A Comparison of Hybrid Heating Systems and New Generation Facilities for Peak Electricity Load Management

K.F. SOLLOWS, P.Eng.,
U.K. SUMATHIPALA, P.Eng., and
J.E.S. VENART, P.Eng.

This paper presents a preliminary evaluation of hybrid heating systems as an electric load-management tool for Canadian utilities, based on an analysis of data for the Province of New Brunswick. In comparison to all-electric systems, the study indicates that hybrid heating systems offer many advantages: they are less costly when peak electricity generation is provided by combustion turbines; they can eliminate the need for new peak generating capacity within the 15 year planning horizon of the utility; the higher energy conversion efficiency of hybrid systems reduces oil consumption, and CO_2 and SO_X emissions; and they can be produced, installed and maintained locally, unlike the major components of power plants and many of their installation and maintenance services, which are imported. The constraints upon implementation of the technology are also discussed. A demand management leasing scheme, in which the utility leases the hybrid heating technology from the customer, is described. It offers political and public relations advantages over more traditional cost allocation schemes and ensures the long-term availability of the technology.

Fondé sur une analyse de données provenant du Nouveau-Brunswick, l'article présente une évaluation préliminaire des systèmes de chauffage mixtes en tant qu'outil à la disposition des entreprises canadiennes productrices d'électricité pour gérer la puissance appelée. Cette étude montre que, comparativement aux systèmes de chauffage électrique intégrés, les systèmes de chauffage mixtes offrent de nombreux avantages: leurs coûts d'exploitation sont moindres dans les cas où la production d'électricité de pointe est assurée par des turbogénérateurs à combustion; ils peuvent éliminer le besoin d'accroître la capacité de production de pointe pendant la période de quinze ans représentant l'horizon de planification de l'entreprise productrice; du fait de leur plus grande efficacité de conversion énergétique, les systèmes mixtes réduisent la consommation de produits pétroliers et l'émission de dioxyde de carbone et d'oxydes de soufre; la production, l'installation et l'entretien de ces systèmes peuvent être faits localement, à l'opposé des centrales électriques, dont les principaux éléments doivent être importés ainsi que beaucoup des services d'installation et d'entretien. L'article expose également les contraintes relatives à la mise en application de cette technologie. Il décrit un plan de location pour la gestion de la demande d'électricité en vertu duquel l'entreprise productrice prendrait en location le matériel de chauffage mixte du client. Par rapport aux plans plus traditionnels de répartition des coûts, ce plan présente des avantages politiques et de relations publiques et assure la disponibilité à long terme de la technologie.

K.F. Sollows is an engineer with the Division of Mathematics, Engineering and Computer Science at the Saint John Campus of the University of New Brunswick. U.K. Sumathipala and J.E.S. Venart are engineers with the Fire Science Centre at the University of New Brunswick in Fredericton.

1. Introduction

Increasing public concern for the environmental, social and financial/economic impact of new electrical generation and transmission facilities has made demand-side load management an attractive option for many utilities. The objective of load management is to reduce the demand for power at times of peak electrical use. By increasing the average utilization of the utility's generating and distributing plant, and reducing the requirement for additional peak generating and transmission capacity, load management can reduce the average cost of electricity. An appropriately designed and managed peak-load management system operates with no customer inconvenience.

Much recent effort, by utilities and others, has successfully focused upon passive energy conservation measures, such as increased insulation of buildings, that tend to reduce energy demand. Such measures lead to a reduction in the total load that the utility must service and can reduce the rate at which new capacity must be added to the utility's grid. Considerable attention has also been directed to the use of advanced heating systems employing air or water source heat pumps. These also reduce the total demand for energy, but they have some drawbacks when

Energy Studies Review Vol. 3, No. 2, 1991 Printed in Canada

compared with other conservation measures. For thermodynamic and/or economic reasons, heat pump heating systems are normally designed to meet only a fraction of the peak heating demand. The excess heating energy demand that occurs on colder days is often met using electric resistance heaters. Unfortunately, this causes the electrical power demand for space heating to increase when the utility's aggregate demand is peaking and the marginal cost of electricity is high.

A hybrid (two-fuel or bivalent) heating system is potentially a more effective measure with which to manage electricity demand in the residential and commercial sectors. In this system, electricity is used for space heating when the utility's load is moderate, and fossil fuel is used to replace electrical energy during periods of peak electrical demand. While the configuration of hybrid systems may vary from building to building, a furnace containing both electric resistance coils and fossil fuel burning capacity is typical and is the basis for the calculations reported on here.

Nelson (1980, 1985) reported on the Minnkota Power Cooperative's experience with a hybrid system operating under the utility's direct control. He reported typical load reductions of 10 kWe per residential installation, and indicated that they were used in place of combustion turbine power plants. Clayton (1984) presented a review of the potential for hybrid systems in Canada on a provincial basis. He concluded that hybrid systems "...offer the greatest efficiency and financial benefits of the various space heating alternatives."

One government-owned electric utility currently estimates that electric space heating contributes 1064 MW to their peak annual load (NB Power, 1991a). This is 40% of the total peak-load and is attributable to approximately 150,000 customers. The average peak generation load is therefore 7.1 kW per customer. Approximately 50,000 residential customers were converted from oil to electric heat during the last decade, and the utility forecasts that 4 400 residential electric heat customers will be added in each of the next 15 years. These two groups, and commercial customers, represent a large potential market for hybrid heating systems.

The utility's current plans rely on combustion turbines for new peak power generating capacity. A careful assessment of a hybrid heating alternative to these plans is therefore appropriate at this time.

2. Cost Comparison

2.1 Introduction

A total cost methodology is used to compare all electric and hybrid heating in this paper. These costs are taken to include oil consumption, and CO_2 and SO_2 emissions, in addition to the economic costs of the physical plant, fuel, maintenance and operations. Nitrous oxide (NO_X) emissions and other environmental considerations are excluded from the present analysis. The hybrid heating system is assumed to be switched between oil and electricity under the utility's direct control, and the estimated cost of the required control system is included in the analysis.

An oil-fuelled hybrid system is examined because the same fuel is burned in combustion turbines, and the alternatives should therefore experience similar fuel price adjustments. Hybrid heating systems that burn propane or compressed natural gas offer some significant advantages over oil: reduced CO_2 and SO_2 emission, reduced risk of groundwater contamination, conservation of liquid fuels, lower equipment costs and lower cost of conversion to distributed natural gas, should it become available. The evaluation of these fuels is beyond the scope of this paper.

