Final Report of the

Market Design Committee

To the Honourable Jim Wilson

Minister of Energy, Science and Technology

January 29, 1999

Market Design Committee

Suite 1100
151 Bloor Street West
Toronto, Ontario
M5S 1S4
Tel: 416-326-3977
Fax: 416-326-3988

Chair
Ronald J. Daniels

Vice Chairs
Donald N. Dewees
John Grant

Members
Thomas Adams
Bruce Boland
Peter Budd
Aleck Dadson
Julie Girvan
Harry Goldgut
David Goldsmith
Fred Hassan
Souit (Syd) Olvet
Dan Pastoric
Stephen Probyn
James Richardson
Rod Taylor
Karl Wahl

Director of Research
Michael Trebilcock

General Manager
Judy Hubert

January 29, 1999

The Honourable Jim Wilson
Minister of Energy, Science and Technology
4th Floor, Hearst Block
Queen's Park
Toronto ON M7A 2E1

Dear Minister:

We are pleased to submit the fourth and final report of the Market Design Committee. The report is presented in four volumes.

- Volume one reports on the MDC's work in the fourth quarter. In structure and content, it is similar to our earlier reports. It contains:

  - an introductory chapter describing the MDC's decision-making process and providing an overview of its work as a whole
  - chapters on each of the main subject areas, presenting further recommendations related to the implementation of the market design that we proposed in our first three interim reports
  - the proposed licence conditions and directives that were developed with Ontario Power Generation Inc. for implementing the market power mitigation framework
  - proposed guidelines and principles for coordinating the roles and responsibilities of the Competition Bureau and the Ontario Energy Board
  - a draft agreement between the Independent Electricity Market Operator (IMO) and Ontario Hydro Services Company Inc. (OHSCI) , under which the IMO secures operational control of most of the transmission assets in Ontario
  - a complete list of all the MDC's recommendations, and
  - a glossary of technical terms.

- Volume two contains draft market rules. The rules are organized into eleven chapters, including a chapter on interpretation and definitions. The rules cover matters such as accreditation, bidding, confidentiality, dispatch, dispute resolution, liability, metering, network access, outage co-ordination, prudential requirements, reliability, settlement procedures, tariff design, and so on. They have been written in conformity with the Government's White Paper, the *Energy Competition Act*, *1998*, and the market design decisions the MDC recommended in its earlier reports.

- Volume three contains the reports of the Wholesale and T&D (transmission and distribution) Technical Panels. Many of the recommendations of these Panels have been incorporated into the market rules. It also contains the report of the IMO Development Technical Panel, along with the proposed Governance and Structure Bylaw for the IMO.

- Volume four is the report of the Retail Technical Panel, which was received and reviewed by the MDC. It contains the detailed research, commentary and recommendations that the MDC is providing as advice to the Ontario Energy Board, on matters related to the introduction of retail competition.

As you will appreciate, our report represents an enormous effort by a great number of people. We would like to thank you and your staff in the Ministry, especially Ken Knox and Les Horswill, for your support for our work during the past year. We would like to thank the many advisors and experts who supported us in our deliberations, and all those who contributed through the Panel and Subpanel process. We also wish to acknowledge the work of our consultants and our Secretariat, particularly David Thomson and Judy Hubert, in keeping the agenda full, the debates challenging, and the paper flowing.

As Chair, I would like to thank my colleagues who served so ably on the MDC Executive. Finally, and most importantly, I would like to record my appreciation and gratitude to the 14 Members of the MDC for the exceptional diligence, co-operation and good-humour they have shown throughout the year. The pace of MDC deliberations was extremely taxing and required Members to make an extraordinary commitment to this enterprise.

With the tabling of this report, the MDC's mandate comes to an end. We have completed the market design, down to a very detailed level. The torch now passes to the IMO and the OEB, who have responsibility for the many implementation-related tasks that need to be completed before the new electricity market opens in the year 2000.

No one should underestimate the challenges that remain. This said, we believe that we have laid a strong foundation and that the goal of a competitive electricity market is now within reach. The extent of the agreement we were able to achieve on the market design in such a short period bodes well for the success of the Ontario market.

We appreciate the opportunity we have had to contribute to the building of the new electricity system in Ontario, and we extend to you our best wishes as you carry this project forward in the months ahead.

Yours faithfully,

Ronald J. Daniels
Chair

The Market Design Committee respectfully submits its Final Report to the Honourable Jim Wilson, Minister of Energy, Science and Technology.

Chair

Ronald J. Daniels

Vice Chair

Donald. N. Dewees

Director of Research

Michael Trebilcock

Vice Chair

John Grant

Members

Tom Adams (from Aug '98)

Harry Goldgut

Stephen Probyn

Bruce Boland

David Goldsmith

James Richardson

Peter Budd

Fred Hassan

Mitchell Rothman (to June '98)

Aleck Dadson

Souit (Syd) Olvet

Rod Taylor

Julie Girvan

Dan Pastoric

Karl Wahl

Market Design Committee

List of staff and consultants

Secretariat

David Thomson
General Manager (to November 98)
Judy Hubert
General Manager (from November 98)

Elizabeth Banfalvi
Rusty Chute
Beverley Ferreira (from June 98)
Mohamed Kassab
Ron McGinley
Mary McKenna
Rhonda Oud (to June 98)
Carolyn Taylor

Central Market Operations

David Goulding, Senior Vice-President

Charlie Graham
Janice Graham
Ken Kozlik
Paul Murphy
Peter Sergejewich

Putnam, Hayes and Bartlett

Fred Baird, Senior Vice-President
Larry Ruff, Senior Vice President

Tanya Bodell
Bob Borlick
John Chandley
Steve George
Brett Graydon
Doug Green
Bill Hieronymus
David Raskin
Brendon Ring
Jeanne Sole
Alasdair Turner

Stikeman, Elliott

John Stransman, Lead Partner

Martine Band
Margaret Grottenthaler
Lawson Hunter
Brian Pukier
Simon Romano

Market Design Committee –Final Report

Table of Contents

VOLUME ONE

CHAPTER ONE

OVERVIEW

Overview

Table of Contents

CHAPTER ONE

OVERVIEW

1.1 Introduction

The Market Design Committee met for the first time on February 13, 1998, and for the last time on January 18, 1999. During its one year mandate, the Committee completed a considerable amount of work on the foundations for Ontario's new electricity market, consistent with the policy objectives and directions set out in the government's White Paper, *Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario* (November, 1997). Specifically, we have delivered to the Government:

- four quarterly reports, totaling almost 500 pages of analysis and recommendations;
- over 300 pages of wholesale market rules;
- over 300 pages of research and advice to the Ontario Energy Board (OEB) relating to the design of the retail market;
- three self-standing reports from other Technical Panels and their Subpanels;
- an agreement with Ontario Power Generation Incorporated (OPGI) on market power mitigation in the generation sector, including a detailed proposal to implement it;
- a proposed Governance and Structure By-Law for the Independent Electricity Market Operator (IMO); and
- a draft Operational Control Agreement between the IMO and Ontario Hydro Services Company Incorporated (OHSCI).

It is worth noting that the Committee's work was completed on time and under budget.

This chapter begins by briefly re-introducing the Market Design Committee, reviewing its mandate, and describing its decision-making process. It then provides an overview of the market design, with readers' guides to some of the key discussions and recommendations. The third section of the chapter briefly covers some of the transitional issues that will need to be addressed between the tabling of this report and the opening of the market in the year 2000. These issues are addressed more fully in the final chapter of the report.

1.2 Who we are and how we did our work

The Market Design Committee was announced on January 20, 1998, pursuant to Order in Council 2156/97. The Committee's mandate was to make recommendations on the rules and protocols that are needed to implement a competitive electricity market in Ontario, consistent with the policy directions set forth in the government's White Paper on electricity restructuring. The Committee was given a one-year term and was instructed to provide quarterly reports on its progress. It was allocated a budget of approximately $10.5 million.

The Committee was composed of 14 members, who were chosen by the Minister to represent a broad cross-section of interests in the electricity industry. Where appropriate, members were expected to consult with their "constituency". One member (M. Rothman) resigned for personal reasons in June and was replaced by a new member (T. Adams) in August to represent similar sectoral interests.

The Committee had a non-voting Executive, comprised of a Chair (R. Daniels), two Vice-chairs (D. Dewees and J. Grant), and a Director of Research (M. Trebilcock). It was supported by a small secretariat of public servants, and had offices at 151 Bloor Street West in Toronto.

Following a competition overseen by a process consultant, the Committee retained Putnam, Hayes and Bartlett as its lead consultant. PHB is a leading international consulting firm with expertise in many aspects of electricity restructuring, including first-hand experience with restructuring in many other jurisdictions. Stikeman, Elliott was retained as the Committee's advisor on a variety of legal questions.

The Committee met 39 times, in full-day sessions. There was an almost perfect attendance record. Members also attended a number of workshops, and participated on the Technical Panels and Subpanels that operated from mid-September to early December.

A special week-end conference of international experts was organized by the Committee, in the spring of 1998, in Toronto. The conference provided members and the broader public with an opportunity to interact with leading utility executives and regulators from a number of electricity jurisdictions that are undergoing restructuring, including Norway, the U.K., Alberta, Australia, New Zealand, Argentina and several U.S. electricity jurisdictions.

At one of its first meetings, the Committee defined and agreed upon six criteria that would be used in evaluating proposals. The criteria were not used in a mechanical or rigorous way, but were often invoked to focus members' attention on the real tradeoffs that had to be made. The criteria were as follows:

- efficiency
- fairness
- reliability
- transparency
- robustness, and
- enforceability.

Committee decisions were made by "substantial consensus", which normally meant at least 10 of the 14 votes were in favour. The debates were full and open. All members contributed equally and constructively. Discussions were carried on with a strong commitment to fair play.

The Committee met in Plenary for the most contentious issues. Starting in the second quarter, it also met in Subcommittee format for more focussed discussion of particular areas, such as Wholesale, Retail, and T&D (transmission and distribution). Members' advisors were permitted to attend Subcommittee sessions and participate freely in the discussions. The advisors made many valuable contributions.

Officials from the Ontario Energy Board and what is currently Central Market Operations, Ontario Hydro, also participated as expert analysts and advisors. CMO staff played an especially important role on the Technical Panels and Subpanels and made numerous presentations to the MDC. Staff from the ministries of Finance and Energy, Science and Technology attended MDC meetings regularly as observers. The Committee benefitted from presentations by the federal Competition Bureau, the OEB, the Ministry of Energy, Science and Technology, and the Ministry of Finance and its external advisors.

The Committee sketched out a "high-level" design for the market in its first two interim reports. It then established a number of Technical Panels and Subpanels to assist with the development of more detailed rules in the third and fourth quarters. The Panels and Subpanels focussed on specific issues or areas of interest. In total, there were six Panels and 20 Subpanels, involving more than 100 people, most of whom were "seconded" to the market design project by a host of sponsoring organizations and companies spanning all parts of the market and all parts of Ontario.

The Panels and Subpanels contributed by conducting research and developing recommendations on specific issues, consistent with the Committee's evaluative criteria and high-level design. After debate by the full MDC, Panel recommendations relating to the wholesale market rules went to a Rules Drafting Team for translation into legal text, while those relating to the retail market and certain aspects of transmission were accepted for transmittal to the OEB.

In addition to drawing in a large number of experts, the Committee sought to maintain a transparent process through the publication of comprehensive interim reports and the maintenance of an internet website. Key papers and minutes were posted on the website, and stakeholder responses to this material were circulated to MDC members. The MDC website had recorded over 50,000 "hits" as of January 29, 1999. All reports, rules and major papers will be available on CD-ROM.

The Committee's recommendations take a number of forms:

- Some recommendations were advice to the government regarding legislation (prior to passage of the *Energy Competition Act, 1998*), and may influence future Regulations.

- Some recommendations have been incorporated directly into the wholesale market rules that we are now presenting for the Minister's approval.

- Some recommendations are advice to the OEB, which has statutory responsibility for deciding the matters in question.

Finally, as an important matter of clarification, we wish to emphasize that the first three interim reports of the Market Design Committee remain vital parts of the Committee's work. These earlier reports should not be regarded as superseded or replaced by this final report. They contain important parts of our analysis, as well as detailed explanations for many of our earlier recommendations. Considerable efforts have been made to ensure consistency across all our reports. Where minor changes have been found necessary in our earlier analyses or recommendations, they are discussed in the appropriate section of this report.

1.3 An Overview of the Market Design

This section highlights some of the key features of the market we designed. It is obviously not possible to provide a detailed summary of all the Committee's work, given the number and complexity of the issues we dealt with. Readers are referred to the full list of recommendations in Appendix A of this report, and to the detailed discussions and background in the interim reports.

The Independent Electricity Market Operator

One of our first tasks was to recommend a governance structure for the new IMO organization that had been proposed in the Government's White Paper, *Direction for Change*. We also had to spell out in detail the full range of functions that the IMO would need to perform. Among other things, this task involved defining the relationships among the IMO, the OEB, and the transmission owners.

We recommended a hybrid structure for the IMO Board, consisting of five independent directors, nine stakeholder directors, and the IMO's chief executive officer. We also recommended a distribution of stakeholder directors by sector, a process for appointing directors and the Chair, voting rules for the Board, a structure of decision-making panels for the corporation, and many other details. The governance recommendations in our *First Interim Report* were referred to frequently in the drafting of Bill 35, the *Energy Competition Act, 1998*, which was introduced in the Legislature on June 9th. With passage of the Bill (on October 30), we are confident that the IMO is being established as a truly independent organization that develops, administers and enforces the market rules in the best interests of the market participants and the consumers of Ontario.

In recent months, we have continued to work on the Governance and Structure By-law for the IMO, and have included a draft of the By-law in this Report. The By-law spells out critical details of how the corporation will operate. We expect our draft to be reviewed, possibly amended, and approved by the IMO Board prior to being approved by the Minister.

We also did considerable work in the final quarter on principles for the IMO tariff. Our recommendation is that the IMO's costs for administering the market should be recovered through a modest registration or licence fee, plus a simple charge to all buyers based on the amount of energy they purchase.

We recommended in our *First Interim Report* that the IMO should have day-to-day operational control of the transmission network, through negotiated contracts with the transmission owners. In the model we proposed, the IMO has clear and unambiguous responsibility for determining system capabilities as well as the real-time dispatch of generation and loads. This approach ensures non-discriminatory access to transmission and provides for efficient and reliable operation of the network. Transmission owners manage their assets and receive a regulated tariff. The approach was adopted in the *Energy Competition Act, 1998*.[1]

The operating agreement between the IMO and the transmission owners must deal with a number of issues, including the duration of the contract, the specific assets to be included and their characteristics, provisions regarding planned outages of equipment, provisions regarding emergencies, provisions regarding liability for damages, provisions relating to the schedule of payments from the IMO to the owners, and many others. The CMO and Ontario Hydro Services Company Incorporated have been negotiating an operating agreement, a draft of which is appended to chapter four of this report. The agreement is being developed pursuant to principles enunciated earlier by the MDC, and could become the model for similar agreements between the IMO and other transmission owners.

This area of our work required us to focus, as well, on the responsibilities of the IMO, the OEB and the transmission companies in relation to system expansion. Our recommendations specify the process by which transmission investment decisions would be made in the short to medium term. The IMO's role is to provide long-term forecasts about system requirements, and to assess the security and reliability implications of various competing proposals. The OEB considers the costs and benefits of potential transmission expansions and provides plan approval. Its assessment will include potential, competing investments in generation, if any such proposals are forthcoming.

Market Power Mitigation

When the electricity market opens in 2000, Ontario Power Generation Incorporated will control about 90 per cent of domestic generation capacity. In an unregulated market, where there are by definition no price controls, OPGI would be able to push up the price to consumers and adopt strategies to effectively keep new competitive generation companies from getting established in the province. We came out strongly in favour of an up-front "structural" solution to this market power problem.

Accepting that immediate divestiture was not an available option, we advanced a three part plan in our *Second Interim Report* involving vesting contracts to control monopolistic pricing, "de-control" of Ontario Hydro's price-setting plants, and OEB oversight of the targets, as part of its more general responsibility for monitoring the structural evolution of the market. Extensive discussions were held with Ontario Hydro over the summer, resulting in significant

[1] Section 26(2) of the *Electricity Act,1998* provides for certain exemptions from the requirement to provide non-discriminatory access.

improvements on this initial plan. As emphasized in our *Third Interim Report*, the framework agreement we reached with Ontario Hydro was endorsed unanimously by the MDC membership. The Government approved the framework in November, and gave the MDC and Ontario Hydro a mandate to complete the details of the package.

We recommended a price/revenue cap that works over a transition period to prevent OPGI from exercising its market power to bid up prices. Briefly, an average annual cap of 3.8 cents per kilowatt hour would apply on 90 per cent of OPGI's estimated domestic energy sales. If the market price is higher than this, OPGI would receive only 3.8 cents and the difference would be rebated by the IMO to all Ontario customers. Other generators would be paid whatever the market price happens to be (or the bilateral price that they had agreed to if they had entered into a bilateral contract). This arrangement removes most of the incentive for OPGI to exercise its market power through "pricing up". The mechanics of the cap were discussed in the Third Interim Report. Further details are provided later in this report.

Second, we recommended that OPGI be required to reduce its control of the price-setting (i.e. marginal) plants in the market to 35 per cent within 42 months of market opening, and its share of the overall market to 35 per cent within 10 years of market opening. The agreement with Ontario Hydro on these market share reduction targets was an historic moment for Ontario and for the electricity industry in this country.

OPGI will have flexibility in determining how to meet its de-control targets. The MDC favours asset sales and long-term leases, but notes that other techniques may also be possible. The essential point is to transfer the ability to influence price from OPGI to some other party.

It is worth reiterating that the de-control numbers are "must meet" targets. Indeed, we would hope that these targets can be met well within the specified time frames.

Complementing the de-control plan, we also recommended that Ontario Hydro Services Company Incorporated make a "best efforts" commitment to increase inter-tie capacity within three years of market opening.

The third major element of the market power mitigation strategy is regular reviews by the OEB. We recommended several OEB reviews, the first of which will occur at 42 months after market opening and will assess OPGI's success in meeting the initial de-control target on the marginal plants. The success of the strategy depends on there being a strong government commitment to ensuring that the review takes place.

We have worked intensively in our fourth quarter to fill in the details of the market power mitigation framework. For example, we have specified precisely what is covered in the 3.8 cent cap; we have proposed a way to calculate and administer rebates; we have dealt with issues related to inter-tie capacity; we have decided on how to deal with *force majeure* events; and we have considered the issues of local market power and market power in the supply of ancillary services. These and related matters are covered in the chapter on market power.

The Wholesale Market Design

The central task given to the MDC was to design detailed rules for the Ontario wholesale electricity market. An initial, difficult challenge was to determine which items should go into the rules and which should be left to licences, codes, or other instruments.

Broadly speaking, we have drafted rules which address the following issues : who is allowed to participate in the market and under what conditions; what participants are allowed to do and what they are prohibited from doing; how they make bids and offers; what kind of products there are; how prices get calculated; how bills are calculated and settled; how information is provided and used; and many other matters.

In developing the rules, we relied to a considerable extent on the rules documents of the Australian State of Victoria, as well as the rules of the England and Wales system. We also paid considerable attention to the type of rules that exist, or are likely to be implemented, in neighbouring electricity jurisdictions, such as New York and PJM (the Pennsylvania, New Jersey, Maryland system).

Our work proceeded in logical, step-wise fashion from “high-level” design principles through to the production of over 300 pages of detailed rules for the wholesale market.

One of our early decisions was that the Ontario market should have a hybrid structure. It should consist of a voluntary “pool” (i.e. spot market, supplemented by financial contracts for differences), but should also permit physical bilateral contracting among market participants, subject to the equivalent treatment of bilateral and spot market traders, and to fair and reasonable allocation of the costs of settlement systems.

Physical bilateral contracts are agreements between individual buyers and sellers of electricity that, having informed the IMO, are netted out of the IMO’s settlement process. (In the case of a financial bilateral contract, the full amount passes through the spot market and is settled with the IMO; the two parties normally settle between themselves for the difference between their contracted price and the spot price.) In our recommendations, the parties to a physical bilateral contract, who must be licensed market participants, will inform the IMO in the pre-dispatch process of the amount of energy they have scheduled between them, and the locations at which it will be injected and withdrawn from the grid. Each site must also independently specify ‘increments and decrements’, in effect telling the IMO that if the market price in the dispatch reaches specific levels, they would be prepared to add to, or subtract from, the scheduled injections or withdrawals. (Any deviations from the scheduled amounts would be settled with the IMO at the market price.) The selling participant must inform the IMO of the amount(s) to be netted out of the IMO’s settlement process, identifying the specific withdrawal locations and quantities.

Market participants expressed a clear and strong preference for a model that permits physical bilaterals. We recommended a hybrid market, based on the principle that traders should have maximum flexibility to structure commercial transactions in whatever manner they regard as best. How much of their business they transact through the spot market and how much through physical bilaterals is entirely up to them.

As noted, however, we did recommend two important limitations on the use of physical bilaterals, one to ensure equal treatment of bilateral and spot traders, and one to ensure that the costs of settling physical bilaterals at the retail level are shared fairly.

We also recommended that the IMO should administer a voluntary, day-ahead forward market for purely financial contracts, in addition to the real-time (pre-dispatch) market.

We concluded that such a market could be run at minimal cost, and could provide a useful hedging mechanism for market participants. We cite the recommendation here as another example of our intent to design a market that gives significant commercial flexibility to market participants.

We discussed the issue of generation capacity at considerable length. In a competitive market, no profit-maximizing generator will want to hold idle or under-performing capacity. This creates concerns that short-term capacity shortfalls could occur. We recommended in our *Second Interim Report* that expected shortfalls in capacity be addressed through a market in a new type of capacity reserve, which the IMO could activate as and when necessary. The principle is that the IMO should have the ability to intervene if an appropriate level of investment is not forthcoming, provided the mechanism used reflects market-based principles and is not unduly intrusive. Our capacity market proposal was outlined in our *Second Interim Report* and is developed in more detail in the wholesale market chapter of this report.

The IMO will, of course, be disseminating information on the long-term market outlook. Generators and transmission owners can use this information to plan their investments. Ultimately, good information and correct price signals are the keys for ensuring the timely expansion of the system.

Our market design includes a bid-based market for certain ancillary services that are needed to ensure system reliability, notably regulation and operating reserves. This recommendation is worth noting because it illustrates a key point about the market design project: the "competitive market" we are designing is necessarily much broader than just a market in commodity electricity.

From a technical point of view, there are many challenges in running multiple, integrated markets in a manner that is fair and efficient, and ensures reliability. The market clearing logic we recommend uses a joint optimization procedure to handle this problem. In the coming months, the market rules we are submitting should be adjusted to include regulation in the optimization procedure as recommended in our *Second Interim Report* (Recommendation 3-8*)*. The market rules also accommodate the provision of ancillary services to the IMO through competitively sourced contracts and must-run contracts when local supply and reliability are an issue.

One of our key recommendations regarding the wholesale market is that there should be a locationally-uniform price for electricity for the first 18 months of the market, but that, thereafter, congestion pricing should be introduced, initially for wholesale market participants and later, with OEB approval, for all retail end use customers. Our recommendations on this topic were contained in our *Second Interim Report*, and continued to inform much of our work in our third and fourth quarters.

When congestion occurs on a section of the transmission network, higher-cost generation has to be substituted for the lower-cost generation that would otherwise be used. For the first 18 months, the cost of this "redispatch" will be spread across all customers and a uniform price will be maintained. Under congestion pricing, energy prices would differ from place to place whenever congestion exists, reflecting the real-time marginal cost of supplying energy at each point on the network.

We strongly support the principle of congestion pricing. The point of introducing a market is to produce price signals that lead to socially desirable decisions. Pricing for congestion ensures more accurate price signals. Customers in an area experiencing persistent congestion get a signal to alter their consumption level and pattern; generators get a signal as to where they should build; and transmission owners and the regulator get a signal about where line improvements or expansions are most urgent. In short, pricing for congestion is essential if we are to secure economically rational investment decisions. Other jurisdictions have adopted congestion pricing, or are moving in this direction.

We strongly reaffirm the review process and dates for congestion pricing that we recommended in our *Second Interim Report*. Throughout our work, we have pursued clarity, certainty and commitment to market-based solutions. These are values that we, as stakeholders, would like to see respected as the government, the IMO and the OEB address the congestion pricing issue in the future.

The Environment

The MDC's terms of reference required it to consider appropriate environmental protection measures in the design of the electricity market. Our *Second Interim Report* included 12 recommendations on the environment. Our representatives have since met with senior staff at the Ministry of the Environment to explain our proposals and encourage their consideration by the government. We also sponsored two environmental workshops.

We understand that the government will be reviewing options for regulating emissions from the electricity sector. In our view, an air emissions cap and trade program should be launched at the same time as the electricity market is opened to competition. Public acceptance of the electricity restructuring initiative is tied intimately to the adoption of measures to control power plant emissions and to otherwise protect and improve the environment.

Also prominent in our *Second Interim Report* were a number of recommendations relating specifically to "green power". For example, we recommended that the market rules should allow green power to be advertised and marketed to customers, subject to development of a mechanism for verifying green power claims and associated provisions in retailer licences. We also recommended that all sellers of electricity to end-use customers provide information on the generation source and the pollution emissions associated with that electricity. These recommendations are based on our desire to ensure opportunities for environmentally-friendly generation, but without compromising consumer protection.

Transmission and Distribution

Most of our work on “T&D” was concentrated in our third and fourth quarters.

As discussed in chapter four of this report, we recommend four classes of transmission service for inclusion in the market rules. The principal class is basic network service, which would be paid by all customers in Ontario.[2]

In simple terms, the rate for basic network service would be determined by dividing the total costs of providing this service, as approved by the OEB, by estimated demand to arrive at a per kilowatt charge. All wholesale customers in Ontario would pay this standard per kilowatt charge times their peak hourly demand in the most recent month. The charge would ultimately be passed through to end-use consumers.

The transmission charge is a “capacity charge”, designed to recover the fixed costs of the transmission infrastructure. It is calculated the same way for all Ontario customers and is amenable to various models of “performance-based” rate setting.[3] The design thus meets the government’s commitments, as set forth in the White Paper.

We concluded that exports and wheel-through transactions should not be charged in respect of the fixed costs of the transmission system. However, the parties to such transactions would be required, like all other bilateral traders, to pay any redispatch costs occasioned by their transactions, plus losses and a pro rata share of the IMO costs. Our recommendation has implications for Ontario’s relationships with neighbouring control areas, particularly in regard to the treatment of wheel-throughs. We recognize the need to consider the reciprocity principle in the application of our proposal.

An interesting policy challenge is posed by new relatively small-scale generators that are built for self-supply or to supply the local distribution company. On the one hand, we do not want to discourage such investments, since new generation will be needed and investments in smaller scale generation are often environmentally preferred. On the other hand, we do not want to create a situation where investments that would not otherwise be undertaken are being undertaken solely to avoid transmission charges. The economic signals are clearly not correct if investors are building new generation with an all-in energy cost that is higher than the price of energy obtainable from the grid.

To deal with this issue of “uneconomic bypass”, we propose to charge for transmission on a gross load basis, which means that market participants who install new embedded

[2] Except where exemptions apply. See Footnote 1.
[3] Ibid.

generation after a defined date would pay for transmission on the basis of their demand inclusive of the amount supplied by the new generation.

We consider the bypass issue to be very important. Tolerating incorrect prices and unfair cost shifting in the initial market design could lead, in the long run, to resource misallocations that are no less serious than those of the old monopoly regime.

The gross load recommendat ion is in fact central to our thinking about transmission. By securing the principle that sunk costs should not be avoided or shifted onto others, it lays the foundation for new ways of thinking about transmission pricing and investment.

Traditionally, investments in generation and transmission were planned and implemented on an integrated basis by Ontario Hydro. With the opening of the market, future generation investments will be undertaken on a decentralized basis by competing firms. This makes it necessary to rethink the process by which investments in transmission will be made, and how generation and transmission expansions will be co-ordinated in a competitive market.

We recommend that transmission investments continue to be centrall y planned during the initial years of the market, with a major analytical and assessment role for the IMO, and oversight by the OEB. The costs of new investments would be rolled into the costs to be recovered through the transmission tariff.

However, we foresee the need to move to a regime where transmission investments are market driven. As mentioned earlier, congestion pricing is a pre-requisite for such an entrepreneurial approach. An entrepreneurial approach also requires acceptance of the idea that the beneficiaries of a transmission expansion should pay for it, and have rights with regard to its future use. In our *Third Interim Report*, we presented a set of principles that we think the OEB should consider when it revisits transmission pricing and investment issues, following the introduction of congestion pricing.

We also dealt with a large number of technical issues in the fourth quarter, leading to rules for outage co-ordination and the calculation and apportionment of line losses.

With regard to distribution, we draw attention to our work on the practical aspects of separating transmission and distribution, and on the importance of separating the distribution wires business from competitive retailing.

Retail Competition

In its White Paper, the government announced its intention to introduce full retail competition at the same time as it introduces wholesale competition. This plan ensures that every consumer in the province, irrespective of size or location, experiences the benefits of industry restructuring.

The OEB has responsibility for most of the key decisions that will shape the nature of the retail electricity market, pursuant to the *Energy Competition Act, 1998*. Given our terms of reference and the need for compatibility between the wholesale and retail markets, we have undertaken to provide the OEB with a substantial volume of research and advice about the retail market.

Our key retail initiative was to require local distribution companies to pass through the wholesale spot market price to end use consumers. This is critical to ensuring that the long-term price reductions expected from introducing competition at the wholesale level flow through to customers, including those who choose to remain on default supply. If the benefits of reform are not fully passed through, then the restructuring will have failed in one of its key objectives.

We recommend that default supply – for those who stay with their traditional supplier – be provided on the basis of a smoothed (averaged) spot market price, with true-ups on a defined schedule. The smoothing methodology and time period would be the same for all default suppliers in the province.

By averaging over multiple billing periods, the smoothed spot option has the advant age of mitigating the cash flow impact of market price volatility on consumers. But, at the same time, it maintains a clear connection to the spot price, giving customers a reason to think about conservation and a benchmark against which they can judge some of the supply options that competitive retailers in their area may offer.

Our *Third Interim Report* explains the advantages of the smoothed price option, relative to, for example, fixed price contracts from the distributors.

The pass through of the spot price is critical to the exercise of genuine customer choice at the retail level. Drawing on the natural gas model, we specified the mechanics of how retail choice will work. Our recommendation is that distributor licences should require the distributor, at a customer's request, to send the customer's spot-priced bill to a competitive retailer named by the customer. The retailer would then pay the bill, and settle up with the customer on the basis agreed between the two of them.

The bill, which reflects the customer's usage and the weighted hourly spot price, is the "foundation" on which customers and retailers can negotiate competitive supply contracts. Using the information on the bill, they can settle between themselves according to whatever terms and conditions they have agreed upon. For example, a consumer seeking strong protection against future price increases could negotiate a fixed-price contract with a competitive retailer. A customer who prefers no price averaging at all could negotiate to simply pay the actual spot price over the billing period. Such contracts are easily written and settled, given the initial bill. The customers are able to exercise choice and select the combination of price and risk that they are most comfortable with. Along the way, the competitive retailer may offer value-added services that would not otherwise be available.

In our more detailed recommendations, we develop the conditions that would allow for alternative billing options, such that the customer could interact exclusively with the retailer, exclusively with the distributor, or with the former for energy and the latter for wires charges. These are refinements that increase market flexibility, at minimal cost beyond that of customer education. We also developed a number of recommendations related to the customer transfer process.

The *Energy Competition Act, 1998* permits default supply and competitive services to be provided by the same corporate entity. Some of our members believe it makes good business sense to organize their affairs this way. Others are concerned about the incremental regulatory burden that will likely be involved in ensuring that the bundling of these activities in a single entity does not result in significant anti-competitive behaviour.

In our *Second Interim Report*, we made recommendations which addressed the risks to the market of two key types of anti-competitive behaviour: cross-subsidization of competitive businesses by monopoly businesses, and preferential access by competitive businesses to default customer information. We continue to believe that these risks are serious.

We also considered the question of how default customers are served if the local distributors provide default supply through their retail affiliate or a third party that provides competitive electricity services. We are concerned that transfer of customer data to an affiliate or a third party could unduly advantage the affiliate or third party, thereby discouraging the entry of new competitive retailers and effectively denying consumers the "real choice" the Government has promised them.

One of the more technical issues we had to address on the retail side concerned the retail settlements system, and specifically, how customers' hourly consumption will be estimated, considering that few customers will have interval (hourly) meters. An estimation technique is needed because bills will be computed using hourly spot market prices.

In the fourth quarter, we examined in detail the vari ous approaches introduced in our *Third Interim Report*, and decided in favour of the net system load shape. The net system load shape is basically the hourly profile that is left when the hourly consumption of all interval metered customers is subtracted from the distributor's hourly purchases from the IMO. Our work on this topic is summarized in the report of the Retail Technical Panel. Importantly, we recommend that competitive retailers not be permitted to compete by offering alternative profiles.

Over the longer term, advances in metering technology will be an important factor affecting the depth of the retail market. In our *Second Interim Report*, we recommended that the retail metering market should be opened to competition for customers above 50-kW consumption in the first year, with the OEB to determine within three years whether further unbundling would be of benefit to small-volume customers.

In the fourth quarter, we pressed forward on a number of aspects of the metering issue. Our Retail Technical Panel advised that, for practical reasons and under current federal law, metering would have to be provided through either the distributor or a retailer. It would not be possible, at least in the period immediately ahead, to have metering companies directly approaching retail customers. However, it will be a significant step in the right direction if distributors begin to contract out significant amounts of their metering work to competitive suppliers.

As in the wholesale market context, we explored many issues around confidentiality and access to data. While we recognize that a robust retail market depends on significant data being available to competitive retailers, we come out firmly on the side of consumer protection and privacy. In our view, the success of the market will depend in large part on the existence of conservative procedures that minimize the risks of customer data being transferred without clear and explicit customer authorization. Similarly, there should be strict controls to prevent the unauthorized transfer of customers from one business entity to another.

One of our key recommendations in this area is that consumers always have the right to access their basic information, such as the records on their meter reads or their payments history. While this is generally the case now, the policy should be enshrined by the OEB through licences to ensure that competitive retailers are covered.

Another key recommendation is that no entity be able to use basic consumer information for secondary purposes unless the consumer explicitly agrees in writing to such use.

Consumer protection goes hand in hand with consumer education. A great deal of work needs to be done to ensure that consumers are ready for the commencement of retail competition in 2000. Consumers need to be informed of how the new system will work, and of their rights and responsibilities. The report of the Retail Technical Panel includes an extensive list of the kinds of information that customers will need in order to understand and evaluate their options.

Among other things, we recommend that the OEB be responsible for ensuring that educational information is available to consumers on an on-going basis. We further recommend that distributors, as a condition of licence, be required to distribute consumer education materials issued by the OEB or the Ministry of Energy, Science and Technology.

1.4 Next Steps

In our fourth quarter, we paid considerable attention to the question of how the market design might best be carried forward, once the MDC disbands. The design work needs to be fine-tuned and quickly moved into implementation mode, including the writing and testing of the market software. A great deal of work remains to be done by others before the Ontario market will be ready for business in the year 2000.

We established a special Transition Panel to deal with such issues. The Panel's task was to identify the major work elements that need to be completed during 1999, and, where they are not already clearly assigned, recommend an appropriate assignment of responsibility. The Panel's report was adopted by the Committee and is the basis for the final chapter of this report.

We make a number of recommendations in regard to continuation of the stakeholder consultation process, the activation of the IMO Technical and Market Surveillance Panels, and the principles that should inform any retail or other pilot projects.

The Committee has had the privilege of working closely with CMO staff over the past year. We have received outstanding advice and support from all levels in that organization. We do not underestimate the challenges the CMO faces in establishing itself as the IMO and implementing a market under the tight timelines that have been given. However, we are confident that this organization is up to the challenge, and that it fully understands the design we are recommending.

The CMO's tasks for 1999 are clearly defined: to fine-tune and complete the market design, to build and test the market and settlements software, and to engage market participants through education and demonstration programs. We understand that a CMO stakeholder consultation process is well under way.

The OEB, as the new electricity regulator, will also play a critical role during the transition. We understand that the OEB is rapidly developing the capability to discharge its new responsibilities. We note the significant steps that have already been taken with regard to licencing and transmission rate orders.

In the final analysis, however, the success of the market hinges on continued leadership by government. We have consistently taken the position that market rules can only be as good as the policy climate that is created for them. With this in mind, we conclude with four comments:

- It will be critical, as the market unfolds, for government to monitor the market structure and to work closely with the OEB and others to ensure that the fledgling market is not undermined by market power abuses. This applies not only to generation, but to all other parts of the electricity industry.
- It will be critical, as well, to move ahead with determination on an emissions standards program and other environmental measures. Done well , the introduction of competitive electricity markets will bring many environmental advantages; done poorly, the result could be both higher emissions and new anti-market forms of intervention and control.
- The Ministry of Energy, Science and Technology should continue to consult with stakeholders, both directly and through the IMO, to ensure fair treatment of all market participants through the market implementation stage and beyond.
- Finally, and perhaps most important of all, it will be essential for government, the OEB, and others, to ensure that substantial, well-designed consumer education programs are in place, so that end-use customers know what is happening, and understand their rights and options.

CHAPTER TWO

MARKET POWER

Market Power

Table of Contents

CHAPTER TWO

MARKET POWER

2.1 Introduction

The Market Design Committee's *Second* and *Third Interim Reports* addressed the issue of market power. In the *Second Interim Report* the concept of market power was discussed, using examples from other jurisdictions, and we developed a menu of possible policy and contractual mechanisms to control market power in Ontario's generation sector. The *Third Interim Report* contained a negotiated market power mitigation strategy that was agreed to by the MDC and Ontario Hydro in consultation with officials from the Ministry of Energy, Science and Technology and the Ministry of Finance. The agreed strategy primarily affects the successor corporation of Ontario Hydro's generation division, Ontario Power Generation Incorporated (OPGI) but some elements affect Ontario Hydro Services Company Incorporated (OHSCI) as well.

These proposals were approved unanimously by the MDC and have been endorsed by the Minister of Energy, Science and Technology.

This report carries our efforts a further step – translating the negotiated market power mitigation agreement into proposed legal instruments. These legal instruments, once instituted, will principally govern the actions of OPGI in the electricity market.

2.2 Summary of the *Third Interim Report* Recommendations

The *Third Interim Report* contained the elements of a market power mitigation strategy in a series of recommendations jointly supported by the MDC and Ontario Hydro.

The major elements of this agreement can be categorized into three areas:

- A "price cap" provision that establishes an average price ceiling ("contract average price", CAP) for a significant proportion of OPGI's power sales ("contract required quantity", CRQ) with provisions for rebates when the price cap is exceeded on an annual average basis;
- Decontrol targets, both short-term and long-term; and
- "Best efforts" undertakings by OHSCI to expand intertie capability with some restrictions on OPGI's ability to monopolize import capacity.

In addition to the jointly agreed set of recommendations, we made some additional recommendations. These recommendations focussed on preferred decontrol actions, accountability for decontrol progress and periodic reviews by the Ontario Energy Board of OPGI's progress in meeting the decontrol targets.

Elaborating these recommendations and making them operational have been the focus of our market power activities since the issuance of the *Third Interim Report*. The MDC and OPGI entered discussions soon after the report was published. These discussions had several objectives:

- Refining the definitions of the CAP and CRQ;
- Specifying how CRQ may be adjusted to account for decontrol measures;
- Defining *force majeure* events and adjustments resulting from them;
- Specifying the rebate mechanism;
- Developing a structure to deal with ancillary services, capacity reserve markets, local market power and location-based marginal pricing; and
- Developing appropriate legal instruments to formalize the structure of the market power mitigation strategy.

2.3 The Legal Framework

The passage of the *Energy Competition Act, 1998* determined the broad legislative and regulatory framework for restructuring the electricity industry. Legal instruments for effectuating the market power mitigation strategy must be derived from this framework.

The menu of legal instruments available within the legislative framework includes the following:

- Regulations;
- Licence conditions;
- Market Rules;
- Directives and Ministerial referrals to the OEB; and
- Agreements.

Individually, or in combination, some of these instruments may be applicable to more than one aspect of the market power mitigation agreement. On the other hand, some of these instruments may not be appropriate for any of the market power mitigation measures.

In the choice of legal instruments, certainty was a desirable objective for us. The more certain the legal instruments for the strategy the higher the probability that its provisions will be carried out.

One of the secondary objectives of the market power negot iations was consideration of the financial viability of OPGI. Providing an adequate capital structure and securing an investment grade credit rating for the successor corporations are primary objectives of the Ministry of Finance. Certainty of the application of the market power mitigation strategy, particularly with respect to the provisions that affect revenues, is also an important consideration for these objectives.

Essentially, the choice of appropriate legal instruments for enacting the market power mitigation strategy is a balancing exercise. Certainty and public accountability are required, but both need to be appropriately balanced to achieve a workable market power solution.

2.4 Matching the Instruments to the Recommendations

Our *Third Interim Report* contained fourteen specific recommendations that formed the market power mitigation strategy. In the post-report negotiations over the legal structure for implementing the strategy, the OPGI and MDC negotiators debated the merits of the individual instruments and how best to match them to the recommendations.

Although the negotiating teams recognized the certainty accompanying regulations, both sides recognized that licence conditions coupled with Ministerial directives and referrals could prove to be an acceptable alternative.

Consultation with Ministry of Energy, Science and Technology and Ministry of Finance officials revealed a strong preference for the method of licence conditions and Ministerial directives and referrals. Therefore, the negotiating teams focussed on this method in developing the legal instruments.

2.5 Issues and Legal Instruments for the *Third Interim Report* Recommendations

In our *Third Interim Report*, we listed seven joint recommendations of the MDC and Ontario Hydro for market power mitigation. In addition, we included seven additional MDC recommendations in the report. These additional recommendations were directly related to market power but were more policy oriented than the joint recommendations.

The following section of this report reiterates the relevant *Third Interim Report* recommendations verbatim[1], includes a short discussion of the issues that were considered in the negotiations for the legal instruments to effectuate each of the recommendations and provides an exhibit reference to the proposed instrument.

Recommendation 1-1

For a period of four years after the opening of the market, 90% of OEGC's expected domestic energy sales will be subject to a price cap of 3.8 cents/kWh on average. This OEGC price cap (which excludes any CTC) will facilitate Ontario customers experiencing immediate and demonstrable benefits from electricity restructuring, and provide for a relatively stable average price for electricity in the province. This price cap and other electricity costs should be structured so that the blended or "all in" price of electricity (energy price, CTC, transmission and distribution tariffs, and IMO charge) would not

[1] References to "OEGC" and "OESC" should be interpreted as references to "OPGI" and "OHSCI", respectively.

exceed the current retail price, which averages 7.2 cents/kWh. The OEGC price cap may be subject to further change as a result of the Minister of Finance's industry financial restructuring efforts and electric power market conditions prevailing at the time of OEGC's capitalization.

The major issue in this recommendation is the calculation of "90% of OEGC's expected domestic energy sales" (the "CRQ", Contract Required Quantity).

The intent of the market power mitigation agreement was to prevent OPGI from receiving excessive financial benefits from exercising market power in the domestic market while not hindering OPGI's ability to participate in export markets. Even without an "obligation to serve" the domestic market in the new legislation, it was expected that OPGI power would comprise the vast majority of supply at least for the initial years of the competitive market. However, the reference to "expected energy sales" requires a predicted quantity based on forecasts of energy supplied by OPGI – a quantity that cannot be known with a great degree of certainty or precision *ex ante*. Accordingly, the CRQ was developed through detailed modeling of OPGI's expected hourly output by advisors to the MDC in consultation with OPGI. (See **Model Output Data, defined in Exhibit A, Part 3, para 1**). Furthermore, the total annual CRQ is a summation of the hourly quantities over the four-year period.

Individual units' hourly contribution to CRQ is required for determining adjustments to the CRQ volumes and rebates for decontrol of facilities and *force majeure* events. The detailed unit data is also expected to assist in preserving the required data for CRQ administration in the event that location-based marginal pricing (LMP) is adopted after market opening. **Exhibit A, Part 3,** defines the licence conditions for OPGI that will establish CRQ and other elements of a price cap mechanism, the events that trigger an adjustment to the CRQ, and the mechanisms for both adjusting CRQ and determining and adjusting the rebate.

Recommendation 1-2

Under the price cap regime, OEGC will provide a rebate to customers when market prices would otherwise result in OEGC receiving an average price greater than 3.8 c/kWh in respect of the defined quantity of energy. OEGC would be entitled to keep all revenues from the sale of energy it produces in excess of the defined quantity. Details of the price cap regime, such as caps and weights, would be public information. The form and operation of this regime are described below.

The negotiating teams agreed quickly that the best instrument for implementing this recommendation was an agreement between OPGI and the IMO (referred to as the Settlement Agreement) coupled with a compliance clause as a licence condition. In addition, since the calculation of the rebate depends on both a price and quantity calculation, parts of the proposed licence conditions for OPGI are also instrumental in fulfilling this recommendation (see previous section).

However, extensive analysis of related issues was required, such as:

- Frequency of rebate calculation and payment (annual);
- Treatment of ancillary services and constrained on/off payments (out) and capacity reserve payments (in) revenues as part of the price cap revenues;
- OPGI permitted to accrue and carry forward shortfalls without interest;
- Treatment of OPGI's physical bilateral contract customers (no adjustment to CRQ, rebates paid to counterparties and may be assigned to OPGI);
- Pass through of rebates to final customers and settlement procedures (Ontario only, delivered to meter); and
- Rebate adjustments for *force majeure* events.

Exhibit E, "Terms and Conditions of Proposed Settlement Agreement Between IMO and OPGI", contains the terms of a Settlement Agreement that would take the form of a contract between the IMO and OPGI. Most of **Exhibit A, Part 3** is relevant to this recommendation as well. In addition, a draft licence condition that binds the IMO to the terms and conditions of the contract is included as part of **Exhibit B.** The responsibility of other market participants to pass-through rebates to final consumers is included in the proposed license conditions in **Exhibit D.**

Recommendation 1-3

By the end of 42 months after the market opens, OEGC will be required to have transferred to others effective control over enough in-service tier 2 capacity that OEGC's effective control of total Ontario in-service tier 2 capacity at that time will be 35% or less. Effective control over a minimum of 4000 MW of in-service capacity must be transferred. At OEGC's discretion, up to 1000 MW of hydroelectric generation could be substituted for tier 2 capacity.

We considered two major issues in the negotiations.

We had to establish a process to determine if a specific action by OPGI will qualify as a transfer of effective control. This function is the responsibility of the OEB at the 42-month decontrol review, or earlier upon OPGI's request to the Board for a determination. These responsibilities are contained in the proposed licence conditions for OPGI, **Exhibit A, Part 4, para.1 and Ministerial directive and request in Exhibit F.**

We also had to determine the consequences in the event that OPGI fails to achieve its decontrol target. The OPGI licence conditions coupled with the Minister's directive and request for the OEB to conduct a review and make recommendations (**Exhibit F),** confer on the OEB the responsibility to recommend appropriate action to the Minister responsible.

Recommendation 1-4

There will be no restrictions on OEGC's ability to export power. During the four-year period over which the price cap is in force, OEGC will be prohibited from purchasing in-bound transmission rights or importing electricity into Ontario, where such rights or imports exceed 35% of the available incoming intertie capability. To the extent that OEGC enters into firm long-term imports, they will be included as parts of OEGC's in-service tier 2 capacity.

Although this restriction on OPGI's import capability seems straightforward there were several issues to consider.

First, the value of intertie transmission capability to importers varies greatly because Ontario's system load shape has distinct peaks (dual winter and summer peaks) and low demand in the shoulder seasons. A single value restriction, such as 35 per cent in the recommendation, could possibly be met by controlling 100 per cent of import capability during peak (high electricity price) seasons and a considerably lower percentage in the shoulder (low electricity price) seasons. Both negotiating teams agreed that this type of outcome was not the intent of the recommendation.

Second, the negotiating teams considered whether this type of restriction should be extended to other market participants in the interests of a competitive market. We decided that the market rules that specify a competitive auction process for allocating intertie capacity are sufficient to prevent the exercise of market power by other market participants. Therefore, extending the 35 per cent restrictions generally to other market participants was unnecessary. **Exhibit A, Part 5** contains the proposed licence conditions for OPGI.

These proposed licence conditions are written to reflect 35 per cent of the existing intertie capability in terawatt-hours for the specific six-month periods designated as winter and summer. This approach is based on the assumption that the market rules applicable to transmission service would preclude transmission customers from reserving transmission service only during peak hours, unless such reservations are submitted shortly before service is to be taken. Such reservations are provided in FERC's Order No. 888 *pro forma* transmission tariffs. If the market rules do not provide similar restrictions, these sections of proposed licence conditions should be rewritten to apply to the acquisition of transmission capacity rights as well as the importation of MWhs of energy.

Recommendation 1-5

OESC will be expected to undertake best efforts to expand intertie capacity with neighbouring jurisdictions by approximately 2000 MW within three years of market opening.

In our *Second Interim Report* we noted the following:

"Ontario Hydro Service Company (Servco) has identified grid investments that could expand by some 1,800 MW the total capacity to import electricity into Ontario from the US, Quebec and Manitoba. If these projects can be justified by proponents on the basis of a cost/benefit evaluation and are approved by the OEB, we believe that they should be implemented as soon as practical."

(*Second Interim Report of the Market Design Committee*, June 30, 1998, page 2-25.)

Discussion around our recommendation focussed on whether the general condition of a 2000 MW expansion was sufficient or should the recommendation be more specific as to which neighbouring jurisdictions should receive expanded service and how large the expansion for each intertie should be. In addition, we discussed how to ensure that uneconomic interties are not constructed. Ultimately, both teams agreed that the general condition was sufficient. They also agreed that the MDC's proposed procedures for OHSCI (or other proponents), the IMO and the OEB to plan and authorize future investments in transmission and intertie capability would be adequate.

While the market power mitigation agreement calls for undertaking "best efforts", both teams recognize that economic tests are a necessary part of the planning and approval procedures for these investments. The teams agreed that the costs associated with the expansion should be allocated and recovered from market participants according to the principles and procedures that will apply to any transmission system expansion. (See Exhibit C, Part 3, "Proposed OESC Licence Conditions".)

Recommendation 1-6

As part of this initial arrangement, OEGC commits to developing a strategy for reducing effective control of enough of its capacity (tier 1 and tier 2) so that by no later than the end of the tenth year after the market opens, OEGC's effective control of the total of tier 1 and tier 2 capacity at that time will be 35% or less, at which time the price cap regime will terminate.

This recommendation is concerned with the stipulation that OPGI commit to developing a strategy for meeting the decontrol targets. This commitment is proposed as a licence condition. **(See Exhibit A, Part 4 para. 1 (a)(iii).)**

Recommendation 1-7

In order to promote a more competitive market structure, by the end of 42 months after the market opens, as part of the program to transfer effective control over some tier 2 capacity, OEGC will undertake not to transfer such control to any entity that will consequently control more than approximately a 25 % market share of the total Ontario tier 2 capacity. Similarly, within the first ten years after the market opens, and as part of

the program to transfer effective control over capacity, OEGC will undertake not to transfer such control to any entity that will consequently control more than approximately a 25% market share of the total of Ontario's tier 1 and tier 2 capacity at that time. Furthermore, these transfers of control will not include any on-going arrangements that could facilitate interdependent behaviour. Transfers that do not meet these two conditions shall not count towards achieving the 35% objectives listed in paragraphs 3 and 6. OEGC may request the Province of Ontario to direct the OEB to determine whether a particular transfer meets these conditions. An OEB review and determination should not exceed three months.

The negotiating teams undertook to clarify the requirement for OPGI to meet the conditions contained in this recommendation. The proposed licence conditions that do so are in **Exhibit A, Part 4, paras. 1 and 3**. **Exhibit F is also relevant.**

Recommendation 1-8

With respect to decontrol actions, the MDC notes its strong preference for sales and long-term leases because they transfer ownership or operating and price setting control.

We, the MDC, reiterate this recommendation to reinforce our position that sales and long-term leases are preferred to any other methods of decontrol. There are no proposed licence conditions, Ministerial directives or referrals associated with this recommendation.

Recommendation 1-9

In order to enhance the credibility of the commitments in this agreement, the MDC recommends that the Government, as part of these ex ante market power mitigation measures, commit itself before the end of 1998 to directing the OEB to initiate, 42 months after the market opens, a review of whether OEGC has met its 42-month target to reduce its share of tier 2 capacity to 35%. As part of their review, OEGC must provide a plan for achieving the 10-year target, including identifying intermediate milestones. To the extent that OEGC has not met the 42- month target, the OEB would be expected to consider a wide range of mechanisms for achieving a stable structural solution to market power through to year ten, including recommending to the Minister additional decontrol of OEGC assets. If the 42-month target has been met, the OEB should evaluate the appropriateness and form of on-going price control over OEGC's tier 1 generation for years five to ten, not altering the long-term objective, and should make recommendations to Government thereon.

