Achieving the Economic Potential for Industrial Cogeneration in Ontario: A Financial Perspective on Electric Utility Policy

This paper is intended to assess the impact of private versus public ownership regimes on the magnitude of achievable industrial cogeneration capacity. Estimates of technical and economical potential are presented for several industrial subsectors and heat demand categories, showing that nearly all of the technically feasible potential of 7600 MW is also economically efficient given a value of power of at least $(1991)0.04/kWh. Using financial data and investment criteria specific to the two forms of ownership, our project evaluation model points to a significantly larger quantum of financial (achievable) potential with public rather than private development of industrial cogeneration. At avoided costs and associated buyback rates of 4 and 5¢/kWh, the achievable cogeneration capacities are about 2400 and 7600 MW under public ownership and 132 MW and 3000 MW under private ownership. Ratepayer savings are significant: the full economic potential can be achieved through public ownership at a buyback rate of 5¢; under private ownership, a comparable capacity requires a 6¢ buyback rate, reflecting additional ratepayer costs of nearly $0.6 billion/year.

Cet article veut évaluer l'impact des régimes de propriété privée par opposition aux régimes publics sur l'ampleur de la capacité industrielle réalisable en cogénération. Des estimations du potentiel technique et économique sont présentées pour ce qui concerne plusieurs sous-secteurs industriels et catégories de demande thermique, montrant que presque tout le potentiel techniquement faisable de 7600MW est aussi économiquement efficace à un prix de l'énergie au moins égal à $(1991)0.04/kWh. Notre modèle d'évaluation du projet qui utilise des données financières et des critères d'investissement spécifiques à ces deux formes de propriété indique un volume considérablement plus grand du potentiel financier (réalisable) dans le cadre du développement public plutôt que privé de la cogénération industrielle. A des coûts évités et des taux associés de rachat de 4 et 5cts/kWh, les capacités de cogénération réalisables sont d'approximativement 2400 et 7600 MW dans le cadre de la propriété publique et 132 MW et 3000 MW dans le cadre de la propriété privée. Les économies réalisées par le contribuable sont importantes: le potentiel économique maximum peut être atteint dans le cadre de la propriété publique à un taux de rachat de 5cts; dans le cadre de la propriété privée, une capacité comparable exige un taux de rachat de 6cts, entraînant des coûts additionnels pour le contribuable de près de 0,6 Md $/an.

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Introduction

Background

Cogeneration is the simultaneous production of both electricity and useful heat energy (in the form of steam or hot water) from a single system. In recent years, increasing concern about pollution from the bulk production of electricity have rekindled interest in the well-established cogeneration family of technologies.[1] Compared with other fossil fuels, the combustion of natural gas produces far less NO_x and CO_2 per kWh electricity output. Moreover, in that some portion of the electricity produced may be consumed on the same site, transmission losses are reduced. Finally, by producing joint products, cogeneration is more fuel-efficient than the separate production of heat energy and electricity. Cogeneration is thus an attractive alternative to grid-supplied electricity where heat demand warrants.

Energy accounts for a large proportion of total input costs for many industries. To the extent that cogeneration is capable of lowering these costs, by either supplying electricity at cost or by providing heat at a discount, industries

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1/ Early cogeneration units appeared in the late 19th century.

can face lower costs and enhance their international cost-competitive-ness.

Finally, cogeneration is, given its relatively small scale, a flexible and adaptive source of supply.[2] Units are, by their nature, always attached to a source of some electricity demand. Depending on the heat demand of the steam host, the corresponding amount of electricity produced can match or at least meet some proportion of on-site electricity consumption. Moreover, the relatively small capital costs associated with purchasing modular gas-turbine and reciprocating engine-based units help to minimize the need for long term debt financing, and lower exposure to capital market risks. From a utility planning perspective, cogeneration has relatively short lead times, a known degree of reliability (high), and foreseeable operating and maintenance costs.

Objectives

Ontario Hydro recently found itself at the convergence of two, unrelated and equally unexpected phenomena: technological problems related to both original and second generation nuclear reactors; and a provincial economic recession with "legs." Both are well, and continuously, documented elsewhere.

In response to these evolving circumstances, Ontario Hydro has undertaken a dramatic restructuring initiative, involving not only the elimination of many jobs (primarily, and not surprisingly, in the construction divisions), but also the structural reorganization of the Crown Corporation.