Hybrid heating systems are only available to manage electricity demand during the heating season. This can make direct comparison with generation plant difficult, because the generation option is available for use throughout the year. In the particular case under consideration, however, this problem should not arise. Figure 1 illustrates the monthly variation in peak and average electrical load. It is clear that periods of peak demand occur during the winter months. The relevant sections of the utility's most recent

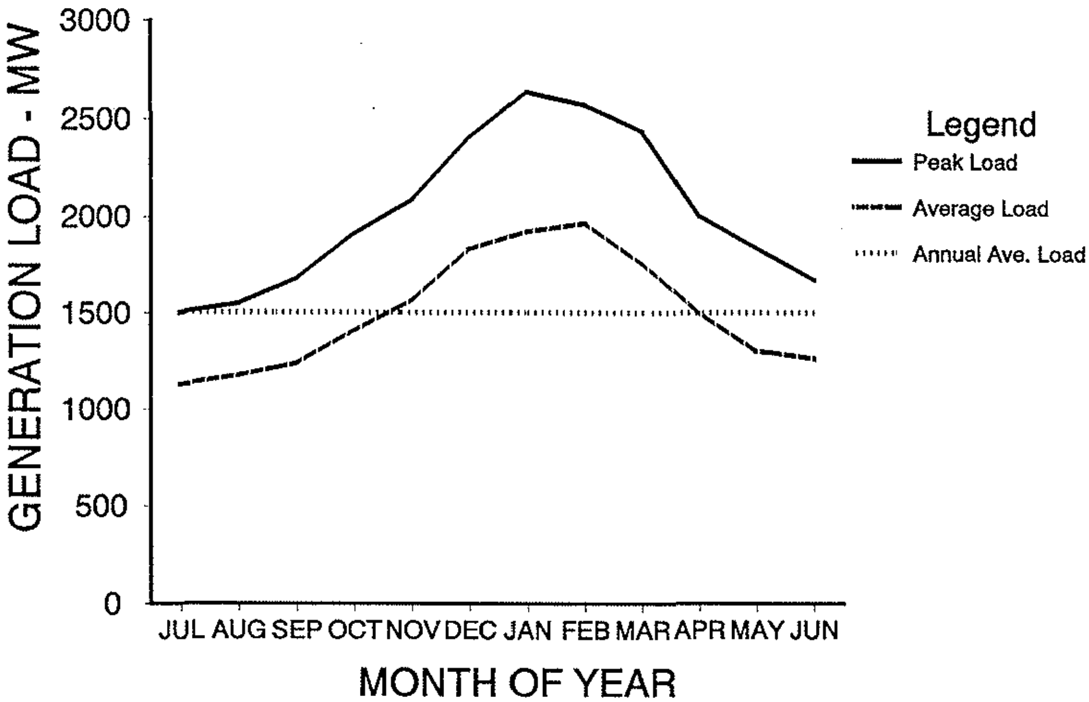

Figure 1: In-Province Electric Loads.
Source: NB Power, 1990a

Load and Resources Review (NB Power, 1990a) also indicate 500-600 MW surplus capacity, in excess of that required for regular maintenance, during the summer months.

2.2 Assessment Parameters

The main assumptions of the analysis are listed in Table 1. These are intended to represent the characteristics of an average space heating customer. They are not intended to represent any particular class or type of customer. They are likely to be typical of a larger single family dwelling, but reflect lower space heating requirements than those of a typical commercial customer.

The 'Installed Capacity' describes the size of the heating system, and is used to estimate its capital cost. Newer, energy efficient homes would imply smaller installations and commercial systems could be much larger.

The 'Peak-Coincident Heating Load' is significantly lower than the 'Installed Generation Capacity' for a number of reasons. The typical daily variation in temperature leads to higher heating loads at night, when excess generating capacity is often available. Heating systems are also "oversized" to permit temperature recovery from periods of low temperature operation, such as night set-back of the thermostat. As long as the thermostats of different customers continue to operate independently of one another, these factors combine with weather variations to produce a load diversity that limits the total peak power demand to a value that is lower than the total installed heating system capacity.

The 'Peak-Coincident Generation Requirement' due to electric space heating was provided by the utility. The generated power is reduced by the transmission losses to estimate the space heating load. The generation load is

Table 1: Heating System Parameters

Description	All-Electric	Hybrid
Installed Capacity (kW electric/oil)	15/0	15/22
Peak-coincident (kW):		
Heating Load	6.0	0.3
Generation Requirement[1]	7.1	0.35
Installed Generation Capacity[2]	8.5	0.42
Annual Energy (kWh)	17,500	17,500
Fraction at Peak (%)	15	15
Energy Conversion Efficiency (% - oil to space heating):[3]		
Peak-load	29	70
Base-load	35	35
Fuel Oil Cost ($/L)	0.25	0.38
Base-Load Electricity Cost ($/kWh)[4]	0.0456	0.0456

1/ Includes an 18% transmission loss per utility data.
2/ Includes a 20% reserve margin per utility policy.
3/ Combined conversion and transmission efficiency.
4/ Current run-out electricity rate is used.

increased by the reserve margin to estimate the total installed generation capacity required to meet this space heating demand. For the hybrid system, the peak-coincident electrical load is estimated at 5% of the all-electric load.

Fifteen percent of the 'Annual Energy' consumption for space heating is assumed to be provided by the peak management system.

The 'Energy Conversion Efficiencies' listed in Table 1 are used to estimate the annual fuel consumptions and costs. They represent the combined efficiency of generating, transmitting and distributing the energy. Roughly 30% of the base-load energy is derived from oil, and the base-load conversion efficiency is used to estimate the resource impact of this oil use. The cost of peak-coincident energy is estimated from efficiency and price data. The current marginal rate for residential electricity sales is used to estimate the cost of base-load electricity.

2.3 Natural Resource Cost

The data of Table 1 are combined with typical values for the physical properties of the fuels to estimate the resource impact of all-electric and hybrid heating. The results of these calculations are presented in Figure 2. The small contribution of coal-source base-load energy to atmospheric emissions is not included.

Hybrid space heating demonstrates a lower resource impact than all-electric heating. Its high, peak-energy conversion efficiency reduces distillate fuel oil consumption by 54%, saving 450 litres per customer-year. The use of residual fuel oil is the same for both systems. The lower use of distillate oil by hybrid heating leads to a 22% reduction in total CO_2 emission and a 5% reduction in total SO_2 emission,[1] as compared with all-electric heating.

2.4 Economic Cost

CAPITAL COST AND SERVICE LIFE

The capital costs of the various heating system components are summarized in Table 2, along with estimates of their service lives. The cost estimates for baseboards/controls, wire, flue and fuel tank are derived from an American source (Mahoney, 1990). They were adjusted downwards to roughly account for the lower labour costs in Atlantic Canada. The net effect of this adjustment is a 4% reduction in the estimated system capital cost. The tabulated costs demonstrate a clear advantage for hybrid heating, which manages the peak demand with a 38% lower initial cost.

The service life estimates of Table 2 are drawn from various sources. A zero salvage value is assumed for each component at the end of its life.

1/ The bulk of the SO_2 emissions are attributable to the use of high-sulphur (2.75%) residual fuel oil to generate base-load electricity. The low-sulphur (0.3% to 0.5%) distillate fuel oil that is burned to meet peak energy requirements generates less than 10% of the total SO_2 emissions, even for all-electric space heating. Hybrid heating only reduces this small fraction of the total SO_2 emissions in proportion to the reduction in fuel consumption.

