MINISTRY OF ENERGY

by its agent the Shared Services Bureau

REQUEST FOR PROPOSALS

FOR 2,500 MW OF NEW CLEAN GENERATION AND DEMAND-SIDE PROJECTS

Request for Proposal No.: **SSB-069092**

Issued: **September 13, 2004**, as amended by Addenda No. 1 - 7

Proposal Submission Deadline: **December 15, 2004 at 3:00 p.m. (EST)**

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I. INTRODUCTION

A. Invitation to Proponents

This document is a Request for Proposals (the “2,500 MW RFP”) for new clean generation and demand-side projects issued by Her Majesty the Queen in right of Ontario as represented by the Minister of Energy, and prepared with the assistance of its technical advisors, NERA Economic Consulting. This 2,500 MW RFP is an invitation to Prospective Proponents to submit Proposals for approximately 2,500 megawatts (MW) of new capacity from new clean generation, demand response, and demand-side management projects as further described in Section II.D – Description of Deliverables.

Only Prospective Proponents, namely entities or persons who submit a Statement of Qualifications in accordance with the Request for Information / Request for Qualifications, issued by the Ministry of Energy (the “Ministry”) on June 25, 2004, as amended (the “RFI/RFQ”), are entitled, but not obligated, to submit Proposals in response to this 2,500 MW RFP. However, the submission of a Statement of Qualifications in accordance with the RFI/RFQ is not an assurance that the Prospective Proponent’s proposed project will satisfy any or all of the mandatory technical and financial requirements set out in this 2,500 MW RFP, and Prospective Proponents are advised to review the mandatory technical and financial requirements in Section III - Evaluation of Proposals in relation to new clean generation, demand response, and demand-side management projects, respectively, prior to preparing and submitting a Proposal.

This 2,500 MW RFP describes all of the terms relating to the process of procuring approximately 2,500 MW of new clean generation, demand response, and demand-side management from New Generating Facilities and Demand-Side Projects, and supersedes and replaces the RFI/RFQ.

More detailed descriptions of the Deliverables to be procured through this 2,500 MW RFP, the Proposal submission and evaluation process, general information and instructions to Prospective Proponents, and a description of selected terms of the Clean Energy Supply (“CES”), Demand Response (“DR”), and Demand-Side Management (“DSM”) Contracts are provided below.

B. Communications with Respect to this 2,500 MW RFP

Interested parties may submit their questions and comments regarding this 2,500 MW RFP and the CES, DR and DSM Contracts through the dedicated website: www.ontarioelectricityrfp.ca under “2,500 MW RFP” and “Submit a Question” prior to the deadline for questions set out in Section IV.A.1. All questions and comments submitted by interested parties regarding this 2,500 MW RFP, and all responses thereto, shall be posted to this 2,500 MW RFP website, without identifying the interested parties who have submitted such questions and comments.

C. Definitions

Capitalized terms used in this 2,500 MW RFP shall have the respective meanings ascribed to them in the Glossary of Terms set out in Appendix B. Unless otherwise indicated, references to Sections and Appendices are references to Sections and Appendices in this 2,500 MW RFP.

II. DELIVERABLES

A. Background

This 2,500 MW RFP is intended to contribute to the Government of Ontario's stated objective of replacing coal-fired generation addressing Ontario's future supply challenge and mitigating near-term reliability concerns in priority areas of the province with new clean sources of generation and demand-side projects. This section provides a general overview of the Deliverables under this 2,500 MW RFP; for further details, readers are directed to the appropriate sections of this document.

B. Ontario Power Authority

On June 15, 2004, the Government of Ontario introduced Bill 100 in the Legislative Assembly of Ontario, entitled the *Electricity Restructuring Act, 2004* (Ontario) which, among other things, would establish the Ontario Power Authority (the "OPA") as a new statutory corporation which is not a Crown agent. If this legislation is enacted in substantially the same form as drafted, the OPA would have the ability to call on the private sector, when needed, for new generating capacity and demand-side initiatives to be secured through competitive and transparent processes. Planning of demand-side initiatives is expected to be coordinated by the Conservation Bureau of the OPA. Under the proposed *Electricity Restructuring Act, 2004* (Ontario), the costs of the OPA, including the costs of the CES, DR and DSM Contracts, would be recovered from all electricity consumers through appropriate settlement mechanisms. Prospective Proponents are advised that provisional credit ratings for the OPA have been issued by Moody's and DBRS and have been posted on the 2,500 MW RFP section of the website: www.ontarioelectrictyrfp.ca.

C. Interim Action

In advance of the establishment of the proposed OPA, the Government of Ontario is taking immediate action to address Ontario's future electricity supply challenge. Procurement requirements have been formulated in consultation with the Ministry of Finance, Management Board Secretariat, the Ministry of the Environment, the Ministry of Municipal Affairs and Housing, Hydro One and the IMO. Ontario Power Generation Inc. (OPG) shall not be permitted to participate either as a Proponent or as the sole member of a Proponent Core Team in this 2,500 MW RFP. Moreover, if OPG is not the sole member of a Proponent Core Team, then OPG shall be deemed not to be a Proponent Core Team member. In addition, OPG shall not be permitted to Control a Proponent. OPG shall however be permitted to participate as a member of one or more Proponent Non-Core Team(s), subject to the non-collusion restrictions set out in Section III.G.

Following the evaluation of the Proposals received in response to this 2,500 MW RFP, subject to the approval of the Cabinet of the Government of Ontario, the Ministry reserves the right to purchase more or less than 2,500 MW of new clean generating capacity and Demand-Side Projects as set out in Section III.D.

The 2,500 MW RFP is one of several opportunities through which the private sector and other participants are expected to contribute to building new generating capacity or providing Demand-Side Projects. Additional requests for proposals, and/or other procurement processes for renewable and other new clean generating capacity may follow in the future. It is expected that the Conservation Bureau will be involved in creating and implementing other demand-side programs, including programs for residential users. Other new programs to encourage demand-side management and demand response projects may also be put forward.

Failure by a Prospective Proponent to qualify under this 2,500 MW RFP does not in any way imply that the generation project or Demand-Side Project proposed by that party will not be eligible for future requests for proposals, procurements, or other programs. Moreover, interested parties are advised that neither this 2,500 MW RFP, nor any of the other procurement projects that either have been or may be put forth by the Ministry are intended to preclude or restrict in any way an interested party from proceeding with the development of new generation or Demand-Side Projects, outside of the scope of such procurement initiatives.

D. Description of Deliverables

The Government of Ontario recognizes that clean generation, demand response, and demand-side management all have a role to play in helping address Ontario’s future supply challenge. This 2,500 MW RFP provides an opportunity for these various approaches to demonstrate their relative competitiveness, thus ensuring that Ontario’s needs are met effectively.

The Selected Proponents will be required to enter into CES, DR or DSM Contracts, as applicable, with the Buyer for the provision of the Deliverables. The provisions of these contracts are outlined in Section V.A., and the description of the Buyer, as counterparty to these contracts, is outlined in Section V.B.

1. New Generating Facilities

The new clean generation being acquired under this 2,500 MW RFP will contribute to replacing coal-fired generation, which has historically operated as Intermediate Generation and has, when required, cycled on and off overnight and handled much of the ramping needed to meet load changes throughout the day. The Ministry therefore expects that Proposals for New Generating Facilities will be capable of cycling and of ramping to meet load changes. In addition, for the 2,500 MW RFP, New Generating Facilities:

a. must not burn Oil as a Primary Fuel; and

b. must not burn any coal or Municipal Solid Waste.

In addition, to the extent that the New Generating Facility forms a part of a larger generating facility (referred to in the CES Contract as the "Facility"), the Facility must not generate electricity through a process by burning Oil as a Primary Fuel or by burning any coal or Municipal Solid Waste.

Co-generation and distributed generation qualify for this 2,500 MW RFP, as do Expansions of Existing Generating Facilities, subject to the other conditions of this 2,500 MW RFP. New Generating Facilities smaller than 5 MW may be aggregated together in order to be eligible under this 2,500 MW RFP.

In the normal course, when a generator's price offers are accepted by the electricity market, the generator's facility is dispatched by the IMO and the generator is paid the market price for its electricity. Whenever the paid market price exceeds the marginal cost of running the generating facility, the generator will have received net revenue, which over time permits the generator to cover its development, construction, financing, ownership and operating costs of the generating facility. However, since the market has generally not provided sufficient net revenues to incent required new investment, this 2,500 MW RFP invites Proponents to submit a monthly amount, being the Net Revenue Requirement needed to cover these costs.

The payment approach in the CES Contract will incent a Supplier to offer electricity supply to the market at a competitive price, on the basis that the New Generating Facility will be dispatched by the IMO. Payments will be determined on the assumption that a Supplier will run the New Generating Facility when the electricity market price exceeds the Energy Cost as determined by the terms set out in this 2,500 MW RFP. This will help to maximize the number of price offers into the electricity market and ensure electricity prices are kept competitive.

Suppliers will not be paid directly by the Buyer for actual electricity production. Rather payments under the CES Contract will depend on whether the net market revenues that the Supplier is deemed to have received from the electricity market are greater than or less than the Net Revenue Requirement. Therefore, depending on market conditions, a Supplier will either (i) receive a monthly payment to supplement deemed market revenues to support the development, construction, financing, ownership and operating costs of the New Generating Facility, or (ii) make a monthly payment to the Buyer to the extent that the deemed market revenues exceed the amount needed to support the development, construction, financing, ownership and operating costs of the New Generating Facility. The magnitude of the payment will be determined each month, depending on the total net market revenues the Supplier is deemed to have earned in that month. The net market revenue that the Supplier is deemed to earn from the electricity market will be determined by calculating the revenue at the electricity market price less the Energy Cost of the New Generating Facility for those periods when the electricity market price exceeds the Energy Cost.

For example, if the Supplier was deemed to not have earned any net market revenues (i.e. where there are no periods in a given month when the electricity market price exceeds the Energy Costs), the monthly payment to the Supplier will be equal to the Net Revenue Requirement stated in the Proposal. However, the monthly payment to the Supplier will be reduced by the amount of net market revenues the Supplier is deemed to have received from the electricity market. If the net market revenues the Supplier is deemed to have received from the electricity market exceeds the Net Revenue Requirement, the Supplier will pay 95% of the surplus to the Buyer and retain 5%.

With this contract structure, the Supplier must manage any operational risks that might lead to the New Generating Facility not producing the expected net market revenues. As a result, the Supplier has strong incentives to routinely offer its output to the market and minimize the impacts of any equipment malfunctions, planned outages or potential fuel shortages and to maintain or improve the efficiency of the New Generating Facility.

New generating capacity from New Generating Facilities under this 2,500 MW RFP must be capable of being reliably delivered to load in the province. Some additional generating capacity can be accommodated by the existing transmission system; however, beyond certain threshold amounts, new capacity may not be able to be delivered to load without transmission system expansions or reinforcement. These thresholds will vary depending on where the New Generating Facilities connect to the transmission system. The potential costs of these transmission system expansions or reinforcements are part of the overall cost of providing new supply for the province's electricity consumers and will be considered in the Economic Evaluation of Proposals for New Generating Facilities. This will ensure that the 2,500 MW RFP minimizes the overall total cost for electricity ratepayers.

For further clarity, the CES Contract is described in detail in Section V.A.2.

2. Demand Response Projects

The ability for consumers to reduce their consumption of electricity in response to high prices or system shortages is a key feature of Ontario's market and future electricity supply and demand equation. Demand response capabilities help to cost-effectively achieve a balance of supply and demand by reducing the need for high priced supply during peak demand periods, or by reducing the need for supply during periods when supply is limited. To be effective, Demand Response Projects must be able to respond to high prices and to Operational Directives issued by the IMO to reduce demand. In particular, for this 2,500 MW RFP, DR Projects must:

a. be able to curtail at least 5 MW of load located in Ontario, which may result from aggregating multiple loads; and

b. be able to curtail load located in Ontario for a period up to 6 hours at a time, between the hours of 8 a.m. and 8 p.m. as directed by the IMO.

The expectation is that the DR Supplier will use the Control Equipment to avoid consuming electricity when prices are high and, as a result, reduce peak demand. Therefore, DR Proposals are expected to include projects that enable load interruptions and/or load shifting. DR Proposals may also include projects that use new on-site generation that results in reductions in the demand for electricity from the Ontario grid, so long as the generating equipment does not burn Oil as a Primary Fuel and does not burn any coal or Municipal Solid Waste. In addition, to the extent that the generating equipment forming part of the DR Project is a part of a larger generating facility, such larger facility must not generate electricity through a process by burning Oil as a Primary Fuel or by burning any coal or Municipal Solid Waste.

This 2,500 MW RFP invites Proponents to submit a minimum monthly amount, being the Net Revenue Requirement, to cover the costs associated with the development, installation, financing and operation and maintenance of the Control Equipment that is required for a Proponent to increase its demand responsiveness, and to provide the system with needed callable capacity in the form of demand reduction. The DR Contract is structured to provide regular payments to provide financial support for these costs. In any Season in which the Supplier has agreed to make demand reduction available, the Supplier will be:

(i) deemed to curtail the electricity demand whenever the electricity market price exceeds the DR Strike Price which is initially set at $350; and,

(ii) required to curtail the electricity demand in response to Operational Directives, subject to certain limits as described in Section V.A.3.d.

If the electricity market price does not exceed the DR Strike Price at any time during a given month in such a Season, the monthly payment to the Supplier will be equal to the Net Revenue Requirement stated in the Proposal. However, given that the Supplier is assumed to curtail electricity demand during hours when the electricity market price exceeds the DR Strike Price, the monthly payment to the Supplier will be reduced by an amount equal to the difference, reflecting the net electricity savings the Supplier would be deemed to have realized. This difference cannot, however, exceed the Net Revenue Requirement; in other words, the Supplier will not be required to make payments to the Buyer, regardless of how high electricity market prices go.

If the Supplier receives an Operational Directive requiring it to curtail demand during hours when the electricity market price is less than the DR Strike Price, the Buyer shall compensate the Supplier to the extent that the DR Strike Price exceeds the electricity market price. This additional compensation will be added to the monthly payment to the Supplier.

For further clarity, the DR Contract is described in detail in Section V.A.3.

3. <u>Demand-Side Management Projects</u>

Demand-Side Management can contribute to achieving a balance of supply and demand by reducing demand through the installation of more efficient equipment. In particular, for this 2,500 MW RFP, DSM Projects must:

a. be able to achieve capacity savings equivalent, as converted in accordance with the formula set out in Appendix L of this 2,500 MW RFP, equal to or greater than 5 MW, which may be achieved by aggregating savings from multiple sites or consumers; and

b. not achieve any of the specified capacity savings from residential load, as it is expected that demand-side management initiatives for residential loads will be implemented by a combination of projects developed by Local Distribution Companies and the Conservation Bureau outside of this 2,500 MW RFP.

The DSM Contract will be structured to provide a Supplier with a monthly payment to provide financial support for energy efficiency measures that would otherwise not be commercially undertaken. The payments are intended to cover the amount required to shorten the Simple Payback Period of the incremental capital cost for new equipment to three (3) years, and to cover the Supplier's costs of project delivery, administration, measurement, and verification. The DSM Contract is further described in Section V.A.4.

E. No Guarantee of Volume of Work or Exclusivity of Contract

The Ministry makes no guarantee of the value or volume of work to be assigned to a Selected Proponent. The CES Contract, DR Contract, or DSM Contract executed with a Selected Proponent will not be an exclusive contract for the provision of the described Deliverables. The Ministry may contract with others for the same or similar Deliverables to those described in this 2,500 MW RFP or may otherwise obtain the same or similar Deliverables by other means.

F. Agreement on Internal Trade

Proponents should note that procurements falling within the scope of Chapter 5 of the Agreement on Internal Trade are subject to that chapter, but that the rights and obligations of parties shall be governed by the specific terms of each particular procurement process. For further reference, please see the Internal Trade Secretariat website at www.intrasec.mb.ca.

III. EVALUATION OF PROPOSALS

A. Overview of Stages of Proposal Evaluation

The 2,500 MW RFP evaluation process will be divided into three (3) distinct stages:

Stage 1 – Evaluation for Completeness

Stage 2 – Technical and Financial Evaluation

Stage 3 – Economic Evaluation

Each Proposal shall consist of a Technical and Financial Submission, Proposal Security, and an Economic Bid Statement.

Stages 1 and 2 will consist of the screening and assessment of the Technical and Financial Submission to determine if it meets the stated completion and minimum mandatory technical and financial requirements, respectively, and review of the Proposal Security to ensure it complies with the requirements set out in Section III.F. Prospective Proponents are advised that the express intention of the Ministry is to pre-assess the requirements in Stages 1 and 2 prior to the initiation of a legally binding bidding process in Stage 3. During the screening and assessment conducted in Stages 1 and 2, the Ministry may require additional information, documentation, or statements from a Proponent as set out in Section IV.A.4. Such information, documentation or statements may be used to verify or clarify the information provided in a Proposal. The Ministry will be under no obligation to do so and Proponents should therefore submit a complete Proposal package. Proponents should be prepared to provide any requested supplementary information in a timely fashion since it is their sole responsibility to meet the requirements of Stages 1 and 2 within the stated timeframe. Those Proponents who fail to do so may be disqualified, in which case their respective Proposals will not be considered any further.

A Proponent whose Technical and Financial Submission meets the requirements of both Stages 1 and 2 will be notified by the Ministry, in writing, of the eligibility of the Economic Bid Statement of the Proponent's Proposal to be evaluated under Stage 3, and will be invited to submit a Notice of Intent to Proceed to Stage 3 in the form attached as Appendix N to the Ministry, on or before the date and in the manner specified in the written notification by the Ministry to the Proponent, evidencing its irrevocable selection of one of the following two (2) options, namely:

(1) to consent to the opening of the Economic Bid Statement by the Evaluation Team and evaluation of the Economic Bid Statement as part of Stage 3, being a legally binding bidding process; or

(2) to revoke and withdraw the Proposal from this 2,500 MW RFP, and request the return of the Proposal Security in accordance with the terms and conditions of this 2,500 MW RFP.

A Proponent who selects the first option above (i.e. to irrevocably consent to the opening of the Economic Bid Statement by the Evaluation Team) shall be deemed to be a Qualified Proponent. A Proponent who selects the second option above (i.e. to revoke its Proposal) shall be deemed to irrevocably withdraw its Proposal from this 2,500 MW RFP process, and the Proposal Security previously tendered by that Proponent shall be returned to the Proponent within ten (10) Business Days after receipt by the Ministry of the Notice of Intent to Proceed to Stage 3. All Proposals for which a Notice of Intent to Proceed to Stage 3 is not received on or before the date and in the manner specified in the written notification by the Ministry described above may be rejected, subject to the rights of the Ministry set out in Section IV.A.9. Proponents should note that their Economic Bid Statements will not be opened by the Ministry unless and until the Proponent has become a Qualified Proponent. Prospective Proponents are advised that it is the express intention of the Ministry that Stage 3, based on and to be governed by the terms and conditions set out in this 2,500 MW RFP, constitutes the commencement of a legally binding bidding process as between the Ministry and all Qualified Proponents and shall be subject to the reserved rights of the Ministry set out in Section IV.A.9.c. For greater certainty, no legally binding bidding process with respect to a Proposal will be deemed to have commenced prior to the commencement of Stage 3 with respect to such Proposal.

These three stages are described in further detail below.

1. <u>Stage 1 - Evaluation for Completeness</u>

This stage is an initial screening of the information and documentation submitted by the Proponent to ensure that the Proposal is complete. It is the responsibility of Proponents to complete all questionnaires, statements, and forms as instructed and to supply all required supporting documentation. The Evaluation Team will verify that the Proponent has completed all questionnaires and has provided all required declarations, statements, and other documents, as enumerated in Section III. The Ministry may require additional information, documentation, or statements from a Proponent as set out in Section IV.A.4. Such information, documentation or statements may be used to verify or clarify the information provided in a Proposal. Only complete Proposals, including Proposals for which all information or documentation has been received or for which clarifications were satisfactorily resolved, pursuant to requests by the Ministry, will proceed to Stage 2. All incomplete Proposals may be disqualified and not evaluated further.

2. Stage 2 - Technical and Financial Evaluation

In the second stage, all Proposals that have passed Stage 1 will be evaluated based on an assessment of each Proposal's submitted technical and financial information on a pass/fail basis.

The Evaluation Team will assess, based on the response to the Technical Questionnaire and Financial Questionnaire and supporting documentation, whether each Proposal satisfies each of the minimum mandatory technical and financial requirements and any applicable Voltage Support Adjustment and/or Priority Electrical Zone Adjustment requirements set forth in Sections III.C.1, III.C.2, III.C.3 and III.C.4. If, in the opinion of the Ministry, the Proposal requires clarification, the Ministry may, but is not obligated to, request such clarification, in accordance with Section IV.A.4.

Proponents are advised that documentation and information provided to satisfy the minimum mandatory technical and financial requirements set forth in Sections III.C.1 and III.C.2, respectively, and the Voltage Support Adjustment requirement and/or Priority Electrical Zone Adjustment requirement set forth in Sections III.C.3 and III.C.4, is subject to review by the Ministry to determine whether such statements and information are correct and accurate. If such statements or information are determined by the Ministry to be incorrect or misleading, the Ministry reserves the right to re-evaluate the Proponent's compliance with the minimum mandatory technical and financial requirements. Any Proposal that fails any one or more of the technical or financial minimum mandatory requirements may be disqualified and not evaluated further.

The Proponents of those Proposals that are determined by the Evaluation Team to pass the technical and financial evaluation will be invited by the Ministry to confirm in writing that they consent to the opening of the Economic Bid Statement by the Evaluation Team and evaluation of Economic Bid Statement, as part of the Stage 3 Economic Evaluation process. The notice shall be delivered by the Ministry in a letter to Proponents and shall require the Proponent, if it wishes to have its Economic Bid Statement considered in Stage 3, to submit a Notice of Intent to Proceed to Stage 3 to the Ministry on or before the deadline date and in the manner specified in such notice by the Ministry to the Proponent.

3. Stage 3 - Economic Evaluation

In the Economic Evaluation stage, the Ministry and its technical advisors will select those Proposals for New Generating Facilities, DR Projects and DSM Projects that are determined to most cost-effectively deliver aggregated capacity that approximates the

Target Capacity from those Proposals that have passed the completeness, technical and financial evaluations described in Stage 1 and Stage 2, and for which their respective Proponents have agreed to have their respective Economic Bid Statements opened and evaluated. A detailed description of the criteria to be used to determine which Proposals are the most cost-effective and the evaluation process to be undertaken in conducting the Economic Evaluation are set out in Section III.D.

Prospective Proponents are advised that it is the express intention of the Ministry that Stage 3, based on the terms and conditions set out in this 2,500 MW RFP, will constitute the commencement of a legally binding bidding process as between the Ministry and each Qualified Proponent with respect to such Qualified Proponent's Proposal, and will be subject to the Ministry's reserved rights as set out in Section IV.A.9.c.