Given the Minister's support for the *Third Interim Report* recommendations on market power and subsequent discussions with Ministry of Energy, Science and Technology officials that indicated support for the directives, we are comfortable that these directives will be forthcoming. (**See Exhibit F.**)

Recommendation 1-10

The MDC recommends that the Government commit itself now to directing the OEB to initiate, 7 years after the market opens, a review of OEGC's progress towards the milestones it identified as part of the 42-month review.

(See Exhibit A, Part 4, para. 2 and Exhibit F.)

Recommendation 1-11

The MDC recommends that the Government commit itself now to directing the OEB to initiate, 3 years after the opening of the Ontario electricity market, a separate review of whether OESC has made best efforts to expand intertie capacity with neighbouring jurisdictions.

(See Exhibit F and Exhibit C, Part 3, para. 2.)

Recommendation 1-12

The MDC recommends that the Government institute appropriate non-statutory means for effectuating these recommendations.

This report provides the Government with a proposed set of non-statutory means to fulfill this recommendation.

Recommendation 1-13

In order to promote a more competitive market structure, the MDC recommends that the existing NUG contracts not be administered by OEGC.

Reflecting our recommendation, we note that Ontario Hydro has initiated a tendering process for transferring control of these contracts to third parties. We also note that OPGI will not administer these contracts.

Recommendation 1-14

The MDC recommends that OEGC file annual reports in the five-year period after the initial four-year review (i.e. years five through nine) with the Energy Returns Officer of the OEB on progress towards the ten-year decontrol target. These reports will indicate the specific actions that OEGC took in the previous year and plans for the upcoming year to progress to the ten-year target.

(See OPGI proposed licence conditions, Exhibit A, Part 4, para. 4.)

2.6 Other Issues Addressed by the Market Power Negotiation

In addressing the central issue of implementing the market power mitigation strategy a number of other subordinate, but important, issues arose. Some of these issues are the result of the particular market design and structure that we are recommending for Ontario. Other issues arose as sub-topics of market power that we did not specifically address in our *Third Interim Report.*

Capacity Reserve Market

The market design we are recommending permits the IMO to establish a capacity reserve market if it determines a need for one. The market design anticipates that this capacity reserve market will be closely aligned with the energy market.

The negotiating teams resolved that if this market is established, then the capacity reserve market prices and revenues should be part of the price cap and rebate regime. This decision required the negotiating teams to develop a formula for calculating a new average market price for price cap comparisons to determine whether a rebate should be paid and the amount of the rebate. This price calculation is described in **Exhibit A, Part 3, paras. 5 and 7.**

The possibility of a capacity reserve market developing also raised another point in the market power negotiations. Counterparties to physical bilateral contracts will have to consider whether they want to contract for capacity reserve at the same time that they contract for energy in anticipation of the possibility of the capacity reserve market being established by the IMO. If they do not contract for capacity reserve they could be liable for capacity reserve payments in addition to their energy payments.

Local Market Power – Constrained On and Constrained Off Payments

Generators have local market power when they can operate behind a constrained transmission interface without competition from other generators. In this situation, generators may be able to predict when they will either be constrained on or off and tailor their bidding behaviour to maximize their returns. These circumstances can arise for any generator.

Because the problem of local market power is not confined to OPGI, the negotiating teams concluded it was inappropriate to imbed a process to mitigate local market power within OPGI's licence conditions. The negotiating teams suggest that procedures for local market power mitigation should be included in the market rules that will apply to all generators and the IMO.

Essentially, the proposed rules establish a market test administered by the IMO to determine if bid prices are competitively set. If the bids fail the test, the IMO can then acquire from generators cost information to establish a high and low range for constrained on/off payments. Also, the IMO is given the power to levy penalties with respect to bids that are outside the cost-based range.

The details of the proposed market rule are contained in **Exhibit G.**

Environmental Laws – Adjustments to CRQ

We recommended in our *Second Interim Report* that the Ministry of Environment establish a tradable emissions permit system for the electricity generation industry. As of now, the future direction of environmental laws with respect to emissions has not been finalized.

However, the negotiating teams were aware that environmental laws and regulations could have a significant impact on decontrol actions taken by OPGI and that they could be a limiting factor in the operation of some generating units by a transferee. Since CRQ is adjusted for decontrol actions, a formula was required to adjust the CRQ credit to reflect the operating constraint that may be imposed on a transferee as a result of an emissions permit system, or any other limiting environmental regulations.

The formula proposed in **Exhibit A, Part 3, para. 3 (b)** is intended to be universal, i.e., it is applicable to the existing regulatory regime for air emissions (NOx and SOx) and possible future standards for other emissions (carbon dioxide, mercury, etc.), and to focus on the limiting condition. For example, the existing regulation for NOx is most likely to be more onerous because it will be a limiting condition at lower levels of energy output than the existing SOx limits.

We expect that similar considerations would apply in determining whether decontrol targets have been satisfied.

Force Majeure

The negotiating teams established a definition and listing of *force majeure* events, i.e. events reasonably outside the control of OPGI, and a sub-set of definitions to handle categories (Isolated *Force Majeure* Event, Cumulative *Force Majeure* Event) of events. These definitions are used to establish materiality thresholds for the events (Isolated *Force Majeure* Event is 250,000 MWh, Cumulative *Force Majeure* Event is 500,000 MWh, and Change in Law *force majeure* is $60 million, measured as the net impact on OPGI's annual net income) and to give OPGI some options for designating how to handle events to minimize financial impacts. **(See Exhibit A, Part 3, para. 2 (c) and 8 (a)**.)

Ancillary Services

The market design that we are recommending permits ancillary services to be provided by a combination of market-based functions and contracts. OPGI may be able to exercise market power in the provision of ancillary services, such as regulation and operating reserves, which may be delivered through a market-based procedure.

The negotiating teams developed a procedure for OPGI to provide these services through a bid cap mechanism that controls the potential exercise of market power while recovering their justifiable costs. Unless the IMO determines that competitive conditions exist for providing these services, then this bid cap process would apply, subject to agreement between OPGI and the IMO on the terms and conditions of the bid cap. In the event that agreement cannot be reached, the parties are to rely on binding, commercial arbitration to resolve their differences. The revenues from the sale of ancillary services by OPGI should be considered separate from, and not included in, the revenues under the price cap and rebate mechanisms. **(See Exhibit A, Part 6.**)

2.6 Co-ordination of the Institutional Roles and Responsibilities of the Ontario Energy Board, the Competition Policy Bureau, and the Market Surveillance Panel of the IMO

In both the MDC's *Second* and *Third Interim Reports*, we made recommendations that the Ontario Energy Board and the federal Competition Policy Bureau should initiate discussions with each other with a view to reaching some form of understanding as to their respective roles and responsibilities for monitoring and redressing competitive abuses in the Ontario electricity industry. This is an important issue, and has proven problematic in other industries and jurisdictions that have embarked upon restructuring of formerly monopolistic industries into competitive industries, where the roles and responsibilities of the industry-specific regulator and the general competition policy authorities have not been well thought through and co- ordinated at the beginning of the process, leading to unnecessary confusion, duplication of effort, and issues falling between cracks. In the case of the Ontario electricity industry, not only is the Ontario Energy Board, as the industry-specific regulator, and the Competition Policy Bureau implicated in monitoring and redressing market abuses, but also the Market Surveillance Panel of the IMO has important monitoring responsibilities in this area.

The MDC sponsored a Workshop on these issues in November 1998, which was attend ed by MDC members and advisors, and representatives of the Ontario Energy Board and the federal Competition Bureau. In the light of the Workshop discussion, a meeting between representatives of the OEB and the Bureau was convened by the MDC executive in December, which led to the draft set of proposals attached hereto, which were circulated to MDC members for reactions in late December.

Some reactions to these proposals have recently been received by the MDC, but time has prevented us from attempting to take account of them, in consultation with the OEB and the Competition Policy Bureau, in further revisions to the tentative set of proposals. Thus, these proposals should be viewed as work in progress. Further reactions would also be welcome. We have passed along reactions that we have received to the Chair of the OEB, the Director of the Competition Policy Bureau, and the Chief Executive Officer of the IMO. Further reactions gshould be sent directly to these agencies, preferably before the end of February. In the light of these reactions, we suggest that representatives of the OEB and the Competition Policy Bureau, in consultation with the Chair of the Market Surveillance Panel of the IMO, once appointed, should formulate a further set of draft proposals for circulation to, and written reactions from, stakeholders, supplemented perhaps with a Workshop where reactions can be explored more fully. In the light of this further round of reactions, we suggest that the Ontario Energy Board, the Competition Policy Bureau, and the Market Surveillance Panel of the IMO set a target for settling a final set of proposals shortly after the appointment of the Market Surveillance Panel. The proposals should, of course, be made public.

See Exhibit H for the specific proposals that were tabled with the MDC in mid-December.

This report and following Exhibits constitute our final contribution to the resolution of the market power question. We are confident that the approach we have taken is responsible and fair to all parties.

EXHIBIT A

PROPOSED OPGI LICENCE CONDITIONS

Note: The numbering used below assumes that general licence conditions would be included as Parts 1 and 2 in all cases. All exhibits may require adjustments to conform to the definitions contained in the IMO market rules.

PART 3. PRICE CAP AND REBATE

1. Definitions and Interpretation

In Parts 3 through 6 inclusive of these Licence Conditions:

"**Average Price**" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by summing the product of the Hourly Price multiplied by the Contract Weight for all hours of that Settlement Period;

"**Changes in Law**" means changes in law (including without limitation environmental laws, laws affecting OPGI's generation facilities, tax laws and the general laws affecting the regulation of electricity in Ontario), but excluding provincial tax laws and, for greater certainty, excluding changes in licence conditions and market rules;

"**Contract Required Quantity**" or "CRQ" means the quantity of energy upon which any Rebate is determined, in respect of a Settlement Period, as set forth in the Model Output Data and as may be modified pursuant hereto. Subject to such adjustments, the CRQ will equal the sum of all Hourly Quantities for all hours in a Settlement Period;

"**Contract Weight**" or "CW_h" means the weighting for each hour in a Settlement Period, h, that is used to calculate the Average Price. For any particular hour, the Contract Weight equals the Hourly Quantity for that hour divided by the CRQ for that Settlement Period;

"**Effective Control**" in respect of output means control over the timing, quantity and bidding into the Ontario market of such output;

"***Force Majeure* Adjustment**" or "FMA" means a reduction in the Rebate as a result of a *Force Majeure* Event;

"***Force Majeure* Event**" means an event defined in clause 2(c)(ii) of Part 3 below;

"***Force Majeure* Replacement Cost**" or "$FMRC_h$" means, for any particular hour in a Settlement Period, h, the predetermined net incremental replacement cost for each OPGI generation unit, as set forth in the Model Output Data that is used in determining the *Force Majeure* Adjustment, and as may be modified pursuant hereto. $FMRC_h$ may be constant in the Model Output Data over the hours in a month or other period;

"**Hourly Quantity**" or "Q_h" means, for any particular hour in a Settlement Period, h, the quantity of energy upon which the Contract Weight is established, as set forth in the Model Output Data. The sum of the Hourly Quantities for all hours in a Settlement Period equals the CRQ for that Settlement Period;

"**Hourly Price**" or "P_h" means, for any particular hour in a Settlement Period, h, the unconstrained spot price for energy for that hour expressed in a price in $ per MWh, as determined by the IMO pursuant to its market rules;

"**Hourly Reserve Capacity Price**" is the hourly market clearing price of reserve capacity;

"**Hourly Unit Quantity**," or "q^i_h" means, for any particular hour in a Settlement Period, h, the hourly quantity of energy associated with a particular OPGI generation unit, i, upon which the Hourly Quantity is established, as set forth in the Model Output Data. The sum of all Hourly Unit Quantities for all OPGI generation units in respect of an hour equals the Hourly Quantity for that hour;

"**IMO**" means the Independent Electricity Market Operator established pursuant to Part II of the *Electricity Act*, 1998;

"**Locational Spot Price**" means, for any particular hour in a Settlement Period, h, and any particular OPGI generation unit, the spot price for energy at such generation unit's interconnection, which will only apply if location-based marginal pricing is developed in Ontario;

"**Model Output Data**" means the data provided pursuant to the Final Report of the Market Design Committee. The Model Output Data contains data, some of which is confidential, derived from a production cost model of the electricity market in Ontario and neighbouring regions under the assumption that OPGI is assumed to bid its generation units in a manner that achieves an average sales price of $ 38/MWh. The resulting CRQ, Q_h, and q^i_h data reflects 90 per cent of OPGI's predicted sales to Ontario customers;

"**OPGI**" means Ontario Power Generation Incorporated, the licensee hereunder;

"**Potential *Force Majeure* Event**" means an event defined in clause 2(c)(i) of Part 3 below;

"**Price Cap**" or "CAP" means $38/MWh, which is the threshold used in calculating the Rebate;

"**Price Spike Adjustment**" or "PSA" means the reduction in the Rebate as a result of qualifying price spikes, as calculated pursuant hereto;

"**Prime Rate**" means the variable annual rate of interest, calculated on the basis of a calendar year, announced from time to time by the IMO's then principal Canadian banker as the reference rate of interest (commonly known as its prime rate) then in effect and used by such bank for determining interest rates on Canadian dollar denominated commercial loans made by it in Canada to customers of varying degrees of credit-worthiness;

"**Rebate**" or "R" means the amount OPGI must pay the IMO as a consequence of the Average Price in any Settlement Period exceeding the Price Cap, less any applicable adjustments;

"**Rebate Carryforward Adjustment**" or "RCA" means the adjustment in which negative Rebates from a Settlement Period are used to offset Rebates in subsequent Settlement Periods;

"**Reserve Capacity Ratio**" is a number greater than 1, such as 1.2, that is set by the IMO for the purposes of multiplying by the hourly demand to determine the reserve capacity target in such hour;

"**Settlement Period**" means each time period over which OPGI's compliance with the Price Cap shall be measured, which shall be over a 12 month period, except that (1) the first Settlement Period shall commence on the opening of the competitive electricity market and shall consist of the first full 12 calendar months plus the days, if any, in the first partial month; and (2) the last Settlement Period shall end on the termination of the provisions of Part 3, and therefore could be less than 12 full calendar months; and

"**Tier 1**" capacity means all nuclear and hydroelectric generation in Ontario and "**Tier 2**" capacity means that portion of Ontario's generation capacity, including inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. For such purposes, generation capacity shall be based upon the maximum continuous rating of a unit, inter-tie capacity shall be based on the average of summer and winter season Ontario transfer capacity, and demand-side bidding shall be based on the sum of the dispatchable and interruptible loads, all expressed in MW.

All dollar amounts referred to are expressed in Canadian dollars.

2. Determination of Rebate

OPGI shall pay a Rebate to the IMO in respect of each Settlement Period in which the Average Price (AP) exceeds the Price Cap (CAP). The amount of the Rebate shall be determined in accordance with the following formula:

R = [(AP - CAP) * CRQ] - (RCA + PSA + FMA)

If the calculated Rebate in respect of any Settlement Period is a negative number, then there shall be no Rebate, and the Rebate Carryforward Adjustment shall be changed as described herein.

(a) Rebate Carryforward Adjustment

Initially, the Rebate Carryforward Adjustment ("RCA") shall be zero. In any Settlement Period in respect of which the calculated Rebate is negative, the absolute value of that amount shall be the Rebate Carryforward Adjustment for the purposes of the next Settlement Period.

(b) Price Spike Adjustment

A Price Spike Adjustment (PSA) shall be calculated for all hours in a Settlement Period in which both (1) the Hourly Price (P_h) exceeds $125/MWh, and (2) OPGI's Generation for that hour is less than the Hourly Quantity (Q_h). The PSA for a Settlement Period shall equal the sum of the adjustments for each applicable hour, which shall be calculated pursuant to the following formula:

PSA = (P_h - $125/MWh) * ($Q_h$ – OPGI's Generation for that hour),

where OPGI's Generation for that hour = OPGI's energy generated from all sources in Ontario (metered as per IMO market rules) the output of which is Effectively Controlled by OPGI and which was included as OPGI energy generated in the Model Output Data, and includes the current power purchase agreement with Manitoba Hydro.

(c) Force Majeure Adjustment

(i) Potential *Force Majeure* Event

A Potential *Force Majeure* Event is any event consisting of any of the following conditions or events that results in the loss or failure of, or the inability to operate, in whole or in part, one or more generation units in Ontario the output of which is Effectively Controlled by OPGI and that, in each case, is beyond the reasonable control of OPGI and which is not a result of OPGI's failure to comply with pre-existing laws or licence conditions or market rules or to reasonably maintain or to use its best efforts to promptly repair any generation unit or units:

(A) acts of war, revolution, riot, sabotage, occupation or vandalism;
(B) earthquakes, tornadoes or severe storms;
(C) other acts of God;
(D) local, regional or national states of emergency;
(E) strikes or other labour disputes;
(F) other failure or damage to an OPGI generating facility, including failure or damage caused by construction defects, fire, or damage to necessary equipment and which is not a result of negligence in the maintenance or repair thereof;
(G) interruptions in the supply of fuel or other essential supplies (excluding variations in water supplies in the case of hydroelectric generation units);
(H) failure of transmission or distribution facilities in Ontario;
(I) other system emergencies in Ontario; and
(J) Changes in Law.

(ii) Definition of *Force Majeure* Event

A *Force Majeure* Event is either an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event.

An Isolated *Force Majeure* Event is that portion of any Potential *Force Majeure* Event that occurs after the Potential *Force Majeure* Event has caused a reduction in the energy actually generated by the applicable units greater than 250,000 MWh from the sum of such units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Event.

A Cumulative *Force Majeure* Event occurs in a Settlement Period when the cumulative reduction in that Settlement Period of energy actually generated by affected generation units in Ontario the output of which is Effectively Controlled by OPGI caused by Potential *Force Majeure* Events exceeds 500,000 MWh when compared to the sum of such affected units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Events. OPGI will, where applicable, designate within

15 days following the end of the applicable Settlement Period that portion of Potential *Force Majeure* Events that is in excess of 500,000 MWh and that qualifies as a Cumulative *Force Majeure* Event.

A Potential *Force Majeure* Event, or a portion of a Potential *Force Majeure* Event, that qualifies as both an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event may at the discretion of OPGI within 15 days following the end of the applicable Settlement Period be designated as either type of *Force Majeure* Event, but not as both, and, for greater certainty, a Potential *Force Majeure* Event designated as one type of *Force Majeure* Event by OPGI shall not be treated for purposes of determining whether the other type of *Force Majeure* Event has occurred.

(iii) *Force Majeure* Adjustment

The *Force Majeure* Adjustment (FMA) in respect of any Settlement Period shall be equal to the sum, for all generation units the output of which is Effectively Controlled by OPGI subject to *Force Majeure* Events, of the *Force Majeure* Replacement Cost ($FMRC_h$) in respect of each applicable unit for each hour during the effectiveness of each *Force Majeure* Event in respect of such unit during the Settlement Period, less any insurance or other recovery in respect of such loss or deemed loss. The *Force Majeure* Adjustment in respect of any Settlement Period for each generation unit the output of which is Effectively Controlled by OPGI whose generation is reduced as a consequence of a *Force Majeure* Event shall be calculated pursuant to the following formula, prior to any recovery adjustment:

$$3_{\mathbf{h}}\mathbf{[q^{i}_{h}\ *\ FMRC_{h}\ *\ ((Capacity\ -\ Reduced\ Capacity_{h})/Capacity)]}$$

where:
Capacity = the maximum continuous rating of the unit at the time of the *Force Majeure* Event (at normal head for hydroelectric generation units); and

Reduced $Capacity_h$ = the reduced capacity in an hour of the unit as a consequence of and during the effectiveness of the *Force Majeure* Event.

(iv) Adjustment to *Force Majeure* Replacement Cost

In the event that over 2,000 MW of OPGI generating capacity the output of which is Effectively Controlled by OPGI qualifies for a particular *Force Majeure* Event, OPGI shall have the right to petition the Board to increase the amount of the *Force Majeure* Replacement Cost in respect of one or more affected unit(s) in the applicable hours, which petition shall be granted if OPGI can demonstrate to the Board's satisfaction higher incremental replacement costs (net of any variable costs avoided as a consequence of the *Force Majeure* Event) than those set forth in the Model Output Data.

(v) Notice

OPGI shall promptly notify the IMO of any *Force Majeure* Event claimed by OPGI and shall provide the IMO with all information reasonably required to verify the *Force Majeure* Event and to calculate the *Force Majeure* Adjustment.

3. Reduction to CRQ and Q_h Upon Decontrol

(a) Unadjusted Reductions

Except as may be provided in (b) below, in the event that OPGI completes the transfer of Effective Control over the output of a generation unit, as determined by the Board upon the application of OPGI, then Q_h for each hour in respect of the current and any subsequent Settlement Period shall be reduced by 110 percent of the q^i_h of the transferred unit for each hour subsequent to the completion of the transfer. As a result, the CRQ in respect of each applicable Settlement Period shall be reduced by these reductions in Q_h.

Despite the foregoing, no adjustments whatsoever shall be made:

(i) in the event that the transferee has or obtains, as a result of the transfer, Effective Control over approximately 25 percent or more of either:

(A) the total in service Tier 2 capacity; or

(B) the total in service Tier 1 and Tier 2 capacity;

in each case at the time of completion of the transfer; or

(ii) in the event that there exist any on-going arrangements to facilitate interdependent behaviour between OPGI and the transferee.

If the Board determines that Effective Control has or has not been so transferred in such circumstances, such determination shall also apply for the purposes of the same determination at a later date under Part 4 below.

(b) Adjustment Necessitated by Environmental Laws

In the event that OPGI transfers Effective Control over the output of a generation unit and the transferee, at the date of completion of the transfer, does not have and cannot reasonably obtain sufficient environmental emission permits or other environmental authorizations ("emission permits"), in respect of the applicable hours in the period commencing following the completion of the transfer of Effective Control (the "applicable hours"), to enable the unit's potential output during the applicable hours (the "transferred permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h of such unit (the "transferred output"), whether as the result of a change in environmental laws or otherwise, then:

(i) any adjustment to Q_h and CRQ otherwise provided for in (a) above will reduced by the proportion that the transferred permitted output is of the transferred output, subject to (ii) below;

(ii) in circumstances where OPGI's remaining emission permits following the transfer of Effective Control are not sufficient to enable its remaining output during the applicable hours (the "remaining permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h's of its remaining units, (the "remaining output"), then, in lieu of the adjustment provided for in (i) above, any adjustment to Q_h and CRQ otherwise provided for in (a) above will be multiplied by the result of the following formula, which if greater than 1.0 shall be deemed to be equal to 1.0:

(transferred permitted output/transferred output)/ (remaining permitted output/remaining output); and

(iii) where the transferee's emission permits are affected by more than one substance, then the resulting adjustment to Q_h and CRQ otherwise provided for in (i) or (ii) above will be that which operates to constrain the transferee's output.

4. Administration of Rebate

OPGI shall enter into and comply with a settlement agreement with the IMO in the form attached as Exhibit E.

5. Capacity Reserve Market

In the event that a capacity reserve market is developed in Ontario at any time while the provisions of Part 3 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 3 above:

> "Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:
>
> **AP=**
>
> $\sum_{h}$ **[CW_h * [P_h + (Hourly Reserve Capacity Price * Reserve Capacity Ratio)]]**

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraph 2(b) of Part 3 above:

PSA = [(P_h + Hourly Reserve Capacity Price * Reserve Capacity Ratio) - $125 / MWh] * ($Q_h$ – OPGI's Generation for that hour);

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market introduced.

6. Location-Based Marginal Pricing

In the event that location-based marginal pricing is developed in Ontario at any time while the provisions of Part 3 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 3 above:

> "Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP =

$$\sum_{h,i} (\text{Locational Spot Price} * q^{i}_{h})/\text{CRQ}$$

(b) the Hourly Price, or P_h, for purposes of determining if a price spike has occurred and in order to calculate the Price Spike Adjustment in each applicable hour, shall be the average price of energy OPGI sells into the IMO spot market in that hour, which average price shall be determined by dividing OPGI's hourly spot market revenue in $ by the quantity (calculated in MWh) of OPGI's spot market sales; and

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the location-based marginal pricing introduced.

7. Capacity Reserve Market and Location-Based Marginal Pricing

In the event that both a capacity reserve market and location-based marginal pricing are developed in Ontario at any time while the provisions of Part 3 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definitions provided for in paragraphs 1, 5 or 6 of Part 3 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$\mathbf{AP =}$$

$$\sum_{h} \mathbf{[CW_h * (Hourly\ Reserve\ Capacity\ Price * Reserve\ Capacity\ Ratio)]}$$

$$+ \sum_{h,i} \mathbf{(Locational\ Spot\ Price * q^i_h)/CRQ}$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraphs 2(b) or 5 of Part 3 above:

$$PSA = [(\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio}) + \sum_{i} \mathbf{((Locational\ Spot\ Price * q^i_h)/Q_h)} - \$125/\text{MWh}]$$

$$* (Q_h - \text{OPGI's Generation for that hour});$$

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market or location-based marginal pricing introduced.

8. Additional Adjustment for Changes in Law

If one or more Changes in Law cause or are reasonably expected to cause a decrease in OPGI's net annual income equal to or greater than $60,000,000, then, rather than treating such Changes in Law as a *Force Majeure* Event for purposes of paragraph 2 above, OPGI may apply to the Board for a variation in the CRQ, Rebate, and/or the Price Cap methodology in respect of the Settlement Period in which the Change in Law occurs and all subsequent Settlement Periods the Change in Law is reasonably expected to affect in order to ensure that OPGI is not materially adversely affected as a result, taking into account all Changes in Law and whether the net effect of these Changes in Law have benefited or are reasonably likely to benefit OPGI during the same time period or any prior or subsequent time period.

9. Termination of Part 3

Upon the date that is 4 years after the competitive electricity market opens, the provisions of Part 3 shall terminate, subject to the following. In the event that the Board determines that the transfer of sufficient Effective Control referred to in paragraph 3 of Part 4 hereof shall have occurred prior to the fourth year after the competitive electricity market opens, then the provisions of Part 3 shall terminate commencing on the date of such determination without prejudice to the payment of Rebates, if applicable, in respect of any preceding period.

PART 4. TRANSFER OF EFFECTIVE CONTROL

1. 42-Month Decontrol Review

(a) OPGI shall provide information to the Board as soon as practicable following the date which is 42 months after the competitive electricity market opens or, at OPGI's discretion, at an earlier date in order that the Board may determine whether or not:

(i) OPGI has completed the transfer of Effective Control over the output of one or more in service Tier 2 generation units such that OPGI's Effective Control over total in service Tier 2 capacity will be 35 percent or less, provided that:

(A) for purposes of this determination, OPGI may, at its discretion, substitute the transfer of Effective Control over up to 1000 MW of in service hydroelectric generation for the transfer of Effective Control over in service Tier 2 capacity. In such event, the amount of in service Tier 2 capacity over which OPGI is deemed to have Effective Control shall be reduced by the amount of hydroelectric generation Effective Control over which was transferred by OPGI;

(B) OPGI's firm purchase contracts for energy generated outside Ontario to be delivered into Ontario for periods of one year or more, including any automatic renewals or renewals at OPGI's option, shall be considered to be in service Tier 2 capacity over which OPGI has Effective Control for such purposes; and

(C) a transfer of Effective Control of output shall be considered not to have occurred if the Board determines that either of the circumstances set forth in paragraph (b) below apply;

(ii) OPGI has completed the transfer of Effective Control over the output of one or more in service Tier 2 generation units representing at least 4000MW of in service Tier 2 capacity, provided that:

(A) for purposes of this determination, OPGI may, at its discretion, substitute the transfer of Effective Control over up to 1000 MW of in service hydroelectric generation for the transfer of Effective Control over an equivalent amount of in service Tier 2 capacity; and

(B) a transfer of Effective Control over output shall be considered not to have occurred if the Board determines that either of the circumstances set forth in (b) below apply; and

(iii) OPGI has developed a plan (including intermediate milestones) for transferring Effective Control over enough of its in service Tier 1 and Tier 2 capacity such that by the end of the tenth year after the competitive electricity market opens OPGI's Effective Control over total in service Tier 1 and Tier 2 capacity will be 35 percent or less, as outlined in paragraph 3 below.

(b) The circumstances referred to in (a) above are:

(i) if any transferee had or obtained, as a result of the transfer, Effective Control over approximately 25 percent or more of either:

(A) total in service Tier 2 capacity; or

(B) total in service Tier 1 and Tier 2 capacity;

in each case at the time of completion of any transfer; or

(ii) if there existed or exist any on-going arrangements to facilitate interdependent behaviour between OPGI and the transferee.

(c) If the Board determines that Effective Control has or has not been so transferred in such circumstances, such determination shall also apply for the purposes of the same determination at a later date under Part 3 above.

2. 7 Year Review

OPGI shall provide information to the Board as soon as practicable following the date which is 7 years after the competitive electricity market opens in order that the Board may review OPGI's progress towards satisfying the intermediate milestones identified in the plan, if any, referred to in clause 1(a)(iii) above, or, in the absence of such plan, OPGI's progress towards transferring Effective Control over the output of enough of its in service Tier 1 and Tier 2 capacity such that by the end of the tenth year after the competitive electricity market opens OPGI's Effective

Control over total in service Tier 1 and Tier 2 capacity will be 35 percent or less, as outlined in paragraph 3 below.

3. Achievement of 10-Year Plan

(a) OPGI shall provide information to the Board as soon as practicable following the date which is 10 years after the competitive electricity market opens or, at OPGI's discretion, at an earlier date in order ththe Board may determine whether or not OPGI has completed the transfer of Effective Control over the output of enough of its in service Tier 1 and Tier 2 capacity such that OPGI's Effective Control over total in service Tier 1 and Tier 2 capacity is 35 percent or less, provided that a transfer of Effective Control over output shall be considered not to have occurred if the Board determines that either of the circumstances set forth in (b) below apply.

(b) The circumstances referred to in (a) above are:

(i) if any transferee had or obtained, as a result of the transfer, Effective Control over approximately 25 percent or more of total in service Tier 1 and Tier 2 capacity at the time of completion of any transfer; or

(ii) if there existed or exist any on-going arrangements to facilitate interdependent behaviour between OPGI and the transferee.

4. Reports

OPGI shall file a report annually with the Energy Returns Officer of the Board commencing in the fifth year and terminating in the ninth year, in each case inclusive, following the opening of the competitive electricity market, within 90 days following the end of each anniversary of the opening of the competitive electricity market, with respect to its progress towards the decontrol target set out in clause 3(a) above, indicating the specific actions taken by OPGI in the previous 12 months and its plans for the upcoming 12 months to progress towards meeting such target, provided that the application referred to in paragraph 2 above shall constitute the report in the seventh year.

PART 5. INBOUND TRANSMISSION RIGHTS AND IMPORT LIMITS

1. Definitions and Interpretation

In this Part 5, "season" means the winter period (the "winter season") from and including November 1 until and including April 30 of the following year or the summer period (the "summer season") from and including May 1 until and including October 31 of the same year, as applicable.

2. Inter-tie and Import Limits

(a) OPGI shall not import energy into Ontario in excess of the energy import limits set forth in (b) below. In no event shall a purchase from the IMO spot market in Ontario be construed as an import of energy into Ontario for such purposes.

(b) The energy import limits referred to in (a) above are:

(i) 7.24 TWh during the winter season (increased to 7.28 TWh in a leap year); and

(ii) 6.58 TWh during the summer season;

all of which figures shall be increased, at the in service date of new or upgraded inter-tie facilities, by 35 percent times the number of hours in a season multiplied by any applicable net increase in inter-tie capacity in Ontario as determined by the IMO from that in effect on the date of the opening of the competitive electricity market. For such purposes, inter-tie capacity shall be based on the Ontario transfer capacity in the applicable season.

(c) The foregoing provisions of paragraph 2 shall not be required to be complied with by OPGI with the IMO's consent in an emergency situation.

3. Export Limits

Unless otherwise provided herein, none of the provisions of Parts 3 through 6 shall limit OPGI's ability to export energy from Ontario.

PART 6. ANCILLARY SERVICES

1. Regulation

Unless the IMO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for Regulation services exists, OPGI shall be required to comply with the following requirements:

(a) the price to be bid by OPGI associated with any OPGI Regulation services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IMO, which bid cap will be designed, taking into account the relevant IMO market rules, to compensate OPGI for its actual cost of providing Regulation services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such Regulation services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such Regulation services, and which agreement shall require OPGI to bid the maximum available amount of Regulation services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(b) in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) in the event that either OPGI or the IMO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IMO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) pending reaching an agreement, or pending the resolution of any dispute, the IMO may at any time set the bid cap and terms on which

OPGI must provide Regulation services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) if the IMO's market rules at any time are such that the market clearing price for Regulation services does not include both the bid price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

2. Operating Reserves

Unless the IMO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10-minute spinning, 10-minute non-spinning and 30-minute non-spinning) exists, OPGI shall be required to comply with the following requirements:

(a) the price to be bid by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IMO, which bid cap will be designed, taking into account the relevant IMO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to bid the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(b) in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) in the event that either OPGI or the IMO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IMO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) pending reaching an agreement, or pending the resolution of any dispute, the IMO may at any time set the bid cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) if the IMO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the bid price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

EXHIBIT B

PROPOSED IMO LICENCE CONDITIONS

PART 3. OTHER

1. Administration of Rebate

The IMO shall enter into and comply with a settlement agreement with OPGI in the form attached as Exhibit E.

2. FERC Licence

The IMO shall use all reasonable efforts, including by seeking to make appropriate amendments to the market rules related to its transmission tariffs, to satisfy FERC's reciprocity requirements, as are currently set forth in FERC Order No. 888.

3. Market Power Mitigation Monitoring

The Market Surveillance Panel of the IMO may monitor OPGI's compliance with the market power related provisions of Parts 3 and 5 of OPGI's licence. Unilateral actions by OPGI to attempt to maintain average prices at the CAP level (as defined in the market power mitigation provisions contained in Part 3 of OPGI's licence) shall not be considered to be inappropriate or anomalous market conduct for the purposes of the IMO's market rules at any time when Part 3 thereof is in effect.

4. Confidentiality

Subject to the IMO's market rules and applicable law, the IMO shall use its reasonable efforts to ensure that it maintains all data contained in the Model Output Data that represents q^i_h data or $FMRC_h$ data in confidence (with all such terms having the meanings ascribed thereto in paragraph 1 of Part 3 of OPGI's licence).

5. Regulation

Unless the IMO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for Regulation services exists, the IMO shall be required to comply with the following requirements:

(a) the price to be bid by OPGI associated with any OPGI Regulation services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IMO, which bid cap will be designed, taking into account the relevant IMO market rules, to compensate OPGI for its actual cost of providing Regulation services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such Regulation services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such Regulation services, and which agreement shall require OPGI to bid the maximum available amount of Regulation services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(b) in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) in the event that either OPGI or the IMO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IMO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) the IMO shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) pending reaching an agreement, or pending the resolution of any dispute, the IMO may at any time set the bid cap and terms on which OPGI must provide Regulation services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) if the IMO's market rules at any time are such that the market clearing price for Regulation services does not include both the bid price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

6. Operating Reserves

Unless the IMO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10 minute spinning, 10 minute non-spinning and 30 minute non-spinning) exists, the IMO shall be required to comply with the following requirements:

(a) the price to be bid by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IMO, which bid cap will be designed, taking into account the relevant IMO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to bid the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(b) in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) in the event that either OPGI or OMI subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IMO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) the IMO shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) pending reaching an agreement, or pending the resolution of any dispute, the IMO may at any time set the bid cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) if the IMO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the bid price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

EXHIBIT C

PROPOSED OHSCI LICENCE CONDITIONS

PART 3. INTER-TIE EXPANSION

1. Inter-tie Expansion

OHSCI shall use its best efforts to expand inter-tie capacity to neighbouring jurisdictions by approximately 2000 MW within 36 months of the date the competitive electricity market opens.

2. Inter-tie Expansion Review

OHSCI shall provide information to the Board as soon as practicable following the date which is 36 months after the competitive electricity market opens or at an earlier date in order that the Board may determine whether or not, as of the end of such 36 month period, OHSCI has used its best efforts to expand inter-tie capacity to neighbouring jurisdictions by approximately 2000 MW.

EXHIBIT D

OTHER PROPOSED LICENCE CONDITIONS FOR GENERATORS, WHOLESALERS, RETAILERS, ETC.

[For all market participants referred to in sections 57(d) and (f) of the *OEB Act* (and others, as applicable)]

1. Pass-Through of Rebate

Prompt pass-throughs, with the normal bill delivered in respect of the month in which the rebate amount was received, of any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, will be required by the licensee so that its ultimate customers in Ontario benefit *pro rata* on the basis of energy consumed.

If requested in writing by OPGI, such licensee shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above shall be promptly returned to the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, for use to offset the IMO uplift.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to the seller or any other party.

Pending pass-through or return to the IMO of any rebate received, the licensee shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

EXHIBIT E

TERMS AND CONDITIONS OF PROPOSED SETTLEMENT AGREEMENT BETWEEN IMO & OPGI

For these purposes, terms with initial capitals not otherwise defined herein shall have the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI or the IMO's market rules, as applicable.

OPGI will be required to rebate annually to the IMO. As soon as practicable and preferably within 15 days following the final settlement of transactions which occurred during each Settlement Period, the IMO shall calculate the Rebate and notify OPGI of such calculated Rebate.

If OPGI agrees with the IMO's calculation then, within 30 days of being notified, OPGI will be required to pay such Rebate, if any, to the IMO. If OPGI does not agree with the IMO's calculation and the parties can agree within a further 30 days on a revised Rebate, then, within 30 days of so agreeing, OPGI will be required to pay the agreed revised Rebate, if any, to the IMO. If OPGI does not agree with the IMO's calculation and the parties cannot agree on a revised Rebate within such further 30 day period, then the matter shall be finally determined by arbitration by the Dispute Resolution Panel of the IMO, and, within 30 days of such final determination, OPGI will be required to pay the finally determined Rebate, if any, to the IMO. The initially calculated, agreed revised, or finally determined Rebate, as applicable, shall be the Rebate in respect of such Settlement Period for all purposes hereof. Unless the Rebate is paid within 30 days of the IMO notifying OPGI, interest at the Prime Rate, calculated and accrued daily, from such 30th day until the date of payment to the IMO will in all cases be added to (and based upon) the final Rebate owing.

The Rebate, if any, shall be paid by the IMO on the next settlement date following the receipt of payment from OPGI. The payment shall be allocated among Metered Market Participants in Ontario in respect of Registered Wholesale Meters (other than Intertie Registered Wholesale Meters) as at the end of the month in which receipt of payment from OPGI occurs (the "Ontario payees"), as follows. The Rebate shall be divided among all Ontario payees on the following basis:

(a) in the event that the Rebate in respect of the applicable Settlement Period is less than $10 million, then such Rebate shall be retained by the IMO and applied by it to reduce the IMO uplift in respect of the next following billing period (or periods, if any balance remains), as reasonably determined by the IMO; and

(b) where para. (a) is not applicable, the Rebate shall be allocated to all Ontario payees on the basis of their pro rata portions of the energy delivered to all Registered Wholesale Meters (other than Intertie Registered Wholesale Meters) (or replaced such meters) of such Ontario payees (or their predecessors) during the applicable Settlement Period.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to OPGI or any other party.

The Settlement Agreement may also include the following terms:

- Definitions and Interpretation
- Notice by OPGI to IMO of Payment and Non-Payment
- Appropriate limitations of liability
- IMO may add its reasonable rebate administration expenses to its uplift
- Appropriate indemnification provisions
- IMO to act on its own behalf and as agent for Ontario Metered Market Participants entitled to rebates to the extent of their interests, and such Metered Market Participants are entitled, provided that they give a satisfactory funded indemnity to the IMO, to enforce, by arbitration, the Settlement Agreement directly against OPGI if desired, with reasonable assistance to be provided by IMO at their expense
- IMO may assign agreement to a qualified replacement upon approval of OEB. No other assignments without consent of other party and OEB
- IMO may subcontract any duties required of it
- Fund transfer instructions, which may be changed on notice to OPGI by IMO
- Arbitration clause with Dispute Resolution Panel as arbitrator
- Recipient registrants responsible for all taxes, if any
- Any interest earned on funds by IMO shall be paid to recipient registrants similarly to other funds

- IMO not to be viewed as in conflict in any respect as a result of its participation in the Settlement Agreement

- IMO may hold funds on deposit with a Canadian financial institution or in short-term obligations of the federal or Ontario government or any Canadian financial institution

- IMO may, but shall not be obliged to, retain and refrain from distributing any funds in the event of any dispute, and may seek advice from the Dispute Resolution Panel

- Termination of agreement when OPGI Rebate obligations terminate and all funds distributed or applied. OPGI/IMO indemnification obligations and third party enforcement rights to survive termination, former indefinitely and latter for 2 years only

- IMO may rely on any document which it believes to be genuine and on the advice of counsel, if it acts in good faith

- IMO not responsible for any non-payment by OPGI

- Binding on successors and permitted assigns

- Notice clause

- Only may be amended in writing

- Governed by the laws of Ontario

- Counterparts clause

- Further assurances clause

EXHIBIT F

PROPOSED FORM OF MINISTER'S DIRECTIVE AND REFERRAL

TO: THE ONTARIO ENERGY BOARD

PART A Directive

Pursuant to Sections 27 and 28 of the *Ontario Energy Board Act*, 1998 (the "OEB Act"), I, the Minister of Energy, Science and Technology for Ontario, hereby direct the Ontario Energy Board (the "Board") as follows:

1. Various Licence Conditions

To implement and maintain as licence conditions and not to subsequently stay, vary, remove, fail to renew or otherwise amend, except as expressly contemplated in such licence conditions or in this document, the proposed licence conditions for OPGI, OHSCI, the IMO and other market participants and their successors related to market power mitigation in the form set forth in the Final Report of the Market Design Committee, provided that for greater certainty the foregoing shall not prevent the Board from taking or omitting to take any action arising in connection with any review, determination, request, advice or recommendation referred to in such proposed licence conditions or in this document.

2. Interim and Transitional Licences

The foregoing shall apply to interim, transitional and permanent licences, provided that interim or transitional licences shall include the following additional provision:

> Any provision of this licence that by its terms would only apply after the anticipated expiry date of this licence shall apply only to the extent that the duration of such licence is extended to include such stated time.

3. Various Reviews

(a) To conduct the reviews or determinations contemplated in paragraphs 1, 2 and 3 of Part 4 of the licence conditions of OPGI and in paragraph 2 of Part 3 of the licence conditions of OHSCI, and to use their best efforts to complete such reviews or determinations within 3 months of their respective commencement.

(b) In addition, at OPGI's request, to determine whether a specific transaction by OPGI represents the transfer of Effective Control over the output of a generation unit and thereby give rise to an adjustment for the purposes as contemplated in paragraph 3 of Part 3 of, or qualify for credit for purposes of paragraphs 1 or 3 of Part 4 of, the licence conditions of OPGI, with the Board to use its best efforts to complete such determination within three months of the request of OPGI and to confirm the applicable rebate adjustments, the amount of output in respect of which a transfer of Effective Control has occurred and the associated Tier of such output, as applicable.

4. Confidentiality

Subject to the Board's rules of practice and applicable law, the Board shall use its reasonable efforts to ensure that it maintains all data contained in the Model Output Data that represents q^i_h data or $FMRC_h$ data in confidence (with all such terms having the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI).

PART B Referral

Furthermore, pursuant to Section 35 of the *Ontario Energy Board Act*, 1998 (the "OEB Act"), I hereby require the Board to examine, report and advise on the following questions respecting energy:

1. 42-Month OPGI Review

Following the determination contemplated in Part A above in respect of paragraph 1 of Part 4 of the licence conditions of OPGI, to report and advise the Minister whether OPGI has satisfied the targets referred to therein, and:

(a) in the event that the Board is of the opinion following such determination that any of the targets referred to in the said paragraph 1 has not been satisfied, to so report to the Minister and to advise the Minister regarding a wide range of mechanisms for achieving a stable structural solution to market power through to the end of the tenth anniversary of the competitive market opening, including recommending to the Minister additional decontrol of OPGI assets; or

(b) in the event that the Board is of the opinion following such determination that all of the targets set forth in the said paragraph 1 have been satisfied, to so report to the Minister and to advise the Minister regarding the appropriateness and form of ongoing price controls over OPGI's Tier 1 generation for the fifth through tenth years following the competitive market opening, not altering the 10 year decontrol target;

and, in the event that the Board is of the opinion following such determination that OPGI has not developed a plan to achieve the targets referred to in clause 1(a)(iii) of Part 4 of the licence conditions of OPGI, to so report to the Minster and to take this failure into account in giving its advice under (a) or (b) above.

2. 7-Year OPGI Review

Following the determination contemplated in Part A above in respect of paragraph 2 of Part 4 of the licence conditions of OPGI, to report to the Minister as to OPGI's progress towards satisfying the targets referred to therein.

3. 10-Year OPGI Review

Following the determination contemplated in Part A above in respect of paragraph 3 of Part 4 of the licence conditions of OPGI, to report to the Minister as to OPGI's progress toward satisfying the targets referred to therein.

4. 36-Month OHSCI Review

Following the determination contemplated in Part A above in respect of paragraph 2 of Part 3 of the licence conditions of OHSCI, to report to the Minister whether OHSCI has satisfied the targets referred to therein and to advise the Minister with respect thereto.

DATED at Toronto this _______ day of _________________, ______.

EXHIBIT G

PROPOSED MARKET RULE TO ADDRESS LOCAL MARKET POWER (CONSTRAINED ON/OFF SITUATIONS)

1. Definitions and Interpretation

"**Constrained On Generation**" means a generation unit called to operate by the IMO to alleviate a transmission or other system constraint when such generation unit would not otherwise be called upon as a result of the IMO unconstrained dispatch of the system; and

"**Constrained Off Generation**" means a generation unit curtailed by the IMO as a result of a transmission or other system constraint when such generation unit would otherwise have been called upon as a result of the unconstrained dispatch of the IMO system.

2. Constrained Off/On Generation

(a) The IMO will call for Constrained On Generation in some areas and for Constrained Off Generation in others when the unconstrained dispatch of the system can not be implemented because of transmission or other system constraints. The IMO will dispatch Constrained On/Off Generation in order to meet system needs at the lowest cost. In each area where there is the need for Constrained On or Off Generation, the IMO will establish a market-clearing price for such generation.

(b) Constrained On Generation will be paid for energy produced at the unconstrained spot energy price plus a constrained on payment, equal to (i) the difference, if any, between the generation unit's energy bid and the unconstrained spot energy price, multiplied by (ii) the amount of energy provided.

(c) Constrained Off Generation will not be paid for energy, but will instead be paid a constrained off payment equal to (i) the difference, if any, between the unconstrained spot energy price and the generation unit's energy bid, multiplied by (ii) the amount of energy curtailed.

(d) The IMO (and, if requested by the IMO, the Market Surveillance Panel) will monitor energy bids in order to determine whether they have been set consistent with competitive market dynamics. Prices will be presumed to be competitively set if:

(i) in an on-peak period, the energy bid is within 5 percent of the unweighted average of the generation unit's accepted on-peak bids over the past 90 days. This criteria only applies if the generation unit has had on-peak bids accepted by the IMO in at least 15 of the previous 90 calendar days. Prior bids may be adjusted for fuel price changes based on appropriate indices;

(ii) in an off-peak period, the energy bid is within 5 percent of the unweighted average of the generation unit's accepted off-peak bids over the past 90 days. This criteria only applies if the generation unit has had off-peak bids accepted by the IMO in at least 15 of the previous 90 calendar days. Prior bids may be adjusted for fuel price changes based on appropriate indices; or

(iii) the IMO otherwise determines, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that the market for the service is competitive.

For the purposes hereof, "on-peak" means between 7:00 a.m. and 11:00 p.m. (Toronto time) on a Monday to Friday other than a statutory holiday, and "off-peak" means any other time.

(e) The IMO may (and, if requested by the IMO, the Market Surveillance Panel shall) inquire into the competitiveness of any energy bid that does not meet either of these two tests. The purpose of the inquiry will be to determine whether the bids fall within a range defined below. In the event that bids do not fall within this range, the generation unit's bid will not be used for the calculation of constrained on and off payments, and a new value based on the range outlined below will be used. The low end of the range will be used for constrained off payments and the high end will be used for constrained on payments:

(i) the low end of the range will be set based on the full load, short run marginal cost of the generation unit, including fuel costs, variable operating and maintenance costs, and opportunity costs for hydroelectric generation units. The bid price may be reduced to recover cycle costs in situations where the unit may be asked to shut down as a result of being constrained off. In no case will the low end of the range be less than zero; and

(ii) the high end of the range will be set based on 110 percent of the full load, short run marginal cost of the generation unit, including fuel costs, variable operations and maintenance costs, and opportunity costs for hydroelectric units. The bid price may be increased to recover cycle costs in situations where the generation unit might not otherwise be called upon to operate. For units that seldom run and might otherwise not recover their total operating costs over the course of a year, bids may be further increased to recover fixed and embedded costs. In evaluating such further increases in bids, consideration should be given to revenues and operating income associated with operations through normal dispatch and the IMO may initiate further inquiries into bids to adjust for actual operating performance and income.

(f) Within 24 hours after having a bid accepted as either constrained on or constrained off, a bidder may by notice to the IMO retroactively revise its bid, at its own discretion, in such a way that the payment it receives by being constrained on or constrained off is reduced.

(g) The IMO shall determine in its discretion when to inquire into the competitiveness of any bid. In such circumstances, the IMO shall determine the low and high end of the range referred to in (e) above. A generator may be subject to a penalty, in the discretion of the IMO, of up to three times the difference between its actual bid, as it may be revised and, in the case of a constrained on payment, the high end of the range as determined in (e)(ii) above, and, in the case of a constrained off payment, the low end of the range as determined in (e)(i) above. In the event that there is any dispute, such dispute shall be resolved by the Dispute Resolution Panel in accordance with IMO market rules.

(h) Pending the results of any inquiry, the IMO may at any time set, in its discretion, interim values for the low and high ends of the range with respect to any generation unit, subject to later adjustment upon final determination with interest at the Prime Rate, calculated and accrued daily.

(i) In any such inquiry, the IMO will, to the extent that it reviews cost and bid information for a generation unit, subject to the IMO's market rules and applicable law, use its best efforts to ensure that it maintains all such data in confidence.

EXHIBIT H

PROPOSED GUIDELINES AND PRINCIPLES FOR COORDINATING THE ROLES AND RESPONSIBILITIES OF THE COMPETITION BUREAU AND THE ONTARIO ENERGY BOARD IN ONTARIO ELECTRICITY MARKETS

I. BACKGROUND

The MDC *Second and Third Interim Reports* recommended that an arrangement be developed between the Ontario Energy Board (OEB) and Competition Bureau (CB) to clarify their roles and responsibilities where they have concurrent jurisdiction in relation to competition issues in order to avoid confusion and overlap.

The *Energy Competition Act*, as subsequently adopted, provide broad potential for overlapping OEB and CB roles and responsibilities for dealing with competition abuses.

The Board has, as its first objective listed in the *OEB Act*, promoting competition. The Board also has powers to include provisions in licences to deal with competition abuses, and to amend licences to deal with competition abuses indicated by either Market Surveillance Panel (MSP) reports or complaints made to the OEB under section 73 of the *OEB Act*. In addition, mergers, amalgamations and asset disposals covered under sections 80-86 of the *OEB Act* (e.g., between wires companies or between wires companies and generators) require OEB approval.

The Competition Bureau enforces the *Competition Act*, which applies generally to competitive market activity and business behaviour, except in certain cases where the activity or behaviour is directly regulated. (footnote 1)

Related issues for consideration are the roles of the MSP in investigating and reporting on potential competition abuses in Ontario electricity markets, and of the Director of Licensing appointed under the *OEB Act*. Arrangements between the MSP, the Director and the CB will also be critical for avoiding unnecessary confusion and overlap in dealing with competition abuses in the Ontario electricity sector.

This note proposes a set of guidelines and principles for the development of an arrangement between the OEB and the Competition Bureau to coordinate their respective roles and responsibilities. Where warranted, recommendations are also made regarding relations with the MSP and the Director of Licensing.

II. TIME FRAME FOR DEVELOPING AN ARRANGEMENT BETWEEN THE OEB AND CB

The development of an arrangement between the OEB and CB should await the appointment of the MSP and Director of Licensing in order to ensure that it will also be consistent with their roles and responsibilities.

Subject to this constraint, it will be essential that relations between the OEB, MSP, Director of Licensing and Competition Bureau be clarified early in order to provide a clear signal to market participants on how the regulatory framework will be applied.

---

1 Regulated activities may be subject to the regulated conduct defence under Canadian competition law. The defence provides that business activity that otherwise would contravene the *Competition Act* may be permitted if it is conducted in response to a constitutionally valid regulatory scheme.