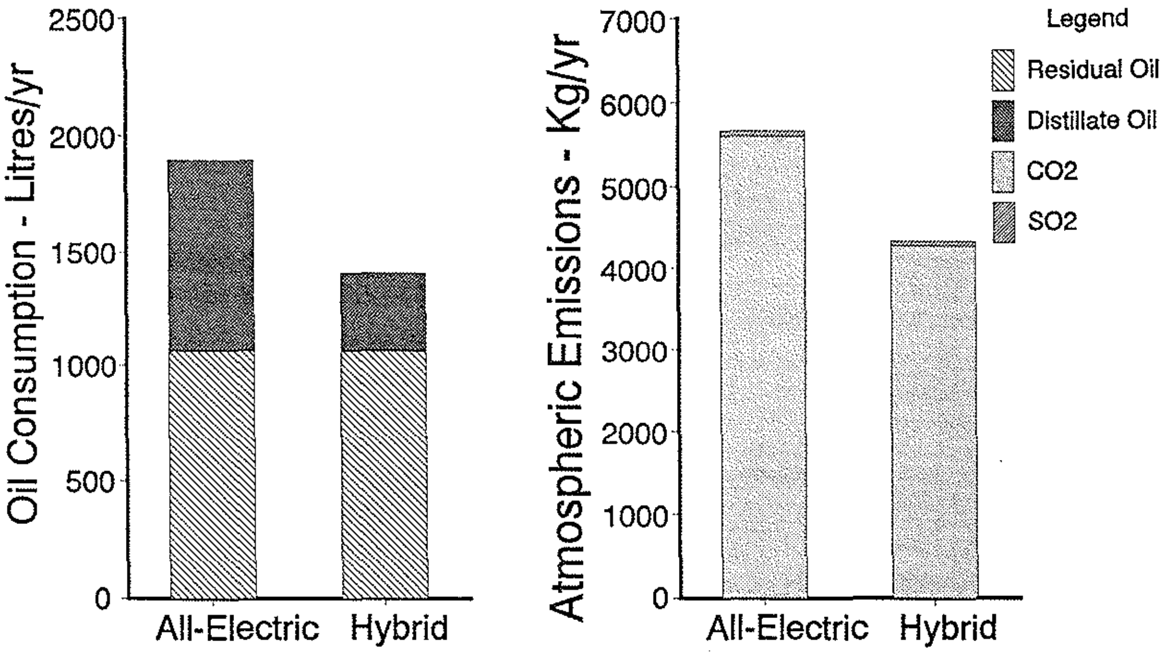

Figure 2: Annual Resource Impact of a Single Space Heating Customer

The annual cost of each component is the annual payment necessary to recover its capital cost during its service life, plus interest at 10%.[2] The sum of these component costs is $1017 per customer-year for all-electric systems and $637 per customer-year for hybrid systems.

The distribution of these capital costs is illustrated in Figure 3. The ducts and flue together represent 36% of the cost of the hybrid system. For that portion of the existing housing stock that has these components in serviceable condition, it would cost approximately $400 per customer-year to convert to hybrid heating.

ENERGY COST

The annual energy cost is computed in two parts. The cost of the base-load electricity for space heating is approximately $680 per customer-year for both systems. The cost of distillate fuel oil that is burned in the combustion turbine for all-electric heat is $208 per customer-year. To meet the same peak demand with the hybrid system, the

2/ The annual cost approach is used in preference to a net present value analysis because it facilitates comparison without estimating end-of-period salvage values or component replacement costs. A net present value analysis of a multi-component system requires that the salvage value of each component be estimated at the end of the analysis period, even if the assumed salvage value of the component is zero at the end of its life. Similarly, the cost of any components that require replacement during the present value analysis period must be estimated. The additional uncertainty that such estimates introduce requires detailed consideration that is left to a later analysis. We note that current utility assessments of hybrid heating are based upon the present value methodology of Seelke (Seelke, 1982; Brockman, 1990; NB Power, 1991b). This method estimates the present value of the annual generation costs that are avoided by a load management investment. It assumes that the generation capacity investment is **deferred** for the service life of the demand management system rather than considering that the capacity is **replaced**. The difficulty that arises when Seelke's technique is applied to hybrid heating lies in the selection of an appropriate deferral life. If, for example, a hybrid system life of 15 years is assumed, then only the oil tank and controls of the hybrid system are at their (assumed) zero salvage value. All of the remaining components have a residual value that must be considered. Failing to explicitly consider these residual values can severely distort the comparison between the generation and demand management alternatives, because Seelke's method implicitly includes the residual value of the supply-side option.

Table 2: Capital Cost and Service Life Data for All Electric and Hybrid Heating

Description	Cost ($)	Life (Yrs)	Annual Cost[1] ($/Yr)
All-Electric System			
Gas Turbine[2]	5277	25	581
Transmission Facilities[3]	2128	45	216
Baseboards/Controls[4]	1170	20	137
Wire[4]	780	30	83
Total	9355		1017
Hybrid System			
Gas Turbine[2]	264	25	29
Transmission Facilities[3]	106	45	11
Furnace[5]	2200	18	268
Ducts[6]	1500	30	159
Flue[7]	660	30	70
Fuel Tank[8]	355	15	47
Central Control[9]	400	15	53
Total	5845		637

1/ Calculated using the specified cost and service life and a real interest rate of 10%.
2/ Gas turbine cost is the product of installed generation capacity and the utility's reported cost for facilities currently under construction: $620 per kW. The service life is that proposed by the utility for future plants; their current depreciation life is 20 years.
3/ Transmission cost is the product of the peak-coincident generation capacity and the utility's reported cost of the facilities: $250 per kW. The service life is the utility's depreciation life: 45 years.
4/ The cost of electric baseboards, thermostats and wiring is estimated at $130 per kW (Mahoney, 1990). The total cost is apportioned 60% to baseboards/thermostats and 40% to wiring. The 20 year service life of baseboards/controls was selected with reference to reported estimates of: 13 years for electric unit heaters, 10 years for electric radiant heaters, 15 years for electric boilers and coils and 16 years for electric controls (ASHRAE, 1987). The life of the wiring is that used for the ducts in the hybrid system.
5/ Hybrid furnace cost is the manufacturer's suggested retail price; such equipment is generally available at discount prices that should roughly compensate for the cost of delivery and installation. The service life is that of an oil furnace (ASHRAE, 1987).
6/ Cost is based upon local quotations for installation in a new single-story home or an existing home with an unfinished basement; service life is from ASHRAE (1987).
7/ Cost is based on a flue length of 20 ft. and published data (Mahoney, 1990); service life is that of ducts.
8/ Cost is from Mahoney (1990); service life is estimated for local conditions.
9/ Cost estimates for other utilities range from $200 to $500 per unit (Sollows, 1991); service life is that of electronic controls (ASHRAE, 1987).

fuel cost is $131. The cost of fuel for the peak-coincident electricity (pump and fans) used by the hybrid system is estimated to be $10 per customer-year. The annual fuel cost estimates are thus $888 per customer for all-electric heating and $821 per customer for hybrid heating.

OPERATION AND MAINTENANCE COSTS

The non-fuel cost of operating and maintaining (O&M) the gas turbine plant is derived from the utility's estimate of $1 million for a 150 MW plant in 1994 dollars (Brockman, 1990). This is discounted at 5% per year for 4 years to yield $5.50 per kilowatt in 1990 dollars. The O&M costs of the transmission capacity, electric baseboards, thermostats and wiring are not included in the analysis.