For many industry watchers, this process of renewal may not go far enough. Present circumstances, many believe, call for the private sector to play a greatly expanded (if not, indeed, an exclusive) role in providing electricity to Ontarians. A particularly opportune way of beginning the process of privatisation, it has been suggested, is to have Ontario Hydro buy more power from non-utility (independent) power producers.

This is a familiar, and to economists and political scientists, interesting debate. Ontario Hydro, at its nascence circa 1909, was intended to be a monopsonistic purchaser and transmitter of electric power; a co-operative of municipal governments was formed to purchase blocks of power from then newly-founded power companies developing hydroelectricity on the Niagara river.[3] The chief impetus for its establishment was the growing monopoly power of local, privately owned (coal based) electric utilities, and the perceived high energy prices demanded by these firms.[4]

Private power producers must, to this day, contract with Ontario Hydro for the supply of non-utility generated (NUG) electricity. Such projects are typically small in scale, the apparently tacit arrangement being that bulk supply would be the exclusive territory of Ontario Hydro. There is, however, no legal sanction against Ontario Hydro building even the smallest of generating facilities, as long as it can be shown to be within its mandate to provide electric power at cost.

An important way in which public and private companies differ is in the financial arrangements that each can make in order to invest in real capital. The objective of this paper is to examine the effects of such differences in financial variables with a view to scrutinizing the argument that cogeneration is best left to the private sector to develop.[5] While the analysis sets aside other differences between public and private ownership that affect efficiency, it is useful to see the impacts of differing financial variables on the assumption that individual cogeneration projects are equally well managed under either ownership regime. It turns out that these differential impacts are substantial, significant enough to affect the quantum of achievable cogeneration capacity,

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2/ Capacity ratings used in this study range from 1.6 MW, corresponding to an average heat demand of 8 million Btu per hour (MMBtu/hr), to 150 MW for average heat demands of 365 MMBtu/hr.

3/ See, for example, W.R. Plewman, *Adam Beck and the Ontario Hydro*, Ryerson Press, Toronto, 1947.

4/ Perhaps an equally salient argument in favour of public ownership was that the hydroelectric resources of the province belonged to all Ontarians, and should not, therefore, be exploited for private gain.

5/ This opinion was expressed by Maurice Strong, Ontario Hydro Chairman, in a letter to the authors dated May 17, 1993.

as well as the price paid for electricity by Ontario ratepayers.

Outline

This discussion proceeds as follows. A methodological overview is presented, including a description of the universe of industrial cogeneration projects studied, definitions and a description of the discounted cash flow model employed. Next, the economic potential of industrial cogeneration in Ontario is defined and estimated. The resulting "supply curve" (the quantity of electricity available at given long run unit costs of supply) is then compared with the potential capacity achieved under two alternative financial assumptions, one for public and one for private ownership. Policy implications are discussed by way of conclusion.

Methodology

A. Technically Feasible Cogeneration Potential

The methodological approach is straightforward. Prospective industrial "markets" for cogeneration were identified and examined to determine the size of their respective heat energy demand. As many as three heat demand categories and corresponding case studies were formulated within each industrial sub-sector, as listed in Table 1. For each category, the number of potential sites was determined, as was the appropriate cogeneration technology and equipment for a "typical" site (based on the heat demand of the steam host).

The capacity associated with each category was then multiplied by the number of sites in that category to yield its estimated *technical potential* (measured in megawatts). Figure 1 shows the technical potential for each of the heat demand categories.

B. Economically Efficient Cogeneration Capacity

After setting other technical characteristics of these case studies (see below), the *economic potential* for a given category is calculated on the basis of its associated resource cost or (pre-tax) levelized unit energy cost (LUEC). Economic potential is

Table 1: Case Study Categories by Sub-sector (MMBtu/hr)

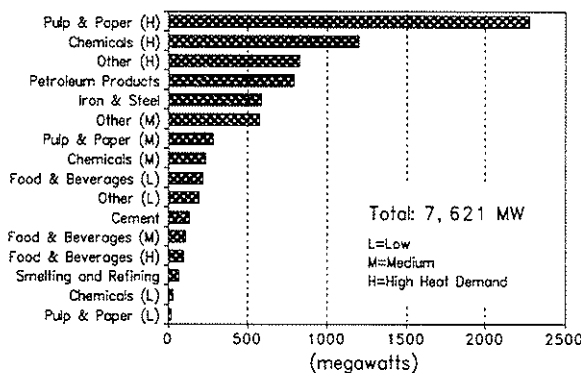|	Heat Demand Category		
	Low (<25)	Medium (25-100)	High (100+)
Cement			X
Chemicals	X	X	X
Food & Beverages	X	X	X
Iron & Steel			X
Petroleum Products			X
Pulp & Paper	X	X	X
Smelting & Refining		X	
Other Manufacturing	X	X	X