Related discussions should commence as soon as possible and should be completed by the late spring or early summer of 1999.

III. FORM OF THE ARRANGEMENT

An arrangement between the OEB and CB could take the form of an exchange of letters between the organizations to clearly lay out areas where there may be overlap and how they will coordinate actions in these areas.

A more binding arrangement involving a further division of jurisdiction might be considered. However, this would likely involve another round of legislative proceedings or uncertain federal provincial discussions. Such an arrangement would also be difficult to amend as circumstances change in the Ontario electricity market. A letter of understanding can be altered as required by the OEB and the CB without the need for third party approval.

An exchange of letters or other arrangement should also be developed as required between the CB and MSP, and the CB and the Director of Licensing.

IV. NOTIFICATION, CONSULTATION AND INFORMATION EXCHANGE

Creating awareness of each others' activities is a basic requirement for the OEB and CB to effectively coordinate their actions in Ontario electricity markets. Accordingly, under their letters of exchange, the OEB and CB should commit to notifying each other of complaints or issues they receive or uncover potentially raising an issue under the other organization's legislation and mandate.

Notification should take place as early as is feasible in order to minimize overlap and duplication. The commitment to notify, however, would be subject to confidentiality restraints imposed on the OEB and the CB by their respective legislation.

Where joint jurisdiction exists with respect to electricity market activity raising a competition concern, the OEB and CB should engage in early consultations to minimize overlap with respect to investigations and, where they are warranted, the imposition of remedies or penalties.

Toward effectively coordinating their actions, the OEB, MSP and CB, before the market opens, should each identify an individual responsible for coordinating on-going interactions between the agencies and developing a notification and consultation regime.

Prior to the opening of the Ontario electricity market, an arrangement should be put in place for circulation of MSP reports that contain findings or allegations of competition abuse to the CB as well as to the OEB.

The CB and the OEB should also commit to sharing of information in order minimize unnecessary cost and overlap of investigations, and to promote the effective control of competition abuses.

Such information sharing, however, would also have to take into account confidentiality restraints imposed on the CB and the OEB in the *Competition Act* and the *OEB Act*.

V. PRINCIPLES / GUIDELINES FOR COORDINATING OEB AND CB ACTIONS ON SPECIFIC ABUSES

Letters of exchange for coordinating the actions of the OEB and CB in regard to specific competition abuses in the Ontario electricity sector should reflect the following guidelines and principles.

A. General

i. Purpose

An exchange of letters would not be for the purpose of restricting the jurisdiction of either the OEB or CB with respect to competition abuses. Rather, its purpose would be to establish ongoing relations between the organizations in order: to ensure that competition abuses are dealt with effectively; to minimize unnecessary overlap and duplication with respect to investigations and actions to prevent, remedy or punish a competition abuse; and to create a more certain regulatory framework for businesses.

ii. Use of Regulatory Forbearance

Under section 28 of the *OEB Act*, the OEB is required to refrain from regulation where it determines, as a question of fact, that there is sufficient competition to protect the public interest. Where the Board refrains, section 28(3) provides that the *Competition Act* will apply.

Toward clearly distinguishing the roles and responsibilities of the OEB and the CB, the OEB, to the extent feasible, should clearly identify products, activities, market participants and practices for which it is refraining from regulation. The CB may provide input and analysis in related proceedings as provided for under section 126 of the *Competition Act*.

In regard to practices and activities for which the OEB is refraining from regulation the provisions of the *Competition Act*, as provided for in section 28(3) of the *OEB Act*, should be relied upon to safeguard the competitive process.

In regard to practices and activities for which the OEB is partially or conditionally refraining from regulation, the remaining partial or conditional regulation should be taken into account in determining what action, if any, should be taken under the *Competition Act*.

iii. The Use of Licensing Restrictions to Prevent Anti-Competitive Abuses

The OEB, as provided for in the *OEB Act*, may choose to deal with competition issues in setting the terms of licences for electricity market participants.

The use of licence restrictions to prevent competition abuses should rely on a fact-based analysis of the relevant market concerning both the potential for anti-competitive abuse and the economic costs of imposing a restriction.

The Competition Bureau, as provided for under section 126 of the *Competition Act*, may provide competition related input and analysis for related OEB licensing reviews or proceedings.

Responsibility for ensuring that businesses adhere to licence restrictions against competition abuses should reside, in the first instance, with the OEB.

B. Mergers

Potential competition issues with respect to electricity sector mergers may be separated into vertical market power concerns, relating principally to ensuring all competitors of open and non-discriminatory access to transmission and distribution facilities, and into horizontal market power concerns, relating to the lessening of competition through the combination of two or more generators, wholesalers or retailers.

Dealing with vertical competition concerns is a central feature of the roles and responsibilities of the OEB in the Ontario electricity sector. Providing generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario is a specific objective of the Board. In addition, under sections 80 - 86 of the *OEB Act*, any mergers, amalgamations or disposals involving transmission and distribution assets must be notified to the OEB for possible review.

Horizontal mergers involving assets at the retail, wholesale or generation level of the market are not subject to a statutory requirement for notification to the OEB. They may be reviewed by the OEB, however, as a consequence of related licensing provisions imposed by the Board, or as part of the OEB's decision on whether to issue a licence to the merged entity.

The *Competition Act* merger provisions apply generally to all mergers in Canada. Large mergers meeting threshold levels set forth in the *Competition Act* must be pre-notified to the CB.

Both vertical and horizontal competition concerns may be considered as part of the merger review process under the *Competition Act*. The *Act*'s merger provisions, and the Bureau's approach to their application are an established feature of the legal framework for businesses in Canada. (footnote 2)

---

2 The framework used by the CB to analyze mergers is set forth in the Bureau's *Merger Enforcement Guidelines*.

Ontario electricity sector mergers, amalgamations and asset exchanges will come within the jurisdiction of both the *OEB Act* and *Competition Act* except in cases where a transaction comes within the bounds of the regulated conduct defence described above.

i Vertical Mergers

In respect of these considerations, the principal responsibility for dealing with vertical market power and access concerns pertaining to transmission and distribution mergers and disposals in Ontario should remain with the OEB.

The Competition Bureau may provide input to the OEB on these matters by intervening in, or providing analysis for related OEB reviews and proceedings as provided for under sections 126 of the *Competition Act*.

In any assessment of mergers or asset disposals involving Ontario transmission and distribution companies under the *Competition Act*, and determining whether to take related action under the *Act*, the Competition Bureau should take into account actions taken by the OEB to create open and non-discriminatory access to transmission and distribution facilities.

ii Horizontal Mergers

Mergers combining assets at the retail, wholesale and generation market levels, whether or not they are part of a transaction also involving transmission and distribution assets, may be examined under the *Competition Act* or by the OEB.

Where such cases arise, consultation should take place between the Competition Bureau and the OEB to minimize overlap and duplication.

Where a competitive assessment of a horizontal merger is being conducted by the Competition Bureau, the OEB should take into consideration the Bureau's findings and conclusions in determining what action it may take. This could involve, for example, the OEB making its approval of a transaction contingent on a Bureau finding that it does not raise an issue under the *Competition Act*. The Board, however, would not necessarily be bound to approving the transaction on the basis of the CB review.

C. False or Misleading Advertising

False or misleading advertising is potentially subject to discipline by both the OEB and the CB. The OEB's role in this area derives from its licensing authority under section 70 of the *OEB Act* and is supported by section 76 of the *Act* which allows the OEB to suspend or remove licences for, among other reasons, fraudulent misrepresentations. The Competition Bureau's jurisdiction is based on the misleading advertising and other marketing practices provisions in sections 52 - 60 of the *Competition Act*.

Toward effectively coordinating their activities in regard to false or misleading advertising in the Ontario electricity marketplace, an arrangement between the OEB and CB should take into account the following principles and guidelines.

To promote the orderly and effective handling of, and response to complaints, a framework should be established for mutual notification of complaints received by the OEB and the CB. This framework should also provide for consultations regarding the actions to be taken by either organization in regard to specific complaints, and for ongoing communications regarding follow-up actions being taken by either organization. Consideration should also be given to the benefits of developing parallel arrangements with the Ministry of Consumer and Commercial Relations and the Director of Licensing.

As a general approach, the OEB should take a leading role in preventing and disciplining false and misleading advertising by setting and enforcing related licensing provisions.

This should not prevent, however, actions being taken by the CB in regard to misleading advertising where they are warranted by the circumstances. To this end, arrangements between OEB and the Bureau should, to the extent feasible, specify the circumstances under which one organization or the other would take a lead investigative and enforcement role. Factors that should be taken into consideration may include, for example: whether the advertising is localized within Ontario or applies across provinces; the impact on the market; the applicability of the OEB and the CB's authority to the relevant circumstances; and the potential remedies available under either the *OEB Act* or the *Competition Act*.

D. Collusion, Price Fixing and Bid-Rigging

Responsibility for detecting and preventing collusion, price fixing and bid-rigging in Ontario electricity markets should be a shared responsibility of the OEB, CB, MSP and the IMO.

Related competition abuses may be explicit, in that they involve communications between parties and an agreement to manipulate prices or other competition dimensions. Alternatively, they may be tacit in the sense that they do not involve explicit communications and agreement between the parties. (footnote 3)

Cases involving explicit price-fixing arrangements and bid-rigging in an electricity market should be referred to the CB for investigation and prosecution under the *Competition Act*. These practices, if they contravene the *Act*, are subject to criminal penalties and remedies including prohibition orders, fines and possibly even jail terms.

The prosecution of price-fixing or bid-rigging under the *Competition Act*, however, should not prevent the IMO and OEB from taking additional measures to prevent it from re-occurring, such as making changes to the market rules or licences to reduce the likelihood of future price-fixing or bid-rigging cases.

---

3 Tacit collusion has been a major concern in electricity restructurings around the world due to the nature of electricity spot markets and opportunities for interdependent behaviour among generators. That is, the repetitive nature of spot markets, combined with the existence of a relatively small number of competitors, at least at certain points on the supply curve, may allow companies to apply interdependent bidding strategies to increase prices without having to enter into explicit arrangements or agreements.

Monitoring the Ontario electricity spot market to detect possible cases of tacit collusion should be an important objective the MSP and the OEB.

Where feasible, cases involving tacit collusion should be prevented or remedied by the OEB and the IMO through amendment to the market rules, or to market participants' licences.

In determining whether or not to take additional action in regard to tacit collusion under the *Competition Act*, the CB should take into account the actions that have been taken, or are being taken by the OEB and IMO.

E. Unilateral Market Power Control and Mitigation

The mere possession of unilateral market power by any electricity market participant, as well as its exercise to raise prices to supra-competitive levels, is not potentially subject to control under the *Competition Act* unless the market power has been obtained through a contravention of the *Act*.

Accordingly, preventing any such exercise of market power, subject to possible legislative or other constraints on its ability to act, should be the responsibility of OEB. (footnote 4) Likewise, the Board, depending on the specific nature of de-control measures set forth in the MDC's *Final Report*, will be principally responsible for monitoring adherence to any market power mitigation measures negotiated with OPGI.

In regard to either the unilateral exercise of market power or the monitoring of the negotiated market power mitigation measures, the Competition Bureau's role will be principally confined to intervening in related OEB proceedings.

F. Other Competition Abuses

The opening of Ontario electricity markets may create the potential for companies to engage in a variety of other competition abuses not specifically

---

4 For example, the OEB is prevented under the *OEB Act* from requiring companies to divest assets.

referred to above. These may include, for example, anti-competitive or exclusionary: cross-subsidization of utilities' competitive businesses from their monopoly transmission and distribution activities, predatory pricing, price discrimination, vertical restrictions with respect to prices or territories, exclusive dealing, product bundling, manipulation of transmission constraints and related information, discrimination in regard to consumer information generated by distributors, and the use of long-term, evergreen or other contract provisions to protect a dominant market position.

In many cases, these practices may be subject to joint OEB and CB jurisdiction. The *Competition Act* includes provisions covering many of the above practices unless they fall within the regulated conduct defence described above. The OEB's potential jurisdiction derives from its general licensing authority, and authority to amend licences in response to a report by the MSP or complaint received under section 74 of the *OEB Act*.

In respect of its objectives and licensing authority, the OEB should be principally responsible for preventing the above anti-competitive or exclusionary practices as they relate to: access to regulated transmission and distribution facilities, cross-subsidization of utilitities' affiliates or activities in competitive markets from their regulated activities, and the utilities' control over information relating to transmission and distribution.

In other cases, where there is strong likelihood of a competitive abuse, or a widespread concern regarding the use of a particular anti-competitive practice, the OEB may choose to use its general licensing authority to deal with the concern. In such cases, the OEB should take into account the considerations outlined in section A(iii) above.

For other cases, where there may be overlapping jurisdiction, the CB and the OEB, to the extent feasible, should specify the circumstances under which one organization or the other will take a lead role.

Where an action is being undertaken in regard to a potential competition abuse by either the CB or OEB, this should be taken into account by the other organization in deciding what action it may take, if any.

CHAPTER THREE

WHOLESALE MARKET DESIGN

Wholesale Market Design

Table of Contents

CHAPTER THREE
WHOLESALE MARKET DESIGN

3.1 Introduction

Our work on wholesale market design during the fourth quarter focused on directing and reviewing the development of the rules by which the wholesale markets administered by the IMO will function. Using our Wholesale Technical Panel and various sub-panels, we developed detailed procedures for all aspects of market operations, including how market participants will interact with the IMO, and what information they will provide to and receive from the IMO; how the IMO will use market participants' bids, offers and bilateral submissions to schedule and dispatch the Ontario system; and what procedures the IMO and market participants will follow during system emergencies that may require suspension of the market rules. In addition, the sub-panels helped us to develop detailed requirements for metering, and create an accounting framework within which settlements and billing will occur for all transactions involving the IMO-administered markets.

We created our Wholesale Technical Panel in August. The Panel then formed five sub-panels to develop rules, policies or procedures in selected areas. The Wholesale Panel met weekly throughout the fourth quarter to review and coordinate the work of the sub-panels, and the various sub-panels met or conferred by conference call at least as frequently. We are indebted to the members of the Panel and sub-panels, and wish to express our appreciation for their excellent work and for the broad expertise and dedication they brought to their assigned tasks. The sub-panels included the following:

- *A bidding, scheduling and dispatch sub-panel.* This group developed the detailed rules under which participants will submit proposals to the IMO to participate in each of the markets administered by it, and by which the IMO will use that information to schedule and dispatch the system. These rules define both physical and financial markets and create markets for energy, regulation, operating reserves, reserve capacity and "financial" transmission rights. The rules also include procedures that will apply during emergency conditions. For the most part, these detailed rules are now set forth in the Market Rules. A related set of rules that describe how the IMO will conduct periodic long-run assessments of the system's expected adequacy and reliability are also set forth in the Market Rules.

- *An ancillary services sub-panel.* This group focused on voltage support/reactive power and black-start capability. These ancillary services are necessary for reliable operations and recovery from system blackouts, but will not be acquired through the IMO's daily and hourly markets. The sub-panel developed procedures under which the IMO will acquire these services competitively under long-term contracts or, where that is not practical, acquire the needed services through negotiated contracts with "must-run" plants, with the contract terms subject to OEB oversight. The sub-panel's work is reflected in the Market Rules.

- *A wholesale metering sub-panel.* This sub-panel developed a detailed draft of a wholesale metering code for Ontario. The code defines the metering requirements that wholesale market participants must meet to participate in the IMO-administered markets, and sets forth installation and testing requirements. The group developed procedures and principles under which Ontario meters can comply with the requirements of Measurement Canada. The group also examined procedures by which existing facilities may be exempted from Measurement Canada requirements during an initial period, so as to avoid excessive investments prior to market start-up if the IMO determines that full compliance with the code is not immediately essential for system reliability, dispatch or settlement purposes. The work of this sub-panel became the basis for the Metering chapter of the Market Rules.

- *A wholesale settlements sub-panel.* This sub-panel created an accounting framework within which the IMO will settle accounts and bill or compensate market participants for all purchases, sales, and services provided or rendered through the IMO-administered markets. The sub-panel examined the implications of alternative billing periods, including the financial exposure that each type of participant would have under different periods. The sub-panel's framework defined settlement and billing periods, payment requirements, payment default procedures, allocation of credit risk and related settlement issues. The work of this sub-panel is the basis for the Settlements and Billing chapter of the Market Rules.

- *A sub-panel on "embedded" generation.* This group examined the settlement and cost-recovery principles that should apply when generation is "embedded" within a distribution system. There are numerous cases, with many variations, in which generators are located within a distribution system rather than connected to the IMO-controlled transmission grid. Because any energy produced by these embedded generators reduces the net demand of the distributor at the point of its interconnection with the IMO-controlled grid, we needed a set of principles to determine how such effects on the distributor's net loads would affect settlements and application of cost-recovery methods for transmission, ancillary services, IMO administrative fees and so on. The sub-panel examined the wide range of cases that might arise and considered whether to distinguish the treatment of existing embedded generation from new embedded generation. We then used their work to define the final principles to apply. These principles are included in the Market Rules.

The Wholesale Panel and sub-panels worked through and developed solutions to literally hundreds of small and many larger issues, all of which we have resolved somewhere within the market rules. In the sections that follow, we discuss the more important of these questions, focusing on those that required us to select between conflicting or significantly different alternative approaches for designing the wholesale market. In particular we discuss the following:

With respect to Bidding, Scheduling and Dispatch (Market Design) rules:

1. How can we ensure that participants choosing spot and/or bilateral transactions are treated in a comparable, equivalent fashion?

2. How should the IMO allocate the interties that connect Ontario with neighboring regions and how can we facilitate efficient inter-regional trading?

3. How should the IMO determine the uniform energy price to be applied during the first 18 months of market operations?

4. What limitations should the IMO impose on the ability of market participants to revise their bids, offers and schedules in the hours prior to dispatch?

5. What capacity market and pricing rules should the IMO use to ensure adequate generating capacity?

With respect to wholesale metering and settlements:

6. How can Ontario's settlement procedures facilitate flexible bilateral trading?

7. How will the settlement system accommodate very small generators and bilateral transactions?

8. How should we design the settlement/billing period to be fair to all participants?

9. What rules will be needed to ensure compliance with Measurement Canada metering standards?

3.2 Ensuring Equivalent Treatment for All Transactions

One of the major principles we have followed since the first quarter is that market participants should be allowed to structure their electricity transactions in various ways and be free to move between spot transactions and different forms of bilateral transactions. Our Market Rules codify this principle, stating that participants may engage in both "financial" and "physical" types of bilateral transactions as well as simple spot trading. The rules then endeavor to ensure that, apart from the mechanics of how each transaction is settled, the IMO treats these alternative transactions in ways that are commercially and operationally equivalent.

To achieve this commercial and operational equivalence, we have developed rules that ensure equivalent handling of spot market bids and offers, on the one hand, and physical bilateral schedules, on the other. In particular, the rules require that all entities participating in the IMO's energy markets indicate in their submissions the prices at which they would be prepared to offer more or less energy to the IMO (or consume more or less energy, for dispatchable loads). This means that participants choosing to engage in physical bilateral contracts may submit their proposed bilateral schedules to the IMO, but they must also submit bids and offers indicating the prices at which, for example, the bilateral generator would be willing to produce more energy than its bilateral schedule amount (and be paid the spot price for this increment), or produce less than its bilateral schedule amount (and buy spot energy to meet its contract obligation and pay the spot price for that energy). Generator offers must cover the full scheduled amount, while bids by dispatchable loads may cover any amount they choose. Moreover, offers from the bilateral generator and bids from the load in a bilateral pair may be completely independent. For example, a bilateral generator may indicate through its offer that at a given spot price (e.g., a spot price below its operating costs), it is prepared to turn off and rely on the spot market to satisfy its bilateral obligation, while the load may decide that it will rely on its contract and not use the spot market at any price, or use it only at some price very different from the generator's offer price. These rules give bilateral generators and loads the same commercial and operating flexibility afforded to individual spot market participants. Equally important, the rules place bilateral participants on an equal footing with spot market participants with respect to access to the IMO-controlled grid by ensuring comparable treatment when the IMO selects which generators or dispatchable loads to redispatch in order to relieve transmission constraints.

Recommendation 3-1

We recommend that the market rules place spot and bilateral participants in the IMO-administered markets on an equal footing by requiring all to indicate in their submissions the prices at which they would be prepared to offer more or less energy to the IMO (or consume more or less energy, for dispatchable loads.) Bilateral generator offers should cover the full scheduled amounts, while dispatchable load bids may cover any amount they choose. Bilateral generators and loads should be allowed to define different price/quantity pairs for their respective offers and bids, to provide these participants the same flexibility as participants using spot transactions.

3.3 Promoting Efficient Allocation of the IMO-controlled Interties and Inter-regional Trading

Once we agreed to use an equivalent bidding process to place bilateral and spot participants on an equal footing with respect to access to the Ontario grid, we determined that we could use the same concept to determine which participants could get access to the IMO-controlled interties between Ontario and neighboring regions. In other words, since every market participant will submit bids or offers to the IMO, the IMO can use the prices from those bids and offers, including those from bilateral participants, to determine which transactions will be allowed to use the IMO-controlled interties. [1] Of course, if the proposed transactions are well within the intertie capabilities, all transactions can be accommodated. However, the interties are limited and can handle only a small percentage of Ontario's total needs. As a result they may often be constrained. When they are constrained the IMO can use the participant's bids as

[1] Some interties may not be subject to this approach such as those that do not form part of the IMO-controlled grid or those that are exempt by regulation made under the *Electricity Act, 1998* from the requirement to provide non-discriminatory access.

indications of the value each participant places on use of the scarce intertie capacity. The IMO can then use these bids to allocate use of the intertie to those whose energy bids and offers indicate they place the highest value on that use, thus efficiently allocating the scarce intertie.

We considered but ultimately rejected alternative approaches to allocating the interties. In some US jurisdictions, for example, transmission-owning utilities with shared interties reserve for themselves the expected transfer capability between them. The transmission owners then sell any excess to others under contracts and tariff rates approved by regulators. This "physical" approach to transmission reservations has come under increasing strain with the advent of wholesale competition and the need to ensure that an increasing number of market participants are treated in a comparable fashion to utilities attempting to serve their own native loads. Some OASIS-based reservation markets have been attempted, but they have not been linked with consistent bidding processes that allow all market participants, including those serving native loads, to indicate the value they place on their transmission uses. We believe our recommended approach ensures comparable treatment for all participants and goes a long way towards solving the problems inherent in traditional approaches.

One advantage of our approach is that it makes it possible to charge those who use the interties for the incremental costs they would impose on the IMO if the IMO accommodated those uses under constrained conditions. Otherwise, Ontario loads would have to pay any such redispatch costs. If market participants schedule more transactions across the interties than the intertie capacity (or security constraints) allow, then the IMO must curtail some transactions to keep flows within the physical and security limits of the interties. The common bidding process discussed above provides an efficient means for deciding which transactions to curtail, but it also provides the IMO with a set of prices from which it can determine the value of energy at various locations relative to the intertie.

As we discuss in the next section, we determined in the second quarter to apply, for a time, a uniform pricing approach *inside* Ontario. However, the bidding rules we have developed allow the IMO to define prices at locations *outside* Ontario that may, and indeed will, be different from the Ontario uniform price whenever the interties are constrained. (This is simply another example of the general rule that transmission constraints cause prices to vary by location.) We then considered whether we would allow the IMO to use those different prices to settle transactions affecting external transactions or whether we would extend the uniform pricing approach to all external transactions as well. We concluded that the former approach was both more efficient from a market perspective and fairer to all participants, including Ontario loads.

Our preferred option is to allow the IMO to define a set of prices for each location or "zone" external to Ontario, based on the bids and offers of participants engaged in transactions using the interties. That is, the IMO can use the following to determine the prices in each of these external zones:

- bids from external loads seeking to purchase from the Ontario spot market or intending to engage in bilateral transactions across the interties;

- offers from external generators seeking to sell to the Ontario spot market or intending to engage in bilateral transactions across the interties.

Under this approach, the IMO can then use the "accepted" bids and offers (that is, the best bids and offers up to the limits of the intertie) to define the external zone prices and then use those defined prices as the basis for settlements in each zone. The IMO will thus use these prices to pay external spot sellers, charge external spot buyers and pay or charge bilateral parties using the interties for deviations from their schedules. Parties with bilateral transactions will indicate to the IMO's settlement process the bilateral amounts that they wish to have credited or debited to each party, thus ensuring that the IMO's settlement mechanics for bilaterals treat bilaterals in an exactly equivalent commercial manner to spot transactions.

We examined an alternative option that would have the IMO follow the same approach of using the bids and offers to identify who gets access to the constrained interties. However, instead of defining a different price for each external zone, the IMO would include all "accepted" transactions in the Ontario market. The IMO would then settle all transactions that were "in" the market using the internal Ontario uniform price.

After considering the merits of these two options, we concluded that the first approach was preferable. By determining a separate market price for each external zone, this approach has the effect of charging each intertie transaction for the costs the IMO incurs to redispatch the Ontario system to accommodate the transaction. Those whose intertie transactions create redispatch costs in Ontario would effectively be charged for those costs in the IMO's settlements, thus leaving Ontario loads whole; conversely, those whose intertie transactions relieved intertie constraints (by creating counterflows), would be compensated for reducing Ontario's redispatch costs. We concluded that this relatively straightforward approach would provide useful price signals to those using the interties, both encouraging beneficial inter-regional transactions that lowered Ontario costs, while encouraging participants to invest in intertie upgrades to relieve intertie constraints. Moreover, we noted that this approach provided a market-based alternative to the stringent (and highly controversial) physical curtailment rules, known as Transmission Loading Relief (TLR), promulgated by the North American Electric Reliability Council (NERC) and approved by the Federal Energy Regulatory Commission (FERC) for US utilities. The application of NERC's TLR rules forced the curtailment of hundreds of inter-regional transactions in June 1998 and contributed to mid-West supply shortages and price spikes.

Because our preferred approach provides a market-based alternative to NERC's TLR curtailments, we expect FERC, which has encouraged US utilities to develop similar market-based alternatives, to view our approach favorably. This should enhance FERC's overall perception of the Ontario transmission access and market rules and improve the chances that Ontario market participants will get access to US markets. This is consistent with our belief that Ontario market rules should be compatible with the North American Free Trade Agreement, inter-provincial trade agreements and mutual open access principles, and should facilitate the ability of Ontario parties to obtain any FERC licences needed to engage in inter-regional trading. However, if subsequent events prove such consistency does not exist, changes to these market rules should be made to ensure that inter-regional trading can take place.

Our preferred approach means that participants engaged in intertie transactions will be subject to either higher (or lower) external zone prices for intertie transactions, depending on the direction of flows and the degree of congestion. Because of this cost exposure, we believe it essential that the IMO implement this approach in conjunction with a set of intertie transmission rights that function as financial hedges against the uncertainty of congestion-related price differences between Ontario and external locations. We have developed a framework for allocating these rights, and completing this work should be a high priority for the IMO during the coming year.

Recommendation 3-2

We recommend that the IMO use the price/quantity offers and bids associated with intertie transactions (including those submitted by external participants seeking to buy from or sell to the IMO-coordinated market), to determine which transactions get access to the interties and to allocate access during constrained conditions to those who place the highest value on use of the interties. We recommend that the IMO use these offer/bid prices to determine prices to apply at each location or "zone" in the interconnected areas outside Ontario in settlements for the intertie transactions. Thus, the uniform pricing approach will apply to prices *inside* Ontario, but different prices may apply *outside* Ontario to reflect the effects of constraints.

3.4 Determining the Uniform Price within Ontario

Earlier in our work, we recommended that the prices Ontarians should pay for energy purchased from the IMO-administered markets should be uniform throughout the province for the first 18 months of market operations. We examined congestion pricing approaches that would recognize the difference in the market value of energy at different locations whenever transmission constraints arose, and we acknowledged that such a pricing system would be more efficient and should ultimately be implemented in Ontario. However, because there could be equity implications in moving to a pricing system that might differ significantly from what the province has traditionally used, we recommended that a uniform pricing approach apply for the initial period. (Following the discussion above, it is worth noting again here that we have concluded this quarter that the uniform pricing approach should apply only to prices *inside* Ontario, and not to prices for locations *outside* Ontario.) We then recommended that the IMO have the ability to calculate, and that it publish during this initial period, the prices that would apply under a nodal form of congestion pricing, although Ontario market settlements would be based on a uniform price that did not reflect congestion effects. The Market Rules include that nodal pricing capability. The related issue we considered this quarter is how the IMO should determine the uniform price within Ontario.

We examined two feasible approaches. The first would require the IMO to use the nodal prices it must calculate in any event and develop an average of those prices, weighted to reflect the loads at each location. The IMO would then use this load-weighted average price as the "uniform" price for settlements. One advantage of this approach is that it builds upon and is consistent with the nodal pricing system that we previously recommended the IMO develop, and might therefore facilitate a transition to a congestion pricing system after the first 18 months. The second approach would ignore the nodal prices, which reflect the effects of congestion, and instead determine the uniform price by assuming the transmission system is not congested or constrained (even when it is) and assuming that there are no security constraints involving transmission elements. Under this approach, the IMO would construct an "unconstrained" dispatch schedule and determine a uniform price from the bids and offers of the marginal generators or dispatchable loads used to balance supply and demand. One advantage of this approach is its apparent simplicity relative to the weighted average method, although we determined that either approach was well within the technical capabilities of the IMO and could easily be implemented. After reviewing the merits of both approaches, the sub-panel recommended the "unconstrained" dispatch approach for the interim period and we accepted their recommendation. This approach is included in the Market Rules.

Having chosen the unconstrained dispatch method, we later considered the degree to which transmission constraints should be included in determining the unconstrained uniform price. We agreed that internal Ontario transmission constraints should be ignored in the calculation as long as uniform pricing is used, but that ignoring constraints across the interties raised issues that required further consideration. The reason requires further explanation.

A uniform "market" price (the price is actually administratively determined) implies a set of corresponding market quantities that each participant would sell or buy at that uniform market price. However, transmission constraints may prevent participants from injecting or withdrawing those corresponding market quantities. In order to relieve the actual constraints and remain within system security limits during the dispatch, the IMO may have to direct generators (and dispatchable loads) to produce (consume) more or less energy than they are willing to produce (consume) at the uniform price, given the prices each participant has indicated in its bid or offer. To induce generators and loads to change their outputs or takes to the required levels, a uniform pricing approach thus requires the IMO to compensate participants for any differences between the uniform price and their bids/offers whenever they are "constrained on" or "constrained off" in order to relieve transmission constraints. We have included methods for determining this compensation in the Market Rules.

These constrained-on and constrained-off payments are a necessary feature in a uniform pricing system. However, it may be possible for certain generators to manipulate these extra payments. While this concern applies generally, there is a particular risk that market participants outside Ontario could submit phantom or unrealistic bids and offers, anticipating that they would be constrained on or off. Participants could thus game the resulting compensation payments, and external participants' gaming would be difficult for the Ontario IMO to detect. To minimize this risk, we concluded that when calculating the uniform price, the IMO should consider the capacity and security constraints of the interties as a "constraint" in determining the uniform price (internal constraints would still be ignored in the determination) and in determining eligibility for constrained on/off payments. In conjunction with the approach we recommend for allocating the interties (see previous section), these rules should limit the IMO's exposure to gamed constrained on/off payments. We have included this approach in the Market Rules.

Recommendation 3-3

We recommend that the IMO determine the uniform price to be used internally for settlements based on the "unconstrained dispatch" approach. This approach will ignore internal transmission constraints. However, we recommend that the uniform price determination explicitly consider the capacity and security constraints of the interties.

3.5 Restrictions on Revising Bids and Offers

In our earlier reports, we assumed that the Market Rules would give market participants a great deal of flexibility to revise their bids, offers and schedules in response to changing market and grid conditions. For example, we assumed the Market Rules would require that bids, offers and schedules be submitted before 11:00 a.m. on the day before the dispatch day, but we also assumed that the rules would permit participants to revise their submissions up to an hour or two prior to each real-time dispatch period.

During the fourth quarter, we reexamined this issue because of two concerns. The first concern is that too much flexibility could create opportunities for a participant with market power to manipulate market outcomes by first submitting partial or misleading price and quantity information to the IMO, causing the IMO to prepare preliminary dispatch schedules that might mislead other market participants. The offending participant would then submit its true intentions with respect to prices and quantities very close to real time, too late for smaller competitors to respond or cover their risks. A second concern is that the IMO might not have sufficient time, given the limitations of software and the time and effort needed to examine security implications, to respond within only an hour or two before real time to a great many revised bids, offers and schedules, without compromising system security. Our Technical Panel and sub-panels considered these concerns and weighed them against market participants' legitimate needs for flexibility to respond to changing market conditions. The sub-panel considered a "strawman" compromise in which participants could revise their submissions without restrictions up until eight hours prior to real time, make limited changes up to four hours before and make only IMO-approved changes thereafter.

We reviewed this proposal and concluded that it went too far in the direction of restricting market participants' flexibility. We note that system operators in other jurisdictions have found ways to deal with the software and security assessment issues and have managed to reduce the period in which participants may no longer submit revisions to one or two hours. We believe the IMO should endeavor to develop software and other procedures that will enable it to examine system security issues within a much shorter time frame than called for by the strawman. Such procedures would allow market participants to use the additional time to revise their price and quantity submissions in ways that respond to changing market conditions. After consulting further with the CMO, we concluded that the initial Market Rules should allow unlimited changes up to four hours prior to real time, minor changes (within 10 per cent) or IMO-approved changes in bid/offer prices or quantities up to two hours ahead, and further changes, with IMO approval, up to any point the IMO's security assessment and dispatch procedures can handle. This more flexible approach is reflected in the Market Rules. We also urge and expect the IMO to make best efforts to move towards an hour or less cut-off time for unlimited revisions, as it gains experience and confidence in its ability to handle last-hour changes.

At the same time, we are concerned that the opportunities for manipulating market outcomes may be exacerbated by moving in this direction. We therefore emphasize the importance of effective market power monitoring and mitigation measures and stress the need for their conscientious enforcement by the IMO's Market Surveillance Panel, the OEB and other affected government institutions. In particular, the Market Rules include explicit authorization for the IMO and affected market participants to examine late changes in offers and schedules, and to refer suspected cases above a certain threshold to the Market Surveillance Panel.

Recommendation 3-4

We recommend that the Market Rules give market participants unlimited flexibility to revise bid and offer quantities and prices up to four hours in advance of each dispatch hour and give limited flexibility (e.g., within 10 per cent, or greater with IMO approval) to make revisions up to two hours in advance. We recommend that the IMO provide some flexibility to accommodate additional changes closer to the dispatch hour, consistent with its system security requirements and its ability to handle last-hour changes. Once the market begins, we recommend the IMO endeavor to further reduce these initial timing restrictions as it gains experience with handling revisions and performing security assessments.

3.6 Market Procedures to Provide Incentives for Adequate Generating Capacity

In our *Third Interim Report*, we examined alternative ways in which the Market Rules could encourage market participants to install and maintain adequate generating capacity to meet acceptable reliability standards. In general, we concluded that there was some risk in relying exclusively on the market's energy and reserve prices to provide a sufficient commercial incentive to induce adequate new investments, or to convince existing plant owners not to retire seldom-used plants that might be needed only on a few days or hours each year. On the other hand, we were concerned that a system of installed capacity requirements would create administrative burdens on the IMO, foster continued centralized planning, and undermine the pricing incentives of a competitive market. We therefore recommended that the Market Rules include a standby market for capacity reserve, that would operate only if activated by the IMO Board, taking into account its assessments of long-run system adequacy and security.

The IMO, in evaluating its own long-run security and adequacy, would consider not only the announced plans of market participants but also the ability of participants to take a wide range of transmission, supply and demand-side measures to improve system adequacy, as well as the lead times needed to implement any of the feasible options. Based on this overall assessment, if the IMO Board determined that a capacity shortage was likely to occur in the not too distant future, it could activate this capacity reserve market. The prices paid in this daily market would give generation owners who bid into the market an incentive to maintain seldom-used plants, while providing an incentive for investors to install new generating capacity.

During the fourth quarter, we examined detailed proposals for how the overall market would work to encourage system adequacy. It became clear that a logical complement of our reserve capacity approach is a pricing mechanism that, even before the capacity reserve market is activated, would allow energy prices to rise to potentially very high levels – up to thousands of dollars per megawatt hour in the event that existing capacity fell short of the IMO's requirements. While there was some discussion of whether this pricing approach was consistent with our third-quarter recommendations, we ultimately concluded that such a mechanism made sense. Without this mechanism, it would be possible for prices to rise to extremely high levels anyway, but only *after* all reserves were exhausted and the province was confronted with mandatory curtailments of non-dispatchable loads – in essence, having the lights go out. We agreed that it would be preferable to have a pricing mechanism that would automatically produce higher prices as soon as the IMO's operating reserves fell below required levels, and increasingly higher prices as the operating reserves neared exhaustion. In this way, the higher prices would encourage generators to make all in-service capacity available to the IMO to preserve reliability, while encouraging dispatchable loads to initiate voluntary reductions in demand well before the Ontario system reached the blackout stage. Our Market Rules therefore include this reserve pricing mechanism in the pricing formulae.

We believe that the use of this mechanism should reduce the likelihood that Ontario will need to activate the capacity reserve market. However, if the IMO Board determines that this backup market is needed, the IMO would begin to accept daily bids for capacity reserve. Eligible bidders would include those who could provide the offered capacity, through energy offers, within two days if called upon by the IMO. (Accepted capacity that was unable to respond within the two days would be penalized at a very high rate.) The IMO would determine a market-clearing price for this capacity reserve based on the supply offers it received and the capacity demand set in advance by the IMO Board. All capacity cleared in this capacity reserve market would receive the market clearing price. During periods with plentiful capacity, the clearing price would be very low or zero, but it could rise to substantial levels during periods when capacity was short. The Market Rules also provide that the clearing price is paid on an hourly basis, such that it mimics the effect of a well-functioning, energy-only pricing system.

Recommendation 3-5

We recommend that the market pricing rules include automatic formulae that would produce higher prices as soon as the IMO's operating reserves fell below required levels, and increasingly higher prices as the operating reserves neared exhaustion. We recommend that this pricing mechanism be used to complement, and perhaps obviate the need for, the reserve capacity market, which the IMO could trigger if the Board determined that available options were unlikely to relieve a predicted capacity shortage.

3.7 Settlement Procedures to Promote Flexible Bilateral Trading

A common feature of many market designs is the requirement that market participants engaging in physical bilateral contracts must reveal their intended bilateral schedules to the system operators (the IMO, in Ontario) well in advance of the dispatch hour. Typically, market rules require bilateral participants to submit their contract scheduling intentions at the same time that spot market participants submit their offers and bids. Our decision to place bilateral and spot participants on an equal footing by using a common offer/bid process for all participants has allowed us to rethink these assumptions and to devise a set of pre-dispatch submission and post-dispatch settlement rules that provide a great deal more commercial flexibility to market participants.

It is clear to us that the IMO will need certain types of information from all generators and potentially dispatchable loads in advance of the dispatch. For example, in addition to knowing each participant's injection or withdrawal location on the grid, the IMO will need from each participant its offer or bid quantities and the prices at which the participant is offering to sell (or bidding to buy) each quantity in a price-quantity pair. The Market Rules allow participants to submit their bilateral schedules in advance of the dispatch. However, for purposes of preparing and executing the resulting dispatch schedule, the IMO does not need to know, prior to the dispatch, what commercial arrangements any generator has with any load. This information, while necessary under some arrangements *for performing settlements*, does not seem to be required by the IMO *for purposes of conducting the dispatch*. In other words, prior to the IMO's dispatch, Generator A will submit its offer quantities and prices, and Dispatchable Load B will submit its bid quantities and prices (if any). However, for purposes of preparing a dispatch schedule and conducting the actual dispatch, the IMO does not care or need to know whether these two participants are acting completely independently, whether they have a financial contract for differences to settle between themselves based on any difference between their contract price and the spot price each receives or pays, or whether they have a physical bilateral contract at some agreed-upon price. This information is relevant only to the IMO's settlement process.

We concluded, therefore, that if the participants have a commercial arrangement between them that affects how the IMO accounts for their settlement, this information could be provided to the IMO later than the information required for the dispatch, and could even be submitted *after* the dispatch occurs. That is, the needs of the settlement process, rather than the needs of the dispatch process, should determine the timing for final submissions to the IMO with respect to commercial arrangements such as physical bilateral contracts.

To illustrate this principle, consider the following example (which ignores losses).

- Generator A and Load B have a contract in which A agrees to supply 10 MW of B's demand at the agreed-upon contract price.

- By the offer/bid deadlines provided by the rules, Generator A submits its offer quantities and prices to the IMO. Similarly, Load B (if it is and wants to be dispatchable) submits its bid quantities and prices.

- The IMO considers all the submitted offer/bid quantities and prices, prepares the dispatch schedule, and implements the dispatch.

- In the dispatch hour, the parties' bids are accepted and Generator A injects 10 MW; Load B withdraws 10 MW.

- The day after the dispatch, Generator A notifies the IMO settlement process that it will be financially responsible for 10 MW of Load B's withdrawals.

- The IMO settlement process nets Generator A's credit for 10 MW against Load B's 10 MW debit, for a net settlement of 0. [2]

This simple illustration shows that those participants who choose to engage in physical bilateral contracts will be settled on a "net" basis. It also demonstrates that information about the commercial arrangement between A and B is not essential to the IMO's dispatch and may therefore be revealed to the IMO settlement process at some later point, even after the dispatch has occurred, and is needed for settlement purposes only.

We then considered what effect these conclusions have on the timing of submissions and the ability of market participants to change their submissions in the hours immediately prior to the dispatch (the issue discussed in section 3.5 above). We determined that the pre-dispatch deadlines for submissions (and the corresponding restrictions on revisions) should relate solely to the information required by the IMO to conduct the necessary security assessments and to prepare its dispatch schedules, but that we could allow market participants much more flexibility with respect to informing the IMO of (or revising) the commercial arrangements that are only relevant for settlement purposes. The Market Rules can therefore focus the pre-dispatch submission deadlines on getting information relevant to the dispatch, while providing increased flexibility and later deadlines, up to six days after the dispatch day, for submitting final information on commercial arrangements such as physical bilateral contracts.

This increased flexibility also extends to the threshold limits for participating in the IMO-administered markets (see following discussion). Even if the rules apply a 1 MW or larger size threshold on participation in the dispatch, the distinction we propose between dispatch information and commercial settlement information means that very small contract quantities can be accommodated in the settlement system. In other words, we need not restrict bilateral contracting to trades of 1 MW or higher, since the settlement system can easily handle much

[2] In this example, the net settlement is zero not only because the amounts are the same but also because both A and B are subject to the same uniform price for settlements at their respective locations. If the transaction is across an intertie and the prices at A's location differ from the prices at B's location, the same netting of A's credits against B's debits occurs, and the net settlement will reflect the congestion-related effects of redispatch costs. In principle, the approach is compatible with congestion-pricing methods that may be used after the first 18 months of market operations.

smaller amounts. For example, a 1 MW generator may participate in the IMO's dispatch, but it may only have a bilateral contract with a load to supply 0.5 MW. As shown by the example above, the generator can inform the IMO settlement system the day after the dispatch that it is financially responsible for 0.5 MW of its load's withdrawals. Thus, the settlement system can handle very small bilateral arrangements even if the dispatch process cannot.

Using the same logic, we determined that there need be no restrictions on the number of bilateral arrangements any one generator might have with different loads. Again, all of these arrangements would be irrelevant to the IMO for dispatch purposes and only relevant for settlement purposes. For example, Generator A could have a 0.2 MW contract with Load B, a 0.1 MW contract with Load C and a 0.7 MW contract with Load D. After the dispatch, the generator could simply inform the IMO settlement process of the quantity amounts of its financial responsibility for each load's payment obligations.

Recommendation 3-6

We recommend that the market rules distinguish between market participant data required by the IMO to conduct its dispatch and data required by the IMO to perform settlements. We further recommend that, given this distinction, the rules provide greater timing and other flexibility to market participants in submitting data about their physical bilateral contracts. We also recommend that the rules use this distinction so that the settlement system can allow multiple physical bilateral contracts for each generator or load and allow the IMO to settle bilateral arrangements smaller than the threshold size that may apply to participation in the dispatch.

3.8 Defining a Size Threshold for Market Participation

It is common in some markets for the rules to set a minimum megawatt threshold – typically 1 MW -- for participating in the IMO's dispatch and market systems. The apparent effect of this requirement is to exclude small generators (and small dispatchable loads) from direct participation in the dispatch, a result that is often equated with exclusion from the market and as unfair to some renewable and small dispersed generation technologies. However, this appearance is misleading, and indirect participation is still possible for small generators and loads, as we discuss below.

We considered whether a nominal 1 MW threshold should apply to the Ontario market. A principal reason for having a size threshold is that the accuracy and sensitivity of typical system operator software and security assessment methods is somewhat questionable at levels lower than one to five megawatts, especially in systems like Ontario's in which more than 20,000 megawatts are typically evaluated and dispatched. Further, if a small plant of, say 0.5 MW, wanted to be subject to the IMO's dispatch control, it is conceivable that very small perturbations in the dispatch model or security software would result in the small plant being either in or out of the dispatch. In real time, such minor perturbations would be insignificant to the total system. For the small plant, however, they might result in volatile dispatch instructions that turned the small plant on and off frequently, an effect that could damage the plant's equipment or cause the operator to incur repeated start-up and shut-down costs.

A 1 MW limitation need not prevent smaller plants from participating in the market. The Market Rules provide, for example, that intermittent generators (e.g., small wind generators) can simply submit forecasts of their hourly outputs and function as "must take" generators. When they produce energy, they will be compensated at the spot price for their output during each hour. If they have bilateral contracts with loads, the value of their output can be credited against the payment obligations of their bilateral loads by the IMO's settlement system, thus achieving the net accounting characteristic of physical bilateral contracting. Under this arrangement, size is not relevant, since there is no attempt to subject intermittent generators to the IMO's normal dispatch instructions. The plants simply run when they can and are compensated or credited accordingly.

We concluded that this basic approach could be applied to any small generator (or dispatchable loads) below a stated threshold. The threshold, initially starting at 1 MW, will apply to participation in the dispatch. Smaller plants of any type can participate in the market under "must-take" procedures and be compensated or credited (for bilaterals) for their output. Under this approach, plants smaller than the threshold will not bid nor be subject to the IMO's dispatch. However, these plants may respond to price on their own if they choose to do so, by, for example, reducing their output when the price falls below their operating costs and increasing it whenever the price rises above that level.

Recommendation 3-7

We recommend that the Market Rules use the distinction between dispatch and settlement data to give increased flexibility to small generators (or dispatchable loads), such that a size threshold of 1 MW may apply to participation in the dispatch, but much smaller entities and transactions can be accommodated in the settlement system. We recommend that small plants be allowed to participate as "must take" generation and be entitled to receive the spot price for their output and, if they engage in bilateral arrangements, to have their credits netted against their bilateral load debits in the same manner as larger bilateral participants.

3.9 Defining a Fair Settlement Period

Our Settlement Sub-panel developed an extensive procedural framework in which settlements for the IMO-administered markets would occur. Part of that framework is a schedule by which metering and settlement data are accumulated and processed by the IMO, each participant's debits and credits are calculated, preliminary statements are prepared and reviewed, and billing from final statements occurs. An important feature of this framework for both creditors and debtors is, of course, how soon debtors (typically loads) must pay their bills and how soon creditors (typically generators) receive their payments from the IMO.

We examined a possible schedule of billing and payments in which preliminary statements would be prepared each month within 10 business days after the previous month's end, with final statements sent out to debtors 20 business days after the month's end. The delay between preliminary and final statements would be used to reconcile conflicting or erroneous metering and other account information, thus minimizing the need for later true-ups. The schedule provided that creditors would receive their payments two days later. This schedule meant that debtors would not pay the IMO until up to 32 calendar days after each month's end, while creditors would not be paid for another two days beyond that.

We then compared that schedule with the typical billing and payment schedule used by Ontario Hydro today. We found that the proposed schedule significantly advantaged debtors at the expense of creditors, relative to current practices. We then considered different options for shortening the IMO's billing and payment schedule to bring it in more in line with what parties do now.

We examined the option of providing billing more frequently, on a rolling basis, rather than waiting until the end of each month. We did not accept this option because it would result in a dramatic change for wholesale customers. We then considered whether the IMO could issue bills based on the preliminary statements (available about 10 business days after the end of the month). Although this option meant that some bills would be inaccurate and might require more frequent adjustments in subsequent billing periods, we concluded that this option provided approximately the same relative advantage to debtors and creditors as Ontario Hydro's current billing practice. This option is in the Market Rules.

Recommendation 3-8

We recommend that the settlement period use the IMO preliminary statements, rather than wait for final statements, as a means to expedite the issuance of bills and to provide a payments schedule that is reasonably consistent with those used today by Ontario Hydro.

3.10 Ensuring Compliance with Meter Requirements

Accurate settlements under these Market Rules will require that there be revenue quality metering for all relevant transactions. Federal law requires that Measurement Canada approve all meters and instrument transformers that will be used at points of interconnection with other control areas and at ownership interfaces specified by the market participants. The metering sub-panel examined the issues raised by these requirements. Their work is reflected in an extensive report that contains detailed draft guidelines the IMO will consider with respect to metering.

Our metering sub-panel determined that most of the expected market participants already have approved metering. The existing direct industrial customers, interconnected tie lines and non-utility generators have metering approved by Measurement Canada. Municipal metering installed after 1982 is also fully compliant. Municipal metering installed prior to 1982 received permission to continue in use on the condition that it be upgraded when the original equipment fails or other major work takes place. Virtually all of the meters have since been replaced with approved units, though some MEU meter installations continue to be billed on instrument transformers subject to the dispensation.

However, except for non-utility generators, most of the generating plants in Ontario have neither approved meters nor approved instrument transformers. New meters will eventually be required to meet the data collection requirements of the Market Rules. Our sub-panel consulted with Measurement Canada and reached an understanding under which the IMO will be responsible for seeking a dispensation from Measurement Canada to allow market operations to begin with existing instrument transformers, provided suitable error correction is applied. The sub-panel recommended, and we agree, that any dispensation sought by the IMO should cover all non-complying meters that will be used by market participants.

Recommendation 3-9

We recommend that the IMO arrange for any and all exemptions that may be required from Measurement Canada to allow use of existing non-complying meters in the new markets.

CHAPTER FOUR

TRANSMISSION AND DISTRIBUTION

Transmission and Distribution

Table of Contents

CHAPTER FOUR

TRANSMISSION AND DISTRIBUTION

4.1 Introduction

During the fourth quarter, our Technical Panel on Transmission and Distribution formed five sub-panels to pursue specific implementation questions. (The Report of the Transmission and Distribution Technical Panel is Appendix Four to this Report.) The sub-panels reported to our Transmission and Distribution Subcommittee toward the end of the quarter, and we have based our recommendations and the relevant sections of the Market Rules largely on the work that they have done. We wish to thank the members of the Technical Panel and the sub-panels for their lengthy and excellent work.

This chapter describes several key issues considered by the Technical Panel relating to transmission and distribution and summarizes our recommendations. In particular, we discuss a number of issues on which we spent the majority of our deliberations:

1. What criteria should Ontario use to identify the assets that will comprise the IMO-controlled transmission grid and to distinguish transmission from distribution facilities?
2. What rules should apply for connecting to the IMO-controlled grid?
3. How should transmission service within Ontario be defined, and how should the IMO determine who gets access to transmission service on the IMO-controlled grid?
4. How should the revenue requirements (fixed and on-going maintenance costs) for the transmission grid be recovered, and which market participants should be charged for these costs?
5. How can Ontario facilitate inter-regional trading, and how should market participants get access to the interties with neighbouring regions?
6. What role should the IMO play in co-ordinating transmission and generation maintenance outages?
7. How should transmission and distribution losses be treated?
8. What responsibilities do the IMO and market participants have to maintain system reliability?
9. What principles and processes should Ontario use to guide new investments in transmission facilities?
10. What types of provisions should be included in the agreements between the IMO and transmission owners?

4.2 Principles for Defining the IMO-Controlled Grid

The electrical system in Ontario consists of a vast network of interconnected transmission and distribution lines and related facilities. The Ontario electricity market will use this entire interconnected network to deliver power from generators to end-use consumers. However, as the system and "market operator," the IMO is empowered by the *Electricity Act, 1998,* to exercise operational control only over the "*transmission* systems with respect to which, pursuant to agreements, the IMO has authority to direct operations." (Emphasis added) One consequence of this provision is that the distribution portion of the network will remain subject to the operational control of local distribution companies (LDCs or "distributors"). As a result, it is necessary to clearly identify which lines and facilities within the network are "transmission"and potentially subject to the IMO's operational control, and which lines and facilities are "distribution." This distinction will also affect how the costs of each type of line or facility will be recovered.