The O&M cost of the hybrid heating option is also the utility's estimate: $82 per customer-year (NB Power, 1991b). This is taken as representing the cost of a maintenance contract for the furnace burner and the electronic controls.

TOTAL COST

These annual cost estimates are summarized in Table 3. Hybrid heating exhibits lower capital and energy costs and higher O&M costs than all-electric heating. In total, hybrid heating saves $412 per customer-year, a 21% reduction in the annual total cost.

The hybrid system exhibits lower costs for both equipment and energy. Escalation of these cost components will therefore improve the economics of hybrid heating, relative to the all-electric option. It is only the O&M costs that offer an advantage to all-electric heating, and the savings ($35 per customer-year) are only 8% of the savings generated by hybrid heating in equipment and energy costs. We also note that the higher O&M cost for hybrid heating largely represents service industry employment within the province.

2.5 Sensitivity Analysis

The results of this cost analysis are sensitive to both the estimated peak-coincident heating load and the estimated capital cost of the hybrid heat-

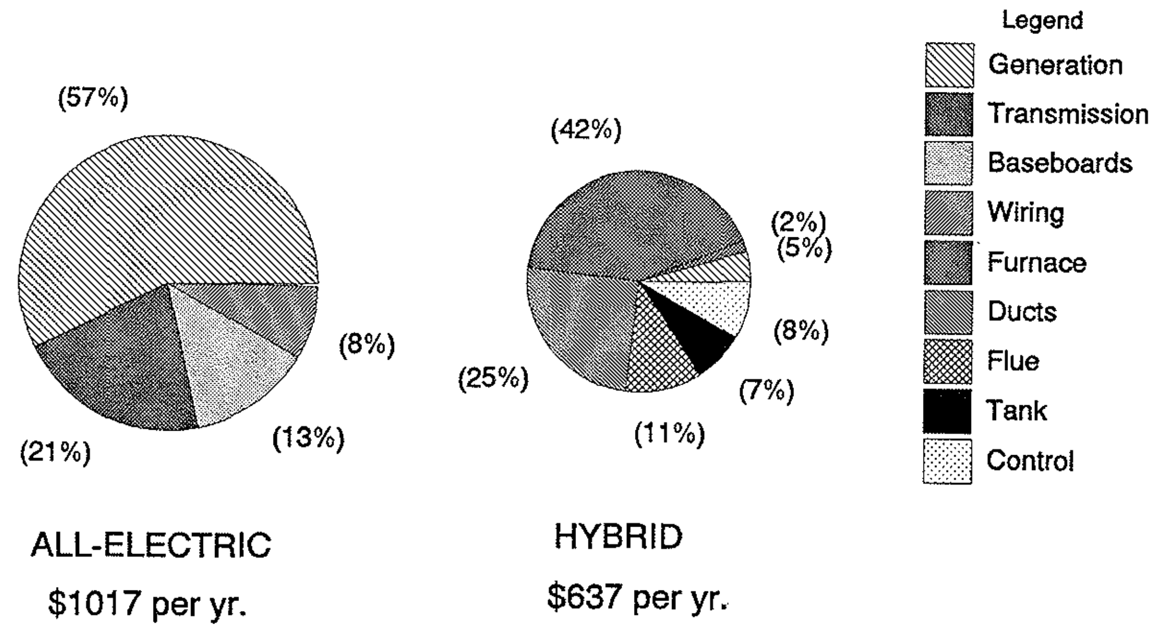

Figure 3: Distribution of Capital Costs for Peak Management Options

ing system, which were 6.0 kW per customer and $5485 per customer, respectively. As well, discounted cash flow analyses are well known to be sensitive to the choice of parameters. The impact of the uncertainty inherent in these estimates must be examined.

PEAK COINCIDENT LOAD

The cost of all-electric heating is sensitive to the peak space heating load because of the high cost of installing and operating the necessary electrical generation and transmission capacity. The cost of hybrid heating is much less sensitive to this parameter. The 6.0 kW average space heating load represents both residential and commercial customers, but commercial space heating customers are few in number and large in size. Consequently, more than half of the customers are expected to exhibit below-average space heating loads. (In statistical terms, the median is less than the mean because the distribution of heating loads is skewed.) The minimum load at which hybrid heating is cost effective is therefore of interest.

This break-even point occurs at 2.9 kW of space heating load, or 3.4 kW of generating load, above which the hybrid option offers lower economic costs. Such a low peak-coincident heating load might reasonably be expected of individual units in recently constructed apartment buildings. The economic assessment of such applications requires further, more detailed, analysis.

CAPITAL COST

The annual cost of hybrid heating is similarly sensitive to its estimated installed cost, and the greatest uncertainty in this cost is that associated with the heat distribution system. The $1500 used in this analysis is the quoted cost of installing ducts in a new, one-story home or an existing home with an unfinished basement. Since the installation of hybrid systems in multilevel and other existing homes could be much more expensive, the maximum installed cost at which hybrid heating is cost effective is also of interest.

This break-even point occurs at $9400 total system installed cost, of which $5400 is associated with the heat distribution system. Hybrid heating remains economic as long as the initial costs remain below these values.

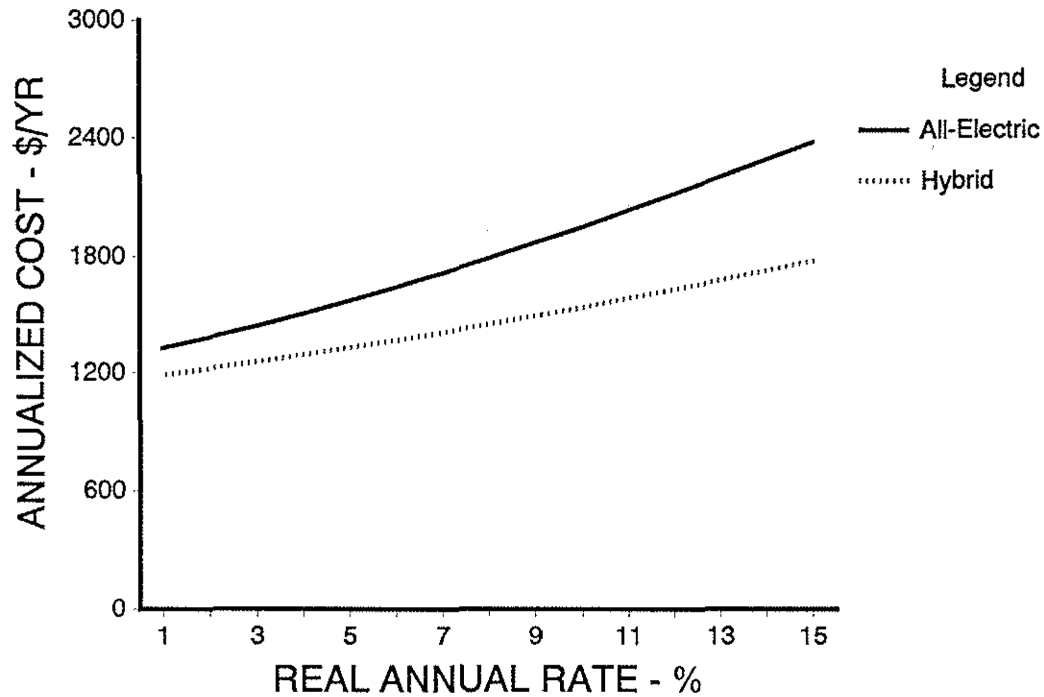

Figure 4: Annual Cost Variation with Interest Rate

FINANCIAL ANALYSIS

The assumptions of a financial analysis can, in general, have a profound impact upon its outcome. For example, when future costs vary inversely with capital costs, as is common with energy projects, the value selected for the discount rate can change the relative ranking of the options. (High discount rates favour low capital cost, high operating cost options). In this case, the chosen discount rate does not affect the ranking because hybrid heating has both lower capital costs **and** lower operating costs. Thus, in this analysis, the hybrid system remains less costly than all-electric heating at every discount rate (Figure 4).

