because the hybrid described here involves using some oil, the most expensive fuel, and some electricity, the next most expensive fuel.

(g) Maintenance Costs

The useful life and performance of any heating plant depends largely on the degree and regularity of maintenance. In practice this varies widely from unit to unit according to homeowner preference. In this report an expected lifetime of twenty years is used as a basis for the amortization of costs and for the definition of maintenance schedules. Below are outlined representative schedules for, and the 1983 costs of, maintenance and repairs for each of the heating systems:

(i) oil furnace

—annual furnace service visit	$ 35 each
—annual cost of filters	$ 5
—chimney cleaning (years, 4, 8, 12, 16, 20)	$ 37
—major repair to air circulation system (year) 10	$110

(ii) natural gas furnace

—biennial furnace service visit (years 2, 4, 6, 8, 10, 12, 14, 16, 18)	$ 32 each
—annual cost of filters	
—major repair to air circulation system (year 10)	$110

(iii) electric furnace

—service plus electrical repairs (years 4, 8, 12, 16)	$ 32 plus $100 each
—annual cost of filters	$ 5
—major repair to air circulation system (year 10)	$110

(iv) oil/electric hybrid

—biennial service of oil furnace including electrical component (years 2, 4, 6, 8, 10, 12, 14, 16, 18)	$ 35 each
—annual cost of filters	$ 5
—chimney cleaning (years 10, 20)	$ 37 each
—electrical repairs (years 4, 8, 12, 16)	$100 each
—major repair to air circulation system (year 10)	$110

It should be noted that all non-expendable furnace components are assumed at the beginning of the amortization period to have an expected lifetime of twenty years, and consequently no exceptional allowance for maintenance and repair of these components has been included above.

Maintenance costs can thus be summarized in a comparative table:

FIGURE 14

ESTIMATED LIFE-CYCLE ANNUAL MAINTENANCE AND REPAIR COSTS FOR RESIDENTIAL SPACE HEATING OPTIONS*

Existing oil furnace:	$53
Natural gas conversion unit:	$25
Natural gas furnace:	$25
All-electric furnace:	$37
Oil/electric hybrid:	$49

* Equivalent Uniform Annual Costs (Assuming 20-year life, 1983 dollars, 10 per cent "Real Use of Capital", 8 per cent real interest rate).

Once again, from the point of view of maintenance costs, there is no particular incentive to adopt hybrid heating. If capital costs are taken into account in the analysis, however, there is a difference.

(h) Total Heating Costs: Capital Charges and Fuel

If capital cost charges for conversion are introduced, then gas still has an edge over all-electric systems, as it is generally less expensive to convert to gas than to all-electric.

However, the hybrid system has one economic advantage that appears when capital costs alone are considered: it is the cheapest to install because it does not require the upgrading of the service entrance and uses many components of the existing system. Current purchase and installation costs of hybrid heating are about \$1,000-\$1,400[9] compared with \$1,600 for natural gas[10] and \$2,400 for all-electric systems. Only the natural gas conversion burner, which uses many parts of the existing oil furnace, provides an off-oil option comparable in capital costs to hybrid electric/oil systems. A representative cost would be \$1,100, but there are only a limited number of homes in which it can be installed. With COSP grants, the consumers' immediate net outlay is \$500-700 for hybrid systems, compared with \$650-\$800 for natural gas and \$1,600 for all-electric. However, COSP grants are taxable and the income tax paid must be added to the capital cost of conversion. In our calculation, we assume a marginal tax rate of 35 per cent. As well, the real annual use-of-capital rate is assumed to be 10 per cent.

Figure 15 summarizes all costs for the consumer going "off-oil" — assuming March 1983 prices and rates. It shows that, for the present, oil is the most expensive fuel for space heating, and gas the cheapest. Hybrid heating is the next least expensive, followed by all-electric heating. If 80 per cent of the oil is backed-out, and the efficiency of the oil furnace is improved, as has been the case in existing installations, within the existing price structures hybrid heating is only about 6 per cent more expensive than gas with a new gas furnace, and about 10 per cent more expensive than the gas conversion burner option.

If, however, a further incentive, such as preferential rates, were offered to use electricity for space heating at off-peak times, the picture would change significantly and hybrid heating would become strongly competitive.

Hydro-Québec is already developing a rate structure for hybrid systems, and has stated its intention to implement them throughout its system for home heating purposes. For the 1982-83 heating season, it is offering an off-peak rate structure for a Hybrid II-type system on an experimental basis. Rate "E", as it is called, bills consumers for electricity on the baseload/peaking plant differentiation, and it is available to a certain number of pre-selected subscribers who have adopted electric/oil hybrid heating systems. Most of the time, electricity will be available at 2.3¢/kWH, or about two-thirds the average 3.5¢ rate for Quebec. However, for up to 300 peak hours each year, all electricity will carry a price of 18¢/kWH — four and half times the average rate (most of those hours will fall in January). This is an approximate reflection of the per-kWH capital cost of combustion turbines, given their infrequent use. Hydro-Québec guarantees that this price will be applied to no more than a maximum of 300 hours per year (out of 8760 total) — that is, about 3 per cent of the time, or 5 per cent of the heating season. The consumer is alerted by a signal in his/her residence when the peak time period has been entered. In some cases, Hydro-Québec switches off the plenum electric hybrid heater ("Hybrid II") by remote control. In other cases, subscribers have to switch them off manually. The peak time period is not linked automatically to either time-of-day or temperature but rather to the aggregate load on the utility.

Time-of-day rates, it is worth noting, have long been considered by the electric utilities and, indeed, have been used in the past to encourage the use of off-peak electricity. Although such rates reflect real load characteristics on average, they cannot capture utility generating costs over time and could create serious problems to utilities if offered as a commitment to users for space heating purposes over a full season. Peak loads have occurred at times which would normally be designated "off-peak" — as was the case on Sunday, January 4, 1981, for Hydro-Québec.

The centrally controlled hybrid — Hybrid II — gets around this problem. It does not matter when space heating related demand peaks and valleys occur, since space heating becomes an interruptible load that the utility can control in accordance with circumstances. Even so, Hybrid I would make a major contribution towards improving the utility's load characteristics. It is therefore quite appropriate on economic and practical grounds for a utility to offer differentiated rates in hybrid markets. From the standpoint of equity, some of the benefits accruing to the utility because of their improved load factor should flow to the consumer. The electric component of the hybrid system, running mostly or entirely off-peak, results in lower than average costs to the utility, so there is an economic justification for differentiated rates. Additionally, it is quite practicable from both the consumer's and utility's points of view to use the hybrid system and share the benefits. The consumer has a back-up furnace to meet space heating needs if the electric heater is shut down, and the electric utility will not be faced with any enormous technical problem ("flyback effect") when it tries to supply power for re-connected electric heaters.

As noted earlier, both Hydro-Québec and Ontario Hydro co-operated with the MOSST project in preparing detailed cost simulations for hybrid heating systems. The Hydro-Québec figures confirmed the viability of Rate "E" for a Hybrid II system. As part of its research, Ontario

FIGURE 15

1982-83 TOTAL HEATING COST FOR AVERAGE-SIZED RESIDENCE IN REPRESENTATIVE CLIMATE (OTTAWA): HYBRID HEATING SYSTEMS WITHOUT INCENTIVE ELECTRICITY RATE

SYSTEM	ANNUAL FUEL COST	ANNUAL MAINTENANCE COST	ANNUAL CAPITAL CARRYING COSTS (WITH COSP GRANT)	TOTAL ANNUAL HEATING COSTS
Oil furnace at 60% seasonal efficiency	$ 1,097	$54	No Conversion	$ 1,151
Natural Gas — new furnace at 60% seasonal efficiency	$ 762	$25	$ 108	$ 895
Natural Gas — conversion burner at 60% seasonal efficiency	$ 762	$25	$ 74	$ 861
All-electric with 200A entrance	$ 811	$37	$ 188	$ 1,036
Dual-Energy/Hybrid Heating 80% electric 20% oil with furnace seasonal efficiency of 70%	$ 834 (16,800 kWH - $648 553 litres - $186)	$49	$ 74	$ 957
Dual-Energy/Hybrid Heating. As above, but including utility incentive grants under Hydro-Québec and Ontario Hydro programs.	$ 834	$49	$ 22 (Qué.) $ 50 (Ont.)	$ 905-933

NOTES: All conversions amortized over 20 years at 8 per cent real interest rate (10% real "use-of-capital"). COSP grants effective value reduced by 35% to allow for marginal tax increase. There may be additional local taxes (e.g., Québec's 9% provincial sales tax levied on electricity sales) which may need to be taken into account in comparing fuel costs outside Ottawa.

Hydro costed a Hybrid I-type system which displaced 87 per cent of the oil used for space heating. However, it was also found to be partially peak-coincident and, accordingly, Ontario Hydro assigned costs to the heater that not only represented marginal fuel costs but also included an adjustment for the capital cost of generating capacity, transmission and distribution equipment.

This costing arrangement supposed a 1982 revenue requirement of 2.92¢/kWH, or 3.2¢/kWH to allow for the 1983 rate rise, for the electric component of the hybrid. This figure is higher than the equivalent 1982 rate of 2.3¢/kWH under Hydro-Québec's Rate "E", but the marginal and operating costs would in any case be higher for Ontario Hydro's thermal-based system. Even so, the 1982 revenue requirement calculated by Ontario Hydro is 18 per cent less than its 1982 average rate of 3.6¢/kWH.

Ontario Hydro also simulated the costs of a Hybrid II-type system designed to avoid local and system peaks. Calculations for Hybrid II-type systems showed a 1982 revenue requirement of 2.72¢/kWH (raised to 2.9¢/kWH for 1983). This figure includes some cost recovery for additional transmission and distribution capacity associated with the maximum use of Hybrid II type opportunities. Moreover, the simulations show that if the utility were able to offer power for hybrid heating without having to incorporate costs for additional transmission and distribution equipment, the power for a Hybrid II-type system would be available for 2.38¢/kWH (raised to 2.6¢/kWH for 1983, for consistency with other figures). This, however, could only be achieved after some years of selective capital renewal but may be possible in the 1990's. It represents a 40 per cent discount off current rates, and is comparable with Hydro-Québec's Rate "E"[11].

Figure 16 gives a summary of space heating costs for Ontario and Quebec in 1982-83 under three different off-peak rate structures. Under these rate structures, the hybrid would be decisively cheaper, being (under Rate "E" in Quebec) 81 per cent of the cost of gas with a new furnace and 61 per cent of the cost of all-electric space heating (compare with Figure 15). The average householder would save $259 annually over gas and $400 over an all-electric system. Even with Hybrid I in Ontario, the dual system is certainly competitive, costing $795 in comparison with the natural gas figure of $895 with a new furnace and $861 with a conversion burner.

Off-peak rates are not the only incentive utilities can offer to encourage the spread of hybrid heating. As was noted above, both Hydro-Québec and Ontario Hydro are now offering conversion grants to their subscribers.[12]

None of these figures are definitive and data will need to be refined further. Nevertheless, subject to usual cautions, certain conclusions can be reached. Summing-up the economics of hybrid systems for consumers, it can be said that:

(i) the hybrid system is the cheapest to install;

FIGURE 16

CALCULATED 1983 TOTAL HEATING COSTS FOR AVERAGE QUEBEC AND ONTARIO RESIDENCE: HYBRID HEATING SYSTEM WITH INCENTIVE ELECTRICITY RATE AS PER HYDRO-QUEBEC'S RATE "E" OR AS PER ONTARIO HYDRO'S COST CALCULATIONS FOR MOSST PROJECT

SYSTEM	ANNUAL FUEL COST	MAINTENANCE	ANNUAL CAPITAL CARRYING COSTS (WITH COSP GRANT AND UTILITY INCENTIVES)	TOTAL ANNUAL HEATING COSTS
A. Oil/Electric (Dual Energy) under Hydro-Québec's Rate "E" 95% Electric (Dual II) 5% Oil. Furnace efficiency at 75%	Electricity (20,000 kWH @ 2.6¢/kWH = $520 Oil (136 litres @ 33.7¢/1) = $45 TOTAL: $565	$ 49	$ 22	$ 636
B. Oil/Electric (Dual Energy) based on Ontario Hydro's "Dual I" calculations/tests 87% Electric 13% Oil. Furnace efficiency at 75%	Electricity (18,270 kWH @ 3.2¢/kWH) = $585 Oil (331 litres @ 33.7¢/1) = $111) TOTAL: $696	$ 49	$ 50	$ 795
C. Oil/Electric (Dual Energy) based on Ontario Hydro's "Dual II" calculations 93% Electric 7% Oil. Furnace efficiency at 75%	Electricity (19,530 kWH @ 2.9¢/kWH) = $566 Oil (181 litres @ 33.7¢/1) = $61 TOTAL: $627	$ 49	$ 50	$ 726

NOTE: See Text. Actual cost of energy under Rate "E" might even be less through additional savings on non-heating uses. However, local electricity or energy taxes (e.g., Quebec's 9% sales tax levied on electricity) may also need to be taken into account.

