DELIVERING VALUE:

The Next Evolution of Electricity Distribution in Ontario

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"Your Home Town Utility"

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The

Distributors'

Electricity

Efficiency

Policy

Group

October 2003

The Distributors' Electricity Efficiency Policy Group includes:

Enersource Hydro Mississauga Inc.

Erie Thames Powerlines Corporation

Oshawa PUC Networks Inc.

Veridian Connections Inc.

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EXECUTIVE SUMMARY

The question is not whether change is necessary in Ontario's electricity market design. It is, rather: "What changes are necessary?" The goal of the Distributors' Electricity Efficiency Policy Group (the "DEEP Group") in preparing this Discussion Paper is to identify impediments to the most efficient and effective electricity distribution sector. Because all aspects of electricity markets are intimately interconnected, this paper also seeks to address broad electricity market design concerns from the perspective of the electricity distributor and its customers. Finally, this Discussion Paper will consider policy options and identify and recommend necessary changes.

The DEEP Group is a diverse group of electricity distributors representing approximately 325,000 customers. The DEEP Group believes that Ontario's electricity distribution sector can and should become more efficient and that the current regulatory environment does not provide the underlying conditions to allow such efficiencies to be realized. More broadly, current features of Ontario's electricity market are unsustainable.[1] These features include a subsidized electricity price, frozen distribution rates, a dominant generator, the debt legacy of Ontario Hydro, and the presence of over 90 electricity distribution companies.

I. DISTRIBUTOR SIZE AND RATIONALIZATION

Considerable progress in finding efficiencies has been made by Ontario's local distribution companies ("LDCs"), leading to current rates that are fair and reasonable. However, these rates cannot be sustained unless further efficiencies can be found in order to balance upward cost pressures.

Studies have shown that the most efficient size for electricity distributors in order to achieve economies of scale is between 500,000 and 1,500,000 customers. At present, 50% of Ontario's LDCs serve an average of less than 5,000 customers each. Only two of Ontario's 95 electricity distributors have a customer base larger than 500,000.

[1] "As it stands, residential and small-business consumers are luxuriating in a fool's paradise where retail electricity rates bear little relation to the cost of generating and distributing power. This price cap, which Premier Ernie Eves imposed 11 months ago, is adding tens of millions of dollars of debt to Ontario's books every month and driving away private investors ..." *The Globe and Mail*, October 11, 2003.

Consolidation is one method of achieving such economies. Other rationalization techniques, including a greater reliance on outsourcing or on co-operation with other LDCs, are also available in order to find such efficiencies for the benefit of customers, shareholders and system reliability.

II. Cost Savings from Rationalization

A significant portion of an LDC's budget relates to fixed overhead costs. These fixed costs relate, among other items, to:

- information technology software;
- the development of billing formats;
- the design of communications materials;
- capital investments in transformer stations and municipal substations; and
- underground lines and feeders.

Such fixed costs decline significantly on a per-unit measurement as the number of customers rises. Rationalization of distributors would dramatically decrease province-wide spending on the foregoing items, since each merged utility or cooperating utility group would only need to purchase one software bundle, design one billing format, and as an example, where two utilities might each only use half the capacity of a transformer station, build one such station instead of two. Strategic outsourcing can also be used to improve efficiency related to these functions.

Similar cost savings would be realized by province-wide entities as well, including the Ontario Energy Board (OEB), the Independent Electricity Market Operator (IMO) and Hydro One Networks Inc., since they would no longer have to interface with or review applications from 95 separate LDCs.

Rationalized LDCs have been demonstrated to:

a) realize economies of scale in billing, settlement and call centers;

b) eliminate redundancies and duplication in administration, service centers, inventory and fleet;

c) conduct more economical planning and asset management over larger areas; and

d) reduce production costs as a result of the standardization of materials and equipment.

III. Reliability Improvements and Service Enhancements from Rationalization

Larger LDCs or LDCs that have driven efficiency through grouping and/or outsourcing services have also been better able to develop the functional expertise required to succeed in the new electricity sector by developing centers of excellence for such functions as:

- wholesale settlements;
- retailer dealings and retailer settlements;
- meter servicing;
- call center functions; and
- prudential and credit issues.

The complexity of the new market and the modern work environment lends itself better to more efficient operations where staff can be trained to specialize in one of the functional areas.

From a system reliability perspective, current LDC service area boundaries are often drawn along municipal boundaries, and not along boundaries which are optimal from an electricity grid point of view. Rationalization in the industry would encourage distributors which share an optimal grid region to work together towards a coordinated application of load control, conservation and distributed resources through local resource planning.

IV. Why Has Further Rationalization Not Already Occurred?

Viewed from a shareholder's perspective, many municipalities made a decision to retain an interest in their utilities based on rules that were subsequently changed. As a result, those municipalities have seen the value of their holdings diminish since the time that decision was made. Having lost significant portions of the financial benefit, they wish to retain the remaining benefit of their decision to maintain ownership of their utility - local control.

The province must create certainty and bring value back to Ontario’s distribution companies in order to create an environment where consolidation will be viewed positively by more distributors and their shareholders. One means of accomplishing that objective is to create the positive incentive for merger discussed in this paper, including important changes to the default supply system.

V. Default Supply Consumer Protection

During the period from May to November of 2002, low-volume consumers were exposed to the extreme fluctuations of the spot market. Partly to deal with this, the Government imposed a 4.3 cent/kWh price freeze. However, the price freeze has the potential to cost the government billions of dollars as it subsidizes electricity consumption, impedes investment in new generation and discourages conservation. LDCs, and in particular larger consolidated LDCs or LDCs who aggregate their customers, can play a significant role in addressing this problem by exploring opportunities to serve as Load Serving Entities (LSEs) along the lines of those described below.

VI. Responsibility for Adequate Default Supply Procurement

LSEs would have the responsibility to acquire all of the load consumed by low-volume default supply customers in their territory, and the freedom to procure that power through a variety of competitively procured power purchase agreements (PPAs) with generators and wholesalers. Each LDC would continue to be responsible for default supply within its service area. However, if an LDC did not wish to carry out those duties, it could opt to merge with another LDC to provide a consolidated LSE over a larger area, or contract out its LSE obligations to another LSE, which may be an LDC or other third party.

High-volume customers could also opt to accept the default supply arrangements available to low-volume consumers, subject to their acceptance of certain conditions imposed by the LSE. Those conditions could include a notice period prior to leaving default supply, credit support requirements, separation of large users' default supply portfolio from that of the low-volume SSS customer or other measures designed to deal with the added volume and credit risks related to larger customers.

VII. Benefits of Competitive Procurement by LSEs

Since an LSE's default supply power purchases would be secured only following a competitive bidding process for PPAs, three important goals will be achieved:

a) default supply customers will receive a stable price based on the passed through costs of a mix of short and long term contracts (as opposed to the volatile pass-through cost of the spot price);

b) the default supply price will be a reasonable price, having been secured in a competitive market; and

c) the introduction of LSEs as purchasers in the PPA market will contribute to the enticement of generation investment in Ontario, since one of the major obstacles to new investment has been the lack of long term contract demand.

VIII. Benefits of a Regulated Portfolio

LSEs would be mandated to procure a diverse portfolio mix, including:

- Contracts of various lengths to ensure price stability;
- Green power contracts to satisfy a renewable portfolio standard;
- Contracts with new capacity to further encourage new generation; and
- Some load to be purchased on spot market.

The precise mix would be a matter left for the government's and the OEB's consideration. LSEs would have both the ability and the incentive to satisfy some of its requirements through local options, thereby encouraging the expansion of distributed generation and reducing the reliability risks (due to either system failure or terrorist attack) associated with heavy reliance on the long-distance transmission system.

The default supply price charged by an LSE would be based on a cost-plus pass through system, set for a given time period at the weighted average contracted price for such period, plus a fixed amount per kWh determined by the OEB to cover default supply administration and a reasonable return. Any LSE that succeeded in reducing its administrative costs would realize a greater return. Any savings in the commodity price would be passed directly through to the customer. However, LSEs would have an incentive to secure such commodity savings on behalf of their customers because their return is directly related to the number of customers and kWh sold on default supply.

IX. Credit Requirements and Transition Options

The LSE system outlined in this paper would reduce prudential requirements for LDCs somewhat, since the resulting smoothed price would minimize the financial risk and burden currently assumed by LDCs as a result of the difference between the fluctuating spot price paid by LDCs and the regulated price collected by them. In addition, since many of their power purchases would be settled directly with generators and wholesalers, IMO prudentials would also be reduced. LSEs would need to provide credit support to the generators or wholesalers, but an ability to pledge or assign the revenue streams associated with default supply, together with sufficient credit worthiness, could serve to reduce or eliminate these requirements.