B. Evaluation for Completeness (Stage 1)

The Proposal shall consist of completed versions of the following documents, which shall be screened for completeness through the Stage 1 evaluation for completeness:

1. <u>Responses to the Technical and Financial Questionnaires and Supporting Documents</u>

The completed Technical Questionnaire as provided as Appendix C-1 (for CES Projects), Appendix C-2 (for DR Projects) and Appendix C-3 (for DSM Projects), and the completed Financial Questionnaire as provided as Appendix D. The responses to such questionnaires will be used for the purposes of the technical and financial evaluation set out in Section lll.C. For greater certainty, the Proponent must only submit a completed version of one of Appendix C-1, C-2, and C-3, as applicable based on the type of project, and must submit a completed version of Appendix D per project.

2. <u>Additional Declarations</u>

The completed Statutory Declaration, Conflict of Interest Declaration, and Tax Compliance Declaration in the forms provided as Appendix H, Appendix I, and Appendix J, respectively.

3. <u>Confidentiality Statement</u>

If applicable, a Confidentiality Statement, as described in Section III.G.4 and in a form prepared by the Proponent, may be included as part of the Proposal.

4. Economic Bid Statement

The completed Economic Bid Statement in a separate, sealed, opaque envelope marked "Economic Bid Statement" followed by the name of the Proponent and the name of the project. Given that the Economic Bid Statement shall only be opened for Proposals if and when the Proponent has become a Qualified Proponent for that Proposal, the Evaluation for Completeness in Stage 1 shall only verify whether the envelope is provided in the form required, at the location required and by the deadline required. The form of the Economic Bid Statement is provided as Appendix E-1 (for New Generating Facilities that are New Gas Generating Facilities only), Appendix E-2 (for New Generating Facilities that are New Non-Gas Generating Facilities only), Appendix E-3 (for DR Projects only), and Appendix E-4 (for DSM Projects only). For greater certainty, the Proponent must only submit a completed version of one of Appendix E-1, E-2, E-3, or E-4, as applicable based on the type of project. Prospective Proponents are advised that the Net Revenue Requirement and any other information provided by the Proponent in the Economic Bid Statement shall not be disclosed or described in any other part of the Proposal, failing which the Proposal shall be disqualified.

5. Proposal Security

The Proposal Security described in Section III.F, by way of certified cheque, bank draft, or in the form provided in Appendix F or Appendix G, as applicable.

Apart from the completion of any blanks, bullets, or similar uncompleted information, a Proponent may not make amendments to the pre-printed wording of the forms of Technical Questionnaire, Financial Questionnaire, Economic Bid Statement, Statutory Declaration, Conflict of Interest Declaration, Tax Compliance Declaration, the Letter of Credit Form (if applicable) of the Proposal Security, and the Bid Bond Form (if applicable) of the Proposal Security. Prospective Proponents are advised that the forms of certain of the Appendices will be made available from the 2,500 MW RFP section of the website www.ontarioelectricityrfp.ca in a writable PDF format. Any such amendments made to the Technical Questionnaire, Financial Questionnaire, Statutory Declaration, Conflict of Interest Declaration, Tax Compliance Declaration, the Letter of Credit Form (if applicable) of the Proposal Security, and the Bid Bond Form (if applicable) of the Proposal Security, whether on the face of such forms or contained elsewhere in the Proposal, may result in disqualification of the Proposal. Likewise, any such amendments to the Economic Bid Statement may be disqualified, subject to the reserved rights of the Ministry set out in Section IV.A.9.c.

C. Technical and Financial Evaluation (Stage 2)

The Technical and Financial Evaluation will be conducted based on the information and documentation provided by the Proponent in response to the Technical Questionnaire set out in Appendices C-1, C-2 and C-3 (as applicable) as well as the Financial Questionnaire set out in Appendix D. Prospective Proponents should note that certain of the minimum mandatory technical and financial requirements, as identified below, will be fulfilled or satisfied by the Proponent simply stating in the response to the Technical Questionnaire or Financial Questionnaire that the requirement is met or by the Proponent providing the required information as part of the response to the Technical Questionnaire or Financial Questionnaire, and may not be verified or evaluated by the Evaluation Team for the purposes of evaluating the Proposal under Section III. However, Prospective Proponents are advised that all statements and information submitted as part of the Proposal are subject to verification and enforcement in accordance with the terms of the CES Contract, DR Contract or DSM Contract, as applicable.

1. Minimum Mandatory Technical Requirements

The objective of the Evaluation Team in its technical evaluation is to assess whether the proposed project is technically sound and the proposed facility has a satisfactory degree of assurance of attaining Commercial Operation by no later than the date specified by the Proponent. This will be considered to be the case if the proposed project satisfies all of the minimum mandatory technical requirements set out below, which will be evaluated based on the information provided in response to the Technical Questionnaire set out in Appendix C-1, C-2 or C-3 (as applicable). Prospective Proponents are advised that submission of all of the applicable information required by the Technical Questionnaire is mandatory and must be submitted for the Proposal to be complete. The minimum mandatory requirements are documented below for each of New Generating Facilities, DR Projects and DSM Projects.

a. New Generating Facilities

The eight (8) minimum mandatory technical requirements for a proposed New Generating Facility are as follows:

i. The New Generating Facility must meet all of the following specifications:

- must not generate electricity through a process by burning Oil as a Primary Fuel, or by burning any coal or any Municipal Solid Waste. In addition, to the extent that the New Generating Facility forms a part of a larger generating facility (referred to in the CES Contract as the “Facility”), the Facility must not generate electricity through a process by burning Oil as a Primary Fuel or by burning any coal or Municipal Solid Waste. Notwithstanding the foregoing, a New Generating Facility and Facility using by-product fuels from industrial processes are eligible to participate in this 2,500 MW RFP. This requirement shall be satisfied by the Proponent's statement to this effect, and the Proponent's description of the fuel to be used, in the response to the Technical Questionnaire;

- has a ramp rate (being defined as the rate of increase or decrease in energy output that the New Generating Facility is capable of achieving after start-up, synchronization to the system, and technically required hold points, with such interval being between the minimum load and the maximum continuous rating), over a single 5 minute interval, of at least "X" MW/minute, where "X" is a value equal to 4% of the CES Contract Capacity set out in the Proposal. This requirement shall be satisfied by the Proponent's specification of a ramp rate of "X" MW/minute, where "X" is a value equal to 4% of the CES Contract Capacity set out in the Proposal;

- provides a minimum CES Contract Capacity of 5 MW. For greater certainty, two or more generating facilities may be aggregated by the Proponent so as be to considered as a single New Generating Facility for purposes of this 2,500 MW RFP, the Proposal, and the CES Contract, provided that each such generating facility being aggregated:

  - meets the other requirements for a New Generating Facility set out in this 2,500 MW RFP; and

  - is controlled by the same Proponent;

  and that:

- such multiple generating facilities must be encompassed in a single Proposal with a CES Contract Capacity which is equal to the aggregate combined Capacity of the multiple generating facilities; and

- for purposes of the CES Contract, the aggregation of such multiple generating facilities is otherwise treated as a single New Generating Facility;

This requirement will be satisfied by the Proponent stating that the CES Contract Capacity is equal to or greater than 5 MW in the response to the Technical Questionnaire;

- is located within the Province of Ontario and affects supply or demand in the IMO-Administered Markets. This requirement shall be evaluated based on the information submitted by the Proponent pursuant to Sections lll.C.1.a.ii and III.C.1.a.iv;

- satisfies one of the following, which requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire, unless otherwise specified:

  - is connected to the IMO-Controlled Grid and is a participant in the IMO-Administered Markets;

  - is connected to the Local Distribution System of a LDC and is a participant in the IMO-Administered Markets; or

  - is connected to an End-user;

- shall not have achieved commercial operation by September 13, 2004. For purposes of this requirement, commercial operation shall mean that the New Generating Facility commences operation in compliance with all laws and regulations after the completion of construction, completion of connection and synchronization to the IMO-Controlled Grid, a local distribution system, or directly to an End-user, and completion of all commissioning tests. This requirement shall be evaluated based on information and data submitted by the Proponent, including, but not limited to, settlement statements or operational data clearly indicating the start of commercial operation; and

- is not an Upgrade of an Existing Generating Facility. For greater certainty, the New Generating Facility may constitute an Expansion of an Existing Generating Facility. This requirement will be satisfied by the Proponent's statement to this effect in its response in the Technical Questionnaire.

ii. The Proponent must submit as part of the Proposal a description of the proposed facility site. To be complete, this description must include:

- a map showing the location of the proposed facility site in relation to neighbouring roads and lands, drawn to a scale of no less than 1:10,000 and no greater than 1:100,000, and having a size of at least 6 inches by 6 inches. The map shall be utilized, together with the plan of survey required below and the documentation submitted in response to the requirement in Section III.C.1.a.iv, to confirm that the proposed facility site is located in the Province of Ontario as required in Section III.C.1.a.i and to confirm that the location of the proposed facility site corresponds to the plan of survey required below, as well as for general information purposes; and

- a plan of survey or its equivalent delineating the boundaries of the lands for the site, including any easements appurtenant to such lands. The survey shall be utilized to identify the lands described in Section III.C.1.a.iv. and to confirm that the location of such lands meets the requirements of this 2,500 MW RFP, as well as for general information purposes.

iii. Intentionally deleted.

iv. The Proponent must submit as part of the Proposal a copy of one of the following: (i) registered title to the lands for the proposed facility site as evidenced by a registered transfer; or (ii) a registered lease, licence, or agreement to use the land for the site with a term starting no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-1 and expiring no earlier than the end of the Term; or (iii) a written agreement to purchase the land for the site with a closing date no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-1; or (iv) a written agreement entitling the Proponent to an option to purchase the land for the site with a closing date no later than the milestone date for the commencement of construction provided by the

Proponent in response to the applicable question in Appendix C-I; or (v) a written agreement entitling the Proponent to an option to lease, licence, or use the land for the site with a term starting no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-I and expiring no earlier than the end of the Term. Where the Proponent has an option to purchase, lease, licence, or use the land for the site, such option must be exercisable at any time by the Proponent for at least one hundred and eighty (180) days after the Proposal Submission Deadline.

If, pursuant to the foregoing provisions, the Proponent is required to submit leases, licences, or agreements, as applicable, for more than ten (10) different sites and each such lease, licence, or agreement, as applicable, has been executed using the same standard form, then instead of providing an executed copy of each such lease, licence, or agreement, as applicable, the Proponent may provide a copy of such standard form together with a statement by the Proponent setting out, in summary form, all information (including the parties, description of the site, commencement date, term, and closing date) that is particular to each such individual lease, licence, or agreement, as applicable.

Alternatively, if the project involves Crown resources, including Crown land for transmission, distribution and ancillary structures, the Proponent must provide instead a written confirmation from the Ministry of Natural Resources that the Proponent has been granted the opportunity to pursue development approvals for a New Generating Facility, in the form of a "Site Release".

v. The Proponent must state the category to which the proposed project belongs according to the Ontario Ministry of the Environment's "Guide to Environmental Assessment Requirements for Electricity Projects" dated March 2001, as referred to in 0. Reg. 116/01 to the *Environmental Assessment Act* (Ontario) entitled "Electricity Projects". For greater certainty, the aforementioned Guide describes three (3) possible categories: Category A, B, and C. If the proposed project is within Category B, as referred to in the aforementioned Guide (i.e. a project subject to an environmental screening process), the Proponent must also submit as part of the Proposal a copy of the published "Notice of Commencement of a Screening" in accordance with the aforementioned Guide, together with a statement of where and when such publication took place if it is not already set out on the published notice. If the proposed project is within Category C, as referred to in the aforementioned Guide (i.e. a project which requires an individual environmental assessment), the Proponent must submit as part of the Proposal a copy of the "Terms of Reference" as submitted to the Ministry of the Environment in respect of such individual environmental assessment, together with a statement of the date of such submission if it is not already set out on the submission. For greater certainty, the statement in the Technical Questionnaire of the category to which the proposed project belongs, as verified according to the "Guide to Environmental Assessment Requirements for Electricity Projects" noted above, and the submission of a copy of all applicable documentation, as described above, will satisfy this requirement. In the case of a Proposal involving generation equipment that is not subject to the *Environmental Assessment Act* (Ontario), the Proponent will satisfy this requirement by stating in the response to the Technical Questionnaire that any applicable Ministry of the Environment certificates of approval for air and noise emissions have been or will be applied for.

vi. The Proponent must have notified the relevant local municipality (or municipalities) and planning authority (or planning authorities) of the Proponent's project. For greater certainty, this requirement shall be satisfied by the Proponent submitting as part of the Proposal a copy of the written notice(s) delivered to the municipality (or municipalities) and planning authority (or planning authorities), notifying them of the proposed project, together with a statement of the date of such delivery if it is not already set out on the notice. In addition, the Proponent must state in the Technical Questionnaire that it has notified all relevant municipalities and planning authorities of the proposed New Generating Facility, and that it has sought advice from such parties about requirements under the *Planning Act* (Ontario) and other approvals and requirements, and that it has sought advice from such parties about which municipalities and planning authorities, if any, should be advised of the proposed New Generating Facility, and that it has so advised such municipalities and planning authorities.

vii. The Proponent must submit as part of the Proposal the completed schedule of major project milestones, in the form set out in Appendix C-

1, identifying the respective dates by which the Proponent will attain each of the following milestone events:

- obtaining project and site approvals, and permitting;
- completion of connection assessments including approval from the IMO, the transmitter, and distributor, as applicable;
- engineering, equipment procurement, and construction contract(s) executed, which shall occur no later than the later of: (i) 2-1/2 years before the milestone date for Commercial Operation, and (ii) six (6) months after signing the CES Contract;
- financial closing, which shall occur no later than the later of: (i) 2-1/2 years before the milestone date for Commercial Operation, and (ii) twelve (12) months after signing the CES Contract;
- equipment ordered;
- equipment delivered;
- commencement of construction;
- completion of construction;
- connection of facility to the transmission system, distribution system, or End-user; and
- Commercial Operation, which milestone date must be no later than June 1, 2009.

Prospective Proponents are advised that, should a Proponent become a Selected Proponent, each of the milestone dates set forth in its Proposal corresponding to the execution of engineering, equipment procurement, and construction contract(s), financial closing, and Commercial Operation for the facility, as required in Appendix C-1, will be transcribed into the schedule of milestones contained in an Exhibit to the CES Contract without negotiation, revision, or correction, while the other milestone dates will be transcribed into the schedule of milestones contained in such Exhibit, but may be subject to revision by the Supplier. For greater certainty, the submission of the completed schedule in accordance with the foregoing will satisfy this requirement.

viii. Prospective Proponents are advised that, as part of the process of developing a generating facility, certain connection-related assessments are required to be conducted in order to review the impact of the proposed generating facility on the electricity system and existing customers. In general, a proposed generating facility connecting to the transmission system will require a "System Impact Assessment" and a "Customer Impact Assessment", while one connecting to a distribution system will need a "Connection Impact Assessment" and, if it has potential impacts on the reliability of the interconnected system, a "System Impact Assessment" and also a "Customer Impact Assessment". Prospective Proponents are directed to review the specifications set out in the OEB's Transmission System Code (in particular, Section 9.1 thereof entitled "New or Modified Generator Connections"), the Market Rules (in particular, Chapter 4 - Section 6 thereof), the IMO Connection Assessment and Approval process (in particular, Market Manual 2.10), the Transmitters' Load & Generation Connection Process (filed with the OEB), and the OEB's Distribution System Code (in particular, Section 6.2 thereof entitled "Responsibilities to Generators"), to determine which requirements are applicable to the Proponent's proposed generating facility.

The Proponent must submit as part of the Proposal the following documents in connection with the proposed New Generating Facility, if required, pursuant to the above specifications as follows:

<u>System Impact Assessment (which is prepared and executed by the IMO)</u>

(ii) a completed System Impact Assessment report which has been prepared and issued by the IMO; or

(iii) an executed copy of a "System Impact Assessment" (SIA) Agreement between the Proponent and the IMO for the System Impact Assessment for the proposed project.

Customer Impact Assessment (which is prepared and executed by the Transmitter)

(i) a completed Customer Impact Assessment or Preliminary Customer Impact Assessment report which has been prepared and issued by the relevant transmitter; or

(ii) both of the following two (2) documents:

- an executed copy of a "Preliminary Study Agreement" between the Proponent and the transmitter for the "Preliminary Customer Impact Assessment" for the proposed project; and

- a copy of a letter or other documentation from the transmitter evidencing that the application form for a "Preliminary Customer Impact Assessment" has been accepted by the transmitter.

Connection Impact Assessment (which is prepared and executed by the Distributor)

(i) a completed assessment of the project impact on the distribution system prepared and issued by the distributor, which would be an Impact Assessment, Connection Assessment, Connection Impact Assessment or Preliminary Connection Impact Assessment, or equivalent; or

(ii) both of the following two (2) documents:

- an executed copy of the "Preliminary Study Agreement" between the Proponent and the distributor for the proposed project; and

- a copy of a letter or other documentation from the distributor evidencing that the application form for a "Preliminary Connection Impact Assessment" has been accepted by the distributor.

ix. The Proponent Team must have "sufficient prior experience", as that term is defined below, in each of the areas of planning, development, construction and operation with respect to at least one (1) generating facility other than the proposed New Generating Facility which has entered into commercial operation. For the purposes of this requirement, “sufficient prior experience” means:

- that, with respect to planning, at least one (1) member of the Proponent Team must have been in a Managerial Capacity for at least two (2) years in the function of project organization, site acquisition, and technical design;

- that, with respect to development, at least one (1) member of the Proponent Team must have been in a Managerial Capacity for at least two (2) years in the function of permitting, financing, negotiation of EPC, design-build or other construction contracts, fuel procurement contracts and other project development contracts;

- that, with respect to construction, at least one member of the Proponent Team must have been in a Managerial Capacity for at least two (2) years in the function of the supervision of a general contractor retained to construct a generating facility pursuant to an EPC, design-build or other construction contract; and

- that, with respect to operation, at least one member of the Proponent Team must have been in a Managerial Capacity for at least two (2) years in the function of the supervision of an operator or manager retained to operate a generating facility pursuant to an operations or similar agreement.

Moreover, for purposes of this requirement, commercial operation shall mean that the generating facility commences operation in compliance with all laws and regulations after the completion of construction, completion of connection and synchronization to the relevant local transmission or local distribution system, or directly to an End-user, and completion of all commissioning tests.

The Proponent must clearly indicate in its response to the Technical Questionnaire which member of the Proponent Team satisfies each of the foregoing requirements for experience, and describe such experience in form of a resume, curriculum vitae, and any professional designation(s). There may be one Proponent Team member or several

Proponent Team members satisfying each of the above-noted requirements; moreover, the experience relating to each area of experience does not have to pertain to the same generating facility.

b. DR Projects

The six (6) minimum mandatory technical requirements for all proposed DR Projects, and the additional seven (7) minimum mandatory technical requirements for those proposed DR Projects that involve the construction of new electricity generators to curtail electricity demand, are as follows:

i. The DR Project must:

- have a minimum Specified Load of 5 MW. For greater certainty, demand response at two or more sites may be aggregated by the Proponent so as to be considered as a single DR Project for purposes of this 2,500 MW RFP, the Proposal and the DR Contract, provided that each such demand response being aggregated:

  - otherwise satisfies all of the mandatory technical requirements of this 2,500 MW RFP applicable to DR Projects; and

  - is controlled by the same Proponent;

  and that:

  - such multiple loads or sites must be encompassed in a single Proposal with a Contracted Demand Reduction equal to the aggregate combined load of the multiple loads or sites; and

  - for purposes of the DR Contract, the aggregation of such multiple loads or sites is otherwise treated as a single load.

  This requirement will be satisfied by the Proponent stating that the Specified Load is equal to or greater than 5 MW in the response to the Technical Questionnaire;

- located within the Province of Ontario and affects demand on the IMO-Administered Markets. For greater certainty, this requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire;

- not be offset by, result in, or in any way cause, an increase in load elsewhere;

- not be in commercial operation prior to September 13, 2004. For purposes of this requirement, commercial operation shall mean that the DR Project commences operation in compliance with all laws and regulations after the completion of construction, completion of connection to an End-user, and completion of any commissioning tests of the Control Equipment. For greater certainty, this requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire;

- require new capital investment in Control Equipment. For greater certainty, this requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire; and

- have a Maximum Contracted Demand Reduction which does not exceed the amount of the Specified Load, and where the Contracted Demand Reduction is aggregated across two or more sites, the Contracted Demand Reduction at each site must not exceed the Specified Load at that site.

ii. Proponents of DR Projects that achieve the proposed demand response through managing the loads of third parties must demonstrate that they have written letters of intent with such third parties representing at least one-fifth (1/5) of the proposed Maximum Contracted Demand Reduction and provide a plan with timelines for securing the balance of such agreements for the DR Project on or before the Commercial Operation Date. For greater certainty, a letter of intent from a third party load must state, at a minimum, that such third party has reviewed this 2,500 MW RFP, the DR Contract, and the proposed written agreement with the third party described in Section III.C.1.b.iii below and that it agrees in principle to permit the Proponent of the DR Project to control its load to enable the Proponent to meet the obligations of the DR Contract.

iii. The Proponent must submit as part of the Proposal the completed schedule of major project milestone events, as required in Appendix C-2, identifying the respective dates by which the Proponent will attain each of the following milestone events:

- equipment ordered;
- equipment delivered;
- for DR Projects requiring the participation of third parties for the purposes of meeting the Contracted Demand Reduction, have executed agreements with third parties that collectively comprise eighty (80%) percent or more of highest value, in MW, of the Contracted Demand Reduction among all Seasons, which milestone date must be no later than one year prior to the milestone date for Commercial Operation stated in the response to the Technical Questionnaire. For greater certainty, a written agreement with a third party load must clearly indicate that the owner of the project site(s): (1) has given permission for the installation of the Control Equipment under an agreement between the Proponent and the site owner; and (2) understands that the installation of the Control Equipment requires inspections, monitoring and measurement of the performance of the measures and agrees to provide access to the project site to the Proponent, the Buyer, and their respective agents during the term of the DR Contract; and
- Commercial Operation, which milestone date must be no later than December 31, 2007.