(ii) Canadian electric utilities — based on figures developed by the two major power companies in Canada — could offer off-peak rates as an incentive for the use of hybrid heating systems;

(iii) such an incentive would make the hybrid system competitive with any other space heating system in the future; and

(iv) the long-term opportunities in electrical resources and generation imply that real costs of hybrid heating would be more likely to go down than up in the years to come.

(i) Industrial and Technology Gains and Future Systems (Advanced Hybrid)

Hybrid heating systems could employ Canadian technologies — from the generation of electric power to its end-use. The dissemination of these systems would provide a number of opportunities for Canada's electrical and electronic industries.

To begin with, Canada has exceptional capabilities for electricity generation. The ideal generating plant for hybrid heating is characterized by the ability to run continuously at minimum overall costs (e.g., large hydro with assured water storage, and nuclear). Over time, assuming they expand the use of hybrid systems in their service areas, utilities can incorporate new baseload equipment into their planned generating mix. Throughout this report, the utilities' own forecasts have been used to project the future availability of surplus power. Virtually all generating plant planned for 1990 is already well-defined as to type. However, plans for plant beyond 1990 may still be flexible with respect to type and beyond 2000 there is not likely to be any new technical constraint on choice of generation. It is in the 1990-2010 time-frame that the widespread adoption of hybrid heating would suggest the acquisition of a particular *type* of new plant by Canadian electric utilities, although it must be emphasized that it would require no *additional* plant.

There is great expertise in Canada in the development of large-scale hydro sites. Hydro-Québec, for example, has developed remote control technology, making it possible to operate individual dams in the James Bay system from a distant control center. As well, the utility has world-wide expertise in long-distance transmission, and this gives it the technical ability to exploit remote hydro sites.

There still remain large potential hydro sites in the country, but they are increasingly remote. Because of the costs of long-distance transmission, these sites have yet to be harnessed, and their development will be contingent upon the existence of markets for large amounts of baseload power. Hybrid heating would open such a market after 1990.

The other Canadian technology that could make a major contribution to meeting Canada's energy needs through hybrid heating is the CANDU nuclear system. Year after year, Canadian nuclear generators have set world records for the long-term continuous availability of their power[13]. They run easily at 85 per cent capacity factor and provide reliable baseload power. The ability of CANDU reactors to run at such high load and capacity factors distinguishes them for their U.S. light-water counterparts which, commonly, only run at about 65 per cent capacity factor, i.e., not much higher than typical coal-fired plant. A major reason for the CANDU's superiority is that it can be refuelled while it is running. By comparison with other designs, CANDU has also demonstrated a very low rate of unscheduled outages (breakdowns).

The widespread adoption of hybrid heating would also give a boost to parts of the Canadian electrical manufacturing industry. Canadian manufacturers have already developed excellent hybrid heating equipment for use in the residential sector. Five designs have been accepted by the Canadian Standards Association (CSA). At present, all of these products are for use with a forced-air oil furnace. However, one firm — P.S.C. Controls — expects to have a hydronic (water) system add-on heater available in the near future. While, as yet, no equipment exists "off-the-shelf" for industrial or commercial buildings, another firm — Lion Industries — is known to have begun developing designs to supply this market. In the United States, there is one manufacturer which provides equipment to Minnkota Power subscribers; these products do not show any advantages over the Canadian ones, but they do include equipment useable for larger-scale applications, e.g., schools, churches and shopping centers. As well, it would be desirable to manufacture, as soon as possible, compact true hybrid furnaces for use in new construction. This would present no technical problems.

Current hybrid heaters in Canada are technologically state-of-the-art. For example, the design and mass production of reliable heating elements is now highly developed. These usually use layered multi-material metal cores that transform 100 per cent of the electrical energy fed to them into heat. Incorporated control circuitry allows automatic progressive reduction in their heat output and current draw so as to prevent overloading the wiring of the building (load shedding). Simple but effective control switches, to respond to "off/on" signals from any one (or more) of several inputs — utility ripple control, external thermister, internal thermostat — are fitted so that maximum flexibility of use can be achieved in the future. All present designs are extremely sophisticated for their intended applications and are unlikely to become obsolete over the medium term. Homeowners can fit them onto their oil furnace now, secure in the knowledge that future advances or system changes — particularly the gradual shift from Hybrid I to Hybrid II systems — can be readily incorporated at low expense and minimum inconvenience.

But it is in the transmission and distribution grid of the hybrid heating system that the greatest opportunities arise for new technology. By the year 2000 and beyond, the control and transmission of signals and power could move beyond Hybrid II systems to the self-regulating "dynamic grid" concept.

According to the theory underlying this concept, minute changes in voltages throughout the electric grid can be used to trigger automatic on/off switches in hybrid heaters. In milder weather, the hybrid electrical heaters would operate to keep buildings comfortable throughout a given district, being put into operation and shut down by the ordinary thermostat inside the building. In such circumstances, the heaters constitute a diversified load. So, also, do other electrically operated devices. Base-load generating plant would therefore serve to meet much larger portions of the total heating demand than is the case at present. Three circumstances could disturb this equilibrium: an intruding winter cold front bringing rapidly declining temperatures; a rising peak in demand from non-heating electrical use; or an equipment breakdown.

If temperatures were to drop sharply, the electrical heaters would come on more frequently and converge into a synchronized load. As the heating and other loads in the district converged, voltage in the local power lines would drop. Micro-processors throughout the area would sense this disturbance. They would detect the change in voltage in power lines, and the intensity and duration of the change in the local grid. Before overload conditions occurred, they would shut down electric heaters by remote control and back-up oil furnaces would provide heat to the buildings. In case of a rise in non-heating demand, there would be a similar loss of diversity in load and the convergence would cause the micro-processors to shed the interruptible load of the heaters. The system would also respond to changes in input voltages: breakdowns would mean a loss of voltage even under stable demand conditions. The micro-processors would here again trigger load-shedding to re-establish equilibrium. The whole sequence of control could be accomplished at very high speeds. The utility would not need to man remote-control switches (e.g., "ripple" control or radio signals) to shut off or turn on the heaters; all of this would be accomplished electronically. The micro-processors would even make possible the reading of individual meters, and factor in any rate incentives so as to calculate costs to the home-owner. The whole grid would become a self-contained dynamic system adapting automatically to its environment.

The technology and mathematics of such systems are being actively developed and they should be technically proven and available for use by the late 1980's.

(j) The Export Market Potential of Hybrid Heating

As part of the MOSST research, a contract was established with a United States consultant to survey the potential for, and feasibility of, exporting Canadian hybrid heating equipment and power to the U.S.[14]. Although this is a preliminary overview it shows there are opportunities in the U.S. market, even though, as might be expected, natural gas is the leading competitor for space heating in that country, where it is available.

The climate throughout much of the U.S. is less severe than in Canada and, as a generalization, most U.S. utilities have a summertime peak in electrical demand from air-conditioning. Nevertheless, many do have a winter peak, or a summer peak that is only marginally higher than the winter peak, or they have greater overall sales in the winter than the summer (even if "instantaneous peaks" occur at some point in the summer). As a result, the widespread adoption of all-electric space heating would cause problems, and the utilities concerned should be interested in winter load management through the adoption of interruptible power systems. These utilities are concentrated in five regions of the U.S.: the Northeast (central Pennsylvania to Maine); the upper mid-west (Pittsburgh to Milwaukee); Northern Plains (Wisconsin to North Dakota); the Northwest; and the "Chesapeake" (Virginia – Tennessee – West Virginia and surroundings).

In the Northeastern region of the U.S. there are about 8.5 million oil-heated housing units. (This is more than twice as many as in the whole of Canada.) The climate is similar to that of Ontario or the Maritimes. If all of these units converted to electric/oil hybrids using 90 per cent electricity and 10 per cent oil, then they would consume 175 billion kWH for hybrid space heating. This is a very large amount. It is about equivalent to 60 per cent of Canada's entire output of electricity.

The electric utilities in this region are, as a generalization, under greater stress in winter than in summer. In recent years, New York State has sold about 5 per cent more power in January than July — 9405 million kWH vs. 8984 million kWH were the average sales in 1980 and 1981. Massachusetts' sales are about 20 per cent greater in winter: 3174 million kWH vs. 2465 million kWH.

However, the costs of electricity in this region are relatively high, averaging about (U.S.) $19/million (MM) BTU (about (U.S.) 7¢ per kWH). This is because much of the region still depends on oil-fired thermal generating plant. Where natural gas is available for heating (and its availability is limited), it is much cheaper — about (U.S.) $5 per thousand cubic feet or $8 per MMBTU tertiary energy.

Because there is no reason to adopt electric/oil hybrid heating where electricity is itself oil-fuelled, any Canadian approach to these markets should be on a "systems basis", i.e., it should offer both hybrid heating equipment and electricity to U.S. utilities within transmission range from Canada, using power from surplus Canadian generating capacity. The power from Canada might have to be offered on an incentive basis (off-peak rates) but, since it could be interruptible power (Hybrid II), this need not be an insuperable hurdle. As an alternative, dedicated near-border Canadian baseload capacity could be offered for reasonably stable demand at average Canadian baseload rates that would be cheaper than both average U.S. electricity rates and U.S. oil-heating costs (gas, as noted above, is not widely available in these markets).

The three regions of the Upper Midwest, Northern Plains and Pacific Northwest are definitely markets for hybrid heating equipment, with or without the export of electricity. These three regions contain almost 2.5 million housing units fuelled by oil. The local utilities are generally winter peaking. For example, in Michigan, electricity sales in January average 5 per cent more than July; for Montana, they are 17 per cent greater; and for Washington State, 22 per cent. The climate is also similar to that of nearby Canadian regions. Chicago has experienced −30°C, but is usually close to Toronto's 3800 Celsius degree-days heating season overall. The Northern Plains' States share the harsh winters of the Canadian prairies. Along the Pacific Coast, there is little difference in climate between Seattle and Vancouver.

U.S. electric utilities in these regions use thermal (coal) and some hydraulic resources for generation. These resources make electricity more competitive in general with other fuels, e.g., natural gas. Besides, there are no significant surpluses of Canadian electricity available for export near these areas. All factors considered, these regions are promising areas for hybrid heating equipment sales.

Minnkota Power itself, of course, is included in the Northern Plains region and, as has been noted, it has successfully developed hybrid heating systems. This utility has been trying energetically to interest other utilities throughout Iowa, Nebraska and surrounding regions, in hybrid (dual energy) heating. One Canadian manufacturer of hybrid heating equipment has already been promoting its products in this market and there are indications of some success. The internal load-shedding circuitry of the Canadian design makes possible lower overall cost of installation to the customer because in most cases no service entrance upgrading is required. Previously, subscribers to Minnkota's dual-energy system had to install the 200A wiring commonly associated with all-electric heating, even though they retain a fossil-fuel back-up. Accordingly, Canadian systems could gain a good share of the market if actively promoted.

Overall, if every household currently using oil in these regions converted to an electric/oil hybrid, utilities could sell an additional 65 million kWH annually. At the present time, the price of electricity in these regions ranges from \$8 to \$13/MMBTU while gas costs \$5.50 to \$8.00/MMBTU tertiary energy after allowing for furnace losses. Relatively modest incentives in the form of differentiated rates could therefore make hybrid heating competitive.

Finally, the Chesapeake region (Virginia, West Virginia, Tennessee and surrounding areas) represents a marginal opportunity. This is a winter-peaking region (winter sales exceed summer sales in these States and in North Carolina and Kentucky), but its mild climate has heretofore favoured conversion to heat-pumps. There are still 1.3 million oil-heated units in the area. The cost of electricity averages \$14/MMBTU, whereas that of gas is about \$4.50/MMBTU, or \$7.00/MMBTU tertiary energy. Accordingly, to be competitive with gas, quite a large off-peak discount would have to be given for hybrids. Electricity is mostly coal-generated with some hydraulic, making the possibility of such an incentive uncertain. The electricity would likely have to be generated locally, as this region is beyond transmission range from Canada.

To sum up, it is possible to identify a total theoretical market for electric/oil hybrid heating systems in the U.S. three times larger than that of Canada, considering the residential sector alone. Although, for reasons of cost, climate, and generating mix, there is less prospect of selling hybrid systems in the United States than in Canada, it would take only a small penetration to yield a significant market. On cost and technical grounds, Canadian manufacturers are well placed to capture such a market. Furthermore, there is a potential for the export of Canadian electricity for hybrid heating purposes, if the appropriate marketing strategy can be developed.