Figure 1: Ontario Industrial Cogeneration — Technical Potential by Sub-sector

defined as the total capacity and energy associated with the aggregate of all economically feasible cogeneration projects. In turn, a project is economically feasible if and only if its *supply price* (expressed here in real $1991/kWh electricity generated) is less than or equal to that associated with conventional bulk electricity supply.[6]

6/ Supply price is a measure of costs, not prices, per unit of energy output. This concept allows consistent comparison among supply and energy conservation projects that may differ in terms of the scale of investment, construction period, economic life and output of electric energy. It may be thought of as the constant real (1991) dollar price of electric energy required to meet project costs at a given discount

Economic potential is differentiated from financial potential in that each embodies a specific analytic perspective. Economic analysis is concerned with the appraisal of an investment from the public or social point of view. Transfer payments from one agent to another, in that they represent no net change to society as a whole, are not relevant when estimating economic potential, but are relevant to private investors' financial analysis. These transfers include taxes, government subsidies and price discounts to steam buyers. Conversely, costs and benefits that are relevant only to society at large, but not to project owners (externalities) are part and parcel of economic analyses, but play no role in estimates of financial feasibility.[7] Finally, economic analysis discounts flows of expenditure and output at a rate determined by the preferences of "society at large" rather than at a rate derived from the capital market.

The supply price and rate of return on equity for each case study have been calculated using an ordinary discounted cash flow algorithm. The economic parameters used are common to both forms of ownership, although it may be argued that some costs are slightly different under the two ownership regimes. For example, legal and other transaction costs associated with project-by-project negotiations related to power, thermal energy and natural gas purchase contracts are likely to be lower with public rather than private project development and ownership and bulk gas purchases by a public utility may result in lower gas costs. On the other hand, higher public sector wages and salaries would lead to higher costs for project design and supervision and project OM&A; however these differences would be small, as labour costs are not a significant fraction of total project cost (cogeneration projects are based on modular, packaged systems supplied by the manufacturers).

Calculations are based upon, first, project-specific technical parameters:
- economic (service) life (years);
- capital cost ($1991);
- construction period (years);
- capital cost distribution over the construction period;
- capacity (MW);
- capacity factor (%);
- minimum fraction of electric energy output available for sale to Ontario Hydro;
- fuel chargeable to power (natural units);[8]
- operating, maintenance and administration costs ($1991/year);
- annual quantity and value of non-electricity output (if any); and
- thermal energy output (MMBtu)

Second, the following three economic parameters are also required:
- real discount rate;
- natural gas prices;
- bulk electricity supply price.

The choice of discount rate has a direct impact on the calculated supply price of any project.[9] The higher the discount rate chosen, the better the economic cost-competitiveness of cogeneration and other relatively short lead time, low capital cost options compared to capital-intensive alternatives with long construction periods. In this analysis, a real discount rate of 5% was employed.[10]

The cost of gas enters the supply price calculation in the same way as annual operating, maintenance and administration costs (OM&A) do. While OM&A can be assumed to remain constant (in real terms) over the life of a project,

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rate. Put another way, the present worth of the project's capital and operating costs is equal to the present worth of the annual product of its supply price and quantity of energy output. Finally, the supply price may also be described as the constant (levelized) production cost per unit of energy output, using real dollars and a real discount rate.

7/ The value of externalities associated with cogeneration and its bulk supply alternatives is not in-cluded in the present analysis.

8/ The incremental amount of fuel consumed for cogeneration that would not be needed if only steam for process was produced.

9/ Also known as "social discount rate," and "rate of time preference."

10/ Ontario Hydro is known to use this rate for its own internal economic analyses, so the present results are comparable with Ontario Hydro computations.

the long term real price of gas, and hence annual cost of gas consumed, is much more difficult to predict.