A transition scheme for allowing LDCs to act as LSEs could incorporate one or more of the following:

a) Guarantees or other credit enhancement from OEFC to back LDC exposure in respect of commodity purchase contracts (or perhaps only the riskier long-term purchase contracts);

b) OEFC itself entering into long-term purchase contracts (making up the riskier portion of the default supply portfolio) and such LDCs procuring the remainder of the default supply portfolio through short-term contracts and on the spot market; and

c) OEFC entering into purchase contracts in respect of the default supply portfolio and assigning them to or entering into back-to-back contracts with such LDCs.

X. Regulation of LSEs

The OEB would be charged with ensuring that the power procurement process was prudent, and that suppliers were credit-worthy. The OEB would also be mandated to approve a standard form of power purchase agreement to be used between LSEs and generators or wholesalers, resulting in significant cost savings with respect to LSE and supplier legal fees and OEB review processes. Finally, the OEB would oversee arrangements where an LDC opted to contract out its LSE responsibilities to another LDC or third party.

XI. LSE Role to Incent Rationalization

In addition, any LDC which arranged to secure any benefit from the outsourcing of its LSE responsibilities should be required to return a portion of the proceeds to customers and/or shareholders. Third party LSEs would not be permitted to include any payments made to the original LDC in its administrative costs or pass such costs through to customers. These provisions will protect consumers and serve to encourage rationalization by returning value to shareholders.

XII. Recommendations

The DEEP Group recommends that the following actions be taken by the Government of Ontario and the appropriate regulatory agencies:

- Provide positive incentives to LDC shareholders to rationalize their distribution operations voluntarily through consolidation and/or other methods that will achieve economies of scale and increased expertise. This can be accomplished through the use of policy instruments such as performance-based regulation, payments-in-lieu of taxes and rates of return.
- Explore the concept of permitting LSEs, be they LDCs, third parties selected by LDCs or other rationalized entities, to enter into power purchase agreements in

order to satisfy their obligations to procure default supply for low-volume customers, together with the conditions necessary for all stakeholders to participate in such a system (including those set out in Box III);

- Allow LSEs to receive an appropriate rate of return for carrying out their functions; and
- Set out a transition plan to allow LDCs to become LSEs if they so wish without undue impact on the financial situation and credit ratings of such LDCs.

INTRODUCTION

The electricity distribution business consists of delivering electricity to end-users through low voltage wires (higher voltage in some cases), reading meters, preparing and sending bills, processing payments, operating, maintaining and managing distribution assets and communicating with customers. Until relatively recently, it was not even seen as a business. It was considered more a municipal service. In the recent past, the electricity industry has changed beyond recognition, and electricity distribution has been at the forefront of this change. The complex and intertwined elements that comprise the electricity system and market cannot be modified in isolation and changes to one aspect of the business have subsequent effects on other elements. In the late 1990's, Ontario embarked on a path to fundamentally change its electricity system, of which the distribution sector is a key element.

This Discussion Paper sets out key issues facing Ontario's electricity distribution companies and provides suggested policy directions to address these key issues. This document was prepared by the Distributors' Electricity Efficiency Policy Group (the "DEEP Group"), a diverse group of electricity distributors representing approximately 325,000 customers.[2] The DEEP Group believes that Ontario's electricity distribution sector can and should become more efficient and that the current regulatory environment does not provide the underlying conditions to allow such efficiencies to be realized. More broadly, current features of Ontario's electricity market are unsustainable. These features include a subsidized electricity price, frozen distribution rates, a dominant generator, the debt legacy of Ontario Hydro, and the presence of over 90 electricity distribution companies.

The question is not whether change is necessary. It is, rather: "What changes are necessary?" The goal of the DEEP Group in preparing this Discussion Paper is to identify impediments to the most efficient and effective electricity distribution sector. Because all aspects of electricity markets are intimately interconnected, this paper also seeks to address broad electricity market design concerns from the perspective of the electricity distributor and its customers. Finally, this Discussion Paper will consider policy options and identify and recommend necessary changes.

[2]Approximate number of customers for each DEEP LDC are:

Enersource Hydro Mississauga Inc.	172,000
Erie Thames Powerlines Corp.	13,000
Oshawa PUC Networks Inc.	48,000
Veridian Connections Inc.	91,000

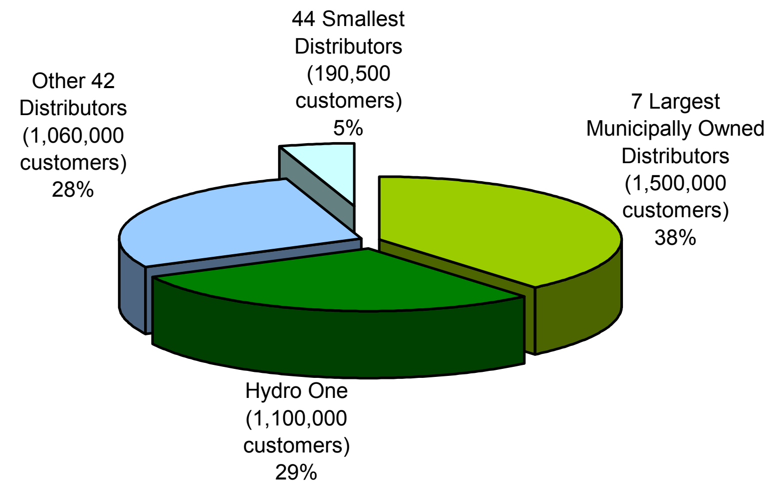
REGULATION OF THE DISTRIBUTOR IN ONTARIO'S ELECTRICITY MARKET

As part of the restructuring of Ontario's electricity sector under the Electricity Act, 1998, electricity distribution utilities moved from a public utilities commission structure to a business structure in 1999 and 2000. The vertically integrated Ontario Hydro was broken up into parts including a generator, Ontario Power Generation Inc. ("OPG"), a transmitter and distributor, Hydro One Inc., an independent electricity market operator (the "IMO"), and a company to hold the stranded debt and non-utility generation contracts, the Ontario Electricity Financial Corporation ("OEFC").

Municipalities were forced to make difficult decisions as to whether to retain their utilities as its sole shareholder, merge their utilities with others and become one of two or more shareholders, or sell their utilities to third party investors, including Hydro One.

The IMO was created to administer the new market and dispatch electricity. The number of electricity distributors in Ontario declined from over 300 in 1999 to about 95 by November of 2000. However, a small handful of utilities service the majority of Ontario's load and customers, and a large number of utilities have customer bases numbering in the thousands or less (see Figure I).

Figure I
Percentage of Customers Served by 44 Smallest LDCs



Distributors incurred millions of dollars in transition costs relating to incorporation of their assets and, in many cases, amalgamations or acquisitions. There were millions more dollars lost to distributors, although tracked in variance accounts, on account of the swing in prices on the day the market opened, in the middle of a billing cycle for many. Distributors expected to be able to recover these amounts in their rate applications following market opening.

In January of 2000, the Ontario Energy Board issued a decision on Performance Based Rates ("PBR") that set the framework for a Market-Based Rate of Return ("MBRR") for distribution utilities. In the spring of 2000, in the face of many distributors applying for maximum permitted rates to reach the allowed MBRR, the Ontario Government introduced Bill 100, legislation that would have limited such rate increases. As distributors opted instead to apply for phased-in rate increases, often over three years, the government decided not to proceed with Bill 100.

Ontario's retail and wholesale electricity markets opened to competition on May 1, 2002. Distributors began to purchase their power at the spot market price through the newly created IMO rather than from Ontario Hydro at a fixed price.

In the new competitive market, customers could enter into fixed rate contracts with electricity retailers for the commodity portion of their electricity bill, or by default they could remain on "Standard Supply Service" with their electricity distributor. Almost all utilities fulfilled their default supply requirements by passing on spot price volatility directly to customers. Some distributors charged their customer a fixed 4.3 cent price for the commodity and created variance accounts to track the differences between the spot price and 4.3 cents, to be settled periodically.

During the hot summer of 2002, spot prices rose sharply as a result of high demand and low supply. Although this was precisely the price signal that the market was designed to send, the dramatic increase to consumers' bills so soon after market opening was politically disastrous. In addition, those utilities that did not immediately pass on these prices were themselves required to finance the purchase of electricity on the spot market, creating unsustainable credit and cash flow issues.