NOTES ON CHAPTER FOUR: THE ECONOMIC AND TECHNOLOGICAL BENEFITS OF HYBRIDS TO CANADA

1. Experiments conducted by AECL, Ontario Hydro, and Hydro-Québec throughout their various tests.

2. This additional gain could also have been taken into account in the earlier sections of the report dealing with national energy security. However, it was not specifically included.

3. In Ontario, not all electricity for hybrids would, in the short-run, be generated by indigenous resources. Most would have to come from imported coal. The latter is much cheaper than oil, of course, and in the long-run nuclear generation provides domestic sources of energy supply.

4. Radio control is the cheapest method and ripple control over the power lines the most expensive. The cost of using telephone lines would be close to that of radio control. Hydro-Québec uses very high frequency transmission, and this may increase the costs of ripple control to this utility — Ontario Hydro may find it cheaper.

5. Hydro with annual water storage refers to hydraulic generation sites that can store enough water in their reservoirs so that any given rated capacity output can be sustained through any season, e.g., the winter heating season. Typically water builds up behind the dam during the spring run-off; large storage capacity enables all the water to be retained for use during the following winter's demands.

6. This is commonly referred to as the "flyback" effect, or problem of "cold-load-pickup". "Flyback" effects are a major reason why electric utilities are not enthusiastic about remote-controlled water heater loads — they would show a severe "flyback" at time of re-connection. Without any supplementary heat source, the water stored in the domestic tanks would cool down. When power was reconnected, the tanks' internal thermostats would immediately trigger the electric heating elements. These elements would become a synchronized load and cause "surge" problems on the power lines ("flyback effect"). Hybrid heaters, however, would not act the same way. The house would have been kept warm by the furnace.

7. It is stressed that this is the replacement cost for the future period for which a utility has to plan. As was described earlier, the present mix actually costs about 4¢/kWH to run. These figures are used to illustrate different revenue requirements and show how future changes in load characteristics will affect real costs of electricity, based on 1982 dollars and cost data.

8. According to Consumers' Gas, the average residential sale of gas for space heating is 112,000 to 113,000 MCF annually (125,000 to 130,000 if hot water is also included). There would also be a small additional amount of gas required to operate the pilot light.

9. The cost of hybrid heating equipment, it should be noted, does not yet reflect mass production or competition. Although an average figure of $1,100 (before COSP) has been used throughout this report, the real 1985 cost may be lower. The price of $1,100 represents the sum of $600 for the retail price of the equipment, and $500 installation costs. However a bulk order for the Department of National Defence was filled at a unit cost for equipment (plenum heaters) of only $400. A skilled installer can readily fit a plenum heater in half a day (3 or 4 hours). Even allowing for the need for an apprentice workmate and other overhead, and assuming a rate of $50/hour for labour, the labour component of the installation cost could be reduced to $200 per unit. A further $150 should be ample to cover the cost of materials (e.g., wiring) for installtion. All of this adds up to only $750. In short, the relative simplicity of the technology and installation procedures suggests that the real price to the consumer of equipment is likely to decline in the long run. By contrast, natural gas and all-electric systems are relatively mature technologies which do not offer much prospect of declining real costs.

10. Natural gas systems may in fact cost more than this. Some recent reports indicate problems with gas condensation in the chimney of buildings converted from oil. The gas may re-vaporize and, being heavier than air, be drawn into the house. Forced draught to eliminate this problem may add $350-$500 per installation. High efficiency condensing furnaces cost still more — $3,500.

11. Minnkota Power's rates are of interest here. Firm power is sold at (U.S.) 4¢/kWH, while interruptible power for the hybrid heaters is made available at (U.S.) 2.4¢/kWH. These are low figures for a U.S. utility. Electricity rates in the U.S. at present average (U.S.) 5.98¢/kWH. Minnkota is essentially a thermal (coal) based utility.

12. The electric utilities may come under strong pressure from another quarter to offer an incentive for the adoption of hybrids. This competition has to do with the desirability of controlling the hot water heating market. The hot water heater is a positive load for both utilities as it is year-round (baseload). When consumers trying to get "off-oil" convert to gas space heating, they are also encouraged to use gas instead of electricity for hot water heating. If electric utilities encourage the adoption of hybrids, they are less likely to lose hot water heaters as a market.

13. In 1981, Ontario Hydro reactors took the first six places for performance among 130 large commercial nuclear reactors in the world.

14. Barry Bruce-Briggs, *Preliminary Survey for Hybrid Heating in the U.S. Market*. Report prepared for MOSST.

CHAPTER FIVE: HYBRID SYSTEMS AND NATURAL GAS

Because of its competitiveness, electric/oil hybrid heating — where it becomes available — will limit the expansion of natural gas sales or cause the utilities to reassess their pricing practices to protect their market share. Either way, the availability of hybrid heating will reduce the revenues of producers who have committed large investments to discover natural gas and bring it to market; it will, as well, reduce provincial royalties on natural gas sales. Fortunately, however, there are several other profitable uses for this commodity.

There is a large industrial market for natural gas which, unlike the residential market, is not seasonal but year-round and thus provides a large baseload demand. If the capital cost of conversion and the price of natural gas make the changeover profitable, Canadian industries will be attracted to natural gas, of which there is a secure and abundant domestic supply, for their process heat requirements.

Demand for natural gas, as for electricity, is subject to diurnal and seasonal variations. As well, because of high fixed costs — which include contractual purchase commitments to suppliers and expensive infrastructure (for transmission, storage and distribution) on which interest has to be paid whether or not it is fully used — natural gas utilities need high load and capacity factors in order to operate profitably. As do the electric utilities, they have an interest in shaving peaks as well as filling valleys.

Industrial process heat is a large market for natural gas which, because it is interruptible, can help to balance the residential demand for space heat and thus contribute to the high capacity factor required by the utilities. The industrial market can be made interruptible by the adoption of a natural gas/residual oil hybrid which works as follows: under normal conditions (i.e., most of the year), natural gas is used to generate industrial process heat with locally stored residual oil serving as a backup. When natural gas has to be diverted from its industrial uses, these are supplied with residual oil. All of this can be achieved by remote control.

It bears noting, however, that electric utilities with abundant baseload power will be prepared to offer off-peak electricity at preferential rates for industrial uses as well as for space heating. Where this happens, industries can be expected to choose those sources of energy which are economically the most attractive, taking into account the capital and operating costs (including fuel prices) associated with the alternatives available.

There are opportunities other than heat for the industrial use of natural gas, particularly as a petrochemical feedstock. Natural gas can be converted, among other things, into methanol for use in both gasoline and diesel engines. Methanol in turn can be transformed into gasoline. Transport fuels command high prices and are likely to be more scarce than other oil products.

The Ontario Research Foundation has done considerable long-term experimentation with a diesel/methanol truck and has found that it can use methanol for up to one-third of its total fuel requirements, and that a larger proportion may be possible in the future. A recent U.S. study[1] has forecast a higher growth rate for methanol over the next twenty years than for liquid fuels in general.

Natural gas is currently the cheapest feedstock for methanol and it is likely that Canadian synthetic fuels derived from it would be cheaper than U.S. synfuels made through coal liquefaction. It must be recognized, however, that vast amounts of methane are now being flared in the world's major oil fields. If the Middle Eastern producers were to decide that the benefits from this large wasted source of energy were such as to warrant its transformation into methanol, it could provide serious competition to Canadian natural gas as a feedstock.

NOTES ON CHAPTER FIVE: HYBRID SYSTEMS AND NATURAL GAS

1. Source: Cook, Paul A.C. and Gilbert M. Rodgers, "Methanol Demand and Supply: New Technological Alternatives", *Proceedings of the 9th Energy Technology Conference*, February 16-18, 1982, Government Institutes Inc., Washington, D.C.

CHAPTER SIX: A FEDERAL APPROACH TO HYBRID HEATING

The present approach to the use of energy in general, and to that of electricity in particular, was shaped at a time when supplies seemed virtually inexhaustible, crude oil was secure and cheap, and interest rates were low. In these circumstances, there was little reason to consider hybrid systems and their benefits. However, since the Middle East oil crisis of the early 1970's, the supply of oil has become insecure and, despite the recent drop from all-time highs, its price has risen to many times what it was. The prices of other forms of energy have also risen notably, in the wake of that of oil. On top of this, high interest rates and continuing inflation have made it more important than ever to seek to ensure that Canada's overall energy system is exploited to maximum efficiency so that an undue strain is not placed on capital markets. However, since these developments are so recent, it is not surprising that the full potential of hybrid heating is only beginning to be appreciated and that policies, programs, and actions for its promotion have come to the fore but recently.

Hydro-Québec's "Programme bi-énergie" was announced publicly on November 1, 1982. As was noted above, it offers a strong financial incentive for the retrofitting of temperature-controlled electric heaters into the plenums of oil furnaces of single-family dwellings. The utility plans to convert 28,000 homes to hybrid electric/oil heating in 1983, and a further 48,000 in 1984. Ontario Hydro, as well, announced a program to encourage the adoption of electric/oil hybrid heating, on March 28, 1983, by retrofitting electric heaters into the plenums of furnaces.

The actions taken by Hydro-Québec and Ontario Hydro should be welcomed by the federal government. In the case of Québec, they could save at least 672,000 barrels of oil in the 1983-84 heating season, and 1,824,000 barrels in 1984-85. (Conversion forecasts, and the resulting oil savings, are not yet available for Ontario). In addition, the temperature-controlled switching systems being installed on individual home heating equipment can easily be adapted to utility-controlled remote switching systems when the latter are adopted by Hydro-Québec and Ontario Hydro.

In the short-term: (1) consumers can convert to hybrid heating at very little expense and use electricity, which is cheaper than oil, for most of their needs; (2) Hydro-Québec and Ontario Hydro will increase their sales substantially at off-peak times when surplus electricity can be generated inexpensively; (3) Canadian oil imports will decrease significantly, as will the associated oil import compensation payments; and (4) Hydro-Québec and Ontario Hydro will not have to increase the size of their generating plant to meet steeper demand peaks.

In the longer run: (1) the Quebec consumer will benefit from preferential off-peak rates for electricity; (2) Hydro-Québec and, if it chooses, Ontario Hydro will be able to eliminate all space heat-related demand peaks; (3) Canadian oil imports will decrease further; and (4) pressures on capital markets from Hydro-Québec and Ontario Hydro should be less than would otherwise have been the case.

The natural gas industry, of course, stands to lose to electricity an important part of the gains it had expected to make in the Quebec and Ontario residential space heating markets. This is a problem which will have to be addressed.

As a result of the greater efficiency in use of Canada's energy systems, electric/oil hybrid heating will help to keep down the price of energy in Canada relative to other countries, and thus will contribute to the industrial sector's competitive stance and enhance our ability to penetrate foreign markets. This advantage is possible largely because of the availability in Canada of substantial amounts of cheap, baseload electricity: it can therefore only be shared by countries which are similarly endowed, favouring us over most of our competitors in foreign markets.

In short, the early and widespread adoption of electric/oil hybrid space heating for Canadian homes would: (1) help achieve national energy security and self-sufficiency by rapidly reducing Canada's dependence on imported oil (plenum heaters back out some 80 to 95 per cent of the oil previously burned); (2) relieve the federal treasury of the burden of substantial oil import compensation payments (and ultimately the federal government of the need to levy the monies for these payments); (3) enable electric utilities to increase sales significantly from existing plant; (4) delay the need for investment in new electricity generation, transmission and distribution facilities; (5) help keep down the cost of space heating to consumers, *provided* off-peak rates are set at appropriate levels; (6) provide industrial opportunities for Canadian manufacturers of electrical products; and (7) give a comparative advantage to Canadian industry in the competition for world trade through the lower energy prices that would accompany the more efficient use of electrical generation systems. However, hybrid heating could result in lost sales for natural gas producers and utilities if new markets for natural gas were not developed, and could also mean reduced economic activity in the industries supporting natural gas distribution.

In short, based on the best available cost projections, experimental data and actual tests, it is the conclusion of this study that electric/oil hybrid systems, of the various space heating alternatives, offer the greatest energy efficiency and financial benefits for Canada.

APPENDIX I

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF NEWFOUNDLAND

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 1,600 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) electricity in hybrid systems: 1979, 70 per cent

(c) Specific provincial limitations on use of hybrids:

Actual off-peak potential from Newfoundland Power undetermined at present. The island of Newfoundland uses a combination of hydro and thermal (mostly oil-fuelled) plant. There may be limits on the hydro capacity beyond those shown here. However, there are already plans for a major intertie between Labrador and the island of Newfoundland, making possible the use of the abundant capacity and potential of Labrador on the island.