Note that gas purchase contracts are typically set (in 1991) at a base price of about $3/Mcf ($3/MMBtu; $0.1057/m^3) and are indexed to one or more escalators pertaining to buyback rates, retail electricity prices and other energy prices. Given Hydro's gas price forecast and those prepared by the National Energy Board, the analysis adopted an annual real gas price growth rate of 2%.[11]

Accordingly, an electricity supply curve is developed (Figure 2), depicting the quantity of cogenerated power that should be provided to the market in response to a given range of supply prices. This is, then, a supply curve of economically efficient capacity given a set of alternative "prices" of bulk supply. Note that even if the supply price of incremental bulk electricity supply is relatively "low" (e.g., 4¢/kWh), nearly all (6684 MW) of the technically available cogeneration capacity (7621 MW) is economically feasible.

C. Achievable Potential for Industrial Cogeneration

As noted earlier, the estimation of achievable potential is founded on the financial perspective of the individual or organization acting as the investment decision-maker. The analysis uses methods of investment appraisal that differ in several ways from those applicable to economic analysis. Financial analysis uses cash flows measured in nominal (inflation-inclusive) units of currency; includes all transfer payments (taxes, subsidies and steam price discounts); includes capital cost allowances for their effect on income tax liabilities; includes assumptions on the capital structure of the investment; excludes external costs and benefits; and uses the market cost of capital. Financial potential is the total electric power (capacity) represented by the aggregate of all financially feasible industrial cogeneration
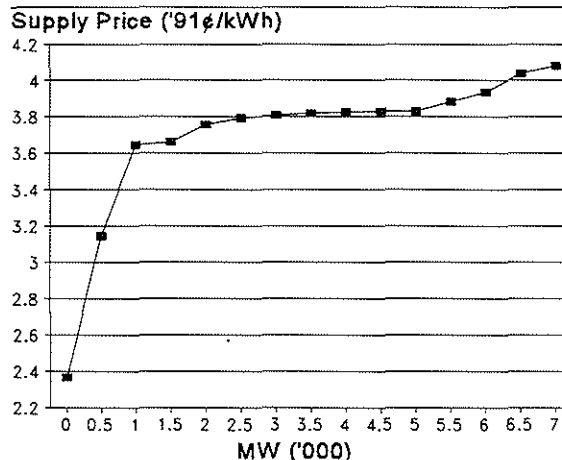

Figure 2: Ontario Industrial Cogeneration — Economic Potential by Supply Price

projects. A project is considered financially feasible if and only if it satisfies one or more investment criteria applicable to the selected form of project ownership.

Typically, it is assumed that private ("third-party") developers own the project and sell thermal energy (steam and/or hot water) and electricity to the industrial steam host and the electric utility, respectively. This serves as the reference case in our analysis of financial potential. The second scenario considered in our assessment assumes that the utility itself owns the project and sells thermal and electric energy to the steam host and to itself, respectively. A third option involving ownership by the steam host is not considered in the present analysis as industry is generally uninterested in getting into the business of generating electric power. Clearly, the form of ownership attached to the cogeneration project will influence the values of the investment decision criteria and many of the other required financial parameters.

The private-sector criterion selected for the current set of financial analyses is the discounted cash flow (DCF) return on equity investment. This return on equity (ROE) criterion measures the after-tax yield of the equity investment, given a project-specific debt-equity ratio and other financial parameters such as rates of income tax and capital cost allowance. It is defined as the discount rate that causes the present worth of

11/ See National Energy Board, *Canadian Energy Supply and Demand, 1990-2010,* June 1991, and Ontario Hydro, *Energy Price Trends Report,* Annual Review (November 1990).

the cash flow stream available to the investor (after taxes and debt servicing) to equal the initial equity investment. If the ROE exceeds the investing entity's target ("hurdle") rate, the project is financially viable. In the case where the public utility owns the cogeneration plant, project financing and project-specific capital structures are not relevant. Instead of the ROE criterion, the appropriate investment indicator is the *DCF return on the total investment*, or ROI. The project is financially viable if the estimated ROI exceeds the utility's incremental cost of capital.

The analysis of financial potential is based on the same technical data used in the economic analysis (Section B). In addition, the financial analysis requires estimates for the values of the selected investment criteria and those of several other financial parameters. The scenario-specific values of these variables are described below; Table 2 provides a summary.

INVESTMENT HORIZON AND SERVICE LIFE. For both ownership scenarios, the investment planning period is set equal to 20 years (the in-service life of a cogeneration unit) plus the construction period (generally three years for larger projects); in specific terms, the planning horizon extends from the start of construction (assumed to be 1991), to 2014, a total of 23 years.