In practice, the distinction between transmission and distribution is essentially arbitrary. Historically, distinctions have been based on voltage levels ("high-voltage" lines are usually called "transmission," while "low-voltage" lines are usually called "distribution"), but there is no universally accepted rule for defining "high" and "low."

Generally, transmission is the regional high-voltage electrical infrastructure through which electricity flows in large quantities between a few concentrated electricity production centres and the many more dispersed load centres. Distribution, on the other hand, is usually the local low- and medium-voltage electrical infrastructure through which electricity is delivered from the regional system to the end-use customer.

The transmission system can be subdivided into the integrated *network*, which is the backbone of the high-voltage system that is shared by all users, and radial *connections*, which are the radial parts of the high-voltage system that are specifically dedicated to serving a single user or small group of generators or wholesale customers directly connected to the bulk transmission system. The distinction between network facilities and connection facilities is important for cost recovery purposes, as discussed in Section 5.3. Historically, the Ontario Hydro transmission system comprised all lines, interconnections, auto transformer stations, and step-down transformer stations that are operated at voltages greater than 50 kilovolts (kV). The distribution systems typically comprised the wires assets downstream of the high-voltage network and connection assets. In Ontario, distribution assets include stations and single-circuit lines and feeders that are operated at less than 50 kV.

Further distinctions may also depend on the degree of integration in a looped network, the importance of a line or facility to network security and operations, the role a line plays in facilitating market operations, ownership or other factors. For example, specific low-voltage lines may be essential to network or market operations, and some "distribution" systems may well use high-voltage lines, as we discuss further below. Hence, there is no clear line for making a distinction.

The *Electricity Act, 1998,* defines transmission to include lines of 50 kV and higher, while distribution includes lines with voltages less than 50 kV. We use this simple numerical criterion as the starting point for defining the IMO-controlled grid, but we also recommend that the IMO be allowed the flexibility to identify specific lines and facilities as either transmission or distribution, and within or outside the IMO-controlled grid, depending on the functional importance of the particular line or facilities to regional operations, security and reliability. It will also be important for the IMO to control lines and facilities that can have a significant effect on market operations at the wholesale level, such as lines that support significant plants subject to the IMO's scheduling and dispatch process. This flexible approach is consistent with that used in other jurisdictions with regional system/market operators and will allow the IMO to control at least the minimum set of lines and facilities necessary to meet the IMO's market and reliability responsibilities under the *Electricity Act, 1998* and the Ontario Market Rules.

It should be recognized that even with this flexible approach, some market participants – such as generators and large loads embedded within distribution systems – will be connected through lines and facilities that are defined as "distribution" and owned by LDCs. Market participation by these entities will therefore require continued co-operation of the LDCs and co-ordination of their distribution facilities with the dispatch and scheduling operations centralized within the IMO. At a minimum, LDC procedures must provide non-discriminatory access for eligible plants and customers to the wholesale markets co-ordinated by the IMO. [1] Procedures must also ensure that the LDC advises the IMO of any condition on its distribution system that may affect the ability of embedded generators and loads to participate in the broader IMO market.

Recommendation 4-1

We recommend that the assets comprising the IMO-controlled grid be based on the 50 kV level referred to by the *Electricity Act, 1998*, and subject to any exemptions made under regulations pursuant to the Act. We further recommend, however, that the IMO be allowed over the next year to identify specific exceptions to ensure that all lines and facilities that are essential to Ontario regional security and reliability, or critical for wholesale market operations, be included within the IMO's control, either directly or through appropriate operating agreements with the facility owners. Subject to the exemptions pursuant to regulations made under the Act, LDC procedures should also ensure that embedded generators and loads have open, non-discriminatory access to the IMO-co-ordinated markets and that LDCs inform the IMO of any distribution conditions that might affect system reliability or market operations.

Our Technical Panel and Sub-Committee also considered the special issues that arise from the fact that some lines in Ontario that operate at less than 50 kV actually function as transmission facilities, either connecting direct customers or transporting bulk power to an LDC, rather than distributing power to customers – that is, they are functionally transmission "connection" facilities. These facilities are typically owned by Ontario Hydro Service Company Incorporated (OHSCI) but comprise only a very small part of OHSCI's total assets. Because there may be different methods for recovering the costs of transmission connection facilities versus distribution facilities, we considered how best to classify these particular facilities.

[1] A transmitter or distributor may be exempt by regulation made under the *Electricity Act, 1998*, from the requirement to provide non-discriminatory access to its transmission or distribution system in Ontario.

Through our Subcommittee, we examined three options for how to treat them:

1. We could classify these low-voltage lines as "transmission," consistent with their apparent function, while ignoring their voltage levels. Given our cost recovery principles, this approach would require that the costs of these facilities be recovered from all loads in Ontario. However, classifying the facilities as "transmission" might legally require the affected LDCs to acquire both a distribution licence and a transmission licence from the OEB. We concluded that this dual licensing requirement would be excessive. In addition, those load customers served directly from the high voltage transmission system would now be required to contribute to the cost of these low-voltage facilities. We judged this to be unfair because these customers do not contribute to these costs today.

2. We could classify the lines as distribution, consistent with their voltage levels, and thus avoid the duplicate licence problem. However, this approach would imply that the affected LDCs, and only those affected LDCs, would bear the costs of these facilities (a "user-pays" principle), even though historically, the facilities' costs had been recovered from all provincial loads except customers connected directly to the transmission system. We concluded that this abrupt change in charging methods would be unfair to the affected LDCs.

3. We could continue the historic method of charging these facilities' costs to all loads (except those load customers served directly from the high-voltage transmission system), as though they were common transmission facilities, but request that OEB recognize an exemption that would relieve the affected LDCs from having to acquire a transmission licence merely because these "transmission" facilities were within their distribution systems. We concluded that this third approach was the simplest and fairest for all concerned.

Recommendation 4-2

We recommend that the current cost recovery method be continued for those low-voltage existing facilities that function as transmission, but that regulations allow affected LDCs to be exempted from a dual licensing requirement solely on that account. However, we also recommend that in the future, all the costs of new transmission connection facilities be allocated on the principle of "user pays". See below.

Recommendation 4-3

We also recommend the following technical boundaries between the transmission system and other facilities:

- **The boundary between distribution and transmission facilities should generally follow the existing Ontario Hydro criteria, including the voltage criterion in the *Electricity Act, 1998,* and be at the load side of the feeder circuit breakers. However, exceptions should**

be allowed with distribution licences permitting distributors to own some facilities that might otherwise be classified as transmission facilities, but without requiring the affected LDCs to obtain a transmission license solely for that reason.

- **The boundary between network transmission facilities and connection facilities should be as described in our *Third Interim Report.***

4.3 Requirements for Connection to the IMO-Controlled Grid

4.3.1 Terms of connection agreements

In principle, there should be an internally consistent set of connection rules that apply to all market participants, including generators, loads, and transmitters/distributors. However, such uniformity may not be practical or necessary to begin the market. Under current rules, existing generators, LDCs and directly connected loads already have some type of connection arrangement with the transmission system serving them. As a general rule, we recommend that these existing connection agreements be continued (grandfathered) at least for the near term, subject to review by the IMO and possible upgrade. For new connections, we expect that the IMO will perform system impact studies of proposed new connections for purposes of determining network impacts. The transmission company will enter into an agreement with each generator, LDC or directly connected load to provide them with a reliable connection service in conformance with the Ontario Grid Connection Code (OGCI), the framework for which we have included as part of the IMO's market rules. (The Technical Panel's Report, Appendix Four, contains a further discussion of this point.)

Recommendation 4-4

We recommend that existing transmission connection arrangements be grandfathered. We recommend that new connections which, in the IMO's judgement, do not require any network upgrades, be initiated by a market participant's application to the transmission company, which will analyze the requirements and then enter into an appropriate connection agreement. Any such agreements must comply with the connection standards set forth in the Ontario Grid Connection Code. We recommend, and the Market Rules assume, that the IMO be the administrator of the Ontario Grid Connection Code. The transmitter will certify to the IMO that the connections comply with the Code. The IMO will review all connection agreements with respect to technical and reliability aspects and oversee periodic testing of connected equipment.

In some cases, the IMO may find that a new connection would require an upgrade of the IMO-controlled grid. In such cases, the principles for new investments, set out in Section 4.10, would apply. In those cases where it is determined that an upgrade is required to meet the OGC standards, we reiterate our *Third Interim Report* recommendation that the OEB endeavor to allocate the costs of the upgrade to the identified beneficiaries, presumably the affected generator, load or transmitter.

4.3.2 Compliance with connection standards

The Technical Panel determined that some of the facilities currently connected to the grid do not meet all of the standards set forth in the proposed Ontario Grid Connection Code. While full compliance is a long-term goal, the Transmission and Distribution Subcommittee agreed that the IMO should be permitted to waive initial compliance with the standards in such cases, without amending the Market Rules, but only if it is satisfied that no serious reliability problems would result. The IMO would establish a process for considering waiver requests, and would make determinations with the intent of avoiding investments in facility upgrades that it determined to be unnecessary to maintain reliability.

Recommendation 4-5

We recommend the IMO establish procedures under which it may waive compliance with the provisions of the Ontario Grid Connection Code (OGC) for existing facilities, subject to the conditions recommended by the Panel. However, in order to preserve fairness between new and existing market participants, we recommend that in those cases where the IMO initially agrees to waive an OGC standard, there must be public notification that a waiver will apply. In cases of dispute, we recommend that any complainant (who must be a market participant) be able to use the IMO's dispute resolution process to obtain a ruling on the fairness of the proposed waiver.

4.3.3 Interconnection agreements with neighbouring systems

The IMO is responsible for negotiating the operational elements, such as the security and reliability aspects, of any interconnection agreements with neighboring control areas. However, the relevant transmission provider is responsible for negotiating how the interconnection is to be physically made. These two aspects of the interconnection agreement should be negotiated together in a co-ordinated manner with the IMO taking the lead.

4.3.4 Testing of connected equipment

All equipment connected to the IMO controlled grid will have to be tested to ensure compliance with the relevant Ontario Grid Connection Code standards. We expect the IMO to oversee and define the conditions for these tests, which will be conducted on a routine basis, as required by the North American Electric Reliability Council (NERC) and the Ontario Grid Connection Code. Under the Market Rules, the IMO will also have the authority to direct that connected entities conduct further tests whenever the operation of the connected equipment indicates that there may be a problem with that equipment.

Similarly, the Market Rules will give the IMO the authority to require equipment that is under contract with the IMO to provide ancillary services to be tested by the owner to demonstrate that the equipment is capable of providing the contracted service. In addition to requiring initial testing to determine eligibility, we expect the IMO to require periodic, routine testing of ancillary service providers at least every three years.

The IMO will oversee such tests of connected equipment and will be responsible for reviewing the results provided by market participants to determine the equipment's initial and continuing eligibility for market participation. The owner of all tested equipment should be responsible for all costs of conducting any tests required by the IMO.

4.4 Defining Transmission Service for the Ontario Market

Under most pre-market US regimes, transmission is a service that is provided automatically to a utility's own connected generators and to loads served by that utility within its defined service area. Users of that service – regarded as native load customers– are obligated to pay the fixed and ongoing maintenance costs of the transmission system through regulated transmission rates and conditions (tariffs). Within these structures, non-utility generators, and loads or generators outside the utility service area are allowed access to the utility's interconnected system only by purchasing or reserving some form of "transmission service" from the transmission-owning utility. Traditionally, such transmission service has been defined using various categories of "firm" and "non-firm" service, with the variations reflecting the degree to which the transmission-owning utility could interrupt the service to ensure serving its own native loads or to avoid incurring additional uncompensated costs. While this structure worked reasonably well in an era in which loads were served exclusively by vertically integrated utilities with well-defined service areas and associated loads, it has become less useful with the introduction and expansion of wholesale and retail competition. The demands of increased wholesale competition have led FERC to impose extensive administrative rules on US utilities in an effort to ensure that non-utility participants get access to each utility's grid on terms and conditions that are comparable (or not unduly discriminatory) to those each transmission-owing utility applies to its own use of the grid. Still, many disputes over whether these terms of access are truly comparable for non-utility participants continue to arise under this framework. Moreover, under this traditional US framework, few if any market-based mechanisms exist for allocating use of the grid to those who place the most value on that use.

During the third and fourth quarters we developed wholesale market designs and proposed rules under which all participants are allowed or required to submit offers or bids to the IMO to reflect the value of their proposed use of the transmission system. These are the same bids and offers the IMO will use to determine which plants get dispatched and in what order. Using this market-based approach, those who place the highest value on grid use (that is, on being scheduled/dispatched) will be accepted, scheduled or dispatched by the IMO. Thus, any participants whose bids or offers the IMO accepts to inject or withdraw energy will automatically gain access to the IMO-controlled grid, enabling those participants to implement their transactions. In this regard, it does not matter whether the transactions are structured purely as purchases or sales of energy in the IMO-coordinated spot market or are structured as bilateral transactions between pairs of buyers and sellers (or some combination of spot and bilateral transactions). Access to the IMO-controlled grid therefore depends on the values that market participants place on their energy transactions, as indicated by the prices in the bids and offers they submit to the IMO.

Given this market design, the problem of ensuring comparable, non-discriminatory access is solved efficiently through market-based prices, and there is no need for the traditional concepts of "firm" and "non-firm" transmission service. We are therefore able to redefine the nature of transmission service and to focus on the important question of how to ensure that transmission owners recover their legitimate costs – both fixed and ongoing maintenance costs – of the transmission system.

The Transmission and Distribution Technical Panel invested substantial effort in working through the issues involved in transmission access and cost recovery. The Panel recommended to us, and we concur, that there should be four transmission "services," as described below:

Recommendation 4-6

Consistent with the wholesale market rules, we recommend that the IMO offer four types of transmission service:

- ***Basic Use Service* – Basic Use Service includes every use of the Ontario IMO-controlled grid to provide transmission to internal Ontario customers, irrespective of the source of the power. Basic Use Service thus covers the use of the IMO-controlled grid to deliver power to all customers located in Ontario (except customers exempted through regulations), whether the power is imported from outside the province or generated within the province. Because this service provides electricity to all non-exempt Ontario customers, they will have access to, and must help pay the costs of, Basic Use Service.**

- ***Export Service* – Export service applies to transactions in which the power is destined for customers located outside Ontario, irrespective of whether the power originates within the province or outside it ("wheeling through" transactions). Generators who use the IMO-controlled grid and its interconnections withneighboring regions to export power to customers outside Ontario will not pay the fixed costs of these facilities, but they will pay any incremental costs that their transactions impose.**

- ***Connection Service* – Connection service applies to Ontario customers who are directly connected to the IMO-controlled grid by transmission line facilities which they have not paid for. Current arrangements under which the costs of existing connections are recovered from all existing loads which would be grandfathered. New load and new generators would acquire new connection service, and the new load and new generators would pay for the new connections, but not for existing connections.**

- ***Transformation Service* – This service will be offered to and paid by those Ontario transmission customers who do not own their own transformation facilities.**

We next focus on how the costs for Basic Use and Export Service should be allocated between market participants.

4.5 Principles for Recovering Fixed Transmission Charges for Basic and Export Service

4.5.1 Uniform Rates for Basic Use Service

Recommendation 4-7

We recommend that Basic Use Service be charged at a uniform rate and that it be provided automatically to LDCs and directly connected customers. All Ontario customers connected at the distribution level will therefore have access to the IMO-controlled grid through their host LDC's access to Basic Use Service. Further, we recommend that LDCs that are embedded in the distribution networks of other LDCs be given the choice of purchasing Basic Use Service directly from the IMO or indirectly through the tariffs of those LDCs, subject to any exemptions made by regulations. All Ontario customers would therefore pay for Basic Use Service, either directly or indirectly, and such payments would recover the transmission owners' revenue requirements, as determined by the OEB. In effect, payments for Basic Use Service would cover the transmission portion of the Ontario "delivery" costs for energy and ancillary services provided to customers located in Ontario. Market participants would be able to use Basic Use Service equally for spot and bilateral transactions.

Recommendation 4-8

Consistent with the legislation, we recommend that the rates for Basic Use Service be set by the OEB, on application from transmission providers, such that revenue requirements are met within a general performance-based regulatory regime. The rates should be set to cover the rolled-in costs of all network transmission (common grid) facilities owned by that provider and charged based on peak monthly usage. We recommend further that the rates be uniform across the province and that they be charged only to loads, not to generators (except that, generators should be metered and pay for any net energy usage). We also recommend that, except for already committed on-site or embedded generators with existing agreements, distributors and direct customers be charged on a gross load basis.

We re-emphasize here the rationale for basing transmission rates as much as possible on gross loads, rather than loads net of new on-site or new embedded generation. We recommended in our *Third Interim Report* that existing agreements that allow rates to be set on a net basis for existing embedded generation be grandfathered. This recommendation applies to existing generators embedded in distribution systems and existing generators located on site with direct connect customers. However, as we noted in our *Third Interim Report*, loads have considerable incentive to bypass these grid charges, but such bypass may not be fair or efficient from the point of view of other market participants or the province as a whole. Where a new generator's economics do not otherwise give it the ability to compete in the energy and ancillary services markets, it may nonetheless appear attractive to construct the new generator if by doing so certain customers can reduce their net usage of the common grid and hence bypass their share of the uniform transmission charge for Basic Use Service. Because transmission charges are designed to recover essentially fixed construction and maintenance costs over the expected life of the grid assets, we believe it both unfair to allow customers to reduce their payments by adding new on-site generation, and inefficient to justify new generation investments on such reductions. Such bypasses would force other customers to bear a larger share of those charges and encourage inefficient investments.

Recommendation 4-9

We recommend that for the purpose of computing the charge for Basic Use Service, the energy produced by new embedded generators or new on-site generators associated with direct connection customers should be added back for purposes of calculating the usage of the customer or LDC through which the customer is served. To determine what connections are "new," we propose that projects committed prior to October 30, 1998 and subject to existing agreements be grandfathered. This cut-off date is the effective date of the *Electricity Act, 1998.*

The IMO will, in effect, contract with load customers who are market participants for Basic Use Service. In its settlement process, the IMO will collect Basic Use Service charges designed to recover the transmission owners' revenue requirements, and it will disburse these revenues to the transmission owners.

4.5.2 Rates for Export Service

Our recommendations for Basic Use Service rates mean that the costs of the Ontario transmission grid, including the costs of the interties owned by Ontario transmission providers, can be fully recovered from Ontario customers through the charges for Basic Use Service. This means that revenue recovery for Ontario transmission owners need not depend on contributions from external loads or generators. This approach also means that Ontario has considerable latitude in deciding whether and how much to charge market participants for using the Ontario grid and its interties for transactions serving out-of-province loads. On the one hand, there is attractiveness in the idea that such transactions should be charged on the same basis as those destined for Ontario loads, or at least make some contribution to the costs that would otherwise be paid by Ontario loads. For example, in the past some jurisdictions imposed charges for exports to serve external loads based on what the transmission owner believed the external participants would be willing to pay. However, this approach is questionable under FERC's principles of comparability. On the other hand, use of the transmission system to serve external loads may not impose any significant additional costs on the grid itself (other than losses), provided the transactions do not create or exacerbate constraints on the interties or other parts of the IMO-controlled grid.

Recommendation 4-10

We recommend that transactions to serve external loads should not have to pay any of the fixed costs of the IMO-controlled grid, but that they should be required to pay for a pro-rata share of the losses and any congestion costs they impose on the Ontario system, plus a

pro-rata share of the IMO's "uplift" – that is, all otherwise unallocated costs of administering the markets (such as charges to recover the costs of certain ancillary services).

If each North American jurisdiction constructs the transmission grid that serves its own needs, and if each then recovers the costs of its grid from its domestic loads (including those loads served by imported energy), but imposes no charge (apart from those above enumerated) for export transactions, then every transaction will be charged only once. Exports would be charged in each importing jurisdiction and paid by the importing jurisdiction's domestic loads. We believe this approach would put inter-regional transactions on an equal footing with intra-regional transactions, thus stimulating interregional trading and competition, while discouraging what otherwise might be a significant restraint on inter-regional trade.

Ontario cannot determine the policies of neighboring jurisdictions. Nevertheless, we note that some neighboring US jurisdictions are adopting this approach. We believe Ontario can establish a beneficial precedent by recommending that export service customers be charged solely for their share of congestion and losses, with an additional fee to recover the IMO's administrative costs.

4.6 Encouraging Efficient Inter-Regional Trading

As discussed in Chapter 3, we recommend that the IMO, which will compute the capacity of the interties as part of its real-time dispatch, allocate that capacity dynamically on the basis of market participants' bids and offers (including incremental and decremental bids supplied by bilaterally-contracting market participants). This is the same process by which the IMO will determine and allocate access to the IMO-controlled grid for internal market participants. In other words, the IMO will use the same market-based approach it uses to allocate use of the internal grid to allocate use of the interties that form part of the IMO-controlled grid. In this manner the use of the interties will be allocated to those market participants whose energy bids and offers indicate they place the highest value on that use.

Given the prices in the bids and offers submitted by market participants proposing to use the interties, the IMO will be able to determine a market clearing price for each region or zone on the other side of the interties from Ontario. When there is congestion, these zonal prices may differ from the uniform price that applies inside Ontario. We recommend that the IMO use these zonal prices as the basis for settlements with external market participants. For example, external loads would be allowed to purchase energy from Ontario's IMO-administered market. In the absence of constraints, the price for that energy would be the same uniform price paid by internal Ontario loads. However, if the external purchases created constraints or required the Ontario IMO to incur additional costs in redispatching the system to accommodate these external transactions, these additional costs would be reflected in the higher prices determined for the external zone. The external loads would be charged the higher zonal price for their purchases , thus compensating Ontario for its redispatch costs and leaving Ontario loads whole. Conversely, if the IMO-controlled interties were constrained into Ontario, the external zonal price could be lower than the Ontario uniform price. In that event, the external loads would settle at their lower zonal prices.

The IMO settlement rules would ensure comparability between spot transactions (purchases by external loads from or sales by external generators to the IMO spot market) and bilateral transactions across the interties. This a pricing approach requires that bilateral intertie transactions be charged for the difference between the external zonal price and the Ontario uniform price. If, for example, a bilateral transaction from Ontario to New York required the IMO to incur redispatch costs (e.g., by constraining the intertie), the IMO would provide a net settlement for the scheduling party that would recognize the difference between the higher New York price and the lower internal Ontario price, effectively charging the transaction for the Ontario redispatch costs. Conversely, if the same bilateral transaction helped relieve a constrained intertie (by creating counterflows), the transaction would be compensated through the IMO settlement process based on the difference in prices.

Recommendation 4-11

We recommend that Ontario allocate use of the IMO-controlled interties based on the bids and offers submitted by market participants. We further recommend that the IMO use these bid and offer prices to determine external "zone" prices that may be different from the internal Ontario uniform price. The IMO should use these determined prices as the basis for settling the transactions involving the interties.

We believe this congestion pricing approach will encourage the efficient use of the interties and will provide useful price signals to market participants regarding the relative merits of alternative investments in generation on either side of the constrained interties or transmission upgrades to expand the intertie capabilities. While the zonal approach has some technical complications that must be addressed (particularly since the interties are not all radial but involve multiple loops), we believe the general approach moves in the right direction and anticipates the type of congestion (nodal or zonal) pricing methods that we recommended in our *Second* and *Third Interim Reports* be implemented after the first 18 months of market operations. If the IMO determines to implement a nodal pricing method after 18 months, the basic concepts of the interim zonal approach can be adapted to the nodal method.

Because the IMO settlements will use zonal prices that may differ during congested period from the Ontario uniform price, there will be hours when the IMO collects more revenue from loads than it pays out to generators in settling accounts. These "congestion rentals" from the settlement surplus must be allocated back to market participants in some way. In other jurisdictions, congestion rentals are used to support a system of financial hedges, sometimes called "financial" transmission rights, that reimburse market participants for intertie congestion charges, and we recommend that such a system be developed for the Ontario market.

These rights are "financial," because they do not guarantee physical access to the intertie (which is allocated to the most competitive bidders in the IMO's scheduling and dispatch process) nor preclude those without rights from gaining access to the grid (hence, the rights cannot be hoarded as a means to exclude competitors from the grid). Instead, holders of these rights are entitled to be compensated by the IMO for the congestion-related difference in prices that arise across constrained interties, thus providing a financial hedge against such price differences. Our proposed rules therefore contemplate that the IMO will administer periodic auctions to allow market participants to acquire such rights. Any participant who acquires a right would then be free either to receive this compensation or to sell its right in a secondary market process. In open, well-functioning markets, the rights between two locations would be expected to sell for the expected value of the congestion-related difference in prices at each location.

It is possible that market participants will choose to structure a large percentage of inter-regional energy transactions through long-term bilateral arrangements. Such participants would presumably wish to assure themselves of price certainty by purchasing hedges against any congestion-related price difference, probably (if possible) through a mix of hedges purchased over an extended period, from many months to no more than days or hours in advance.

Framework principles for designing such an auction are under development, and we have determined that net auction revenues, after compensating those market participants who resell their rights in each auction, should be used to offset the revenue requirements for Basic Use Service. We believe the IMO should give high priority to completing the development of the auction rules and compensation process. Among other things, the IMO will have to consider alternative methods for defining the amount of intertie capacity to be covered by each set of auctioned rights, to ensure that the auctioned set can, under normal grid conditions, be fully supported by the expected congestion rentals from the settlement surplus. Our settlement rules will include provisions that use the uplift account to provide full support for the hedges when the surplus is less than the hedge obligations, and reimburse the uplift account when the settlement surplus is larger than needed to fund the hedges. We expect other parties, moreover, to create effective secondary markets for these auctioned rights and to design innovative ways to repackage and market combinations of rights that will be attractive hedges to market participants. [2]

Recommendation 4-12

We recommend that the congestion rentals collected from the intertie pricing approach be used by the IMO to support a system of "financial" rights or hedges that would be allocated, through IMO auctions, to market participants as a means to hedge the price uncertainties associated with congestion-related price differences on IMO-controlled interties. Net auction revenues should be used to offset revenue requirements for Basic Use Service. The amounts by which the settlement surplus from intertie transactions exceed or are less than the payment obligations of the allocated rights for any settlement period should be managed through an uplift account. The IMO should give high priority to completing the auction rules and defining auction modeling assumptions.

[2] As we note in Chapter 3, we expect these procedures to enhance the favorable perceptions of Ontario market rules at FERC, thereby improving the ability of Ontario parties to meet any NAFTA or FERC-imposed reciprocity requirements that may be conditions for participating in US markets. However, if it is deemed that the proposed procedures are not consistent with either NAFTA or the mutual open access principles, changes to these market rules should be made to ensure that inter-regional trading can take place.

4.7 Outage Co-ordination

From time to time, all of the equipment and structures used in the electricity system must be taken out of service so that they can be maintained and, if necessary, repaired or upgraded. The asset owner has a natural interest in scheduling such outages in such a way as to minimize its net cost (lost revenue opportunities, maintenance expense, etc.). However, when the equipment involved plays a significant role in maintaining the stability or performance of the larger system or in determining market outcomes, both the IMO and market participants have an interest in ensuring that maintenance is not scheduled at inappropriate times. For example, when a transmission line is out of service, it may be impossible for generators and/or loads on that line to inject or receive power from the grid. For this reason, one would expect that the parties involved in such dependencies would have an incentive to find mutually satisfactory outage schedules (e.g., generators might schedule their outages at the same time as the transmitters), since the performance of the network as a whole can be affected either through increased congestion or other forms of degradation of service.

We therefore devoted considerable time to considering an appropriate process for coordination of such outages. In general, the process we recommend attempts to balance the interests of asset owners with those of the users of the system as a whole.

Our Technical Panel agreed that the IMO must be responsible for assessing the adequacy and security of the IMO controlled grid in response to the submitted outage plans. At the same time, market participants and transmission providers are responsible for managing the economic aspects of both their outages and those of others. To allow this to occur, the Market Rules provide that market participants and transmission service providers to the IMO-controlled grid must advise the IMO of their outage plans, so that the IMO can conduct security and adequacy assessments based on the intentions of the asset owners. The IMO would then publish the results of its assessments to provide signals to market participants and transmission service providers as to the economic impact of the outage plans. Participants and asset owners would then be able to adjust their plans in ways they deemed to be in their best interests.

We believe this co-operative process will a llow market participants to avoid many of the market problems that unilaterally planned outages might create. However, the IMO would also have the authority to veto outage plans within two days prior to a planned outage. This authority could be exercised whenever the IMO determined that a planned outage would pose a significant concern relating to generation adequacy or other indices of system security. Those participants (except transmission providers, whose costs are recovered through regulated rates) who have their outages cancelled by the IMO under these circumstances would be allowed to make a claim against the IMO for any direct costs that could be attributed to the outage cancellation.

4.8 Treatment of Losses

Our Transmission and Distribution Sub-Committee developed three general principles that should apply during the period when uniform pricing is in effect. First, losses will be allocated between transmission and distribution. That is, losses incurred on the distribution system should be allocated to the distributors (and recovered through each distributor's rates to its customers). Losses from the transmission system, on the other hand, should be recovered by the IMO and recovered from wholesale customers (including LDCs and direct connect customers). Second, during the uniform pricing period, the additional costs incurred by generators in providing (making up for) losses should be recovered through an uplift charge that will be assessed against all loads, whether they obtain their energy through spot purchases or through bilateral contracts. Third, the amount of the uplift attributed to losses will be defined as the additional marginal costs generators incur (and the IMO or distributors must pay) to replace the losses on each system. The precise mathematical formula by which losses are calculated and their costs allocated by the IMO are set forth in the Market Rules under the Settlement provisions.

We examined methods the IMO can use to determine losses on the IMO-controlled grid and allocate their costs. In general, the IMO will determine injections, off-takes and net intertie flows and then determine losses from the differences between injections and off-takes. The IMO will then apply these losses to a single reference node in the *ex post* pricing software. This should produce a uniform price for Ontario that includes losses but not costs associated with transmission constraints. In its settlement system, the IMO can then allocate the costs of losses – based on the volume of losses times the uniform price) to each off-take node in the same proportion that each load bears to total Ontario load. This method will allocate the cost of losses in the same manner as other uplift costs.

Additional issues may arise in allocating the costs of losses to distribution customers in regions where distributors read customer meters on an infrequent basis. A discussion of this problem and proposed solutions are set forth in Chapter 6, Retail Competition.

4.9 IMO and Participant Responsibilities for Maintaining Reliability

Within the limits of the uniform pricing policy (to be employed for the first 18 months), our proposed market rules have been designed to allow market participants to react to market and grid conditions in accordance with their respective market interests. As a general rule, the IMO will rely on these market responses to solve grid and market problems to the maximum extent practical. While the IMO has the clear authority to intervene in the market and indeed suspend market operations if necessary to preserve system security and reliability, its first option must be to rely on market responses. Moreover, even during periods of emergency and market suspensions, the Market Rules are designed to encourage and allow the IMO to use market mechanisms whenever practical to resolve system conditions and help the system return to normal market operations.

When market mechanisms fail, the Market Rules provide that the IMO will have adequate and clear authority to take whatever measures it deems necessary to maintain or restore system security and safety. The IMO will, of course, co-ordinate its emergency activities with asset owners and other market participants. They in turn, while generally required to take prompt action as directed by the IMO to deal with emergency or high-risk situations, will have the right to prevent physical injury or physical damage to their equipment if they determine such consequences would result during emergency conditions.

Our proposed Market Rules require market participants to respond promptly to IMO directives. Prompt response will be especially critical during emergency conditions. For example, IMO procedures will specify that market participants respond to directives within a reasonable time frame and accuracy, given the particular conditions. We expect the IMO and market participants to establish prior agreements on appropriate response times for each critical facility, consistent with the IMO's needs to maintain reliability and each facility's response capabilities. If the parties cannot agree on an appropriate period of response, we expect that the dispute will be taken to the IMO's dispute resolution process for resolution.

Each year, the IMO will publish a report containing forecasts of the adequacy of the generation and transmission facilities to meet the expected loads. These adequacy forecasts are intended to inform the market and government officials of the potential magnitude, duration and location of expected shortages.

The Market Rules generally define three operating states respecting the status of the IMO-controlled grid:

- normal operations, when all facilities are operating within their normal ratings and the system is meeting the demands placed upon it;

- high-risk operations, when there is a high probability that a contingency, including a contingency not normally observed, may occur.

- emergency operations, when the criteria for normal operations cannot be met without curtailing non-dispatchable load.

During a declared emergency, the IMO may suspend market operations and, in a non-discriminatory manner, direct participants to take any number of measures to protect and/or restore system reliability and security. It may extend security limits beyond those that would normally apply, cancel already approved outages and require the return to service of both generation and transmission facilities. Once it suspends market operations, the IMO may issue dispatch instructions that are different from those that would have applied during normal market conditions.

During a declared high-risk period, the IMO may selectively adjust the level of security required with respect to the loss of plant, operate to respect more stringent security criteria, and cancel planned maintenance work and other outages that the IMO determines would adversely affect the reliable and secure operation of the power system.

At all times, market participants will be required to operate their equipment and otherwise act in a manner that is consistent with the reliable operation of the IMO-controlled grid. Consequently, the Market Rules require participants to meet various responsibilities. For example, they must:

- provide ratings and operating restrictions for all facilities and equipment connected to the IMO-controlled grid;
- inform the IMO of material changes to the status of those facilities and equipment where those changes may impact on the reliability of the IMO-controlled grid;
- promptly comply with directions from the IMO, except where those directions would cause physical damage, cause substantial environmental harm or give rise to conditions of danger to persons; and
- follow procedures and controls for shedding load in emergency situations under the direction of the IMO. (We expect the IMO will develop these procedures with input from stakeholders.)

The IMO will have the responsibility to monitor the real-time power system status and to maintain the integrated power system within acceptable security limits, in co-operation with the asset owner concerned. In doing so, the IMO will also act as the NERC control area operator and security coordinator, assuming the responsibilities which go with those functions, and will enter into agreements with adjacent control area operators for the reliable operation of the interconnected power systems.

It should be noted that electric system reliability standards and requirements are established by NERC and the NPCC. These may be augmented in the Market Rules to meet specific Ontario needs. For obvious reasons, the Market Rules do not repeat all of these standards and requirements. However, the IMO is bound to comply with all standards and requirements, and it will enforce this obligation on market participants through the Market Rules.

4.10 Processes to Guide New Investments in Transmission Network Facilities

In our *Third Interim Report*, we proposed that in the long run, transmission investment processes and decisions should be market-driven as much as possible. We noted that a market-driven approach would require Ontario to move as soon as possible to some form of congestion pricing, so that market participants would see, and be able to respond to, market prices that reflected the scarcity value of constrained transmission. When implemented, congestion pricing should provide important signals to market participants about whether and where transmission investments, or alternative investments in new generation or loads, would provide a net benefit. We also recommended that the costs of new transmission investments be borne as much as possible by those expected to benefit from the investments, rather than be "rolled" into rates and recovered from all participants or loads.

However, we recommended that in the first years of the new market, at least until congestion pricing is introduced, Ontario should rely on more traditional approaches to transmission planning, investment and cost recovery for new network facilities. We noted that at least until it began to use congestion-based pricing signals, Ontario would require more central planning and direction, with consequently more regulatory involvement by the OEB. We then directed our Transmission and Distribution Panel and Sub-committee to recommend transmission planning procedures that would be suitable for this initial period.

Under the proposed planning process, the IMO will conduct periodic long-run assessments of the adequacy and reliability of the Ontario integrated power system, considering both generation and transmission adequacy. The IMO's assessments will be conducted annually, looking at periods up to 10 years ahead; monthly, looking at periods up to 18 months ahead; and weekly, focusing on periods two to four weeks ahead. All market participants will be required to provide information to support the IMO's periodic assessments, and the IMO will apply appropriate criteria established by NERC and other regional reliability organizations. At the end of each assessment period, the IMO will issue and publish a report on the adequacy of generation and transmission facilities to maintain reliable system operations. These reports will then be available to the government and be forwarded to the OEB for its consideration and use during any proceedings to determine the merits of proposed transmission upgrades and expansions.

The IMO's reports will also be available to market participants to help them make investment decisions, and will be used by the IMO Board to help it determine whether to activate the reserve capacity market provided for in the market rules. In addition, the reports will identify the need for future investments in transmission facilities in order to maintain the required reliability and security of the integrated power system or to relieve any significant transmission constraints that the IMO expects to have a material affect on reliability or market operations.

Pricing data from current operations will be especially useful in the planning process. Although congestion pricing will not yet be in effect, the IMO will calculate and publish, preferably daily, the hourly prices that would apply under a nodal congestion pricing approach. These prices can then be used by the IMO and market participants to evaluate the long-term benefits and costs of alternative transmission investments intended to relieve constrained transmission facilities. In addition, the IMO can publish the total redispatch costs it incurred during any period of uniform pricing.

To ensure the co-operation of market participants in providing information about their plans and expectations, the IMO will apply clear guidelines to protect commercially sensitive information from general disclosure. Such guidelines might require, for example, that particular information be published only in aggregated forms, or that certain data be removed from the public versions of the reports. Our Technical Panel developed principles for these guidelines, and we expect the guidelines to be refined over the next year, prior to market operation, as prospective market participants become aware of the types of information to which the IMO will have access.

The proposed rules provide that facility owners keep the IMO informed of the operational status of their facilities and especially advise the IMO of all plans that may have a material effect on the overall integrated power system adequacy and reliability. For example, any transmission owner planning to retire a line or remove it from service for an extended period would be required to notify the IMO several months in advance of its intentions. The Market Rules would then allow the IMO to request that a proposed retirement not proceed where the reliability and security of the integrated power system would be adversely effected. Should the transmission asset owner disagree with the IMO's assessment, the matter would be subject to resolution through the IMO's dispute resolution panel.

Under the recommended planning approach, each long-run assessment by the IMO would indicate where and under what conditions the IMO expected the IMO-controlled grid to suffer significant constraints that would have a material affect on either reliability or market operations. If the IMO identified such a constraint, it would ask the transmission owners and market participants for alternative proposals to alleviate the constraint. The proposed procedures would allow owners of generation or prospective generation to offer such proposals, but would require the owners of transmission facilities in the affected areas to submit at least one technically feasible option for relieving the constraint. In all cases, those submitting proposals would be required to indicate whether they would promote the proposal and also indicate their willingness to bear some portion or all of its costs. The IMO would then screen all proposals it received, including viable supply options, considering both their technical feasibility and their likely impact on the operations of the IMO-controlled grid and the IMO-administered markets. This evaluation would be submitted to the OEB for its consideration in any application proceeding to obtain approval and/or rate recovery for the investment.

If the IMO identified a transmission constraint that it considered to be sufficiently severe that it must be relieved for power system reliability reasons during the next few years, the IMO would request proposals to remedy the situation. If no technically feasible proposals were submitted, the IMO would be empowered to direct the relevant transmission owner in that location to prepare a detailed proposal for filing with the OEB and other relevant agencies.

Similarly, if the IMO identified a constraint which, while not raising a security and reliability concern, would either cost more to relieve or cost less to relieve than the savings flowing from the relief of the constraint, then the IMO would provide that assessment to the OEB for its use in evaluating proposed investment decisions.

Under these proposed procedures, market participants would be free to present transmission investment proposals to the OEB at any time, with or without a supporting assessment from the IMO. If there were no applicable periodic assessment, the participant could ask the IMO to evaluate the technical and economic feasibility of the proposal, with the participant meeting the costs of the evaluation. If the participant filed a proposal with the OEB, the OEB could also seek the assistance of the IMO in evaluating the proposal, and the IMO could intervene in the OEB proceedings to present the results of its assessments.

Recommendation 4-13

We recommend that Ontario use a transmission planning process based on the recommendations prepared by our Transmission and Distribution Technical Panel (and summarized in this Chapter). This process will rely on the IMO's long-term security and adequacy assessments for evaluating the need for new transmission investments and encourage market participants to come forward with transmission investment proposals

that address any long-run security and adequacy concerns identified by the IMO. We further recommend that the IMO advise the OEB and be able to participate in any proceedings initiated by the OEB or by market participants to consider the merits of transmission investment proposals.

4.11 IMO-OHSCI Contract Negotiations

Section 5(b) of the *Electricity Act, 1998*, provides that one of the objectives of the IMO will be to enter into agreements with transmitters under which the IMO will direct the operation of the IMO-controlled grid. The most important such agreement will be between the IMO and Ontario Hydro Services Company Incorporated (OHSCI) which will be the owner/operator of Ontario Hydro's transmission assets. Earlier this year, we decided that we would not participate directly in the negotiation of the operating agreement between IMO and OHSCI, but that we would obtain periodic reports regarding these negotiations to ensure that the negotiations were proceeding in a manner consistent with the market design decisions of the MDC.

The IMO-OHSCI negotiations began in earnest during the fourth quarter of 1998. We received oral reports periodically updating us on the status of the negotiations, the structure of the proposed agreement, and the key issues under negotiation. The parties reported that they have reached conceptual agreement on most of the significant issues that they anticipate to arise during the negotiations. We expect that the agreement will identify those OHSCI-owned facilities that will be included initially in the IMO-controlled grid. The parties have tentatively agreed that all of OHSCI's transmission facilities operating at 115kV and higher will be included in the IMO-controlled grid, but that the IMO will delegate certain responsibilities to OHSCI for 115kV facilities that normally operate in a radial mode. (Virtually all of OHSCI's transmission facilities are 115 kV or higher.) The parties have also reached conceptual agreement regarding the scope of each party's operating responsibilities, the requirements for communicating information between them, the respective obligations for maintenance outage planning, and the protocols for operating the IMO-controlled grid during emergency conditions.

The IMO and OHSCI have circulated a draft contract, attached as Exhibit A, incorporating their agreements to date for our review. We are comfortable with the general direction of these negotiations, which appear to be consistent with the requirements of the *Electricity Act, 1998* and the market design we have recommended. The IMO and OHSCI are continuing to negotiate this contract and have stated that they expect to conclude the negotiations and sign the contract well before the effective date of the Market Rules.

Recommendation 4-14

We recommend that the IMO and OHSCI complete the development of their agreement and continue current negotiations to ensure completion well before the market operations begin and consistency with the *Electricity Act, 1998* and our Market Rules.

EXHIBIT A

Note to Readers: This Draft Operating Agreement is being released for publication with the Fourth Quarter Report of the Market Design Committee prior to the completion of negotiations between the IMO and OHSCI[1] It is subject to change as a result of further negotiations between the IMO and OHSCI and to incorporate relevant materials from the final version of the Market Rules and to become consistent with terms of licences yet to be issued by the OEB. The Parties believe that they have reached agreement on most of the matters that need to be covered in their Operating Agreement. The one notable exception is agreement on some of functional responsibilities associated with directing and operating the 115 kV network.

DRAFT

IMO-OHSC OPERATING AGREEMENT

This IMO-OHSC Operating Agreement ("Agreement"), dated as of _________, 1999, is made and entered into between Ontario Hydro Services Company Inc. ("OHSC"), an Ontario corporation organized pursuant to Part IV of the Electricity Act, 1998, and the Independent Electricity Market Operator (the "IMO"), an Ontario corporation organized pursuant to Part II of the Electricity Act, 1998. OHSC and the IMO are also referred to individually herein as a "Party" and collectively as "Parties."

WHEREAS the Government of Ontario has chosen to establish a competitive electricity market for the Province of Ontario beginning in the year 2000;

WHEREAS the Energy Competition Act, 1998, provides, among other things, the legal framework necessary for the establishment of a competitive electricity market in the Province of Ontario and, as part of that legal framework, further provides for the creation and continuing existence of OHSC and the IMO;

WHEREAS under the Energy Competition Act, 1998, OHSC is charged with the responsibilities of ownership, operation and maintenance of certain transmission and distribution facilities in Ontario and will be licensed as a Transmitter;

WHEREAS under the Energy Competition Act, 1998, the IMO is charged with the responsibility for Directing the Operation and maintaining the reliability of those transmission facilities owned and operated by OHSC and other Transmitters that comprise the IMO-Controlled Grid, and for administering certain competitive markets related to the provision of electricity;

[1] References to "OHSC" should be interpreted as references to "OHSCI", Ontario Hydro Services Company Incorporated.

WHEREAS Part II, Section 5(b) of the Electricity Act, 1998, provides the IMO with authority to enter into an agreement with OHSC, under which the IMO will obtain the right to Direct the Operation of OHSC's transmission facilities that are part of the IMO-Controlled Grid; and

WHEREAS OHSC and the IMO, with this Agreement, hereby intend to set forth their obligations to one another in accordance with and in furtherance of their respective obligations under the Energy Competition Act, 1998;

NOW, THEREFORE, in consideration of the foregoing, and the covenants and mutual consideration set forth herein, the sufficiency of which is hereby acknowledged by the Parties, and intending to be legally bound, the Parties agree as follows:

ARTICLE I
DEFINITIONS

Section 1.1 *Defined Terms*. As used in this Agreement, the following terms shall have the following meanings (such meanings to be equally applicable to both the singular and the plural forms of the terms defined). **[Note: This Article will be amended to incorporate applicable definitions from the Market Rules when they are completed].**

"Administrative Committee" means the committee established pursuant to Article __ of this Agreement for the purpose of coordinating the Parties' activities and resolving disputes arising under this Agreement.

"Direct the Operation" means, with respect to the transmission facilities, the responsibility for establishing security limits, monitoring power flows, managing system security, assessing the impact on reliability of maintenance outage plans, and issuing instructions for deployment of transmission facilities, including equipment loading, restoring equipment to service, controlling voltage, contingency planning, and determining the configuration of facilities (including issuing instructions for the opening and closing of switches and circuit breakers).

"Effective Date" means the later of (a) the date set forth in the first paragraph of this Agreement and (b) the date that the Market Rules established pursuant to Section 32 of the Electricity Act first become effective.

"Electricity Act" means the Electricity Act, 1998, as set forth in Schedule A to the Energy Competition Act, 1998.

"Emergency" means any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

"Forced Outage" means an unplanned reduction in the capability, or removal from service, in whole or in part, of a Transmission Facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the reasonable control of the owner or operator of the Transmission Facility. A reduction in capability or removal from service of a Transmission Facility by OHSC in response to changes in economic market conditions shall not constitute a Forced Outage.

"Good Utility Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

"IMO-Administered Markets" means the markets for electricity and related services established by the Market Rules.

"IMO-Controlled Grid" means the Transmission Facilities owned and operated by OHSC that are identified in Schedule A to this Agreement and those transmission facilities of other Transmitters that are included in the IMO-Controlled Grid pursuant to an operating agreement between the IMO and such Transmitter.

"Instructions" means written and verbal directives and approvals issued by the IMO to OHSC or any Generator, Transmitter, or Distributor for the purposes of, and in connection with, Directing the Operation and maintaining the reliability of the IMO-Controlled Grid.

"Licence" means the licence obtained by a Party pursuant to Part V of the OEB Act.
"Market Participant" means [insert definition from Market Rules].

"Market Rules" means the rules established pursuant to Section 32 of the Electricity Act for the operation of the IMO-Administered Markets.

"NERC" means the North American Electric Reliability Council or its successor.

"NPCC" means the Northeast Power Coordinating Council or its successor.

"OEB" means the Ontario Energy Board.

"OEB Act" means the Ontario Energy Board Act, 1998, as set forth in Schedule B to the Energy Competition Act, 1998.

"Ontario" means the Province of Ontario, Canada.

"Ontario Arbitration Act" means the Arbitration Act, 1991, Statutes of Ontario, 1991, Chapter 17, as amended.

"Operate" means, with respect to the Transmission Facilities, the exercise of direct physical control of facilities and equipment through switching and other automatic and manual control devices and mechanisms.

"Operating Directives" means the written directives formulated by the IMO and OHSC setting forth the detailed procedures and methods to be used by each Party to satisfy its responsibilities under this Agreement and the Market Rules. Operating Directives include those that are independently developed and internal to each party as well as those that are jointly developed and impact on both parties .

"Planned Outage" means the scheduled removal from service, in whole or in part, of any Transmission Facility for inspection, maintenance or repair in accordance with a schedule approved by the IMO pursuant to the Market Rules.

"Promptly" means performing a required act or task in an expeditious manner and without undue delay, using due diligence, and with the intent of completing the act as quickly as practicable in light of the nature of the specific act or task in question.

"TOMC" means the Transmission Operations Management Centre operated by OHSC.

"Transmission Customers" means those Market Participants that are eligible to purchase Transmission Services under Chapter 9 of the Market Rules;

"Transmission Facilities" means the lines, structures, auxiliary equipment and facilities owned and operated by OHSC that are used to transmit electric energy at voltages of 50kV and higher, and which OHSC is required to use to provide non-discriminatory transmission services pursuant to the Market Rules and OHSC's Licence.

"Transmission Rates" means the rates and charges approved by the OEB for the provision of transmission services under Chapter 9 of the Market Rules and OHSC's Licence.

"Transmission Service" means the transmission services identified in and provided pursuant to Chapter 9 of the Market Rules;

"Transmitter" means OHSC and any other owner or operator of transmission facilities within Ontario whose transmission facilities are covered by the Market Rules.

ARTICLE II
PURPOSES OF AGREEMENT

Section 2.1 This Agreement defines the Transmission Facilities of OHSC that are part of the IMO-Controlled Grid, and sets forth various responsibilities of the IMO and OHSC with respect to the secure and reliable use and operation of the Transmission Facilities in accordance with the Market Rules. This Agreement shall be subject to and supplemented by the rights and obligations of the Parties under the Market Rules and their respective Licences. The provisions of this Agreement should be construed, whenever possible, to be consistent with the Market Rules and the Parties' Licences. In the event of an irreconcilable conflict between any provision of this Agreement and a provision contained in either the Market Rules or a Party's Licence, the Market Rules and Licences shall prevail.

ARTICLE III
IMO-CONTROLLED GRID

Section 3.1 OHSC *Facilities*. All Transmission Facilities operated at voltages of 500kV, 345kV, 230kV and 115kV shall be included in the IMO-Controlled Grid. [The Parties agree that step-down power transformers are not part of the IMO-controlled Grid, however this needs to be checked for consistency with the Act]. All such Transmission Facilities existing as of the Effective Date are identified in Schedule A to this Agreement. Any Transmission Facilities that may be constructed in the future for operation at voltages higher than 500kV, or at voltages between 115kV and 500kV, shall also be included in the IMO-Controlled Grid, unless the IMO, applying the criteria in the Market Rules for defining the IMO-Controlled Grid, concludes that such Transmission Facilities should not be included in the IMO-Controlled Grid, or if OHSC successfully challenges the IMO's designation of any such Transmission Facilities as part of the IMO-Controlled Grid pursuant to the dispute resolution process in Article XII. Transmission Facilities operated at voltages below 115kV that are constructed and placed into operation after the Effective Date shall not be part of the IMO-Controlled Grid unless the IMO, applying the criteria in the Market Rules for defining the IMO-Controlled Grid, concludes that such Transmission Facilities should be included in the IMO-Controlled Grid, and OHSC does not successfully challenge the IMO's designation of any such Transmission Facilities as being part of the IMO-Controlled Grid pursuant to the dispute resolution process in Article XII. Schedule A shall be revised to include the appropriate designation of any Transmission Facilities that are constructed and placed into operation after the Effective Date.

Section 3.2 Directing *the Operation of OHSC Facilities*: The IMO shall Direct the Operation of all Transmission Facilities that are part of the IMO-Controlled Grid. The IMO shall delegate various functions associated with Directing the Operation of Transmission Facilities as defined in Schedule A to OHSC. The IMO's delegation of certain responsibilities to OHSC shall be subject to the following conditions: (1) OHSC shall provide the IMO prompt notification of any actions it takes with respect to the delegated functions that could have an effect on the IMO-Administered Markets or the economic rights or obligations of any Market Participant; and (2) OHSC shall follow Instructions issued by the IMO with respect to the delegated functions in accordance with the Market Rules to prevent a material adverse effect on the secure and reliable operation of the IMO-Controlled Grid.

Section 3.3 Withdrawal *or Termination of Delegation*. In the event the IMO determines that the delegation to OHSC under Section 3.2 above is adversely affecting the IMO's ability to carry out its responsibilities under the Electricity Act, the IMO may withdraw all or any part of such delegation; provided that the IMO shall provide OHSC adequate notice and an explanation of the reasons for such withdrawal, and OHSC shall have the right to contest such withdrawal pursuant to the dispute resolution process set forth in Article XII. OHSC shall have the right, subject to providing adequate notice to the IMO, to terminate its responsibilities under a delegation from the IMO, in which event the IMO shall assume such responsibilities; provided that the IMO shall have the right to contest such termination pursuant to the dispute resolution process set forth in Article XII. If the IMO withdraws a delegation hereunder, OHSC may seek compensation from the IMO for investments made subsequent to the Effective Date and prior to the withdrawal in order for OHSC to perform under the delegation, and OHSC's right to such compensation shall be an issue subject to dispute resolution under this Agreement. The IMO may seek compensation from OHSC for any additional costs it incurs to undertake responsibilities following a termination of a delegation hereunder by OHSC, and the IMO's right to such compensation shall be an issue subject to dispute resolution under this Agreement.