(d) Comments:

Province is heavily dependent on oil — 77 per cent of all secondary energy. Electric potential is calculated on basis of inter-connected grid only (i.e. does not include Labrador-based plant dedicated to out-of-province use).

FIGURE 17

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN NEWFOUNDLAND, 1979-80

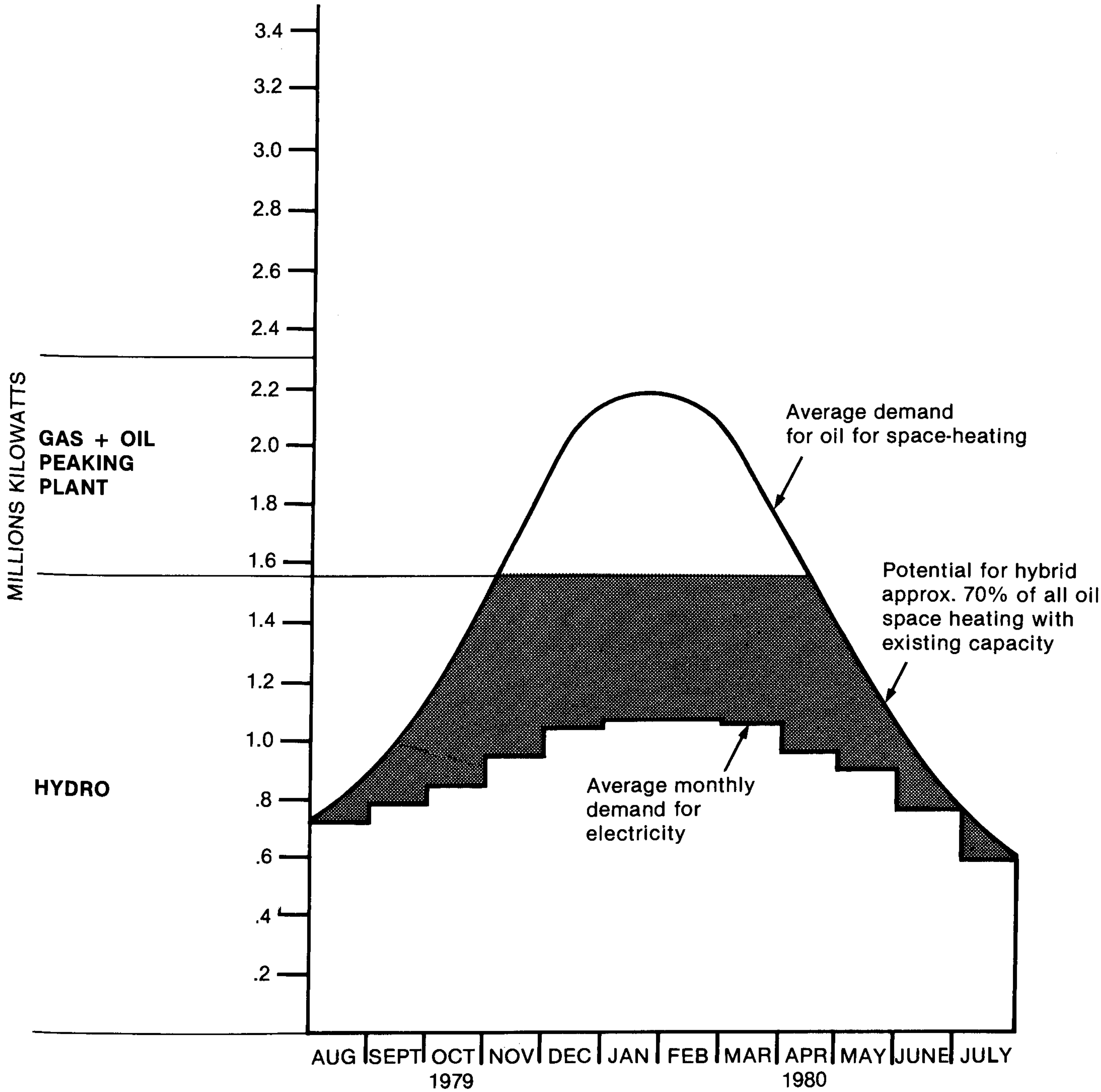
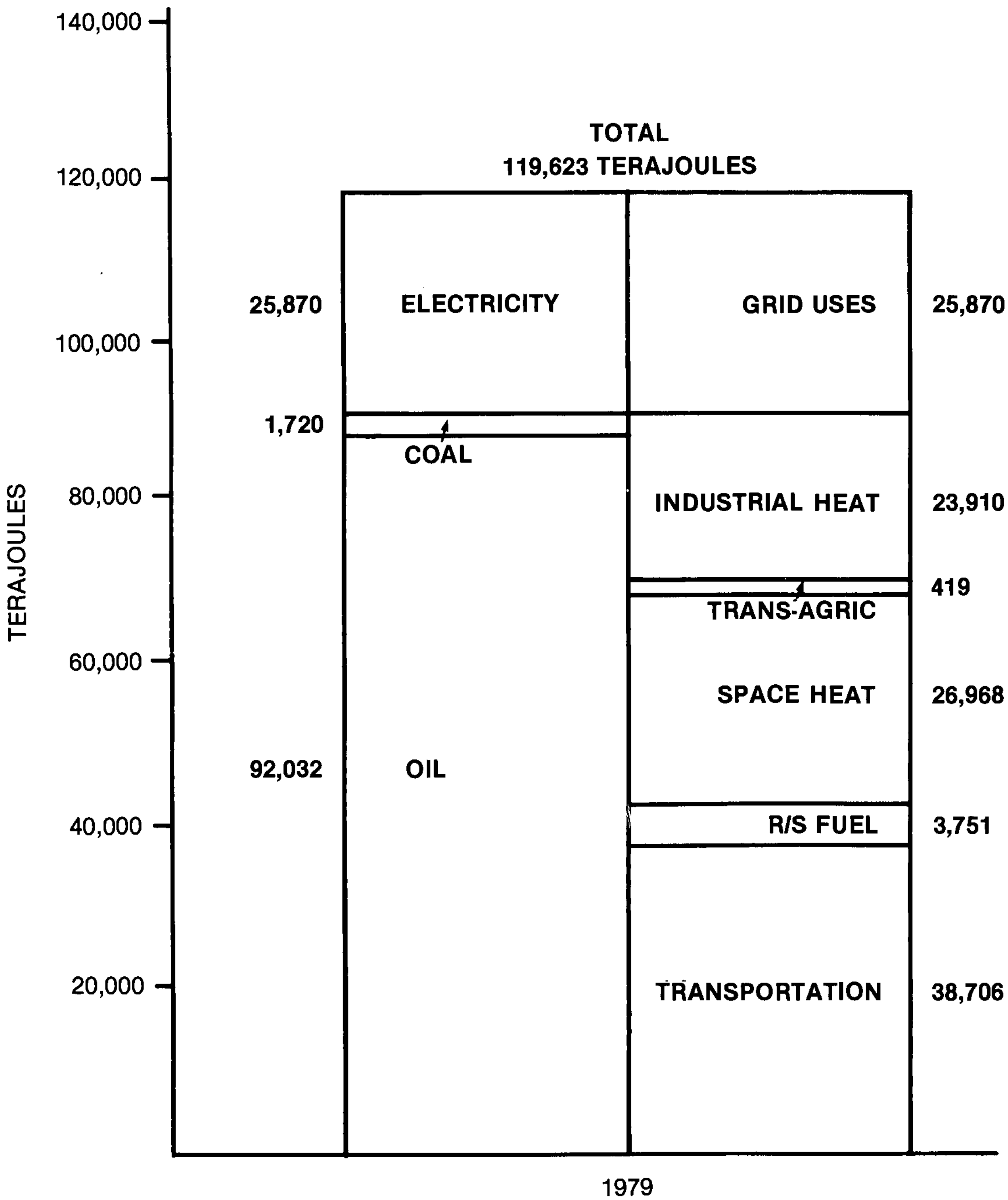


FIGURE 18

NEWFOUNDLAND'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX II

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF NOVA SCOTIA

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 850 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) electricity in hybrid systems: 1979, 11 per cent

(c) Specific provincial limitations on use of hybrids:

Province has oil-fuelled baseload plant which could progressively be converted to coal-fuelled plant suitable for hybrid heating.

(d) Comments:

Province is 78 per cent secondary-energy-dependent on oil.

FIGURE 19

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN NOVA SCOTIA, 1979-80

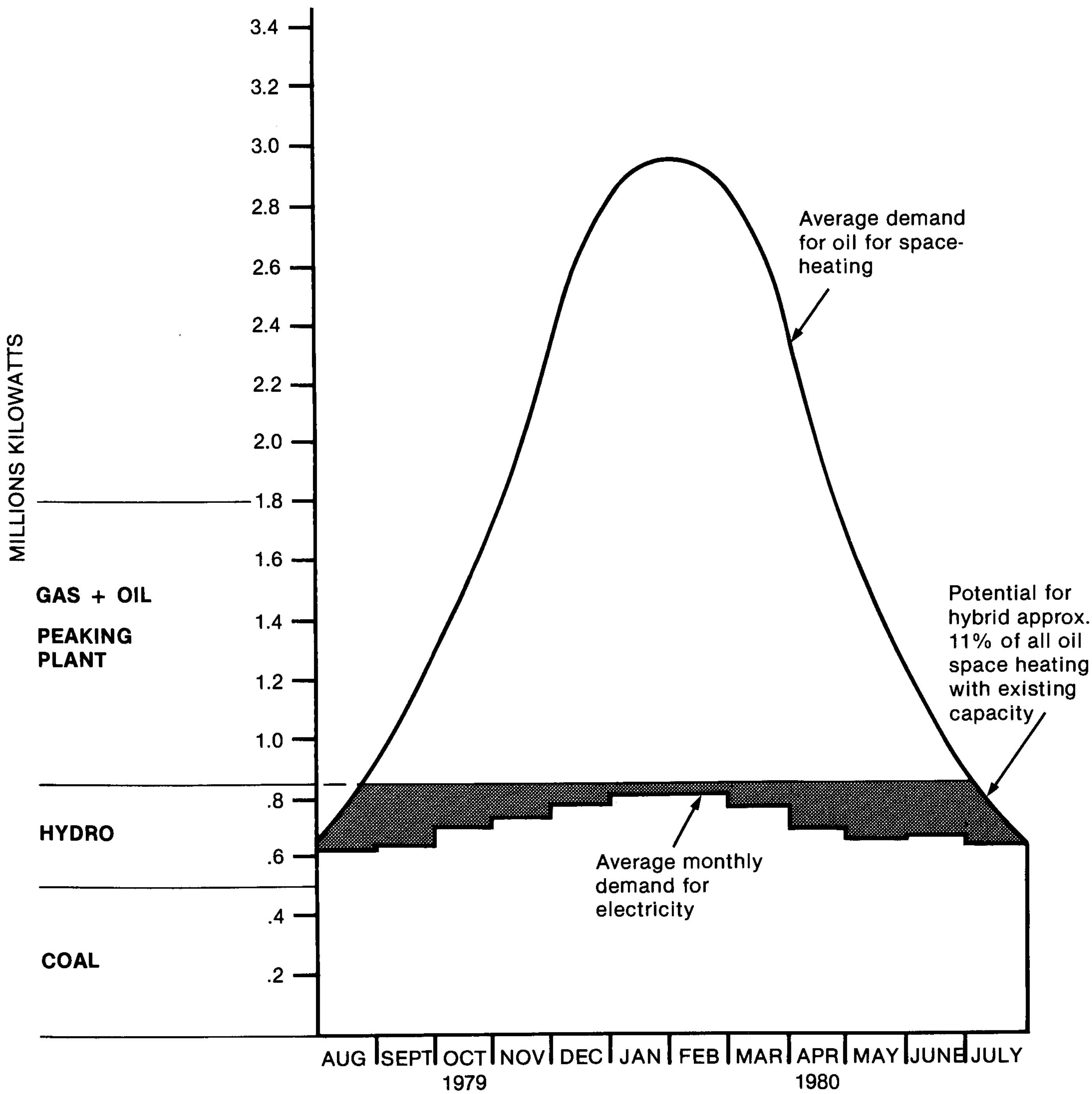
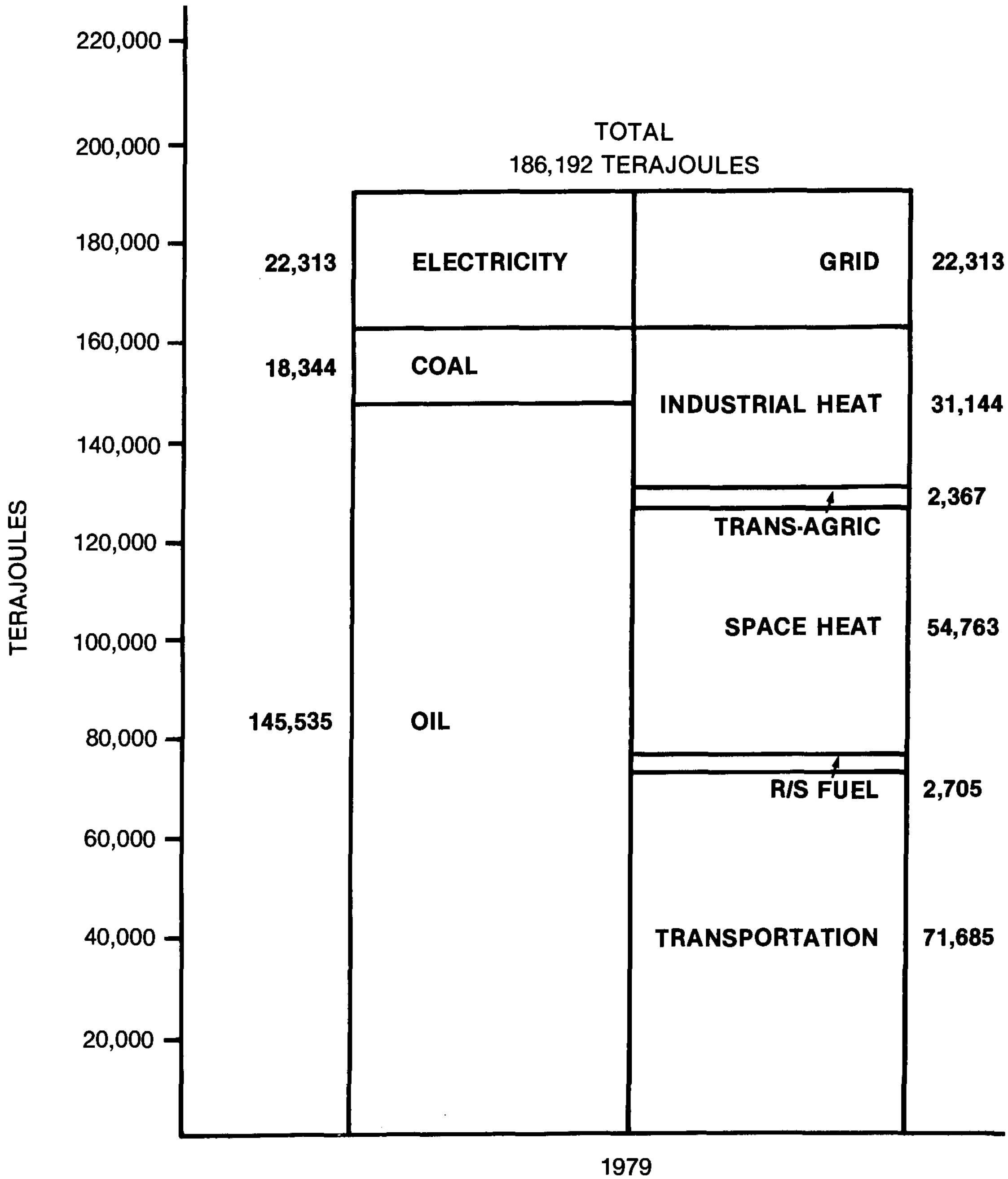