The Government responded. In the fall of 2002, the Electricity Supply, Pricing and Conservation Act ("Bill 210") imposed a price freeze on the electricity commodity for the benefit of residential, small commercial and certain other designated consumers, representing over 90% of the customers in the province and over 50% of the load. The price freeze applied retroactively from market opening. Electricity distributors bore the costs of implementing the freeze through changes to electronic billing and settlement systems, and of mailing out refund cheques.

Furthermore, Bill 210 imposed a freeze on distribution rates until 2006. Prospects vanished for timely recovery of transition costs and power purchase variance accounts accumulated by distributors.

IMPEDIMENTS TO OPTIMAL ELECTRICITY MARKET EFFICIENCY

Ontario's electricity distributors face numerous political and structural impediments to an efficient and effective electricity market. From the perspective of the electricity distributor, these impediments include:

a) lack of sufficient economic incentives to encourage efficiency;

b) inability to recover legitimate expenditures through rates;

c) rate-setting that fails to set a level playing field for distributors;

d) long delay between expenditures and recoveries due to slow rate-setting process;

e) no involvement in the purchase and pricing of the electrical commodity for their default customers;

f) assumption of both the retail and wholesale market risk (if the 4.3 cent/kWh price freeze were eliminated);

g) distribution territories historically related to municipal boundaries, but bearing little relation to optimal electricity distribution service areas; and

h) potentially legitimate but non-financial influences on shareholders to retain stand-alone local distribution companies.

From the wider perspective of the distributor's interest in an efficient and reliable electricity system and market, and from the customer's perspective, impediments include:

a) a frozen and subsidized electricity commodity price leading to:

    i) fewer opportunities for potential generators to enter into forward contracts;

    ii) less incentive to invest in generation in Ontario;

    iii) less incentive to conserve electricity or shift consumption to off-peak hours;

iv) higher demand; and

v) higher spot prices.

b) lack of competition in generation;

c) general uncertainty regarding the regulation of the system and the market;

d) market restructuring stuck between a public power model and a market-driven model (market mechanisms are not present to ensure resource adequacy yet government and regulatory agencies have not assumed this responsibility);

e) a range of issues relating to OPG's role, including:

i) market dominance;

ii) uncertainty surrounding further government investment in existing nuclear generation; and

iii) uncertainty regarding status of decontrol.

CREATING EFFICIENCIES THROUGH CONSOLIDATION AND RATIONALIZATION

I. WHY RATIONALIZE?

The distribution sector in Ontario has already experienced considerable rationalization. As noted above, there are now around 95 distributors in the province, down from around 300 a few years ago. Does this mean that the distribution sector in Ontario would not, on balance, benefit from further consolidation and/or rationalization?

Critics of continuing consolidation argue that any efficiencies emerging from mergers or acquisitions are relatively small, that such efficiencies are outweighed by the related administrative and transaction costs and that, given the relatively small percentage of the customer's total electricity bill represented by distribution charges, further consolidation is not worth the effort. overall utility cost structure. However, those local distribution companies ("LDCs") in Ontario which have consolidated or rationalized their operations have on average been operating more effectively and efficiently since the restructuring of 1999 and 2000. Given the right circumstances and conditions, greater efficiencies can be achieved through further rationalization in the distribution sector, leading to greater savings for customers, higher returns for shareholders, better customer service and potentially increased reliability. Consolidation of LDCs is one method of rationalization which has resulted in such efficiencies in Ontario and in other jurisdictions in the past. There are other methods to consider as well, including a greater reliance on outsourcing or on co-operation with other LDCs.

The specific benefits of further rationalization are set out in the sections that follow.

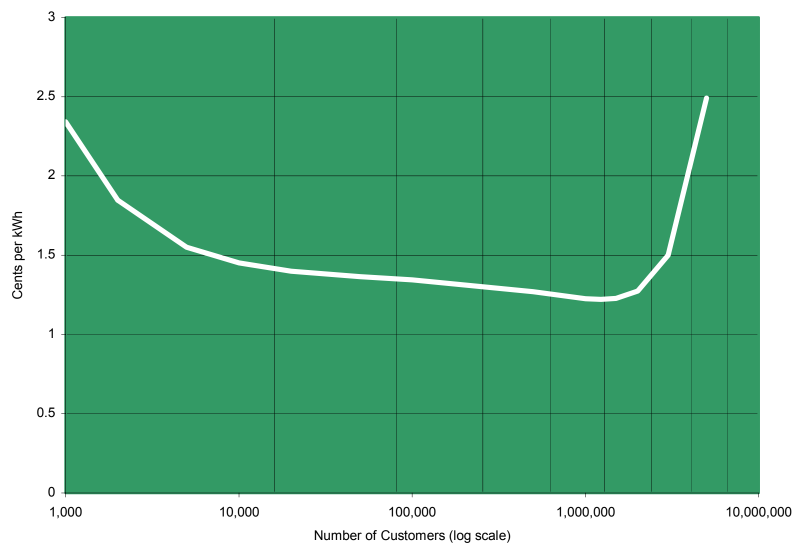
II. THE RIGHT SIZE

While skeptics argue that economies of scale can be elusive, this applies only with respect to merging entities that are already large distribution utilities. Research shows that efficiencies continue to be realized until the size of the customer base reaches 500,000 to 1.5 million.[4] Since no distributor in Ontario other than Hydro One and Toronto Hydro comes even close

[4] *T&D Economies of Scale and the Mysteriously Fitted Curve: A First Cut at the Question of Whether There are Any*, Leonard S. Hyman, R.J. Rudden Associates, September 2003.

to this level, it is safe to say, even in a very general way, that significant economies can be gained through rationalization in Ontario. Whether through a formal consolidation effort or otherwise through shared services and processes, it is evident that serving a larger customer base will provide long term financial and performance benefits to all stakeholders.

Figure II
Distribution Costs



Source: Kwoka, John. *Electric Power Distribution Costs: Analysis and Implications for Restructuring*. February 2001: George Washington University.

III. THE COST-CONTROL IMPERATIVE

Whether or not further rationalization of the distribution sector takes place, utilities will continue to explore opportunities to control costs to help balance the upward pressures on distribution rates that will arise from factors such as the completion of phase-in of MBRR, increased pension costs and recovery of transition costs and power purchase variance accounts.

Looking beyond the frozen distribution rate period imposed under Bill 210, an anticipated PBR regime, associated with unit-cost benchmarking, is expected to drive best practices. Consolidation of the sector into significantly fewer LDCs and/or the elimination of inefficiencies through sharing or outsourcing of services offer opportunities to reduce these unit costs. It could also help create more effective commodity markets by potentially reducing the number of parties that retailers have to deal with in regard to settlements, and could reduce the cost of regulation.

Experience shows that rationalization within the distribution sector has untapped potential for efficiency gains and improvements in customer service as a result of a number of factors, including:

a) economies of scale in billing, settlements, call centers, etc.;

b) the elimination of redundancies and duplication in administration, service centers, inventory and fleet;

c) seamless planning and asset management over larger areas; and

d) the standardization of materials and equipment, leading to lower costs through longer production runs of transformers and cables.

These economic efficiencies and reliability improvements have been demonstrated repeatedly through the mergers and acquisitions that reduced Ontario's over 300 LDCs to about 95.

At the same time, it is important to recognize that different functions have different scale economies. This influences how some functions are best delivered (e.g., by the local or regional LDC or by a centralized service provider). In this regard, best practices (e.g. Reliability Centred Maintenance, automation, resource optimization, etc.) are increasing the need for IT/Infrastructure and driving the search for scale and centralization. Whether it is interactive voice response ("IVR") in call centres, the complications introduced by open markets, work management and trouble outage systems, CIS tools or just the need to automate information flow, all require and are moving towards a heavier reliance on IT solutions. These can have very high initial cost but very low incremental cost, which means that it is desirable to have a limited number of such providers in the province. Many of the existing utilities in the province will never realize the efficiencies in service provision that are made possible through the utilization of these IT tools due to their high cost. Only through a shared service model, consolidation and/or outsourcing can existing distribution utilities truly optimize their processes.