Prospective Proponents are advised that, should a Proponent become a Selected Proponent, the milestone dates set forth in its Proposal corresponding to having executed agreements with third parties and to attaining Commercial Operation for the facility will be transcribed into the schedule of milestones contained in an Exhibit to the DR Contract without negotiation, revision, or correction, while the other milestone dates will be transcribed into the schedule of milestones contained in such Exhibit, but may be subject to revision by the Selected Proponent. For greater certainty, the submission of the completed schedule in accordance with the foregoing will satisfy this requirement.

iv. The Proponent must submit as part of the Proposal a detailed description of the Control Equipment to be installed and implemented, as applicable, indicating how such equipment, software and associated services will enable the Proponent to: (1) curtail or reduce demand for electricity in response to electricity market prices, or in response to an Operational Directive from the IMO; and (2) verify the load reduction as a result of the operation of the Control Equipment. For greater certainty, this requirement shall be satisfied by the Proponent's submission of the description and explanation to this effect in the response to the Technical Questionnaire.

v. The Proponent must submit as part of the Proposal an outline of a Measurement and Verification Plan in respect of the use of Control Equipment to accomplish the demand curtailment that the Proponent is intending to achieve by virtue of the proposed DR Project. Since demand response can be provided in several ways, the outline should state whether the DR Project is based on load interruption, generation, or load shifting. The outline should be consistent with the Measurement and Verification Guidelines for DR, where applicable, and should, for example, contain descriptions of how the baseline will be measured; how the DR Project will be monitored, including measurement techniques and data collection frequency; and clearly demonstrate the use and effectiveness of the Control Equipment in achieving the Contracted Demand Reduction, as well as the electrical location(s) of the Contracted Demand Reduction. Prospective Proponents are advised that such outline is required for information purposes only and will not be evaluated by the Ministry under Section III. Moreover, the receipt and review of such outline by the Ministry shall not under any circumstances be constituted or deemed to be an express or implied acceptance or approval by the Ministry of the form, content, or methodology set out therein and shall not bind or constitute an estoppel against the Buyer or the Supplier for purposes of agreeing upon the form, content, and methodology of the measurement and verification plan to ultimately be submitted by the Supplier pursuant to the DR Contract.

vi. The Proponent Team must have "sufficient prior experience" in the planning and development of at least one (1) demand response project other than in relation to the proposed DR Project which has entered into commercial operation. For the purposes of this requirement, "sufficient prior experience" means that, with respect to planning and development, at least one (1) member of the Proponent Team must have been in a Managerial Capacity for at least one (1) year in the function of project organization, technical design, and financing. Moreover, for purposes of this requirement, commercial operation shall mean that the demand response project has commenced operation in compliance with all laws and regulations after the completion of construction, and completion of connection to the End-user. The Proponent must clearly indicate, in its response to the Technical Questionnaire, which member of the Proponent Team satisfies the requirement for experience in planning and development, and describe such experience in form of a resume, curriculum vitae and any professional designation(s). There may be one Proponent Team member or several Proponent Team members who satisfy each of the above-noted requirements; moreover, the experience relating to such area of experience does not have to pertain to the same demand response project.

If the proposed DR Project involves the construction of new generation of electricity which will be used to effect the proposed demand response, then the following additional seven (7) minimum mandatory technical requirements must each be satisfied:

vii. If the DR Project meets the demand response requirements through the generation of electricity, it must not generate electricity through a process by burning Oil as a Primary Fuel, or by burning any coal or any Municipal Solid Waste. In addition, to the extent that the Control Equipment is a part of a larger generating facility, such larger facility must not generate electricity through a process by burning Oil as a Primary Fuel or by burning any coal or Municipal Solid Waste. Notwithstanding the foregoing, DR Projects or any such larger facility using by-product fuels from industrial processes are eligible to participate in this 2,500 MW RFP. This requirement shall be satisfied by the Proponent's statement to this effect, and the Proponent's description of the fuel to be used, in the response to the Technical Questionnaire.

viii. Intentionally deleted.

ix. The Proponent must submit as part of the Proposal a description of the proposed facility site. To be complete, this description must include:

- a map showing the location of the proposed facility site in relation to neighbouring roads and lands, drawn to a scale of no less than 1:10,000 and no greater than 1:100,000, and having a size of at least 6 inches by 6 inches. The map shall be utilized, together with the plan of survey required below and the documentation submitted in response to the requirement in Section III.C.1.b.x, to confirm that the proposed facility site is located in the Province of Ontario as required in Section III.C.1.b.i and for general information purposes; and

- a plan of survey or its equivalent delineating the boundaries of the lands for the site, including any easements appurtenant to such lands. The survey shall be utilized to identify the lands described in Section III.C.1.b.x and to confirm that the location of such lands meets the requirements of this 2,500 MW RFP, as well as for general information purposes.

x. The Proponent must submit as part of the Proposal a copy of one of the following: (i) registered title to the lands for the proposed facility site as evidenced by a registered transfer; or (ii) a registered lease, licence, or agreement to use the land for the site with a term starting no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-2 and expiring no earlier than the end of the Term; or (iii) a written agreement to purchase the land for the site with a closing date no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-2; or (iv) a written agreement entitling the Proponent to an option to purchase the land for the site with a closing date no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-2, or (v) a written agreement entitling the Proponent to an option to lease, licence, or use the land for the site with a term starting no later than the milestone date for the commencement of construction provided by the Proponent in response to the applicable question in Appendix C-2 and expiring no earlier than the end of the Term. Where the Proponent has an option to purchase, lease, licence, or use the land for the site, such option must be exercisable at any time by the Proponent for at least one hundred and eighty (180) days after the Proposal Submission Deadline.

If, pursuant to the foregoing provisions, the Proponent is required to submit leases, licences, or agreements, as applicable, for more than ten (10) different sites and each such lease, licence, or agreement, as applicable, has been executed using the same standard form, then instead of providing an executed copy of each such lease, licence, or agreement, as applicable, the Proponent may provide a copy of such standard form together with a statement by the Proponent setting out, in summary form, all information (including the parties, description of the site, commencement date, term, and closing date) that is particular to each such individual lease, licence, or agreement, as applicable.

Alternatively, if the project involves Crown resources, including Crown land for transmission, distribution and ancillary structures, the Proponent must provide instead a written confirmation from the Ministry of Natural Resources that the Proponent has been granted the opportunity to pursue development approvals for a New Generating Facility, in the form of a “Site Release”.

xi. The Proponent must state the category to which the proposed project belongs according to the Ontario Ministry of the Environment’s “Guide to Environmental Assessment Requirements for Electricity Projects” dated March 2001, as referred to in O. Reg. 116/01 to the *Environmental Assessment Act* (Ontario) entitled “Electricity Projects”. For greater certainty, the aforementioned Guide describes three (3) possible categories: Category A, B, and C. If the proposed project is within Category B, as referred to in the aforementioned Guide (i.e. a project subject to an environmental screening process), the Proponent must also submit as part of the Proposal a copy of the published “Notice of Commencement of a Screening” in accordance with the aforementioned Guide, together with a description of where and when such publication occurred if it is not already set out on the published notice. If the proposed project is within Category C, as referred to in the aforementioned Guide (i.e. a project which requires an individual environmental assessment), the Proponent must submit as part of the Proposal a copy of the “Terms of Reference” as submitted to the Ministry of the Environment in respect of such individual environmental assessment, together with a statement of the date of such submission if it is not already set out on the submission. For greater certainty, the statement in the Technical Questionnaire of the category to which the proposed project belongs, as verified according to the “Guide to Environmental Assessment Requirements for Electricity Projects” noted above, and the submission of a copy of all applicable documentation, as described above, will satisfy this requirement. In the case of a Proposal involving generation equipment that is not subject to the *Environmental Assessment Act* (Ontario), the Proponent will satisfy this requirement by stating in the response to the Technical Questionnaire that any applicable Ministry of the Environment certificates of approval for air and noise emissions have been or will be applied for.

xii. The Proponent must have notified the relevant local municipality (or municipalities) and planning authority (or planning authorities) of the Proponent’s project. For greater certainty, this requirement shall be satisfied by the Proponent submitting as part of the Proposal a copy of the written notice delivered to the municipality (or municipalities) and planning authority (or planning authorities), notifying them of the proposed project, together with a statement of the date of such submission if it is not already set out on the notice. In addition, the Proponent must state in the Technical Questionnaire that it has notified all relevant municipalities and planning authorities of the proposed project, that it has sought advice from such parties about requirements under the *Planning Act* (Ontario) and other approvals and requirements, that it has sought advice from such parties about which entities should be advised of the proposed project, and that it has so advised those entities.

xiii. The Proponent must submit as part of the Proposal the respective dates, in the form set out in Appendix C-2, by which the Proponent will attain each of the following milestone events:

- obtaining project and site approvals, and permitting;
- completion of connection assessments including approval from the IMO, the transmitter, and distributor, as applicable;
- engineering, equipment procurement, and construction contract(s) executed, which shall occur no later than the later of:

(i) 2-1/2 years before the milestone date for Commercial Operation, and (ii) six (6) months after signing the DR Contract;

- financial closing, which shall occur no later than the later of: (i) 2-1/2 years before the milestone date for Commercial Operation, and (ii) twelve (12) months after signing the DR Contract;
- commencement of construction;
- completion of construction; and
- connection of the facility to the End-user.

The above-noted milestone events are in addition to those milestone events set out in Section III.C.1.b.iii. Prospective Proponents are advised that, should a Proponent become a Selected Proponent, the milestone dates set forth in its Proposal corresponding to the execution of engineering, equipment procurement, and construction contract(s), financial closing, and Commercial Operation for the DR Project will be transcribed into the schedule of milestones contained in an Exhibit to the DR Contract without negotiation, revision, or correction, while the other milestone dates will be transcribed into the schedule of milestones contained in such Exhibit, but may be subject to revision by the Supplier. For greater certainty, the submission of the completed schedule in accordance with the foregoing will satisfy this requirement.

xiv. Prospective Proponents are advised that as part of the process of developing a generating facility, certain connection-related assessments (depending on the type of connection required) are required to be conducted in order to review the impact of the on the electricity system; in general, a proposed generating facility located on the site of a load that is connected to the transmission system will require a “System Impact Assessment” and a “Customer Impact Assessment”, while one connecting to a distribution system will need a “Connection Impact Assessment” and, if it has potential impacts on the reliability of the interconnected system, a “System Impact Assessment” and also a “Customer Impact Assessment”. Prospective Proponents are directed to review the specifications set out in the OEB’s Transmission System Code (in particular, Section 9.1 thereof entitled “New or Modified Generator Connections”), the Market Rules (in particular, Chapter 4 -

Section 6 thereof), the IMO Connection Assessment and Approval process (in particular, Market Manual 2.10), the Transmitters' Load & Generation Connection Process (filed with the OEB), and the OEB's Distribution System Code (in particular, Section 6.2 thereof entitled "Responsibilities to Generators"), to determine which requirements are applicable to the Proponent's proposed generating facility.

The Proponent must submit as part of the Proposal the following documents in connection with the facility, if required, pursuant to the above specifications referred to as follows:

<u>System Impact Assessment (which is prepared and executed by the IMO)</u>

(i) a completed System Impact Assessment report which has been prepared and issued by the IMO; or

(ii) an executed copy of a System Impact Assessment (SIA) Agreement between the Proponent and the IMO for the System Impact Assessment for the proposed project

<u>Customer Impact Assessment (which is prepared and executed by the Transmitter)</u>

(i) a completed Customer Impact Assessment or Preliminary Customer Impact Assessment report which has been prepared and issued by the relevant transmitter; or

(ii) both of the following two (2) documents:

- an executed copy of a "Preliminary Study Agreement" between the Proponent and the transmitter for the "Preliminary Customer Impact Assessment" for the proposed project; and

- a copy of a letter or other documentation from the transmitter evidencing that the application form for a "Preliminary Customer Impact Assessment" has been accepted by the transmitter.

Connection Impact Assessment (which is prepared and executed by the Distributor)

(i) a completed assessment of the project impact on the distribution system prepared and issued by the distributor, which would be an Impact Assessment, Connection Assessment, Connection Impact Assessment or Preliminary Connection Impact Assessment, or equivalent; or

(ii) both of the following two (2) documents:

- an executed copy of the "Preliminary Study Agreement" between the Proponent and the distributor for the proposed project; and
- a copy of a letter or other documentation from the distributor evidencing that the application form for a "Preliminary Connection Impact Assessment" has been accepted by the distributor.

c. DSM Projects

The seven (7) minimum mandatory technical requirements for a proposed DSM Project are as follows:

i. The DSM Project must:

- be able to achieve DSM Project Equivalent Capacity equal to or greater than 5 MW. For greater certainty, this may be achieved through aggregating savings from multiple sites or consumers so as be to considered as a single site or measure for purposes of this 2,500 MW RFP, the Proposal and the DSM Contract, provided that each such site or measure being aggregated:
  - otherwise satisfies all of the minimum mandatory technical requirements of this 2,500 MW RFP applicable to a DSM Project; and
  - is controlled by the same Proponent;

  and that:

- such multiple sites or measures must be encompassed in a single Proposal with DSM Project Annual Energy Savings equal to the aggregate combined savings of the multiple sites or measures; and

- for purposes of the DSM Contract, the aggregation of such multiple sites or measures is otherwise treated as a single DSM Project.

This will be satisfied by the Proponent submitting, in its response to the Technical Questionnaire, a schedule indicating the DSM Project Annual Energy Savings and the corresponding DSM Project Equivalent Capacity, which shall be calculated in accordance with the conversion formula set out in Appendix L, that will be realized as a result of the DSM Project for each year that the proposed project will be in effect;

- be located within the Province of Ontario, affect demand on the IMO-Administered Markets and achieves DSM Project Annual Energy Savings entirely from loads located in the Province of Ontario. For greater certainty, this requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire;

- not derive any consumption reduction or portion of the DSM Project Annual Energy Savings through any manner of transfer of electricity consumption to a location whose change in electricity consumption is not considered, accounted for and otherwise included in the determination of the DSM Project Annual Energy Savings;

- not be in commercial operation prior to September 13, 2004. For purposes of this requirement, commercial operation shall mean that the DSM Project commences operation in compliance with all laws and regulations after the completion of construction, completion of connection to an End-user, and completion of any commissioning tests. For greater certainty, this requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire;

- require new incremental capital improvements or equipment, including related control equipment having a Simple Payback Period of more than three (3) years. For greater certainty, this requirement shall be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire;

- derive DSM Project Annual Energy Savings entirely from load other than residential load; for greater certainty, residential load is the load of a dwelling, a property as defined in the *Condominium Act, 1998* (Ontario), a residential complex as defined in the *Tenant Protection Act, 1997* (Ontario), or a property that includes one or more dwellings and that is owned or leased by a co-operative as defined in the *Co-operative Corporations Act* (Ontario). For greater certainty, this requirement will be satisfied by the Proponent's statement to this effect in the response to the Technical Questionnaire;

- achieve the DSM Project Annual Energy Savings by direct reduction in kilowatt-hour electricity consumption of operating equipment only of a type for which the *Energy Efficiency Act* (Ontario) currently prescribes a minimum efficiency, used or to be used at the proposed project site(s), through the Term of the DSM Contract by the Proponent. For greater certainty, only equipment regulated under the *Energy Efficiency Act* (Ontario) and equipment that directly controls the consumption of electricity of products regulated under the *Energy Efficiency Act* (Ontario) are eligible (the "Qualifying Equipment"). This requirement will be satisfied by listing (i) existing equipment, if any, from which electricity savings will be achieved, (ii) the equipment meeting the current minimum efficiency requirements prescribed by the *Energy Efficiency Act* (Ontario) that will be assumed for incremental capital cost purposes and where applicable, for Efficiency Baseline purposes, and (iii) the equipment that will be installed. Notwithstanding the foregoing, district heating and cooling equipment replacing or used in the place of, and providing reductions in kilowatt-hour electricity consumption relative to, operating equipment of a type for which the *Energy Efficiency Act* (Ontario) currently prescribes a minimum efficiency, shall be eligible to participate in the 2,500 MW RFP;

- not include Interactive Effects, voltage reduction, and Operational Changes or Functional Changes to equipment or facilities; and

- not directly or indirectly burn Oil as a Primary Fuel or burn any coal or any Municipal Solid Waste, if the DSM Project includes district heating or cooling equipment. Notwithstanding the foregoing, such DSM Projects which directly or indirectly use by-product fuels from industrial processes are eligible to participate in this 2,500 MW RFP. This requirement, if applicable, shall be satisfied by the Proponent's statement to this effect, and the Proponent's description of the fuel(s) to be used, in the response to the Technical Questionnaire.

ii. Proponents of DSM Projects that require the participation of third parties in respect of achieving the savings must have, and provide written proof of, written letters of intent with such third parties representing at least one-fifth (1/5) of the total amount of proposed DSM Project Equivalent Capacity, and provide a plan with timelines for securing the balance of such agreements for the DSM Project on or before the Commercial Operation Date. For greater certainty, a letter of intent from a third party load must state, at a minimum, that such third party has reviewed this 2,500 MW RFP, the DSM Contract, and the written agreement described below, and that it agrees in principle to permit the Proponent of the DSM Project to install the DSM measures to meet the obligations of the DSM Contract.

iii. The Proponent must submit as part of the Proposal the completed schedule of major project milestones and the respective dates by which the Proponent will attain such milestone events, in the form set out in question 5 of Appendix C-3, identifying the date for each of the following:

- equipment ordered;

- equipment delivered;

- Commercial Operation, which milestone date must be no later than December 31, 2007; and

- for DSM Projects requiring participation of third parties, for the purposes of achieving the DSM Project Equivalent Capacity, Proponents must specify a date upon which third parties collectively representing 80% of the DSM Project Equivalent Capacity will have entered into agreements, which shall be no later than the later of: (i) six months after the date of the DSM Contract, and (ii) one year before the milestone date for Commercial Operation. For greater certainty, a written agreement with a third party must state that the owner of the project site(s): (1) has given permission for the installation of the DSM measures under an agreement between the Proponent and the third party; and (2) understands that the installation of the DSM measures requires inspections, monitoring and measurement of the performance of the measures and agrees to provide access to the project site to the Proponent, the Buyer, and their respective agents during the term of the DSM Contract.

Prospective Proponents are advised that, should a Proponent become a Selected Proponent, the milestone dates set forth in its Proposal corresponding to having executed agreements with third parties and to attaining Commercial Operation for the DSM Project will be transcribed into the schedule of milestones contained as an Exhibit to the DSM Contract without negotiation, revision, or correction, while the other milestone dates will be transcribed into the schedule of milestones contained as an Exhibit to the DSM Contract, but may be subject to revision by the Supplier. For greater certainty, the submission of the completed schedule in accordance with the foregoing will satisfy this requirement;

iv. The Proponent must submit as part of the Proposal an Hourly Electricity Savings Profile for a Typical Week for each Season as well as an Hourly Electricity Savings Profile for the Typical Peak Day for each Season. This information is required for the evaluation of the Proposals;

v. The Proponent must submit as part of the Proposal the methodology used to determine such DSM Project Annual Energy Savings. The Measurement and Verification Guidelines for DSM provide acceptable methodology for estimating energy savings. Prospective Proponents are advised that this methodology is required for information purposes only and will not be evaluated by the Ministry under Section III. Moreover, the receipt and review of such methodology by the Ministry shall not under any circumstances be construed or deemed to be an express or implied acceptance or approval by the Ministry of such methodology and shall not bind or constitute an estoppel against the Buyer who shall be entitled to authenticate and amend same through a third party verification consultant under the DSM Contract;

vi. The Proponent must submit as part of the Proposal an outline of a Measurement and Verification Plan in respect of the electricity savings that the Proponent is intending to achieve by virtue of the proposed DSM Project during the Term. The outline should contain descriptions of how the Efficiency Baseline will be measured, how project changes will be verified; how and to what extent electricity consumption affected by the Project will be monitored, including measurement techniques and data collection frequency; how equipment operation and permanence will be assured throughout the project and how other factors that can affect electricity consumption, such as changes in occupancy, function and weather, will be monitored and compensation made. Prospective Proponents are advised that such outline is required for information purposes only and will not be evaluated by the Ministry under Section III. Moreover, the receipt and review of such outline by the Ministry shall not under any circumstances be construed or deemed to be an express or implied acceptance or approval by the Ministry of the form, content, or methodology set out therein and shall not bind or constitute an estoppel against the Buyer or the Supplier for purposes of agreeing upon the form, content, and methodology of the Measurement and Verification Plan to ultimately be submitted by the Supplier pursuant to the DSM Contract which meets the requirements of the Measurement and Verification Guidelines for DSM as confirmed by the third party verification consultant referred to below. The DSM Contract will require the Supplier to implement the measurement and verification plan prior to Commercial Operation at the Supplier's expense, using an approved qualified third party with demonstrated and verifiable expertise and experience in measurement and verification of electricity related to DSM Projects relevant to the DSM measures being proposed; and

vii. The Proponent Team must have "sufficient prior experience" in the planning and development of at least one (1) demand-side management project other than in relation to the proposed DSM Project which has entered into commercial operation. For the purposes of this requirement, "sufficient prior experience" means that, with respect to planning and development of a demand-side management project, at least one (1) member of the Proponent Team must have been in a Managerial Capacity for at least one (1) year in the function of project organization, technical design, and financing. Moreover, for purposes of this requirement, commercial operation shall mean that the demand-side management project commences operation in compliance with all laws and regulations after the completion of construction, and completion of connection to the End-user. The Proponent must clearly indicate, in its response to the Technical Questionnaire, which member of the Proponent Team satisfies the requirement for experience in planning and development, and describe such experience in form of a resume, curriculum vitae and professional designation(s). There may be one Proponent Team member or several Proponent Team members satisfying the above-noted requirement; moreover, the experience relating to such area of experience does not have to pertain to the same demand-side management project.

2. Minimum Mandatory Financial Requirements

The objective of the Evaluation Team in the financial evaluation is to assess whether the financing plan provided in the Proposal is sound and whether there is a reasonable degree of assurance that the project will attain Commercial Operation by no later than the deadlines set out in Section lll.C.1.a, Section lll.C.1.b and Section lll.C.1.c. This will be considered to be the case, for any New Generating Facility, DR Project or DSM Project, if the Proponent satisfies the following minimum mandatory financial requirements, which will be evaluated based on the information requested in Appendix D - the Financial Questionnaire, as applicable. Prospective Proponents are advised that all of the information required by the Financial Questionnaire is mandatory and must be submitted for the Proposal to be complete.

In response to question 1 of the Financial Questionnaire set out in Appendix D, the Proponent is asked to provide a complete description of the financing plan for the project, comprising all sources of current and future financing or credit support for the project, including the names of all sources of financing, the characterization of each source as either equity, debt, or other (i.e. neither debt nor equity), the amount of financing provided by each such source, and the total amount of financing for the project. For greater certainty, loans from affiliated entities, project partners, and loans that are subordinated to the primary or senior project financing should be reported as equity.

a. For Equity Sources of Financing

If and to the extent that the financing plan specifies that equity (including, contributions that are structured as subordinated debt) is a source of financing for the proposed project:

i. the Proponent must submit:

- to the extent that the equity structure for the project is not yet in place at the time of submission of the Proposal, Commitment letter from each equity provider, as described in the financing plan submitted in response to the Financial Questionnaire, stating that equity provider's agreement in principle to advance its equity contribution by the milestone date for financial closing provided by the Proponent, and specifying the amount of the proposed or actual equity contribution, as applicable; or

- to the extent that the equity structure for the project is in place at the time of submission of the Proposal, a confirmation letter from each equity provider, as described in the financing plan submitted in response to the Financial Questionnaire, confirming that its equity is in place and the amount of its equity contribution.

ii. in respect of 35% of the total project equity, the Proponent must submit a list of the names of any one equity provider who accounts for the 35% of the total project equity, or if applicable, any group of equity providers who together account for the 35% or more of the total project equity, together with each such equity provider(s)' percentage contribution of total project equity, and evidence (as described below) of each such equity provider(s)' Tangible Net Worth. Such one equity provider, or group of equity providers on a collective basis, shall have Tangible Net Worth:

- with respect to a New Generating Facility, of at least $500,000/MW of CES Contract Capacity;

- with respect to a DR Project, of at least $500,000/MW of Maximum Contracted Demand Reduction; and

- with respect to a DSM Project, of at least $500,000/MW of DSM Project Equivalent Capacity (expressed in MW).