FIGURE 20

NOVA SCOTIA'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX III

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF NEW BRUNSWICK (INCLUDES PRINCE EDWARD ISLAND)

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 1,100 M.W.

(b) proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) electricity in hybrid systems: 1979, 18 per cent

(c) Specific provincial limitations of use of hybrids:

Although the province had inadequate non-oil fired baseload capacity in 1979, additional baseload from the Point Lepreau CANDU reactor will significantly enhance hybrid potential. In March, 1983, the reactor had reached 95 per cent of its capacity. In addition, New Brunswick Power has recently converted its largest oil-fired plant to coal firing. These factors have improved the 1983 potential of hybrid heating to probably 80 per cent.

(d) Comments:

Province is currently heavily dependent on oil — 82 per cent of secondary energy.

FIGURE 21

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN NEW BRUNSWICK 1979-80

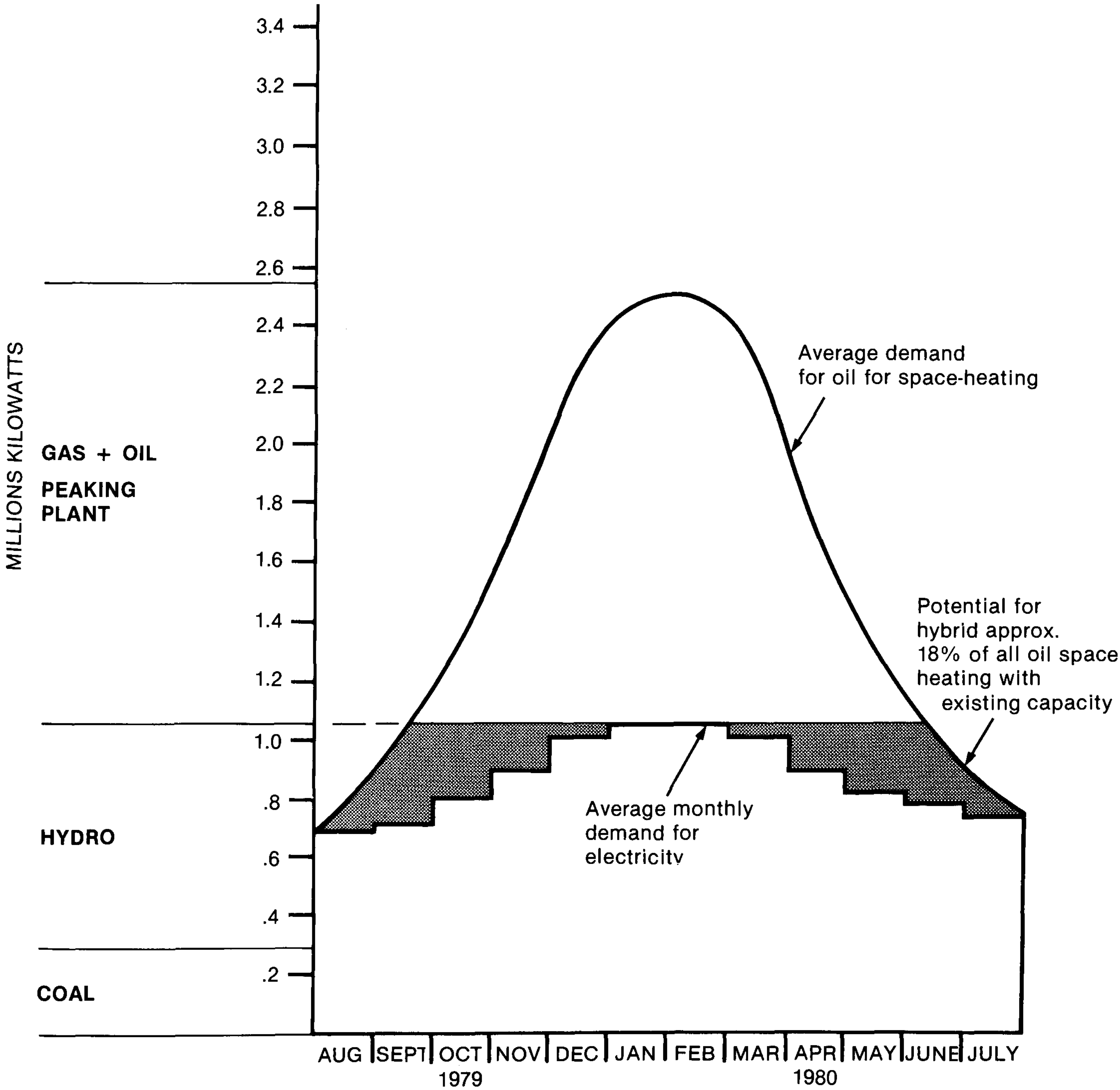
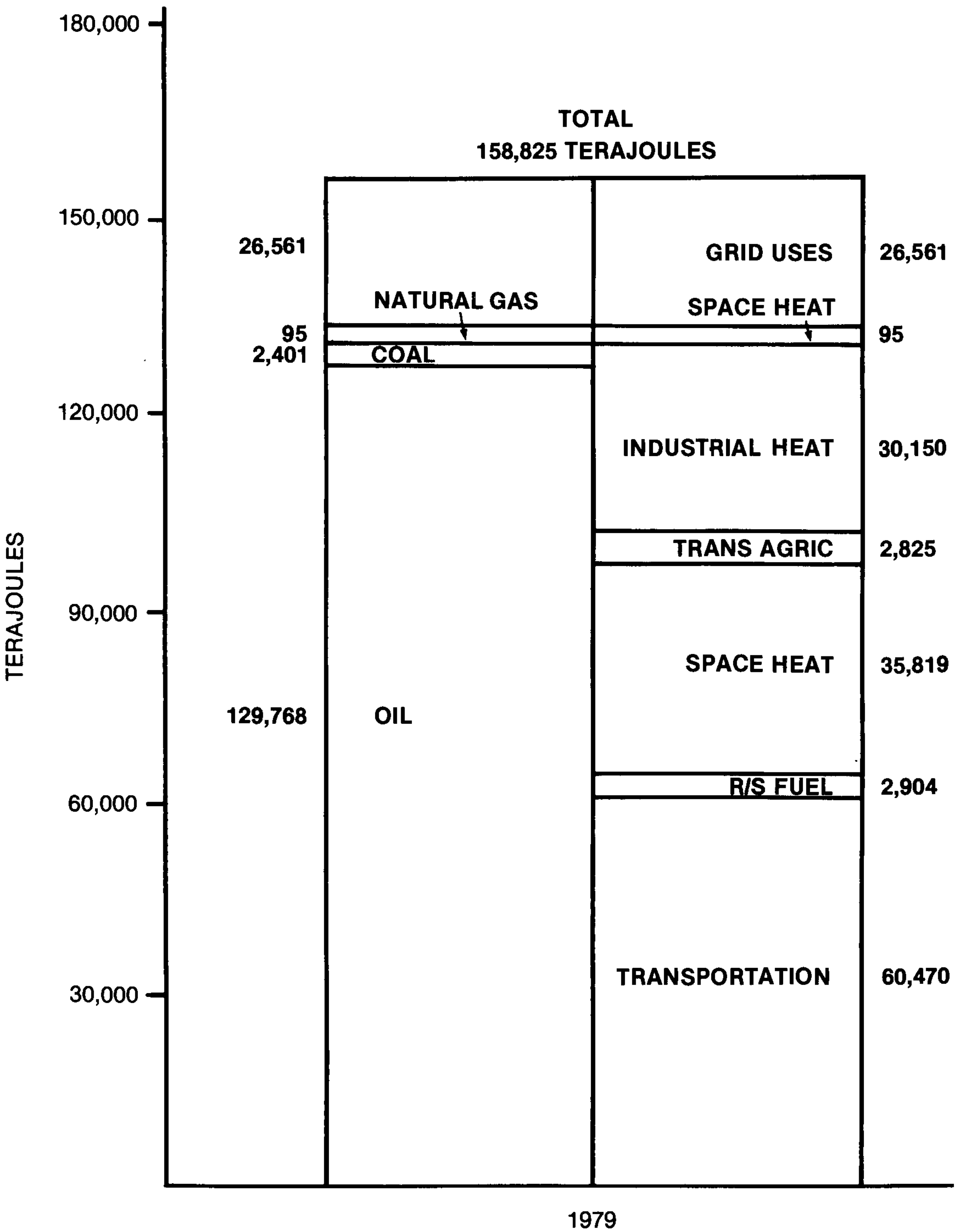


FIGURE 22

NEW BRUNSWICK'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX IV

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF QUEBEC

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 19,000 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) in hybrid systems: 1979, 75 per cent.

(c) Specific provincial limitations on use of hybrids:

Hydro-Québec is ideally placed to employ hybrid ("bi-énergie") systems, having substantial off-peak potential from its large water storage reservoirs.

(d) Comments:

Utility has established a major incentive program for hybrid heating involving non-taxable grants of up to $650 which, in combination with grants available under the federal COSP program, effectively offset conversion costs to zero. Hydro-Québec has also developed an experimental rate structure for a Hybrid II-type system — Rate "E". Several manufacturers of hybrid heating equipment that have met CSA approval are located in Quebec. Several tens of thousands of applications have been received by Hydro-Québec for its "Bi-énergie" program, which is widely regarded as a very successful initiative.

APPENDIX V

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF ONTARIO

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 21,500 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) in hybrid systems: 1979, 90 per cent

(c) Specific provincial limitations on use of hybrids:

Utility will be adding more baseload (CANDU) plant to its capacity, which will reduce the cost of power to hybrids in the long run.