BOX I

CASE STUDY: MERGER

During the initial restructuring of Ontario's electricity industry in 2000, seven former small LDCs merged to create Veridian Connections Inc., a utility which now serves over 90,000 customers. Cost savings directly attributable to the merger were realized in very short order, as a result of the following consolidation factors:

Economies of Scale: *One metering, billing, settlement and electronic business transaction system was installed, saving on the high fixed costs of seven different systems. One efficient call centre was established on a sufficient scale to take advantage of modern call centre software and staff specialization. One system control and dispatch centre was established to operate all system equipment and dispatch staff from a central location on a 7 x 24 hour basis, as opposed to the 9-5 operations of some of the former LDCs. Fixed costs associated with governance and basic administrative services are now spread over a significantly larger customer base. The insurance, audit fees and legal fees on a consolidated basis are significantly less than the aggregate of the seven utilities. With regard to the interface with labour, seven collective agreements were able to be consolidated into one.*

Elimination of Duplication: *Four administration centers were closed down and two more were scaled back. The fixed carrying costs, taxes, insurance, utilities and telephone service declined dramatically. Much of the underutilized and redundant equipment which each utility had to have on hand in the event of emergency was able to be eliminated and higher utilization factors for the equipment that was retained was achieved.*

Seamless Planning over Larger Areas: *Two large service areas serving over 50,000 customers were consolidated into one seamless area. The result was the integration of the distribution system and the availability of transformer stations to supply load across municipal boundaries, improving utilization factors and providing improved reliability at the former service area interfaces.*

Standardization of Materials and Equipment: *Ontario's over 90 distribution utilities use many different material and equipment suppliers and different material and equipment specifications, leading to short uneconomic production runs for material such as wire, cable and distribution transformers. One transformer manufacturing plant can produce Veridian's entire annual requirement for padmounted transformers in a single day. The expense of setting up small production runs for much smaller quantities of unique product for smaller LDCs is a needless inefficiency. The high fixed costs of these production runs become embedded in distribution prices, resulting in a significant premium charged to the customer. Longer production runs stemming from the standardization of materials when utilities merge has the potential to lead to significant savings.*

IV. INCREASED EXPERTISE

Increased expertise leads to better customer service and reliability. What gains will consolidation/rationalization bring to specific distribution functions? The complexity of wholesale and retail settlement systems, meter reading, call centres and management of prudential requirements in today's electricity market has resulted in equally challenging processing requirements. Larger LDCs or LDCs that have driven efficiency through grouping and/or outsourcing services are better able to develop the functional expertise required to work within this new environment by developing centres for excellence within the following areas:

Wholesale Settlements

- Periodic polling of wholesale injection and withdrawal points and reconciliation of same with the values measured by the IMO;
- periodic polling of embedded Hydro One or other LDC (the host utility) injection and withdrawal points and reconciliation of same with the values measured by the host utility;
- periodic polling of the LDC's interval metered customers and the development of the net system load shape and the weighted average price for billing of non-interval metered customers;
- validation of monthly invoices from the IMO and host utilities;
- quality control and editing and validating systems.

Retailer Transactions

- Dealing with retailers regarding customer issues;
- processing of electronic hub transactions pertaining to customer enrolments, customer drops, customer consumption, billing data and periodic financial settlement with regards to the retailers' customers;
- expertise in dealing with invoice bill ready ("IBR") transactions.

Retail Settlements

- Periodic settlement with the retailer's customers (distributor or retailer consolidated billing) and the LDC's customers (standard supply service billing);

- editing, validating and quality control of all retail bills processed and sent to customers;
- reporting all statistical information required by the regulator.

Meter Servicing

- Accreditation of Meter Service Providers qualified to provide metering installations to the IMO's exacting standards with the appropriate investments in test facilities and meter service provider processes and training;
- complex remote interrogation of interval meters over telephone lines or virtual private networks;
- sample testing of installed meter inventory consistent with Industry Canada and IMO standards;
- development of integrated smart meter technology and demand side response systems.

Call Centre Functions

- Operating a modern call centre, resourced with staff with specific skill sets in dealing with customers and the complex questions they ask in today's market environment;
- operating with sophisticated call centre software and integrated voice response systems to enhance the customer's opportunities for self administered service;
- operating a trouble dispatch on a 24/7 basis to deal with power interruptions and life-threatening emergencies;
- meeting exacting OEB requirements for call response.

Prudential and Credit Issues

- Establishing prudential requirements consistent with OEB codes and ensuring consistency in application.
- prudence in collections while being sensitive to customers with risky credit profiles.

The extra degree of specialization and complexity required in today's work environment lends itself better to larger operations where staff can be specifically trained to become expert in one of the functional areas and develop centres for excellence, rather than mastering many different skill sets and being expert at none.

V. AGING WORKFORCE

Over the next five years there will be a steady replacement of skilled workers in the distribution sectors. Some utilities will experience up to a 50% attrition rate during that period. The key area that will be affected are the skilled trades, designers and technicians. It will become increasingly difficult for individual utilities to replace and retain the required skill set. Outsourcing agencies will begin to experience the same knowledge gap as employees move from the private sector to the utilities as opportunities arise.

This will result in a huge knowledge and skill gap that could be reflected in long term erosion of system quality and reliability. Through pooling of talent in a consolidated or shared service model, resources can be centrally coordinated, thus mitigating the result of this skill and "brain drain".

VI. INFORMATION TECHNOLOGY

In addition to the functional specialization, there are large embedded fixed costs for software systems and software maintenance systems that do not substantially change if more customers are served by the same LDC or LDC service group. In addition to the software costs, the fixed costs of developing billing formats and communication pieces can also be spread over more customers if the scale of operation is enlarged. The economies of scale are huge and unit customer costs can be reduced significantly as the number of customers billed approaches 100,000 customers and beyond.

VII. ASSET MANAGEMENT

Considerable savings can be realized in managing assets on a larger scale. LDCs by their nature are capital-intensive businesses. On average, LDCs currently have approximately $2,000 invested in plant related expenditures for every customer connected to their systems. The marginal cost per customer of distribution infrastructure could be as much as double this amount. Plant related capital items for electricity distribution companies includes the costs of

Transformer Stations and Municipal Substations (facilities required to step down voltages so that power can be efficiently delivered to the end use consumer), overhead lines and feeders (the poles and wires along main thoroughfares that move power through the system) and underground lines and feeders (cables, switchgear and protective devices that eventually supply power to end use consumers primarily in residential areas).

For utilities with larger customer bases, system planning engineers in electric utilities examine the consumption habits of their customers as well as the number of customers being added to the system in order to forecast future electrical demand. This information is used to assess the adequacy of supply of existing facilities and to determine if new facilities need to be added to meet future demand. In growing utilities, the timing of when to build facilities to accommodate new electrical demand has a significant impact on its cash flow, profitability and ultimately, the rates it charges its customers.

One of the problems facing planning engineers is that load generally grows at a uniform rate while transformation supply is provided for in large increments (i.e. as a step function). Transformer stations are built in large increments for the following reasons:

a) There are economies of scale in building larger transformer facilities (i.e. the cost per MVA of transformation is generally lower in a 250 MVA station than in a 50 MVA station).

b) Each station requires some form of environmental assessment. Building multiple stations would make the approval process more difficult and pose additional environmental concerns.

c) Land may not be available for multiple sites.

It usually takes a number of years before a new transformer station is fully loaded. This creates unused capacity in plant related assets, which ultimately becomes a charge to consumers. This occurs because the utility is incurring costs related to interest and depreciation charges on the new facility but is not recovering sufficient revenue to fully recover these costs, since the station is not fully loaded. Given that a transformer station can cost as much $25 million, this can pose a significant problem.

Given the existing LDC configuration in Ontario, utilities assess their supply and demand requirements in isolation (i.e. they make capital expenditures to accommodate only their electric load requirements). To the extent that unused transformation capacity can be used by a neighboring utility, capital expenditures can be deferred and assets can be used more efficiently, leading to significant aggregate cost savings for the utilities.[5] Consolidation is one means of achieving these savings, but cooperation between LDCs could achieve the same objective.

These savings can be passed onto consumers in the form of lower rates or to the shareholder in the form of higher profits. Similar arguments can be made for sharing capacity in primary distribution feeders that run adjacent to two LDCs' borders.

VIII. System Reliability

The importance of system reliability was illustrated in the most fundamental way possible during the recent blackout. Ontario must seek to provide the highest possible reliability at the lowest achievable price, arguably two conflicting requirements. Yet rationalization can help to achieve both these goals.

Distribution companies play a key role in the provision of reliable service to customers. They form the final link with customers and through daily contact, the distribution company will know particular customers' reliability concerns. Distribution capital and maintenance programs are driven both by Ontario Energy Board system reliability requirements as well as local safety and reliability concerns of larger customers, for whom the impact of an outage can be in the many thousands of dollars. Outages for companies also have an impact on the local and provincial economy.