The Proponent shall satisfy the requirement of evidence of Tangible Net Worth by providing annual financial statements of the applicable equity provider(s) for the most recently completed fiscal year. Financial statements must be audited, but if audited financial statements are not available, then an officer of the equity provider must declare that such financial statements present fairly, in all material respects, the financial position of the equity provider in conformity with generally accepted accounting principles in Canada or the United States consistently applied. In addition, whether financial statements are audited or unaudited, an officer of each applicable equity provider must confirm, to the best of his or her knowledge, that there are no facts or circumstances that would materially adversely affect the equity provider's financial condition as set out in the annual reports or financial statements submitted in response to this requirement. The evidence of Tangible Net Worth will be used by the Evaluation Team to determine the Tangible Net Worth of each such equity provider (or group of equity providers) and whether each such equity provider (or group of equity providers) meets the minimum Tangible Net Worth Requirements set out above;

iii. the equity provider(s) accounting for 35% of the total project equity listed in response to the above requirement must each:

- have an Investment Grade Credit Rating, and in such case, the Proponent must provide all available credit ratings for such equity provider(s) from the following agencies: Standard and Poor's Rating Services ("S&P"), Moody's Investors Services Inc. (Moody's), Dominion Bond Rating Service Limited ("DBRS"), and Fitch IBCA, if and as applicable; however, if any such credit rating(s) are not publicly available, then the Proponent must provide a letter from the applicable rating agency confirming the credit rating of the equity provider; or

in the alternative, the Proponent must provide, with respect to such equity provider(s), either:

- a confirmation letter from a financial institution (meeting the minimum requirements of a financial institution set forth in Section lll.C.2.b. below) that the equity provider(s) has credit available under an approved facility sufficient to fund its equity contribution; or

- a certificate of an officer of the equity provider setting out the debt coverage ratio of the equity provider, which shall be calculated as at the last day of the most recently completed fiscal year, by dividing (a) Debt, by (b) EBITDA, which ratio must be no greater than 7:1. The certificate of the officer shall also set out the calculations of Debt and EBITDA. The Proponent must also provide financial statements for the most recently completed fiscal year. Financial statements must be audited, but if audited financial statements are not available, then an officer of the equity provider must declare that such financial statements present fairly, in all material respects, the financial position of the equity provider in conformity with generally accepted accounting principles in Canada or the United States consistently applied. In addition, whether financial statements are audited or unaudited, an officer of the equity provider must confirm, to the best of his or her knowledge, that there are no facts or circumstances that would materially adversely affect the equity provider's operating revenues from cash flow as set out in the annual reports or financial statements submitted in response to this requirement. Notwithstanding the foregoing, the delivery of such documentation under this Section lll.C.2.a.iii is not required where the Proponent has delivered the annual reports or financial statements of the equity provider(s) required under Section Ill.C.2.a.ii.

b. For Debt Sources of Financing

If and to the extent that the financing plan specifies that debt is a source of financing for the proposed project, the Proponent must submit a commitment letter from each and every lender, as identified in the financing plan submitted in response to the Financial Questionnaire, stating that lender's agreement in principle to the necessary debt financing for the project by the milestone date for financial closing, and specifying the amount of its proposed credit facility or loan. For the purpose of this requirement, the Proponent must confirm that each lender is a financial institution listed in Schedule I or II of the *Bank Act* (Canada), or is such other financial institution or other entity having the minimum credit rating (i) A with S&P, (ii) A3 with Moody's, (iii) A low with DBRS, or (iv) A with Fitch IBCA;

however, if any such minimum credit rating(s) are not publicly available, then the Proponent must submit a letter from the applicable rating agency confirming the credit rating of the lender. For greater certainty, the submission of all such commitment letters shall satisfy this requirement.

c. For Neither Debt Nor Equity Sources of Financing

If and to the extent that the financing plan specifies a source or sources of financing for the proposed project other than equity or debt, the Proponent must submit a commitment letter from each such source, as identified in the financing plan submitted in response to the Financial Questionnaire, stating its agreement in principle to provide such financing for the project by the milestone date for financial closing provided by the Proponent and specifying the amount of its proposed financial contribution. By way of example and without limiting the generality of the foregoing, to the extent that the financing of a project proposed under this 2,500 MW RFP by a cooperative or unincorporated association is funded by the contributions of its members, the Proponent must provide such commitment letters from its members; or if a portion of the financing of a project is to come from government grants, the Proponent must provide such a commitment letter from the relevant government(s) providing such funding or grants.

For greater certainty, an agreement in principle by an equity provider, lender, or other source of financing other than debt or equity described in Sections III.C.2.a, III.C.2.b and III.C.2.c must state, at a minimum, that such equity provider, lender, or other provider has reviewed this 2,500 MW RFP, one of the CES Contract, DR Contract or DSM Contract as applicable to the Proponent's Proposal, and the financial model (including projected costs and revenues) of the proposed project, and that it agrees in principle to advance, provide or underwrite the amount of equity or debt financing, as applicable, specified in the commitment letter by the milestone date for financial closing specified by the Proponent in response the Technical Questionnaire, subject to the satisfaction of specific objective conditions. The commitment letter must disclose any and all of such objective conditions. A commitment to simply arrange the equity or debt financing will not be considered sufficient to satisfy the Minimum Mandatory Financial Requirements. Moreover, a commitment that is conditional on amending the CES Contract, DR Contract, or DSM Contract, as applicable, in a manner inconsistent with Section 11.3 of each of such contracts will not be considered sufficient to satisfy the Minimum Mandatory Financial Requirements.

3. Voltage Support Adjustment Requirements

If a Voltage Support Adjustment is expected to apply to a Proposal for a New Generating Facility, DR Project, or DSM Project, as applicable, then the Proponent should submit, as part of the Proposal, all of the documentation required in Appendices C-1, C-2, and C-3, as applicable.

A New Generating Facility, DR Project, or DSM Project will be considered to provide Automatic System Voltage Support if all of the following requirements are met:

a. For a New Generating Facility, or a DR Project which involves the generation of electricity:

- such facility or project meets all relevant requirements under the Market Rules for a generator, whether directly connected to a Transmission System, Local Distribution System, or End-user, including the requirements described in the amendments approved by the IMO and described in http://www.theimo.com/imoweb/pubs/mr/mr_00244-ROO_BA.pdf.

b. For a DSM Project, or a DR Project which does not involve the generation of electricity:

- such project shall be equipped with facilities to provide continuously acting power factor or VAR (i.e. volt amperes reactive) control that can automatically maintain, at the Connection Point: (i) a power factor within a range of +/- 1% between power factors of 90% lagging and 95% leading, or (ii) VAR consumption within +/- 2.5% of the rated MVA of such project under steady state conditions;

- the power factor or VAR controller shall have an adjustable effective response time between 10 and 60 seconds;

- the power factor or VAR controller will automatically, and in less than 5 seconds, reduce the project's reactive power consumption by (i) 0 MVAR in response to a voltage reduction of 2 percent or less, and by (ii) an amount increasing continuously to a maximum amount equal to "X" MVAR in response to a voltage reduction at the Connection Point of 5 percent or greater, where *"X"* is a number equal to one-half of the Contracted Demand

Reduction or Seasonal Capacity as expressed in MW. By way of example, if a DR Project has a Contracted Demand Reduction of 8 MW, then the maximum amount of reduction referred to in this subparagraph (ii) will be equal to 4 MVAR in response to a voltage reduction at the Connection Point of 5 percent or greater;

- the project will operate in compliance with Market Rules associated with reactive power dispatch including, when directed by the IMO, reduce its reactive power consumption up to a maximum amount equal to "X" MVAR, where "X" is a number equal to one-half of the Contracted Demand Reduction or Seasonal Capacity as expressed in MW; and

- the project will operate at all times in compliance with the load power factor requirements under the Market Rules.

The documentation required in Appendices C-1, C-2, and C-3, as applicable, will be reviewed by the Evaluation Team to determine whether or not the Voltage Support Adjustment is applicable and should be applied to the Proposal for purposes of the Economic Evaluation. The Evaluation Team shall have the right, but not the obligation, to verify the information provided by the Proponent. This determination may result in the Voltage Support Adjustment not being applied to the Proposal for purposes of the Economic Evaluation of that Proposal, but will not, in and of itself, result in the disqualification of the Proposal. Failure to provide all of the documentation described in the Technical Questionnaire will not disqualify a Proposal, but may result in the Voltage Support Adjustment not being applied to the Proposal for purposes of the Economic Evaluation of that Proposal.

4. <u>Priority Electrical Zone Adjustment Requirement</u>

If a Proponent expects a Priority Electrical Zone Adjustment to apply to its Proposal for a New Generating Facility, DR Project or a DSM Project, as applicable, then the Proponent should state, in the Technical Questionnaire, that:

a. in the case of a New Generating Facility, the New Generating Facility will be located within the Priority Electrical Zones, and where the New Generating Facility is comprised of multiple facilities, each facility will be located within the Priority Electrical Zones; or

b. in the case of a DR Project, the DR Project will affect load of an End-user that is located within the Priority Electrical Zones, and where the DR Project is comprised of multiple loads, each load of an End-user is located within the Priority Electrical Zones; or

c. in the case of a DSM Project, the DSM Project will be located within the Priority Electrical Zones, and where the DSM Project is comprised of multiple sites or measures, the demand of each site or measure will be located within the Priority Electrical Zones.

In addition to the foregoing statement, the Proponent shall provide a single line electrical drawing which identifies the Connection Point for the proposed New Generating Facility, DR Project, or DSM Project, as applicable, clearly showing area transmission and distribution facilities, including the transmission station that is electrically closest to the proposed facility or project. The single line electrical drawing may be provided in the Proponent's response to the Technical Questionnaire in connection with the requirements of Section lll.C.3.

The single line electrical diagram will be reviewed by the Evaluation Team, in addition to the statements made above, to determine whether or not the Priority Electrical Zone Adjustment is applicable and should be applied to the Proposal for purposes of the Economic Evaluation. The Evaluation Team shall have the right, but not the obligation, to verify the information provided by the Proponent. This determination may result in the Priority Electrical Zone Adjustment not being applied to the Proposal for purposes of the Economic Evaluation of that Proposal, but will not, in and of itself, result in the disqualification of the Proposal. Failure to provide all of the statements and documentation described above will not disqualify a Proposal, but may result in the Priority Electrical Zone Adjustment not being applied to the Proposal for purposes of the Economic Evaluation of that Proposal.

D. Economic Evaluation (Stage 3)

1. <u>Overview</u>

All Proposals that are complete and meet the minimum mandatory technical and financial requirements, and for which a Notice of Intent to Proceed to Stage 3 has been received by the Ministry confirming the respective Proponents' agreement to have their Proposal proceed to Stage 3, will have their Economic Bid Statement opened and evaluated. Proposals for New Generating Facilities and DR Projects will be combined and ranked or “stacked” from lowest to highest Evaluated Costs in Dollars per MW-month, to create a “Stack”. Prior to incorporating

DSM projects into the “Stack”, the Evaluation Team will determine the Simple Payback Period for each DSM Project using the Average Cost of Electricity (Proposal) and the methodology set out in Exhibit Q to the DSM Contract. All Proposals for DSM Projects will be integrated into the Stack using an Evaluated Cost that is directly comparable to that used for New Generating Facilities and DR Projects and that implements the Total Resource Cost Test (or TRC Test), as described in Section lll.D.2.b.viii. The result of this process is the selection of those Proposals for New Generating Facilities, DR Projects and DSM Projects that most cost-effectively deliver aggregated capacity that approximates (which, for greater certainty, may be above or below) the Target Capacity.

a. Calculating Evaluated Costs

Proponents of New Generating Facilities and DR Projects must submit, as part of their respective Economic Bid Statements, a Net Revenue Requirement stated in Dollars per MW-month, exclusive of applicable GST and PST. Additionally, depending on the type of project proposed, such Proponents may also be required to submit as part of their Economic Bid Statements, the proportion of the NRR to be adjusted, O&M Costs, a Specified Heat Rate and a Start-Up Cost, and for Prospective Proponents for DSM Projects, the cost data needed to conduct the TRC Test. An Evaluated Cost will then be calculated for each New Generating Facility, DR Project, and DSM Project from the submitted information.

In summary, the steps in creating the Evaluated Cost for Proposals for New Generating Facilities, DR Projects, and DSM Projects will be as follows:

(i) for Proposals for New Generating Facilities and DR Projects, convert the NRR to a Real Indexed NRR. This conversion will account for the different contract lengths and for the NRR indexing options chosen by the Proponent. This step is described in greater detail in Section III.D.2.b.i;

(ii) for DSM Projects, determine the DSM Costs by:

- calculating the present value of all resource costs required to implement the Proposal for the DSM Project;
- determining from the Peak Electricity Savings the DSM Project Equivalent Capacity; and
- converting the present value of resource costs to the real levelized resource cost expressed in 2007 dollars per MW-month of the DSM Project Equivalent Capacity.

(iii) apply any applicable System Reliability Enhancement Adjustments as set out in Section III.D.2.b.iii;

(iv) for Proposals for New Generating Facilities, account for the monthly averaged Estimated Net Revenue, which is calculated using the Energy Costs. This step with respect to New Generating Facilities is described in more detail in Section III.D.2.b.iv. For Proposals for DR Projects, account for the monthly averaged DR Strike Price Reduction, using 24 months of certain historical market data. At this point, the Evaluated Cost will have been determined for DR Projects;

(v) for Proposals for DSM Projects,

- calculate the Avoided Energy Cost to the Province that will result from the DSM Project, using 24 months of historical market data;

- convert the Avoided Energy Cost to dollars per month of DSM Project Equivalent Capacity; and

- subtract the Avoided Energy Cost expressed in dollars per MW-month of DSM Project Equivalent Capacity from the DSM Cost, which is also stated in dollars per MW-month of DSM Project Equivalent Capacity to determine the Evaluated Cost for the DSM Project;

(vi) for Proposals for New Generating Facilities, adjust the initial Evaluated Cost to account for a provisional determination of Transmission Upgrade Cost Impacts, resulting in the Provisional Evaluated Cost for New Generating Facilities. These Provisional Evaluated Costs are dependent on the number, size, and location of the proposed New Generating Facilities within the Areas, Zones, and Sub-Zones of the province described in Appendix Q. The initial determination of Assigned Incremental Transmission Expansion Costs is described in greater detail in Section III.D.2.b.ix. Until such time as the Evaluated Cost of Proposals for the New Generating Facilities has been finally determined as a result of the final determination of the Assigned Incremental Transmission Expansion Costs to such projects, the Evaluated Cost will be referred to as the "Provisional Evaluated Cost". At this point, the Provisional Evaluated Cost for New Generating Facilities will have been initially determined;

(vii) Proposals for New Generating Facilities will be screened so that Proposals for no more than 2,500 MW of New Generating Facilities will be evaluated from each of the six Areas of the province. This screening is appropriate as the Target Capacity is 2,500 MW and only those Proposals for New Generating Facilities with the lowest Evaluated Cost representing 2,500 MW in each Area need be evaluated to provide a reasonable likelihood of selecting the lowest cost combination of Proposals overall. The screening process is described in Section III.D.2.b.x. below.

b. Development of Initial Stack

All Proposals for New Generating Facilities that have passed the screening process described above, together with all Proposals for DSM Projects and DR Projects, will be placed in order in the Stack from the lowest to highest Evaluated Cost (Provisional Evaluated Cost for Proposals for New Generating Facilities), such that the aggregated capacity of all of the Proposals in the Stack approximates the Target Capacity. Once this Stack is identified, Transmission Cost Upgrade Impacts will be recomputed assuming that the Proposals for New Generating Facilities in the Stack form the universe of Proposals for New Generating Facilities over which Incremental Transmission Expansion Costs will be determined and assigned. To the extent that:

- a Proposal for a New Generating Facility placed in this initial Stack has a Provisional Evaluated Cost, after the computation of the Transmission Upgrade Cost Impact described immediately above, that is lower than the initial Evaluated Cost (i.e., prior to any consideration of Transmission Upgrade Cost Impacts) of any Proposal that was not placed in the Stack; and

- a Proposal for a New Generating Facility placed in the Stack does not share in an allocation of Incremental Transmission Expansion Costs with another Proposal in the Stack that has a Provisional Evaluated Cost after the computation of Transmission Upgrade Cost Impacts that is higher than the initial Evaluated Cost (i.e., prior to any consideration of Transmission Upgrade Cost Impacts) of any Proposal that was not placed in the Stack,

then Proposals for such New Generating Facilities will be deemed to be selected for inclusion in the final Stack of Proposals for New Generating Facilities, DR Projects, and DSM Projects. Additionally, all DR Projects and DSM Projects in the initial Stack will be deemed to be selected for inclusion in the final Stack of Proposals for New Generating Facilities, DSM Projects and DR Projects.

If the aggregate capacity of the Proposals determined at this stage to be in the Stack is equal to the Target Capacity, or exceeds the Target Capacity by no more than 150 MW, the resulting Stack will be the final Stack of Proposals for New Generating Facilities, DSM Projects and DR Projects. If the aggregate capacity of the Stack exceeds 2,650 MW, the most expensive Proposal shall be removed from the Stack. If the aggregate capacity of the Proposals determined at this stage to be in the Stack is more than the Target Capacity less 150 MW, the Stack will be the final Stack of Proposals for New Generating Facilities, DSM Projects, and DR Projects. If the aggregate capacity of the Proposals determined at this stage of the Stack is less than the Target Capacity less 150 MW, additional Proposals will be added to the Stack based on a review of all possible combinations of such other Proposals (as further detailed in Section III.D.2.b.x.) such that:

- the added Proposals, taken together with the Proposals already deemed to be in the final Stack, result in aggregate capacity between plus and minus 150 MW of the Target Capacity; and

- the added Proposals in combination with the Proposals initially selected result in the combination (Stack) with aggregate capacity between plus and minus 150 MW of the Target Capacity, that has the lowest weighted average cost per MW of capacity of any combination of Proposals within this capacity range, taking into consideration the Evaluated Cost of Proposals for DR Projects and DSM Projects and the initial Evaluated Cost of Proposals for New Generation Facilities and the Transmission Upgrade Cost Impact of the combination. The Stack selected through this process will be the final Stack of all Proposals (New Generating Facilities, DSM Projects and DR Projects), subject to the right of the Ministry to recommend a Stack with greater or lesser aggregate capacity within an acceptable cost tolerance.

The Ministry will then recommend the Proposals in the Final Stack as its selected Proposals for the approval of the Cabinet of the Government of Ontario. The Ministry, under certain circumstances, may recommend an alternative Final Stack as described in Section III.D.2.b.xi.(C) and Section III.D.2.b.xi.(E).

Notwithstanding the foregoing, subject to the approval of the Cabinet of the Government of Ontario, the Ministry reserves the right to select Proposals that together offer significantly less than the Target Capacity if there are insufficient Proposals that meet the minimum mandatory technical and financial requirements and propose acceptable costs. In addition, the Ministry reserves the rights set out in Section IV.A.9.c in respect of the conduct of the Economic Evaluation.

2. Evaluation Process Details

a. Data

The following data will be used in conducting the Economic Evaluation. The data will be available to the public and posted on the website for this 2,500 MW RFP (www.ontarioelectrictyrfp.ca), which will enable Proponents to prepare their Economic Bid Statements, and is comprised of the following:

(i) The relevant one, two and three hour ahead pre-dispatch data for each hour during the period from and including August 1, 2002 through July 31, 2004;

(ii) HOEP during the period from and including August 1, 2002 through July 31, 2004;

(iii) The Gas Price Index during the period from and including August 1, 2002 through July 31, 2004; and

(iv) The Specified Index, and the Specified Forecast Index as set out in Appendix R, together covering the years 2002 to 2030, inclusive;

The data will be used as described below.

b. Evaluation Process

The Evaluated Cost for New Generating Facilities and DR Projects consists of the NRR set out in the Economic Bid Statement (which is assumed to represent the resource cost of developing and maintaining these projects over the applicable Term) less the Estimated Net Revenue, or DR Strike Price Reduction, as applicable, from the project which represent the net avoided cost of the New Generating Facility or DR Project. Hence, the Evaluated Cost of New Generating Facilities, DR Projects and DSM Projects are all conceptually identical in that they represent the resource cost of developing and maintaining the project over the applicable Term less the net avoided cost expected to be achieved over such Term.

i. Calculation of Real Indexed Net Revenue Requirement for New Generating Facilities and DR Projects

In order to compare the relative costs of Proposals for New Generating Facilities and DR Projects for the purposes of the Economic Evaluation, the Net Revenue Requirement for each such Proposal will be converted into an adjusted real indexed net revenue requirement.

The adjustments to the Net Revenue Requirement and its conversion into an adjusted real indexed net revenue requirement, ultimately expressed in Dollars per MW-month (the "Real Indexed NRR"), will be done using the following methodology:

(A) Contracted Demand Reduction for a DR Project will be adjusted to an equivalent average monthly capacity by multiplying the Contracted Demand Reduction for each Season by 0.85 (to account for the fact that demand response is not available for the entire range of hours that new generation is available) and then multiplied by the applicable seasonal weighting factors of 40% for Summer, 40% for Winter and 20% for the Other Season; and

(B) for Proposals for New Generating Facilities and DR Projects, the annual payment attributable to the NRR will be converted to a net present value using a real discount rate of 5%, adjusted to a nominal discount rate of 7% after taking inflation into account. In making this conversion, NRR adjustment will be accounted for using the Specified Forecast Index, and based on the percentage of the NRR that is subject to adjustment as specified by the Proponent in its Economic Bid Statement. The net present value will be over the Term, which is twenty (20) years for New Generation Facilities and, at the Proponent's discretion, between five (5) and twenty (20) years for DR Projects.

(C) The Real Indexed NRR to be used for evaluation purposes will be the 2007 dollar equivalent of the annual value for the first year of the Term of the CES Contract or DR Contract, as applicable, that, rising at the Specified Forecast Index over the Term of the applicable contract and discounted at the discount rate specified above, produces over the Term of the applicable contract the net present value described in the paragraph immediately above.

For evaluation purposes, the present value of the annual payment attributable to the NRR will be divided by twelve to determine a monthly Real Indexed NRR, and will be further divided by the Contract Capacity of the New Generating Facility or the Contracted Demand Reduction of the DR Project, adjusted as provided above, to state the Real Indexed NRR in per MW terms.

Examples of the above calculations are included in Appendix P.

ii. Determination of DSM Cost for DSM Projects

The total cost associated with the implementation of the DSM Project for purposes of the Economic Evaluation (the "DSM Costs"), will be determined as follows:

(A) The following costs associated with the DSM Project as provided by each Proponent of a DSM Project:

a) the DSM Incremental Capital Costs; and

b) the annual DSM Variable Costs;

will be utilized, as set out below, in determining the DSM Costs for a given DSM Project.