ELECTRICITY BUY-BACK RATES.[12] As the estimated financial potentials are expressed in terms of supply curves, a range of buy-back rates from 4 to 8¢ (1991$/kWh) is used in the analysis of both scenarios. These real values are escalated by the CPI to provide nominal dollar values. Note that in the case of utility ownership, the buy-back rate serves as a "transfer price" between two divisions of the same electric utility.

NATURAL GAS PRICES. As discussed above in the analysis of economic potential, the base period price of natural gas is set at $3/MMBtu. The real rate of escalation in gas prices is assumed to be 2%/year. These values are used in the

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12/ Note that as all of the cogenerated electricity is sold to the utility, the analysis requires the buy-back rate and not the retail (purchase) price of electricity. In the jargon of the cogeneration business, the financial analysis is based on "purchase" rather than "load displacement" projects.

Table 2: Summary of Financial Assumptions

Item	Form of Ownership	
	Third-Party	Utility
Investment Horizon (yrs)	23	23
Facility Service Life (yrs)	20	20
Annual Rate of Change in CPI (%)	3	3
Base Period Buy-back Rate (1991$/MWh)	4-8	4-8
Real Annual Change in the Buyback Rate (%)	0	0
Base Period Natural Gas Price (1991$/million Btu)	3	3
Real Annual Change in the Price of Natural Gas (%)	2	2
Steam Price Discount (%)	15	15
Capital Cost Allowance Rates	Class 34 & other	NA
Fraction of Investment Cost Eligible for Class 34 (%)	90	NA
Corporate Income Tax Rate (%)	50	NA
Capital Grant (%)	0	0
Capital Structure (% Debt)	80	NA
Real Cost of Short-term Debt (%)	5	NA
Real Cost of Long-term Debt (%)	5	NA
Debt Amortization Period (yrs)	15	NA

analysis of both ownership scenarios, although it may be argued that higher-volume purchases by the utility could enjoy a lower unit price than that attached to relatively small gas purchases by third-party developers.

CONSUMER PRICE INDEX. Forecasts of the CPI are used to convert real (1991) dollars to nominal ("as spent") dollars. It was assumed that the CPI would escalate at an annual rate of 3% over the period 1991 to 2014.

STEAM PRICE DISCOUNT. From the perspective of the steam host, the decision to buy rather than make steam involves a degree of incremental risk. To offset this risk, developers of cogeneration plants typically sell thermal energy at a discount relative to the energy cost associated with the steam host's "make" option. Although each case

has its own unique pricing features, the generic analysis presented here used a 15% steam discount in pricing the thermal energy sales of the cogeneration plants owned by private developers. The same discount is applied to thermal energy sales from utility-owned plants, although a case could be made for lower discounts based on the steam host's perception of Ontario Hydro as a reliable supplier.

CAPITAL COST ALLOWANCE. Cogeneration projects are eligible for accelerated (Class 34) rates of capital cost allowance.[13] Class 34 permits the owner to depreciate eligible assets over a three-year period, with 25% allowed in the first year, 50% in the second and 25% in the third. In our sample of case studies, 90% of the total investment cost is estimated to be eligible for Class 34; the remaining capital cost is depreciated at conventional rates of 4%/year, calculated on a declining balance basis. Note that in any one year, the CCA claimed cannot be greater than project-specific pre-tax net income.[14] Where in any one year the calculated CCA exceeds net income, the excess is entered into a "carry-forward" pool that is depleted in subsequent years subject to the net income ceiling.

Note that depreciation *per se* is not a cash expense; it is relevant to DCF analysis as it provides a tax saving or "tax shield" as a result of its deductibility from taxable income. For this reason, it is included in the scenario involving private (third-party) owners subject to income tax, and excluded in the scenario involving public (utility) ownership.

CORPORATE INCOME TAX RATE. For the purposes of this study, a corporate income tax rate of 50% has been assumed. While the rate may vary from project to project, or among different types of developer, this represents a reasonable estimate of actual tax rates faced. The public utility is assumed not to pay income tax.

FRACTION OF INVESTMENT COST ELIGIBLE FOR CAPITAL GRANT. In both ownership scenarios, it is assumed that cogeneration investments would receive no incentives in the form of capital grants or subsidies.