In the new electricity market, reliability must be looked upon as a system issue, where the system extends completely from the generation to the customer load. New technologies in the areas of demand side management, system automation, load side reliability measures and distributed generation must be brought into play in a coordinated fashion in order to optimize the reliability and efficiency of the system to the customer. The distribution companies have

[5]For example, if Utility A has recently built a new transformer station with unused capacity of 30 MVA, and Utility B, an adjacent utility, expects load growth of 10 MVA per year over the next 10 years, then under a consolidation regime, Utility B could use the 30 MVA of Utility A's unused capacity, and defer the construction of its own transformer station by 3 years. If the transformer would have cost $15 million to build, then the deferred costs are as follows:

Interest Charges - $15 million x 7% x 3 years	=	$3,150,000
Depreciation Charges - $15 million/40 x 3	=	$1,125,000
Total costs deferred:	=	$4,275,000

been involved in various parts of these activities in the past and they need to play the key role in this integrated activity going forward.

Coordinated application of load control, conservation or distributed resources through a process known as local integrated resource planning can delay the need for transmission expansions or large generating plants. This activity can also improve reliability levels to customers. To be effective this process must sometimes occur across the traditional boundaries of today's LDCs. As an example, feeder automation across boundaries combined with some form of load control could delay the need for a transmission line and transformer station and also allow a more cost effective station to be built when finally required.

Particular customer reliability concerns can be addressed by analyzing the total delivery system. Influencing upstream protection settings on transmission equipment combined with local reliability enhancements at a particular piece of machinery in a customer plant as can lead to a more efficient use of resources when compared to large capital expenditures on the transmission or distribution infrastructure.

Tomorrow's distribution companies must be of sufficient size to effectively carry out these important responsibilities. In the alternative, regional distribution zones that incorporate a systems approach for delivering reliable service to customers must be effectively designed and implemented across the borders of cooperating LDCs in order to optimize effectiveness and reliability of the distribution system. These companies or LDC groups will have the size needed to effectively deploy the integrated technologies that will be critical to the success of the new electricity market.

IX. Standardization of Distribution Rate Design

The basis on which distribution rates are set varies widely across the Province.

Most rate structures have a fixed and variable component, which is consistent with the underlying cost drivers. However fixed charges range from under $2 to over $26 per month, and the variable distribution rate from under 0.25 c/kWh to over 4c/kWh.[6]

Furthermore, some LDCs weight residential rates in favour of commercial rates, and some the reverse.

The OEB's decision has been that utilities embedded in distribution systems (such as municipal LDCs embedded within and served off Hydro One's distribution system) should pay "low voltage" charges to cover the costs of wheeling power across the distribution system. These charges have not been implemented.

In addition, most LDCs were on a path to phase-in market based rates of return over three years, but were at varying stages of that three year phase-in when Bill 210 froze all rates, wherever they were in the process.

As a result of the all the above, rates across Ontario are not currently set on a consistent and cost-reflective basis.

Consolidation and rationalization provide a means for rates to be harmonized over regions and over time in a manner which reflects the characteristics of the region. This will tend to reduce large discrepancies that currently exist between the rates for customers of neighbouring systems.

X. Service Area Boundaries and Municipal Boundaries

As noted above, there are now about 95 Ontario LDCs, down from over 300 before the new legislation. However, the distribution sector still remains highly fragmented. There are an estimated 202 distinct service territories among these 95 LDCs. This has occurred because non-contiguous LDC service territories have resulted from either municipal or LDC

[6] *Report on Ontario's Electricity Bills*, Salvatore Badali, FCA, March 1, 2003, pp. 37-38.

amalgamations. For example, Chatham-Kent Hydro has 11 service territories and Westario has 14 service territories.

Optimal electric distribution service area boundaries often bear little relation to municipal boundaries. In addition, municipal boundaries, unlike most other political boundaries, are subject to continuous revision through annexation and amalgamation.[7]

While some LDCs serve areas which conform to the municipal boundaries of their shareholder or shareholders, many others serve lesser or greater areas. Municipal amalgamations have meant that many municipalities have more than one LDC. Further, LDC mergers and acquisitions have meant that a number of LDCs serve more than one municipality and serve all or part of municipalities other than those of their shareholder(s).

An estimated 45 of the 95 LDCs serve a full, single municipality, with the others serving less than all of the one or more municipalities where they have a presence. Of the other 50 LDCs, an estimated 31 serve less than the single municipality where they are present. An estimated 19 remaining LDCs serve more than one municipality, but only 3 of the 19 serve to the boundaries of all the municipalities where they are present. (See Figure II – LDC Service Territories.)

Most LDCs border on a limited number of other LDCs (usually one or two), given their origins as municipal entities. The exception is Hydro One Networks which borders on an estimated 88 of the 95 LDCs (54 of them exclusively), and 195 of the 202 distinct service territories (158 of them exclusively).

This raises issues as new customer growth occurs in many instances on the fringes of LDC service territories (whether inside or outside the municipality where the LDC is present). There may be some situations where local utilities can provide new connections to customers at a lower incremental cost than Hydro One. However, regional rationalization offers the potential for lower overall costs by optimizing the use of available capacity across a larger region. In addition, LDC expansion does not produce any rationalization benefits, whereas regional coordination does.

[7]Urban municipal boundaries are generally drawn around areas serviceable (either now or in future) by water and sewers which results in discreet urban areas (the cities, towns and villages). Rural municipalities are generally not serviced. The municipal infrastructure is therefore not continuous across the province and for gravity based sewer mains it often follows the drainage pattern of river watersheds. Electricity distribution on the other hand is seamless and continuous and does not respect municipal boundaries or topographical features. As such the organization of such distribution systems is more dependent on larger regional nodes of population rather than municipal boundaries.

LDC boundaries need to be clearly defined and left generally unchanged in order to permit effective system planning (given asset longevity), maintain service and reliability standards, and minimize the safety hazards resulting from overlapping service territories. Consolidation or coordination based on rational operating territories substantially eliminates boundary issues.

FIGURE III

LDC SERVICE TERRITORIES

	LDCs	Distinct Service Territories
Number	95	202
Serving More Than One Municipality	19	*N/A*
Serving a Full Municipality	45	*N/A*
Serving Less Than a Full Municipality	31	*N/A*
Bordering Hydro One	88	195
Bordering Hydro One Exclusively	54	158

XI. ADMINISTRATIVE EFFICIENCY

Often overlooked, a massive consolidation in the number of LDCs, or regulatory coordination among groups of LDCs, can also reduce the administrative costs for the IMO and the OEB with regard to dealing with so many entities. The opportunity to foster the rationalization of the distribution industry through appropriate mechanisms now is a far better alternative than attempting to do so in times of distress later on.

As affirmed by a report commissioned by the government, "a benefit of further consolidation is the reduction in the spread of regulatory oversight needed to support the current environment of almost 100 LDCs. With fewer distribution companies, the OEB could be freed from dealing with the same issue essentially 100 times."[8] The same logic would apply to the IMO and Hydro One's transmission as well, leading to a reduction in the administrative burden of these organizations and potential cost savings.

[8] *Report on Ontario's Electricity Bills*, Salvatore Badali, FCA, March 1, 2003, p. 40.

XII. Better Value for Ontario

Whether through consolidation of the distribution sector or other forms of rationalization, there is a significant opportunity to bring better value to electricity consumers. Cost savings are only one potential benefit of such efforts; others would include a more reliable distribution network and enhanced customer service.

THE SHAREHOLDER PERSPECTIVE

The municipal shareholder has for the most part been patient with respect to its expectations for a modest return on its holdings up to now. Different shareholders will have different views about performance of their distribution companies going forward. Some distributors believe that they can continue "as is", and that their shareholders have come to accept diminishing returns. Others believe that consolidation should take place if there is a business case for the consolidation, but they remain to be convinced that there are further benefits to be realized in the distribution sector through consolidation. The remaining distributors believe the business case exists, but it is not sufficiently strong to overcome the inertia and uncertainty of the status quo.

Notwithstanding the financial drivers that may currently support consolidation of LDCs into larger units (or achieving economies and/or expertise through other forms of rationalization), there are significant pressures that may not be in the best interests of the shareholder or the customer in an ideal market. In addition, throughout the privatization process, municipal shareholders have watched the value of their holdings fluctuate significantly with changing regulation and, just like any prudent investor, they are waiting for certainty before taking their investment in a new direction. The regulatory framework should be revised to provide positive incentive for rationalization of LDCs.

As the regulator demands new embedded levels of productivity improvements in the rate submissions that it will approve in the future, LDCs will be required to come up with creative approaches in reducing OM & A expenses and increasing external revenues. Also, there will be pressure for LDCs to deliver the commercial returns to their shareholders that were intended, while maintaining an acceptable risk profile. If these trends are allowed to continue, for many, if not most LDC shareholders, repeated anemic or negative returns on equity are going to lead to decisions to divest of the LDC or to merge with others to achieve the economies of scale to support appropriate returns on their investment.