(B) The DSM Costs for a given DSM Project are equal to the sum of all of the discounted present values of the costs set out above, converted into a real levelized (over the Term) annual value in 2007 dollars expressed in Dollars per kW by dividing such sum by the DSM Project Equivalent Capacity. Finally, the annual value will be converted to a monthly value by dividing by 12. The resulting cost is then adjusted for any applicable System Reliability Enhancement Adjustments (as described below) to determine the final DSM Costs.

iii. System Reliability Enhancement Adjustments

The Economic Evaluation explicitly recognizes an urgent need for New Generating Facilities, DR Projects and DSM Projects to be located in the two Priority Electrical Zones. Both Capacity and specific voltage control capabilities are required in these Priority Electrical Zones. Accordingly, for the sole purpose of the Economic Evaluation, the following adjustments will be made to the Real Indexed NRR of Proposals for New Generating Facilities and DR Projects and the DSM Cost of Proposals for DSM Projects, with the attributes described below:

- Priority Electrical Zone Adjustments will be made for New Generation Facilities, DR Projects, and DSM Projects that will be located in the Priority Electrical Zones;

- Voltage Support Adjustments will be made for New Generation Facilities, DR Projects and DSM Projects located in the Priority Electrical Zones that will provide Automatic System Voltage Support; and

- Timing Adjustments will be made for New Generation Facilities that will meet certain target dates in furtherance of the Ministry's policy to phase-out coal-fired generation by December 31, 2007 and recognizing other urgent system reliability needs.

Priority Electrical Zone Adjustments, Voltage Support Adjustments and Timing Adjustments are collectively referred to as "System Reliability Enhancement Adjustments".

Where a Proposal for a New Generating Facility, DR Project or DSM Project involves the aggregation of two or more facilities, sites or measures, as applicable, the Real Indexed NRR or DSM Cost of the Proposal, as applicable, will only be adjusted by a System Reliability Enhancement Adjustment if each facility, load, site or measure that is aggregated as part of such Proposal is individually eligible to receive the applicable System Reliability Enhancement Adjustment.

(A) Priority Electrical Zone Adjustment and Voltage Support Adjustment

The application of Priority Electrical Zone Adjustments and Voltage Support Adjustments are intended to encourage Proposals for Projects that respond to the province's urgent reliability needs in specific Priority Electrical Zones, as identified below. In particular, these Priority Electrical Zones require both Capacity and enhanced Automatic System Voltage Support to ensure overall system reliability in the province.

The Priority Electrical Zones are as follows:

- Priority Electrical Zone 1: Downtown Toronto – Leaside Sector; and

- Priority Electrical Zone 2: GTA West of Toronto.

The boundaries of each Priority Electrical Zone are set out in Appendix O.

A Proposal for a New Generating Facility, a DR Project or a DSM Project located in either or both of the Priority Electrical Zones will have the Real

Indexed NRR for the New Generating Facility or DR Project, or the DSM Cost of the Proposal for a DSM Project, reduced by 2.0% for the sole purpose of the Economic Evaluation.

Further, a Proposal for a New Generating Facility, a DR Project or a DSM Project located in either or both of the Priority Electrical Zones and will provide Automatic System Voltage Support in the Priority Electrical Zone(s) will have the Real Indexed NRR for the New Generating Facility or DR Project, or the DSM Cost of the Proposal for a DSM Project, reduced by an additional 5.0% for the sole purpose of the Economic Evaluation.

As a result, a Proposal for a New Generating Facility, DR Project or DSM Project that is located in either, or both, of the Priority Electrical Zones and that will also provide Automatic System Voltage Support in a Priority Electrical Zone, will have the Real Indexed NRR for the New Generating Facility or DR Project, or the DSM Cost of the Proposal for a DSM Project, reduced by a total of 7.0% for the sole purpose of the Economic Evaluation.

(B) Timing Adjustment

In furtherance of the Government of Ontario’s policy to phase-out coal-fired generation by December 31, 2007 and recognizing other urgent system reliability needs, as identified by the IMO, this 2,500 MW RFP will encourage Proposals for New Generating Facilities that will achieve Commercial Operation by December 31, 2007 by applying a Timing Adjustment in the Economic Evaluation.

Therefore, a Proposal for a New Generating Facility that commits to:

- achieve Commercial Operation after December 31, 2006 and by December 31, 2007 will have the Real Indexed NRR reduced by 5.0% (the “2007 Adjustment”) for the sole purpose of the Economic Evaluation; or

- achieve Commercial Operation by December 31, 2006 will have the Real Indexed NRR reduced by 7.0% (the “2006 Adjustment”) for the sole purpose of the Economic Evaluation.

For certainty, a Proposal that qualifies for the 2006 Adjustment shall not in addition receive the 2007 Adjustment.

(C) Combination of System Reliability Enhancement Adjustments

If a Priority Electrical Zone Adjustment, a Voltage Support Adjustment and a Timing Adjustment are applicable in the case of a Proposal, such System Reliability Enhancement Adjustments shall be combined and treated as a single reduction in the Real Indexed NRR for such Proposal for a New Generating Facility or DR Project, or the DSM Cost for a DSM Project.

For example, a Proposal for a New Generating Facility that is located in either or both of the Priority Electrical Zones, will provide Automatic System Voltage Support, will achieve Commercial Operation by December 31, 2006, and will have its Real Indexed NRR reduced by a total of 14.0% for the sole purpose of the Economic Evaluation.

iv. <u>New Generating Facility - Estimated Gross Energy Market Revenue</u>

For each New Generating Facility, the evaluation will then determine, based on actual market prices, and actual gas prices as represented by the Gas Price Index from the 24-month period commencing August 1, 2002 and ending July 31, 2004, if applicable, the total Estimated Net Revenues (being the amount by which the Estimated Gross Energy Market Revenues is greater than the Energy Cost, determined as described below) for each month in the 24-month period. The total Estimated Net Revenues will be used to calculate the Contingent Support Payment or Revenue Sharing Payment for each month in the 24-month period, and those 24 values will be averaged over the 24 months to determine the monthly average net payment, expressed in dollars per MW-month. The monthly average net payment will be converted to 2007 dollars by applying the Specified Index and the Specified Forecast Index, as applicable, for the period 2003 to 2007. The Estimated Gross Energy Market Revenue calculation for evaluation purposes will use the methodology described in Section V.A.2.e. This methodology will deem operation based on actual market prices and imputed gross revenue based on HOEP, prior to implementation of a day-ahead market. Refer to Section V.A.2.e. for further information

Start-Up Costs applicable to the imputed operation will be limited to no more than one (1) imputed start-up per day.

The Energy Cost for a New Generating Facility will be calculated as follows:

(A) Energy Cost for New Gas Generating Facility

The Energy Cost (to be expressed in $/MWh) for a New Gas Generating Facility will be calculated using:

- a Specified Heat Rate provided by the Proponent, which will be constrained to be within 5,000 and 8,000 BTU/KWh and which will be directly applied to the natural gas prices, as reported by the Gas Price Index and converted to Canadian dollars, stated in $/MMBTU; and

- O&M Costs, as set out in the Economic Bid Statement and adjusted by the Specified Index.

Energy Costs will be calculated based on a deemed pattern of operation and start-up. For evaluation purposes, that pattern will be determined by applying the market contract methodologies as described in Section V.A.2.e. to historic market data for the period August 1, 2002 to July 31, 2004.

(B) Energy Cost for New Non-Gas Generating Facility

The Energy Cost (to be expressed in $/MWh) for a New Non-Gas Generating Facility will be submitted by the Proponent, as part of its Economic Bid Statement. The Energy Cost and O&M Costs as submitted by Proponents will be converted to 2003 and 2004 dollars fully indexed to the Specified Index.

Energy Costs will be calculated based on a deemed pattern of operation and start-up. For evaluation purposes, that pattern will be determined by applying the market contract methodologies as described in Section V.A.2.e. to historic market data for the period from and including August 1, 2002 to and including July 31, 2004.

v. <u>New Generating Facilities – Provisional Evaluated Cost</u>

The Evaluation Team will then calculate a Provisional Evaluated Cost for each New Generating Facility which will be the “nominal” Contingent Support Payment in 2007 dollars for the first month of the Term, and which shall be equal to the difference between the Real Indexed NRR for the New Generating Facility, calculated as described above, and the monthly average Estimated Net Revenue converted to 2007 dollars, as described above. This Provisional Evaluated Cost depends on the result of the allocation of Transmission Upgrade Cost Impacts described in Section III.D.2.b.ix below.

The initial Evaluated Cost will exclude the allocation of the Transmission Upgrade Cost Impacts.

vi. DR Project – Evaluated Cost

For each DR Project, the evaluation will then determine, based on actual market prices from the 24-month period ending July 31 2004, the total DR Strike Price Reduction (as calculated for the entire Contracted Demand Reduction for all hours in which both HOEP and the three-hour ahead Pre-Dispatch Price are greater than the DR Strike Price for each month in the 24-month period. The DR Strike Price set out in this 2,500 MW RFP will be converted to 2003 and 2004 dollars using the Specified Index. The total DR Strike Price Reduction will be averaged over the 24-month period to determine a monthly average DR Strike Price Reduction, expressed in Dollars per kW-month and will be converted to 2007 dollars by adjusting for inflation using the Specified Index and the Specified Forecast Index between 2003 and 2007. The Evaluated Cost for each DR Project will be the "nominal" Contingent Support Payment in 2007 dollars which shall be equal to the difference between the Real Indexed NRR for the DR Project based on the adjusted equivalent capacity (as further described in Section III.D.2.b.i.(A)) and the monthly averaged DR Strike Price Reduction per kW of adjusted equivalent capacity, as determined above.

vii. Avoided Energy Cost (for DSM Projects)

The "Avoided Energy Cost" is expressed in kW of DSM Project Equivalent Capacity that will be used for the purposes of the Total Resource Cost Test set out in Section III.D.2.b.viii, and which will be determined by (1) comparing the Hourly Electricity Savings Profile for a Typical Week in each Season to the historical HOEP for the period of August 1, 2002 through July 31, 2004, (2) multiplying the hourly energy savings by HOEP and summed, (3) dividing the resulting sum by 24 (the number of months), (4) further dividing the result by the DSM Project Equivalent Capacity, and (5) converting the result to 2007 dollars by applying the Specified Index and the Specified Forecast Index between 2003 and 2007 (the same adjustment made to convert Estimated Net Revenue to 2007 dollars).

DSM Project Equivalent Capacity will be calculated in accordance with Appendix L.

viii. The Total Resource Cost Test and the Evaluated Costs of DSM Projects

The Total Resource Cost Test will be used to determine which DSM Projects are cost-effective and are to be included in the final Stack. The Total Resource Cost Test will compare: (1) for each Proposal for a DSM Project, its Evaluated Cost, which is calculated as the DSM Cost less the Avoided Energy Cost, with (2) the Evaluated Cost of New Generating Facilities and DR Projects, which is the Provisional Evaluated Cost of those New Generating Facilities displaced by the DSM Project in the Stack, and which is the Evaluated Cost of those DR Projects displaced by the DSM Project in the Stack.

A DSM Project will pass the Total Resource Cost Test if the result in (1) is less than the result in (2) above.

ix. Determination of Incremental Transmission Expansion Costs for New Generating Facilities

New generating capacity contracted through this 2,500 MW RFP must be capable of being reliably delivered to load in the province. Some additional generating capacity can be accommodated by the existing transmission system. However, beyond certain threshold amounts, new capacity may not be able to be delivered to load without system expansions or reinforcement. These thresholds will vary depending on where the New Generating Facilities connect to the transmission system. The potential costs of these transmission system expansions or reinforcements are part of the overall cost of providing new supply to the province’s customers and need to be considered in the Economic Evaluation of Proposals for New Generating Facilities. This will ensure the 2,500 MW RFP minimizes the total cost for new capacity for electricity ratepayers.

It is neither feasible nor necessary to conduct an individual evaluation of the transmission system upgrade costs associated with each Proposal for a New Generating Facility for the purpose of the Economic Evaluation. Therefore a process will be undertaken through the Economic Evaluation which will allocate estimated Total Transmission Expansion Costs to Proposals that trigger the need for the expansion(s), and then rank Proposals according to Evaluated Cost adjusted for these Assigned Incremental Transmission Expansion Costs. The transmission Sub-Zones, Zones and Areas, as well as a cost impact matrix (the

"Cost Impact Matrix") outlining the Capacity Ranges and the Total Transmission Expansion Costs for each Sub-Zone, Zone and Area are provided in Appendix Q.

The method that will be used to allocate the Incremental Transmission Expansion Cost is illustrated below for one Area.

Illustrative Allocation of Assigned Incremental Transmission Expansion Cost for West of London Area

For the purposes of the Economic Evaluation and selection process, Proposals are allocated costs for necessary incremental transmission upgrades. An illustrative example of such an allocation is provided below for the West of London Area, based on the upgrade costs in the following matrix. Prospective Proponents are advised that the matrix set out below is a model that has been developed to ensure that the Economic Evaluation is as clear and transparent as possible, and that the capacities, costs, and other values or descriptions contained in the matrix below should not be relied upon by Prospective Proponents as being definitive of the actual capacities, cost, or other values or descriptions that may be payable or applicable by a Prospective Proponent.

West of London Cost Impact Matrix

Area	Zone	Sub-Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
				Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
West of London			2,000	$50	2,500						
	London to Sarnia		2,000	$50	2,500						
		London	100	$25	300	$75	800	$175	2,500		
		Sarnia	100	$25	300	$100	800	$300	2,500		
		Lambton	2,000	$25	2,500						
	London to Windsor		1,000	$100	1,500	$200	2,500				
		Lauzon-Kent	200	$25	400	$75	800	$175	2,500		
		Keith	0	$50	600	$100	800	$200	2,500		

***Note: Incremental Transmission Expansion Costs and Capacity Ranges are determined by comparing the difference between Total Costs and Max capacity in the applicable Step Upgrade columns, respectively.**

The allocation example considers three illustrative Proposals for New Generating Facilities, as follows:

Gen A – 1,200 MW in the Keith Sub-Zone

Gen B – 600 MW in the Lauzon/Kent Sub-Zone

Gen C – 400 MW in the Lambton Sub-Zone

Incremental Transmission Expansion Costs are allocated according to the ranking of Proposals by Evaluated Cost, with the lowest cost Proposals receiving priority for the lowest allocation of Incremental Transmission Expansion Costs. Although it may not always be the case, for simplicity in this example only, it is assumed that initial Evaluated Costs are such that Gen A is always the lowest cost Proposal and Gen C is always the highest cost Proposal.

(A) Sub-Zone allocation

- Gen A, at 1,200 MW, would require Incremental Transmission Expansion Costs in the Keith Sub-Zone at Step 1, Step 2 and Step 3 Upgrade levels, with a total incremental cost of $200 million, allocated entirely to Gen A.

- Gen B, at 600 MW, would require Incremental Transmission Expansion Costs in the Lauzon/Kent Sub-Zone at Step 1 and Step 2 Upgrade levels, with a total incremental cost of $75 million, allocated entirely to Gen B.

- Gen C, at 400 MW, would require no Incremental Transmission Expansion Costs, as the Lambton Sub-Zone has 2,000 MW of available existing capacity.

(B) Zone allocation

Assuming that an adjusted Evaluated Cost (including allocation of Sub-Zone Incremental Transmission Expansion Costs) produces the same ordering of Proposals, if Gen A and Gen B are both in the London to

Windsor Zone, with combined capacity of 1,800 MW, and require $200 million in Incremental Transmission Expansion Costs, then,

- Gen A gets precedence due to having a lower cost after the Sub-Zone allocation of Incremental Transmission Expansion Costs because 1,000 MW of Gen A's capacity fits within the existing available Zone capacity. Gen A would be allocated a $40 million share of the $100 million Step I Upgrade in proportion to the 200 MW that falls within the Step I Upgrade ([200/5001 x $100 million = $40 million).

- Gen B would be allocated a $60 million share of Incremental Transmission Expansion Costs in proportion to the 300 MW that falls within the Step 1 Upgrade (i.e. [300/500] x $100 million = $60 million) plus all of the $100 million Step 2 Incremental Transmission Expansion Costs. The Total Zone Incremental Transmission Expansion Costs allocated to Gen B equals $160 million.

- Gen C would require no upgrade in the London to Sarnia Zone, and therefore, would not be allocated any Incremental Transmission Expansion Costs.

(C) Area Allocation

Assuming that the Provisional Evaluated Cost (including allocation of Incremental Transmission Expansion Costs) produces the same ordering of Proposals:

- Gen A, Gen B and Gen C have combined capacity of 2,100MW, requiring $50 million in Incremental Transmission Expansion Costs.

- Based on the ordering of Provisional Evaluated Costs, Gen A and Gen B would not be allocated any Incremental Transmission Expansion Costs.

- Gen C would be allocated the full $50 million in Incremental Transmission Expansion Costs.

(D) Combined Result

- Gen A would have an Assigned Incremental Transmission Expansion Cost of $250 million.
- Gen B would have an Assigned Incremental Transmission Expansion Cost of $225 million.
- Gen C would have an Assigned Incremental Transmission Expansion Cost of $50 million.

Note, however, that it is possible that as a result of triggering no Sub-Zone or Zone impacts, Gen C could have a higher Provisional Evaluated Cost than Gen A and Gen B, but a lower Evaluated Cost after Sub-Zone and Zone transmission costs have been allocated to Gen B and Gen A. In that case, Gen C would have priority with respect to the Area transmission capacity at zero cost, thus allowing for a Proposal with a higher initial Evaluated Cost being more economic due to its location in a favourable transmission Zone or Sub-Zone.

This concludes the illustration.

For the purpose of the Economic Evaluation, the Assigned Incremental Transmission Expansion Cost for a Proposal will be converted to a monthly per kW real levelized value in 2007 dollars. This conversion will be done by taking the Assigned Incremental Transmission Expansion Cost for a Proposal, dividing it by the CES Contract Capacity in kW and then multiplying the result by an annual carrying charge associated with the Assigned Incremental Transmission Expansion Costs, and which accounts for the conversion of the investment to a monthly real levelized value in 2007 dollars. The initial Evaluated Cost will be adjusted by adding the real levelized value, known as the Transmission Upgrade Cost Impact to develop the final Evaluated Cost that will be used in the Economic Evaluation.

The allocation process described above will be used to allocate Incremental Transmission Expansion Costs over all Proposals to develop an Assigned Incremental Transmission Expansion Cost for each Proposal and a Transmission Upgrade Cost Impact for each Proposal for a New Generating Facility. The process will be applied in the sequence described above so long as there are less than 2,500 MW of Proposals for New Generating Facilities in an Area. If an Area has over 2,500 MW of Proposals for New Generating Facilities, the screening of New Generating Facilities for that Area will be conducted prior to this step, and only Proposals that pass the screen will be considered in the determination for that Area.

x. Screening of Proposals for New Generating Facilities for Areas with over 2,500 MW of New Generating Facility Proposals Prior to Determining Transmission Upgrade Cost Impacts for Proposals for New Generating Facilities in that Area

Proposals for New Generating Facilities will be screened so that no more than 2,500 MW of New Generating Facility Proposals will be evaluated from each of the six areas of the Province. This screening will be accomplished as follows:

(A) If an Area has less than 2,500 MW of Proposals for New Generating Facilities, all such Proposals are deemed to pass the screen.

(B) If an Area has more than 2,500 MW of Proposals for New Generating Facilities, all combinations of such Proposals in the Area that provide between 2,000 MW and 2,500 MW of aggregate capacity will be identified and the total cost of each combination will be examined. The total cost will be the weighted average initial Evaluated Cost of the New Generating Facilities in the combination plus the Incremental Transmission Expansion Cost resulting from the combination converted to a real levelized monthly value per MW of the aggregate capacity of the combination. All Proposals for New Generating Facilities in the lowest cost combination will be deemed to pass the screen.

(C) If an Area has more than 2,500 MW of Proposals for New Generating Facilities but has no combinations of Proposals for New Generating Facilities with aggregate capacity between 2,000 MW and 2,500 MW, the range will be expanded in 500 MW increments and the process repeated until a range is populated with at least one combination.

(D) Any Proposal for a New Generating Facility that is not deemed to pass the screen will no longer be evaluated and will be eliminated from the process, unless a Proposal for a New Generating Facility that has passed the screen becomes no longer valid (as described in Section III.D.2.b.x) at which point the screen will be re-applied as if the Proposal that is no longer valid was never submitted. Notwithstanding the above, if the Ministry observes that due to the particular size of bids in an Area, a Proposal that could potentially contribute to the lowest overall solution has failed the screening process, the Ministry may at its sole discretion elect to consider the Proposal as part of the analysis of combinations of Proposals to be added to those initially selected through the initial Stacking process. It is, however, possible that this additional step will not be required as the initial Stack may be the final Stack. The Ministry is under no obligation to further consider any Proposal that fails the screening process.

xi. Selecting the Stack of Proposals for New Generating Facilities, DSM Projects and DR Projects to Most Cost Effectively Approximate the Target Capacity

(A) Once the first adjustment of Evaluated Costs to incorporate Transmission Upgrade Cost Impacts has been done, a provisional Stack of Proposals based on the Provisional Evaluated Costs will be created. Only Proposals that have passed the screen will be considered from this point forward and all references after this point should be read to include only Proposals for New Generating Facilities that have passed the screen. The provisional Stack will order Proposals, including New Generating Facilities, DSM Projects, and DR Projects, from the lowest to the highest Evaluated Costs (Provisional Evaluated Costs for New Generating Facilities) such that the aggregate capacity delivered by the Proposals in the Stack most closely approximates the Target Capacity. This will be determined by comparing aggregate capacity with and without the Proposal that causes the aggregate capacity to exceed the Target Capacity, and including such Proposal only if the aggregate capacity is closer to the Target Capacity with the Proposal included. At the conclusion of this step, the allocation of Incremental Transmission Expansion Costs and Transmission Cost Upgrade Impacts will be recomputed assuming that only Proposals in the provisional Stack are selected Proposals and then the Stack will be reviewed to identify all Proposals in the Stack:

- that have an adjusted Evaluated Cost after the re-computation of Transmission Cost Upgrade Impacts described immediately above that is lower than the initial Evaluated Cost (i.e., the Evaluated Cost absent any consideration of Transmission Upgrade Cost Impacts) of any Proposal that was not placed in the Stack; and,

- that do not share in an allocation of Incremental System Transmission Expansion Costs with another Proposal in the Stack that has an adjusted Evaluated Cost after the recalculation of Transmission Cost Upgrade Impacts described immediately above that is higher than the initial Evaluated Cost (i.e., the Evaluated Cost absent any consideration of Transmission Upgrade Cost Impacts) of any Proposal that was not placed in the Stack,

and such Proposals will be deemed to be selected for inclusion in the final Stack of Proposals for New Generating Facilities, DR Projects and DSM Projects.

(B) If the aggregate capacity of the Proposals determined at this stage to be in the Stack is equal to or exceeds the Target Capacity by no more than 150 MW, the resulting Stack will be the final Stack of Proposals for New Generating Facilities, DR Projects and DSM Projects. If the aggregate capacity of the Proposals determined at this stage to be in the Stack is more than 150 MW above the Target Capacity, the Proposal for the last project shall be removed from the Stack. If the aggregate capacity of the Proposals determined at this stage to be in the Stack is less than the Target Capacity less 150 MW, all possible combinations of remaining Proposals will be considered to determine the Stack of Proposals that taken together with the Proposals deemed to be in the Final Stack result in aggregate capacity between plus and minus 150 MW of the Target Capacity and has the lowest weighted average cost per MW of capacity in the Stack, taking into consideration the initial Evaluated Cost of all Proposals in the Stack and the Incremental Transmission Expansion Costs for the Stack as a whole. The Stack selected through this process will be the final Stack of all Proposals for New Generating Facilities, DR Projects and DSM Projects.