Section 3.4 Operation *of OHSC Facilities.* OHSC shall Operate the Transmission Facilities in accordance with the Market Rules. With respect to all Transmission Facilities that are part of the IMO-Controlled Grid, OHSC shall, in accordance with Chapter __ of the Market Rules, implement, or cause to be implemented, the IMO's Instructions Promptly after receiving such Instructions.

ARTICLE IV
TRANSMISSION SERVICE

Section 4.1 *Transmission Service.* Chapter 9 of the Market Rules sets forth the terms and conditions pursuant to which OHSC shall meet its obligation under Section 26 of the Electricity Act to provide non-discriminatory access to the Transmission Facilities. OHSC shall make the Transmission Facilities available for the provision of Transmission Services in accordance with Chapter 9 of the Market Rules, and in order to permit the IMO to Direct the Operation of the IMO-Controlled Grid. During the term of this Agreement, the IMO shall administer Chapter 9 of the Market Rules so that Transmission Service will be available to Market Participants in the IMO-Administered Markets.

Section 4.2 *Settlement and Revenue Collection.* In accordance with the procedures set forth in the Market Rules, the IMO shall (1) calculate and settle all charges for Transmission Service and other services provided by OHSC under the Market Rules; (2) bill and collect the charges for Transmission Service and other services provided by OHSC under the Market Rules; and (3) transfer to OHSC the revenues received from the provision of Transmission Services and other services provided by OHSC under the Market Rules to which OHSC is entitled pursuant to the applicable rate orders of the OEB. To the extent that any Transmission Customer fails to make timely payment for Transmission Service or any other service provided by OHSC under the Market Rules, the IMO shall seek to obtain payment from the non-paying Transmission Customer, and shall take such actions as are available to it under the Market Rules, including disconnection of a Transmission Customer where permitted under the Market Rules, in the event of a default by any Transmission Customer. The IMO shall not be liable to OHSC for any shortfall in revenues resulting from the failure to obtain payment for Transmission Service from a

Transmission Customer. Nothing in this Section 4.2 or any other portion of this Agreement is intended, or shall be construed, to limit, in any way, OHSC's right to pursue whatever rights and remedies it may have under the law to obtain payment from any defaulting Transmission Customer in circumstances where the IMO has been unable to secure payment.

Section 4.3 *OHSC Transmission Rates.* OHSC shall design Transmission Rates for Transmission Services defined in Chapter 9 of the Market Rules, and, not less than 180 days prior to the date that the Market Rules take effect, shall file such Transmission Rates with the OEB for the OEB's approval pursuant to Section 78 of the OEB Act. By no later than one year after the Effective Date, OHSC shall design and file for approval with the OEB, pursuant to Section 78 of the OEB Act, Transmission Rates for the Transmission Services in Chapter 9 of the Market Rules that include (unless directed otherwise by the OEB) performance incentives consistent with those specified in Section 6.4 of this Agreement.

Section 4.4 New *Investment* OHSC and the IMO shall carry out their respective responsibilities under the Market Rules with respect to planning and investment in new transmission facilities. The Parties shall coordinate and provide assistance to each other in completing and placing into operation new transmission facilities approved for construction by the OEB.

ARTICLE V
COMMUNICATIONS, METERING AND CONTROL

Section 5.1 Information *Requirements.* The information requirements of each of the Parties is set forth in Schedule B to this Agreement. Each Party shall supply the information required by Schedule B to the other Party in a manner deemed acceptable to the receiving Party.

5.2 Operational *Metering and Telecommunications.*

5.2.1 *Existing Monitoring and Telecommunication Facilities.* OHSC will own all monitoring facilities (RTUs, SCADA masters, and associated equipment). OHSC is responsible for ongoing maintenance and performance of monitoring facilities, and will pay all operation and maintenance costs. OHSC is responsible for the reliability of the operational metered data supplied at the terminal side of the communications access device. The IMO is responsible for managing and arranging communications to deliver operational metered data from OHSC's monitoring facilities to IMO's control centre site. IMO is responsible for the costs associated with providing communications needed to meet its obligations for operational metered data.

Performance standards for operational metered data and communications are initially set by the IMO but are subject to review and benchmarking against industry standards, through an appropriate forum, as established by the IMO Board. Any changes to established standards that are more onerous than the initial standards set by the IMO or industry standards require documented justification by the IMO.

5.2.2. *Additional Monitoring and Telecommunications Facilities.* Additional monitoring facilities, required as a result of load growth or additional data requests as identified by the IMO, will be owned and paid for (including ongoing operation and maintenance costs) by OHSC. Additional communications facilities, required as a result of load growth or additional data requests as identified by the IMO, will be arranged and paid for by the IMO. Additional monitoring and communications facilities required as a result of additional data requirements as identified by OHSC will be paid for by OHSC.

5.2.3 *System Voice Circuits.* OHSC and the IMO will enter into an agreement outlining sharing of charges and costs associated with the provision of System Voice Circuits (SVCs) required for communications between IMO's control centre, OHSC's control centre, and OHSC's territory centres.

Section 5.3 Code *of Conduct.* If, in the IMO's judgment, OHSC is receiving or will receive information from the IMO that is commercially sensitive, or that is of value in relation to any competitive merchant activities of OHSC in the IMO-Administered Markets but is not available on comparable terms to other Market Participants ("Prohibited Information"), the IMO may condition OHSC's receipt of such Prohibited Information on OHSC's adopting a code of conduct acceptable to the IMO which prohibits all OHSC employees and consultants involved in OHSC competitive merchant activities in the IMO-Administered Markets from obtaining access to Prohibited Information. Any information that OHSC receives from the IMO's Energy Management System ("EMS") shall automatically be considered as Prohibited Information for purposes of this Section 5.3.

Section 5.4 *Confidentiality.* Each Party shall treat information received from the other Party under this Agreement that is not generally available to other Market Participants as confidential, and shall not disclose such information to any third parties without the consent of the supplying Party; provided that either Party may disclose such information without prior consent if and to the extent necessary to take actions in coordination with others to maintain or restore the reliability of the IMO-Controlled Grid.

Section 5.5 *Revenue Metering.* **[To be developed as required].**

Section 5.6 *Protection and Control.* Schedule C specifies accountabilities for Protection and Control, including those related to special protection systems.

ARTICLE VI
OPERATION AND MAINTENANCE STANDARDS

Section 6.1 *Operations Standards and Practices.* OHSC shall, at all times, act in accordance with Good Utility Practice to operate and maintain the Transmission Facilities in good operating condition in order that the Transmission Facilities will be available to provide safe and reliable electric service to Ontario electric consumers and to permit the IMO to provide Transmission Services and meet its other responsibilities under the Market Rules. For purposes of this Article VI, Good Utility Practice shall include, in addition to the definition thereof set forth in Article I of this Agreement, the following:

Section 6.1.1 Compliance with all requirements, standards, guidelines, and criteria of the NERC, NPCC and the Canadian Standards Association, and any successors to these three organizations, applicable to Transmitters.

Section 6.1.2 Prompt restoration of all Unplanned Outages of Transmission Facilities in accordance with the IMO's Instructions and the Operating Directives. For purposes of this subsection, prompt restoration shall mean: (1) where the IMO notifies OHSC that an outage of Transmission Facilities is or may be creating or contributing to a situation that threatens the reliability of the IMO-Controlled Grid, the use of all reasonable means at OHSC's disposal to fix the problem as Promptly as practicable, including recalling off-duty personnel where necessary; and (2) in all other cases, the deployment of those personnel and other resources then available to OHSC without recalling off-duty personnel or incurring extraordinary expense.

Section 6.1.3 Maintenance of all OHSC-owned equipment and facilities in good operating condition and repair, including refurbishing or replacing equipment that is functionally impaired, except where OHSC determines that specific equipment is no longer required to provide reliable electric service to consumers or that the level of expense required to repair such equipment is unreasonably high in relation to the benefits provided by the facilities such that the expenditure would be imprudent if charged to electric consumers. Provided, however, that any decision by OHSC to retire any Transmission Facilities under this subsection shall be subject to and in accordance with the Market Rules governing retirements of transmission facilities.

Section 6.1.4 Prompt completion of all maintenance and repairs when Transmission Facilities are taken out of service pursuant to Planned Outages.

Section 6.2 *OHSC Remedy*. If OHSC believes that the IMO has acted unreasonably under Section 6.1.2, and as a result has caused OHSC to incur expenses that should not have been incurred pursuant to Good Utility Practice, OHSC may bring the matter for dispute resolution pursuant to Article XII.

Section 6.3 *IMO Remedy*. If the IMO believes that OHSC has failed to meet any of its obligations under Section 6.1, the IMO may bring the matter for dispute resolution pursuant to Article XII.

Section 6.4 Performance *Based Regulation Filing.* Within one year after the Effective Date, OHSC shall file with the OEB, pursuant to Section 78 of the OEB Act , a proposal to charge Transmission Rates (and related performance provisions unless directed otherwise by the OEB) that are designed to provide an economic incentive for OHSC to operate and maintain the Transmission Facilities in accordance with the Operational Standards set forth in Section 6.1 and any additional standards contained in OHSC's Licence, the Market Rules, or established by the OEB pursuant to its authority under the OEB Act. The IMO may intervene in any proceeding before the OEB in which OHSC's performance based regulation proposal is being reviewed.

Section 6.5 Publication of Performance Compliance Data.

Section 6.5.1 Beginning no later than 18 months after the Effective Date, and no less than once each year thereafter, the OHSC shall publish a written report setting forth a comparison of the level of historical availability and performance of the Transmission Facilities over the prior five years and during the most recently completed year. In addition, such reports will provide a comparison of availability and performance data for the Transmission Facilities, for the prior five years and the most recently completed year, with equivalent data from at least two other agreed upon transmission system owners operating in North America.

Section 6.5.2 Promptly after the Effective Date, OHSC shall present the IMO a detailed proposal for the type and scope of the availability data that it will present in its report. The IMO and OHSC shall meet and attempt to reach agreement on the data that must be supplied by OHSC hereunder. If the IMO and OHSC are unable to agree on the type and scope of the data that will be presented in the reports, the matter shall be subject to dispute resolution in accordance with Article XII.

ARTICLE VII
MAINTENANCE OUTAGE SCHEDULING

Section 7.1 *Outage Coordination.* In accordance with the Market Rules, the IMO shall coordinate Planned Outages in order to protect the security and reliability of the IMO-Controlled Grid. OHSC shall provide proposed schedules of Planned Outages of the Transmission Facilities to the IMO. The IMO shall approve schedules supplied by OHSC unless the IMO determines that OHSC's proposed schedule could adversely affect the security or reliability of the IMO-Controlled Grid. In accordance with the Market Rules, the IMO may cancel any Planned Outage that it has previously approved if the IMO determines that such cancellation is necessary to maintain the security or reliability of the IMO-Controlled Grid; provided that, before canceling any previously approved Planned Outage, the IMO shall consider other alternatives to cancellation that could be accomplished with a lesser impact than the proposed cancellation.

ARTICLE VIII
EMERGENCY AND RESTORATION OPERATIONS

Section 8.1 *Emergency Operations.* The IMO is authorized to declare an Emergency in accordance with the Market Rules. During an Emergency (the duration of which shall be determined by the IMO in accordance with the Market Rules), the IMO shall be authorized (a) to temporarily Direct the Operation of all Transmission Facilities as necessary to maintain the reliability of the IMO-Controlled Grid, and (b) to take any other actions with respect to the Transmission Facilities that the IMO deems necessary to maintain the reliability of the IMO-Controlled Grid or to restore a Normal Operating State, consistent with the Market Rules.

Section 8.2 *High Risk Operating State.* The IMO is authorized to declare and determine the duration of a High Risk Operating State (as defined in the Market Rules) in accordance with the Market Rules. During a High Risk Operating State, the IMO may take any actions with respect to the Transmission Facilities, consistent with the Market Rules, that the IMO deems necessary to maintain the security and reliability of the IMO Controlled Grid.

Section 8.3. *Restoration After An Emergency.* Following an Emergency, the IMO shall, in coordination with OHSC, issue Instructions for the purpose of directing the restoration of the Transmission Facilities affected by the Emergency. The IMO shall issue such Instructions to the TOMC (and other OHSC local operating centres as permitted hereunder), for the purpose of restoring the Transmission Facilities to a Normal Operating State, and OHSC shall implement, or cause to be implemented, such Instructions in accordance with the Market Rules.

Section 8.4 *Restoration Priority.* The IMO, in coordination with OHSC, shall determine the priority of any restoration actions with respect to the Transmission Facilities following an Emergency.

Section 8.5 *Records; Review Process.* OHSC shall maintain appropriate records relating to all Emergencies and shall make such records available to the IMO as necessary to assist the IMO in reviewing the event. Following an Emergency, OHSC and the IMO shall jointly review and analyze the cause(s) of the Emergency and shall take such steps as they believe reasonably necessary to prevent such causes of the Emergency from recurring.

ARTICLE IX
ADDITIONAL OBLIGATIONS AND RESPONSIBILITIES OF OHSC

Section 9.1 *Purpose.* This Article IX sets forth certain obligations and responsibilities of OHSC under this Agreement, which are in addition to the responsibilities and obligations of OHSC described elsewhere in this Agreement, in OHSC's Licence and in the Market Rules.

Section 9.2 *Inspection and Maintenance.* OHSC shall inspect, repair, and maintain the Transmission Facilities in accordance with Good Utility Practice and the operating performance standards set forth in Article VI of this Agreement.

Section 9.3 *Governmental Approvals.* OHSC shall Promptly apply for any governmental approvals that may be required for the use and operation of the Transmission Facilities in accordance with this Agreement and the Market Rules.

Section 9.4 *Connections.* In accordance with Chapter 4 of the Market Rules, OHSC shall, Promptly after receiving a request for a new connection, perform all analyses and studies reasonably required to put in place such connection, and shall enter into a connection agreement with the entity seeking to connect to the Transmission Facilities providing for the acceptability of design, construction and operation of the connection.

Section 9.5 *Interconnections.* In accordance with Chapter 4 of the Market Rules, OHSC shall enter into interconnection agreements with the owners of all transmission facilities which interconnect, or propose to interconnect, with the Transmission Facilities, setting forth the obligations of the interconnecting parties for designing, constructing, operating and maintaining the transmission facilities and equipment comprising the interconnection.

Section 9.6 *Transmission Facility Ratings.* OHSC shall provide Transmission Facility ratings to the IMO; consistent with the requirements set forth in Schedule D to this Agreement. The IMO shall use these ratings to establish security limits for the IMO-Controlled Grid. In the event that OHSC proposes to change the categories of ratings that it will supply to the IMO (including removing a ratings category for any Transmission Facility), or the specific rating(s) applicable to any Transmission Facility, it shall notify the IMO in writing of the change. If the IMO disagrees with any of such changes, the disagreement shall be resolved in accordance with the dispute resolution process set forth in Article XII. For any change in a ratings category made by OHSC that is disputed by the IMO, the prior ratings category shall remain in effect during the dispute resolution process. For any change in the rating for a Transmission Facility (under the pre-existing categories set forth in Schedule D) made by OHSC that is disputed by the IMO, the changed rating shall be in effect during the dispute resolution process.

Section 9.7 *Access To Property.* Upon reasonable notice from the IMO, OHSC shall provide the IMO with access to its property during normal business hours for the purpose of (1) inspecting any equipment owned by the IMO and located on or adjacent to OHSC's property, or (2) conducting tests or participating in the testing of OHSC or IMO facilities and equipment in accordance with the Market Rules; provided that OHSC shall provide the IMO such access to its property outside of normal business hours if and to the extent necessary for the IMO to Promptly inspect and fix equipment that it needs to meet its operating responsibilities.

Section 9.8 *Communications. Breakdown* In the event that OHSC is unable to establish communications with the IMO's operating personnel at any time, it shall in accordance with Good Utility Practice operate the Transmission Facilities without Instructions from the IMO until communications are restored. The Parties shall issue Operating Directives covering their operations during periods when communications systems are not functioning properly

Section 9.9 *Communications. Following a Contingency* Following a contingency on the IMO-controlled Grid (i.e. loss of one or two elements such as a transmission line) OHSC will initiate a tri-party conversation amongst OHSC's local operating centre, TOMC and the IMO.

ARTICLE X
ADDITIONAL OBLIGATIONS AND RESPONSIBILITIES OF THE IMO

Section 10.1 *Purpose.* This Article X sets forth certain obligations and responsibilities of the IMO under this Agreement, which are in addition to the responsibilities and obligations of the IMO described elsewhere in this Agreement, in the IMO's Licence and in the Market Rules.

Section 10.2 *System Operation.* The IMO shall Direct the Operation of those Transmission Facilities that are part of the IMO-Controlled Grid. During a Normal Operating State (as defined in the Market Rules), the IMO shall communicate its Instructions to the TOMC. During an Emergency, the IMO shall initiate a tri-party conversation amongst the IMO, OHSC's TOMC and OHSC personnel located at other local operating centres operated by OHSC. In circumstances where personnel at the TOMC are unavailable to communicate with the IMO, the IMO may communicate directly with personnel at local operating centres of OHSC; provided that, in such cases, the IMO shall Promptly inform the TOMC of such communications with local operating centres.

Section 10.3. *Interconnection.* In accordance with Chapter 4 of the Market Rules, the IMO shall act as the NERC-defined Control Area Operator and Security Coordinator for the province of Ontario and interact with other Control Area Operators as required to establish system operating limits and rules for interconnected operations, including entering into interconnection agreements with adjacent Control Area Operators providing for interconnected operations other than the physical facility requirements for interconnections, which shall be the responsibility of OHSC.

Section 10.4. *Other Operational Powers and Duties.* In order to protect the Transmission Facilities from undue damage, wear and tear, the IMO shall:
Section 10.4.1 In accordance with Good Utility Practice; maintain power flows on all Transmission Facilities within the applicable ratings supplied by OHSC pursuant to Section 9.6 of this Agreement.

Section 10.4.2. Direct the operation of the IMO-Controlled Grid within security limits and transfer capabilities established by the IMO in accordance with Good Utility Practice and the Market Rules and based on the Transmission Facility ratings supplied by OHSC.

Section 10.4.3. To the extent authorized by the Market Rules, ensure that all Market Participants abide by the facility and equipment design, operating standards, and other rules and procedures applicable to each category of Market Participant set forth in Chapters 4 and 7 of the Market Rules.

Section 10.4.4 In accordance with NERC, NPCC and other applicable regional reliability organization requirements and Good Utility Practice, coordinate with other Transmitters and interconnected electric power systems with respect to the scheduling and interchange of power to ensure the security and reliability of the IMO-Controlled Grid.

ARTICLE XI
ADMINISTRATIVE COMMITTEE

Section 11.1 *Duties and Responsibilities.* The Parties shall form an Administrative Committee under this Agreement. The Administrative Committee shall consider and adopt policies and recommendations relating to the Parties' performance of their obligations under this Agreement, attempt to resolve disputes between the Parties in order to avoid arbitration pursuant to Article XII of this Agreement, and shall have the responsibility to undertake any other actions specifically delegated to it pursuant to this Agreement. The Administrative Committee may establish such other committees, subcommittees, task forces, working groups or other bodies, as it deems necessary and appropriate for purposes of administering this Agreement.

Section 11.2 *Representatives.* Within 30 days of the Effective Date, OHSC and the IMO each shall appoint two representatives to serve as members of the Administrative Committee with the authority to act on their behalf with respect to actions or decisions taken by the Administrative Committee. A Party may, at any time upon providing prior notice to the other Party, designate a replacement representative or alternate representative to the Administrative Committee.

Section 11.3 *Meetings.* The Administrative Committee shall hold meetings no less frequently than once each calendar quarter. The matters to be addressed at all meetings shall be specified in an agenda, which shall contain items specified by either Party in advance of the meeting and sent to the representatives of the other Party. Special meetings may be called at any time if the Administrative Committee deems such meetings to be necessary or appropriate.

Section 11.4 *Coordination and Planning.* The Administrative Committee shall be responsible for the planning and coordination of all actions required under this Agreement.

Section 11.5 *Initial Dispute Resolution.* In accordance with Article XII hereof, the Administrative Committee shall, in the first instance, attempt to resolve all disputes that arise between OHSC and the IMO with respect to this Agreement. Upon referral of any dispute to the Administrative Committee, the Administrative shall have 30 days from the date of such referral to resolve the dispute, unless the Parties agree to extend such 30-day period.

Section 11.6 *Status of Transmission Facilities.* The Administrative Committee shall periodically, and in any event at least once every calendar quarter, review the description of the Transmission Facilities in the IMO-Controlled Grid in Schedule A to this Agreement for accuracy and completeness. The Administrative Committee shall modify Schedule A whenever necessary to maintain an accurate updated list of the IMO-Controlled Grid.

Section 11.7 *Operating Directives.* The IMO and OHSC each shall formulate Operating Directives to assist in the fulfillment of their respective obligations under the Market Rules. The parties shall submit for review a sub-set of those directives that have material impact on the other Party’s mandate, to the Administrative Committee within 30 days of the Effective Date. No Operating Directive shall be developed by either party that is inconsistent with the Market Rules or with either party’s responsibilities as set forth in this Operating Agreement. The Administrative Committee shall maintain an updated listing of Operating Directives currently in effect that have operating impact on the other party. Upon review of the submitted Operating Directives each party may request the Administrative Committee to facilitate and effect amendments to the Operating Directives. At least once each year, the Administrative Committee shall review the Operating Directives of each Party that have operating impact on the other party to determine whether any changes thereto are necessary or appropriate. In the event that either party or the Administrative Committee is unable to agree on the initial set of Operating Directives, or on any changes thereto, the disagreement shall be submitted for dispute resolution in accordance with the process set forth in Article XII.

ARTICLE XII

DISPUTE RESOLUTION

Section 12.1 *Scope.* The dispute resolution procedures set forth in this Article XII shall apply to all disputes arising between OHSC and the IMO with respect to this Agreement and shall be the exclusive means for resolving such disputes; provided that (1) nothing herein is intended to limit the rights of third parties to obtain relief from the OEB or any court or other agency with jurisdiction over any claims that such third party may have against a Party in connection with a matter or activity covered by this Agreement, and (2) in the event that any action is brought by a third party before the OEB or another agency or court, either Party may seek to have a related dispute hereunder consolidated with the OEB, or other agency or court proceeding in order to provide for a uniform and efficient resolution of the dispute.

Section 12.2. *Duty to Negotiate.* The Parties shall not be permitted to commence arbitration pursuant to this Article XII with respect to any dispute unless and until they have attempted in good faith and failed to resolve any such dispute through negotiation in accordance with Section 12.3 hereof.

Section 12.3 Negotiated Resolution of Disputes.

Section 12.3.1 The complaining Party shall refer in writing to the Administrative Committee all disputes arising between the Parties with respect to this Agreement. The referral shall set forth the nature of the dispute and the complaining Party's position with respect to the dispute and its proposed solution thereto. The Administrative Committee shall attempt in good faith to resolve such dispute within 30 days of the date of the referral, except that the Parties may extend such 30-day period for any period on which they mutually agree. Any resolution of the dispute agreed upon by the Administrative Committee shall be in writing and executed by authorized officers of the Parties. Such resolution shall be binding on the Parties, their successors and assigns, and not thereafter subject to arbitration or challenge in any court or other tribunal. If either Party thereafter refuses to honour the Administrative Committee's resolution, the other Party may immediately commence arbitration hereunder to enforce such resolution.

Section 12.3.2 If and to the extent that the Administrative Committee does not resolve any dispute referred to it within the applicable time period, it shall refer the dispute (or, if applicable, whatever portion of the dispute remains unresolved) to the chief executive officers of the Parties, who shall in good faith attempt to negotiate a resolution of the dispute within a period of 30 days from the date that the dispute was referred to them. The chief executive officers may extend the period of negotiation for any period on which they agree. Any resolution of the dispute agreed upon by the Parties' respective chief executive officers shall be in writing and binding on the Parties, their successors and assigns, and not subject to arbitration or challenge in any court or other tribunal. If either Party thereafter refuses to honour the resolution reached by the Parties' chief executive officers, the other Party may immediately commence arbitration hereunder to enforce such resolution.

Section 12.4 Arbitration Procedures.

Section 12.4.1 If at the end of any period of required negotiation pursuant to Section

12.3 of any dispute between the Parties, such dispute, or any material part of such dispute, remains unresolved, the Parties shall submit the dispute to binding arbitration in accordance with the arbitration procedures set forth in this Section 12.4. The arbitrator(s) shall have exclusive authority to hear and decide any dispute between the Parties that is subject to arbitration pursuant to Section 12.1 hereof.

Section 12.4.2 Any dispute submitted for arbitration pursuant to this Section 12.4 shall be submitted for resolution to a single individual selected by the Parties, unless the Parties are unable to agree upon the designation of such individual. The Parties shall negotiate in good faith the selection of such individual arbitrator. If, after a period of 10 days, the Parties are unable to agree on an individual arbitrator, the Parties shall each select an individual to serve as one of a three-person arbitration panel. The two arbitrators selected by the Parties (each a "Party Arbitrator") shall in good faith select, within 10 days of their selection, a third individual to act as the third arbitrator (the "Neutral Arbitrator"). The Neutral Arbitrator shall possess expertise in the electric power industry relevant to the matter in dispute. The Neutral Arbitrator shall finally decide all issues, including all procedural issues, that may arise during the arbitration process in the event that the Party Arbitrators do not agree with respect to any such issue. Neither Party may at any time during the arbitration revoke its agreement as to the individual arbitrator or its selection of a Party Arbitrator unless the other Party consents thereto in writing.

Section 12.4.3 Within 20 days of the selection of the individual arbitrator or the arbitration panel, as the case may be, the complaining Party shall submit to the arbitrator(s) a written statement, which shall describe the nature of the dispute, the complaining Party's positions with respect thereto, any claims for relief, the grounds for such relief, the proposed resolution or relief sought, the names of any third parties with material knowledge or information relevant to the dispute, and any documents that the Party wishes the arbitrator(s) to consider in connection with the written statement(s). The other Party shall have 20 days to respond to such filing, setting forth its position and such of the information set forth in the previous sentence that it deems relevant. The arbitrator(s) shall have the authority to direct that the filings under this subsection be made simultaneously by the Parties.

Section 12.4.4 There shall be no discovery of facts taken, sought, or otherwise instituted by any means except as approved by the arbitrator or arbitrators. The arbitrators shall provide a time schedule for any such discovery. The arbitrator(s) may at any time retain non-Party technical experts to advise and assist the arbitrator(s) during the arbitration.

Section 12.4.5 Any document or other information made available in the arbitration and not otherwise available to the other Party may be designated in good faith as "Confidential" by the Party making such document or information available; provided that the Parties must first submit to the arbitrator(s) a mutually-agreed upon written statement of procedures for handling and protecting material designated as "Confidential", which the arbitrator(s) may accept or modify as the arbitrator(s) may deem appropriate.

Section 12.4.6 The arbitrator(s) may adopt any procedural rules deemed, in the arbitrator(s) sole discretion, to be appropriate to conducting the arbitration and facilitating the resolution of the dispute. No such procedural rule adopted by the arbitrator(s) shall extend the time period set forth in Section 12.4.7 in which the arbitrator(s) must render a final disposition of the dispute may not be extended or reduced, unless the Parties consent thereto in writing. The refusal by any Party to comply with an order of the arbitrator(s) adopting or modifying any procedural rule shall constitute, in the sole discretion of the arbitrator(s), grounds for default and a finding in favour of the other Party.

Section 12.4.7 Any dispute submitted for arbitration pursuant to this Section 12.4 shall be finally decided by the arbitrator(s) no later than 150 days from the date of the responding Partys' submission to the arbitrator(s) of its written statement pursuant to Section 12.4.3 hereof (the "Disposition Date"). Unless the Parties agree otherwise in writing, the arbitrator(s) final decision shall (a) set forth in writing the arbitrator(s) findings of fact and any conclusions of law and (b) be based on the evidence before the arbitrator(s), the laws of Ontario and Canada applicable therein, the Market Rules, the Licences, and any relevant decisions of courts or agencies, or of prior arbitrations pursuant to this Section 12.4.

Section 12.4.8 All decisions of the arbitrator(s) shall be final, binding, and not subject to any challenge or appeal by any Party to any court or other tribunal, including to the fullest extent permitted by law any application under the Ontario Arbitration Act to set aside the arbitrator(s) decision. Each of the Parties waives to the fullest extent allowed by law any right or ground it believes that it has or at any time hereafter may have to challenge or appeal in any way, or otherwise seek to set aside in any court or other tribunal, any decision by the arbitrator(s). Notwithstanding anything else in this Section 12.4.8, in the event either Party fails to act in accordance with the decision of the arbitrator(s), the other Party may then seek enforcement of the decision in any court of competent jurisdiction pursuant to, and in accordance with, the Ontario Arbitration Act.

Section 12.4.9 Nothing in Section 12.4 of this Agreement shall be construed as affecting any rights available to the Parties pursuant to Section 3 of the Ontario Arbitration Act. If and to the extent that any provision of Section 12.4 hereof is adjudged or otherwise deemed invalid by a court of competent jurisdiction, the provisions of the Ontario Arbitration Act shall apply to the extent applicable to the subject matter of the invalid provision.

Section 12.4.10 The Parties shall bear responsibility for their own costs associated with arbitrating disputes under this Section 12.4 and shall share on an equal basis all other costs associated with the arbitration, including arbitrator fees and the fees of any technical experts retained by the arbitrator(s); provided that, if either Party fails to comply with the decision of the arbitrator(s), and the other Party thereafter seeks relief therefrom pursuant to Section 12.4.8 hereof, the Party seeking such relief shall be entitled to receive from the other Party its costs of seeking such relief (including its reasonable legal costs) upon the issuance of a final, non-appealable order in its favour with respect to the application for such relief from a court of competent jurisdiction.

ARTICLE XIII
LIABILITY AND INDEMNIFICATION

Section 13.1 *Liability for Damages.* Each Party shall be liable to the other Party for losses, damages, claims, or other liabilities of any kind, costs or expenses (including reasonable legal fees and expenses) arising from its wilful misconduct or the negligent performance of its obligations and duties under this Agreement, or the breach or nonperformance of such obligations and duties.

Section 13.2 *Limitation of Damage.* Notwithstanding Section 13.1, neither Party shall be liable to the other Party under any circumstances whatsoever, whether liability arises out of contract, tort, strict liability, or any other cause or form of action, for any consequential, indirect, incidental, special or punitive damages, costs, expenses, or losses arising from any act or failure to act for which a Party may be liable pursuant to Section 13.1 hereof.

Section 13.3 *Enforcement of Obligations.* Each Party shall enforce any obligations of the other Party under this Agreement pursuant to the procedures for dispute resolution set forth in Article XII, which shall be the exclusive means for the Parties to obtain enforcement of such obligations as against each other.

Section 13.4 *IMO Insurance.* The IMO shall maintain insurance policies covering part or all of its potential liability under this Agreement with such insurance companies and containing such policy limits and deductible amounts as shall be determined by the IMO Board from time to time in accordance with the Market Rules. The IMO shall take all steps necessary to ensure that OHSC is a beneficiary under such policies or is otherwise lawfully entitled to receive any proceeds from such policies to the extent of OHSC's lawful interest therein.

Section 13.5 *Indemnification.* Each Party shall indemnify the other Party for, and hold the other Party harmless against, all losses, damages, claims, costs or expenses (including reasonable legal fees and expenses) or any other liabilities of any kind, arising from any third party claims that arise from any act or omission of the Party from which indemnification is sought, except to the extent that such losses, damages, claims, costs or expenses, or other liabilities are found to have been caused by the negligence or wilful misconduct of the Party seeking indemnification, or its officers, directors, or employees. The indemnified Party under this provision shall Promptly give written notice to the indemnifying Party of any third party claims against which the indemnified Party is entitled to be indemnified under this Section 13.5 after becoming aware of any such third party claims. Upon acknowledgment of its obligation hereunder to provide indemnification with respect to any such third party claims, the indemnifying Party shall be entitled to control any litigation relating to such third party claims (including settlement and other negotiations) and the indemnified Party shall cooperate fully with the indemnifying Party in defense of such claims, subject to its right to be indemnified against any resulting costs of such cooperation.

ARTICLE XIV
TERM, TERMINATION, AMENDMENT, AND WAIVER

Section 14.1 *Term and Termination.* This Agreement shall be effective as of the

Effective Date and shall continue in effect for a period of 20 years from the Effective Date, and for such further period as the Parties may, at the end of such 20-year term, agree; provided, however, that this Agreement shall terminate automatically in its entirety if, at any time during the term hereof, (1) the Electricity Act (or a superseding provision of Ontario law) ceases to provide legal authorization for the continued existence of either the IMO or OHSC, (2) either Party ceases to hold a Licence from the OEB to perform its responsibilities hereunder, or (3) the Electricity Act is amended or superseded such that the responsibilities of the IMO or OHSC are no longer consistent with their responsibilities as set forth in this Agreement.

Section 14.2 *Amendment.* This Agreement may be amended at any time during the term hereof by an instrument in writing signed on behalf of each of the Parties. No amendment shall be permitted that is inconsistent with either Party's obligations under its Licence or the Market Rules.

Section 14.3 *Waiver.* By written notice provided to the other Party, either Party may (a) extend the time for the performance of any of the obligations or other acts required by this Agreement or (b) waive compliance with any of the agreements or conditions contained in this Agreement; provided that no such extension or waiver shall relieve a Party from its responsibilities under its Licence or the Market Rules. The failure of a Party to assert any of its rights under this Agreement, or to waive or extend an obligation hereunder, shall not constitute a waiver of such rights or any other rights hereunder in the future. The granting of a waiver or extension or use on more occasions shall not obligate a Party to grant a waiver or extension on subsequent occasions.

Section 14.4 *Assignments and Conveyances; Mergers.* No Party may assign or otherwise transfer any of its rights or obligations under this Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld; provided that no such consent shall be required for an assignment or other transfer that is necessary to the consummation of a lawful corporate reorganization or restructuring of a Party (including a sale of substantially all of the Party's assets, a merger, or the acquisition of the Party by another person) when such transaction is made in accordance with the Party's Licence and the Market Rules.

ARTICLE XV
UNCONTROLLABLE FORCES

Section 15.1 *Force Majeure Events.* With respect to the obligations of OHSC and the IMO under this Agreement, a "Force Majeure Event" means any act of God, labour disturbance, act of a public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond a Party's reasonable control. Subject to Section 15.2 hereof, neither OHSC nor the IMO shall be in default in respect of any obligation under this Agreement if prevented from performing the obligation (in whole or in part) because of a Force Majeure Event.

Section 15.2 *Obligations in the Event of a Force Majeure Event.* In the event of a

Force Majeure Event that prevents a Party from performing any of its obligations under the Agreement, such Party shall (1) Promptly notify the other Party of the Force Majeure Event and its good faith assessment of the effect that the Force Majeure Event will have on its ability to perform any of its obligations, which notice shall be confirmed in writing as soon as reasonably practicable if such immediate notice is not in writing; (2) not be entitled to suspend performance of any of its obligations under the Agreement to any greater extent or for any longer duration than is caused by the Force Majeure Event; (3) use its best efforts to mitigate the effects of such Force Majeure Event, remedy its inability to perform, and resume full performance of its obligations hereunder; (4) keep the other Party informed of such efforts on a continuing basis; and (5) provide written notice to the other Party of the resumption of the performance of any obligations affected by the Force Majeure Event. Notwithstanding any of the foregoing, settlement of any strike, lockout, or labor dispute constituting a Force Majeure Event shall be within the sole discretion of the Party to the Agreement involved in such strike, lockout, or labour dispute and the requirement that a Party must use its best efforts to remedy the cause of the Force Majeure Event and mitigate its effects and resume full performance hereunder shall not apply to strikes, lockouts, or labour disputes.

ARTICLE XVI
MISCELLANEOUS PROVISIONS

Section 16.1 *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of Ontario and the laws of Canada applicable hereto.

Section 16.2 *Execution in Counterparts.* This Agreement may be executed in counterparts, each of which when so executed shall be deemed to be an original and all of which when taken together shall constitute one and the same agreement.

Section 16.3 *Severability.* If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant or condition is held to be invalid as to any person, entity, or circumstance, or is determined to be not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in effect to the maximum extent permitted by law and, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected, but shall remain in full force and effect and the Parties shall be relieved of their respective obligations under this Agreement only to the extent necessary to comply with the court or government agency holding.

Section 16.4 *Titles; Construction of Agreement.* The captions and headings of this Agreement are intended only to facilitate reference within the Agreement and shall have no bearing on the interpretation or construction of any terms or conditions of the Agreement. Any ambiguities or uncertainties in the wording of this Agreement shall not be construed in favour of or against any Party, but shall be construed in a manner that most accurately reflects the purpose of this Agreement.

Schedule A - IMO-Controlled Grid

- The IMO-controlled Grid includes facilities with respect to which, the IMO has authority to direct the operations.

- Principles, adopted by the MDC technical panel on T&D, to guide the determination of facilities which make up the IMO-controlled Grid are:

  Principle 1: The set of IMO-controlled facilities should be those which allow the IMO to meet the matters for which it is accountable under Bill 35

  Principle 2: The set of IMO-controlled facilities should be those required by IMO to meet its scheduling and (real-time) dispatch obligations to market participants

  Principle 3: The set of IMO-controlled facilities should be those required by IMO to meet its "control area" obligations

  Principle 4: The set of IMO-controlled facilities should be those required by IMO to maintain secure and reliable operation of the power system and should include associated protection systems and system auxiliaries as appropriate

- Based on the above principles, all 500KV, 345KV, 230KV, and 115KV facilities owned by OHSC are included as part of the IMO-controlled Grid

Direct the Operation

- IMO has authority to direct the operation of the transmission facilities which are included as part of the IMO-controlled Grid

- Activities associated with "directing the operation" include:
  -Establishing security limits
  -Monitoring power flows and assessing system conditions
  -Issuing instructions for the status and loading of system elements
  -Assessing impacts of outages on reliability

- Various functions are included as part of the activities identified above. The IMO has authority to delegate any of these activities and functions to OHSC. Table A-1 below outlines and delineates the functions for directing the operation of components of the IMO-controlled Grid as agreed between the parties.

- A list identifying the specific facilities included as part of the IMO-controlled Grid and any functions for various facilities which the IMO has delegated authority to OHSC, consistent with Table A-1, will be developed and maintained by the Parties.

- Table A-2 identifies additional operating accountabilities.

.

Table A-1
Delineation of "Direct the Operation" Functions

Major Component	Specifics	Accountabilities			
		500 kV Facilities	345 kV Facilities	230 kV Facilities	115 kV Facilities
Security Limits	-establish and publish system security limits -establish and publish equipment ratings	IMO OHSC	IMO OHSC	IMO OHSC	IMO OHSC
Monitor Power Flows and Equipment Status	-monitor system flows and status -monitor equipment flows and status	IMO OHSC	IMO OHSC	IMO OHSC	IMO OHSC
Manage System Security	- assess system security - evaluate and select options to remain secure (contingency plans) - approve and authorize corrective actions - carry out authorized transmission actions	IMO IMO IMO OHSC	IMO IMO IMO OHSC	IMO IMO IMO OHSC	IMO IMO IMO OHSC
Deploy Transmission. This includes issuing Instructions related to	- maintaining equipment loading (pre and post contingency) within ratings - authorizing restoration - controlling voltage - authorizing system configuration - authorizing load transfers	IMO IMO IMO IMO N/A	IMO IMO MO IMO N/A	IMO IMO IMO IMO N/A	* * * * *
Plan and Perform Maintenance Outages	- formulate and propose outage plans - assess security impact of outage plans - approve plans - carry out outages and maintenance	OHSC IMO IMO OHSC	OHSC IMO IMO OHSC	OHSC IMO IMO OHSC	OHSC IMO IMO OHSC

***- Accountability yet to be determined**

Table A-2
Additional Operating Functions

Major Component	Specifics	Accountabilities			
		500 kV Facilities	**345 kV Facilities**	**230 kV Facilities**	**115 kV Facilities**
Manage Equipment Integrity	- ensure Equipment Performance - ensure Human Safety - ensure Environmental Safety	OHSC OHSC OHSC	OHSC OHSC OHSC	OHSC OHSC OHSC	OHSC OHSC OHSC
Manage Customer Connection	- ensure connection reliability - ensure connection quality - develop contingency plans	OHSC OHSC OHSC	OHSC OHSC OHSC	OHSC OHSC OHSC	OHSC OHSC OHSC

Schedule B "Information Requirements"

The lists of information requirements included here are illustrative of the nature of information needed and will be detailed/revised later.

Overview:

The schedule elaborates on the principles in Article V of this agreement.

OHSC and the IMO shall use reasonable efforts to provide each other the information identified forthwith in this Schedule B, so as to facilitate discharge of their respective duties and functions. All information provided in accordance with Schedule B shall be maintained current.

This schedule will be amended from time to time as may be necessary to facilitate ongoing discharge of the IMO and OHSC duties and functions.

In the event of loss of access to information, the supplying party will promptly advise the other party and mutual arrangements shall be made and agreed to for an alternate means of estimation.

Part 1) Information Required by the IMO from OHSC

Operating Contacts:

- Designated operating contacts, their phone #'s, what facilitates they are Controlling Authority of and associated interfaces between Controlling Authorities and with Local Distribution Companies and Generation Providers

- Availability and coverage (e.g. 24 hours per day, 7 days of the week every day of the year).

- Contractual arrangements amongst them whereby one party acts as an agent for Operating Control of IMO Controlled Grid facilities owned by the other party.

Information

- Technical (essential for the derivation and modification of Operating Security Limits, & calculation and posting of transmission availability.

  - Equipment nameplate data and all data needed for power system modelling.

  - Physical characteristics, operating parameters and algorithms to calculate real time thermal ratings

  - Device / protection scheme settings and times (i.e. breaker interruption times, relay operating times, relay settings) required so recognized contingencies can be properly simulated and appropriate relay margins calculated.

- Line physical geometry and right of way data.

- Operating Diagrams

  - similar to what is now X5094, X5500, station operating diagrams, territorial overview diagrams, microwave diagrams

  - engineering function diagrams (i.e. EE prints for protective relaying schemes)

  - SPS functional diagrams

  - operational impactive wiring diagrams

- Procedures

  - Relevant Operating Procedures

  - Protection Standards

  - Facility Description (example Bruce SPS)

- Reporting

  - disturbance analyses,

  - NERC, RRO submissions relevant to the IMO accountabilities

  - Emergency Operating Procedure test summaries (i.e. voltage reduction, CSCC evacuations, rotational load shedding, restoration drills & tests)

Electrical Parameters / Quantities

- Telemetered quantities (dynamic MW, MX, voltage, frequency, transformer tap position, circuit breaker/switch status)

- For each Substation

  - Unique substation identifier, substation name and land location for each substation;

- Unique bus number, nominal bus voltage and area code for each substation;
- Unique transformer identifier, number of windings and nameplate data for each transformer;
- Unique transformer identifier, rated voltage, bus number to which the transformer connects, MVA rating of winding, connection of each winding (delta/wye), positive, negative and zero-sequence resistance and reactance on the transformer, all tap points and tap changing strategy (manual, automatic, settings) for each tie or power transformer;
- Unique bus number, MVAR rating at unity voltage and the switching strategy used to control the device for every shunt capacitor or reactor;

- For each Transmission Line:
  - Line name or number;
  - Bus data for all mid-line busses in the following format: Unique bus number, 8-character bus name, nominal bus voltage, area code, unique transmission line identifier;
  - Unique Line identifier, line section number, the two unique bus numbers between line segments, positive, negative and zero-sequence real and reactive shunt admittance for all line segments.
- For each Static Device (i.e. static capacitor bank):
  - A unique source name, identifier (nomenclature) and bus number;
  - Rated minimum, maximum, continuous and emergency real and reactive capability;
  - Positive, negative and zero-sequence resistance and reactance;
  - Rated, maximum and minimum voltages;
  - Standard control system block diagram model with parameters.
- Outage Reports:

  Monthly summaries of forced outages including an assessment of apparatus and protection performance, restoration plans and progress updates regarding noted performance deficiencies. Captured SCADA, fault recorder and power swing monitoring device records will be provided on request where necessary for assessment of system performance.

Part 2) Information / Data Required by OHSC from the IMO

- Power System Modelling

  All necessary System, facility and forecast information (i.e. load) of sufficient quantity and quality to maintain an appropriate and accurate electrical model of the Ontario Integrated Power System for the current year and following years. Load flow and stability models for systems outside Ontario.

- Historical customer peak load and energy consumption for purposes of rate development.

- Historical OHSC equipment loading.

- System event recorder data.

- Forecast operational data.

- Access to reports as necessary to support the fulfilling of OHSC's obligations within this Operating Agreement.

- IMO Operating Directives

  IMO Operational Directives, procedures, bulletins and/or other information relating to operation and planning of the Transmission System or use of OHSC's IMO Controlled Grid Facilities for provision of access services.

- System Operating Limits

Requirements for Access to EMS Information and Tools

OHSC access to IMO EMS data and tools has not been discussed. This could include access such as the following:

- Real Time Data on the Transmission System including critical elements on the interconnected system:
  - MW and MX flows on all transmission circuits including tie lines
  - MW and MX flows through all transformers
  - MW and MX flows from all generators
  - MW and MX flows to all loads delivery points
  - MX flows at all synchronous condensers
  - MX flows at all capacitors
  - MX flows at all reactors
  - Status of all breakers and disconnect switches'

  - Arming statuses of Special Protection Schemes
  - Voltages at all busses

- Real Time Output from the following Network Analysis Tools:
  - Thermal Monitoring (OOLM)
  - Post Contingency Thermal Monitoring (PCTM)
  - Voltage Magnitude Monitoring
  - System Interface Limit Monitoring (SYSM)

- Demand Access to the Study Mode version of the Network Analysis Tools (OLCAS)

- Access to reports produced from the Real Time data and the Real Time output from the Network Analysis Tools:
  - Management Reporting System (MRS)
  - Power System Reporting (PLRPTO)
  - Daily Load Summary
  - Four o'clock Report
  - Hourly Interconnection Data (HPD)
  - Hourly NUG Production
  - Unit Status Report
  - Unit Limitation Report

Schedule C

Delineation of Accountabilities for Protective Relaying and Special Protection Systems

The IMO's role is to adapt reliability standards to the conditions in Ontario. In many cases NERC and NPCC do not specify a detailed implementation process for their standard so the IMO must fill in these details.

Functions of the IMO and OHSC with respect to protective relaying are tabulated below in table A, "Protective Relaying", and table B, "Special Protection Systems".

The IMO speaks for the Ontario Control Area regarding the reliability of the integrated system.

Table A - Protective Relaying

Function		
	IMO	OHSC
Represent the Control Area in reliability forums	X	
Set reliability standards within Ontario	X	
Provide functional description to IMO		X
Monitor material impactive compliance with standards (NERC/NPCC and Ontario's Standards)	X	
Report failures and corrective actions		X
Coordinate and approve additions or changes: a) impacting system reliability	X	
b) coordination of protective relaying		X
Notify neighbours of changes (Regarding Interconnections with neighbours)	X	X
Notify neighbours of changes (Regarding Internal Transmission system within Ontario)	X	
A/R Selection and settings	X	X
Investigate misoperations	X	X
Set policies for operating with degraded protection systems: a) impacting system reliability	X	
b) for equipment protection		X
Set operating criteria for underfrequency protections	X	X
Set operating criteria for undervoltage protections	X	X
Design and Specifications		X
Construct		X
Maintain		X
Test and submit compliance reports		X

Table B - Special Protection Systems

Function	IMO	OHSC
Represent the Control Area in reliability forums	X	
Set reliability standards within Ontario	X	
Provide functional description to IMO		X
Monitor compliance with standards (NERC/NPCC and Ontario's standards)	X	
Report failures and corrective actions		X
Coordinate and approve additions or changes	X	
Notify neighbours of changes: a) involving or impactive on interconnections/interconnected utilities	X	X
b) regarding internal transmission system within Ontario	X	
Classify and deploy SPS	X	
Monitor status of SPS	X	X
SPS settings	X	X
Investigate misoperations	X	X
Set policies for operating with degraded capability: a) impacting system reliability	X	
b) for impact on equipment		X
Design and Specifications		X
Construct		X
Maintain		X
Test and submit compliance reports		X
Adequacy Assessment	X	
Planning/System Investment process	X	X
Decommissioning/replace, Repair , Leave Out of Service, Reduction in capability	X	X

SCHEDULE D
Equipment Operating Ratings

1. OHSC will provide equipment operating ratings to the IMO for all OHSC transmission equipment under IMO direction.
2. Equipment ratings will be provided in electronic format - data base (the format is still to be decided and agreed to).
3. The IMO will be notified when a rating change becomes effective. OHSC will provide the IMO with any planned changes to operating ratings X working days before the new rating is expected to becomes effective. The IMO will be given prompt notice of an unplanned rating change.
4. Ratings for new equipment will be provided X working days before the new equipment is expected to be ready for service.
5. Transformer ratings that result in accelerated aging will only be used if needed to prevent load loss.
6. OHSC will be notified promptly if an equipment operating rating has been exceeded or any operation of equipment beyond the continuous ampacity rating.
7. OHSC will continue to provide any parameters or algorithms required by the IMO in calculating on-line equipment operating ratings.
8. The IMO is required to seek OHSC's approval of the accuracy of tools used for on-line monitoring of equipment operating ratings.

The following equipment operating ratings will be provided by OHSC to the IMO:

Transmission Circuits (overhead & cable)

ampacity ratings

- continuous rating
- 5-minute limited time rating
- 15-minute limited time rating

These ampacity ratings will be provided as function of the following for overhead transmission circuits (not provided for transmission cables):

- ambient temperature
- wind speed
- solar radiation (day/night)

In addition the limited time ratings will be provided as a function of circuit preload for all transmission circuits (overhead and cable).

Autotransformers

voltage rating
ampacity ratings

- nameplate rating as a function of cooling
- continuous rating (L1 rating)
- 5-minute limited time rating
- 15-minute limited time rating
- Maintenance Rating (L2 rating) - results in accelerated aging

The continuous and limited time ratings will be provided as a function of maximum daily ambient temperature.
In addition the limited time ratings will be provided as a function of equipment preload.

Step-down Transformers

voltage rating
ampacity ratings

- continuous (nameplate rating) as a function of cooling
- 10-day limited time rating as required - results in accelerated aging
- 2-hour limited time rating if requested
- 1-hour limited time rating if requested

Circuit Breakers

voltage rating
resistor thermal duty cycle/cool down time
short circuit withstand rating
ampacity ratings

- continuous rating
- 5-minute limited time rating
- 15-minute limited time rating

These ampacity ratings will be provided as function of ambient temperature

In addition the limited time ratings will be provided as a function of equipment preload.

Disconnect Switches

ampacity ratings

- continuous rating
- 5-minute limited time rating
- 15-minute limited time rating

These ampacity ratings will be provided as function of ambient temperature

In addition the limited time ratings will be provided as a function of equipment preload.

Station Bus

ampacity ratings
- continuous rating
- 5-minute limited time rating
- 15-minute limited time rating

These ampacity ratings will be provided as function of the following:
- ambient temperature
- wind speed - if outdoor
- solar radiation (day/night) - if outdoor

In addition the limited time ratings will be provided as a function of circuit preload.

Shunt Reactors and Shunt Capacitors

Voltage Ratings

Line Traps

ampacity ratings
- continuous rating
- 5-minute limited time rating
- 15-minute limited time rating

These ampacity ratings will be provided as function of ambient temperature.

In addition the limited time ratings will be provided as a function of circuit preload.

CHAPTER FIVE

IMO
GOVERNANCE AND DEVELOPMENT

IMO Governance and Development

Table of Contents

CHAPTER FIVE

IMO GOVERNANCE AND DEVELOPMENT

5.1 Introduction

During the third and fourth quarters, the IMO Development Technical Panel (the "IMO TP") was tasked with the examination of a variety of issues relating to the governance and development of the IMO. The MDC extends its appreciation to the members of the IMO TP for the time and effort which they devoted to this task and for the contribution which they have made towards the further development of important IMO governance matters.

Among the tasks undertaken by the IMO TP were the further elaboration of the IMO's Governance and Structure By-law, a review of the development of the IMO's technical infrastructure and the development of policies relating to the IMO's administrative responsibilities as market and system operator.

The results of the IMO TP's work, including its recommendations, are described in its report, annexed as Appendix Five to this Report. As noted in the IMO TP's report, some of the recommendations of the IMO TP have found their way into the Governance and Structure By-law, some have been translated into draft market rules and others take the form of recommendations to the IMO (confidentiality policy, accreditation and prudential requirements and IMO fee structure) or the Ontario Energy Board (IMO licence).