(d) Comments:

Utility has numerous active hybrid heating experiments throughout the province and has just announced a program to encourage consumers to convert from oil to electric/oil hybrid heating. This program provides a non-taxable grant of $200 (over and above the federal COSP grant) to offset conversion costs. By establishing its own specifications for plenum heaters and acting as prime contractor, Ontario Hydro has, in effect, fixed conversion costs at $1,040 per installation. The resulting immediate out-of-pocket cost to the consumer is only $320.

APPENDIX VI

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF MANITOBA

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 4,000 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) in hybrid systems: 1979, 96 per cent

(c) Specific provincial limitations on use of hybrids:

Generally, provincial utility has substantial water storage capacity behind dams for baseload operation, but much off-peak power is sold to other electric utilities. As well, power is purchased from other electric utilities at times of peak demand.

(d) Comments:

An investigation of Manitoba Hydro's interties and their impact on hybrid heating has been done by a Winnipeg consulting firm for the MOSST project. Their findings have been included in this report.

FIGURE 23

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN MANITOBA, 1979-80

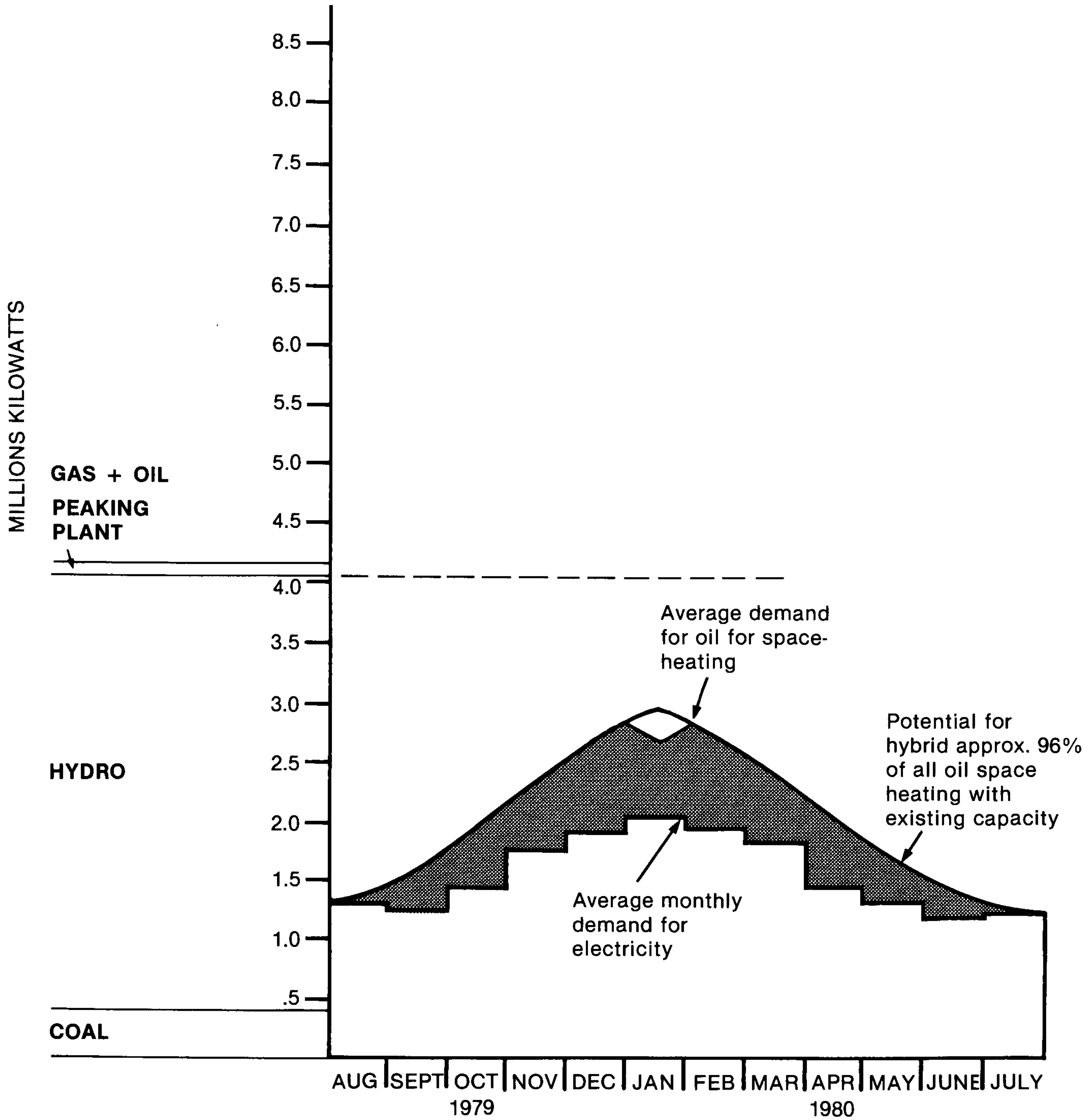
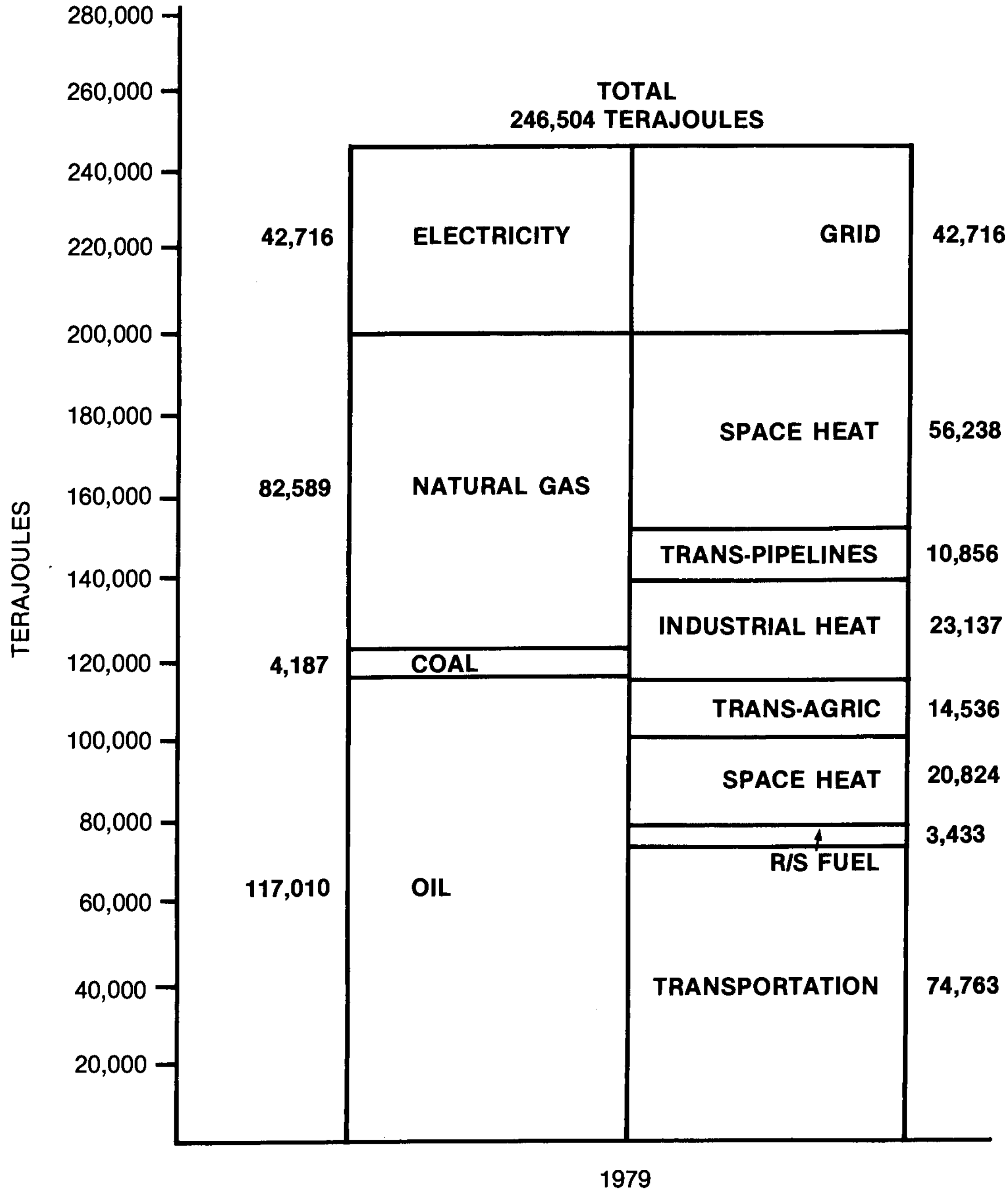


FIGURE 24

MANITOBA'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX VII

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF SASKATCHEWAN

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 1,700 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) in hybrid systems: 1979, 70 per cent

(c) Specific provincial limitations on use of hybrids:

Much of urban Saskatchewan is space heated by low-cost natural gas, although many oil-heated buildings remain in rural areas.

(d) Comments:

Saskatchewan Power and Light is interested in hybrid heating, and is keeping up-to-date with the activities of other utilities in this area.