The Organization for Economic Cooperation and Development, in their study *The Projected Costs of Generating Electricity from 1995-2000* (OECD, 1989), states that most utilities in member countries use a discount rate of 5%; they go on to say that a 10% discount rate illustrates the opportunity cost of capital in industry generally. This higher discount rate is used in this analysis.

The sensitivity of the annualized cost to changes in the discount rate is illustrated in Figure 4. At the 5% rate, hybrid heating saves $240 per customer-year. This represents a 16% reduction in the total annual cost of providing space heating, in comparison with the all-electric option.

2.6 Net Cost to Utility

The above analysis indicates that hybrid heating is preferable to all-electric heating on a total cost (utility + consumer) basis. It is therefore appropriate to examine the net cost, to the utility, of the peak management alternatives. An electric space heating customer is normally expected to pay for the wiring and baseboard heating equipment as well as for electricity consumption. When these costs are subtracted from the Total Cost given in Table 3, the net cost of peak management results.

This cost of peak management is $933 per customer-year for an all-electric heating customer and $521 for hybrid heating customers. Under the existing rate structure, the utility absorbs this peak management cost (attributable to electric heating customers) and apportions it to all of its customers. If the utility were instead to pay the entire incremental cost of the hybrid peak management system, the cost to its customers would be 44% lower.

3. The Impact

The above analysis indicates that hybrid heating is a lower cost alternative to the construction of new combustion turbines to meet peak space heating loads. It exhibits a lower natural resource impact, lower first cost, lower annual total cost and lower net cost to the utility. These conclusions are robust in the sense that they remain valid in the face of significant changes in the critical parameters. The extent of the potential applications should, therefore, be examined.

3.1 Electrical Power Impact

The utility's most recent load review indicates that peak power demand is expected to grow by approximately 79 MW per year (NB Power, 1990a). This compares reasonably with past experience and underlies an ambitious program for the construction of up to 750 MW of gas turbine generation capacity.

If the 4400 new, all-electric space heating customers per year that are anticipated were to use hybrid systems, the growth in peak demand could be reduced by 40%, to 48 MW per year.[3] If a further 6800 existing customers per year were to be converted from all-electric to hybrid heating, then the rise in peak demand could be completely eliminated. Space heating provided by 11800 hybrid systems is equivalent to a 100 MW combustion turbine.

The investment schedule required for hybrid heating can be estimated from the utility's load forecast and its planned generating capacity. A summary of this schedule is presented in Table 4.

The demand data are taken from the utility's load forecast. The net base generation capacity is the total available capacity reduced by an amount equivalent to the required reserve margin. It represents the generation capacity available in a given year. Planned capacity purchases and sales and repatriated base-load capacity are included, as are scheduled plant retirements and new base-load plant additions.[4] New gas turbine generation capacity is, of course, excluded.

Table 3: Economic Cost of All-Electric and Hybrid Heating Systems

Description	All Electric ($/Yr)	Hybrid ($/Yr)
Capital	1017	637
Energy	887	820
Operation and Maintenance	47	82
Total Cost	1951	1539

The difference between the peak power demand and the net capacity represents the demand that must be met by the peak management system. This deficit grows with the increase in peak demand and falls as new base-load capacity becomes available. As Table 4 shows, a maximum of 44,000 hybrid systems are required to manage the expected increase in peak demand in the coming 15 years. The market penetration rate for hybrid heating is also listed. The potential market is assumed to be new customers and those who converted from oil to electric; a maximum of 52% of these customers must adopt hybrid heating to eliminate the peak by demand management.

3/ The utility's peak load due to space heating increased by 114 MW in the last two years, during which approximately 16,000 electric space heating customers were added. This represents 7.1 kW per customer and thus supports the use of the average value to represent future customer loads.

4/ Consistent with utility planning practice, the capacity data of Table 4 do not reflect the projected long-term outage of the utility's only nuclear unit for pressure tube replacement in 1998/1999. Detailed examination of load and resources estimates for this period indicates a 390 MW capacity shortfall and a 414 GWh energy shortfall during the winter months. The power shortfall could be reduced by installing additional hybrid systems. The energy shortfall could be eliminated, without installing additional equipment, by operating the 42,400 **planned** systems to meet 56% of the space heating energy requirement during that year only.

Table 4: Required Investment for Hybrid Heating Capacity

Year	Peak[1] Power Demand (MW)	Net Base[2] Generation Capacity (MW)	Power Deficit (MW)	Number[3] of Hybrid Systems	Cumulative[4] Penetration Rate (%)
1991	2637	2611	26	4000	8
1992	2723	2679	44	7000	13
1993	2789	2679	110	16000	27
1994	2884	3008	-124	0	25
1995	2985	3039	-54	0	24
1996	3072	3039	33	5000	22
1997	3163	3039	124	18000	24
1998	3252	3039	213	32000	40
1999	3339	3039	300	44000	52
2000	3423	3428	-5	0	49
2001	3506	3412	94	14000	47
2002	3587	3373	214	32000	45
2003	3666	3373	293	43000	43
2004	3743	3723	20	3000	41
2005	3818	3675	143	21000	39

1/ Forecast in-province load (NB Power, 1990a).

2/ Net Base Generation Capacity = Total electricity resource + proposed base-load capacity - scheduled new combustion turbine capacity - reserve margin (NB Power, 1990a).

3/ The number of hybrid systems required to offset the projected power deficit, assuming a saving of 6.75 kW per installed system. The numbers shown are not cumulative.

4/ Percentage of a potential market, consisting of 50,000 existing customers plus 4400 new customers per year, that must adopt hybrid systems if the power deficit is to be covered. Of the existing customers, only those that were converted from oil systems are included in the potential market.

3.2 *Electrical Energy Impact*

The total impact of hybrid heating on the utility's energy sales can also be examined. The cost analysis assumed that 15% of the space heating energy was derived from the fossil fuelled portion of the hybrid system. The approximately 44,000 hybrid systems that will be required to manage the peak demand by the year 2003 are thus expected to displace about 116 GWh of electrical energy consumption annually. This represents less than 1% of the total in-province sales (NB Power, 1990a).

3.3 *Environmental Impact*

The general issue of oil use for residential space heating should also be addressed. The main impetus for oil-to-electric heating conversions has been to reduce the dependence upon price-volatile oil markets. However, it is clear from the data presented in Figure 5 that the increase in electrical energy use of the last five years has been dominantly satisfied by use of oil-fired generating facilities. Low oil prices have served to limit the economic impact of this oil use, until recently.