Although most of the recommendations of the IMO TP generally found favour with the MDC, a number of issues were the subject of more intense debate and discussion. This Chapter of the Report provides a synopsis of the major points of discussion relating to the IMO TP's recommendations and to certain additional matters (notably liability), and highlights a small number of elements where it was thought desirable to revisit recommendations made by the MDC in previous reports. In some cases, the decision to revisit the recommendations was motivated by a need to respect the provisions of the *Electricity Act, 1998.*

5.2 Governance and Structure By-law

The elements to be included in the IMO's Governance and Structure By-law were delineated in the MDC's *First Interim Report*, and the task of the IMO TP was to translate these elements into a draft By-law for submission to and review by the IMO Board of Directors. As the entity with the authority to adopt the Governance and Structure By-law, and whose activities will be governed thereby, the IMO Board of Directors necessarily retains the discretion to make such modifications to the draft By-law as it determines appropriate prior to submitting same for approval by the Minister of Energy, Science and Technology.

The draft Governance and Structure By-law annexed as Schedule "A" to the IMO TP's report is generally consistent with the parameters set forth in the MDC's *First Interim Report*, with such modifications as were required to respect the provisions of the *Electricity Act, 1998*. However, the following are areas where, upon further reflection, it was thought appropriate to revisit the recommendations contained in the MDC's *First Interim Report.*

a) Rule Amendment Procedures

During the IMO TP's deliberations, it became clear that there was a difference of opinion as to the respective authority and role of the IMO's Technical Panel and the IMO's Board of Directors in effecting changes to the market rules. Accordingly, the matter was submitted to the MDC for clarification and direction. Given the statutory responsibility and accountability of the IMO Board of Directors in respect of amendments to the market rules, it was decided by the MDC that the Technical Panel should play an advisory role only and that the IMO Board of Directors should have final authority in respect of all amendments to the market rules. In the case of "urgent" rule amendments made under the expedited procedure contemplated in section 34 of the *Electricity Act, 1998,* however, it was determined appropriate to permit such amendments to be made either by the IMO Board of Directors or by a committee of the IMO Board of Directors composed of the Chief Executive Officer and two additional directors. Where an urgent rule amendment is made by the committee, the IMO Board of Directors retains the authority to stay implementation of the amendment.

b) Dispute Resolution Panel

In its *First Interim Report*, the MDC recommended that a Dispute Resolution Panel composed of at least three people be selected by majority vote of the IMO Board of Directors. In order to ensure the greatest independence from the IMO of the members of the Dispute Resolution Panel, while preserving the Panel forum for the resolution of disputes to maximize the potential for the development of a consistent body of decisions relating to the interpretation and application of the market rules, a number of safeguards have been introduced:

1. The Dispute Resolution Panel will consist of a roster of a minimum of ten members from which individuals will be appointed by the Secretary of the Panel (appointed by the IMO Board of Directors from among the roster) to mediate or arbitrate a given dispute on a case-by-case basis.

2. The IMO Board of Directors will hire one or more expert arbitrators to select potential members of the Dispute Resolution Panel. The persons so selected must be appointed by the IMO Board of Directors unless they fail to meet the qualifications for membership (independence, expertise, etc.) set forth in the

Governance and Structure By-law. Vacancies in the Dispute Resolution Panel will be filled in a like manner.

3. Remuneration of members of the Dispute Resolution Panel will be fixed by outside experts or advisors rather than by the IMO Board of Directors.

c) Other

The MDC further agreed that the following additional modifications to the initial recommendations regarding the content of the Governance and Structure By-law be made:

1. The introduction of a disclosure mechanism (the requirement for a signed declaration in the form set forth in Appendix "A" to the By-law) to replace restrictions on participation in the nominations process for members of the IMO Board of Directors and the Technical Panel.

2. The extension of the term of the initial members of the Technical Panel from staggered terms of 1, 2 and 3 years to staggered terms of 2 and 3 years.

3. The extension of the term of office for members of the Market Surveillance Panel from 3 years to 5 years.

5.3 Accreditation and Prudential Requirements

Accreditation and prudential requirements for participation in the IMO-administered markets proved to be one of the more contentious issues falling within the IMO TP's mandate, with debate focussed primarily on (i) the nature and amount of the prudential requirements to be provided; and (ii) the manner in which residual risk of default would be managed and apportioned among market participants. The IMO TP solicited direction from the MDC in this regard and, following receipt of directions and further deliberation, put forward a paper containing the IMO TP's recommendations and highlighting areas which will require further elaboration in 1999. The paper is reproduced as Schedule "C" to the IMO TP's report and some of the recommendations have also been reflected in the draft market rules.

The IMO TP's paper was adopted by the MDC subject to the caveat that the following concerns regarding the recommendations contained therein would be expressly noted:

1. Generators expressed concerns that they are expected to share in the residual risk of default, particularly since the risk of default in payment is caused almost entirely by buyers rather than sellers into the market.

2. Purchasers (both industrial consumers and distributors) expressed concern with respect to the obligation to provide, for the first time, significant prudential requirements (including letters of credit or cash deposits), particularly in cases where they have shown themselves to be creditworthy in their past transactions.

3. The MDC as a whole expressed its concern that, although the markets should be structured such as to inspire confidence, the potentially onerous nature of the proposed prudential requirements may motivate market participants to focus on physical bilateral transactions and bypass the spot market altogether.

As noted above, certain recommendations of the IMO TP with respect to prudential requirements and residual risk management have been included in the draft market rules, notably in Chapter Two and in the enforcement provisions of Chapter Three. These draft market rules are intended to provide a structure and framework to guide the further development of more detailed rules to govern these issues. In elaborating the details of the accreditation and prudential requirements regime next year, the IMO should be attentive to, among others, the three concerns noted above.

5.4 IMO Licence

The IMO TP's recommendations to the Ontario Energy Board with respect to the terms and conditions of the licence to be issued to the IMO, as set out in Schedule "D" to the IMO TP's report, were adopted by the MDC. One issue which was highlighted in particular as requiring further consideration by the Ontario Energy Board is the extent to which the authority of the IMO to "cut off" defaulting buyers should be enshrined in the IMO's licence.

5.5 IMO Fee Structure

Schedule "E" to the IMO TP report sets forth a recommended fee structure for the IMO, to be used to guide the IMO in preparing a fee structure to be submitted to the Ontario Energy Board for approval.

The MDC recommends a proposed fee structure consisting of a modest registration fee (in the order of $5,000.00) and a fee per MWh payable by all metered wholesale buyers for all energy purchased. The Ontario Energy Board is, however, encouraged to require that the IMO include in its annual fee applications to the Ontario Energy Board an allocation of its costs as between system and market operations. It is also recommended that the Ontario Energy Board review the appropriateness of the proposed fee structure within two years of the date of opening of the markets with a view to ascertaining whether there may be an alternative fee structure, such as one which distinguishes between system operation costs and market administration costs, that better reflects actual costs.

With respect to export and wheel-through transactions, the MDC determined that such transactions should be the subject of a charge (in other words, that charges should be levied on all Ontario loads plus export transactions plus wheel-through transactions) in order to provide similarity of treatment between spot and bilateral transactions. The Ontario Energy Board could, however, as part of the review noted above, revisit the issue having regard to developments in other jurisdictions.

5.6 Accessibility and Confidentiality of Information

The MDC generally endorsed the recommendations made by the IMO TP in the proposal set forth as Schedule "B" to the IMO TP's report. Specifically, the MDC supports the proposal for the development by the IMO of rules relating to information security and confidentiality (including the classification of information according to degree of sensitivity) which embodies the principles proposed by the IMO TP.

Certain of the principles of accessibility and confidentiality proposed by the IMO TP have also been translated into draft market rules.

5.7 Draft Market Rules

A number of the recommendations were made by the IMO TP in support of the development of market rules pertaining to the IMO's administrative and surveillance functions. These elements are now also reflected in the draft market rules.

a) Rule Amendments

The IMO TP presented to the MDC a synopsis of the draft market rules relating to the process whereby the market rules will be amended. The process generally encourages the use of the IMO's Technical Panel for all rule changes where possible, with the IMO Board of Directors retaining ultimate authority.

The synopsis was favourably received by the MDC, although the following points were noted:

1. The rule amendment process must be flexible and should not be so prescriptive as to be overly burdened by time limitations and procedures which may be unsuited to certain types of rule changes.

2. There may be a need to provide a specific rule amendment procedure applicable to amendments which may be dictated by a standards authority (i.e., NERC). At the present time, it is not known whether such standards authorities will be in a position to impose rule changes (in other words, it is not clear whether there will be any discretion for the IMO not to implement rule changes put forward by such bodies).

b) Market Monitoring and Market Surveillance

The IMO TP also presented to the MDC a synopsis of the draft market rules proposed to govern the monitoring and surveillance functions to be conducted by the IMO.

An issue which engendered considerable discussion was that of the confidentiality of information in the hands of the Market Surveillance Panel and the dissemination of reports of the Panel which contain confidential information. The MDC took note of the fact that, in this respect, the market rules as presently drafted reflect an interpretation of the provisions of section 37 of the *Electricity Act, 1998* which is not universally shared by all members. Specifically, the market rules are based upon a more liberal and purposive interpretation of section 37 which would permit the Market Surveillance Panel to provide reports containing confidential information to (i) the independent members of the IMO Board of Directors; (ii) the Ontario Energy Board; and (iii) such other persons as the Market Surveillance Panel deems appropriate.

In addition to the concerns raised as to the propriety of this interpretation, the debate engendered a further discussion as to the manner in which confidential information may as a result find itself in the public domain if the Market Surveillance Panel's report triggers a hearing before the Ontario Energy Board. Section 37(9) of the *Electricity Act, 1998* contemplates that documents, records, photocopies and returns made in the course of an investigation by the Market Surveillance Panel are admissible in evidence as part of a review by the Ontario Energy Board under section 38 of the *Electricity Act, 1998*. It was also noted that (i) the Ontario Energy Board is subject to the *Statutory Powers Procedure Act*, which contains provisions that permit the protection of confidential information; and (ii) the rules of practice of the Ontario Energy Board do likewise.

c) Dispute Resolution

A synopsis of the market rules relating to dispute resolution was also presented by the IMO TP to the MDC. The only area of sustained discussion respecting the dispute resolution process centered around the manner in which members of the Dispute Resolution Panel are selected and appointed to mediate or arbitrate disputes. Specifically, certain members expressed a desire to be permitted to select their own nominees to preside over an arbitration, while others noted that selection from among the members of the Dispute Resolution Panel (the proposed approach, consistent with the MDC's *First Interim Report*) would likely contribute to a more consistent body of decisions relating to the interpretation and application of the market rules over time. As noted in section 2(b) above, changes have been proposed to be made to the Governance and Structure By-law which should address the concerns that appear to have motivated the request to be permitted to independently select arbitrators. The MDC has endorsed the IMO TP's approach in this regard.

5.8 Enforcement

Finally, the MDC considered an outline of the market rules pursuant to which the IMO would monitor and enforce compliance with the market rules. This outline was presented by MDC consultants and did not form part of the IMO TP process.

Two issues in particular raised concerns among members of the MDC. The first was the ability of the IMO to suspend a market participant's right to trade in the event of bankruptcy or insolvency and the effect that such right of suspension could have in terms of project financing. It was noted that project lenders will often have, for example, rights of substitution which would enable them to take over the operations of a bankrupt or insolvent market participant and be in a position to cure a default in payment or prevent one from occurring in the first instance. This should be reflected in the suspension process included in the market rules.

Second, it was noted that the enforcement provisions of the market rules should include provisions permitting the disconnection of a market participant who acts in violation of the reliability provisions of the market rules and endangers the functioning of the system.

5.9 Contractual Force of the Market Rules

Towards the end of the fourth quarter, the MDC had occasion to consider the question of what, if any, contractual force should be given to the market rules to permit the IMO and market participants to make claims against one another in respect of damages or losses which may be sustained as a result of non-compliance with the provisions of the market rules.

In this regard, the MDC recommends that the market rules should have contractual force as between the IMO, on the one hand, and each market participant, on the other, but that the rules should not have contractual force between and among market participants themselves.

In making this recommendation, the MDC was motivated by the following factors:

1. market participants are well positioned to manage their risks by means of insurance and other contractual arrangements, as appropriate;

2. there are relatively few instances where disputes arising under the market rules need to involve any person other than the IMO and the market participant whose conduct is at issue in the dispute;

3. the potential for burdening the dispute resolution process with a multiplicity of protracted, multi-party suits arising under the market rules should be minimized; and

4. although market participants will not be in a position to make claims based on breach of contract against one another specifically in respect of breaches of the market rules, they retain any common law rights of action (such as in tort) they might otherwise have.

The MDC also discussed the merits of including in the market rules a right of subrogation pursuant to which a market participant could "step into the shoes" of the IMO and pursue other market participants in circumstances where, for example, the IMO chooses not to. Given that this approach could have the potential of creating a *de facto* "contractual commons" among all market participants, its adoption would not be consistent with the recommendation that the market rules not have contractual force as between market participants. Accordingly, the inclusion of such a right of subrogation is not recommended at this time.

5.10 Liability

A related and equally critical issue which the MDC had occasion to revisit late in the fourth quarter is that of the liability of the IMO and of market participants in respect of non-compliance with the market rules. It will be recalled that, in its *First Interim Report*, the MDC recommended that "traditional liability concepts apply to the IMO as a corporate entity and that there be no statutory exception to those". More recent discussions surrounding this issue focussed on the question of whether the IMO should be subject to liability only in instances where it was negligent or guilty of willful misconduct, or whether the IMO should be held to a higher standard akin to strict liability in respect of actions in non-compliance with the market rules (such actions being made possible by giving the market rules contractual force as between the IMO and each market participant as discussed in the preceding section).

The regime relating to liability now recommended by the MDC comprises both a liability element and a penalties element as described below.

a) Liability of the IMO

Where the IMO breaches a market rule (including by reason of having misinterpreted a rule) and a market participant suffers damage or loss as a result, the liability of the IMO will be determined on the basis of breach of contract. Liability will be strict, in the sense that no negligence or willful misconduct needs to be proven. The issue of whether any alternative limits (for example, by class of damages) should apply to the liability of the IMO is discussed in section (d) below. In keeping with this recommendation, the draft market rules attached to this report do not contain any limitation of liability provisions.

It should be noted that, in a number of cases where the IMO is found to have some financial liability to one market participant, the monies themselves may well have found their way into the hands of another market participant as a result of the misapplication or misinterpretation of a rule. These are monies which, in essence, aver themselves as having been paid or omitted to be collected from that other market participant as a result of the IMO's misinterpretation or misapplication of a market rule. The IMO should be permitted to recover such monies from the unjustly enriched market participant in such cases.

In addition to the above, where the IMO breaches a market rule, it will also be open to the Dispute Resolution Panel, as part of its award, to direct the IMO to desist from acting or interpreting the market rules in a particular manner. Any such direction will be reported to the Board of Directors of the IMO and consideration could be given to more widespread publication as a means of reinforcing the accountability of the IMO in respect of its obligations under the market rules.

This latter remedy will be available in addition to any remedy which a market participant may have for damages or compensation in respect of a breach by the IMO of the market rules and will be available even in cases where no damage or loss has been sustained by a market participant as a result of a particular breach. It is recommended, however, that the remedy be available only in circumstances where the Dispute Resolution Panel is satisfied that the breach could have been avoided by the exercise of due diligence by the IMO (in other words, the IMO has a due diligence defence in respect of this remedy). The cost of pursuing this remedy will be awarded to the complaining market participant unless the Dispute Resolution Panel determines, in exceptional cases, that a different award of costs is just and reasonable.

b) Liability of Market Participants

Where a market participant breaches a market rule and the IMO suffers damage or loss as a result, the liability of the market participant will be determined on the basis of breach of contract in the same manner as is the case for the IMO. Again, liability will be strict, in the sense that no negligence or willful misconduct needs to be proven.

In addition, where a market participant breaches a market rule, the market participant will be susceptible to the imposition of financial penalties, subject only to the market participant successfully raising a due diligence defence. The quantum of penalties to be imposed in any given case will reflect, among others, the need to provide incentives to ensure compliance with the market rules. This enforcement mechanism will be available regardless of whether the IMO has sustained any loss or damage in respect of any particular breach of the market rules by a market participant. The IMO's costs in enforcing compliance with the rules in any given case (including any costs of having the matter resolved by the Dispute Resolution Panel) will be payable by the market participant unless the Dispute Resolution Panel determines, in exceptional cases, that a different award of costs is just and reasonable.

c) *Costs and Appeals*

Except as noted above, it is recommended that the Dispute Resolution Panel retain the discretion to award costs as it determines appropriate in any given case. That having been said, it is expected that costs will generally be awarded to the successful party in keeping with the practice generally followed by courts of law.

In its *First Interim Report*, the MDC recommended that, subject to two exceptions, decisions of the Dispute Resolution Panel be final and binding. The first exception relates to a right of appeal to the Ontario Energy Board in respect of (i) the imposition of financial penalties in excess of a specified amount; and (ii) the suspension or revocation of a market participant's accreditation. This right of appeal is now enshrined in section 36 of the *Electricity Act, 1998*. The second exception provided a right of appeal to the courts in cases where procedural irregularities arose in the course of the Dispute Resolution Panel's proceedings.

Given that disputes arising under the market rules may involve substantial sums of money, and that the Dispute Resolution Panel may, from time to time, err, the MDC discussed the possibility of now recommending that parties to a dispute be permitted to appeal decisions of the Dispute Resolution Panel to a court of competent jurisdiction on questions of law, fact or mixed law and fact. However, given that the Ontario Energy Board appears to have exclusive jurisdiction to hear appeals in respect of orders of the IMO (and by extension the Dispute Resolution Panel) requiring the payment of penalties and "other amounts of money" in excess of an amount to be prescribed by regulation, it does not appear warranted to provide such a right of appeal, at least in respect of orders relating to the payment of penalties or other sums of money. That having been said, in the event that the amount prescribed by regulation for purposes of triggering a right of appeal to the Ontario Energy Board is very high, some consideration could be given to allowing a right of appeal to the courts for penalties or amounts of money which fall below the threshold but are above some *de minimis* amount, although this would inrease the risk of the development of inconsistent jurisprudence relating to the market rules.

d) *Implementation and Limitations of Liability*

It is recognized by the MDC that the recommendations made above, and those relating to the liability of the IMO in particular, may expose the IMO to considerably greater financial risk or liability than is the case in other markets. It is also acknowledged that time constraints have not permitted an exhaustive examination of the issue in all of its many and complex commercial and legal facets. The MDC therefore considers it advisable that, in the months preceding the opening of the competitive markets, the IMO and stakeholders give further consideration to the issue of liability, including the following:

1. introduction of a minimum monetary threshhold (or deductible) below which no claims for damages may be made;

2. limiting liability to direct damages and excluding liability for consequential or indirect loss (such as loss of profits);

3. providing, where appropriate, a higher standard for liability (be it negligence, failure to use "best efforts" or failure to act in accordance with "good utility practice") in respect of operational matters where the failure to do so may have a significant dampening effect on the ability or willingness of IMO staff to take immediate and appropriate action to ensure the reliable operation of the IMO-controlled grid, particularly during system emergencies; and

4. introduction of a customary commercial force majeure clause excusing non-performance where such non-performance is the result of specified factors outside the non-performing party's control.

The MDC recommends that, to the extent that liability is to be expressly addressed, it should be addressed in the bilateral agreements (referred to in the market rules as the "participation agreement") to be entered into between the IMO and each market participant rather than in the market rules themselves.

e) Other Contracts

The recommendations of the MDC with respect to liability for breaches of the market rules are not intended to affect the right of market participants to agree to different liability standards in agreements which they may have with one another.

A final issue which may require further consideration in the coming months is the extent to which the recommendations made with respect to liability for purposes of the market rules may have to be adjusted to accommodate the liability and indemnification provisions of agreements which are already in place or have already been negotiated and which are related to the market rules. In this regard, there may be a need to avoid the application of different liability standards and obligations to the same factual situation.

CHAPTER SIX

RETAIL COMPETITION

Retail Competition

Table of Contents

CHAPTER SIX

RETAIL COMPETITION

6.1 Introduction

The work of the Market Design Committee on retail competition during the fourth quarter was performed by the MDC, its Retail Subcommittee and the Retail Technical Panel (RTP).

The RTP established four sub-panels: Load Profiling and Settlements, Retail Metering, Licences and Contracts, and Consumer Protection. The sub-panels included members of the RTP and others with particular expertise or experience in the sub-panel issues. The members of the RTP and the four sub-panels devoted an enormous amount of time to their work between August and December 1998, taking time from their usual duties. The MDC appreciates the hard work of these members and of the RTP chair, Larry Murphy, without whom the retail market design work of the MDC could not have been completed.

In Chapter 4 of our *Second Interim Report*, and in Chapter 3 of our *Third Interim Report*, we set out the high-level design principles for the operation of retail competition in Ontario in a set of recommendations directed principally to the Ontario Energy Board (OEB). Every Local Distribution Company (LDC) will be required to offer to pass through the hourly wholesale spot price to any customer that requests it, and to direct the customer =s bill to a retailer at the customer=s request. This effectively separates the retail settlement function from the wholesale settlement function, as retailers will settle with LDCs for the electricity consumed by customers in each LDC=s service area. Customers who choose neither electricity service from a retailer nor the spot price pass-through option will receive by default a **smoothed** pass-through of the hourly wholesale spot price from the LDC. The smoothed price is expected to reduce price volatility to the customer. The retail settlement system is not required to process Aphysical bilateral contracts@, but LDCs are obligated to enter into good faith negotiations with retailers and customers who want this settlement service and are prepared to pay for it. The RTP has developed recommendations to the OEB for a settlement system that will support these recommendations, which are in section 3 of the RTP Report. The RTP Report also recommends a method for developing load profiles for billing customers served by kWh meters and for the allocation of losses and unaccounted-for energy among customers. The report also considers the allocation of costs on the customer bill and prudential requirements for retail market participants.

Retail competition requires that procedures be developed for transferring customers from the LDC=s default supply service to a retailer, from one retailer to another, and from a retailer back to default supply. This is addressed in section 4 of the RTP report.

The MDC recommended that retail metering be competitive for customers with loads greater than 50kW. Customers should not be required to purchase an interval meter in order to switch to retailers, but the load profile applied to a customer should be the same whether s/he is served by an LDC on default supply or by a competitive retailer. Accompanying these recommendations by the MDC were other recommendations dealing with the details of competitive metering. The RTP developed a series of detailed recommendations to implement this general design in section 5 of its Report, ACompetitive Metering.@ This section defines the 50-kW threshold and deals with the eligibility of parties to provide metering and data services, meter ownership rules, and relationships between LDCs and parties providing meters or meter services.

The advice of the MDC and of its RTP on these matters is largely directed to the OEB, which will be responsible for issuing licences to LDCs and retailers. The OEB can govern the conduct of retail market participants through licence provisions or through codes of conduct, obedience to which will be required by licences. The RTP therefore provided advice in section 6 of its report on licences and codes. The primary focus of this work concerned connection, disconnection, the obligation to provide service, and separation of competitive and regulated activities. Although resolution of these issues is essential to the development of an effective retail market, time did not allow the RTP to address them fully.

Finally, the MDC=s *Second Interim Report* contained recommendations regarding what entities are allowed access to customer data and under what circumstances. Section 7 of the RTP considers these issues. In addition, the RTP considered consumer education, examining the information process that would be needed to assist consumers in making informed decisions in the new competitive electricity market and the marketing and selling practices that could be embodied in codes of conduct to support informed decision-making.

While the RTP report provides an enormous amount of detail and many recommendations, there is still much work to be done. The OEB will consider many of these issues, receiving not only the RTP and MDC reports but also submissions from stakeholders Municipal Electric Utilities (MEUs), retailers and other participants will be interested in speedy resolution of these issues so that they can prepare their business plans, purchase and develop necessary software and hardware, and establish the procedures needed to operate effectively in the new competitive electricity market. We urge the OEB to work to resolve these issues as quickly as possible.

6.2 MDC Disposition of the Retail Technical Panel Report

The draft RTP report was received and reviewed by MDC members and discussed by the MDC at a series of meetings in December 1998. Most of the recommendations discussed were accepted without controversy. Some, however, stimulated considerable discussion and were accepted with qualifications, comments or reservations. Because of time limitations, not all recommendations were discussed by the MDC. The text below focuses on changes from earlier MDC principles or matters that attracted qualification, comment or reservation from the MDC. The RTP Report was amended to respond to the MDC discussion as noted below. The resulting RTP report is attached as Appendix 6 to this MDC report and is offered by the MDC as advice to the OEB.

6.2.1 Retail Settlement Process

Recommendation RTP 3-10 states that wholesale loads connected to an LDC system should have the same loss and unaccounted for energy (UFE) adjustments applied to them as retail loads of similar size and location. While MDC members approved the principle of treating similarly situated parties in a similar manner, there were differences of opinion regarding whether UFE should apply to interval-metered customers, which would include all wholesale loads. It was noted that most UFE arises from profiling error and energy theft. There is no profiling error for interval-metered loads. Moreover, theft by interval-metered customers is much more difficult to accomplish because of the sophistication of the metering, and is easier to detect. In any event, theft by a wholesale load is a cost to the IMO, not to the LDC. On the other hand, it was argued that theft is a common problem that should be paid for by all customers connected to the LDC's wires. Furthermore, if interval-metered customers, including all large customers, avoid paying for UFE, the burden will fall more heavily on residential customers. Ultimately there was not sufficient support for amending the recommendation, but it was agreed to note the concern that the recommendation, as written, would not conform with the generally accepted principle of assigning costs to those who impose them.

Recommendation RTP 3-12 originally proposed that LDCs not provide special settlement calculations for time-of-use meters because there are too few such meters to make this economical. It was suggested, however, that some LDCs may have a significant number of these meters, and in recognition of this, the recommendation is that providing settlements for time of use meters is at the discretion of the LDC, with the OEB determining how the costs should be allocated.

6.2.2 Customer Registration and Transfer

The discussion of customer registration and transfer procedures noted the costs to LDCs of processing requests for information, verifying customer requests, and generally engaging in communications about retail activities. Some members expressed concern about recommendation RTP 4-3, that retailers secure a signed authorization from customers before the LDC will begin transfer procedures, noting that the recommendation was inconsistent with the move to electronic commerce. Other members felt that, given some of the practices that have occurred in gas marketing in the past, a written authorization was desirable. A similar concern was expressed regarding Recommendation RTP 4-4, which requires a signed authorization from customers before LDCs will transfer customer information, and there was even more support for retaining this requirement. LDCs expressed concern about having to send a letter to a current retailer to inform it that a customer had signed up with another retailer, but again there was broad support for this requirement. In general, the MDC did not vary the recommendation of the RTP, preferring to minimize the risk of customer data or customers themselves being transferred without clear and explicit customer authorization.

Recommendation RTP 4-8 deals with the timing of customer transfers and the need for meter readings in order to issue final bills. To avoid the expense of special meter reads, the RTP recommended that transfers occur on the date of the next normal meter read. It was noted that retailers would like to know the date of the next read date so that they could determine when a customer was officially theirs. On the other hand, it was suggested that the meter read date could be determined approximately, or in some cases precisely, by looking at a customer=s bill, so that retailers could determine this information without interrogating the LDC. On this issue, the MDC was divided and was unable to make a recommendation. When the issue reaches the OEB, data regarding costs and impacts would assist in the decision-making process.

6.2.3 Competitive Metering

The MDC recommended that metering be competitive for customers with a demand greater than 50kW (*SIR*, RM 4-18). In Recommendation RTP 5-4, the RTP suggests that only LDCs and retailers may be responsible for offering Meter Service Provider (MSP) and Meter Data Management (MDMA) services to customers although LDCs, and retailers may discharge this responsibility by contracting with qualified third parties. The reasons for the limitation in the RTP report include the following: the federal *Electricity and Gas Inspection Act* says that Acontractors@ are responsible for meters and it is unclear how broadly Acontractor@ may be defined; there is no explicit authority for the OEB to license MSPs and MDMAs separately; and confusion will be reduced at market opening if only two parties may be held responsible. Given these factors, it was felt that an initial authorization to LDCs and retailers would be feasible and would simplify the transition to a competitive market at a time when many changes will be taking place simultaneously. The MDC has approved the recommendation of the RTP, but with the express concern that there be movement over time to expand the range of parties allowed to provide these services.

The MDC was also concerned about Recommendation RTP 5-5, that meter ownership be limited to MSPs while meter communication system ownership should be limited to MDMAs. The argument for limiting meter ownership is that single ownership would facilitate rotating the meter stock during reverification, and that accuracy would be easier to ensure by limiting ownership to the service provider. The MDC has approved this recommendation, noting that the recommendation itself says that ownership should be subject to a review by the OEB three years after market opening, to determine whether broader ownership would be in the public interest.

The interpretation of the 50-kW threshold for competitive metering for customers without a demand or interval meter was also a matter of concern. After reviewing load factor data, the RTP concluded that either 10,000 or 12,500 kWh per month could be consistent with a 50-kW peak demand. Assuming that the MDC favoured an aggressive approach to competition, the RTP recommended the use of 10,000. Some MDC members, however, felt that an equivalence was not necessary since all customers above 50kW would have demand meters, and that if an equivalence was necessary, 10,000 kWh was much too low. The Technical Panel noted that 12,500 kWh per month might be a more neutral interpretation of the equivalence, that this value is often used for defining rate blocks, and that Ontario Hydro and the Municipal Electric

Association had proposed that 50kW or 150,000 kWh per year, which is approximately 12,500 kWh per month, be used as the boundary between large and small customers for licensing purposes.[1] The MDC agreed that the equivalence should be set at 12,500 kwh per month, and requested the technical panel to change its recommendation accordingly.

6.2.4 Licensing and Codes

The issue of the application of the Electrical Safety Code to LDCs, reflected in Recommendation RTP 6-7, attracted the attention of the MDC, as it had the attention of the RTP. MEU representatives noted that they were not now subject to the Code for work on distribution assets, and that imposing Code compliance on them would raise costs substantially -- which would be passed on to consumers. Representatives of large industrial consumers were concerned that in many cases they had more distribution assets than some of the smaller MEUs, that they had equally long experience with the safe installation of electrical equipment and that they should be exempted along with LDCs. It was suggested that there should be an assurance of a high level of safety, but that unnecessary costs should not be imposed. The RTP text and recommendation 6-7 reflect these concerns and invite the OEB or the Electrical Authority to find an interpretation that strikes a reasonable balance.

Concern was also expressed by MEU representatives regarding recommendation RTP 6-8, which requires consistent guidelines for applications, cost allocation, capital allocation and ownership options across all LDCs with respect to the costs of connection of new customers. It was noted that currently MEUs have varying policies with regard to these costs of connection, and some have used this flexibility as a means of achieving municipal goals, such as encouraging new investment. The recommendation will reduce local flexibility at a time when the government is giving municipalities responsibility for an increasing range of services. The MDC did not debate this issue, so the recommendation has not been changed; but the concern is noted here and could be raised at the OEB.

6.2.5 Consumer Protection

Substantial debate was engendered by the issue of what customer-specific data customers can demand be transferred to a prospective new retailer. It was agreed that customers have a right to have basic customer data as defined in the RTP report transferred by LDCs at the customer=s request, as proposed in Recommendation RTP 7-6. Some members believed that competition would be promoted if customers who had been served by a retailer could also direct the retailer to transfer information, including basic and additional information. Other members believed that such a requirement would inhibit competition by forcing the disclosure to

---

[1] AAdvisory Report on Licence Requirements for the Marketing of Natural Gas and Electricity to Residential and Small Commercial Customers,A Report to the Ministry of Energy, Science and Technology, October 6, 1998, p. 41.

competitors of the retailer's confidential information, such as the structure of its retail contracts. Ultimately it was agreed that LDCs and the IMO should have a duty to transfer customer information at a customer=s request, but that competitive retailers would have no obligation to transfer information. This obligation would remain with LDCs even if default supply was being performed through a third party. The effect of this decision is to amend Recommendation 4-27 in our *Second Interim Report*, by eliminating the independent obligations of a retailer or meter service provider with the exception of special metering requirements discussed in Section 5 of the RTP Report.

Attention was also directed to Recommendation RTP 7-30, which invites the OEB to set limits on the duration of contracts that may be imposed on consumers during the first two years of retail market operation. On the one hand, this provision would protect consumers from being locked into long-term arrangements during a time when they would not be very knowledgeable about the new electricity market and about their options. The experience with gas marketing supports some such limitation. On the other hand, consumers have had experience with retail markets for gas and telephone for some time, and there will be a consumer information program so consumers should have some level of knowledge by the time retail selling begins. Furthermore, limiting the duration of such contracts may limit some desirable market activities, such as green power generators signing up customers for a long term to help finance the construction of new green power generation projects. On this matter the MDC concluded that the OEB should limit retail contracts with residential customers to a duration of one year during the first year of market operation. This issue and the issue on consumer education prior to market operation are discussed in detail in Chapter 8, Transition, of this MDC Report.

6.3 Default Supply and Affiliate Separation

The issue of default supply and affiliate separation has extensively engaged the MDC throughout its mandate, and was the subject of detailed recommendations in both the MDC =s S*econd* and *Third Interim Report*s. However, in the course of the fourth quarter of the MDC =s work, a further issue in this context has been the subject of protracted and vigorous debates. Given the retail default supply arrangements proposed in earlier reports of the MDC, to what extent can an LDC choose to provide default supply through an affiliate or a third party when that affiliate or third party is engaged in competitive electricity retailing activities?

Ultimately the MDC approved the following resolution:

The MDC acknowledges that subsection 70(9) of the *Ontario Energy Board Act* contemplates that a distributor, subject to the OEB=s licensing requirements, may comply with its obligation to supply electricity under section 29 of the *Electricity Act, 1998* either: a) directly, b) through an affiliate, c) through another person with whom the distributor or affiliate of the distributor has a contract, or d) through a combination of the methods described in a), b) or c) above. Before the OEB accepts the proposal of a distributor to comply with its obligations under section 29 through either b)

or c) involving a competitive affiliate or retailer that also provides competitive electricity services, we recommend that the OEB impose codes or standards of conduct and other terms and conditions on the competitive affiliate or retailer, so as to ensure conformance with the principles recommended in Chapter 4 of our *Second Interim Report.* In particular the OEB must be satisfied that the code of conduct will ensure that there will be no cross-subsidy of competitive activities by the default supply activities, that there will be no preferential access to customer data including the customer list by any person within the competitive portion of the entity providing the default supply, and that the default customers remain effectively contestable if and when they make their names available for solicitation.

6.4 Further Retail Work

Implementing the policy recommendations of the MDC and the more detailed operational recommendations of the RTP will require a tremendous amount of work by the OEB and by other retail market participants before market opening. These matters are outlined in section 2.4 of the RTP Report. Key tasks facing LDCs bear summarizing here in order to alert existing MEUs, Public Utility Commissions and other distributors as to what lies ahead.

In general, LDCs must be prepared to settle electricity transactions with the IMO, customers and retailers operating in their service area. This means that they will have to revise or replace their information systems in general, and their customer information systems in particular, so that they can:

- offer a spot price pass-through to any customer;
- offer a smoothed spot price to any default customer;
- send any customer's bill to a retailer; calculate at least one load profile for their customers without interval meters;
- exchange data with retailers; and
- calculate customer bills based on the spot price (smoothed or not).

They must prepare to handle customer transfers from default supply to the spot price pass-through or to a retailer and back. They must prepare to work with retailers and MDMAs regarding the installation and registration of meters and the communication of meter data. At a more general level, LDCs will have to decide whether to perform these billing, settlement and record-keeping functions themselves or to contract them out to third parties.

Finally, MEUs and other distributors will have to decide whether they intend to establish competitive affiliates to handle any functions that will not or can not be performed by the LDC. If an affiliate is to be established, the MEU must develop a business plan for that affiliate in the light of such separation codes and other requirements that the OEB may establish.

CHAPTER SEVEN

ENVIRONMENTAL PROTECTION

Environmental Protection

Table of Contents

CHAPTER SEVEN

ENVIRONMENTAL PROTECTION

7.1 Background

In its *Second Interim Report* the MDC endorsed the importance attached to environmental protection in the report of the MacDonald Committee and the government's commitment in the 1997 White Paper to an objective of "enhanced safety, reliability and environmental protection." We noted concerns that competition in electricity generation could allow generators to bypass existing air pollution control regulations that apply specifically to Ontario Hydro and commitments made by Ontario Hydro, or that increased electricity imports from generating stations with high emission rates could reduce air quality in Ontario. The MDC made a number of recommendations in Chapter Five of the *Second Interim Report* (*SIR*) that were intended to maintain and enhance current levels of environmental protection. These recommendations dealt with air pollution emissions, energy efficiency, green power marketing, electricity labeling, environmental approvals and nuclear decommissioning and waste disposal.

The cornerstone recommendations (*SIR* RMS 5-1, 5-2, 5-3, 5-4) call for an air pollution cap and trade program which, if implemented, would ensure that the generation of electricity for Ontario would not contribute to a degradation of air quality in the province. The recommendations encourage the Ministry of the Environment to set caps on the emissions of the relevant pollutants and allow pollution sources to trade among themselves, achieving the environmental goal at least cost. The recommended trading among pollution sources is consistent with the market principles endorsed by the MDC. The MDC did not identify the actual emission limits, deferring to the expertise of the Ministry of the Environment. While Recommendation 5-1 stated that the trading program should be in place at the start of market operation, it did not specify precisely which pollutants should be capped, although the preceding text listed sulphur oxides (SOX), nitrogen oxides (NOX), carbon dioxide (CO2), particulate matter and air toxics.

With respect to energy efficiency, the MDC recommended (*SIR* RM 5-4) that the wholesale market design allow for demand-side bidding, which would allow large loads that are capable of reducing their electricity consumption on short notice to indicate the price at which such reductions would be undertaken, thereby reducing peak demands on the system. This recommendation is implemented in Chapter 7 of the market rules, section 3.5. We also recommended (*SIR* RM 5-5) that the Ministry of Energy, Science and Technology increase its support for consumer energy conservation programs that would provide information on energy conservation and energy efficiency standards for products.

Acknowledging that some consumers may be willing to pay a premium for electricity generated from environmentally benign sources, the MDC recommended that green power marketing be allowed, using a definition of "green power" developed through the EcoLogo national stakeholder process. The MDC also noted the serious risk of fraud in green power marketing, since the consumer cannot tell whether the power has been generated from green sources or not, and recommended that green power marketing begin only after a method of verifying green power marketing claims has been developed and approved. (*SIR* RMS 5-6, 5-7)

In addition to green power marketing according to the EcoLogo definition, the MDC wanted to encourage all consumers to evaluate their energy supplies based on the source of the generation and the associated pollution emissions. We therefore recommended (*SIR* RMS 5-8, 5-9) that all energy retailers be required to provide information regarding the generation source and pollution emissions for the electricity that they supply. This information would be required in all advertisements and in all consumer bills, and would follow a standard format that is to be developed by the ministries of Energy, Science and Technology and of the Environment pursuant to the powers provided in section 88 of the *Ontario Energy Board Act.* As with green power marketing, energy labeling would require a reliable verification program to avoid substantial risks of fraud.

The MDC noted concerns by generators and transmitters about the time required in the past to secure various planning and environmental approvals for their projects. There were also concerns that existing procedures were developed when these activities were undertaken predominantly by government-owned bodies while in the future much of the activity might be open to private-sector corporations. We recommended (*SIR* RM 5-10, 11) that the approval process be reviewed to ensure that the requirements depend on the nature of the project and the risk of environmental harm, rather than on the ownership of the proponent, and that the process is as efficient as feasible while ensuring the achievement of environmental objectives.

Finally, the MDC noted that it was desirable that the owners of nuclear power plants set aside funds to pay for the eventual decommissioning of the plants and for the safe disposal of spent fuel. We recommended (*SIR* RM 5-12.) that the OEB require the owners of nuclear power plants to establish such funds.

7.2 Third and Fourth Quarter Activities

During the last two quarters of 1998, staff at the Ministry of the Environment and the Ministry of Energy, Science and Technology have explored the recommendations made in our *Second Interim Report* regarding green power marketing and electricity labeling. MDC members, executive and consultants met with ministry staff and participated in workshops held in November and December by both ministries, which discussed the implementation of these recommendations. Similar interactions have taken place with respect to the recommendations for the air pollution cap and trade program, including a workshop sponsored by the Ministry of the Environment in November. These workshops explored the substantial technical work involved in implementing the recommendations, including the need to record and analyze detailed data regarding electricity generation and sales at the retail level. The MDC also met with a representative of TerraChoice, the firm that administers the federal EcoLogo program , to receive clarification regarding the process for adopting and amending EcoLogo definitions. MDC members and executive members met with ministry staff to discuss our recommendations regarding environmental approvals and the feasibility of using class environmental assessments for projects put forward by separate private proponents.

In its *Second Interim Report* the MDC indicated that it would consider the need for additional market-based mechanisms to encourage environmentally benign technologies, such as renewable resources. During the fourth quarter, half of the MDC members who voted supported a proposal that the MDC set up a technical panel to develop a proposal that would require retailers to secure a specified fraction of their energy from renewable resources, but this support fell short of substantial consensus. Supporters of this proposal felt that it would increase the likelihood of developing additional renewable resource generation. The debate over this proposal included expressions of concern as to whether further action was necessary, given the recommendations for a cap and trade program for air pollutants. Adequate control of air emissions should meet the same environmental concerns that motivate proponents of renewable portfolio standards. It was assumed that SOX and NOX would be subject to emissions caps, but there was great uncertainty about carbon dioxide. As a result, the Chair of the MDC wrote to the Minister of the Environment and received written assurance that the existing voluntary commitment by Ontario Hydro to reduce CO2 emissions would remain in place, pending the development of Canada's formal response to the Kyoto Protocol on climate change. The Minister also noted that controls on SOX, NOX and CO2 would necessarily reduce emissions of particulate matter, that mercury emissions were being considered at a national level, and that air toxics were being addressed through the Ministry's air standards-setting process.

Prior to receiving the Minister's response, the MDC held a workshop open to non-MDC members on November 30, 1998 "to discuss market mechanisms, the role of renewables and the valuation of externalities in the context of the MDC's decision on renewable portfolio standards and the future Ontario power market." The workshop reviewed progress made to date on a range of issues including green power marketing, small generation, environmental tracking, new approaches to environmental assessment and alternatives to renewable portfolio standards. Vehicles for stakeholder input were also discussed. Many of the workshop attendees expressed a strong desire to see a continuation of a process to ensure that the implementation of open market rules is consistent with environmental objectives.

We believe that it is important that the environmental rules under which the competitive electricity market operates ensure that the environment not be degraded by the introduction of competition. The Ministry of the Environment and the Ministry of Energy, Science and Technology have taken some steps to pursue the MDC's recommendations in the sixth chapter of our *Second Interim Report*, but significant design issues remain unresolved at this time. Considerable work remains to be done and some important policy decisions must be taken to ensure that the necessary regulations are in place by the time of market opening. We believe that this work would benefit from input from environmental groups, consumer groups, retailers and generators to advise the ministries on these important matters.

Recommendation 7-1

We recommend that the Ministry of Energy, Science and Technology and the Ministry of the Environment jointly establish an environmental panel including environmental, consumer, retailer and generation representatives to provide advice that would facilitate effective and expeditious implementation of the environmental recommendations in our *Second Interim Report* and to provide advice regarding further steps to protect the environment upon the establishment of competition in electricity generation and retailing.

CHAPTER EIGHT

TRANSITION

Transition

Table of Contents

CHAPTER EIGHT

TRANSITION

8.1 Introduction

We established several Technical Panels to explore the detailed technical implications of our policy decisions. The input from these panels was intended to assist us to develop a set of rules to govern the actions of market participants after the market has opened.

During the fourth quarter we also established a Transition Panel, whose mandate and composition were somewhat different. In its terms of reference, the panel was asked to consider transition issues, i.e. issues that will arise after the MDC has finished its work and prior to the opening of the market, and to bring forward recommendations. In preparation for this task, the Panel developed the following objectives:

- To identify major restructuring issues that will arise during the transition period and ensure that they are assigned to the responsible entities; and

- To consider the need for a successor entity to the MDC.

The Panel initiated a stakeholder process to gather viewpoints and suggestions for its deliberations. Initially, the Panel sent letters to a number of stakeholders, including key government entities, seeking their input on the relevant transition issues and the actions needed to resolve them. Follow-up discussions were held with some of these groups to ensure that the Panel understood their concerns. Finally, the Panel asked each of the other MDC Technical Panels to provide an assessment of the issues that would require further work after the MDC was wound up.

A discussion of each of the main issues considered by the Panel, and the associated recommendations, follow.

8.2 Stakeholder oversight during the transition period

In their submissions to the Panel, several stakeholders took the view that the restructuring process is "organic", i.e. it will require continuous oversight and care if it is to flourish and survive. Concerns were raised that the process might be unduly delayed, fragmented, or captured by parochial interests if there were not a forum where ongoing decisions were subjected to open debate. The Transition Panel understood the importance of these issues. However, the Panel also recognized that a number of important institutions already exist, or will be created soon, that could effectively address the concerns and preserve the MDC's legacy and its market vision.

The Panel identified a number of bodies that will play supervisory roles during the transition period and which have made significant provision for stakeholders' input. The Independent Electricity Market Operator (IMO) and the new Ontario Energy Board (OEB) with an expanded staff and mandate are the two primary institutions that will fulfil these functions.

The IMO will have the responsibility for administering the wholesale electricity market, operating the IMO-controlled transmission grid and electricity dispatch system, providing wholesale settlements and disseminating vast amounts of market-generated information. The IMO Board of Directors will be appointed early in the transition period, and the Board and its associated Technical Panel will have strong, balanced representation from stakeholders. The CMO (Central Market Operations, a division of Ontario Hydro and the IMO's predecessor) has already established a stakeholder process comprised of a number of advisory committees composed of selected representatives from specific stakeholders and their professional associations. These advisory committees are already beginning to address post-MDC issues in a forum and process that is very similar to the MDC Technical Panels.

The OEB, as the independent regulator of the electricity system, will fulfill a number of statutory duties during the transition period. It will issue licenses to all market participants, develop market rules for the retail market, establish transmission and distribution tariffs as part of its regulatory role for monopoly functions in the sector, and protect the public interest in all aspects of the restructured industry. It has begun a series of educational seminars and public consultations seeking input from stakeholders on licensing conditions and associated codes. These initiatives will continue throughout the transition period. The OEB is also seeking advice from stakeholders regarding rate-setting for the monopoly distribution and transmission entities.

A key forum for stakeholder input to the provincial government is the Electricity Transition Committee. This committee of senior officials from the private energy industry, MEUs and related associations, as well as MPPs, provides advice directly to the Minister of Energy, Science and Technology. The group has been meeting since January 1998 on a regular basis. Its mandate extends to the entire energy industry, not just the electricity restructuring process. Its focus has been on broad policy concerns, while the details of electricity market design have been left to the MDC. The Electricity Transition Committee thus could address many of the concerns that were expressed to the Panel. However, it may be appropriate to broaden its membership after the MDC disbands.

A number of provincial government ministries will be involved in the post-MDC restructuring period. The Ministry of Energy, Science and Technology (EST) has the largest policy carriage role, from its legislative mandate as the proponent of *The Energy Competition Act, 1998*. The ministries of Finance, Environment, Consumer and Commercial Relations, Natural Resources and Economic Development, Trade and Tourism will provide leadership in important aspects of electricity market implementation as well.

For example, the Ministry of Finance is responsible for the financial restructuring of Ontario Hydro and issues such as taxation of utilities, determination of categories and amount of stranded debts and charges to reduce and retire these stranded debts. The Ministry of Natural Resources manages resource development and use, including rivers and other waters, which can have significant impacts on hydroelectric production and development. The Ministry of the Environment establishes environmental policy, including setting emission standards, which can affect the operation and development of generation plants. The Ministry of Consumer and Commercial Relations provides guidelines and regulations that govern commercial behaviour and protects consumers from unethical business practices. The Ministry of Economic Development, Trade and Tourism promotes investment in the province and assists business in locating or expanding their operations here.

To coordinate activities, an Implementation Com mittee within the provincial government has met regularly since the summer, ensuring that restructuring activities are assigned to the appropriate bodies.

Although the Transition Panel was impressed by the stakeholders' consistently expressed concerns about the restructuring process during the post-MDC transition period, no consensus emerged from its consultations for a successor body with a mandate similar to the MDC's. The rules for the new wholesale market have now largely been written, and the nature of the responsibilities to be shouldered has changed. By the very nature of the process, many bodies will take responsibility for diverse parts of the restructuring as it continues. The Panel encourages the Minister to continue to communicate with the public on a regular basis as the restructuring proceeds, flagging important developments, and thus providing assurance that the restructuring is on track.

We offer the following recommendations to address the need for stakeholder input during the transition period.

Recommendation 8-1

The Minister of Energy, Science and Technology should continue to issue periodic progress reports on the restructuring to the public during the transition period, identifying key milestones and providing assurance that the process is on track.

Recommendation 8-2

The Electricity Transition Committee should expand its membership to augment and broaden the range of interests represented. We recommend that the Electricity Transition Committee should continue to provide stakeholder feedback to the Minister.

Recommendation 8-3

The Ministry of Energy, Science and Technology should ensure that it continues to have effective liaison with stakeholders, including among others, investor owned utilities, marketers, representatives of residential and small commercial users, and other ministries, to assist in the coordination of the implementation and transition processes.

Recommendation 8-4

The IMO and OEB stakeholder consultation processes should be broadly based, be alert to diverse concerns that may be expressed, and not be limited themselves only to narrowly focussed technical issues.

8.3 Further Development of the Legislative Framework and Wholesale Market Rules During the Transition Period

Although our recommendations on the principles of wholesale market design will be essentially finished by the end of our mandate, some work will remain to complete a full and comprehensive set of market rules so that the necessary market systems, processes, and procedures can be specified and developed. During this transition period, a process will be required to manage the remaining (wholesale) market rule development, amendment activities and the issues that will arise in implementation as the result of policy decisions or changes in the market environment.

The process must provide a means for developing those detailed market rules that either could not be completed by the end of our mandate or remain to be added, i.e. "filling the gaps", for example, the proposed rules on transmission rights. It must provide a means of obtaining clarification and/or interpretation of market rules already recommended by the MDC or IMO Board. Future market participants, stakeholder groups and IMO staff may request these clarifications and interpretations. And finally, it must provide a means of screening and addressing requests for amendments to the market rules already recommended by the MDC or IMO Board. These requests for amendments may come from future market participants, stakeholder groups, or the IMO itself in response to rules-related implementation issues.

Recognizing this need, we recommend a process for continuing the development of rules during the transition period.

In our view, the IMO is the logical institution to take responsibility for developing additional wholesale market rules during the transition period. The IMO Board, through its legislative authority, will be accountable for making and amending market rules in the competitive market. The IMO Board will be composed of stakeholder and independent representatives, thus offering the opportunity for balanced views and a thorough debate of alternative approaches to solving problems associated with incomplete or conflicting market rules. Also, the stakeholder representatives on the Technical Panel will assist the IMO Board in its consideration of amendments and additions to market rules. In addition, rule development and amendment during the transition period would appear to be an appropriate part of the IMO Board's duties.

However, some market participants expressed concern that the IMO may have too much autonomous power to change or amend market rules during the transition period. To overcome this concern, we believe that the IMO Board should be required to secure ministerial approval during the transition period for all new and amended rules.

We recognize that the rule amendment process described in the initial set of market rules recommended by the MDC and the rule appeal process described in the *Electricity Act, 1998* are likely to be unduly time-consuming during the transition period. The IMO Board should adopt an expedited version of the process for the transition period.

Recommendation 8-5

We recommend that the Minister direct the IMO Board to implement the MDC's recommended rules, and to undertake the remaining wholesale market rule development, amendment activities and the technical refinements that may arise from these actions. In addition, EST should deal expeditiously with developing regulations and necessary refinements in legislation that will be required because of policy considerations during the transition period and thereafter.

Recommendation 8-6

We recommend that rules and rule amendments referenced in Recommendation 8-5 should be submitted by the IMO Board to the Minister for approval prior to these rules becoming operational and enforceable.

Recommendation 8-7

During the transition period, all proposed new rules and rule amendments should be reviewed and discussed both by the IMO Board and its Technical Panel, as constituted under the Governance and Structure By-law. An expedited process for recommending amendments to the wholesale market rules should be implemented during the transition period.

Recommendation 8-8

During the transition period, any proposed changes to the recommendations contained in the MDC's reports should require stakeholder consultation and approval, with rationale, by the IMO Board.

8.4 Electricity Market Pilot Projects

The White Paper refers specifically to the possibility of establishing retail pilot projects prior to market opening:

> "As a means of ensuring a smooth transition, it may be useful to introduce retail pilots prior to the launch of full retail competition." (P. 17)

Our Terms of Reference also list, as one of the MDC's activities, advising the Minister on the usefulness of pilot projects as a preparatory tool for market participants:

> "The [MDC] final report shall include…recommendations regarding the feasibility and objectives of retail access pilot programs…." (Order in Council, p.4)

Prior to the MDC process, some people anticipated that several alternative sets of market rules might be developed and then tested with pilot programs to determine the best design. Also, it was expected by some that the period of time prior to market opening would be lengthy enough to support a large-scale pilot program in which virtually all market participants could take part, essentially an extensive practical education program in market functions and mechanics.