(C) If any Stack with aggregate capacity between 2,650 and 3,250 MW determined in the same way as set out in paragraph (B) above has a weighted average Evaluated Cost (including total Transmission System Expansion Costs) which is less than or equal to 105% of the weighted average Evaluated Cost of the final stack between 2,350 MW and 2,650 MW as described above, the Ministry reserves the right to select such Stack between 2,650 MW and 3,250 MW, as an alternative final Stack of Proposals for New Generating Facilities, DR Projects and DSM Projects which the Ministry may use in developing its recommendation to the Cabinet. Alternatively, if any Stack with aggregate capacity between 1,750 MW and 2,350 MW determined in the same way as set out in paragraph (B) above has a weighted average Evaluated Cost (including total Transmission System Expansion Costs) that is less than or equal to 95% of the weighted average Evaluated Cost of the final stack between 2,350 MW and 2,650 MW as described above, the Ministry reserves the right to select such Stack between 1,750 MW and 2,350 MW, as an alternative final Stack of Proposals for New Generating Facilities, DR Projects and DSM Projects which the Ministry may use in developing its recommendation to the Cabinet. Proponents should note that the Ministry's decision as to whether or not to examine Stacks between 1,750 MW and 2,350 MW, or between 2,650 MW and 3,250 MW, as set out above, is entirely discretionary and the Evaluation Team may not examine any such stacks.

(D) At this point, a check will be performed to determine if there is a seasonal imbalance in the available capacity between Summer and Winter. Specifically, if the total capacity available in the Summer exceeds that available in the Winter by 250 MW or more, then, based on their respective Evaluated Costs, DR Projects with greater Summer capacity will be removed from the Stack until the imbalance does not exceed 250 MW. If the imbalance is reversed, then, based on their respective Evaluated Costs, DR Projects with greater Winter capacity will be removed from the Stack in a similar manner to address the imbalance.

(E) Once the final Stack has been selected pursuant to paragraph (C) above, the Evaluated Costs (the initial Evaluated Costs before allocation of Incremental Transmission Expansion Costs in the case of Proposals for New Generating Facilities) of the Proposals in the Stack, starting with the Proposal with the highest Evaluated Cost may be reviewed. If the Evaluated Cost of the most expensive Proposal in the Stack is more than 25% greater than the weighted average Evaluated Cost of the other Proposals with lower Evaluated Costs in the Stack, then the Ministry reserves the right to reject such Proposal. If it determines to reject such Proposal, then if the Evaluated Cost of the next most expensive Proposal in the Stack is more than 25% greater than the weighted average Evaluated Cost of the other Proposals with lower Evaluated Costs remaining in the Stack, the Ministry may determine to reject such Proposal, and so on in respect of the next most expensive Proposal, until the last Proposal remaining in the Stack. Other than the Proposal with the lowest Evaluated Cost, the Ministry may reject each Proposal in the Stack that has an Evaluated Cost that is more than 25% greater than the weighted average Evaluated Cost of the other Proposals remaining in the Stack provided it has determined to reject each of the immediately preceding Proposals with greater Evaluated Costs. For certainty, if a Proposal in the Stack has an Evaluated Cost that is equal to or less than 25% more than the weighted average Evaluated Cost of the less expensive remaining Proposals in the Stack, the Ministry will not have discretion to reject the next Proposal in the Stack with a lower Evaluated Cost even if its Evaluated Cost is more than 25% greater than the weighted average Evaluated Cost of the other Proposals in the Stack with lower Evaluated Costs.

xii. Potential for Need to Repeat Evaluation in Event a Proposal is No Longer Valid

All applicable CES Contracts, DR Contracts, and DSM Contracts will be executed first by the Selected Proponents. The Contracts will be executed by OEFC (or the OPA, if established) once all Contracts have been executed by all Selected Proponents. If for any reason a Proposal ceases to be valid, such as if a Selected Proponent does not execute a CES, DR or DSM Contract, as applicable, and post Completion and Performance Security in accordance with Section IV.A.8, it will be determined whether the invalid Proposal has shared in the allocation of Incremental Transmission Expansion Costs with a still valid Proposal or Proposals. If it has, the Provisional Evaluated Cost of the still valid Proposal or Proposals will be recomputed to reflect that the Proposal that is no longer valid will not be able to share in the Incremental Transmission Expansion Cost. In this event, the Economic Evaluation will be re-done as if the Proposal or Proposals that are no longer valid were never submitted. However, all Proposals in the selected Stack that did not share in an allocation with the Proposal that is no longer valid shall be left in the Stack and the Stack shall be completed by examining combinations required to reach aggregate capacity between plus and minus 150 MW of Target Capacity using the methodology above to fill out a Stack. The Ministry reserves the right to conduct such a re-evaluation at such time as it becomes aware that a Proposal is no longer valid up until the time at which the OEFC (or the OPA, if established) has executed and delivered to Selected Proponents all CES, DR and DSM Contracts.

xiii. Final Determination of Proposals to be Recommended for Selection

The resulting Stack will represent the lowest cost Proposals for New Generating Facilities, DR Projects and DSM Projects that, taken together, deliver aggregate capacity approximate to the Target Capacity. The Ministry reserves the rights set out in Section IV.A.9.c in respect of the conduct of the Economic Evaluation, including selection of the final Stacks. Where the Ministry has selected an alternative final Stack pursuant to Section III.D.2.b.xi.(C) or Section III.D.2.b.xi.(E), the Ministry may present an alternative resulting Stack which will represent a lower weighted average cost of Proposals for New Generating Facilities, DR Projects and DSM Projects. Provided that the proposed prices of the Proposals in either Stack are acceptable, all of the Proposals in one of these two resulting Stacks will be recommended by the Ministry to the Government of Ontario to be accepted, subject to the approval of the Cabinet of the Government of Ontario.

E. Economic Bid Statement

Proponents are to submit their Economic Bid Statements in a separate, sealed, opaque envelope, marked “Economic Bid Statement” followed by the name of the Proponent and the name of the project. The Net Revenue Requirement, as defined below, is to be expressed in Canadian Dollars per MW per month and shall be exclusive of applicable GST and PST payable by the Buyer in respect of the CES, DR, and DSM Contracts and includes, for the New Generating Facility or Demand-Side Project as applicable, all development (including obtaining required permits and approvals), construction, financing, operations, maintenance and capital improvement costs for the project, including those related to connecting the facility to the IMO-Controlled Grid, a local distribution system or End-user, if applicable.

The Net Revenue Requirement must be entered precisely in numeric form using the format provided below without further information, condition, or qualification whatsoever in the Proposal. Prospective Proponents are advised that any deviation from the required format of the Economic Bid Statement whatsoever, such as the provision of a price range, conditional price, qualified price, or an incomplete price, shall result in the disqualification of the Proposal. Moreover, the Net Revenue Requirement and any other element of the Economic Bid Statement shall not be disclosed or described in any other part of the Proposal, failing which the Proposal shall be disqualified.

1. Economic Bid Statement for a New Generating Facility

An Economic Bid Statement for a New Generating Facility must include:

a. Net Revenue Requirement

A Net Revenue Requirement (NRR) for the New Generating Facility, expressed as $/MW-month, which is to be the price per MW per month that the Proponent proposes to receive under the CES Contract and to recover from the market, pursuant to the opportunities provided under the CES Contract, to cover capital and financing costs for the development and construction of the facility, including connection costs considering that the CES Contract will generally provide for operating and fuel costs and will involve offsetting and adjustment of additional revenue sources that arise over the course of the term of the CES Contract. The offsetting and adjustment provisions of the CES Contract are described in Section V.A.2.d. below. In addition, the Proponent must indicate what percentage of the NRR is to remain level over the term of the CES Contract and what percentage is to be adjusted at the Specified Index. The Proponent may choose any value between 0% and 20% for the portion of the NRR that is to be adjusted at the Specified Index. This adjustment will be taken into account in the Economic Evaluation.

b. Connection Costs

Separate estimates of the costs which are payable by the Supplier in relation to the reliable connection of the New Generating Facility to a Transmission System, a Local Distribution System, or an End-user, as applicable, as specified pursuant to the System Impact Assessment, the Connection Impact Assessment and Customer Impact Assessment, as applicable (which together comprise the Connection Costs), together with the name of the entity that prepared any such estimates. Such estimates, where applicable, must be provided notwithstanding that the identification of the required facilities and the associated costs may not have been provided, or agreed, by the relevant Transmitter, Distributor, or End-user.

Prospective Proponents are advised that the Connection Costs will be considered to be included in the Net Revenue Requirement (i.e. these costs must be covered by the NRR). Any risks associated with variances between actual Connection Costs and any estimates of such Connection Costs used in preparing a Proposal are the sole responsibility of the Prospective Proponent, whether or not the Prospective Proponent has completed the applicable connection assessments. Notwithstanding the foregoing, Prospective Proponents are advised that in the event that the OEB orders that transmitters or distributors instead of the relevant generators pay any or all of such Connection Costs, the NRR set out in the CES Contract will be reduced by mutual agreement.

Nonetheless, the NRR and the Evaluated Cost of a Proponent's Proposal will not be reduced for purposes of conducting the Economic Evaluation and the selection of Selected Proponents based on Evaluated Cost as described in Section III.D.

c. Specific Information Relating to Gas and Non-Gas Facilities

In addition to these general provisions, the following specific provisions shall apply as applicable depending upon the type of New Generating Facility:

i. New Gas Generating Facility

An Economic Bid Statement for a New Generating Facility that is a New Gas Generating Facility must also include the following:

- a Specified Heat Rate for the New Gas Generating Facility, expressed in BTU/kWh, which must be within the range of 5,000 and 8,000 BTU/kWh and which will be applied as a higher heating value heat rate by applying this value directly to the Gas Price Index adjusted only for exchange rate;
- the O&M Cost for the New Gas Generating Facility, expressed as $/MWh, which will be fully indexed to the Specified Index; and
- Start-up Costs expressed in an amount of BTUs per start-up. This will be converted to a dollar value by applying the Gas Price Index to the stated BTUs per start-up;

ii. New Non-Gas Generating Facility

An Economic Bid Statement for a New Non-Gas Generating Facility must also include the following:

- an Energy Cost for the New Non-Gas Generating Facility, expressed as $/MWh, which will be fully indexed to the Specified Index; and

- Start-Up Costs expressed in $ per start-up, which will be fully indexed to the Specified Index.

2. Economic Bid Statement for Demand-Side Projects

a. DR Projects

An Economic Bid Statement for a DR Project must include:

i. The Net Revenue Requirement, or NRR, for the DR Project, expressed as $/MW-month, which is to be the maximum price per MW per month that the Proponent will receive under the DR Contract to cover the DR Costs (as defined in the DR Contract). The Net Revenue Requirement set out in the Economic Bid Statement must be based on an estimate of the DR Costs and the Net Revenue Requirement shall be evaluated in the Economic Evaluation on the assumption that these estimated costs are accurate. The Supplier must also specify the length of the Term, which shall be a whole number from 5 to 20 years.

b. DSM Projects

An Economic Bid Statement for a DSM Project must include:

i. The DSM Project Equivalent Capacity, as calculated by the Proponent using the methodology set out in Appendix L to the 2,500 MW RFP;

ii. The DSM Incremental Capital Cost, as calculated by the Proponent using the methodology set out in Exhibit Q to the DSM Contract;

iii. The DSM Project Annual Electricity Savings, as calculated by the Proponent using the methodology set out in Exhibit Q to the DSM Contract;

iv. The Average Cost of Electricity (Proposal), as calculated by the Proponent using the methodology set out in the DSM Contract;

v. A proposed length of Term, which shall be a whole number from 5 to 20 years; and

vi. The total annual DSM Variable Costs for each year of the proposed Term.

F. Proposal Security

Prospective Proponents must submit, as part of each Proposal, financial security payable and in favour of “Ontario Electricity Financial Corporation” in the form of:

i. a certified cheque or a bank draft issued by a financial institution listed in either Schedule I or II of the *Bank Act* (Canada);

ii. an irrevocable and unconditional standby letter of credit issued by a financial institution listed in either Schedule I or II of the *Bank Act* (Canada), or such other financial institution having a minimum credit rating of (i) A– with S&P, (ii) A3 with Moody’s, (iii) A low with DBRS, or (iv) A with Fitch IBCA, in the form attached as Appendix F; or

iii. a bid bond issued by a surety with a financial strength rating of A- or higher by A.M. Best in financial size category VIII or higher, in the form attached as Appendix G.

The value of the Proposal Security shall be $25,000 per MW of CES Contract Capacity, Maximum Contracted Demand Reduction, or DSM Project Equivalent Capacity, as applicable, subject, however, to a minimum of $125,000 and a maximum of $1,000,000. No other form of Proposal Security will be acceptable. Failure to tender the Proposal Security in the form required in respect of a Proposal may result in disqualification of the Proposal. Proposal Security will be reviewed by the Evaluation Team for completeness, then if found to be complete, will be held by the Shared Services Bureau in accordance with the terms and conditions of this 2,500 MW RFP.

Once a Proposal has entered Stage 3, then the Proposal Security will be subject to being drawn upon in accordance with the terms of the 2,500 MW RFP.

An authorized director or officer of the Proponent must complete and sign a declaration in the form set out in Appendix H certifying, amongst other things, that the Proponent agrees that Ontario Electricity Financial Corporation, as directed by the Ministry, shall be able to draw upon the Proposal Security if, from and after Stage 3, the Proponent is found to have made any material misrepresentation in its Proposal or if the Proponent of a New Generating Facility, DR Project or DSM Project, having become a Selected Proponent, fails to sign the CES Contract, DR Contract or DSM Contract, respectively, within ten (10) Business Days of the date on which the Proponent is given the final CES Contract, DR Contract, or DSM Contract to sign.

Proposal Security will be returned to Proponents in accordance with Section IV.A.6.

For any Proposal disqualified in Stages 1 or 2, only the Proposal Security and the unopened envelope containing the Economic Bid Statement shall be returned to the Proponent. The remaining documents comprising the original copy of the disqualified Proposal shall be returned to the Proponent upon written request by the Proponent.

After the announcement by the Ministry of the execution of the CES Contracts, DR Contracts, and DSM Contracts by the respective Suppliers, the Proposal Security shall be returned to those Qualified Proponents who were not Selected Proponents. The remaining documents comprising the original copy of such Proponent's Proposal shall be returned to the Proponent only upon written request by the Proponent.

G. Additional Declarations and Confidentiality Statement

As part of its Proposal, each Prospective Proponent shall complete, sign and submit the declarations described below and in the forms set forth in Appendices H, I, and J, and may submit a Confidentiality Statement, as described below, if applicable. The pre-printed wording of the declarations may not be altered, as previously noted in Section III.B. Prospective Proponents are reminded that the onus is solely on the Proponent to conduct all investigations and verifications necessary, including any investigations required of any member(s) of the Proposal Team, in order to confirm that each of the statements set out in the declarations can be made.

If any member of the Proponent Non-Core Team provides any advice or assistance in the preparation of the Proposal(s) of Another Proponent Team, or if any such member of a Proponent Team will be privy to information relevant to Another Proponent Team's Proposal(s), then Proponents are reminded that the Proponent must have taken and/or put in place appropriate measures or protections to ensure that such person does not serve as a conduit for the exchange, sharing or comparison of information relating to any Proposal between multiple Proponent Teams.

All completed declarations, statements, and forms must be signed by a director, officer or other person who has the authority to bind the Proponent. Prospective Proponents are advised that if, in the sole and absolute determination of the Ministry, any matter declared in the following declarations is not materially true and correct, then the Proposal may be disqualified, and in the event that the Proposal has entered Stage 3, then Ontario Electricity Financial Corporation, as directed by the Ministry, may, in addition to any other remedies available at law or in equity, draw upon the Proposal Security. In instances where the Proposal is not disqualified notwithstanding a discrepancy or inconsistency between the declarations described below and a Proponent's Proposal, the declarations shall be deemed to prevail.

1. Appendix H: Statutory Declaration

Each Proponent must provide a statutory declaration, in the form provided in Appendix H, providing confirmations with respect to the following matters:

a. Proposal Validity and Proposal Security

The Proponent must declare: (i) that the Proposal is valid and all statements, specifications, data, confirmations, and other information set out in the Proposal are accurate; (ii) that the Proposal will remain valid and open for acceptance until the date that is one hundred and eighty (180) days from the Proposal Submission Deadline; (iii) that the Proponent agrees to be bound by the terms of the CES or DR Contract, as applicable, including any security that may be required under the CES or DR Contract; and (iv) that the Proponent, its proposed facility or any member of the Proponent Team is not the subject of any bona fide legal proceedings, investigation or regulatory hearings that could materially impact the financial condition of the Proponent or any of the entities involved in financing and operations for the proposed New Generating Facility or Demand-Side Project. Moreover, the declaration shall certify that the Proponent agrees that provided the Proposal has entered Stage 3, then Ontario Electricity Financial Corporation, as directed by the Ministry, shall be able to draw upon the Proposal Security if the Proponent is found to have made any material misrepresentation in its Proposal or if the Proponent of a New Generating Facility, DR Project or DSM Project, having become a Selected Proponent, fails to sign the CES Contract, DR Contract or DSM Contract, respectively, within ten (10) Business Days of the date on which the Proponent is given the final CES Contract, DR Contract, or DSM Contract to sign.

b. Non-Collusion Declaration

The Proponent must declare that:

i. in preparing its Proposal(s), no member of its Proponent Team has discussed or communicated any information relating to its Proposal(s) with Another Proponent Team;

ii. the Proponent:

- is not a member of any other Proponent Team, except as a Proponent of a Proponent Team that is not Another Proponent Team;

- has not coordinated its Economic Bid Statement or any other aspect of any of its Proposal(s) with Another Proponent Team;

- has no knowledge of the contents of the Proposal(s) submitted by Another Proponent Team; and

- has kept and will continue to keep its Proposal(s) confidential until the Selected Proponents are publicly announced;

iii. no member of its Proponent Core Team has entered into any agreement or arrangement with any member of Another Proponent Core Team, which may, directly or indirectly, affect the Economic Bid Statement or any other aspect of the Proposal(s) submitted by the Proponent and/or Another Proponent Team;

iv. no member of its Proponent Core Team has provided advice or assistance in the preparation of the Proposal(s) of Another Proponent Team; and

v. no member of its Proponent Non-Core Team has provided any advice or assistance in the preparation of the Proposal(s) of Another Proponent Team. In the alternative, if such person has provided such advice or assistance to Another Proponent Team, or if such person will be privy to information relevant to Another Proponent Team's Proposal(s), then the Proponent has taken and/or put in place, or caused to be taken and/or put in place, appropriate measures or protections to ensure that such person does not serve as a conduit for the exchange, sharing or comparison of information relating to any Proposal between multiple Proponent Teams.

2. Appendix I: Conflict of Interest Declaration

Each Proponent must provide a statutory declaration, in the form provided in Appendix I, declaring whether it has an actual or potential Conflict of Interest, and if so, the nature of such actual or potential Conflict of Interest. However, if, at the sole and absolute discretion of the Ministry, the Proponent is found to have a Conflict of Interest, the Ministry may, in addition to any other remedies available at law or in equity, disqualify the Proposal submitted by the Proponent. The Proponent, by submitting the Proposal, warrants that to its best knowledge and belief no actual or potential Conflict of Interest exists with respect to the submission of the Proposal other than those disclosed in the Conflict of Interest Declaration. Where the Ministry discovers a Proponent's failure to disclose all actual or potential Conflicts of Interest, the Ministry may disqualify the Proponent or terminate the CES, DR or DSM Contract, if awarded to that Proponent in accordance with this 2,500 MW RFP.

3. Appendix J: Tax Compliance Declaration

The Government of Ontario expects all Suppliers to pay their provincial taxes on a timely basis. The Proponent must provide a Tax Compliance Declaration, in the form attached as Appendix J, confirming that the Proponent's provincial taxes are in good standing. The Ministry will forward to the Ontario Ministry of Finance a copy of each Proponent's signed Tax Compliance Declaration Form for verification. By signing this form, the Proponent is consenting to the release of such information from the Ministry to the Ministry of Finance and from the Ministry of Finance to the Ministry for this purpose. In the event that the Ministry of Finance finds that the Proponent is not in compliance with all of the tax statutes administered by the Ontario Ministry of Finance as required in the Tax Compliance Declaration, a Selected Proponent may be permitted to rectify any such non-compliance but must do so as a pre-condition to, and without delaying, the requirement for the Selected Proponent of a New Generating Facility, DR Project or DSM Project to sign the CES, DR or DSM Contract, respectively, within ten (10) Business Days of the date on which the Selected Proponent is given the final CES, DR or DSM Contract to sign.

4. Confidentiality Statement

Information provided by a Proponent is subject to, and may be released in accordance with, the provisions of the *Freedom of Information and Protection of Privacy Act* (Ontario). The Proponent will clearly indicate in a separate confidentiality statement, in a form provided by the Proponent, any portion of the Proposal that contains proprietary or confidential information for which confidentiality is to be maintained by the Ministry and its technical advisors. Such portions of the Proposal will be clearly marked "Proprietary and Confidential" by the Proponent. In the event that no confidentiality statement is provided, the Proponent will be automatically deemed to certify to the Ministry that no portion of the Proposal contains proprietary or confidential information for which confidentiality is to be maintained by the Ministry or its technical advisors.

The confidentiality of any such information identified by the Proponent will be maintained by the Ministry and its technical advisors, except where an order by the Information and Privacy Commission, a court, or a tribunal requires the Ministry to do otherwise.

Notwithstanding the foregoing, the Ministry shall not be required to maintain the confidentiality of any such information that:

a. is or becomes generally available to the public without fault or breach on the part of the Ministry and its advisors of any duty of confidentiality owed by the Ministry and its advisors to the Proponent or to any third party;

b. the Ministry and its advisors can demonstrate that it had been rightfully obtained by the Ministry and its advisors, without any obligation of confidence, from a third party who had the right to transfer or disclose it to the Ministry and its advisors free of any obligation of confidence;

c. the Ministry and its advisors can demonstrate that it had been rightfully known by, or in the possession of, the Ministry and its advisors at the time of disclosure, free of any obligation of confidence when disclosed; or

d. has been independently developed by the Ministry and its advisors.

Proponents are advised that their Proposals will, as necessary, be disclosed on a confidential basis, to the Evaluation Team the Government of Ontario, and the Ministry's advisers retained for the purpose of evaluating or participating in the evaluation of the Proposals.

IV. TERMS AND CONDITIONS OF THE 2,500 MW PROCUREMENT PROCESS

A. General Information and Instructions

1. Timetable

The timetable with respect to the entire procurement process for this 2,500 MW RFP is set out below. Following the deadline for the Submission of Proposals, the procurement process will proceed to the Evaluation of Proposals and the finalization of contracts. All dates shown are in 2004, except as otherwise set out below.