DEBT FINANCING - TERMS AND CONDITIONS. For privately owned projects, a debt ratio of 80% is applicable (the remaining 20% is financed through equity investment). The nominal (pre-tax) cost of both short-term debt (interest during construction) and long-term debt is assumed to be 8%. Given an inflation forecast of 3%, this interest rate corresponds to a real rate of about 5%. The long-term debt is amortized on the basis of equal annual payments that blend interest and principal. This is an important consideration in DCF analysis as interest payments are tax-deductible, whereas principal repayment is drawn from after-tax cash flow. Finally, the amortization period is set at 15 years based on discussions with financial institutions.

In the case of ownership by the public utility, project financing is not applicable; as shown below, the utility would compare the return on total invested capital with its cost of capital.

INVESTMENT DECISION CRITERIA. Surveys of the industry, discussions with developers and Ontario Hydro documents have indicated that the private sector generally adopts 18% (15% real) as their target rate of return on equity (after-tax).[15] In the case of ownership by the public utility, an 8% (5% real) cost of capital (and hence required ROI) is used.

Results and Discussion

First, the data gathered for this study indicate that in 1991, the amount of electricity generating capacity that could be installed at Ontario's major industrial heat energy-consuming sites is around

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13/ Industrial cogeneration projects meet the Class 34 criterion that requires an energy-efficient power generation process whose so-called "fuel chargeable to power" or FCP is no greater than 7000 Btu/kWh. For details of the Class 34 regulations, see Energy, Mines and Resources Canada, *Class 34 Accelerated Capital Cost Allowance*, Ottawa.

14/ If the owner had other energy-related business income, the full amount of the CCA could possibly be claimed by applying it against such income. We have assumed that in the young business of cogeneration, the developers would lack such additional taxable income and the stand-alone project ceilings would apply.

15/ Ontario Hydro, EAB DSP hearing, response to interrogatory #1.15.196.

Table 3: Cogeneration Supply Prices & Rates of Return by Buyback Rate & Ownership Type (1991)

Sub-sector	Heat Demand	Supply Price ('91¢/kWh)	4¢/kWh Private ROE	4¢/kWh Public ROI	5¢/kWh Private ROE	5¢/kWh Public ROI	6¢/kWh Private ROE	6¢/kWh Public ROI
			Rate of Return (%)					
Pulp & Paper	Low	4.477	--	--	--	7.7	21.4	12.5
	Med	4.023	--	4.1	--	11.3	31.4	16.3
	High	3.264	--	10.1	29.2	15.5	39.5	19.8
Iron & Steel	High	3.725	--	6.9	24.6	13.6	36.5	18.4
Chemicals	Low	4.221	--	2.3	--	9.5	26.3	14.3
	Med	3.992	--	4.4	--	11.5	31.7	16.4
	High	3.982	--	4.5	--	11.6	31.8	16.4
Food & Beverages	Low	4.473	--	--	--	7.8	21.5	12.5
	Med	4.197	--	2.4	--	9.9	27.7	14.8
	High	4.113	--	3.2	--	10.6	29.7	15.6
Smelting & Refining	Med	3.992	--	4.4	--	11.5	31.7	16.4
Petroleum Products	High	3.994	--	4.3	--	11.5	31.6	16.4
Cement	High	3.027	26.1	14.7	44.6	20.7	59.4	26.0
Other Manufacturing	Low	4.332	--	1.6	--	8.5	22.9	13.1
	Med	3.918	--	5.1	--	11.9	32.4	16.7
	High	3.972	--	4.6	--	11.6	32.0	16.5

7600 MW. For comparison purposes, this is over 1000 MW larger than the installed capacity at the Bruce nuclear generating facility. The analysis presented above also suggests that, assuming a natural gas price of $3/MCF escalated in real terms at 2%/year over the life of these projects, the supply price or LUEC of cogenerated electricity is less than 4.5¢/kWh, regardless of project size (see Table 3). This compares with the value of power provided from Ontario Hydro's bulk supply sources, which was recently estimated by the utility to be in the neighbourhood of 5¢/kWh. Hence, all of the technical potential identified here could be deemed economically attractive under the set of assumptions described.

Considerations of economic efficiency indicate then, that the quantum of cogeneration capacity estimated here should be adopted as a planning maximum when future additions to utility capacity are under consideration. Note that even if the actual value of bulk-supplied power is 4¢/kWh, 92% of the technically feasible cogeneration capacity discussed here could be developed without sacrificing economic efficiency.

The achievable (financially feasible) potentials associated with private and public forms of project ownership are presented in Table 4.