In reality, neither of these expectations has been realized. Given the fact that the market rules are now essentially complete and, more important, that the time remaining before market opening is very short, the case for conducting pilot projects is seriously weakened.

Our research led us to draw a distinction between pilot projects and testing. Unquestionably there will have to be a period in which the new market hardware and software are rigorously tested before the market can be declared ready for opening. During this period, market participants and the IMO will wish to make "dry runs" of market procedures such as bidding and will want to go through simulations of various situations, including emergencies, to test and validate the protocols and procedures involved. The CMO has made provision for such a period in its planning and is currently working with its Stakeholder Advisory Group to prepare for this period. Pilot projects, on the other hand, typically involve a limited number of market participants in trying out relatively narrowly defined, specific rules or activities.

As part of its deliberations, the Transition Panel reviewed the use of pilot programs in other jurisdictions, the lessons learned from them, and their applicability to the Ontario situation. This research examined the experience in Australia, New Zealand, and several jurisdictions in the United States (California, PJM) with pilot projects at both the retail and wholesale level. Experience in other markets showed that pilot projects tended to be at best, of marginal usefulness, and, at worst, could be unhelpful in establishing impartial and fair markets.

The Transition Panel found this experience in other jurisdictions compelling. However, before settling on a set of recommendations the Panel heard from several proponents of specific pilot programs for the Ontario market. These presentations were enlightening and informative. Furthermore, the proponents seemed genuinely interested in the MDC process and in facilitating a better understanding of the competitive market.

The Transition Panel found that proponents' views of pilots encompassed a wide variety of concepts – retail pilots, wholesale pilots, market testing and "ghost" markets. The proponents also held different views about the extent of the wholesale and retail market systems that would need to be in place and operational in order to support a pilot project.

However, the Transition Panel concluded that none of the proposals as presented satisfied the criteria of a general market test. The Panel was concerned that participation in pilot projects, necessarily limited to a few participants, could bestow inappropriate advantages relative to non-participants; for example, participants could use their practically-acquired knowledge about market functions and behaviour to secure competitive advantages after the opening of the market.

The Transition Panel also decided that much of the information normally acquired through pilots focused on the retail market could be gathered through surveys. Also, the Panel had concerns that the introduction of pilots could delay the opening of the market without generating sufficient additional benefits of a market-wide character to justify it.

The Transition Panel concluded that it would be inappropriate for the MDC to recommend a specific project proposal for endorsement. Instead the Panel decided that a more useful approach would be to establish a set of criteria and principles by which the Government could evaluate specific pilot project proposals, should they come forward.

Recommendation 8-9

The Government, specifically the Ministry of Energy, Science and Technology, in its assessment of the need for pilot projects should ensure that the following principles are incorporated into the project design:

- **Pilot projects must have clear, achievable objectives;**
- **Projects must not give any group of market participants an advantage over others prior to market opening;**
- **All information gathered through pilot projects must be shared and to the benefit of the market overall;**
- **Any projects should be undertaken over a reasonable time period within which to gain meaningful information;**
- **The costs of pilots must be borne by the participants; and,**
- **The introduction of pilots must not delay the implementation of the market.**

8.5 Market Design Testing

The Transition Technical Panel is convinced that thorough testing of the IMO’s market systems hardware and software is imperative. The CMO has developed an implementation plan that contemplates extensive trial runs and debugging during the transition period. We encourage the IMO to engage a wide cross-section of market participants in this activity. Also, we suggest that the IMO share the experience and lessons learned from these activities as widely as possible.

Determining when the market systems and participants are ready to assume their roles in market operations is a crucial function. Premature operation of the market could result in serious difficulties and financial liabilities for market participants, their agents and customers. We need to ensure that determining when the market is ready to function will be based on when the market and its supporting functions can operate efficiently and effectively. The declaration of market readiness should be a joint responsibility of the IMO and the OEB. Both of these agencies should inform the Minister when they are satisfied that the market systems and participants are prepared to fulfill their respective roles. This will enable the Minister to promulgate any sections of relevant legislation to ensure that legal responsibilities operate in parallel with “real market” functions.

Recommendation 8-10

The IMO and the OEB should be given the responsibility of determining when market systems, institutions and market participants are prepared to fulfill their respective roles. The IMO and the OEB should inform the Minister of Energy, Science and Technology, who has the responsibility for declaring the market open, when they are satisfied that the market can operate efficiently and effectively.

8.6 Market Power, Customer Education and Market Participant Readiness

In our *Third Interim Report* we outlined a negotiated agreement between the MDC and Ontario Hydro’s Generation Division (Genco) to control the successor generation company's (OPGI, Ontario Power Generation Incorporated) market power. [1] These recommendations included specific limits on OPGI’s revenues to prevent it from benefiting from exercising market power, decontrol targets for OPGI’s generation facilities, and periodic review of OPGI’s decontrol progress by the OEB. With the exception of Ministerial direction to the OEB for the periodic reviews, we intended that the provisions of the market power agreement be implemented and come into force when the market opens.

However, during the transition period a number of general issues with respect to market power may emerge. Other market participants, in addition to the dominant incumbent utilities, may seek to exploit opportunities during the transition period to acquire market power prior to the market opening date. For example, attempts to commit residential retail customers to long-term contracts prior to market opening, when full information on market prices and opportunities is lacking, could become a problem.

During the transition period there are a number of options for caretaker arrangements for the market power mitigation strategy and oversight of the nascent market:

- The Market Surveillance Panel (MSP) of the IMO Board could assume oversight functions in addition to its normal activities, including investigating market participants’ complaints;
- The OEB could be directed by the Minister to perform oversight functions; and,
- EST could assume oversight functions, using the Electricity Transition Committee as a

[1] Chapter 2 outlines the legal instruments for implementing the market power strategy.

"complaint bureau" for market participants.

From the MDC's viewpoint, the best option would be to have the OEB function as overseer of the market power mitigation strategy, since it will likely have the authority to oversee the market in general and protect market participants from potential abuses of all kinds. Moreover, once the market power mitigation strategy comes into effect, the OEB has been designated as the agency that will conduct reviews of decontrol actions, monitor progress toward the decontrol targets and make recommendations to the Minister on the need for further actions to control the abuse of market power.

The Transition Panel is convinced of the importance of customer education and awareness and market participants' readiness to assume their roles in the restructured market. Moreover, Ontario's recent experience with deregulation of natural gas markets reinforced that consumer education must be a key activity during the transition period, and second, that potentially anti-competitive behaviour must be prohibited during that period.

Considering the changes that are contemplated within the next two years in the electricity industry, the Panel and the MDC are concerned that small volume electricity consumers are unlikely to be fully aware of their opportunities and obligations in the new marketplace. In part, this concern motivated us to adopt a market design default supply option that requires no action from individual customers to initiate. However, successful markets depend on informed and motivated participants to achieve efficient outcomes and realize the benefits of competition. We are concerned that residential customers will not have sufficient knowledge and basic information to make informed judgements about the types of service they will need or want after the opening of the market during the transition period.

General oversight of the electricity sector prior to market opening is a quasi-regulatory activity that should be vested with the OEB. The OEB will be issuing, in the near term, interim licences for all market participants, including retailers. The Transition Panel was concerned that issuing licences prior to an extensive educational program could potentially lead to abuse in the marketplace at the expense of uninformed consumers. Without any information or experience with how the market will function or how the prices obtained in that market will evolve, residential customers may unwittingly limit their options, potentially by opting for long-term contracts.

The OEB should, through its licencing authority, limit retail contracting altogether until comprehensive education programs have been completed. Furthermore, the OEB should consider contract length restrictions during the transition and during the first year of market operation, once contracting is permitted, in order to prevent exploitation of customers and to ensure the integrity of the retail market.

At the wholesale level we are confident that most eligible market participants are aware of the broad outlines of the restructured industry. We are concerned, however, that a significant number of wholesale participants are unaware of the extent of reforms contemplated and the need for them to participate in activities in which they have no experience or expertise. The evidence from other jurisdictions shows that even fully experienced market participants can sometimes suffer substantial financial losses from unanticipated market events.

We are convinced that a focussed and intensive education program, primarily for end-use customers and, to a lesser degree, for wholesale market participants, is the best way to forestall these potential threats to electricity industry reform. We made specific recommendations in our previous interim reports about the need for a consumer information program and requiring LDCs to provide customers with a detailed explanation of the default supply option.

Our Retail Technical Panel has studied the need for customer education in detail and made a number of specific recommendations. We support these recommendations, focussing on the central role of the Government, specifically EST and the OEB, to provide neutral, unbiased and factual information that is necessary for all market participants to make informed judgements about their choices in the electricity market. This information should be provided both before the market opens and as an ongoing responsibility. In addition, a significant number of MDC members supported the view that education programs should be shown to be effective before relaxing any restrictions on retail contracting.

We are recommending some limits on retail contracts to residential customers to enable the education programs to be widely disseminated and have some effect prior to the market opening. However, we acknowledge a requirement for prior notification to end the limits on contracting in order for retailers and marketers to plan their contracting activities and make the necessary investments.

We acknowledge and welcome the willingness of trade associations such as the M unicipal Electric Association (MEA) and the Association of Major Power Consumers in Ontario (AMPCO) to play a key role in preparing their members for the coming reforms. Furthermore, the Electricity Transition Committee has provided valuable leadership in educating its constituent groups about the restructuring process and the value of preparation for the future market. Education partnerships with the Government should be an initiative pursued by these, and other, associations. In particular, the long-established relationship between LDCs and customers should be a principal vehicle for consumer education.

Recommendation 8-11

The OEB should monitor pre-market activity to ensure that the provisions of the market power mitigation agreement are not impaired by the actions of any prospective market participants prior to market opening.

Recommendation 8-12

During the transition period, the Ministry of Energy, Science and Technology should implement a comprehensive education program that gives consumers factual information about the reforms being instituted. This information should be communicated directly to consumers through a variety of means and use a phased approach with general information followed by more detail as the market design develops.

Recommendation 8-13

We recommend that no retailer be permitted to execute a contract for the supply of electricity with any residential consumer prior to a date fixed by the Minister and following completion of the educational program. We recommend that the Ministry announce this date in advance, so that retailers can prepare for it.

Recommendation 8-14

The Minister should request the OEB to assume general oversight of the electricity sector during the transition period to prevent any non-competitive practices and market power exploitation prior to market opening.

Recommendation 8-15

As a specific condition of the licenses that it issues to retailers, brokers and marketers, the OEB should consider limiting the length of contracts for the supply of electricity that retailers may execute with residential consumers to one year (365 days). This limitation would apply only to contracts executed prior to the first anniversary of the date that the market opens.

APPENDIX A

LIST OF RECOMMENDATIONS

FROM THE

MARKET DESIGN COMMITTEE REPORTS

First Interim Report

List of Recommendations

I. Creation of an Independent Market Operator (IMO)

We recommend the creation of an Independent Market Operator (IMO).

II. Functions of the IMO

We recommend that the following functions be performed by the IMO in conjunction, where appropriate, with OEB oversight.

- Operate and manage a spot market for trading electricity in Ontario.
- Carry out financial settlement for exchanges through the spot market.
- Contract with transmission owners through leasing or similar contractual arrangements for use of their integrated transmission system for energy trading and transport according to market rules. Transmission owners must be provided with adequate incentives including contracts and performance-based rates to preserve asset value, improve the capability of equipment, and achieve operational efficiencies.
- Manage the secure operation of the integrated power system; determine system capabilities and operating rules and manage real time dispatch within these capabilities.
- Control the dispatch of generators, transmission, and loads to match demand for electricity in Ontario and ensure adequate operating reserves including scheduled exchanges of energy and ancillaries with electric systems within and beyond Ontario.
- Provide forecast and after-the-fact information to market participants to facilitate their operating and investment decisions.
- Forecast and assess supply, demand, and transmission conditions and advise on the adequacy of reliable supply and delivery capability.
- Monitor and enforce compliance with commercial and technical standards for the integrated power system and the spot and ancillary markets.

III. Structure of the IMO Board

We recommend that there be a maximum of 15 voting members on the IMO Board as follows:

Membership*	Number of Representatives
Generation Providers**	2
End Use Customers (including one each from Residential, Commercial, and Industrial)	3
Transmission Providers	1
Distribution Providers	2
ABMs***	1
President/CEO of the IMO	1
Independent Members	5
Maximum Number of Members	15

* No company can occupy more than one seat on the Board.
** Generation providers must operate generation assets in the province of Ontario.
*** The ABM cannot be an affiliate of either a transmission or distribution provider.

We recommend that the IMO have at least two by-laws, one of which should be a Structural and Governance By-law containing some of the fundamental structural rules of the IMO. Amendments to these by-laws will be subject to non-disapproval by the Minister representing the electric power sector within a 60-day period. The IMO should also have a general by-law containing the housekeeping-type items that are typically found in the by-laws of other corporations. The IMO Board should be responsible for making amendments to these by-laws. Public notice and comment will be used for changes to the Structure and Governance By-law to increase the transparency of the decision-making process.

IV. Selection of IMO Board Members

a) We recommend that criteria be established for IMO Board members that set minimum levels of expertise and experience. For the independent directors, we also recommend that the eligibility criteria ensure against conflicts of interest. These criteria should be included in the IMO=s Structure and Governing By-law.

Market participant members of the Board must be:

- a representative of a licensed market participant.
- an end-use customer or an individual representing a class of end-use customers.

Companies with interests in a number of different areas of the industry will be able to select only one class to represent their interest.

To be eligible for consideration as an independent member of the board, a person must meet *both* of the following criteria:

- professional qualifications and experience relevant to the activities of the market including: corporate finance, commodity trading, corporate law, economics, environmental policy, or the energy industry. These criteria are designed to ensure that the independent Directors collectively reflect a diversity of backgrounds and public interest.
- no direct commercial affiliation with any of the market participants.

b) We recommend that the selection of members from the different market participant classes follow the process described below. Licensed market participants will select one class of participant to represent them on the Board. Licensed market participants within each class will nominate an individual(s) to represent their class on the Board. Where more names are proposed than there are seats available, the Minister responsible for the electric power sector will appoint nominees from that list who meet the eligibility criteria listed above. Where an end-use customer is not a licensed participant, an organization representing that class of market participant can propose the name of an individual to represent the interest of the class to the Minister responsible for the electric power sector. The nominees need not be members of the organizations proposing their names. Again, where more names are proposed than there are seats available, the Minister will appoint the Directors from that list.

c) We recommend that the Minister responsible for the electric power sector select the independent Directors from a list of candidates nominated by the Board; the list is to include at least 2 nominees per vacancy. We recommend that the nominating committee of the board oversee this process; we further recommend that the committee comprise only the independent Directors. The nominating committee will develop a list of names to be submitted to the full Board for consideration and approval by simple majority vote. The list of names approved by the Board will be submitted to the Minister responsible for the electric power sector. The Minister will choose the required number of Directors from that list.

d) To ensure the independence of the Board, we recommend that the Chair be selected from among the independent members of the Board. The selection is to be made by a simple majority vote of the Board with a quorum in attendance.

e) We recommend that the CEO/President be selected by the Board: the selection is to be made by a simple majority vote of the Board with a quorum in attendance.

f) We recommend that the pr ocess for the initial selection of market participant members to the Board should follow the process detailed above for end-use customers who are not licensed participants. For the initial selection of the independent members of the Board, we recommend that the MDC provide a list of at least ten nominees to the Minister responsible for the electric power sector.

V. Decision Rules for the IMO Board

a) We recommend the decision-making powers of the IMO Board should be exercised in accordance with the following principles.

For the transaction of business at meetings of the Board, we recommend that 10 Directors constitute a quorum. We recommend that super-majority voting rules be adopted for changing:

- the IMO=s corporate structure and functions;
- market rules;
- fees payable by market participants to cover the IMO=s costs; and
- the operating agreement between the IMO and transmission owners.

A super-majority vote of 10 must be received for a motion to be carried. For all other motions, we recommend a simple majority with a quorum in attendance. We recommend simple majority voting rules with a quorum (to be determined by the Board) in attendance at the committee level.

b) We recommend that the proposed *Electricity Act* explicitly provide that the Directors, Panel members, officers, employees and agents not be liable for any act or omission in good faith in:

- the performance or intended performance of duties;
- the exercise or failure to exercise any powers under the Act; or,
- neglect or default in performance or exercise in good faith of such duties or powers.

Such a limitation should also explicitly include liability arising under provisions of other provincial statutes which impose statutory Director liability including, without limitation, those provincial statues which provide for statutory liability of Directors and officers for environmental liabilities, except as provided in the Regulations. We recommend that the IMO purchase Directors and officers liability insurance to protect against any residual liabilities which may arise (including statutory liability imposed by any federal statutes, such as liability for non-payment of certain taxes, etc.). We recommend that traditional liability concepts apply to the IMO as a corporate entity and that there be no statutory exception to these.

VI. Panels of the IMO Board

a) We recommend that to assist the Board in the operation of the competitive marketplace and to ensure that its regulatory obligations are met, three Panels be constituted: a Technical Panel, a Dispute Resolution Panel, and a Market Surveillance Panel.

b) We recommend that the Technical Panel:

- review market rules for deficiencies;
- develop and implement changes to market rules, as required; and
- provide advice to the Board and the OEB on specific technical issues related to market and system operations.

We recommend that the Panel should have a maximum of 11 members encompassing 9 market participants and 2 members from the IMO. The 9 market participants should come from the same participant classes identified for the Board and that they be in the same proportion as on the Board; 3 end users, 2 generation providers, 2 distribution providers, 1 transmission provider; and 1 ABM. Of the two members from the IMO, one will be the CEO/President of the IMO; he/she will also chair the Panel. The CEO/President should also appoint the second member from the IMO staff.

For the selection of the 9 market participant members to sit on the Panel, we recommend a similar process to that recommended for the selection of market participant members to the Board. In this case, where more nominees are proposed that there are seats available, *the Board* (rather than the Minister responsible for the electric power sector) will select the required number of Panel members from among the list of nominees proposed. Simple majority voting rules will govern the selection of Panel members. We recommend that Panel members serve three-year terms. As with the incorporating Board, we recommend that initial terms be staggered and that there be an initial drawing of lots to determine the length of term to be served by each Panel member; terms will range from 1 to 3 years. Panel members will be limited to serving two consecutive terms, although re-appointments are possible following a break from the Panel.

We recommend that the Panel follow super-majority voting rules. Thus, a motion must receive 8 votes to pass. If a motion receives 6 or 7 votes it can either go back to the Panel for further discussion or it can be referred to the Board for review and decision.

All proposed changes to market rules that are adopted by the Technical Panel will be published and filed with the OEB. The IMO Board should have the right to stay the implementation of any proposed rule change and to send it back to the Technical Panel for re-consideration. The OEB will have authority to review changes to market rules upon appeal, as set forth below.

We recommend that once a proposed rule change has been filed with the OEB there should be a minimum stay of implementation: the period should be the greater of 21 days and the number of days set by the Technical Panel (to allow for the development of requisite software, etc.). We recommend that any person with an interest adversely affected by a new market rule be able to file an appeal to the OEB within a 21-day period following the filing of the rule change with the OEB. If the rule is not appealed, it will automatically go into effect after 21 days.

When a proposed change to market rules is appealed, we recommend that rule change may be rejected by the OEB only on any one of the following three grounds:

- The rule is inconsistent with the purposes and objectives of the legislation or violates a specific provision thereof.
- The rule unduly discriminates against or in favour of a market participant or class of market participants.
- The rule is otherwise unreasonable.

If the OEB rejects a rule change, it should provide a written opinion setting forth the reasons for its rejection and remand the rule change back to the IMO for reconsideration in accordance with its written opinion; the opinion may contain a direction to the IMO regarding modifications and implementation.

We recommend that Government approve the initial market rules proposed by the MDC and that they not be subject to the appeal process described above.

c) We recommend that the <u>Dispute Resolution Panel</u> be responsible for settling disputes on the application or interpretation of market rules. We contemplate three categories of disputes involving the interpretation and application of the IMO=s market rules:

- cases where the staff of the IMO finds that one or more market participants have violated a market rule;
- cases where one or more market participants believe that the IMO staff has violated or misapplied a rule; or
- disputes between or among market participants over each other=s compliance with market rules.

We recommend that a dispute resolution process employing a number of techniques be followed, including:

- Mandatory fact finding/ mediation where the disputing parties get together to try to resolve their differences. As a minimum, the parties will be required to articulate issues and agree to facts.
- Binding arbitration, the purpose is to reach a settlement among the disputing parties and, if not possible, to issue specific and enforceable determinations. Other than in the circumstances listed below, the decision of the arbitrator will be final and only procedural irregularities will be appealable to a court of law.

The Dispute Resolution Panel should include at least three people, any one of whom could be called upon to mediate or arbitrate a dispute at any time. (The same member will not mediate and arbitrate the same case.) Panel members will be independent of the IMO and will have no commercial affiliation with any of the market participants. They will be required to have experience in the arbitration of disputes as well as detailed knowledge of the technical aspects of the electricity market.

We recommend that the decisions of the Dispute Resolution Panel on issues of substance be final; they can only be appealed where either of the following is the case:

- the violation requires the offending participant to pay a penalty or refund which exceeds a threshold amount; or
- the participant=s accreditation with the IMO is to be suspended or revoked.

In either of these cases, the market participant may appeal the decision of the Dispute Resolution Panel to the OEB. The OEB may reverse or modify the decision of the Panel if it finds that the Panel=s decision was unreasonable.

d) To ensure that the market is functioning competitively, it will be necessary to periodically review the operation and structure of the market. To this end we recommend that a <u>Market Surveillance Panel</u> be selected and that it operate in accordance with the following rules.

We recommend that Panel members be chosen by simple majority vote of the independent members of the IMO Board. The Panel is to consist of individuals that have no commercial affiliation with any of the market participants, but who have a reputation for expertise in the operation of competitive electricity markets. The Market Surveillance Panel should have the resources to hire expert advice, as required, and will be able to rely on the assistance of IMO staff.

We recommend that the Market Surveillance Panel be responsible for periodic reviews and reports:

- identifying inappropriate market conduct and market inefficiencies;
- recommending remedial actions to mitigate such behaviour and inefficiencies; and
- assessing whether the underlying structure of the marketplace is consistent with the efficient and fair operation of the competitive market.

To the extent that the Market Surveillance Panel recommends changes in the market rules, it is expected that the IMO Board will refer such recommendations to the Technical Panel, to be considered pursuant to the regular procedures for adopting and implementing changes to market rules. If the Market surveillance Panel raises concerns pertaining to a market participant=s conduct, we recommend that they be referred to the IMO. Such concerns may also be referred to the OEB or to the Minister responsible for the electric power sector together with recommended responses to structural problems in the market. We recommend that the federal Competition Bureau be advised of concerns relating to potential violations of the *Competition Act* such as collusive or predatory behaviour).

We recommend that the Panel will make its findings through written reports to the independent members of the IMO, the OEB, the Minister responsible for the electric power sector and, where appropriate, the federal Competition Bureau. All reports will also be make publicly available; however, the Panel will edit confidential information from the public versions of its reports before releasing them. It is recommended that such reports be prepared at least once each year and that they be prepared more often if directed by the IMO Board or the OEB.

In order to conduct its investigations, we recommend that the Market Surveillance Panel have access to all of the information available to the IMO in the course of performing its functions and that it enter into arrangements with the IMO to protect the confidentiality of commercially sensitive information. In the event that the Panel believes it needs information that is not available to the IMO, the Panel may request the OEB to direct market participants to provide such information to it, subject to appropriate measures to protect against the public disclosure of confidential information.

If the Panel intends to include findings to the effect that one or more market participants have engaged in improper conduct, it should discuss its findings with the affected participants before including them in its report; it should also give the affected participants an opportunity to respond in writing to the allegations. All such written responses will be included in the Panel=s published reports (subject to the appropriate editing of confidential information).

We recommend that a Market Assessment Unit be established at the IMO staff level to provide information to the Market Surveillance Panel and to assist the Panel, as required.

VII. Reporting Requirements for the IMO

We recommend that the new Electricity Act require an annual report by the IMO to the Minister responsible for the electric power sector, to be tabled in the legislature. It is intended that such report would include, among other things:

- business strategy, budget, and proposed capital expenditures for the IMO over a 3 to 5 year planning horizon;
- bench marking and best practice activities undertaken by the IMO in the previous year and those planned over the next 3 to 5 year period;
- an assessment of IMO=s performance as measured against a set of performance measures that have been approved by the Board; and
- a summary of principal developments in the preceding year.

A published statement of priorities could also be considered.

The following information related to market surveillance, dispute resolution, and rule changes should be reported by the IMO at least annually:

- an assessment of the extent to which the operation of the market has met market objectives;
- a summary of, and reasons for, any changes to the market rules;
- a summary of appeals to changes in market rules;
- a summary of material breaches of the market rules and the actions taken in response, including particulars of any sanctions imposed;
- a summary of any disputes and their resolution; and
- a summary of breaches in the code of conduct by IMO employees.

The following long-term projections should be reported annually:

- projections of aggregate demand and energy requirements;
- generating capabilities of existing generating units and generating units for which formal commitments have been made for constructions or installation;
- planned plant retirements;
- statements of network capabilities and constraints; and
- operational and economic information about the market to assist planning by both market participants and potential market participants.

VIII. Participation in the Market

a) We recommend that the licensing process for participants in the wholesale market be accomplished in two stages. First, the IMO should develop accreditation requirements for different categories of applicants for a wholesale license. These accreditation requirements are intended to ensure that all wholesale licensees meet technical and prudential criteria necessary to protect the integrity of, and create public confidence in, the operation of the wholesale market; they will form part of the market rules.

If the IMO staff determines that an applicant for a wholesale license meets the accreditation requirements, it will certify to the OEB that the applicant is eligible for a wholesale license. If the IMO staff determines that an applicant does not meet the accreditation requirements, the applicant may appeal the decision to the OEB.

When the accreditation requirements are met, the OEB will then be responsible for issuing a wholesale license. This license will bind the applicant to abide by the IMO=s market rules and any other requirements that may be established, by statute or OEB order, for that category of licensee. The legislation should make the license requirements enforceable in court, and/or by the OEB or IMO in accordance with IMO rules.

b) We recommend that wholesale licenses be established for the following different categories of wholesale market participants:

- generators connected with the Ontario system;
- transmission service providers;
- distribution service providers;
- wholesale ABMs (including generators selling into the Ontario market from neighbouring systems);
- wholesale buyers; and,
- the Independent Market Operator.

The accreditation and licensing requirements associated with these categories would be different, reflecting the different roles these entities play in the wholesale market.

c) We recommend that the OEB have responsibility for issuing licenses to all sellers who sell power directly to end-use consumers in Ontario, other than those selling solely to affiliated entities or to entities licensed by the OEB to participate in the wholesale market. This retail license would be separate from, and in addition to, any wholesale license that such retailer may need to participate in the wholesale market. The primary function of the retail license would be consumer protection, and would include, among other things, the provision of relevant information to consumers.

d) We recommend that if necessary to ensure compliance with licensed market rules, th at the IMO enter into a short, standard-form contract with each participant in the wholesale market. The purpose of the contract will be to give contractual force to whatever market rules are in place at any given time. Contracts will allow the use of standard legal remedies to deal with issues of non-compliance in addition to remedies established by legislation or market rules.

e) We recommend that transmission services be offered under a tariff that identifies the different services to be offered, the terms and conditions under which those service will be provided, and the rate levels to be charged.

In a competitive environment, this tariff should accomplish two objectives:

- the IMO=s objective of assuring the provision of all services required of a competitive electricity market under a rate structure that is consistent with the market rules; and,
- the transmission owners= objective of being fairly compensated for the assets and services provided.

To achieve these two objectives, we recommend that the IMO enter into a contractual arrangement, termed an operating agreement, with transmission owners to define the different types of transmission service that must be provided to support the market and to obligate transmission owners to make their facilities available for such services. In return, the IMO will administer the tariff, under which transmission customers will be charged rates designed to compensate transmission owners for the services they provide. We recommend that the tariff rates include incentives for transmission owners to preserve asset value, improve the capability of equipment, and achieve operational efficiencies.

We recommend that subject to oversight by the MDC, Central Market Operations and the transmission owners develop the initial terms and conditions of the operating agreement and the tariff rate structure (other than rate levels), including the terms and conditions under which transmission services will be offered. These documents will be reviewed and approved by the MDC and submitted with the initial market rules for approval by the Government.

If, at some later date, either the IMO or transmission owners wish to change any of the operating agreement or tariff provisions that were approved with the initial market rules, they will attempt to reach agreement on such changes. If they are unable to do so, or if they do agree but another market participant objects to the change, we recommend that the matter may be appealed to the OEB in accordance with the same rules that apply to changes in the market rules.

IX. Cost Recovery and Funding of the IMO

a) We recommend that during the transition to independence, Ontario Hydro should provide sufficient funding to support the establishment of the IMO and the development of the marketplace. This incremental funding is to be considered a loan, to be repaid once competition is implemented.

b) As with the transmission tariff, the IMO=s rate structure and terms and conditions of service must be consistent with the MDC=s design of the future market. We therefore recommend that the MDC develop the initial tariff for the IMO. As a not-for-profit organization, the IMO=s revenue requirement and rate levels will be established to recover its costs on an annual basis. Once the IMO is established, we recommend that its revenue requirement and rate levels be established by the IMO Board and that they be filed with the OEB. This information should be subject to review and modification by the OEB in the event of an appeal by a market participant in accordance with the rules for appeals to changes in market rules.

Second Interim Report

List of Recommendations

Chapter Two – Market Power

2-1 The Government should adopt necessary *ex ante* market power mitigation measures as part of the initial market design. *Ex post* intervention in the market should be implemented only in the event that experience in the market indicates that the initial measures adopted are inadequate to address the abuse of market power.

2-2 The Government should establish the MS P as the body responsible for initially assessing the need for *ex post* mitigation measures to replace or supplement *ex ante* measures.

2-3 With respect to requests to the OEB for *ex post* market power action, we recommend that:

> The OEB should address these complaints through a process at which all affected parties would be given the opportunity to present facts and expert opinions regarding the complaint.
>
> The OEB should tailor its procedures to accommodate the need for an expeditious decision on these market power issues.
>
> Based on the record developed at such hearings, the OEB should issue a public decision setting forth its findings on whether a market power problem exists and what mitigation measures, if any, are required to remedy the problem.

Decisions should be subject to review by Cabinet.

To reinforce the need for expeditious decisions, we suggest that appeals be filed within 30 days from the date of the OEB decision.

Cabinet should consider appeals in an expeditious manner; *we* suggest 60 days from receipt of an appeal. If Cabinet does not choose to reject or vary the OEB ruling within this time limit, the ruling should stand.

With respect to other issues associated with *ex post* market power we recommend that:

> While the mitigation measures available to the OEB do not include ordering divestiture (e.g. change in the ownership of assets) which will be the sole discretion of the Minister, the OEB should be able to make recommendations on divestiture to Government after appropriate public consultation if other market power mitigation measures are found to be ineffective.

The OEB should have the ability to mitigate market power by imposing conditions for the issuance or continuation of a license. Examples of these types of conditions include, but are not restricted to, Codes of Conduct, restrictions on the terms and conditions of contracts between generators and customers, and price caps. Divestiture would not be a condition for issuing a license.

The OEB and the federal Competition Bureau should immediately initiate discussions on a Memorandum of Understanding (MOU). This MOU would define the responsibilities of the respective agencies for market power issues in a deregulated electricity sector where there may be concurrent jurisdiction, e.g. collusion, bid-rigging, predatory pricing, price discrimination, exclusive dealing, tying, abuse of dominance and mergers. Such an MOU will avoid the confusion and overlaps in institutional roles that have characterized other industries in transition from monopoly to competition.

Chapter Three - Wholesale Market Design

3-1 We recommend that the IMO administer a forward market for each hour of the following day. Initially, this should be a single day-ahead market, as described in Appendix 3A, based upon day-ahead bids and schedules submitted by market participants for those hours. Thereafter, if the IMO Board finds sufficient interest in this forward market, the IMO Board may decide to implement other forward markets (e.g., an hour-ahead).

3-2 We recommend that the bids submitted by generators to the IMO for its day-ahead and real-time energy markets be one-part bids, rather than multi-part bids indicating separate start-up costs, minimum generation costs and incremental running costs. Each generator would perform its own unit commitment. Each bidder would rely on its bidding strategy to recover its start-up and minimum generation costs.

3-3 During the first eighteen months of operations, we recommend that the IMO use a province-wide uniform price for settlements in the IMO's spot market. Before it is implemented, however, we strongly urge that rules be developed to discourage gaming of side payments and to limit unfair arbitrage of the differences between uniform prices and underlying marginal costs.

3-4 We recommend that the IMO calculate and publish at least monthly, hourly nodal prices from the beginning of market operations. During the first eighteen months, we further recommend that the IMO develop the capability to implement nodal pricing

3-5 We recommend that the IMO Board undertake an annual review of the results of congestion pricing and uniform pricing and adopt appropriate adjustments in market pricing rules as needed. At the end of the first annual review, the IMO Board would indicate the form of congestion pricing it intended to implement. The form would be implemented unless disapproved by the OEB.

Other recommended adjustments made by the IMO (subject to OEB appeal) might include, but not be limited to:

Revising the approach to uniform pricing
Refining the conditions, if any, under which consumers could switch between uniform and congestion pricing
Delaying the start of congestion pricing for generators and wholesale market consumers.

3-6 We recommend that beginning in the nineteenth month of market operations, some form of congestion prices (nodal, zonal or some variant) be used in settlements for generators and wholesale market buyers.

3-7 We recommend that for the first three years of market operations, retail end-users continue to be subject to uniform pricing for spot purchases and sales rather than congestion pricing. Toward the end of this period, the OEB would determine whether to continue uniform pricing or to adopt congestion pricing (with or without mitigation and the appropriate form thereof) for such consumers.

3-8 We recommend that the IMO administer hourly markets for certain ancillary services, initially regulation and operating reserves, and acquire other services through contract arrangements. We further recommend that the IMO investigate the feasibility of acquiring such other ancillary services on a short-term market basis. Our recommendation includes the elements set forth in Appendix 3A.

3-9 We recommend that the IMO have the ability to administer a market for capacity reserves, integrated with the hourly energy and operational reserve markets. If the IMO Board decides that additional incentives are necessary to assure the availability of adequate generating capacity to meet peak loads and reserve requirements, it would set the capacity reserve requirement under which the market would operate.

Chapter Four – Retail Competition

4-1 We recommend that the OEB be empowered to develop, and that it expedite the development of, a code that governs the relationship between regulated local distribution companies and any competitive affiliates and that recognizes the distinctive features of the electricity industry. The code should be designed to support the principles of avoiding cross-subsidy of competitive activities of affiliates, avoiding preferential access by affiliates to services of the local distribution company, and avoiding preferential access to markets by the affiliates. The same rules should apply to MEUs, Servco and other electricity distribution entities.

4-2 We recommend that the same rules be applied to MEUs, Servco, and all other electricity distribution entities with regard to the obligation to provide default supply services, as provided in Section 28 of the proposed *Electricity Act*, 1998 tabled June 9.

4-3 We recommend that all local distribution companies should be required to offer to all customers electricity supply priced at a "smoothed" pass-through of the wholesale market spot price, based on an average forecast price, adjusted perhaps on a quarterly basis, and including a regulated recovery of administrative costs. The local distribution company may contract out fulfilment of this regulated obligation to other appropriate parties.

4-4 We recommend that all local distribution compa nies should also be required to offer to all customers the option of buying energy at the wholesale market hourly spot price, including a regulated recovery of administrative costs. The local distribution company may contract this regulated function out to other appropriate parties.

4-5 We recommend that the spot price pass-through bill amount be the actual wholesale spot price multiplied by the customer's usage in each interval for customers with interval meters. For customers with watt-hour meters, an appropriate profile should be used to allocate total kilowatt-hours over the billing period to the individual intervals for pricing purposes.

4-6 We recommend that local distribution companies be required to provide bills that unbundle energy charges from other charges, including wires charges and charges for other services.

4-7 We recommend that local distribution companies be required to provide default metering services, including the provision of interval metering to customers who request it, at rates approved by the Ontario Energy Board, as part of the default supply service.

4-8 We recommend that rules be developed to ensure that the local distribution company's security of payment is not decreased by the introduction of competitive retailing, to protect competitive retailers from customer non-payment and to protect the customer from the risk of having to pay twice if his retailer defaults. This may require substantial qualification and indemnification rules for competitive retailers before they may be licensed to participate in the market.

4-9 We recommend that parties licensed to participate in the wholesale market, including generators, distribution entities, large customers, and agents, brokers and marketers (ABMs) whose aggregate load is sufficiently great, should be provided with a settlement system that will track and deal with "physical bilateral contracts" at the wholesale level. The support for physical bilateral contracts for ABMs at the wholesale level does not constitute a commitment to provide any support for those contracts downstream from the wholesale level. Downstream support is covered by recommendation 4-10.

4-10 We recommend that all local distribution companies be required, at the customer's request, to send the customer's spot price bill to a designated licensed retailer, who would be responsible for paying the LDC for the amount of that bill. The retailer and consumer would then be responsible for settling their bilateral contract totally independent of the LDC.

4-11 We recommend that settlement systems not provide for tracking physical bilateral contracts at the retail level, except in those cases where the retailers and customers trading through physical bilateral contracts jointly pay all incremental costs associated with developing, implementing and operating the required settlement systems.

4-12 We recommend that local distribution companies be required to enter into good faith negotiations with retailers and customers at their request regarding the provision of settlement system modifications that can accommodate "physical bilateral contracts", provided that such negotiations do not lead to any arrangement whereby the incremental costs of those systems are paid for by the LDC or its customers who do not use those services. The OEB should be empowered to be the ultimate arbitrator of disputes between retailers and LDCs on these matters.

4-13 If downstream data processing and aggregation are requested and paid for by retailers, we recommend that the IMO establish data validation, reporting and timing standards for downstream data aggregation required to track physical bilateral contracts to retail customers, and that local distribution companies be responsible for implementing settlement systems which comply with those standards if required.

4-14 We recommend that the IMO set meter and data standards for wholesale market participants.

4-15 We recommend that the IMO may provide and charge for additional services to existing or new market participants beyond those required for the basic settlement system, provided that these arrangements do not increase the cost of the mandatory settlement services to other market participants, and that the provision of these services does not delay the introduction of competition.

4-16 We recommend that the market rules not require the installation of interval meters for customers who switch electricity supplier, nor for customers of any particular size. Local distribution companies retain the right to require interval metering for customer classes as they believe necessary to collect billing-determinant data for OEB-approved tariffs. However if interval metering is required for a particular class of customers connected to an LDC, it will be required of all customers in that class, whether they buy electricity from the LDC or from a competitive supplier. LDCs shall not require the installation of interval metering as a precondition for switching to a competitive supplier.

4-17 We recommend that if a customer switches to a competitive supplier without installing an interval meter, the load profile used to estimate the customer's load shape must be the same profile that would be used if the customer had not switched.

4-18 We recommend that the ownership, installation and maintenance of electricity meters, meter reading and data provision be opened to competitive supply for all customers above 50 kW demand coincident with the advent of retail electricity supply. However, if it is not possible to implement this recommendation by the time that retail competition would otherwise proceed, retail competition should not be delayed. No later than three years after the implementation of retail competition, the OEB should conduct a review to determine whether at that time small consumers would benefit from further unbundling of these activities.

4-19 We recommend that LDCs be required to supply to a customer and/or a competitive retailer at the customer's request relevant information about the existing meter and its installation and about the LDC's meter requirements for calculating bills and for planning the distribution system. The LDC must remove the existing meter or have it removed and returned by the competitive supplier. The LDC must accept for revenue calculation the data provided by the competitive supplier from an approved meter.

4-20 We recommend that customers who switch to a competitive meter supplier should receive a credit on their bill that reflects the cost avoided by the LDC as a result of the switch. We further recommend that the LDC calculate this avoided cost using a standard OEB-approved methodology designed to ensure that the costs of switching are not shifted to customers who choose not to switch, and assuming reasonable efforts by the LDC to mitigate these costs.

4-21 We recommend that the OEB, in conjunction with the review proposed in Recommendation 4-18, consider whether smaller consumers require some protection against the lock-in effect of metering contracts.

4-22 We recommend that LDCs be required to maintain a meter registration database of meter ownership and characteristics and meter number for all customers connected to their wires.

4-23 We recommend that when a customer chooses a competitive metering supplier, that supplier should be required to provide the LDC with timely access to the same type of information necessary for billing purposes and for distribution planning and operation as the LDC had prior to the customer's switch to the competitive supplier. Provision of any additional information is voluntary and subject to market pricing and access rules discussed below.

4-24 We recommend that the licence or accreditation of competitive meter suppliers require that their meters meet all applicable standards for functionality, installation, safety, calibration and accuracy. Rules should be established regarding the reasonable rights of LDCs and other stakeholders to have these meters tested for accuracy.

4-25 We recommend that rules establish that a competitive meter supplier bear liability for safety violations, installation problems, billing errors, damage to the distribution system and damage to customer property arising from faulty or improper installation.

4-26 We recommend that competitive meter data agents be subject to any existing federal standards and any new standards for data validation, estimation and editing and for the process for and timeliness of data provision to LDCs and other relevant parties.

4-27 We recommend that upon written request by a customer, the IMO, LDCs and competitive retailers or meter service providers must make available to the customer and to customer-designated competitive providers of electricity, metering services or other electricity-related services the following data: customer name, service and billing address and, if available, telephone number; 24 months of historical metered usage, demand data and any other billing determinants including read dates; the tariff designation under which the customer is served; the meter type; and credit information. The data should be provided in a common format to be approved by the OEB. These parties are under no obligation to provide any data other than those listed here.

N.B. This recommendation was subsequently changed during the fourth quarter as indicated below.

> **4-27** We recommend that upon written request by a customer, the IMO, and LDCs must make available to the customer and to customer-designated competitive providers of electricity, metering services or other electricity-related services the following data: customer name, service and billing address and, if available, telephone number; 24 months of historical metered usage, demand data and any other billing determinants including read dates; the tariff designation under which the customer is served; the meter type; and credit information. The data should be provided in a common format to be approved by the OEB. These parties are under no obligation to provide any data other than those listed here.

4-28 We recommend that no charge may be levied for the provision of data requested under recommendation 4-27 for the first two requests by a customer in any calendar year. LDCs and the IMO may levy a charge for additional requests, subject to approval by the OEB while competitive retailers may levy a charge which may be reviewed by the OEB and revised if it is found to be unreasonable.

4-29 We recommend that no customer data may be used for purposes not essential for the provision of services which the customer has requested unless the customer has signed a special section or paragraph of a contract which explains the customer's right to keep the data confidential and which nonetheless explicitly authorizes the LDC or retailer to use or sell these data for secondary purposes.

4-30 We recommend that LDCs be prohibited by the terms of their licence from providing preferential access to any and all customer-specific information to its competitive affiliate. Any information shared with a competitive affiliate must be made available on the same terms and conditions to non-affiliated competitors. Significant penalties should be imposed for violations of the resulting rules.

4-31 We recommend that rules and procedures for the sharing of current customer usage information be developed in accordance with the following principles: 1) LDCs, the IMO and retailers must continue to have access to the same information for billing purposes and for distribution and planning as they had before the customer switched to a competitive metering supplier; 2) common validation, estimation and editing procedures must be established and followed by all meter service providers; 3) common data formats, secure access and dissemination procedures must be established and followed by all meter service providers; 4) all contracts and tariffs must clearly indicate to customers the rights and obligations of meter data agents to provide access to usage information by other parties as necessary for billing.

4-32 We recommend that customers be giv en a right of unrestricted electronic access without charge to all metering data from the metering equipment at their own facilities.

Chapter Five – Environmental Protection

5-1 We endorse the amendment to the *Environmental Protection Act* (Ontario) proposed in Schedule D, Section 10 of the proposed *Energy Competition Act, 1998* and recommend that it be enacted as written. We recommend that the Ministry of the Environment set caps for the relevant electricity-related air pollutants at levels that are consistent with the mandate of the White Paper, with due regard for seasonal environmental impacts and local impingement issues. These caps should take effect at the same time that the competitive electricity market is established in the year 2000. All sources subject to the emission limits should be allowed to trade credits among themselves, and to vary their individual emissions as long as the aggregate emissions level remains within the emissions cap.

5-2 We recommend that in designing the allocation and trading mechanism for emissions allowances, the Ministry of the Environment consider the problem of market power by a dominant generator in order to ensure that the cap and trade program does not create artificial barriers to entry in electricity generation in Ontario.

5-3 We recommend that the Ministry of the Environment develop regulations and/or legislation to ensure, to the extent practical, that imports of electricity into Ontario do not increase pollutant emissions beyond those levels that would have occurred if the electricity had been generated in Ontario.

5-4 We recommend that the wholesale market design provide for demand-side bidding by licensed wholesale market participants. This should allow large consumers and demand aggregators to modify their demand during peak periods and thereby reduce the need to build additional generation and transmission capacity.

5-5 We recommend that the Ontario government augment the Ministry of Energy, Science and Technology's efforts to encourage consumer energy efficiency through the distribution of information on energy conservation benefits and product efficiency standards. The Ministry should also exercise its authority to pursue energy efficiency programs beyond information and education programs, emphasizing cost-effective demand-side investments for consumers who are not targeted by private DSM providers. These programs should be funded at an appropriate level given the decline in funding by Ontario Hydro. As these programs have social benefits for all citizens, it is appropriate to fund these programs using public monies.

5-6 We recommend that the market rules allow green power to be advertised and marketed to interested customers, subject to recommendation 5-7 below. We embrace the EcoLogo definition of green power embodied in the "alternative source electricity generation" as a starting point for the single definition of green power, subject to any amendments that may be made before December 31, 1999. As the definition is updated through a broad consultative process, the controlling definition of green power also should be updated by the OEB no more than once a year to reflect the new definition and other considerations.

5-7 We recommend that once the operation of the competitive market begins, no retailer may advertise or differentiate its product as generated by green power until a mechanism has been put in place to verify green power claims and ensure that no significant fraud can occur. To this end, we recommend that the Ministry of Energy, Science and Technology establish a task force to develop solutions to the problem of verifying green power sales. The task force should include representatives of the Central Market Operator (CMO), MEUs familiar with settlement systems, environmental groups, consumers and energy generators and retailers. The mandate of the task force should be to devise a workable solution that would ensure verification of green power marketing in the year 2000. Once the task force produces a solution that ensures no significant fraud can occur, the OEB should require qualifying retail suppliers to follow the approved verification procedure as a condition of their licence.

5-8 We recommend that the Ministry of Energy, Science and Technology and the Ministry of the Environment jointly develop rules to be submitted to the Lieutenant Governor in Council for the purposes of Section 87(1)(f) the proposed *Ontario Energy Board Act, 1998*. These rules should require all sellers of electricity to prepare a standard label that must appear in all advertisements for electricity and other means of customer communication, disclosing the mix of energy sources used by that seller and associated pollution emissions. These rules should be developed through a stakeholder process involving environmental group representatives, generators, retailers and consumer representatives. The design of the label should consider informational needs of the consumer and labelling requirements in surrounding jurisdictions.

5-9 We recommend that the Ministry of Energy, Science and Technology and the Ministry of the Environment jointly and in consultation with the OEB develop an audit mechanism to verify the accuracy of information in disclosure labels, to be operational at the start of retail competition in the year 2000. Until a verification mechanism exists for the contents of the labels and associated marketing claims, we recommend that a single label reflecting the general mix of generation in the power pool be used by every retailer that sells electricity to customers.

5-10 We recommend that the OEB, the Ministry of the Environment and the Ministry of Municipal Affairs and Housing examine the current procedures for environmental, planning and other approvals and amend those procedures so that the approval process depends on the size and type of project and its potential environmental impacts rather than on its corporate form or ownership.

5-11 We recommend that regulators pursue additional mechanisms for streamlining the environmental approval process; these procedures should be both effective and efficient, and impose costs and delays that are no greater than necessary to meet reasonable environmental objectives. In particular, we recommend that regulators allow and encourage the use of joint hearings in the approval process when multiple laws or regulations are at issue and the use of class environmental assessment as two measures to streamline the process.

5-12 We recommend that the Ministry of Energy, Science and Technology consider the issue o f nuclear plant retirement and waste disposal, and that the OEB require that the owners of the nuclear power plants, as a condition of license, establish a funding mechanism to accumulate and set aside monies in a segregated fund in order to provide for the safe disposal of nuclear waste and decommissioning of nuclear plants.

Chapter Six – IMO Development

6-1 We recommend that the following facilities and systems be included within the scope of the IMO:

An Energy Management System and Market Interface System to perform traditional power system monitoring and control functions, and to perform functions related to operations planning, scheduling, utilization monitoring and IMO contract management.

A Bidding System to receive and process bids and bilateral schedule nominations, and to provide essential bidding information.

Metering Infrastructure to perform wholesale meter data acquisition and processing. The CMO will provide standards related to meters, communications, and other requirements, for wholesale meter data acquisition and processing.

A Settlement System to perform settlement, data management and market administration functions.

Communications Facilities including 1) a Participant Network to enable communications between market participants and the IMO, and 2) an IMO Network to enable communications between the Clarkson Control Center and other IMO sites and interconnected systems.

A Backup Operations Center to provide a high level of reliability for IMO systems related to operation of the electricity system, market operation, and settlements.

6-2 We recommend that provision of market participant facilities to connect to the communication network, the installation of interval meters where required by the market rules, and of facilities for retail meter data acquisition and processing, where applicable, should be carried out by market participants in accordance with IMO standards, and should be a condition of market participation.

6-3 We recommend that the design limit for the number of market participants who will interact with the IMO and require its settlement services be 5000.

6-4 We recommend a balanced approach to IMO implementation, which will provide a sound platform for the evolution of the market after the year 2000, but will not implement specific capability to deal with future potential market changes unless they are flagged in the market rules. IMO processes and systems should possess a high degree of reliability, consistent with their meeting the ambitious year 2000 market commencement date and being delivered within budget. The CMO should exercise prudent judgement in applying this implementation philosophy to specific commercial decisions. We further recommend that, in the development of IMO processes and systems: maximum use should be made of existing CMO facilities and systems; commercially-available systems should be utilized whenever feasible; and, software customization should be minimized.

6-5 We recommend that the development of market in-sensitive IMO processes and sys tems by the CMO should commence as soon as possible.

6-6 We recommend that an IMO user's group be created by the CMO to serve as a mechanism for the provision of stakeholder input to IMO development, and that for the duration of the MDC's mandate the activities of this group be subject to review by and coordinated with the activities of the MDC.

Third Interim Report

List of Recommendations

Chapter One – Market Power

1-1 For a period of four years after the opening of the market, 90% of OEGC's expected domestic energy sales will be subject to a price cap of 3.8 cents/kWh on average. This OEGC price cap (which excludes any CTC) will facilitate Ontario customers experiencing immediate and demonstrable benefits from electricity restructuring, and provide for a relatively stable average price for electricity in the province. This price cap and other electricity costs should be structured so that the blended or "all in" price of electricity (energy price, CTC, transmission and distribution tariffs, and IMO charge) would not exceed the current retail price, which averages 7.2 cents/kWh. The OEGC price cap may be subject to further change as a result of the Minister of Finance's industry financial restructuring efforts and electric power market conditions prevailing at the time of OEGC's capitalization.

1-2 Under the price cap regime, OEGC will provide a rebate to customers when market prices would otherwise result in OEGC receiving an average price greater than 3.8 c/kWh in respect of the defined quantity of energy. OEGC would be entitled to keep all revenues from the sale of energy it produces in excess of the defined quantity. Details of the price cap regime, such as caps and weights, would be public information. The form and operation of this regime are described below.

1-3 By the end of 42 months after the market opens, OEGC will be required to have transferred to others effective control over enough in-service tier 2 capacity that OEGC's effective control of total Ontario in-service tier 2 capacity at that time will be 35% or less. Effective control over a minimum of 4000 MW of in-service capacity must be transferred. At OEGC's discretion, up to 1000 MW of hydroelectric generation could be substituted for tier 2 capacity

1-4 There will be no restrictions on OEGC's ability to export power. During the four-year period over which the price cap is in force, OEGC will be prohibited from purchasing in-bound transmission rights or importing electricity into Ontario, where such rights or imports exceed 35% of the available incoming inter-tie capability. To the extent that OEGC enters into firm long-term imports, they will be included as part of OEGC's in-service tier 2 capacity.

1-5 OESC will be expected to undertake best efforts to expand inter-tie capacity wit h neighbouring jurisdictions by approximately 2000 MW within three years of market opening.

1-6 As part of this initial arrangement, OEGC commits to developing a strategy for reducing effective control of enough of its capacity (tier 1 and tier 2) so that by no later than the end of the tenth year after the market opens, OEGC's effective control of the total of tier 1 and tier 2 capacity at that time will be 35% or less, at which time the price cap regime will terminate.