Submission of Proposals:

Announcement of 2,500 MW RFP	January 20
Release of RFI/RFQ	June 25
Technical Consultation Session	July 6
Release of draft CES Contract	July 21
Release of draft DR Contract	July 26
Interested parties submit questions and comments regarding the RFI/RFQ and draft Contracts	June 30 to August 27
Release of the final 2,500 MW RFP	September 13
Deadline for submission of Statement of Qualifications	September 16 at 3:00:00 p.m. (EDT)
Release of Appendices to 2,500 MW RFP	September 20
Technical Consultation Session #2	October 6
Release of CES, DR and DSM Contracts	October 8
Interested parties submit questions and comments regarding the 2,500 MW RFP and Contracts	September 30 to November 5
Deadline for Issuing Addenda to the 2,500 MW RFP	November 15
Proposal Submission Deadline	December 15 at 3:00:00 p.m. (EST)

Evaluation of Proposals and Finalization of Contracts

Evaluation of Proposals and confirmation of Qualified Proponents	December 16, 2004 to February 7, 2005
Finalization of CES, DR Contracts, and DSM Contracts	February, 2005

The Ministry reserves the right to accelerate and postpone the dates set out in this Section IV.A.1 upon notice to Proponents.

2. Communication After Issuance of this 2,500 MW RFP

a. Access to and Questions on this 2,500 MW RFP

This 2,500 MW RFP is accessible through the section of the website www.ontarioelectricityrfp.ca dedicated to this 2,500 MW RFP process. A notice relating to this 2,500 MW RFP shall be posted on MERX™, the electronic tendering system used by the Province of Ontario, directing Prospective Proponents to this 2,500 MW RFP website.

Prospective Proponents shall promptly examine all of the documents comprising this 2,500 MW RFP and:

i. shall report any errors, omissions or ambiguities; and

ii. may direct questions regarding this 2,500 MW RFP,

in writing, on or before the deadline for questions on November 5, 2004, through the section of the website www.ontarioelectricityrfp.ca dedicated to this 2,500 MW RFP process. No such communications are to be directed to any person or in any manner other than through this website. All questions and answers will be posted on the section of the website www.ontarioelectricityrfp.ca dedicated to this 2,500 MW RFP. The identity of any Prospective Proponent asking a particular question will not be revealed. The Ministry is under no obligation to provide additional information, but it may do so at its sole discretion. It is the responsibility of the Prospective Proponents to seek clarification, by submitting questions on any matter it considers to be unclear. The Ministry shall not be responsible for any misunderstanding on the part of the Prospective Proponents concerning this 2,500 MW RFP or its process.

b. Addenda to this 2,500 MW RFP

This 2,500 MW RFP may be amended only by addendum in accordance with this Section. If the Ministry, for any reason, determines that it is necessary to provide additional information relating to this 2,500 MW RFP, such information will be communicated to all Prospective Proponents by an addendum, which shall be delivered to Prospective Proponents by posting same on the section of the website www.ontarioelectricityrfp.ca dedicated to this 2,500 MW RFP process, on or prior to the Deadline for Issuing Addenda for this 2,500 MW RFP. Each addendum shall form an integral part of this 2,500 MW RFP.

Each addendum may contain important information including significant changes to this 2,500 MW RFP. Prospective Proponents are responsible for checking the aforementioned website as often as necessary to ensure that they obtain all addenda issued from time to time. In the form of the Statutory Declaration attached as Appendix H, Proponents must confirm their receipt of all addenda to this 2,500 MW RFP issued by the Ministry.

c. Post-Deadline Addenda and Extension of Proposal Submission Deadline

If any addendum is issued after the Deadline for Issuing Addenda, the Ministry may at its discretion extend the Proposal Submission Deadline for a reasonable amount of time having regard to the circumstances.

3. Submission of Proposals

a. General Information

Only Prospective Proponents, namely those entities or persons who submit Statements of Qualifications in accordance with the RFI/RFQ, are entitled to submit Proposals in response to this 2,500 MW RFP. For a proposed New Generating Facility or Demand-Side Project for which a Statement of Qualifications was submitted in accordance with the RFI/RFQ, if the Prospective Proponent changes between the time of submission of the Statement of Qualifications and the time of submission of the Proposal, the Proposal must include a written notice, signed by the Prospective Proponent which originally submitted the Statement of Qualifications, informing the Ministry of the change and certifying that the Proposal is for the same proposed New Generating Facility or Demand-Side Project as set forth in the Statement of Qualifications.

A Proponent may submit Proposals for more than one New Generating Facility or Demand-Side Project, subject to the restrictions set out in Sections II.D.1, II.D.2 and II.D.3 and the non-collusion requirements set out in Section III.G.1. Prospective Proponents are advised that only one Proposal may be submitted by a Proponent in respect of each proposed project and that a Proposal may not be entered into more than one Project Stream. However, where the Proponent changes the Project Stream of a proposed project described in the Statement of Qualifications between the time of submission of the Statement of Qualifications and the time of submission of the Proposal, the Proposal must include a written notice, signed by the Prospective Proponent which submitted the Statement of Qualifications, informing the Ministry of the change in Project Stream and certifying that the Proposal is for the same proposed project contemplated by the Statement of Qualifications.

Prospective Proponents are responsible for submitting Proposals on time at the locations specified below and for ensuring that the Proposals are complete. Each Proponent should note that its entire Proposal, consisting of both:

i. the Technical and Financial Submission, together with the Proposal Security; and

ii. the Economic Bid Statement;

must be submitted by the Proposal Submission Deadline. However, Prospective Proponents should note that the Technical and Financial Submission, together with the Proposal Security, should be submitted to the address set out in Section IV.A.3.b, and the Economic Bid Statement should be submitted to the address of the Bid Repository, which will be set out in an Addendum to this 2,500 MW RFP. Further, a Proponent's Economic Bid Statement, which may not be altered after the Proposal Submission Deadline (but which may be withdrawn together with the balance of the Proposal), will only be opened by the Ministry when the Proponent has become a Qualified Proponent.

b. Technical and Financial Submission

To be considered, the Technical and Financial Submission, together with the Proposal Security, must be received no later than 3:00:00 p.m. (EST), on December 15, 2004 at the following address:

Shared Services Bureau
Strategic Procurement Branch
Tenders Office
56 Wellesley St. West, 2nd Floor
Toronto, ON M5S 2S3

Attention: 2,500 MW RFP

The postal code is to aid in identifying the building only. The onus remains solely with Prospective Proponents to instruct courier and delivery personnel to deliver the Technical and Financial Submissions to the exact floor location specified above by the Proposal Submission Deadline. Prospective Proponents assume sole responsibility for late deliveries if these instructions are not strictly adhered to.

The required elements of the Technical and Financial Submission are set out in Sections III.B.1, III.B.2, and III.B.3. The Proposal Security is described in Section III.B.5. In addition, the Technical and Financial Submission should include, in a form to be provided by the Proponent, a table of contents which identifies the page numbers of such required elements.

A Prospective Proponent must submit one (1) original copy of the Technical and Financial Submission and the Proposal Security, all of which is prominently marked “Original Copy”. For ease of identification, the Proposal Security should be contained in an envelope marked “Proposal Security”. The Prospective Proponent must also submit 11 additional collated copies of all elements of the Technical and Financial Submission excluding the Proposal Security. In addition, and for reproduction purposes, the Prospective Proponent should provide one unbound copy of the Technical and Financial Submission or an electronic copy of the Technical and Financial Submission (in Microsoft Word from the Microsoft Office Suite 97 or later, or Adobe Acrobat 4.0 or higher) excluding only the Proposal Security. The entire Technical and Financial Submission, including the original, the specified copies (including the unbound copy or the electronic copy), and the envelope containing the Proposal Security should be submitted in a sealed package. Only one Technical and Financial Submission and one envelope containing the Proposal Security shall be submitted per sealed package.

On the outside of the sealed package, using the Technical and Financial Submission Return Label attached at Appendix K, Technical and Financial Submissions should be prominently marked with this 2,500 MW RFP title and number as set out on the cover page of this 2,500 MW RFP, with the full legal name of the Prospective Proponent and its return address. If the full legal name of the Proponent is not the same as the name of the Prospective Proponent set out in the Statement of Qualifications, then the Prospective Proponent should also provide, in the space provided on the Technical and Financial Submission Return Label, the name of the Proponent as set out in the Statement of Qualifications. To the extent that the failure to affix the specified Technical and Financial Submission Return Label to the submission envelope or package results in the Technical and Financial Submission arriving late at the Tenders Office of the Strategic Procurement Branch of the Shared Services Bureau, the entire Proposal (i.e. including the Economic Bid Statement) may be deemed late, disqualified and returned unopened to the Prospective Proponent.

The Technical and Financial Submission must be in English only, and should be typed or printed neatly in black ink on both sides of 8.5 x 11 inch paper, and all pages should be numbered sequentially. The answers to the Technical and Financial Questionnaires, as well as the signed and completed Statutory Declaration, Confidentiality Statement, and Tax Compliance Declaration can be bound or stapled (except for one unbound copy as noted above). The content of websites or other external documents referred to but not included in the Proposal will not be considered to form part of the Proposal.

Except where expressly set out to the contrary in this 2,500 MW RFP, all Proposals shall become the property of the Ministry and shall not be returned to the Proponent.

c. Submission of Economic Bid Statement

All Economic Bid Statements should be received no later than 3:00:00 p.m. (EST), on December 15, 2004 at the address of the Bid Repository to be specified by way of an Addendum to this 2,500 MW RFP.

The postal code is to aid in identifying the building only. The onus remains solely with Prospective Proponents to instruct courier and delivery personnel to deliver the Economic Bid Statement to the exact location of the address of the Bid Repository by the Proposal Submission Deadline. Prospective Proponents assume sole responsibility for late deliveries if these instructions are not strictly adhered to.

The required elements of the Economic Bid Statement are set out in Section III.E and Appendices E-1, 2, 3, and 4, as applicable. A Prospective Proponent must submit one (1) original copy of the Economic Bid Statement in a separate envelope as specified in Section III.B.4. Only one Economic Bid Statement shall be submitted per sealed envelope.

On the outside of the sealed envelope, using the return label to be specified by way of an Addendum to this 2,500 MW RFP, the envelope should be prominently marked with this 2,500 MW RFP title and number as set out on the cover page of this 2,500 MW RFP, with the full legal name of the Proponent and its return address. If the full legal name of the Proponent is not the same as the name of the Prospective Proponent set out in the Statement of Qualifications, then the Proponent should also provide, in the space provided on such return label, the name of the Prospective Proponent as set out in the Statement of Qualifications. To the extent that the failure to affix the specified return label to the submission envelope results in the Economic Bid Statement arriving late, the entire Proposal may be deemed late, disqualified and the Economic Bid Statement shall be returned unopened to the Prospective Proponent.

Except where expressly set out to the contrary in this 2,500 MW RFP, all Proposals shall become the property of the Ministry and shall not be returned to the Proponent.

d. Proponents to Follow Instructions

Proponents should structure their Proposals in accordance with the instructions in this 2,500 MW RFP. Where information is requested in this 2,500 MW RFP, any response made in a Proposal should reference the applicable section numbers of this 2,500 MW RFP where such request is made.

e. Amending or Withdrawing Proposals

At any time prior to the Proposal Submission Deadline, a Proponent may amend or withdraw a submitted Proposal. The right of Proponents to amend or withdraw prior to the Proposal Submission Deadline includes amendments or withdrawals wholly initiated by Proponents and amendments or withdrawals in response to subsequent information provided by addenda to this 2,500 MW RFP.

Any amendment to a Proposal prior to the Proposal Submission Deadline should clearly indicate what part of the Proposal the amendment is intending to affect or replace.

After the Proposal Submission Deadline, a Proponent shall not be able to amend its Proposal except pursuant to a written request by the Evaluation Team for further information or documentation pursuant to Sections III.A.1 and IV.A.4. However, after the Proposal Submission Deadline, a Proponent shall be able to withdraw its Proposal by submitting in writing a notice of withdrawal, or the Notice of Intent to Proceed to Stage 3 completed accordingly, in the same manner as prescribed in this 2,500 MW RFP for the submission of the Technical and Financial Submission. Any notice of withdrawal submitted by any other method will not be accepted and shall be ignored.

At no time after the Proposal has entered Stage 3 may a Proponent withdraw a submitted Proposal.

f. 2,500 MW RFP Incorporated into Proposal

All of the provisions of this 2,500 MW RFP are deemed to be accepted by each Proponent and incorporated into each Proponent's Proposal.

g. Confidential Information of Ministry

All information provided by or obtained from the Ministry in any form in connection with this 2,500 MW RFP, either before and after the issuance of this 2,500 MW RFP (including any passwords that may be provided to Prospective Proponents in order to access any restricted portion of this 2,500 MW RFP website www.ontarioelectrictyrfp.ca):

i. is the sole property of the Ministry and must be treated as confidential;

ii. is not to be used for any purpose other than replying to this 2,500 MW RFP and the performance of the CES, DR and DSM Contracts;

iii. must not be disclosed without prior written authorization from the Ministry; and

iv. shall be returned by the Proponents to the Ministry immediately upon the request of the Ministry.

h. Irrevocability

Proposals shall be irrevocable in the form submitted by the Proponent from the time, if applicable, that the Proposal has entered Stage 3 until the date that is one hundred and eighty (180) days from the deadline for Submission of Proposals.

4. Ministry May Seek Clarification and Incorporate Response into Proposal

The Ministry reserves the right to seek clarification, and request additional information, documentation and statements, in relation to Proposals after the Proposal Submission Deadline. Any such requested information, documentation or statements should be submitted to the Evaluation Team within five (5) Business Days of the date of such request. After the Proposal Submission Deadline, Proponents shall only be permitted to provide information, documentation or statements requested by the Evaluation Team.

The response received by the Ministry from a Proponent shall, if accepted by the Ministry, form an integral part of that Proponent's Proposal. In the event that the Ministry receives information at any stage of the evaluation process which results in earlier information provided by the Proponent being deemed by the Ministry to be inaccurate, incomplete or misleading, the Ministry reserves the right to revisit the Proponent's compliance with the minimum mandatory technical and financial requirements set out in Section III.

5. Changes to Proponent Team

Prospective Proponents are advised that no changes in the Proponent Team or any lenders identified in the Proposal in connection with any source of financing and set forth by the Proponent in its response to question 1 of the Financial Questionnaire shall be permitted between the Proposal Submission Deadline and the execution of the CES, DR or DSM Contract, as applicable, without the prior written consent of the Ministry. Otherwise, the Proposal may be disqualified.

6. Cancellation or Return of Proposal Security

For each Proponent whose Proposal fails the completeness evaluation described in Section III.B.1 (Stage 1) or the evaluation of minimum mandatory technical and financial requirements described in Section III.C.2 (Stage 2), the Proposal Security will be cancelled or returned within ten (10) Business Days of the Proponent being notified that it has failed to progress in the evaluation process to the next stage. For each Proponent whose Proposal passes the minimum mandatory technical and financial requirements described in Section III.C.2 (Stage 2) but does not become a Qualified Proponent, Proposal Security will be cancelled or returned within ten (10) Business Days of the Evaluation Team's determination of the Qualified Proponents. For each Qualified Proponent, the applicable Proposal Security will be returned or cancelled within ten (10) Business Days of the Ministry's announcement of the Suppliers. For each Supplier, the applicable Proposal Security will be cancelled or returned following assessment of all Suppliers and delivery of the Completion and Performance Security due under the terms of the CES, DR or DSM Contract by the Supplier.

7. Selection of Selected Proponents

The Evaluation Team will make its recommendation to the Ministry and the Ministry will select the Selected Proponents, subject to the approval of the Cabinet of the Government of Ontario. The Ministry will notify each Selected Proponent in writing of such selection, and each Selected Proponent will then be required to execute the finalized CES, DR or

DSM Contract, as applicable, with OEFC (or if established, the OPA). Should a Selected Proponent of a New Generating Facility, DR Project or DSM Project fail to sign the CES, DR or DSM Contract, respectively, within ten (10) Business Days of the date on which the Selected Proponent is given the final CES, DR or DSM Contract to sign, the Evaluation Team may recommend, and the Ministry may agree, that another Proponent be selected in its place in accordance with the stacking procedure described in Section III.D. Once executed by the Selected Proponent (who is then referred to as the Supplier), the CES, DR, or DSM Contract will be returned to the Buyer for execution. Once all of the CES, DR and DSM Contracts with Selected Proponents have been executed by all Selected Proponents and the Buyer, there will be a public announcement of the Suppliers and their respective projects.

8. Contract Arrangements

After the Economic Evaluation described in Section III.D has been provisionally concluded, those Qualified Proponents that are selected will be advised that they are Selected Proponents and will be required to finalize the CES, DR and DSM Contracts, with the Buyer, as described in Section V.A.1.

Upon execution of a CES, DR or DSM Contract, as applicable, the Proposal Security will be returned by the Buyer to the Supplier and simultaneously replaced by the Completion and Performance Security to be posted under the executed CES, DR or DSM Contract.

The Completion and Performance Security under the CES Contract for New Generating Facilities shall be in the following amounts:

a. $100,000 per MW of CES Contract Capacity for New Generating Facilities with Commercial Operation Dates prior to December 31, 2006 (and shall be lowered to $25,000 per MW after the Commercial Operation Date);

b. $70,000 per MW of CES Contract Capacity for New Generating Facilities with Commercial Operation Dates on or after December 31, 2006 and prior to December 31, 2007 (and shall be lowered to $25,000 per MW after the Commercial Operation Date); and

c. $50,000 per MW of CES Contract Capacity for New Generating Facilities with Commercial Operation Dates on or after December 31, 2007 (and shall be lowered to $25,000 per MW after the Commercial Operation Date).

The Completion and Performance Security shall be in the amount of $50,000 per MW of Maximum Contracted Demand Reduction or DSM Project Equivalent Capacity, as applicable, which amount shall be lowered- to $25,000 per MW of Maximum Contracted Demand Reduction or DSM Project Equivalent Capacity after the Commercial Operation Date in accordance with the terms of the DR and DSM Contracts, respectively.

9. General Terms

a. No Liability for Costs and Expenses Incurred by Proponent

Each Proposal will be prepared at the sole cost and expense of the Proponent. Proponents will bear all costs and expenses in connection with their Proposal, including any costs incurred in the review of this 2,500 MW RFP and any expert advice required in responding to this 2,500 MW RFP. The Ministry and its technical advisors shall not be liable to pay any Proponent costs under any circumstances. In particular, the Ministry will not reimburse the Proponent in any manner whatsoever in the event of rejection of any or all Proposals or submissions, or in the event of the cancellation of this 2,500 MW RFP. By submitting a Proposal in response to this 2,500 MW RFP, the Proponent irrevocably and unconditionally waives any claims against the Ministry and its technical advisors relating to the Proponent's costs and expenses.

b. Rights of the Ministry during Stage 1 and Stage 2

Prospective Proponents are advised that the express intention of the Ministry is to pre-assess the Proposals, in its sole discretion, based on the requirements in Stages 1 and 2 prior to the initiation of a legally binding bidding process in Stage 3. Prospective Proponents are advised that during Stages 1 and 2, the Ministry may, among other things:

i. make public the names of any or all Proponents and members of Proponent Teams;

ii. check references other than those provided by any Proponent;

iii. verify with any Proponent or with a third party any information set out in a Proposal;

iv. disqualify any Proponent or the Proposal of any Proponent who has engaged in conduct prohibited by this 2,500 MW RFP;

v. make changes, including substantial changes, to this 2,500 MW RFP provided that those changes are issued by way of addenda in the manner set out in this 2,500 MW RFP;

vi. cancel this 2,500 MW RFP process at any stage;

vii. cancel this 2,500 MW RFP process at any stage and issue a new request for proposals for the same or similar deliverables;

viii. accept any Proposal in whole or in part;

ix. discuss with any Proponent different or additional terms to those contemplated in this 2,500 MW RFP or in any Proponent's Proposal;

x. if a single Proposal is received, reject the Proposal of the sole Proponent and cancel this 2,500 MW RFP process or enter into direct negotiations with the sole Proponent; or

xi. reject any or all Proposals in its absolute discretion;

and the Ministry shall not be liable for any expenses, costs, losses or any direct or indirect damages incurred or suffered by any Proponent or any third party resulting from the Ministry exercising any of its express or implied rights under this 2,500 MW RFP.

c. Reserved Rights of the Ministry during Stage 3

Prospective Proponents are advised that in light of the fact that a legally binding bidding process between the Ministry and each Qualified Proponent comes into effect upon the commencement of Stage 3, the Ministry, in Stage 3, reserves the right to:

i. make public the names of any or all Proponents and members of Proponent Teams;

ii. request written clarification of a Proposal from any Proponent and incorporate a Proponent's response to that request into the Proponent's Proposal;

iii. waive formalities and accept Proposals which substantially comply with the requirements of this 2,500 MW RFP;

iv. verify with any Proponent or with a third party any information set out in a Proposal;

v. reject any, all, or portions of the Proposals received for being incomplete or for failure to meet any criteria set forth in this 2,500 MW RFP;

vi. check references other than those provided by any Proponent;

vii. disqualify any Proposal that contains material misrepresentations or any other materially inaccurate or misleading information;

viii. disqualify any Proponent or the Proposal of any Proponent who has engaged in conduct prohibited by this 2,500 MW RFP;

ix. make changes, including substantial changes, to this 2,500 MW RFP provided that those changes are issued by way of addenda in the manner set out in this 2,500 MW RFP;

x. cancel this 2,500 MW RFP process at any stage;

xi. cancel this 2,500 MW RFP process at any stage and issue a new request for proposals for the same or similar deliverables;

xii. accept any Proposal in whole or in part;

xiii. discuss with any Proponent different or additional terms to those contemplated in this 2,500 MW RFP or in any Proponent's Proposal;

xiv. if a single Proposal is received, reject the Proposal of the sole Proponent and cancel this 2,500 MW RFP process or enter into direct negotiations with the sole Proponent; or

xv. reject any or all Proposals in its absolute discretion;

and these reserved rights are in addition to any other express rights or any other rights which may be implied in the circumstances and the Ministry shall not be liable for any expenses, costs, losses or any direct or indirect damages incurred or suffered by any Proponent or any third party resulting from the Ministry exercising any of its express or implied rights under this 2,500 MW RFP.