There are a number of examples of LDCs which are held by multiple municipal shareholders. Such shareholder structures, especially where there isn't a dominant shareholder, have some inherent advantages in that they tend to be more commercial in nature and less driven by non-financial considerations.

Encouraging rationalization is ultimately going to bring greater value to shareholders, higher payments-in-lieu of tax contributions ("PILs") to the government and higher levels of customer service to the consumer. The removal of barriers and elimination of uncertainty in the market, as well as the introduction of positive incentives for merger, are necessary if the efficiencies and improvements in service that accompany rationalization are to be realized.

Viewed from a shareholder's perspective, many municipalities made a decision to retain an interest in their utilities based on rules that were subsequently changed. As a result, those municipalities have seen the value of their holdings diminish since the time that decision was made. Having lost significant portions of the financial benefit, they wish to retain the remaining benefit of their decision to maintain ownership of their utility; local control.

The province must create certainty and bring value back to the distribution companies in this province in order to create an environment where consolidation will be viewed positively by more distributors and their shareholders. One means of accomplishing that objective is to create the positive incentive for merger discussed in this paper.

STANDARD SUPPLY SERVICE REFORM

I. THE NEED FOR LOAD SERVING ENTITIES

The present system of spot market procurement for default supply does not serve Ontario's needs. Generators who would invest in Ontario need long term contracts to secure financing. The current regime removes the entire default supply load from the contracts market. Furthermore, consumers are exposed to the extreme price volatility which has proven to be politically unacceptable for low-volume customers. Of all jurisdictions that have restructured their electricity markets, there are few, if any, that have opted to pass through spot-price volatility to such customers.

Accordingly, Ontario's electricity market needs entities which would have the obligation to ensure that they have acquired an adequate amount of electricity for those customers within their service area who have not made purchases of power from a third party ("Default Supply" customers). One recommended system would allow for such entities to satisfy their Default Supply obligations by entering into power purchase contracts.[9] Such contracts would provide incentive for new generation and would provide a smoother price to the vast majority of consumers, and voters, who remain on Standard Supply Service ("SSS"). The entities that would carry out such functions can be referred to as "Load Serving Entities" ("LSEs").

II. LOCAL DISTRIBUTION COMPANIES AS LSEs

As those who are closest to the Default Supply customers, LDCs would be appropriate entities to fulfill the role of securing adequate supply (if the conditions set out below are met). Forcing Default Supply customers into relationships with retailers and wholesalers would not to be in the best interests of customers.

LDCs are in the best position to promote demand-side management initiatives across their service areas. They are also well placed to trade resulting emission credits to the benefit of their customers, and are the primary and initial contact point for most customers, particularly

[9] "Utilities that are required to assume responsibility for [default supply] should be allowed to sign long-term contracts and must have reasonable expectations of cost recovery." *Distribution Utilities: Business Models and Financial Issues*, Center for the Advancement of Energy Markets, June 14, 2001 Draft.

Default Supply customers, during times of price volatility, even though at present distributors have no control and bear no responsibility for shifts in commodity price.

In recognition of these factors, the current system already places responsibility for SSS squarely on the local distribution company. This must not change. Every LDC should continue to be obliged to provide SSS in its fixed service area.

However, some LDCs may not have the resources or capacity to fulfill this important role. Therefore all LDCs should have the right to contract out their LSE functions to aggregators, other LDCs or other third parties. This is consistent with the positions advocated by other interested groups.[10]

BOX II

CASE STUDY: A UNIQUE RELATIONSHIP

A recent customer survey done for a large municipally-owned Ontario LDC demonstrates the unique relationship between the utility and its customers.

When asked what are the most important things the utility could do to improve customer service, the response of 37% of the respondents was lower prices - an obvious association of the utility with the total menu of services including the commodity. When asked whether, given the choice, they would choose another utility service provider, 70% of customers indicated they had a favourable rating of the utility, and 54% of residential customers responded by saying that they would definitely stay with their utility - indicative of the commitment and loyalty they have to their utility to provide them with the best products and services.

This demonstrates the unique trust that customers have in their distribution utility to provide them with reliable electricity at a reasonable price.

III. PITFALLS OF A SINGLE AGGREGATE PURCHASER

One such group which supports allowing LDCs to contract out the role of LSE also goes further to suggest the possibility of a single provincial entity such as the OEFC acting as the aggregate procurer of Default Supply across the province.[11] This approach is too risky, for a number of reasons:

[10] "The power for standard supply customers would be secured through a portfolio of power purchase agreements arranged through one or more credit-worthy public or private entities, such as the Ontario Electricity Financial Corporation" *Policy Imperatives for the Way Ahead*. Stakeholders' Alliance for Electricity Competition & Customer Choice, September 23, 2003.

[11] Ibid.

- Such a system could lead Ontario down the road to a situation where the entire provincial SSS load could be priced too high as a result of a single contract or market event.
- Just as a single generator with market dominance is an obstacle to true competition, so is a single consumer. Were OEFC or any other aggregator to act as the sole purchaser for all low-volume Default Supply customers in Ontario, it could be buying up to 30% of the total Ontario demand. This scenario is not conducive to the promotion of a true competitive market. Encouraging multiple buyers and multiple sellers is the most effective way to promote true competition and new supply in Ontario.
- Responsibility for the purchase of supply must be as close as possible to the customer. A central provincial aggregator could not be as effective as decentralized or community-based LDCs with respect to knowledge of local customer behaviour, load forecasting and responsiveness to customers' concerns over high or volatile prices.
- Centralized power planning has not been a success in recent Ontario history. Just as centralized generation has failed to produce optimal results, so would centralized purchasing.

IV. The Generator's and Wholesaler's Perspective

Generators and wholesalers should not be concerned with either the existence or the identities of the LSEs. A greater number of purchasers in the contract market is to their benefit, and the creation of a new class of medium- and long-term contract purchasers will provide the financial and contractual incentives necessary for generators to start constructing new supply in Ontario.

For suppliers to be able to enter into such contracts with any confidence, however, they will have to be assured that the contracting LSE is able to meet its obligations. This will be achieved if the LSE in question either has an acceptable credit rating or has the ability to assign the revenue stream from Default Supply customers to the generator.

V. The Retailer's Perspective

Retailers could have some concerns with the proposed structure. If the Default Supply system were to provide a competitive price that was stable for all customers over the long term, customers might be discouraged from entering into retail contracts.

In order to minimize the effect on the retail market, therefore, the LSE Default Supply option should only be available to those customers who need it most, i.e those who are least likely to have the sophistication to enter into a retail contract and are least able to endure the fluctuations of the spot market. While residential and small commercial customers meet this description, larger users should be left to accept a spot price pass-through unless they expressly choose either to enter into a fixed price electricity contract or to accept the Default Supply arrangements available to low-volume consumers, subject to certain conditions imposed by the LSE. These conditions might include a notice period prior to leaving default supply, credit support requirements, separation of large users' default supply portfolio from that of the low-volume SSS customer or other measures designed to deal with the added volume and credit risks related to larger customers.

In addition, any mark-up to the SSS price of power, whether designed to encourage new or green generation, compensate LDCs for their administrative costs, give LDCs a rate of return on Default Supply or mitigate prudential or credit requirements, would be welcomed by the retailers. An obligation on LSEs to continue to purchase a percentage of default supply from the spot market, the LSE's return on default supply sales, and LDC prudential requirements would ensure that retailers would have sufficient "headroom" within which they can compete for residential and small commercial customers.

VI. The Government's Perspective

Both the Government and the regulators require a system that is **simple, transparent, and easily reviewable**. Although LDCs will have to earn some return on the LSE function, there should not be an incentive for the LDC to seek higher commodity prices. In fact, there should either be a clear incentive for the LDC to seek the lowest possible SSS price, or a simple mechanism whereby the OEB can provide direction and oversight to guard against imprudent procurement strategies.

Government, and all market participants, will also want a system which encourages the development of new generation over the long term, since this has in fact always been the primary goal of electricity restructuring. In addition, Government will be seeking a relatively smooth price for Default Supply customers, avoiding the significant price fluctuations of 2002. Ensuring that Default Supply portfolios are diversified and include a portion procured from longer term contracts will assist in these regards.

Any new Default Supply structure should also provide proper price signals with respect to a significant portion of the load for the purposes of encouraging conservation and demand side management. Leaving large volume customers on the spot price would achieve this.