FIGURE 25

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN SASKATCHEWAN, 1979-80

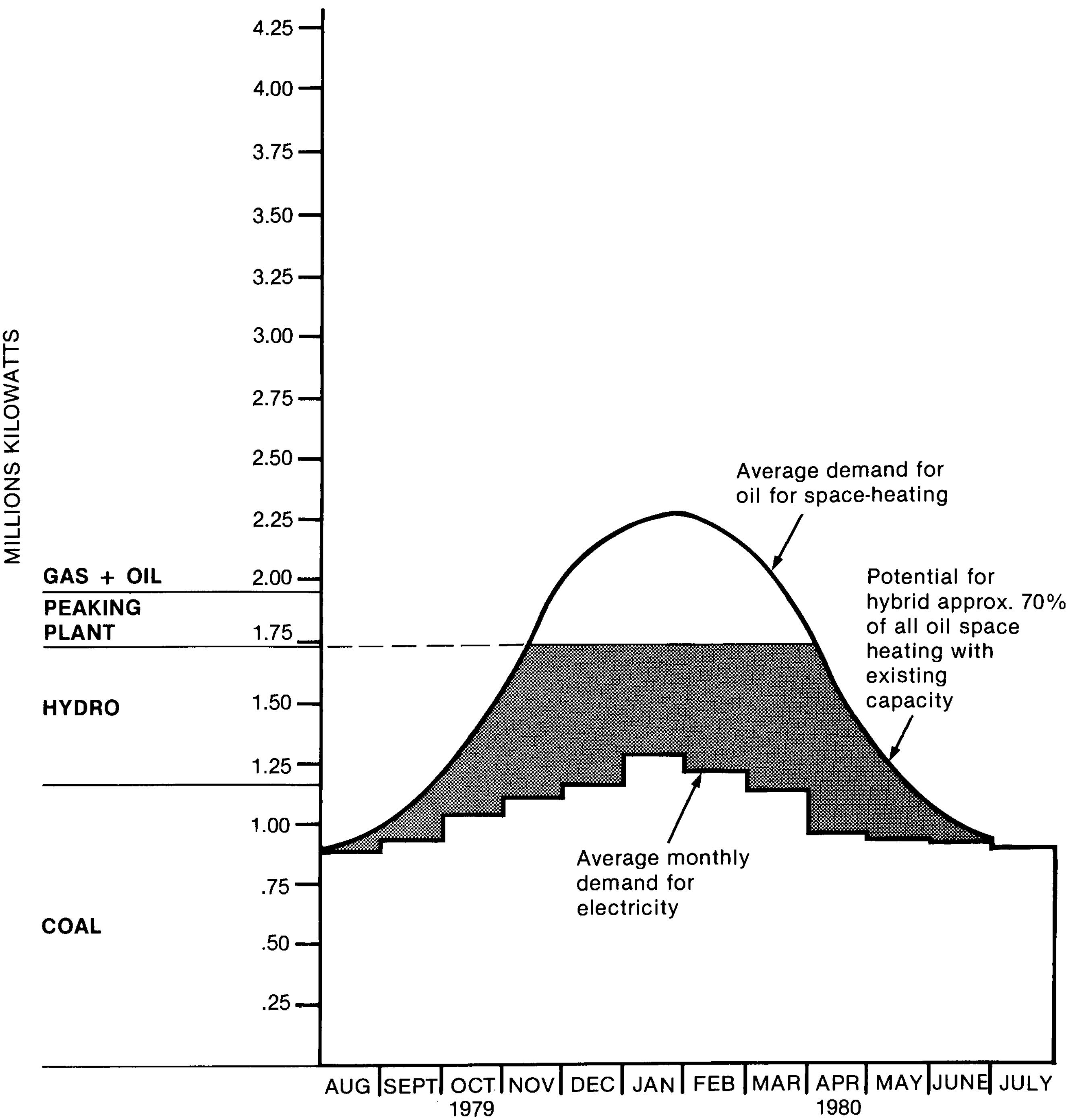
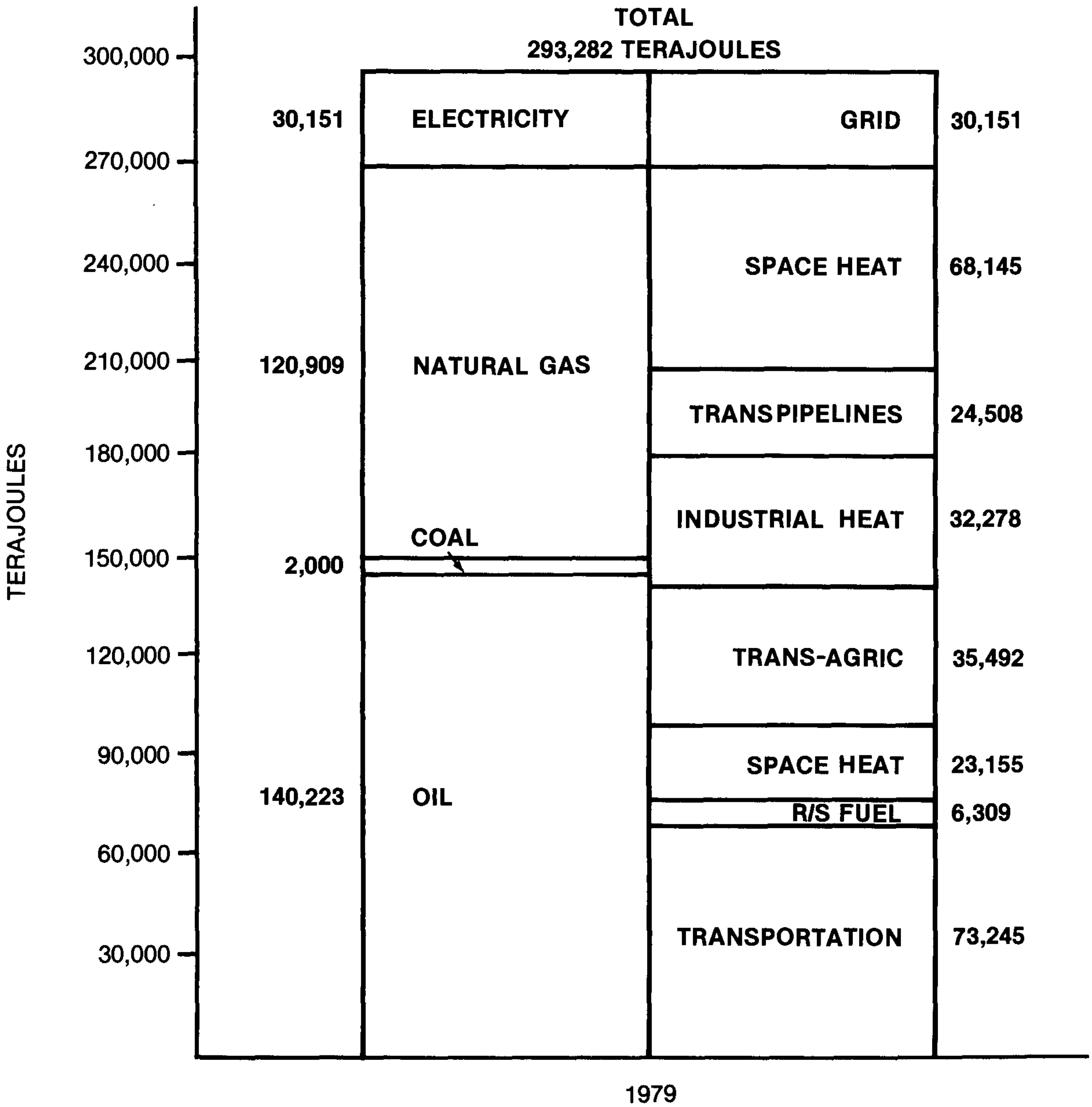


FIGURE 26

SASKATCHEWAN'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX VIII

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF ALBERTA

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 3,500 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) in hybrid systems: 1979, 90 per cent

(c) Specific provincial limitations on use of hybrids:

Much of Alberta is space heated with low-cost indigenous natural gas.

(d) Comments:

In the more distant future, Alberta could acquire baseload generating plant that would enable the province to employ hybrid heating to stretch its indigenous fossil-fuel reserves.

FIGURE 27

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN ALBERTA, 1979-80

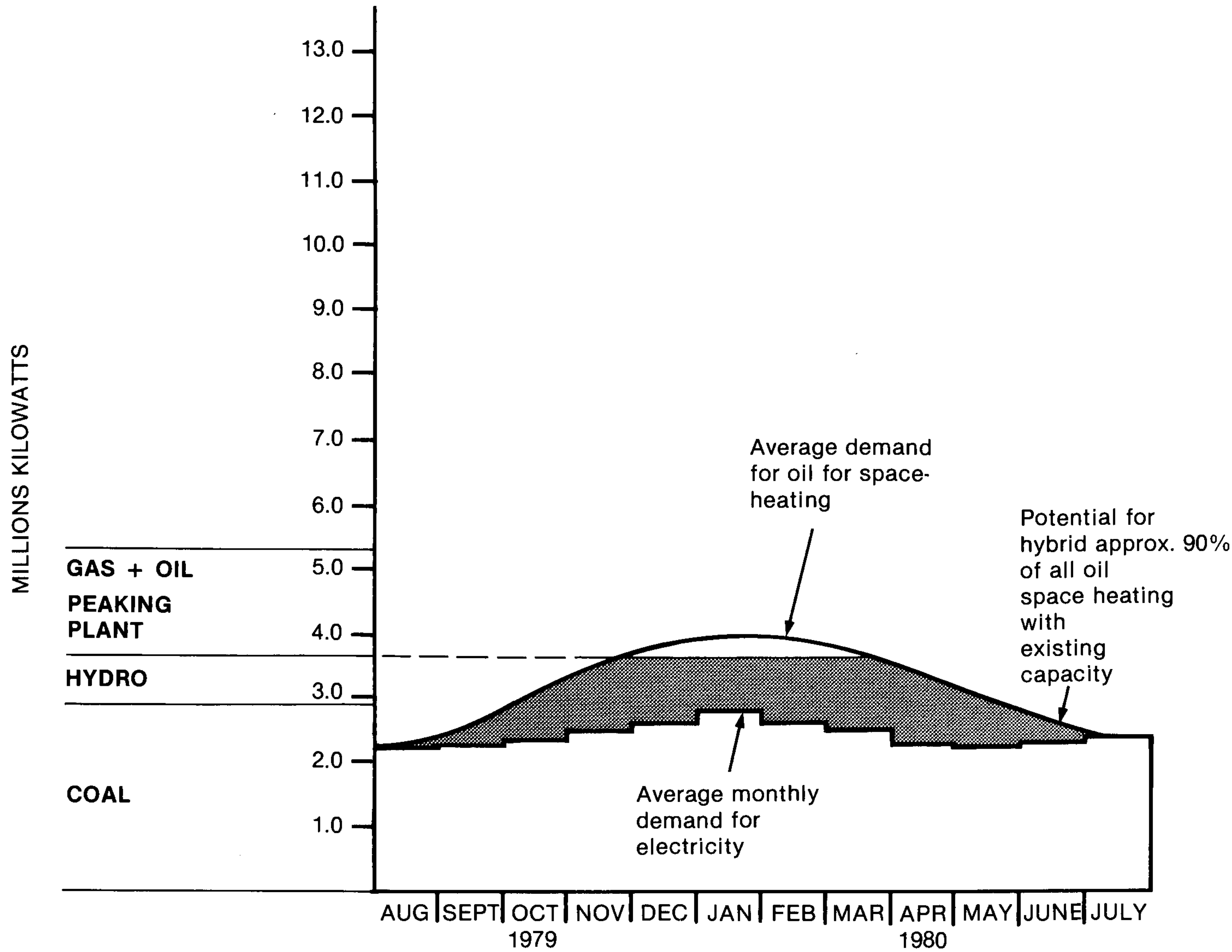
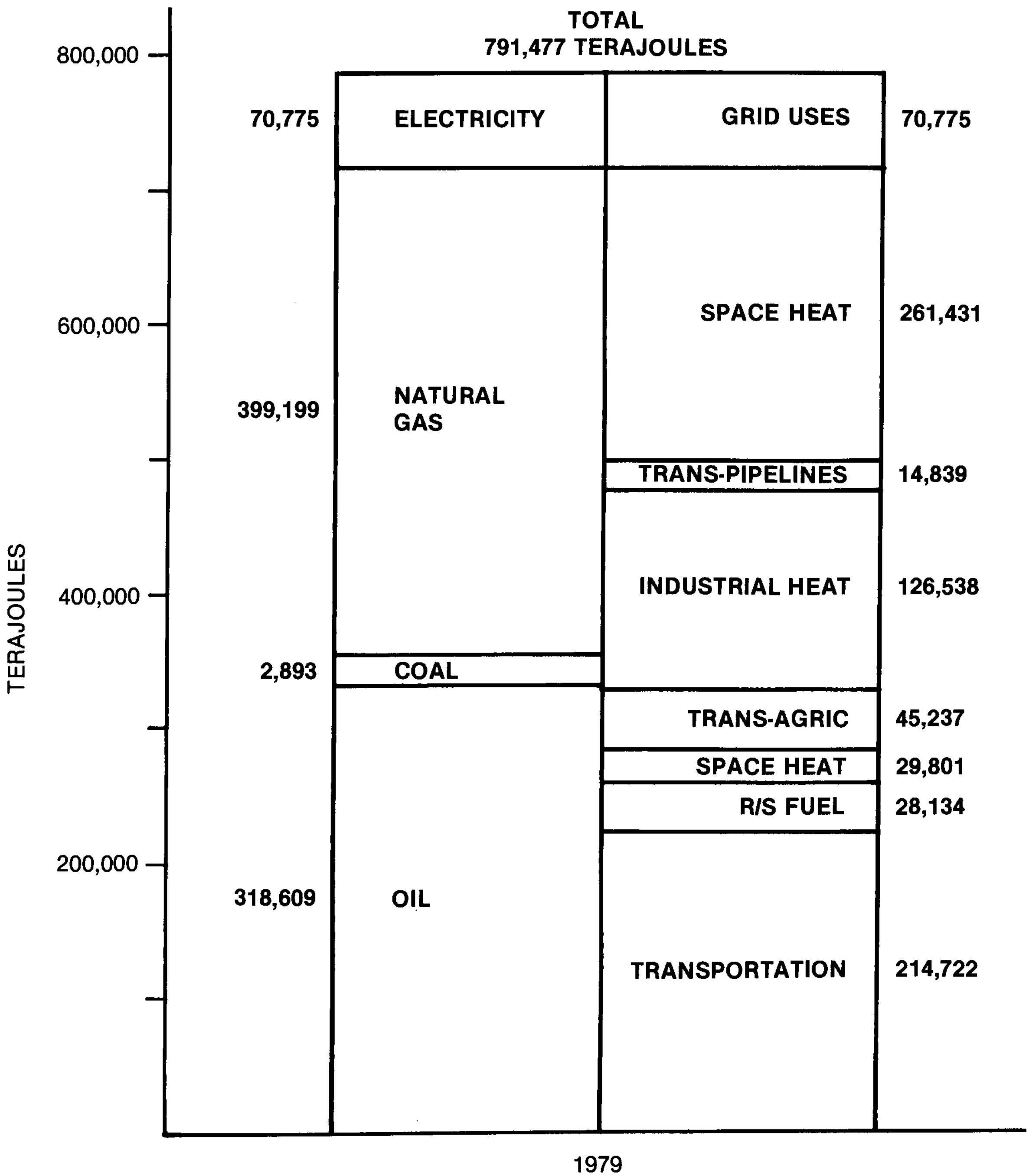


FIGURE 28

ALBERTA'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX IX

THE ELECTRIC HYBRID POTENTIAL IN THE PROVINCE OF BRITISH COLUMBIA

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant): 6,100 M.W.

(b) Proportion of total oil space heating that could be met by baseload (i.e. non oil- or gas-fired plant) in hybrid systems: 1979, 96 per cent

(c) Specific provincial limitations on use of hybrids:

British Columbia has had water stream-flow constraints. This could recur. This would favour the adoption of hybrids to provide back-up fuel in years of drought. CANDU technology could avoid this problem.