If the investment and operation schedule outlined in Table 4 is followed, then hybrid heating would save 175 million litres of distillate fuel oil over the next 15 years. This would reduce the atmospheric emissions of CO_2 by 475,000 tonnes and reduce SO_2 emissions by 1200 tonnes. These environmental impacts are based upon the displacement of electricity from oil-fired combustion turbines. If the hybrid heating systems were operated to replace electricity generated from high-sulphur, residual fuel oil or coal, the SO_2 reductions would be much larger.

If electricity generated from residual fuel oil with 2.75% sulphur content is displaced, SO_2 emissions would be reduced by more than 94%. If coal with a 4% sulphur content is burned in a plant equipped with flue gas desulphurization capable of a 90% removal rate, then SO_2 emissions would be roughly equal to those from the hybrid system. However, in this case, the cost of installing and operating the scrubber equipment would be much higher than the cost of sulphur removal from the light heating oil. A reduction in the sulphur content of light heating oil could be easily achieved to reduce the hybrid systems' SO_2 emissions to levels well below those of a coal-fired plant with scrubbers. In addition, flue gas scrubbing generates a waste stream, with attendant landfill and disposal problems, while oil desulphurization processes can produce elemental sulphur. Displacement of residual fuel oil- or coal-derived electricity would be expected to reduce CO_2 emissions by 50 to 60% per unit of energy delivered.

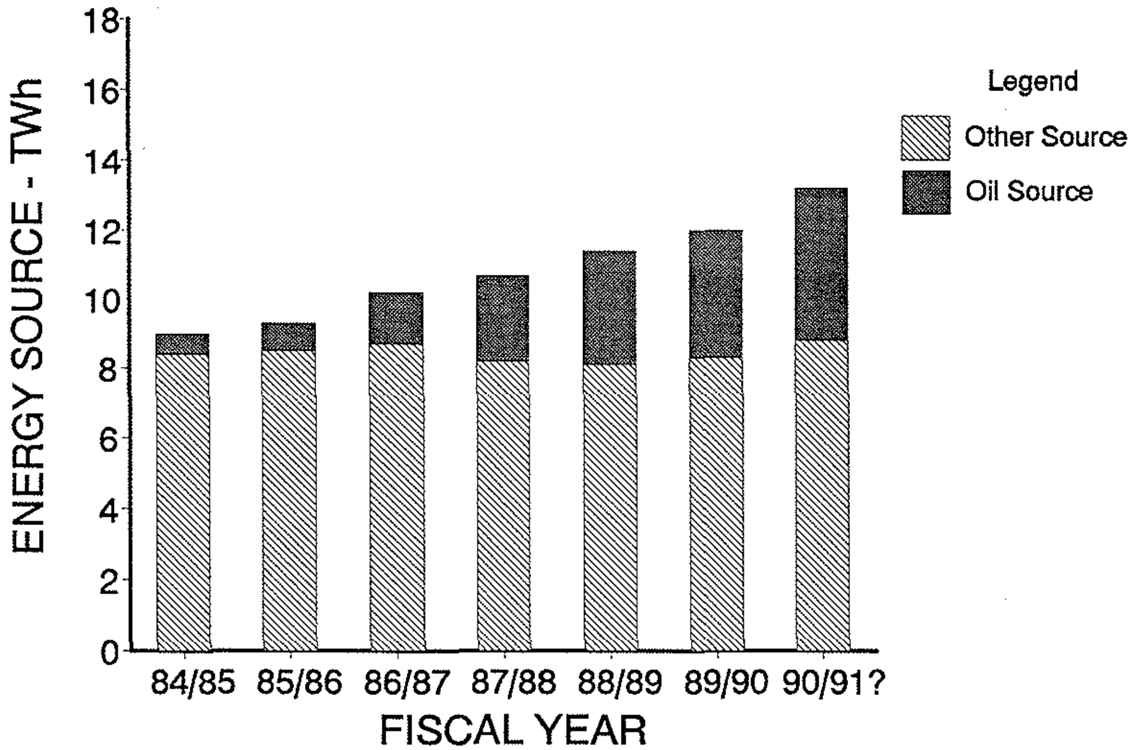

Figure 5: In-Province Sources of Electrical Energy
Source: NBP Annual Report

3.4 Secondary Economic Impact

The primary economic benefits of hybrid heating (i.e., the lower total cost of meeting peak space heating load and the improved utilization of existing generation capacity) have been adequately addressed above. The secondary economic benefits are also important.

Few of the boilers, pumps, turbines, heat exchangers, valves and piping that essentially define a large thermal generating plant are manufactured within the Atlantic region. Indeed, many of the major components are imported from the United States, Japan and Europe. The combustion turbines that the hybrid heating systems are intended to replace are imported, essentially preassembled, and the technology for installation and maintenance would likely be imported as well. In comparison, there are several manufacturers of small combustion heating equipment based within the region who are quite capable of producing hybrid furnaces and boilers. These conditions indicate that the hybrid strategy for peak management may result in a larger net economic impact than the utility's capacity addition approach, in spite of its lower cost. Put simply, much less money would be spent to meet peak space heating requirements with hybrid systems, but more of that money would provide high value, long-term jobs within the region.

3.5 Flexible Planning

A further benefit of the hybrid heating system is the flexibility provided by central heating, which unlike electric resistance baseboards, can either be conveniently modified to switch fuels, or adapted to advanced heat pump technologies. While this analysis deals with only fuel oil, the potential for natural gas distribution within the Eastern Provinces should also be examined. Natural gas may become available within the next 10 to 20 years, either from an extension of the Trans-Canada Pipeline or from regionally-based production. The experience of other regions and nations indicates that it will be a relatively plentiful and inexpensive fuel. The decisions that are made now, however, will dictate its availability for space-heating use.

If central, hybrid heating systems are preferentially installed in new and existing structures, then the cost to convert to natural gas will be the cost of a replacement furnace. The cost of gas distribution will be recovered by the utility in the gas rate, which will vary inversely with the customer density. If many structures have central heat distribution systems, then market penetration of natural gas will be maximized and the gas rate will be minimized.

If, however, electric resistance baseboards dominate the space heating market when natural gas becomes available, the cost to convert must be higher to pay for the ducts, plumbing, and flue. This will reduce the market penetration, causing distribution costs to be recovered from fewer customers, and increase the unit price of gas. This could well cause gas distribution to be economically unfeasible. In this case, the only viable option may be to burn natural gas in power plants, generating electricity for use in electrically-heated homes. This will mean that twice as much gas must be burned to achieve the same space heating levels because of the low efficiency of converting fossil fuel to electricity (70% of the fuel's energy is wasted). Consequently, the CO_2 production would double to meet a given heating load. In addition, the direct substitution of natural gas in oil- or coal-fired generation plants may incur a penalty in reduced plant capacity. Expensive boiler modification or replacement may be required if plant capacity is to be maintained when natural gas is burned.

4. Implementation

Any program to implement hybrid heating will be subject to economic, legislative and behavioral considerations. We examine them briefly in the following sections.

4.1 Economic Considerations

Hybrid heating is based upon a relatively simple and mature technology. As such, most of the manufacturing, construction and service infrastructure that it requires is currently available, even in the less-developed regions of the country.