1-7 In order to promote a more c ompetitive market structure, by the end of 42 months after the market opens, as part of the program to transfer effective control over some tier 2 capacity, OEGC will undertake not to transfer such control to any entity that will consequently control more than approximately a 25 % market share of the total Ontario tier 2 capacity. Similarly, within the first ten years after the market opens, and as part of the program to transfer effective control over capacity, OEGC will undertake not to transfer such control to any entity that will consequently control more than approximately a 25% market share of the total of Ontario's tier 1 and tier 2 capacity at that time. Furthermore, these transfers of control will not include any on-going arrangements that could facilitate interdependent behaviour. Transfers that do not meet these two conditions shall not count towards achieving the 35% objectives listed in paragraphs 3 and 6. OEGC may request the Province of Ontario to direct the OEB to determine whether a particular transfer meets these conditions. An OEB review and determination should not exceed three months.

Supplementary MDC Recommendations

1-8 With respect to decontrol actions, the MDC notes its strong preference for sales and long-term leases because they transfer ownership or operating and price setting control.

1-9 In order to enhance the credibility of the commitments in this agreement, the MDC recommends that the Government, as part of these ex ante market power mitigation measures, commit itself before the end of 1998 to directing the OEB to initiate, 42 months after the market opens, a review of whether OEGC has met its 42-month target to reduce its share of tier 2 capacity to 35%. As part of their review, OEGC must provide a plan for achieving the 10-year target, including identifying intermediate milestones. To the extent that OEGC has not met the 42- month target, the OEB would be expected to consider a wide range of mechanisms for achieving a stable structural solution to market power through to year ten, including recommending to the Minister additional decontrol of OEGC assets. If the 42-month target has been met, the OEB should evaluate the appropriateness and form of on-going price control over OEGC's tier 1 generation for years five to ten, not altering the long-term objective, and should make recommendations to Government thereon.

1-10 The MDC recommends that the Government commit itself now to directing the OEB to initiate, 7 years after the market opens, a review of OEGC's progress towards the milestones it identified as part of the 42-month review.

1-11 The MDC recommends that the Government commit itself now to directing the OEB to initiate, 3 years after the opening of the Ontario electricity market, a separate review of whether OESC has made best efforts to expand inter-tie capacity with neighbouring jurisdictions.

1-12 The MDC recommends that the Government institute appropriate non-statutory means for effectuating these recommendations.

1-13 In order to promote a more compet itive market structure, the MDC recommends that the existing NUG contracts not be administered by OEGC.

1-14 The MDC recommends that OEGC file annual reports in the five-year period after the initial four-year review (i.e. years five through nine) with the Energy Returns Officer of the OEB on progress towards the ten-year decontrol target. These reports will indicate the specific actions that OEGC took in the previous year and plans for the upcoming year to progress to the ten-year target.

Chapter Two – Transmission and Distribution

2-1 A non-fixed, usage-based transmission charge should apply for the immediate future to recover the sunk, maintenance and refurbishment costs of the existing common grid asset costs. This charge will allocate the annual revenue requirements for common grid assets between distributors and direct customers based on a measure (or measures, if a multiple part tariff is adopted) of actual usage. We will assign to the technical panel the task of examining ways in which "actual usage" could be defined and the periods over which it could be tracked.

2-2 To the extent practical, with respect to incremental embedded generation, customer transmission charges should be determined on a gross-load basis, so as to mitigate the potential for uneconomic bypass without discouraging efficient bypass. Other mitigation mechanisms such as stand-by or back-up charges, exit fees and regulatory oversight should be examined as fall-back solutions in the event that the gross charging approach proves impractical.

2-3 For the initial period, new investment in the common transmission grid should be centrally planned with a major analytical and assessment role for the IMO and oversight from the OEB.

2-4 For the initial period, the costs of new invest ments should be rolled into the uniform transmission charge, except to the extent that the OEB determines that specific beneficiaries should be charged a greater share of the incremental cost.

2-5 In the longer term, we recommend a move to a more entrepre neurial approach to transmission Investment after the market adopts locational pricing.

2-6 Grid users who currently pay a charge for connection assets will continue to pay those charges. The cost of all remaining connection assets, except for transformer facilities, that exist or are committed at this time should be rolled into the revenue requirements of the existing common transmission grid. New connection assets should be funded by the connecting party(ies).

2-7 A uniform transmission pricing regime with centralized investment coordination should be implemented for the short-term so as to avoid the problems associated with implementing a new and fundamentally different transmission pricing regime in the limited time frame available before market commencement. Any changes to the regime in the future should be implemented in an economically sound manner that recognizes the transition and practical considerations and acknowledges the regulatory environment.

2-8 While we recommend no specific timetable, OEB should revisit transmission pricing issues following the commencement of congestion pricing at the wholesale level. At a minimum, the following broad principles should be used to guide the eventual development of a market-based transmission pricing regime:

- congestion pricing should be used in the wholesale energy market to provide efficient price signals;
- to the extent practical, investments in transmission should be entrepreneurial, that is, driven by market participants responding to efficient prices, with those benefiting from new investments paying for those investments;
- to the extent practicable, the recovery of the sunk costs of the existing network should not vary with usage;
- tariffs should be designed to avoid promoting inappropriate incentives for inefficient embedded generation without creating unnecessary barriers to economic embedded generation.

2-9 The following illustrative principles should be considered by OEB when it revisits transmission pricing issues after the commencement of congestion pricing.

1. The sunk costs of the existing common grid, as well as ongoing maintenance costs to retain its current capability, would be paid solely by existing loads, defined as of the date this new regime commenced, who would pay a uniform charge to recover these costs. Cost allocation would be determined based on some measure of historic usage and would remain fixed, based on that historic level. The existing common grid base might be assumed to "wither" at some rate to reflect the gradual displacement of the original "existing" grid with new grid enhancements and upgrades. This would gradually (over, say, 30 years) move the pricing from the common grid regime to the pricing regime for "new investments."

2. Since these principles would be applied at some date in the future, the definition of the "common grid" would be taken from that date; it might therefore include today's existing connection and interconnection assets that had been treated and paid for as

part of the common grid.

3. New users (or new uses by existing users beyond their historic levels) would not be assessed any of the sunk/maintenance costs of the existing common grid, except to the extent they agreed to share those costs in exchange for receiving a share of the financial transmission rights used to hedge the effects of congestion. Hence, these users' rates/charges would, in relation to use beyond their historic levels, be different from existing users. This principle assumes the existing common grid could accommodate the new uses. If not, new investments would be required, and the principles applicable to new investments would apply.

4. New transmission investments for upgrades and expansions to the grid would be proposed and paid for by potential beneficiaries. Beneficiaries might be a few grid users, many grid users, or in some cases, all grid users.

5. The process for defining the need for, and allocating the cost of, new grid investments would be largely market driven by market participants responding to market prices and likely to benefit from the investments. Potential free riders would be encouraged to participate in such negotiations and eventually required to share in the expansion costs by various means, including the use of a regulator (IMO/OEB) as a referee/arbitrator. This principle assumes that some form of congestion pricing would be in effect, and that financial transmission rights would be allocated to those agreeing to pay the costs of grid expansions in order to shield them from future congestion charges resulting from increased grid use by other parties.

6. New connection lines and facilities would be paid for by those specific users – whether generators or loads – who use them to connect to the common grid. Subsequently, potential new users of these newly built connection facilities could negotiate with those paying the facilities' costs to obtain use in exchange for an agreement to share the costs.

7. Given a system of congestion pricing and financial transmission rights, transmission utilities would be expected to maintain the capability of the grid against excessive or unreasonable outages that might cause high congestion charges and/or prevent the IMO from funding the hedges. To encourage transmission utilities to properly maintain the capability of their systems, transmission utilities could be required by contract to back the funding of such hedges whenever excessive or non-force majeure outages resulted in an underfunding.

2-10 Distributors should pass transmission charges through to end-use customers in a manner which, to the extent possible, does not interfere with competition and efficiency in the wholesale energy market.

Chapter Three – Retail Competition

3-1 We confirm Recommendation 4-3 from the *Second Interim Report* that the local distribution companies that are required to provide or arrange default supply to all customers who have not elected an alternative supplier do so based on a "smoothed" pass-through of the wholesale market spot price. We also reiterate Recommendation 4-4 from the *Second Interim Report* that all local distribution companies be required to offer to all customers the option of buying energy at the wholesale market hourly spot price. Both options should include a regulated recovery of administrative costs.

3-2 We recommend that the OEB proceed to develop the details of default supply based on a smoothed spot price pass-through as soon as possible, so that LDCs can begin preparations for administering this service at the start of retail competition in the year 2000. The smoothing methodology and time period should be the same for all LDCs in the province.

Final Report

List of Recommendations

Chapter Three – Wholesale Market Design

3-1 We recommend that the market rules place spot and bilateral participants in the IMO-administered markets on an equal footing by requiring all to indicate in their submissions the prices at which they would be prepared to offer more or less energy to the IMO (or consume more or less energy, for dispatchable loads.) Bilateral generator offers should cover the full scheduled amounts, while dispatchable load bids may cover any amount they choose. Bilateral generators and loads should be allowed to define different price/quantity pairs for their respective offers and bids, to provide these participants the same flexibility as participants using spot transactions.

3-2 We recommend that the IMO use the price/quantity offers and bids associated with intertie transactions (including those submitted by external participants seeking to buy from or sell to the IMO-coordinated market), to determine which transactions get access to the interties and to allocate access during constrained conditions to those who place the highest value on use of the interties. We recommend that the IMO use these offer/bid prices to determine prices to apply at each location or "zone" in the interconnected areas outside Ontario in settlements for the intertie transactions. Thus, the uniform pricing approach will apply to prices *inside* Ontario, but different prices may apply *outside* Ontario to reflect the effects of constraints.

3-3 We recommend that the IMO determine the uniform price to be used internally for settlements based on the "unconstrained dispatch" approach. This approach will ignore internal transmission constraints. However, we recommend that the uniform price determination explicitly consider the capacity and security constraints of the interties.

3-4 We recommend that the Market Rules give market participants unlimited flexibility to revise bid and offer quantities and prices up to four hours in advance of each dispatch hour and give limited flexibility (e.g., within 10 per cent, or greater with IMO approval) to make revisions up to two hours in advance. We recommend that the IMO provide some flexibility to accommodate additional changes closer to the dispatch hour, consistent with its system security requirements and its ability to handle last-hour changes. Once the market begins, we recommend the IMO endeavor to further reduce these initial timing restrictions as it gains experience with handling revisions and performing security assessments.

3-5 We recommend that the market pricing rules include automatic formulae that would produce higher prices as soon as the IMO's operating reserves fell below required levels, and increasingly higher prices as the operating reserves neared exhaustion. We recommend that this pricing mechanism be used to complement, and perhaps obviate the need for, the reserve capacity market, which the IMO could trigger if the Board determined that available options were unlikely to relieve a predicted capacity shortage.

3-6 We recommend that the market rules distinguish between market participant data required by the IMO to conduct its dispatch and data required by the IMO to perform settlements. We further recommend that, given this distinction, the rules provide greater timing and other flexibility to market participants in submitting data about their physical bilateral contracts. We also recommend that the rules use this distinction so that the settlement system can allow multiple physical bilateral contracts for each generator or load and allow the IMO to settle bilateral arrangements smaller than the threshold size that may apply to participation in the dispatch.

3-7 We recommend that the Market Rules use the distinction between dispatch and settlement data to give increased flexibility to small generators (or dispatchable loads), such that a size threshold of 1 MW may apply to participation in the dispatch, but much smaller entities and transactions can be accommodated in the settlement system. We recommend that small plants be allowed to participate as "must take" generation and be entitled to receive the spot price for their output and, if they engage in bilateral arrangements, to have their credits netted against their bilateral load debits in the same manner as larger bilateral participants.

3-8 We recommend that the settlement period use the IMO preliminary statements, rather than wait for final statements, as a means to expedite the issuance of bills and to provide a payments schedule that is reasonably consistent with those used today by Ontario Hydro.

3-9 We recommend that the IMO arrange for any and all exemptions that may be require d from Measurement Canada to allow use of existing non-complying meters in the new markets.

Chapter Four – Transmission and Distribution

4-1 We recommend that the assets comprising the IMO-controlled grid be based on the 50 kV level referred to by the *Electricity Act, 1998*, and subject to any exemptions made under regulations pursuant to the Act. We further recommend, however, that the IMO be allowed over the next year to identify specific exceptions to ensure that all lines and facilities that are essential to Ontario regional security and reliability, or critical for wholesale market operations, be included within the IMO's control, either directly or through appropriate operating agreements with the facility owners. Subject to the exemptions pursuant to regulations made under the Act, LDC procedures should also ensure that embedded generators and loads have open, non-discriminatory access to the IMO-co- ordinated markets and that LDCs inform the IMO of any distribution conditions that might affect system reliability or market operations.

4-2 We recommend that the current cost recovery method be continued for those low voltage existing facilities that function as transmission, but that regulations allow affected LDCs to be exempted from a dual licensing requirement solely on that account. However, we also recommend that in the future, all the costs of new transmission connection facilities be allocated on the principle of "user pays".

4-3 We also recommend the following technical boundaries between the transmission system and other facilities:

- The boundary between distribution and transmission facilities should generally follow the existing Ontario Hydro criteria, including the voltage criterion in the *Electricity Act, 1998,* and be at the load side of the feeder circuit breakers. However, exceptions should be allowed with distribution licences permitting distributors to own some facilities that might otherwise be classified as transmission facilities, but without requiring the affected LDCs to obtain a transmission license solely for that reason.

- The boundary between network transmission facilities and connection facilities should be as described in our *Third Interim Report*.

4-4 We recommend that existing transmission connection arrangements be grandfathered. We recommend that new connections which, in the IMO's judgement, do not require any network upgrades, be initiated by a market participant's application to the transmission company, which will analyze the requirements and then enter into an appropriate connection agreement. Any such agreements must comply with the connection standards set forth in the Ontario Grid Connection Code. We recommend, and the Market Rules assume, that the IMO be the administrator of the Ontario Grid Connection Code. The transmitter will certify to the IMO that the connections comply with the Code. The IMO will review all connection agreements with respect to technical and reliability aspects and oversee periodic testing of connected equipment.

4-5 We recommend the IMO e stablish procedures under which it may waive compliance with the provisions of the Ontario Grid Connection Code (OGC) for existing facilities, subject to the conditions recommended by the Panel. However, in order to preserve fairness between new and existing market participants, we recommend that in those cases where the IMO initially agrees to waive an OGC standard, there must be public notification that a waiver will apply. In cases of dispute, we recommend that any complainant (who must be a market participant) be able to use the IMO's dispute resolution process to obtain a ruling on the fairness of the proposed waiver.

4-6 Consistent with the wholesale market rules, we recommend that the IMO offer four types of transmission service:

- *Basic Use Service* – Basic Use Service includes every use of the Ontario IMO-controlled grid to provide transmission to internal Ontario customers, irrespective of the source of the power. Basic Use Service thus covers the use of the IMO-controlled grid to deliver power to all customers located in Ontario (except customers exempted through regulations), whether the power is imported from outside the province or generated within the province. Because this service provides electricity to all non-exempt Ontario customers, they will have access to, and must help pay the costs of, Basic Use Service.

- *Export Service* – Export service applies to transactions in which the power is destined for customers located outside Ontario, irrespective of whether the power originates within the province or outside it ("wheeling through" transactions). Generators who use the IMO-controlled grid and its interconnections with neighboring regions to export power to customers outside Ontario will not pay the fixed costs of these facilities, but they will pay any incremental costs that their transactions impose.

- *Connection Service* – Connection service applies to Ontario customers who are directly connected to the IMO-controlled grid by transmission line facilities which they have not paid for. Current arrangements under which the costs of existing connections are recovered from all existing loads which would be grandfathered. New load and new generators would acquire new connection service, and the new load and new generators would pay for the new connections, but not for existing connections.

- *Transformation Service* – This service will be offered to and paid by those Ontario transmission customers who do not own their own transformation facilities.

4-7 We recommend that Basic Use Service be charge d at a uniform rate and that it be provided automatically to LDCs and directly connected customers. All Ontario customers connected at the distribution level will therefore have access to the IMO-controlled grid through their host LDC's access to Basic Use Service. Further, we recommend that LDCs that are embedded in the distribution networks of other LDCs be given the choice of purchasing Basic Use Service directly from the IMO or indirectly through the tariffs of those LDCs, subject to any exemptions made by regulations. All Ontario customers would therefore pay for Basic Use Service, either directly or indirectly, and such payments would recover the transmission owners' revenue requirements, as determined by the OEB. In effect, payments for Basic Use Service would cover the transmission portion of the Ontario "delivery" costs for energy and ancillary services provided to customers located in Ontario. Market participants would be able to use Basic Use Service equally for spot and bilateral transactions.

4-8 Consistent with the legislation, we recommend that the rates for Basic Use Service be set by the OEB, on application from transmission providers, such that revenue requirements are met within a general performance-based regulatory regime. The rates should be set to cover the rolled-in costs of all network transmission (common grid) facilities owned by that provider and charged based on peak monthly usage. We recommend further that the rates be uniform across the province and that they be charged only to loads, not to generators (except that , generators should be metered and pay for any net energy usage). We also recommend that, except for already committed on-site or embedded generators with existing agreements, distributors and direct customers be charged on a gross load basis.

4-9 We recommend that for the purpose of computing the charge for Basic Use Service, the energy produced by new embedded generators or new on-site generators associated with direct connection customers should be added back for purposes of calculating the usage of the customer or LDC through which the customer is served. To determine what connections are "new," we propose that projects committed prior to October 30, 1998 and subject to existing agreements be grandfathered. This cut-off date is the effective date of the *Electricity Act, 1998*.

4-10 We recommend that transactions to serve external loads should not have to pay any of the fixed costs of the IMO-controlled grid, but that they should be required to pay for a pro-rata share of the losses and any congestion costs they impose on the Ontario system, plus a pro-rata share of the IMO's "uplift" – that is, all otherwise unallocated costs of administering the markets (such as charges to recover the costs of certain ancillary services).

4-11 We recommend that Ontario allocate use of the IMO-controlled interties based on the bids and offers submitted by market participants. We further recommend that the IMO use these bid and offer prices to determine external "zone" prices that may be different from the internal Ontario uniform price. The IMO should use these determined prices as the basis for settling the transactions involving the interties.

4-12 We recommend that the congestion rentals collected from the intertie pricing approach be used by the IMO to support a system of "financial" rights or hedges that would be allocated, through IMO auctions, to market participants as a means to hedge the price uncertainties associated with congestion-related price differences on IMO-controlled interties. Net auction revenues should be used to offset revenue requirements for Basic Use Service. The amounts by which the settlement surplus from intertie transactions exceed or are less than the payment obligations of the allocated rights for any settlement period should be managed through an uplift account. The IMO should give high priority to completing the auction rules and defining auction modeling assumptions.

4-13 We recommend that Ontario use a transmission planning process based on the recommendations prepared by our Transmission and Distribution Technical Panel (and summarized in this Chapter). This process will rely on the IMO's long-term security and adequacy assessments for evaluating the need for new transmission investments and encourage market participants to come forward with transmission investment proposals that address any long-run security and adequacy concerns identified by the IMO. We further recommend that the IMO advise the OEB and be able to participate in any proceedings initiated by the OEB or by market participants to consider the merits of transmission investment proposals.

4-14 We recommend that the IMO and OHSCI complete the development of their agreement and continue current negotiations to ensure completion well before the market operations begin and consistency with the *Electricity Act, 1998* and our Market Rules.

Chapter Six – Retail Competition

The MDC approved the following resolution:

The MDC acknowledges that subsection 70(9) of the *Ontario Energy Board Act* contemplates that a distributor, subject to the OEB=s licensing requirements, may comply with its obligation to supply electricity under section 29 of the *Electricity Act, 1998* either: a) directly, b) through an affiliate, c) through another person with whom the distributor or affiliate of the distributor has a contract, or d) through a combination of the methods described in a), b) or c) above. Before the OEB accepts the proposal of a distributor to comply with its obligations under section 29 through either b) or c) involving a competitive affiliate or retailer that also provides competitive electricity services, we recommend that the OEB impose codes or standards of conduct and other terms and conditions on the competitive affiliate or retailer, so as to ensure conformance with the principles recommended in Chapter 4 of our *Second Interim Report.* In particular the OEB must be satisfied that the code of conduct will ensure that there will be no cross-subsidy of competitive activities by the default supply activities, that there will be no preferential access to customer data including the customer list by any person within the competitive portion of the entity providing the default supply, and that the default customers remain effectively contestable if and when they make their names available for solicitation.

Chapter Seven – Environmental Protection

7-1 We recommend that the Ministry of Energy, Science and Technology and the Ministry of the Environment jointly establish an environmental panel including environmental, consumer, retailer and generation representatives to provide advice that would facilitate effective and expeditious implementation of the environmental recommendations in our *Second Interim Report* and to provide advice regarding further steps to protect the environment upon the establishment of competition in electricity generation and retailing.

Chapter Eight – Transition

8-1 The Minister of Energy, Science and Technology should continue to issue periodic progress reports on the restructuring to the public during the transition period, identifying key milestones and providing assurance that the process is on track.

8-2 The Electricity Transition Committee should expand its membership to augment and broaden the range of interests represented. We recommend that the Electricity Transition Committee should continue to provide stakeholder feedback to the Minister.

8-3 The Ministry of Energy, Science and Technology should ensure that it continues to have effective liaison with stakeholders, including among others, investor owned utilities, marketers, representatives of residential and small commercial users, and other ministries, to assist in the coordination of the implementation and transition processes.

8-4 The IMO and OEB stakeholder consultation processes should seek a wide representation, be alert to broad concerns that may be expressed, and not limit themselves only to narrowly focussed technical issues.

8-5 We recommend that the Minister direct the IMO Board to i mplement the MDC's recommended rules, and to undertake the remaining wholesale market rule development, amendment activities and the technical issues that may arise from these actions. In addition, EST should deal expeditiously with developing regulations and necessary refinements in legislation that will be required because of policy considerations during the transition period and thereafter.

8-6 We recommend that rules and rule amendments referenced in Recommendation 8-5 should be submitted by the IMO Board to the Minister for approval prior to these rules becoming operational and enforceable.

8-7 During the transition period, all proposed new rules and rule amendments should be reviewed and discussed both by the IMO Board and its Technical Panel, as constituted under the Governance and Structure By-law. An expedited process for recommending amendments to the wholesale market rules should be implemented during the transition period.

8-8 During the transition period, any proposed changes to the recommen dations contained in the MDC's reports should require stakeholder consultation and approval, with rationale, by the IMO Board.

8-9 The Government, specifically the Ministry of Energy, Science and Technology, in its assessment of the need for pilot projects should ensure that the following principles are incorporated into the project design:

- Pilot projects must have clear, achievable objectives;
- Projects must not give any group of market participants an advantage over others prior to market opening;
- All information gathered through pilot projects must be shared and to the benefit of the market overall;
- Any projects should be undertaken over a reasonable time period within which to gain meaningful information;
- The costs of pilots must be borne by the participants; and,
- The introduction of pilots must not delay the implementation of the market.

8-10 The IMO and the OEB should be given the responsibility of determining when market systems, institutions and market participants are prepared to fulfill their respective roles. The IMO and the OEB should inform the Minister of Energy, Science and Technology, who has the responsibility for declaring the market open, when they are satisfied that the market can operate efficiently and effectively.

8-11 The OEB should monitor pre-market activity to ensure that the provisions of the market power mitigation agreement are not impaired by the actions of any prospective market participants prior to market opening.

8-12 During the transition period, the Ministry of Energy, Science and Technology should implement a comprehensive education program that gives consumers factual information about the reforms being instituted. This information should be communicated directly to consumers through a variety of means and use a phased approach with general information followed by more detail as the market design develops. We recommend that no retailer be permitted to execute a contract for the supply of electricity with any residential consumer prior to a date fixed by the Minister and following completion of the educational program. We recommend that the Ministry announce this date in advance, so that retailers can prepare for it.

8-13 The Minister should request the OEB to assume general oversight of the electricity sector during the transition period to prevent any non-competitive practices and market power exploitation prior to market opening.

8-14 As a specific condition of the licenses that it issues to retailers, brokers and marketers, the OEB should consider limiting the length of contracts for the supply of electricity that retailers may execute with residential consumers to one year (365 days). This limitation would apply only to contracts executed prior to the first anniversary of the date that the market opens.

APPENDIX B

GLOSSARY OF TERMS

Glossary of Terms

This glossary has been prepared solely for the convenience and assistance of readers by providing a narrative, non-technical description of some of the terms used in the various chapters of this Report. The draft market rules attached to this Report contain a chapter devoted exclusively to defining the terms used in the market rules and the provisions of this glossary have no application to the market rules.

AECB

The Atomic Energy Control Board of Canada.

AC Power

Alternating current power: electric power associated with (provided by) electricity whose current reverses direction, or alternates, at regularly recurring intervals. The frequency of most of the electricity produced in Ontario is 60 cycles per second or 60 Hertz.

Aggregator, Broker, Marketer (ABM)

A profit-motivated entity that acts as an intermediary in arranging transactions between, or on behalf of, generators and customers. It may assemble load or generation into larger blocks (aggregator), act as a negotiator between buyers and sellers (broker), or buy, sell and take physical positions in the marketplace (marketer).

Ancillary Services (Interconnected Operation Services - IOS)

Ancillary services, or IOS, are functions required to support the reliable operation of the integrated transmission and generation system. They are provided by generators, loads and transmission equipment, and are coordinated and controlled by the System Operator (the CMO or IMO in Ontario) as part of system operations. Ancillary services include various types of operating reserves, regulation (frequency control), voltage control, black-start capability, load following, energy imbalance services and more. The system operator uses ancillary services to meet several essential reliability objectives:

- *Continuous balancing of generation and demand*
- *Constant frequency and voltage control*
- *Transmission system security*
- *Response to unexpected outages and other contingencies, including emergency conditions*
- *Management and integration of the above.*

Arbitrage

A transaction undertaken to profit from a difference between the prices at which a security, currency or commodity is traded in two or more markets. Typically an arbitrageur would sell in the more expensive market and buy in the less expensive market. The net profit will depend on the cost of the transaction including bid-ask spreads, commissions, delivery and other charges.

Arbitrage, by exploiting price differences, tends to eliminate them. The elimination of artificial differences in the price of an asset between markets is a sign of market efficiency.

Asset Swap

In the context of this Report, an arrangement whereby a generation owner would exchange one or more of its plants for plant(s) owned by an entity in some other geographic region. Asset swaps have been discussed as a means by which a dominant generator within a geographic market, such as Ontario Hydro, could reduce its market share in its local market.

Auctionable Bidding Contract

A contract auctioned by a generator to other market participants that allows them to bid the generator's output into the market. Bidding contracts have been considered as a means of mitigating market power, by providing other market participants the right to set the prices at which the generator's output would be offered to the market.

Available Transfer Capability (ATC)

A measure of the remaining physical capability in a transmission network for commercial activity, over and above that already committed to users. Already committed uses would include commitments for both system reliability and commercial transactions.

Backup Supply Service

The provision of capacity and energy to a market participant, either when needed to replace the loss of its generation sources, or to cover that portion of demand that exceeds the generator's capacity to supply for more than a short time. In the proposed market, this service would be provided automatically by the IMO's dispatch and ancillary services.

Baseload Capacity

The category of generating capacity that, primarily due to its low operating costs, tends to operate continuously and steadily. Its output is generally not varied to follow changes in demand. In the Ontario system, nuclear units are generally operated as baseload.

Black Start

This service involves the provision of generating equipment that can be started without an outside electrical supply. Black start capability allows a defined portion of the transmission system to be energised following a system blackout, so that it can then be synchronised to the rest of the IMO-controlled grid system in the process of restoring transmission system operation.

Board of Directors

A group of individuals appointed or elected, usually at an annual meeting, by the shareholders of a corporation and empowered to carry out certain tasks as spelled out in the corporation's charter and by-laws.

Bus

An electrical connection point between different parts of the interconnected system such as the connection between a generating facility and the transmission grid in a power station switchyard. Also referred to as a "node."

CMO

The Central Market Operator, the entity that today is the System Operator for Ontario's transmission and generation system. Once the restructuring of Ontario Hydro is completed, the CMO will become the Independent Electricity Market Operator (IMO).

CANDU

Canadian Deuterium Uranium Reactor. A standardized design developed in Canada for a nuclear generating station. All nuclear generating units in Ontario use the CANDU design.

Capacity

The maximum power that a generating unit, generation station, or other electrical apparatus can supply, usually expressed in megawatts.

Capacity Reserve Market

An hourly market in which the IMO purchases generating capacity additional to that required to meet demand and operating reserve requirements in a given future hour.

Congestion

The condition under which the transactions that market participants wish to implement exceed the constraints on the transmission grid. Congestion usually requires the system operator to adjust the output of generators, decreasing it in one area to relieve the constraint and increasing it in another to continue to meet customer demand.

Congestion Pricing

A method of pricing in which all energy bought and sold in the IMO-administered spot market settles at market-based prices that account for the effects of congestion. Settlement prices are determined from the marginal cost (price) of serving an increment of load at each location.

Connection Asset

Any line, transformer or other piece of transmission equipment that is required to connect a generator or load to the common transmission grid. Typically, connection assets are used by only one or a few entities, and electrical flows tend to be in one direction only.

Constraint

A restriction on a transmission system or segment of a transmission system that may limit the ability to transmit power between, and hence to inject or withdraw power at, various locations. Constraints may be the result of physical limitations, such as the thermal limits of a transmission line; local voltage and stability *restrictions; and contingency limits that assure secure operations in the event of an unexpected failure of a transmission or generation facility.*

Contestable Market

With respect to market power analysis, any market that is open to outside competitors that would be able to limit the market power of a dominant player, whether or not such outside competitors currently exist or compete in that market.

Contract for Difference (CFD)

A CFD is a financial contract between two parties whereby they mutually agree on a price (the "strike price") and one pays the other the difference between the Spot Market Price and the strike price depending on whether the latter is higher or lower. Such a contract may exist between an energy supplier and customer, or between a third party (ABM) and a supplier or customer. Through such a contract the parties can mitigate the price volatility in a Spot Market.

Control Area

A region on the electricity grid where supply and demand are kept in balance through dispatch by the system operator. Most of the Ontario transmission system operates as a single control area operated by the CMO.

Cost of Service Regulation

See ***Rate of Return Regulation****.*

Day-Ahead Market

A forward market conducted a day before real-time operations. In our proposed market design, the IMO would operate a day-ahead market based on bids and offers submitted by market participants.

Decommissioning

The act of taking a facility out of service permanently. In the case of a nuclear plant this includes safely closing, and possibly dismantling (or otherwise disposing of) the existing facilities at the end of their service life.

Default Supply (Service)

In the context of the retail market, it is the electricity service that local distributing companies (LDC) must provide to small volume customers who have not indicated that they wish to purchase energy through any specific retailer.

Demand Side Management (DSM)

Measures undertaken to control the level of energy usage at a given time, by increasing or decreasing consumption or shifting consumption to some other time period. DSM efforts can be undertaken by consumers, utilities or third parties.

Demand Bid

A bid submitted to the market indicating the price a purchaser is willing to pay for a specified quantity (MWh or kWh) of electricity.

Derivative Contract

A contract whose value is based on, or derived from, the price of an underlying financial asset or index. Examples of derivatives include Forward Contracts, Futures Contracts, Options.

Dispatch

The process by which the System Operator directs the real time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to or taken off of the system. Dispatch control includes instructions to synchronize, desynchronize, increase or decrease electrical output and any other instruction relevant to maintaining system security.

Dispatchable Demand

Customer demand that can be adjusted in response to dispatch directions from the System Operator.

Dispute Resolution Panel

A panel established by the IMO for the purpose of resolving or attempting to resolve a dispute between market participants, or a dispute between one or more market participants and the IMO. [Electricity Act, 1998]

Distributor

Any entity that owns and is responsible for the maintenance of local distribution network systems which connect the bulk transmission grid to the end-use customer. In Ontario, the distributors include the MEUs, Ontario Hydro's retail arm, and Great Lakes Power.

Dynamic Scheduling Service

Allows a market participant's generation or demand to be moved "electrically" out of its host Control Area to and into a different Control Area.

Eastern Interconnection

Comprises those interconnected electricity systems in the eastern half of North America extending from Saskatchewan to eastern New Mexico and eastward, excluding Quebec and Texas.

Electricity Labeling

The disclosure of specific information related to the electricity being offered by an electricity supplier in a uniform easy to read "label" that allows a consumer to make comparisons among various offers. For example the label may provide information on the environmental impacts associated with the facilities used to generate the electricity being offered.

Embedded Generation

Generation which is not directly connected to the IMO-controlled grid, and is usually within a distribution system.

Emission Cap

An upper limit placed on the allowable airborne emissions from a polluting facility or from a group of such facilities within a defined region

End-use Consumer or Customer

A residential, commercial, or industrial customer in the electricity marketplace who buys electric power for its own consumption and not for resale.

Energy Imbalance Service

Provides correction for any hourly mismatch between a transmission customer's energy supply and the demand the customer is obligated/contracted to serve. In our proposed market design, energy imbalance would be provided by the IMO's dispatch service and associated spot market.

Ex Ante Measures

With reference to possible ways to mitigate market power, those measures taken before the beginning of market operations to prevent or discourage the exercise of market power, as opposed to measures taken after the market begins (ex post).

Executive Committee

A committee of the Board of Directors that has been delegated all the powers of the Board, except for those powers which can effect a fundamental change to the corporation.

Exit Fee

A charge imposed on a transmission customer when it physically disconnects from the common grid. The fee is imposed to help recover the transmission customer's share of the grid's sunk costs.

Ex Post Measures

With reference to possible ways to mitigate market power, those measures taken after the beginning of market operations to prevent the recurrence of market power abuses observed during market operations. (See ex ante measures.)

FERC

Federal Energy Regulatory Commission. Federal counterpart to state utility regulatory commissions in the United States that regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC's Order 888, issued in 1996, defines the requirements under which regulated monopolies and power pools must provide non-discriminatory access to participants engaging in wholesale transactions.

Financial Bilateral Contract

A form of agreement between two parties to trade electricity at a price determined by the parties. Financial contracts are not scheduled with the IMO, but their associated physical deliveries are effected through bids and offers in the spot market. For purposes of settlements, the IMO charges each party for the gross amounts injected and taken, while the parties settle between themselves for differences between the contract prices and amounts and the IMO's settlement prices and amounts. Also known as a Contract for Differences.

Financial, Security and Commodity Exchanges

Institutions created to facilitate trading in securities, options or future contracts. For example, the Toronto Stock Exchange or New York Mercantile Exchange.

Forward Contract

An agreement between two parties in which they agree to the purchase or the sale of a commodity at some future time under fixed conditions.

Futures Contract

A standardized, tradeable agreement between a buyer and a seller to purchase a specified quantity of a commodity (e.g. electrical energy) of specified characteristics, at a later date at a fixed price.

Futures Market

A market in which standardized contracts for the future delivery of commodities or financial instruments are traded.

Futures Option

A contract that confers the right, but not the obligation, to buy a futures contract.

Generator

An entity that owns and operates an electricity generation facility.

Governance

The process and structure used to direct and manage the business and affairs of a corporation with the objective of enhancing shareholder value, which includes ensuring the financial viability of the business.

Green Field Investments

Investments in new generation or transmission facilities that are located on new sites, rather than at sites with existing facilities.

Green Power Marketing

Commercial process of marketing and selling the output of certain generation sources identified as "green" because they meet certain standards for being deemed environmentally preferable.

Gross Load

Within a distribution system, the total load, including that served by embedded generation.

Hedge

A risk management instrument by which a customer or investor seeks to protect a current position or anticipated position in some market by using an opposite or offsetting position in options or futures.

Hydraulic Power

Electricity produced by water falling through turbines. Hydro-electric power.

IPPs

Independent Power Producers. Generators owned by entities other than an electric utility. In Ontario, several IPPs are under long-term contract to deliver power to Ontario Hydro. Also referred to as Non-Utility Generators or NUGs.

IMO-Controlled Grid

The transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operations. [Electricity Act, 1998]

Independent Electricity Market Operator (IMO)

Under the proposed market design, the entity that will perform both market operator and system operator functions. The IMO will be responsible for administering one or more short-run markets in electricity. Functions may include, but are not restricted to:

- *receiving and evaluating bids, offers and nominations from market participants*
- *developing schedules based on acceptable bids, offers and nominations*
- *reconciliation of participant actual performance to promised performance*
- *determination and posting of market-clearing prices*
- *settlements of market transactions at market-clearing prices*
- *monitoring market operation, recommending/implementing improvements*
- *education of participants in market operation and changes*

This entity is independent in that it has no commercial interest in market transactions.

Independent System Operator (ISO)

Similar to the IMO in Ontario, the term used in U.S. jurisdictions for a system and market operator who is independent of other market interests.

Integrated System

The electric system encompassing generation, loads, transmission and distribution facilities.

Interconnected System

Two or more individual transmission systems that have one or more interconnecting tie-lines.

Interface

The set of transmission interconnections between any two regions.

Intermittent Power Source

A generator, such as a wind turbine, whose output may vary considerably over short periods due to the variability and unpredictability of its external energy source.

Intertie

A transmission line that interconnects two adjacent control areas.

Interval Metering

Metering capable of measuring and recording the amount of electricity used during a defined period, such as every five or 15 minutes.

kWh

Kilowatt-hour, a standard unit for measuring electricity. Consumers are charged in cents per kilowatt-hour. In 1996, the average residential consumer in Ontario purchased 860 kWh per month.

kWh Metering

Metering capable of measuring the total usage or flow of kilowatt hours on a continuing basis, but not capable of recording and tracking such usage over shorter intervals, such as every hour or half-hour.

LDC

Local Distribution Company. An entity that owns a distribution system for the delivery of energy to consumers from the IMO-controlled grid.

Least-Cost Dispatch

The scheduling of power production as demand for electricity varies, according to the lowest cost generation sources available to the System Operator, given transmission limits and other constraints.

LMP

Locational marginal pricing, or locational pricing. Shorthand for a form of congestion pricing that determines the price of energy at each location on the grid as the marginal cost of serving an increment of load at that location.

Load

An end-use device or customer that receives power from an electricity system.

Losses

The energy that is consumed (lost) in the transmission and distribution of electricity from generation to load.

LSE

A load-serving entity. Historically, electric utilities that had an obligation to serve consumers. In the future, an LSE will include both the default utility or MEU and competing entities that take on a contractual obligation to serve a retail consumer.

Load Following

An ancillary service that adjusts generation to meet the hour-to-hour and daily load variations between generators and demands. In the proposed market design, this ancillary service will be provided by the IMO's dispatch.

Load Profile

An approximation of the amount of energy typically taken during each hour by a consumer or class of consumers over a defined period, such as monthly, given the total amount of energy metered for that defined period. Load profiles are needed for consumers who do not have interval meters, and are used to allocate total kWh usage over the month to each hour, in order to perform settlements that are based on hourly prices.

Load Shedding

The process by which the system operator deliberately removes (either manually or automatically) preselected customer demand from the power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loop Flow

Unscheduled flow that arises from the physical nature of electricity whereby it follows the path of least resistance. Loop flow occurs on transmission paths other than the path contracted for by transacting parties. Also referred to as parallel path flow.

MDC

The *Market Design Committee. A committee of industry and customer representatives commissioned by the Ontario Government to develop recommendations for the design and operation of the Ontario electricity market.*

MEU

Municipal Electric Utility. An organization that purchases power at wholesale from Ontario Hydro and provides retail electric service to many Ontario cities, towns, and villages, and to certain townships adjacent to them.

Market-Clearing Price

The price at which a market clears, such that there are no further gains to be made from further trading.

Market Concentration

A measure of how market share is distributed among competing firms.

Market Operator

The entity with the responsibility to operate the real time spot market for electricity and any other centrally administered forward markets. In our proposed market design, the IMO will be the market operator in Ontario.

Market Participant

Any entity that is authorized by the market rules to produce, buy, sell, trade, or transmit products in the IMO-administered wholesale markets. The Ontario Energy Board will license all wholesale market participants in Ontario.

Market Power

The ability of a market entity to exercise significant influence or control over prices or the terms and conditions of sale, through means other than superior competitive performance.

Market Power Mitigation

The means by which a firm's ability to exercise market power is discouraged, limited or prevented.

Market Rules

Rules administered by the IMO, governing the IMO-controlled grid and all trading activities in the IMO-administered markets. The market rules clearly and fully set forth the terms and conditions for the operation of the marketplace. They include operating rules, rules for dispute resolution, connection requirements, etc.

Market Share

An individual firm's share of the total market sales revenues.

Market Surveillance Panel (MSP)

A panel of independent experts that will be selected by the IMO Board investigate any activity related to the IMO-administered markets and to report thereon, including recommendations relating to the abuse or possible abuse of market power.

Market Transparency

The ability of market participants to observe and understand the workings of the market.

Megawatt (MW)

Unit of electrical power, used to measure the generating capability capacity of a generating station or the maximum demand of an electricity consumer.

Megawatt-hour (MWh)

A measure of the energy produced by a generating station over time: one megawatt of power produced for 24 hours provides 24 megawatt-hours of energy (as does 24 megawatts produced for one hour).

Meters or Metering

Equipment that measures and registers the amount and direction of electrical quantities with respect to time.

Monopoly

A single firm which is the sole producer of a commodity for which there is no close substitute.

"Must-Run" Plant

A specific generation facility that the IMO may need to call upon under certain conditions to maintain the reliability of the IMO-controlled grid.

NEPOOL

New England Power Pool.

NERC

North American Electric Reliability Council. An association of electric utilities established in 1968 in response to the 1965 blackout in the Northeastern U.S. and Ontario. Through the work of 10 regional councils and one affiliate council, NERC members ensure the reliability of the integrated North American bulk power system. NERC develops standards, guidelines and criteria for assuring system security and evaluating system adequacy, and has succeeded in maintaining a high degree of grid reliability throughout North America.

NPCC

Northeast Power Coordinating Council. One of the 10 regional councils under NERC, it is composed of all the major interconnected utilities in Ontario, Quebec, the Maritimes, New York and New England.

Net Load

With respect to embedded generation, the resulting (net) load served by the IMO-controlled grid after the effects of embedded generation are taken into account.

Network Stability Services from Generation Sources

Provided by special equipment, devices, software or systems that are required at generating plants to enable the System Operator to meet reliability requirements. Examples include generation rejection or runback schemes.

Nodal Pricing

A pricing regime in which the (clearing) price for electricity is determined at individual nodes or buses within a transmission system.

Non-Discriminatory Access

The rules that assure that all market participants have access to the market, the transmission system, distribution systems and ancillary services under the same terms and conditions, with no preferential treatment for those entities who may own, or are affiliated with the owners of, transmission system or distribution system assets.

Non-Utility Generators

See IPPs.

OEB

Ontario Energy Board. As the regulator under the proposed market structure, the OEB establishes the conditions for licensing market participants and regulates rates for transmission and distribution.

OHSCI

Ontario Hydro Services Company Incorporated.

OPGI

Ontario Power Generation Incorporated.

Operating Reserve

Reserve generating capacity that is available for system operations and can be brought on line within a short period to respond to a contingency. Operating reserve from generation that is already on-line (synchronized) and loaded to less than its maximum output, is available to serve customer demand almost immediately. Operating reserve may also be provided by interruptible load.

Option

A contract that gives the right, but not the obligation, to buy or sell an asset for a fixed price at, by, or before a specific date.

PJM

The Pennsylvania, New Jersey, Maryland Interconnection, a multiple utility pool in the eastern United States that has been restructured into a competitive market with an Independent System Operator.

PUC

Public Utilities Commission. Refers to a state or provincial utility regulatory commission that provides oversight, rate regulation policy guidance and direction to electric public utilities within its jurisdiction. In Ontario, it also refers to a public utility that may be established through municipal bylaw as a local board or commission to provide services such as water, public transit and/or electricity.

Peaking Capacity

Generating capacity typically used only to meet the peak demand, the highest demand for electricity during the day. Peaking capacity is typically provided by hydro-electric generators or gas-fired combustion turbine generators.

Performance Based Regulation (PBR)

Any rate-setting mechanism that attempts to link rewards (usually profits) to desired results or targets.

Physical Bilateral Contract

An agreement between two parties to trade a specified quantity of electricity at a price determined by the parties. For purposes of settlements, the IMO will net out the contract amounts specified by the contracting parties prior to calculating the IMO's settlements balances with market participants. The contract amounts are settled between the parties themselves.

Pool

Term sometimes used to refer to the generation dispatch coordinated by the System Operator, based on bids to sell and offers to purchase submitted by market participants, and the associated settlement system.

Postage Stamp Rates

Transmission rates that are uniform across an entire system.

Prudential Requirements/Criteria for Participants

Conditions placed on market participants to ensure that they will be able to meet their financial obligations in the marketplace.

RFP

Request for Proposals. A process for obtaining competing proposals from providers of a service or product.

Ramp Rate

The rate, expressed in megawatts per minute, at which a generator can increase or decrease its output.

Rate

The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.

Rate of Return Regulation

Process of regulation whereby the regulator sets rates at a level that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the invested property devoted to the business. Also known as Cost of Service Regulation.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must make good the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

Reactive Supply and Voltage Control From Generating Sources Service

Provision of reactive power through changes to generator reactive output to maintain acceptable transmission system voltages and facilitate electricity transfers.

Real Power

The amount of electric power produced, transferred, or used, usually expressed in kilowatts (kW) or megawatts (MW).

Real Power Losses

The power lost during transmission through a conversion to heat. Losses must be made up by additional generation and the providing generators must be compensated.

Reconciliation

With reference to the settlement process, the step in which the settling entity, such as the IMO or MEU, determines, through reference to metered data, the actual levels of electricity generated or consumed and compares it to that which was scheduled to occur. Reconciliation also includes the calculation of the market clearing prices and the determination of all moneys owing in the IMO administered markets.

Regulation

The oversight of a market by an administrative agency or regulator, including any intervention in the markets to set rates and other terms and conditions under which the regulated service must be provided. Traditional electric regulation attempts to put a monopoly under restraints to achieve prices (rates), output and investment levels comparable to those that would occur under a competitive market.

Regulation and Frequency Response Service

This service provides moment-to-moment balancing between demand and supply within a Control Area, while maintaining specific frequency levels. It is provided by either generation or load that is equipped to respond to automatic control signals issued by the IMO.

Regulator

An entity that, through power of law or some other legitimate means, has the authority to impose regulation. In Ontario, the regulator responsible for overseeing the electricity market will be the Ontario Energy Board (OEB).

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Restoration Service

An ancillary service that provides an offsite source of power to enable a Control Area to restore its system, or enables a generator to start its generating units or restore service to its customers if local power is not available. Sometimes referred to as black-start capability.

Retail Market or Retail Access

A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as Direct Access.

Retailer

An entity that purchases electricity for the purpose of selling electricity to a consumer or acting as agent or broker for a consumer or another retailer with respect to the sale of electricity.

Re-verification (of a meter)

As required by the Electricity and Gas Inspection Act, meters used for obtaining a basic charge for electricity must, once every eight years, be submitted for testing, re-calibrated if necessary, and resealed.

Scheduling, System Control, and Dispatch Service

Provides a) scheduling, b) confirming and implementing an interchange schedule with other Control Areas, including intermediary Control Areas providing transmission service, and c) ensuring operational security during the interchange transaction. These services will be provided by the IMO, as System Operator for the Ontario Control Area.

Settlement

The accounting and billing process whereby an entity such as the IMO determines the amounts that each market participant should pay or be paid to compensate for the energy and other services supplied or used, or bought and sold in the market.

Self-Regulation

A regulatory approach whereby industry participants develop and administer the rules governing their operations, subject to appeal to a government regulator.

Spot Market

A market in which goods are traded for immediate or near-immediate delivery. In our proposed market design, the IMO would operate and administer settlements for a spot market in electricity, in which suppliers could submit bids to sell and purchasers could submit offers to buy energy through an IMO-coordinated auction, with settlements based on market-clearing prices determined by the IMO. Market participants would be free to use the spot market to sell/purchase energy at market-clearing prices, as needed.

Spot Market Prices

The market-clearing prices determined in a spot market and used as the basis for settlements for all purchases and sales in that spot market.

Standardized Contracts

A contract in which most, if not all, of the terms and conditions are predetermined and not negotiated individually between the parties. An example of a standardized contract is a futures contract.

Stand-by Charge

A charge imposed on a transmission customers to have access to the grid and the generation and ancillary services provided by the grid. Traditionally, stand-by charges have been imposed on customers who relied on the grid only intermittently, on a "stand-by" basis.

Stranded Costs/Investment

Costs that cannot be recovered from market prices. With respect to electricity competition, stranded investments are those assets owned by a utility that would become uneconomic in a competitive market.

Strike Price

With reference to bilateral contracts, the price at which parties to the contract have agreed to trade and to settle their transactions.

System Black Start Capability

The System Blackstart Capability service consists of physical generating equipment that, following a system blackout, can start without the availability of an outside electrical supply, and be available to participate in the system restoration plan that is under the control of the System Operator.

System Operator

The entity with the responsibility to monitor and control an electric system in real time. (The term can also refer to the individual at an electric system control centre who is monitoring and controlling the electric system in real-time.) In the proposed market design, the IMO will be the System Operator.

System Operating Procedures

A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Tariff

The terms and conditions under which a service or product will be provided, including the rates or charges that users of service or product must pay. Tariffs are usually proposed by the service or commodity provider, and are subject to regulatory approval. Typically, the rates and terms for obtaining transmission service are set forth in a tariff. In the proposed market design, the rates and conditions for the IMO's services may also be set forth through a tariff.

Time-of-Use Meter

A meter capable of measuring and recording the amount of electricity used during a defined set periods for which specific tariffs for electricity consumption are applicable, such as daytime peak, nighttime off-peak, winter, summer.

Trading Period

The time period in the marketplace for which physical trades are defined. The trading period for most short-run electricity markets is an hour or half-hour. All bids, offers, nominations must be defined in terms of the trading period (e.g. half-hour, hour etc.). Each trading period has its own schedule and dispatch, as well as its own market-clearing price and settlement.

Transformer

Apparatus which increases or decreases the voltage (the "pressure," as opposed to the current strength) at which electricity flows.

Transmission Right

A tradable contractual right to a payment based on the difference between energy prices at different locations (e.g. across an Ontario Intertie).

Transmission Services

The acceptance, transmission and delivery of power within a Control Area. May include specific ancillary services.

Transmission Tariffs

The authorized charges levied for provision and use of transmission services.

Unbundling

The process of separating a bill or rate into its component parts. In the present context, unbundling usually means defining separate prices for each type of electricity service, such as transmission, distribution, energy and so on. Unbundling is also used to describe the process whereby competing suppliers are allowed to provide one or more of the unbundled products or services.

Uniform Pricing

A method of pricing in which all energy bought and sold in the IMO's spot market is settled at the same price regardless of location and regardless of the effects of congestion. The costs incurred by the IMO in dealing with congestion at various locations are recovered through a uniform (e.g., $/MWh) charge (also known as an "uplift charge") on all end-users.

Uplift Charges

Charges added to the price of electricity to reflect those costs that are determined to be common to all purchasers. Typically, uplift charges are used to recover the costs of ancillary services, costs of administration, and, under uniform pricing, the costs incurred by the IMO in dealing with congestion.

Vesting Contracts

Contracts that are entered into prior to the start of a new market. Typically, vesting contracts are used to assure that the benefits (or costs) of key resources owned by the incumbent utility are captured by (or imposed upon) consumers for some defined period after competition begins. In the current context, vesting contracts may be used to fix the prices that OEGC would receive for the output of certain of its generating units in order to discourage the exercise of market power.

Voltage

The "pressure" under which electric current is transmitted; analogous to water pressure. (The strength of the current, as opposed to its "pressure", is measured in amperes; the power transmitted is the product of the two.)

Voltage Support

See Reactive Power.

Voluntary Load Shedding

Arrangements made between consumers and the System Operator in which the consumer agrees to shed load at the direction of the System Operator, in exchange for compensation. Customers may offer this load to the System Operator as Operating Reserve.

Wheeling

The use of an interconnected transmission system to implement electricity transactions that transmit power into (wheeling in), within, out of (wheeling out) or through (wheeling through) that system.

White Paper

The Government's paper, <u>Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario</u>, which indicated its proposed policy framework for an electricity market in Ontario.

Wholesale Market

In this Report, this refers to the market in which electricity and other energy services are sold to wholesalers/retailers/distributors (who in turn sell to retail or end-use customers). A wholesaler/retailer/distributor of power would have the option to buy its power from a variety of generators, and the generators would be able to complete to sell their power to a variety of wholesalers/ retailers/distributors.

Zonal Pricing

A pricing regime in which the price for electricity is determined for specific regions or zones of a transmission system.