(d) Comments:

The mild climate of much of British Columbia's urban regions may make heat-pumps an attractive option. Vancouver Island would be a particularly attractive possibility for hybrid heating because space heating is provided chiefly by oil, at present. Experimental work has begun under a project funded as part of MOSST research.

FIGURE 29

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN BRITISH COLUMBIA, 1979-80

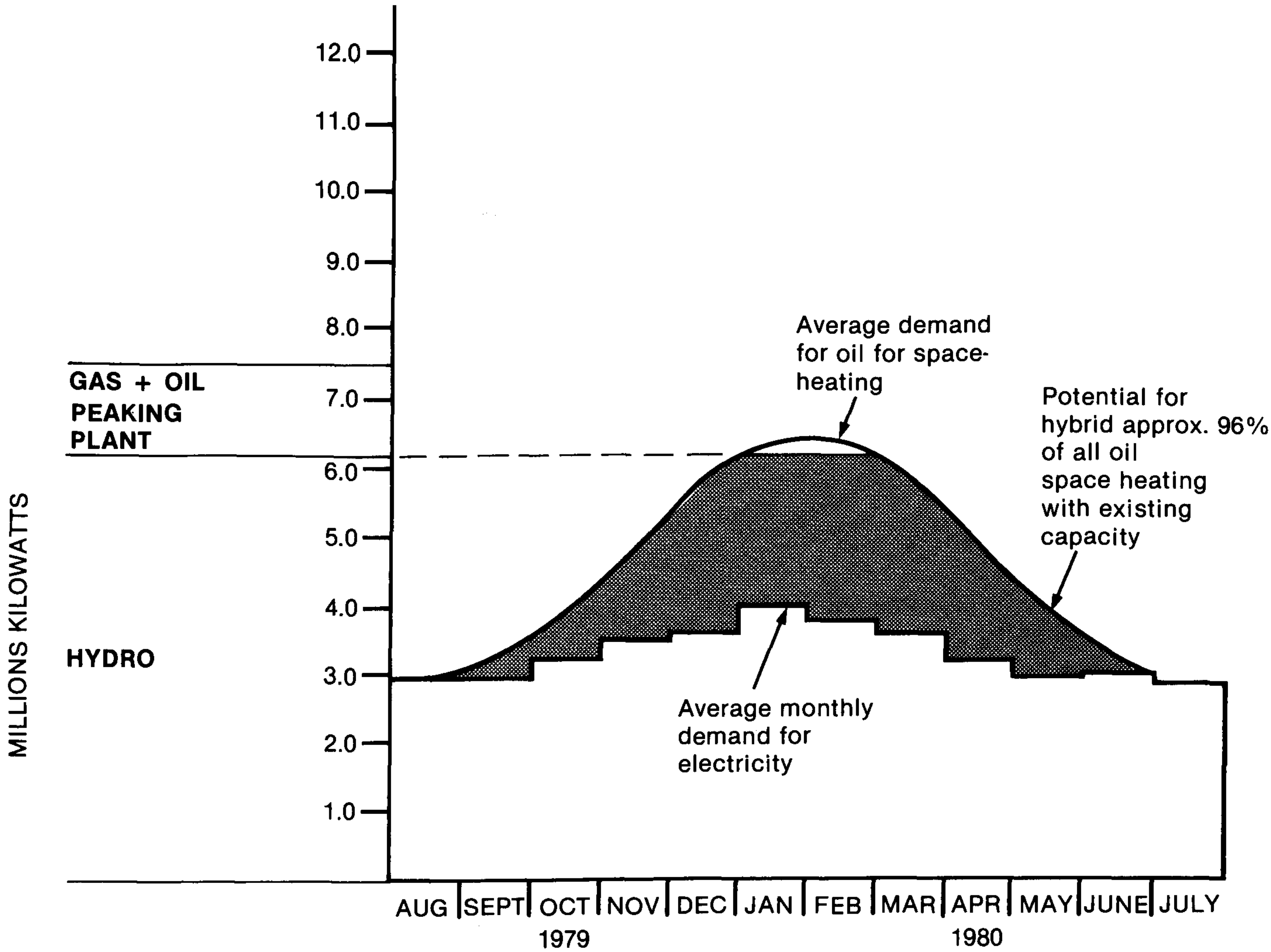
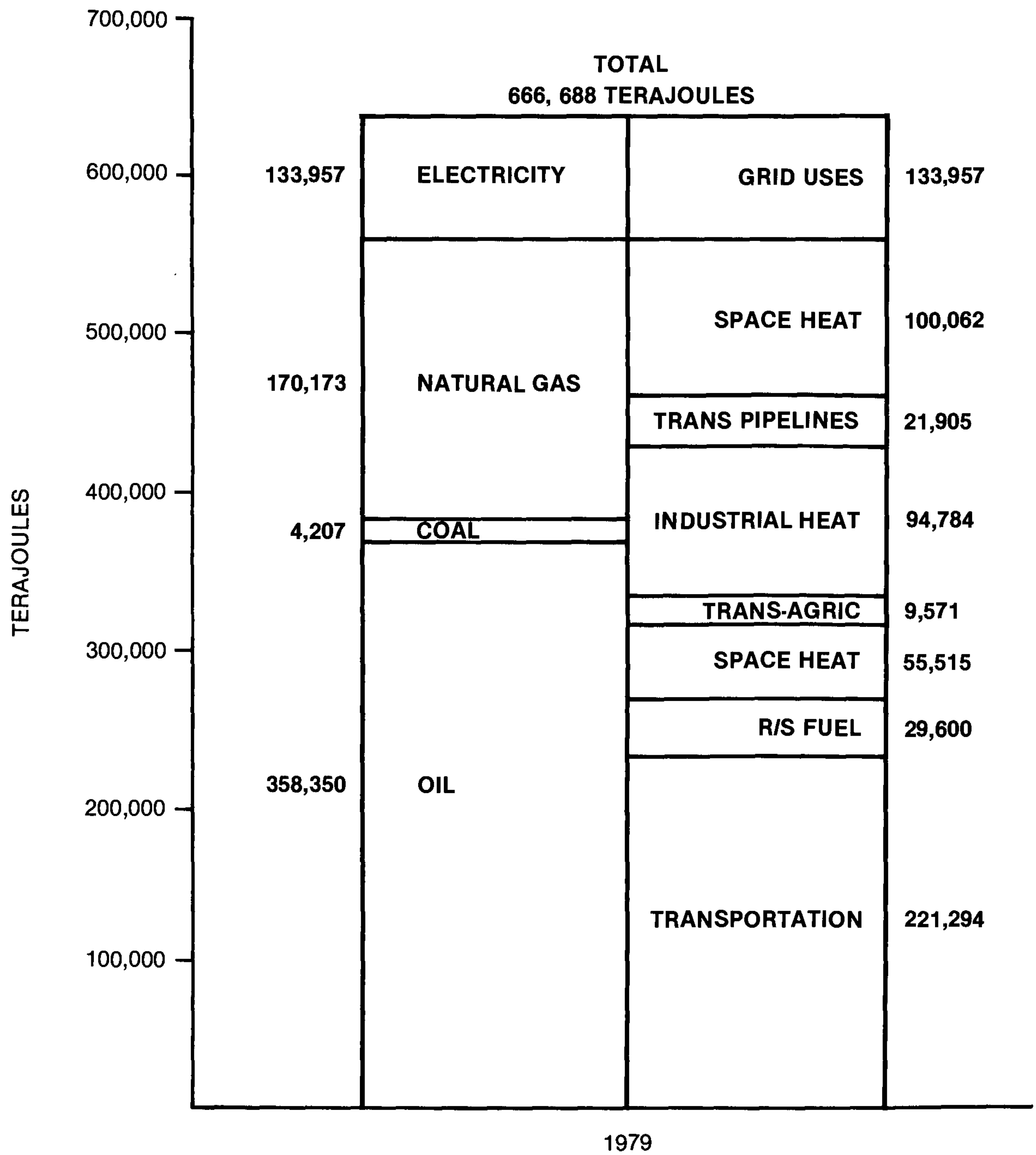


FIGURE 30

BRITISH COLUMBIA'S END-USE ENERGY SUPPLY AND DEMAND BALANCE



APPENDIX X

THE ELECTRIC HYBRID POTENTIAL IN THE TERRITORY OF THE YUKON

(a) Electric generating plant, 1979
(excluding oil and gas peaking plant)
Connected grid only: 58 M.W.

(b) Proportion of total oil space heating that could be met by electricity in hybrid systems (regions served by connected grid only): 1979, 45 per cent

(c) Specific provincial limitations on use of hybrids:

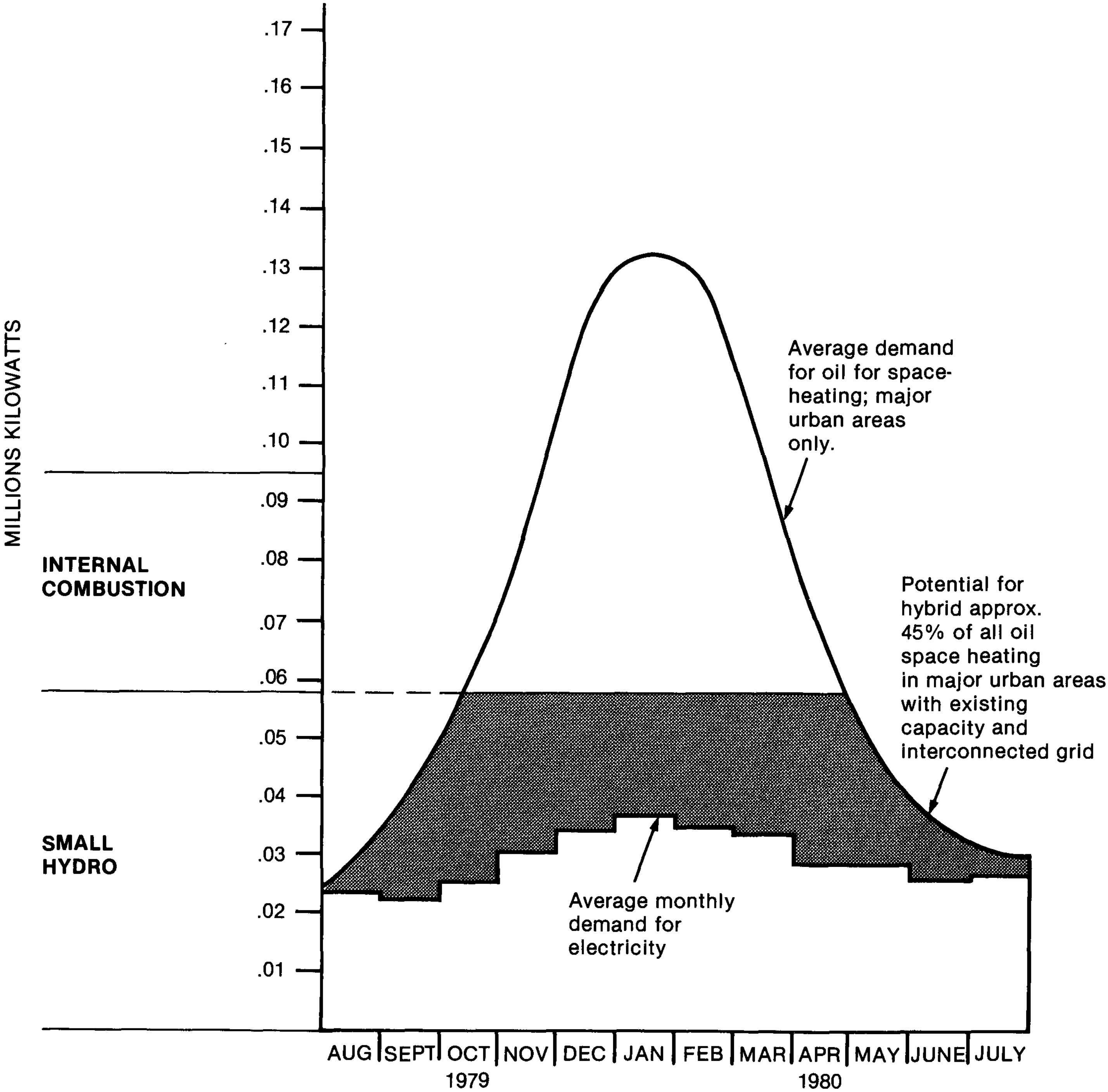
Only a relatively small part of the territory has a connected grid using non-oil or gas generating plant (hydro). This could be increased, but because of sparse population, it would be very expensive.

(d) Comments:

Territory heavily dependent on oil. Hybrid system applicable to the area, but connected grid would need to be expanded at considerable expense.

FIGURE 31

HEATING POTENTIAL OF OIL/ELECTRIC HYBRID IN YUKON TERRITORY: MAJOR URBAN AREAS (INTERCONNECTED GRID) ONLY



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