The most obvious problem is the suitability of the existing housing stock for conversion to hybrid systems. We have, therefore, considered only the portion of the existing housing stock that was converted to electric heating from oil heating. The heat distribution systems and flues of many such homes remain serviceable, even though unused.

The 120,000 homes currently heated by electric baseboards represent a market that is more difficult to penetrate. While the previous analysis shows that these customers need not convert to manage the peak demand, we will consider them briefly. Multi-story homes and those with finished basements are particularly problematic. In the case of multi-story homes, hydronic (water) distribution systems become necessary. The cost of equipment for such systems is greater than for air distribution systems, but their ease of installation and reduced space requirements make them preferable to the latter. The considerably higher cost of the installation will reduce the economic advantage of the hybrid system, though this may be partly compensated by the higher peak-coincident power consumption of the larger home. For homes with finished basements it may be desirable to locate the heat source outside the dwelling. This is technically feasible and may offer economic and safety advantages. In both cases, the net economic impact is an increase in the cost of the hybrid system, the effect of which was examined in the break-even analysis.

Further technical analysis is required to determine the impact of hybrid heating on electrical system reliability and to develop suitable predictive models for hybrid system availability. The accurate determination of the achievable peak-coincident load reduction is critical to any economic analysis, and the distribution of space heating loads should therefore be subject to careful experimental verification. As well, a further analysis should include the secondary economic costs and benefits of both alternatives.

4.2 Legislative Considerations

The objective of the electric utility's enabling legislation reads as follows (Electric Power Act):

> "The intent, purpose, and object of this Act is to provide for the **continuous supply of energy** adequate for the needs and future development of the Province and to promote economy and efficiency in the generation, distribution, supply, sale, and use of power [emphasis added]."

For the purpose of this Act, energy is defined by:

> "'energy,' 'power,' includes electricity, gas, steam and by-products resulting from the generation of power."

Leaving aside the legislation's less than rigorous use of the words 'energy' and 'power,' the requirement for continuity of supply should be examined. If the phrase '...continuous supply of energy...' is interpreted as referring to reliability of end-use energy service, as the economy and efficiency principles might suggest, then the development of direct load control techniques such as hybrid heating should not be restrained. In contrast, if the phrase is interpreted strictly in terms of the Act's definition of energy, then the supply of electricity could not be interrupted and the development of direct load control technologies could be restrained. In that event, individual, contractual arrangements between the utility and its customers, such as the leasing scheme described below, could be used to circumvent the restriction.

A related, and perhaps more important, issue is the Act's focus on **energy supply**. The increasing importance of demand-side management (DSM) techniques in meeting society's energy requirements at reduced economic and environmental cost is now widely recognized. Modification of the Act's objective to both recognize this important fact and give DSM equal prominence with supply-side alternatives is particularly appropriate because the utility takes the objective as its mandate (NB Power, 1990b). While any such changes must be carefully considered, changing '...for the continuous supply of energy adequate...' to '...for the maintenance of a reliable energy market adequate...,' and a suitable change in the definition of energy, may be sufficient to address the issue. Under such a revision, the appropriate measure and level of reliability could be determined through the regulatory process.

A final legislative issue relates to the inclusion of 'gas' in the definition of energy and power. If this is interpreted as including natural gas, then it is proper that consideration of the issues related to distribution of natural gas be examined in the utility's capacity planning process (see Section 3.5, above). We note that the requirement to '...promote economy...' could be interpreted as restricting the planning and development of gas distribution facilities since they would, to some extent, duplicate or supplant existing and planned electricity distribution facilities. Balanced against this is the requirement to '...promote...**efficiency** in the generation, distribution, supply, sale **and use** of power.' This would support the distribution of natural gas, since its use to provide sustained heat is demonstrably and significantly more efficient than the use of electricity derived from gas-fuelled thermal generating stations and consumed in electric resistance heaters.

4.3 Behavioral Considerations

The most difficult problems associated with implementation of hybrid heating are likely to be behavioral. It is well understood that simply showing a technology to be economically and environmentally preferable is not sufficient to ensure its adoption. In the brief discussion that follows, we will examine the potential for appropriate, market-based incentives for adoption of hybrid heating. Building code requirements and other such legislative techniques are not examined. While these could ensure that new housing stock is constructed with central heat distribution systems, market-driven incentives will have more general application to a variety of demand management and conservation technologies.

Any market-based approach to promote hybrid heating must recognize the realities of the housing market. Few houses are built and occupied by the person that originally selected the heating system. Builders and first owners are often speculators that anticipate short-term ownership and the early sale of an appreciated asset. It is also clear that home valuation is inherently subjective. Many considerations rank before the type of heating system and the cost of utilities in the mind of the home buyer (Horne, 1991). In other words, the initial home owner/decision maker does not intend to own the building in the long term and therefore discounts future cost savings excessively. The prospective buyer's valuation of the property is also unlikely to reflect the longer term social and economic cost of the heating system to a significant degree. These considerations lead to the selection of a heating system that would conform to the housing market's norms and expectations and exhibit **least first-costs**. The *de facto* standard, in this utility's jurisdiction, is electric resistance baseboard heating.

EFFICIENT COST ALLOCATION

A program to promote demand management must address both the initial adoption of the technology and its continued availability to manage the peak demand. Pricing strategies that allocate costs efficiently can satisfy both requirements.

It is generally agreed that electricity pricing should (Munasinghe, 1982):

i) reflect the true cost of supply to permit efficient resource allocation;
ii) provide for fair and equitable allocation of costs, reasonable price stability and a minimum level of service for the disadvantaged;
iii) provide revenue sufficient to meet the financial requirements of the utility;
iv) be simple, to facilitate metering and billing; and,
v) be flexible enough to provide for other economic, environmental and political considerations.

The same authors suggest that basing electricity prices on the long-run marginal cost of service (LRMC) will address these issues. The LRMC relates the price to future costs; it thus provides price stability. However, the LRMC of a unit of energy varies with the total load connected to the utility, and thus requires time-of-use (TOU) metering. The expense of TOU metering equipment, a more complicated billing structure and the relatively inelastic demand of low-consumption, residential customers can all reduce the acceptability of the strategy. While TOU pricing may be efficient for high-consumption residential, commercial and industrial customers (Acton, 1978; Acton, 1982), any attempt to partition customers into such classifications raises the complicated issue of equity.

Changing the electric rates to their true LRMC on a time-of-use basis also has political and public relations impacts. These can be important considerations for government-owned electric utilities when one considers the magnitude of the required price adjustment.[5]

While a rigorous application of LRMC pricing for residential customers may not be feasible, it is clear that users of peak-coincident energy impose power-related (capacity-related) costs on the utility in addition to the energy cost. Indeed, our analysis indicates that these capacity costs are most significant for all-electric space heating. A slight modification to the existing rate structure — adoption of a monthly service charge commensurate with each customer's estimated peak-coincident load — could reflect these costs without investing in TOU metering. While this rate structure may have the advantages of simplicity and lower metering cost, it would imply increasing the monthly service charge from \$10 to roughly \$75 for the average space-heating customer. Political consideration will obviously make this course of action difficult.