A number of observations may be made based on the results shown in Tables 3 and 4. First, at low buyback rates, few projects are financially viable for the private sector. This analysis indicates that at 4¢/kWh buyback rate, only highly specialized units installed in the cement manufacturing sector are attractive at all. It is

Table 4: Achievable (Financially Feasible)
Potentials for Cogeneration (MW)

Form of Ownership	Buyback Rate		
	4¢/kWh	5¢/kWh	6¢/kWh
Private	132	2993	7621
Public	2409	7621	7621

noted, nonetheless, that such projects offer extremely good returns.

Second, while raising the buyback rate expands the universe of feasible projects, there would seem to be a threshold buyback rate between 5 and 6¢/kWh where all privately-owned projects begin to earn positive rates of return under the scenarios used here. "Fine tuning" the buyback rate offered to private developers in order to raise their returns on equity investment is fraught with difficulty, given the inherently conflicting goals of private parties, Ontario Hydro, and the general public. In any event, such "fine tuning" of buyback rates is inconsistent with the principle that buyback rates should be set equal to the utility's avoided costs.

Third, it is clear that relatively high rates of return on total investment are available at lower buyback rates under the "public" set of investment assumptions. If the differences between the two sets of financial parameters assumed here are valid, then it must be concluded that public ownership could more readily develop economically efficient cogeneration projects, and still earn reasonable "rates of return" for Ontario's ratepayers. For example, in order for the full economic potential for cogeneration capacity to be exploited (assuming a 5¢/kWh value of power), the private sector would require a buyback rate of close to 6¢/kWh. Achieving an equivalent cogeneration capacity at a 1¢/kWh saving has significant implications for ratepayers. The difference (assuming all economically efficient plants are built and that these operate at an 85% capacity factor) amounts to some $566 million per year, or over $11 billion over the operating life of cogeneration plants.

A further difference between the two forms of ownership concerns the sharing of benefits associated with industrial cogeneration projects

when the actual ROEs exceed the required rate of return. The mechanisms for allowing industrial steam hosts and/or other electricity consumers to share in these benefits are more numerous and flexible under public ownership. For example, under a "power-at-cost" regime, the utility division charged with cogeneration development could sell thermal energy to a steam host at a discount such that it earns no more than its required rate of return. Alternatively, the utility could offer its cogeneration division a buyback rate that is no higher than that necessary for it to earn its required rate of return. With privately owned projects, these and other types of sharing arrangements may or may not emerge after costly and time-consuming negotiations on a case-by-case basis.

Additional benefits of public ownership relate to planning and implementation issues. Power system planning would be better served by a utility-owned project developed when and where it is needed, and with a capacity and energy output profile that serves the needs of both the steam host and the utility. As a corollary benefit, the number of industrial steam hosts interested in cogeneration may well increase if the project is designed and owned by a familiar and reliable supplier rather than a third-party private developer.

It may be argued that these differences in achievable cogeneration potential stem from the income taxes borne by only the private developer. This is a simplistic and incomplete explanation. To fully explore the reasons behind these differences would require a study of both taxes and subsidies (for example, Class 34 depreciation), as well as an analysis of appropriate risk-adjusted rates of return for these types of investments in cogeneration plant and equipment. As this paper was intended "only" to identify the differential impacts of these ownership regimes on achievable capacity under a set of currently accepted values for the relevant financial variables, such analysis will need to be the subject of further research.

Conclusions

Traditionally, as a matter of public policy, cogeneration has been left exclusively to the private

sector to develop. In light of current, valid concern over rates of return for privately owned projects, escalating power rates, utility operating losses and related corporate down-sizing, this public policy choice between private and public ownership has been shown here to be in need of re-assessment.

By setting out realistic values for important parameters used in assessing the purely financial viability of cogeneration projects, it has been shown that the difference between what can feasibly be exploited under public ownership vastly exceeds that which meets private sector investment constraints and approval criteria where economic efficiency (and consideration of the ratepayer) dictates the course of development.

The situation suggests that the conventional approach, whereby the ownership of cogeneration projects is left exclusively to the private sector may be sub-optimal from the perspective of economic efficiency. Should the planning process be altered such that supply choices are based on a menu of supply/conservation alternatives, formulated on the basis of LUECs and environmental impacts, Ontario Hydro (i.e., public) ownership and promotion of appropriate cogeneration projects could prove beneficial to all Ontarians.