Finally, with Government's focus on green energy, LDCs may be expected to include a Renewable Portfolio Standard in their power purchase portfolios.

VII. DEFAULT SUPPLY PORTFOLIO

In order to satisfy the requirements and preferred features outlined thus far, an LDC's Default Supply portfolio should be comprised of a mix of contracts for various terms and power types and from various suppliers. In addition, in order to include some price signals from the daily market, and to provide the LDC with some flexibility to account for customers who switch into or out of SSS, a certain amount of the portfolio must continue to be purchased on the spot market.

Some of the attributes of a prudent LSE's Default Supply would include the following:

- Various contract lengths to ensure price stability
- Inclusion of green power to satisfy a renewable portfolio standard
- Mandate some contracts with new capacity (to encourage new generation)
- Some load to be purchased on spot market

The precise mix with respect to each of these factors would be a determination appropriate for the OEB to make after a hearing.

VIII. Distributed Generation

Conferring the LSE role on LDCs and mandating a diverse portfolio mix would encourage the expansion of distributed generation, since LDCs would have the ability and the incentive to look at local options for its purchase decisions.

This would serve to introduce another positive element to the system, as distributed generation provides local solutions to local concerns, and minimizes the reliability risk, due to either system failure or terrorist attack, associated with heavy reliance on the long-distance transmission system. American think-tanks have already acknowledged this reality,[12] as has the U.S. Congressional Budget Office.[13] Distributed generation and a more diverse supply mix may be why the state of New York was able to rebound so much more quickly than Ontario in the wake of the August 2003 blackout.[14]

IX. Credit Support

The role of LSE involves some degree of risk. Firstly, there is the risk that spot and/or forward prices may drop unexpectedly, causing default supply customers to abandon SSS in favour of lower priced retail contracts. This could force the LDC to sell its high cost surplus power on the lower priced spot market. Secondly, there is the risk that, for one reason or another (including regulator interference), the LDC may not be able to pass through the full costs of the commodity to the end-use customer. These are in addition to the LDC's existing risks, including the risk that a customer will not pay its bill, leaving the LDC to cover the entire amount, including commodity cost, of the customer's bill.

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[12] "For decades we have been dependent upon a highly centralized electricity grid. This structure automatically makes it far more vulnerable to large power outages, whether from terrorist attack, transmission congestion, storms, falling trees, or even the occasional squirrel-caused accident. We must work toward a more resilient grid, characterized by 'distributed generation,' that is electricity produced from smaller-scale, decentralized energy generators like wind, solar, fuel cells and other CHP (combined heat and power) systems which are connected to the grid but can continue to generate power for local use if the grid goes down, thus helping to lessen the extent of blackouts." *Fresh Look at Energy Policies Needed in Wake of Blackout*, Environmental and Energy Study Institute, September 5, 2003.

[13] "Most of the nation's electricity comes from large central generation plants and moves over an extensive network of transmission lines, which would be difficult to defend against a physical attack…. If more of the nation's electricity supply originated in the homes and businesses where it was consumed, the adverse consequences of any attack that disrupted the network would be diminished." *Prospects for Distributed Electricity Generation*, Congressional Budget Office, September 2003.

[14] See "The Creaks and Groans of a System in Distress," *The Globe and Mail*, August 22, 2003, page A14.

In order to ensure that LDCs are in a position to manage and absorb these risks, the IMO requires LDCs to post security (called "prudentials") to guarantee performance of their settlement obligations. The financing costs associated prudentials can have a significant impact on an LDC's bottom line, particularly where the LDC does not have a strong credit rating.

Prudential requirements should decline under the proposed default supply system, since the variance between current spot price paid by the LDC and the present rate collected by the LDC would be minimized under a smoothed price system. But such decline would only apply to that portion of the prudentials related to residential and small commercial for whom Default Supply is procured via wholesale supply contracts rather than on the spot market. Prudential requirements would not change with respect to large consumers, whose Default Supply remains on the spot market under the proposed structure.

With respect to credit requirements, the conventional approach is that LDCs with higher credit ratings would be required to post less security. In theory a AAA-rated utility might not have to post any collateral until a certain exposure threshold was reached. In reality, however, because of the quantity of electricity to be purchased for Default Supply, especially if several areas are consolidated and served by a single default supplier, that exposure threshold may be reached rather quickly.

Credit requirements could also be reduced if LSEs had security they could pledge to their suppliers. The ability to assign the revenue stream related to the Default Supply customer class to a generator or wholesaler counterparty would create a security interest for such counterparty. If generators had the legal right to sell their power directly to the customers in the event of LSE default or failure, then lower prudentials or security will be required.

A transition scheme for allowing LDCs to act as LSEs could incorporate one or more of the following:

a) Guarantees or other credit enhancement from OEFC to back LDC exposure in respect of commodity purchase contracts (or perhaps only the riskier long-term purchase contracts);

b) OEFC itself entering into long-term purchase contracts (making up the riskier portion of the default supply portfolio) and such LDCs procuring the remainder of the default supply portfolio through short-term contracts and on the spot market; and

c) OEFC entering into purchase contracts in respect of the default supply portfolio and assigning them to, or entering into back-to-back contracts with, such LDCs.

X. REGULATION OF LSEs

In addition to verifying that LSEs abide by the mandatory portfolio mix ultimately set by the OEB, the OEB would be charged with the task of ensuring that the procurement process was conducted prudently, by ensuring for example that a minimum number of bids were sought and that the most appropriate bid was accepted. This would be similar to the current system for OEB review of natural gas Default Supply, where the OEB ensures the integrity of the utility's purchasing strategy, not the adequacy of the actual individual contracts.

It may also be advisable for the OEB to approve the identity of suppliers selected by LSEs and the price of the contracts, strictly to ensure their viability and credit-worthiness and the supplier's ability to fulfill the contract through the end of the term.

In order to simplify this review process while protecting LDCs from potentially onerous generator demands, the OEB would approve a standard form of power purchase contract to be used by LSEs and generators or wholesalers for the purchase of standard supply. The standard form contract could have a series of optional terms or conditions, and could contain schedules to account for the unique terms of each power purchase arrangement. The basics of the contract, however, would be pro forma, resulting in significant cost savings with respect to LSE and supplier legal fees and OEB review processes.

Further, where an LDC opts to contract out the LSE role for its area to another LDC or a third party, the OEB must have the ability to consent to such arrangement or such third party.

There would also be an important role for the IMO. In this model, the LSE would have an obligation to purchase an adequate amount of supply for the customers it serves. This adequacy obligation would be evaluated by the IMO. In fulfilling its obligation to report on the overall status of demand and supply in the Province, the IMO would aggregate the adequacy criteria for all LSEs and other Market participants to provide a Provincial view of this important item. A new reporting mechanism dealing with the adequacy of contracts entered into in the Province would be an interesting market signal that new generation investors would be watching closely. Early in the evolution of the market, it is likely that

LSEs will be deficient in meeting their objective of a percentage of power from new sources, which again, should be one of the market signals needed to attract new supply.

XI. Determination of Default Supply Price

Some jurisdictions use a "price-to-beat" format, setting a fixed rate for default supply and allowing LSEs to keep the savings from any lower priced wholesale supply contracts that they are able to procure[15]. Among the benefits of this format are the potential for increased return to the LSE, and the incentive to seek lower prices.

However, such a system only works if the price set by the regulator is at the right level, and continues to be at the right level as the regulator changes the price-to-beat from time to time. The prospects for accurate price predictions by the OEB in Ontario are not positive. The OEB in effect already set an SSS price to beat when it capped third party Default Supply at 5.3 cents per kWh.[16] This estimate was clearly off the mark, and as a result not a single service area in the province had its SSS supplied by a third party. Such a miscalculation by the OEB in a price-to-beat system could be devastating to LDCs, whose shareholders would have to cover the difference if the OEB estimate was below the actual contract market price. Similarly, if the price to beat set by the OEB were too high, LSEs would receive an artificial windfall and customers would end up paying higher prices which would increasingly approximate the elevated regulated price.