5/ The marginal cost of peak energy provided by the combustion gas turbines currently under construction will be more than \$0.30 per kWh. While the LRMC is somewhat less than this, the marginal price paid by residential customers is currently only \$0.0456 per kWh.

DEMAND MANAGEMENT LEASING

Demand management leasing offers some advantages over the electricity pricing methods described above. Rather than penalizing customers for their peak-coincident demand, it rewards them for their peak-coincident demand reduction. In this way, it overcomes the political difficulties associated with cost allocation schemes. Such a leasing proposal may be generally applicable to load management technologies that operate under the utility's control, but we will consider only its application to hybrid heating.

Basically, the hybrid heating customers would offer the electric utility direct control over their space heating load. The utility would pay for this service under a long-term lease. The customer would assume all of the costs associated with providing the service, except those associated with the utility's portion of the central control system. This arrangement would offer the utility lower and more stable costs than the combustion turbine option. The utility would pay only for measured and delivered performance, and it would pay at a rate lower than the cost of constructing and maintaining its own facilities. Specialized metering equipment would only be required for the customers that install hybrid systems, and its cost could be incorporated in the lease payments. These payments to the customer would reflect the value of both power (kilowatts) and energy (kilowatt-hour) savings to the utility.

The magnitude of the payments based on **power** savings to the utility can be estimated from the previous analysis. The cost of the gas turbine and transmission capacity and non-fuel operation and maintenance cost is equivalent to \$140 per kilowatt-year, where the power is measured at the customer's meter. Hybrid heating equipment costs approximately \$80 per kilowatt-year, over and above the cost of electric baseboards and wiring. Thus, adopting a lease payment of \$110 per kilowatt-year would benefit both parties.

The customer would also receive payment for the peak-coincident **energy** substitution. The rate should equal (at least) the difference between the gas turbine fuel cost and the utility's marginal billing rate. This difference is approximately \$0.034 per kWh in this analysis. The volatility of the oil market suggests that the lease should provide for review and change of the energy rate from time to time.

Assuming that these power and energy rates apply, the average customer would receive roughly \$750 per year in lease payments; the utility would save about \$180 per year compared with an investment in gas turbine generation capacity. These savings are relatively secure, because the payments are only made for measured and delivered performance. This creates an incentive for the space-heating customer to provide the demand management service on an ongoing basis. In contrast, utility-financed grant or loan programs can only encourage the adoption of a technology; they cannot ensure its continued availability. Of course, it is quite possible that lower lease payment rates would result in adequate market penetration by hybrid heating. The lower conversion cost of customers with existing heat distribution systems, the satisfaction associated with reduced environmental impact of space heating and the simple novelty of receiving a substantial annual payment from the electric utility could all encourage market acceptance of the technology at lower lease payment rates.

It is clear that the terms and conditions of the demand management lease must be carefully crafted. Simply basing the lease payments upon measured load reductions would be counterproductive. This would encourage space heating customers to use **more** peak-coincident electricity, not less. (Turning up their thermostats to warmer-than-normal temperatures during the peak morning hours would increase their space heating load and thus increase the revenue from the lease). This difficulty could be avoided by basing the lease payment upon a peak-coincident load that is calculated from the annual energy consumption and an appropriate load factor.[6] If, for example, a 30% load factor was used for this calculation, a 10% increase in energy use

6/ The load factor is the ratio of average and peak electrical loads.

would increase the customer's electricity bill by \$80 per year but only increase the lease payment by \$70 per year; the net loss would discourage excess consumption. Of course, it would still be necessary to verify peak-load reduction to ensure that the hybrid heating system remains available for demand management purposes.

5. Conclusions

The preceding analysis indicates that hybrid heating offers significant potential for peak electrical load management for a winter-peaking utility. It offers lower environmental and economic costs than electricity generated by combustion turbines. It also offers significant secondary economic benefits through its greater use of indigenous manufacturing infrastructure.

Demand management leasing, in which the utility pays customers for their demand management service, is proposed to encourage the adoption of hybrid heating, with the expectation that such a system will overcome the public relations/political difficulties associated with rate-based, cost allocation schemes, and ensure the continued availability of the service to the utility.

References

Acton, J.P., B.M. Mitchell, and W.G. Manning Jr. (1978) *Peak-Load Pricing of Electricity* (Santa Monica: Rand Corporation) pp.18-19.

Acton, J.P., D.F. Kohler, B.M. Mitchell, and R.E. Park (1982) *Promoting Energy Efficiency Through Improved Electricity Pricing* (Santa Monica: Rand Corporation) pp.61-62.

ASHRAE (1987) *Heating, Ventilating and Air-Conditioning Systems and Applications* (Atlanta: ASHRAE) p.49.7.

Brockman, L.B., R.L Reeves, L.P. Brownell, and C.A. Vice (1990) *New Brunswick Electric Power Commission Integrated Resource Planning Study: Final Report, Volume I* (Atlanta: Energy Management Associates).

Clayton, R.H. (1984) *Electric/Oil Hybrid Heating Systems* (Ottawa: Minister of State for Science and Technology).

Horne, W.R. (1991) 'The Effects of Energy Considerations on House Purchase Decisions' *Energy Studies Review* 3:1:54-60.

Mahoney, W.D. (ed.) (1990) *Building Construction Cost Data 1990* (Kingston, MA: R.S. Means).

Munasinghe, M. and J.J. Warford (1982) *Electricity Pricing: Theory and Case Studies* (Baltimore: Johns Hopkins) pp.10-14.

NB Power (1990a) *Load and Resources Review: 1990* (Fredericton: NB Power).

—(1990b) *Prefiled Evidence on Capacity Planning* (Fredericton: NB Power) p.5-1.

—(1991a) 'Residential Heating Demand Estimates: Fiscal Year 1989/90,' *Evidence on Capacity Planning* N.B. Public Utilities Board, Exhibit NBP-25.

—(1991b) 'Cost Comparison of Dual Fuel Heating Versus System Avoided Costs Using EMA/NB Power Methodology for DSM Evaluation,' *Evidence on Capacity Planning*, N.B. Public Utilities Board, Exhibit NBP-26.

Nelson, M.D. (1980) *Minnkota's Load Management Program: Economic Aspects* IEEE Trans. on Power Apparatus and Systems, PAS-99:5:1886-93.

—(1985) *Load Management from a Power System Operator's Perspective* IEEE Trans. on Power Apparatus and Systems, PAS-104:2:373-80.

New Brunswick Legislature, 'Electric Power Act,' (Fredericton: New Brunswick Legislature) Chap.E-5, Sections 1-2.

Organization for Economic Cooperation and Development (1989) *Projected Costs of Generating Electricity from Power Stations for Commissioning in the Period 1995-2000* (Paris: OECD) pp.35-36.

Seelke, J.L. Jr. (1982) *Assessing the Benefits of Load Control* IEEE Trans. on Power Apparatus and System, PAS-101:10:3892-3901.

Sollows, K.F., U.K. Sumathipala, and J.E.S. Venart (1991) 'Responses to Interrogatories on Demand Side Management: A Lesser Cost Alternative,' *Evidence on Capacity Planning* N.B. Public Utilities Board, Exhibit SOL 2, p.27.