The natural gas industry in Ontario uses a price pass-through system, a variation of which could be appropriate for default electricity supply. Specifically, SSS price could be based on a "cost plus" pass through system. Effectively, the weighted average contracted price for a given period (likely as long as the shortest term contract entered into by LSEs) would be passed through to SSS customers, together with a charge to cover the LSE's administrative costs incurred in administering the Default Supply, and a specified rate of return. The rate of

[15] For example in Texas, the default supplier is the retailer previously affiliated with the former LDC in a given service area (for example, TXU Energy Services). The default supplier is required to offer residential and small commercial customers (those with peak demand below 1 MW) who have not signed a retail contract a standard rate offering, or price-to-beat (PTB), set by the regulator. The rate is 6% less than the rates that were in effect on January 1, 1999, adjusted twice per year by the regulator to account for changes in fuel costs. This rate is designed to give default supply customers a discount, and allow competing retailers the "headroom" to offer lower rates. Customers served by the default supplier will continue to pay the PTB until 2007, or until at least 40% of the utility's customers have chosen competing suppliers. At that point, the default supplier may charge competitive rates, and will have to manage fuel costs without the twice-annual adjustment.

return could be set at a fixed amount per kWh of SSS sold. Such fixed amount would approximate the administrative costs related to the SSS function plus a reasonable return, and as in the PBR system, the LSE would have an incentive to find efficiencies and reduce its administrative costs, thereby increasing its return.

Including the rate of return in the SSS price pass through, rather than as part of the LDC's normal distribution rate, is appropriate. This would result in responsibility for the LDC's return on SSS being allocated only to SSS customers, as would have been the case with the price-to-beat method.

XII. Load Forecasting

LSEs ought to assume responsibility for load forecasting within their service areas. The risk exposure in contracting for Default Supply gives them the greatest incentive to seek a high level of accuracy, tying the risk to the responsibility. In order to achieve this level of accuracy, it is important that any entities engaging in significant demand side management initiatives provide the LSE with appropriate notice.

Load forecasting, however, can be a complex function, and some LDCs may not be in a position to satisfy the obligation. As with the Default Supply obligation, LDCs should be responsible for either forecasting load themselves or contacting that responsibility out to someone who will. For those LDCs which transfer their default role to another LSE or consolidate Default Supply with other LDCs, they could and likely would transfer or consolidate their load forecasting obligations at the same time.

XIII. What LDCs Would Need in Order to Act as LSEs

For LDCs to take on the role of LSEs, there will need to be certainty on a number of conditions. Some of these conditions are described in Box III below.

[16] Section 2.2.3 of the Standard Supply Code allows an LDC to contract out its SSS obligations to a third-party, including an affiliate of the LDC. However the SSS price charged by third-parties has been capped by the OEB at 5.3 cents/kWh, and therefore no LDC has been able to take advantage of this option.

BOX III

Conditions For LDCs to Act as LSEs

1. *The LSE must be allowed to earn a return / margin on the power it is purchasing on behalf of its Default Supply.*

2. *LSEs must be able to aggregate their purchases of power, and make rates for their customers so that the full cost of those purchases, including administration and margin, can be passed on to their Default Supply customers without discount.*

3. *The LSE must be able to transact in the wholesale spot market to sell power when it is long, and purchase power when it is short. Further, the LSE must have the right to maintain a variance account where such short-term transactions will be accounted (the "Variance Account"). Finally, the LSE must have the right on a periodic basis (e.g. quarterly) to bring the Variance Account to zero balance by flowing such amounts as are appropriate to the shareholder and the rate payers.*

4. *LDCs must have the exclusive right to act as LSE within the LDC's fixed service area, but must also have the right to contract such responsibility out to another entity.*

5. *Regulation must be post action, so as to not leave the LSE in a position where it is paying for power and cannot recover the full cost from its customers. In other words, the LSE cannot be put in a position where it is waiting many months to have rates approved for purchases it is making on behalf of customers at the present time.*

6. *Small customers should have the option to leave Default Supply but should they wish to return after leaving, they must agree to conditions regarding minimum notice periods should they decide in the future to leave Default Supply again.*[17]

7. *Where there is a large industrial or commercial consumer that typically would have access to spot market pricing on a pass through basis, that customer should have the option of becoming a Default Supply customer, but must be subject to certain conditions imposed by the LSE. Those conditions could include a notice period prior to leaving default supply, credit support requirements, separation of large users' default supply portfolio from that of the low-volume SSS customer or other measures designed to deal with the added volume and credit risks related to larger customers.*

[17] This is similar to the situation in Massachusetts, where there is one default supply system for initial standard offer service customers, and a different structure for those who return to default supply after having previously switched to a retailer.

THE LINK BETWEEN LSEs AND RATIONALIZATION

This paper has discussed the financial and service improvement benefits achievable through consolidation or other forms of rationalization. The need for positive incentives to merger is clear. A unique opportunity exists to positively encourage consolidation by permitting distributors to become LSEs.

Our proposal suggests that LDCs would either be required to provide default supply themselves (singly or as a group) as an LSE, or through a contract with a third party LSE. Obviously, there would be potential for distributors to outsource their LSE responsibilities to a third party in exchange for a fee or a percentage of revenues, in an effort to realize accelerated gains and delegate any risks. This on its own would not serve to create an incentive for merger.

However, if LDCs that outsourced their LSE functions to a third party were required to return a portion of the proceeds of any such arrangement directly to customers, shareholders or the system, this would incent distributors to look into the alternative of becoming an LSE itself in order to keep more of the associated returns. Prohibiting third party LSEs from passing on the costs of such payments to consumers by specifically excluding them from recoverable administrative costs would also serve to reduce the amounts such LSEs would be willing to pay to the LDC.

As a result, LDCs will be more inclined to examine ways they can fulfill the LSE role themselves in the most efficient and effective manner possible. LDCs who wish to realize the financial benefits of serving as an LSE would be positively incented toward merger because the ability of a distributor to become an effective and efficient LSE increases with the size of the distributor. Therefore, those distributors with a desire to increase their value will be encouraged to do so through a larger entity that would be the result of a merger.

TRANSITION TO LSE STRUCTURE

With the milestone date of 2006 fast approaching, and the need for new supply in Ontario, a transition to a structure providing for LSEs with an adequacy obligation must be established relatively soon, including implementation of the conditions described in Box III. Further, with a limited number of new entrants to address Ontario's supply shortage issues, market liquidity must be created soon to attract more supply and demand side investments.

Prior to the lifting of the price freeze imposed by Bill 210, perhaps as early as by the end of 2004, LDCs should declare their intention with respect to becoming LSEs. For those LDCs that indicate a willingness to become an LSE they must be in a position to "go live" as an LSE by the time the price freeze expires. Those LDCs who decline to serve as LSEs must demonstrate that they have contracted with a third party to perform that function by the same time. It will of course be imperative that the OEB define the parameters respecting the LSE portfolio mix and such details as:

- Minimum percentage of contracted-for supply (as opposed to spot-market purchase) in the portfolio;
- Renewable Supply (RPS) percentage in the portfolio;
- Adequacy obligation;
- Standardized supply contract provisions (such as ISDA contracts) for the portfolio;
- Regulated uplift on the Default Supply obligation to compensate the LSE for administrative overheads and a reasonable margin; and
- Regulatory codes and oversight for the LSE's obligation.

The preceding Default Supply conditions enumerated in Box III should be in place by the end of 2004 with a scheduled implementation date of May 1, 2006. This implementation date has to coincide with the elimination of the commodity and transmission and distribution rate freeze.

However, we simply cannot wait until 2006 to begin the process of contracting for supply or we could find ourselves at 2010 before new supply is available to take the place of retiring plant and provide supply for load growth. In the interim period, therefore, in order to allow those LDCs who are willing and able to encourage new generation by assuming the LSE role and entering into power purchase agreements before 2006, OEFC should provide credit enhancement with respect to any such contracts, in order to mitigate the adverse impact such undertakings might initially have on LDCs' credit worthiness.

We recommend that the IMO collect a power system congestion constraint uplift on all settlements to provide a pool of funding from which it would incent incremental new generation capacity above a base production limit. The incentives could take the form of an uplift in the settlement prices per kWh to suppliers in the capacity constrained area.

RECOMMENDATIONS

The DEEP Group recommends that the following actions be taken by the Government of Ontario and the appropriate regulatory agencies:

- Provide positive incentives to LDC shareholders to rationalize their distribution operations voluntarily through consolidation and/or other methods that will achieve economies of scale and increased expertise. This can be accomplished through the use of policy instruments such as performance-based regulation, payments-in-lieu of taxes and rates of return.
- Explore the concept of permitting LSEs, be they LDCs, third parties selected by LDCs or other rationalized entities, to enter into power purchase agreements in order to satisfy their obligations to procure default supply for low-volume customers, together with the conditions necessary for all stakeholders to participate in such a system (including those set out in Box III);
- Allow LSEs to receive an appropriate rate of return for carrying out their functions; and
- Set out a transition plan to allow LDCs to become LSEs if they so wish without undue impact on the financial situation and credit ratings of such LDCs.