By submitting its Proposal, the Proponent, on its own behalf and on behalf of each member of the Proponent Team to which it belongs, authorizes the collection by the Ministry of the information set out under Sections IV.9.b.ii, IV.9.b.iii, IV.9.c.iv and IV.9.c.vi in the manner contemplated in those Sections.

d. Governing Law of this 2,500 MW RFP Process

This 2,500 MW RFP process shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

e. No Fettering

Proponents are advised that no provision of this 2,500 MW RFP is intended to operate, nor shall any provision have the effect of operating, in any way so as to interfere with or otherwise fetter the rights of the Government of Ontario in the exercise of its legislative powers.

f. Notification to Other Qualified Proponents of Outcome of Procurement Process

Once all Suppliers have executed their respective CES, DR and DSM Contracts with the Buyer, then all Qualified Proponents who have not become Suppliers will be notified by the Ministry in writing of the outcome of this 2,500 MW RFP procurement process and the award of the CES, DR and DSM Contracts to the Suppliers.

g. Debriefing

Proponents who were not Selected Proponents may request a debriefing after receipt of a notification of the award to the Selected Proponents. All requests must be in writing through this 2,500 MW RFP website www.ontarioelectricityrfp.ca, and must be made within 30 days of the notification of Selected Proponents. The intent of the debriefing information session is to aid the Proponent in presenting a better proposal in subsequent procurement opportunities. Any debriefing provided is not for the purpose of providing an opportunity to challenge this 2,500 MW RFP procurement process.

h. Prohibited Proponent Communications

The Ministry may, in its sole and absolute discretion, without any liability, cost or penalty, and in addition to any other remedies available to it at law, revoke the Proponent's status as a Prospective Proponent, Proponent, Qualified Proponent, or Selected Proponent and reject any potential or actual Proposal submitted by the Proponent, if any Proponent (and Prospective Proponent who has not submitted a Proposal) or any of their respective employees, agents, contractors or representatives:

i. discusses this 2,500 MW RFP, any Proposal, or the CES, DR or DSM Contracts with any agent or representative of the Ministry, any member of the Evaluation Team, any expert or other adviser assisting the Evaluation Team, any staff or employee of the Ministry's offices, any staff of the Premier of Ontario's office or the Cabinet of the Government of Ontario, and any members of the Cabinet of the Government of Ontario or their staff, except through the website www.ontarioelectricityrfp.ca dedicated to this 2,500 MW RFP process or in response to a request by the Evaluation Team for further information documentation or clarification as part of Stages 1 and 2; or

ii. directly or indirectly communicates with the media in relation to this 2,500 MW RFP, any Proposal, or the CES, DR or DSM Contracts without first obtaining the written permission of the Ministry, pursuant to a request made through the section of the website www.ontarioelectricityrfp.ca dedicated to this 2,500 MW RFP process.

The Proponent shall not engage in any Conflict of Interest communications or in any communications that would violate the prohibition against collusion set forth in Section III.G.1, and should take note of the Conflict of Interest and anti-collusion provisions contained in this 2,500 MW RFP.

For greater certainty, a Prospective Proponent, Proponent, Qualified Proponent, or Selected Proponent may publish any notices that are required in connection with regulatory processes relating to the development of the proposed CES, DR or DSM Project.

V. DESCRIPTION OF THE CES, DR AND THE DSM CONTRACTS

A. 2,500 MW RFP Contract Structures

1. Overview

A Selected Proponent, depending upon the type of project proposed, will be required to execute one of the CES Contract, the DR Contract or a DSM Contract as “Supplier”, and OEFC (or if established the OPA) shall be the “Buyer”. If OEFC is the Buyer, it is expected that OEFC will transfer the CES, DR and DSM Contracts to the OPA if established. The CES, DR and DSM Contracts shall take effect from the date it is signed by both parties and shall expire at the end of the term for the applicable contract, as outlined below. The three forms of contract are designed to operate in a complementary fashion and to meet the system’s requirements for new supply, demand response and demand-side management, respectively, while accommodating a wide variety of futures for the sector.

The contracts require the Supplier to design, build, operate and maintain the New Generating Facility, DR Project or DSM Project as outlined in its Proposal, using good engineering and operating practices and in compliance with the applicable Market Rules and applicable laws and regulations. Proponents are solely responsible for obtaining and maintaining federal, provincial and municipal permits, licences and approvals that are currently, or may in the future, be required for the development, construction and operation of the project. Demand-Side Projects are required to attain Commercial Operation on or before December 31, 2007, and New Generating Facilities are required to attain Commercial Operation on or before June 1, 2009.

Many Suppliers will be market participants and all licenced generators are subject to the requirements of the Market Rules. The Buyer does not take title to any products of the facilities constructed as a result of this 2,500 MW RFP, although the Supplier will be required to operate the facility in accordance with the CES, DR or DSM Contract, as applicable.

The CES, DR and DSM Contracts will be issued by the Ministry in final form in accordance with the timetable set out in Section IV.A.1, and Prospective Proponents are advised to review the CES, DR and DSM Contracts in their entirety for a detailed and complete description of the parties’ respective rights and obligations, and not simply those selected provisions that are summarized in this 2,500 MW RFP. Prospective Proponents are advised that the terms and conditions set out in the CES, DR and DSM

Contracts are not subject to negotiation; rather, the finalization of the CES, DR and DSM Contracts shall be limited only to the completion of any blanks, bullets, or similar uncompleted information, and the attachment of any Exhibits, that is required in order to tailor the CES, DR and DSM Contracts to the particular New Generating Facility, Demand Response Project or Demand-Side Management Project and, subject to the agreement of the Supplier, to address any provisions rendered inapplicable as a result of the *Electricity Restructuring Act*, 2004 (Ontario) and any regulation thereunder.

Any conflict or inconsistency between any of the CES, DR and DSM Contracts, this 2,500 MW RFP, and the Proposal shall be resolved by interpreting such documents in the following order from highest priority to lowest priority, namely:

i. the CES, DR or DSM Contract as applicable;

ii. this 2,500 MW RFP; and

iii. the Proposal,

where a document of a higher priority shall govern over a document of a lower priority to the extent of any conflict or inconsistency.

2. Structure of CES Contract

A Selected Proponent of a New Generating Facility will execute a CES Contract, pursuant to which the Selected Proponent, as Supplier, will supply energy and Ancillary Services from the Supplier's project, directly or indirectly, to the IMO-Administered Markets. The CES Contract shall be effective from the date of execution, while the Term shall commence upon the Term Commencement Date and expire the day before the twentieth (20th) anniversary thereafter. Commercial Operation shall be deemed to occur when (a) the New Generating Facility commences operation in compliance with all laws and regulations after the completion of construction, completion of connection and synchronization to the IMO-Controlled Grid, a Local Distribution System or LDC, or directly to an End-user, and completion of all commissioning tests, and (b) the Buyer has received a certificate addressed to it from an independent professional engineer duly qualified to practice engineering in Ontario, procured at the expense of the Supplier, and attesting to certain matters more particularly set out in the CES Contract including the level of completion of the New Generating Facility, the location of Connection Point(s), the provision of Automatic System Voltage Support (if applicable), and the ability of the New Generating Facility to generate electricity in the amounts and for the period required by the CES Contract.

Prospective Proponents are advised that New Generating Facilities that are not participants in the IMO-Administered Markets but supply electricity to End-users will be required to implement metering and outage planning provisions in conformity with the Market Rules.

a. Compensation to Supplier

The payments from the Buyer to the Supplier under the CES Contract, in addition to revenues received or costs avoided from the sale of its electricity and Ancillary Services, are intended to cover, over the Term, costs incurred by the Supplier in connection with the development and construction, financing, operation, maintenance, capital improvements and Connection Costs.

As compensation, under the CES Contract, the Supplier would receive any Contingent Support Payments, which are monthly payments to compensate the Supplier for the net difference between (i) the Supplier's Net Revenue Requirement and (ii) the imputed revenues of the Supplier based on the facility's Energy Cost and real-time market prices for electricity.

Any compensation payable to the Supplier will be net of any Revenue Sharing Payments, as described below.

b. Payments from Supplier to Buyer

To the extent that the Supplier would have been expected to earn net revenues from the market in excess of the Supplier's Net Revenue Requirement, the Supplier shall pay 95% of the excess to the Buyer, which is defined in the CES Contract as a Revenue Sharing Payment.

c. Contingent Support Payment ("CSP") and Revenue Sharing Payment ("RSP")

As the CES Contract is structured to provide support payments over the net revenues available in the market, the CES Contract contains detailed provisions and methodologies for determining "Estimated Net Revenue," or the amount of net revenue that the Selected Proponent is deemed to have received from the IMO-Administered Markets. Under the support payment structure, the Proponent identifies the amount that is needed to support the development, construction, ownership and operation of the New Generating Facility and the desired rate of return on investment in the context of the CES Contract. Under this contract structure, the cost of fuel is recovered from sales by the Supplier in the electricity market.

At the end of every month during the Term of the CES Contract, the Buyer will calculate the Estimated Net Revenues for the facility, which shall be the amount by which a Supplier's Estimated Gross Energy Market Revenues exceeds its Estimated Variable Energy Cost using the real-time market prices for the relevant period and other information provided by the IMO. All such calculations will be made using the applicable Energy Cost of the Supplier and taking into account typical and reasonable operating characteristics for the relevant technology of the facility and allowing for forced and maintenance outages.

For the months where the Supplier's Estimated Net Revenues are determined to be less than the Net Revenue Requirement specified in the Supplier's Economic Proposal, the Buyer will pay to the Supplier an amount equal to the difference. This difference, in $/MW–month, is referred to as the Contingent Support Payment ("CSP"). Examples of this calculation for a New Gas Generating Facility and a New Non-Gas Generating Facility are provided in Appendix A.

For the months where the Supplier's Estimated Net Revenues are determined to be greater than the Net Revenue Requirement specified in the Supplier's Economic Proposal, the Supplier will pay to the Buyer a Revenue Sharing Payment, in $/MW–month, equal to 95% of any portion of Estimated Net Revenues that exceed the Net Revenue Requirement.

d. Offsetting and Adjustment

If additional revenue sources (other than those available at the time the CES Contract is signed) become available to a Supplier over the Term of the CES Contract from Related Products (excluding steam and hot water) that relate to the Contract Capacity, including but not limited to environmental credits, except as noted below, then (1) 100% of the net revenue arising from such products that are Capacity Products, and (2) 50% of the net revenue arising from all other such products, shall be credited to the Supplier's Estimated Net Revenues for any given month, and all payments under the CES Contract will be adjusted accordingly.

The Buyer will, at no cost to the Supplier, assign rights existing as of September 13, 2004 and pertaining to the project and to credits and allowances provided under the Ontario Emissions Trading Program ("OETP") operating under Regulation 397/01 of the *Environmental Protection Act* (Ontario) to the Supplier. Revenue arising from OETP credits and allowances will not be credited to the Supplier's Estimated Net Revenues. The Buyer will reserve rights to any other existing or future environmental credit or allowance program that may arise during the contract term. Assignment and accounting for the revenue arising from any of these rights will be at the Buyer's sole discretion.

e. Operating Characteristics and Methodologies

The process by which operation is deemed to occur will recognize that each day a New Generating Facility will have an Energy Cost that is intended to represent its variable cost. For the period prior to the existence of a day-ahead market, New Generating Facilities will be deemed to have operated and incurred Start-Up Costs based upon a comparison of the three-hour ahead Pre-Dispatch Prices and actual prices (issued by the IMO) to the Energy Cost. The first hour for which the three-hour ahead Pre-Dispatch Price exceeds the Energy Cost and the HOEP is greater than the Energy Cost in that hour or the previous hour will start a period of deemed operation. The use of three-hour ahead Pre-Dispatch Prices for deeming start-ups and operation will provide operators of New Generating Facilities some notice to assist them to be able to operate when deemed, and the use of the actual price will help avoid false start-ups being assigned. The last hour of a period of deemed operation will be defined as the first hour in which one of the two following conditions is satisfied: (i) an hour in which none of the one-hour ahead, two-hour ahead, or three-hour ahead pre-dispatch prices published in that hour exceed the Energy Cost, or (ii) an hour that is the second consecutive hour in which the real-time market price, HOEP, is below the Energy Cost. For all deemed hours of operation, the output is assumed to be equal to the CES Contract Capacity. The total Estimated Net Revenue for each period of deemed operation will be determined by summing the hourly differences between the HOEP and the Energy Cost multiplied by the CES Contract Capacity, less the cost of a start-up if it is the first period of deemed operation in a day and it is not the continuation of a period of deemed operation from the previous day. If the total imputed Estimated Net Revenue for any period of deemed operation is negative, it will be set equal to zero, recognizing the fact that any operating losses under typical deemed operating conditions can be recovered from the IMO-Administered Markets through the Generator Cost Guarantee feature contained in Chapter 7 of the Market Rules.

The CES Contract will provide a detailed description of the formulae that will be used to implement these concepts, including provisions for the transition of all CES Contracts entered into by the Buyer under this 2,500 MW RFP to a day-ahead market if a day-ahead market is implemented as well as provisions for the amendment of the CES Contract in the event there is a change, whether in the IMO Market Rules or otherwise, such that HOEP becomes unavailable or is replaced.

The CES Contract for New Gas Generating Facilities will index daily Energy Costs to the Gas Price Index, which is a day-ahead gas index denominated in US dollars. The Gas Price applicable during each day “d”, which is posted on the Gas Price Index on day “d-1” (being the day immediately prior to day “d”) will be converted from US dollars to Dollars utilizing the Bank of Canada noon spot exchange rate between US dollars and Dollars on day “d-1”. If the Bank of Canada does not publish a noon spot exchange rate on day “d-1”, then the exchange rate used to convert the Gas Price from US dollars to Dollars shall be the simple average of the Bank of Canada noon spot exchange rate between US dollars and Dollars: (i) on the first day prior to day d-1 where the noon spot exchange rate is published, and (ii) on the first day after day d-1 where the noon spot exchange rate is published.

Suppliers will need to account for intra-day adjustments and associated risks.

Proponents may submit Proposals for non-gas facilities. Those facilities will be deemed to operate based on the Energy Costs specified in the Proposal. All Proponents of gas and non-gas facilities will need to factor into their Proposals the energy revenue that they expect to receive from the real-time market.

The above contract structure will provide incentives for the New Generating Facility to operate whenever economic and also enable the New Generating Facility to hedge its exposure to deemed Estimated Net Revenues by operating and realizing market profits. The capability to operate will cease to apply during outages. To account for this, the CES Contract will limit the amount of Estimated Net Revenue that is imputed during an outage by capping the price of electricity for any day during which there are outage hours at a maximum of the Energy Cost plus a specified amount as set out in the CES Contract.

Notwithstanding the foregoing, during such time as the Supplier is unable to perform or comply with its obligations under this Agreement as a result of a force majeure, no calculations pursuant to Exhibit J of the CES Contract shall be made, and no amounts shall be imputed or payable, in respect of such time.

f. Reductions in CES Contract Capacity

The option to reduce CES Contract Capacity is intended to benefit both the Supplier and the market as a whole. This option is principally being offered in order to free up capacity under the CES Contracts and provide the Supplier with additional opportunities and the market with additional hedging power, when it becomes economic for the Supplier to do so. This arrangement does not require monitoring as it is presumed that the Supplier will only exercise this option when it believes it can maximize the value of its asset by doing so.

Each CES Contract will be for a specified CES Contract Capacity. Under the terms of the CES Contract, the Supplier will be granted the option to reduce the CES Contract Capacity by providing the Buyer with the requisite notice and complying with all applicable terms and conditions as specified in the CES Contract. In the event that a Supplier exercises this option, any reduction in CES Contract Capacity shall be permanent and neither Supplier nor Buyer will have the option to increase the CES Contract Capacity for the balance of the Term of the CES Contract.

Pursuant to the option described above, the Supplier may designate for reduction all or any portion of the CES Contract Capacity, provided that if there is any remaining CES Contract Capacity, then such remaining capacity is a minimum of 5 MW, and the CES Contract shall apply to any such balance of the CES Contract Capacity on a pro-rated basis. The Supplier may exercise this option more than once during the Term of the CES Contract, provided that the option may only be exercised once in any given year.

It is anticipated that the value of this option will be considered by Proponents when determining the Net Revenue Requirement in their Economic Proposals.

g. Change to Electricity Market Structure

Until such time as a day-ahead Ontario electricity market is established, the Supplier will receive energy revenues from the real-time market. The CES Contract is structured so that, if a day-ahead market is established, the deemed operating hours will be based on day-ahead market prices and settlements under the CES Contract will be done against day-ahead prices. The Ministry foresees that this will reduce commitment and fuel procurement risk. The CES Contract will also provide that the contract shall survive in the event of changes to energy price calculations or electricity markets in Ontario.

h. Remedies for CES Contract Supplier Default

Given the importance placed by the Buyer on the Supplier attaining Commercial Operation of the facility by the corresponding milestone date set out by the Supplier, in the event that Commercial Operation is not attained by the corresponding milestone date, the CES Contract shall require the Supplier to pay to the Buyer, as liquidated damages and not as a penalty, an amount to be specified in the CES Contract. After a delay of one year, the Supplier shall be in default unless the Supplier has, on or prior to such date, paid all liquidated damages accruing to such one year date and the full amount of the required Completion and Performance Security is being held by the Buyer. However, the Supplier will be in default if Commercial Operation is delayed by eighteen months.

The Buyer's rights and remedies for a Supplier Event of Default (as defined in the CES Contract) will depend on the nature of such event of default, but will include the following:

- the Supplier will forfeit the entire Contingent Support Payment otherwise payable to the Supplier for the settlement month in which such Supplier Event of Default occurs, as liquidated damages and not as a penalty;

- the Buyer may levy a performance assessment set-off as liquidated damages and not as a penalty, equal to three (3) times the average Contingent Support Payment payable to the Supplier for the most recent twelve (12) settlement months (or the number of settlement months that have elapsed from the Term Commencement Date if less than twelve settlement months have elapsed), in the event of repeated failures;

- termination of the CES Contract, at the Buyer's option, and

- automatic termination of the CES Contract.

Also, a failure by the Supplier to achieve a minimum availability for the facility of a percentage of the CES Contract Capacity, as specified in the CES Contract, will be considered a Supplier Event of Default and shall give rise to the additional rights and remedies of the Buyer set out above, as applicable. However, if the facility is unavailable as a result of force majeure, the hours during which the facility is unavailable will not be included in the calculation of the minimum availability of the facility.

i. System Upgrade Costs

In the event that the OEB determines that System Upgrade Costs are not to be borne by the generator, the reimbursement of System Upgrade Costs to the Supplier shall be adjusted in accordance with the terms of the CES Contract.

3. Structure of DR Contract

A Selected Proponent of a DR Project will execute a DR Contract, pursuant to which the Selected Proponent, as the Supplier, will, using the Control Equipment, curtail the electricity demand of the load in response to Operational Directives from the IMO and will be deemed to have curtailed the electricity demand of the load in response to market prices. The DR Contract shall be effective upon the date of execution and the Term shall commence upon the Term Commencement Date and run for a Term of between five (5) and twenty (20) years. Commercial Operation shall be deemed to occur when (a) the Measurement and Verification Plan submitted by the Supplier has been approved by the Buyer, (b) the Supplier agreed to abide by the DR Protocols specified by the IMO and has demonstrated its readiness to do so, which has been confirmed by the IMO; and (c) the Buyer has received a certificate addressed to it from the DR Verification Consultant attesting to certain matters more particularly set out in the DR Contract including the level of completion of the DR Project, the location of Connection Point(s), the provision of Automatic System Voltage Support (if applicable), and the ability of the DR Project to curtail the electricity demand of the load as a direct result of the operation of the Control Equipment in response to Operational Directives in the amounts and for the periods required by the DR Contract.

In the case of a DR Project that requires the participation of third parties in respect of managing their respective loads, the Supplier must deliver to the Buyer, no less than one year prior to the milestone for Commercial Operation, proof acceptable to the Buyer of executed agreements with such third parties representing at least eighty percent (80%) of the Maximum Contracted Demand Reduction.

a. Compensation

The payments from the Buyer to the Supplier under the DR Contract are intended to cover the Fixed Costs incurred by the Supplier up to the Commercial Operation Date and the M&V Costs incurred by the Supplier during the Term. The terms “Fixed Costs” and “M&V Costs” are defined in the DR Contract. The NRR from which the monthly payments to the Supplier will be calculated will be the sum of the NRR (Fixed Costs) and the NRR (M&V) as determined from time to time (and which terms are defined in the DR Contract), but which sum shall not exceed the value of NRR set out in the Economic Bid Statement.

The Supplier shall submit to the Buyer, no later than the Term Commencement Date, evidence of its Fixed Costs incurred up to and including to the Term Commencement Date. After verification by the Buyer, such Fixed Costs shall be converted into a value of NRR (Fixed Costs) to be fixed for the Term of the DR Contract. The NRR (M&V) will, for the first year of the Term, be a value to be provided by the Supplier to the Buyer prior to the Term Commencement Date and which must represent a reasonable estimate of the M&V Costs to be incurred by the Supplier during such time. For each successive year thereafter, the NRR (M&V) shall be estimated based on the actual M&V Costs for the prior year, and shall be readjusted based on those actual M&V Costs for such successive year which would have been paid to the Supplier provided that those actual M&V Costs, when converted to a value of NRR(M&V), plus NRR(Fixed Costs), cannot exceed the value of NRR set out in the Economic Bid Statement.

As compensation, under the DR Contract, the Supplier would receive:

- any monthly Contingent Support Payments which are, subject to certain adjustments, calculated as monthly payments equal to the Supplier’s Net Revenue Requirement in $/MW-month for the Contracted Demand Reduction less the amount of the DR Strike Price Reduction, provided that the Contingent Support Payment will never be reduced below zero; and

- any DR Strike Price Payments, which are payments from the Buyer to the Supplier as compensation for Non-Strike Curtailment during Non-Strike Curtailment Hours.

b. Contingent Support Payment

The DR Contract is intended to enable electricity consumers who are exposed to real-time market prices or time-of-use rates to become demand responsive by removing the uncertainty of the short-term payoff of the necessary investments through financial support for the development, installation, financing and operation and maintenance of the Control Equipment that is required in order for a Proponent to increase their demand responsiveness, and to provide the system with a reliable form of callable capacity in the form of demand reduction.

The DR Contract will be structured such that the Supplier is deemed to curtail the electricity demand of the load for the DR Project in an amount equal to the Contracted Demand Reduction whenever both the three-hour ahead Pre-Dispatch Price for that hour and the real-time market price exceeds the DR Strike Price. It is deemed that when market prices are above the DR Strike Price, DR Suppliers would have curtailed on their own, to avoid paying electricity costs, independently of the DR Contract. The DR Contract contains detailed provisions and methodologies for determining a Supplier's "DR Strike Price Reduction", which is the amount of electricity savings that a Selected Proponent is deemed to be able to achieve as a direct result of the operation of the Control Equipment, and the "DR Strike Price Payment", which is the amount to be paid to a Supplier as compensation for load curtailment in response to Operational Directives that were issued at times when the market price for electricity was below the DR Strike Price. These methodologies are explained in Section V.A.3.d. Under the support payments structure, the Proponent identifies the amount that is needed to support the development, installation, financing and operation and maintenance of the Control Equipment in the context of the DR Contract. To the extent that electricity savings are imputed to have been achieved in response to real-time market prices for electricity that exceed the DR Strike Price, the Buyer shall reduce the support payment that is to be paid to the Supplier accordingly. For those hours for which the real-time market price exceeds the DR Strike Price, the Contingent Support Payment will be reduced by an offset equal to the imputed revenues for the curtailed electricity based on the difference between the real-time market price and the DR Strike Price. For those hours for which the real-time market price is less than the DR Strike Price and the Supplier was required to curtail the electricity demand of the load in response to an Operational Directive, the Buyer shall pay compensation to the Supplier for the demand curtailment that would not have taken place in the absence of the DR Contract. Such payment from Buyer to Seller will increase the amount of the support payment payable to the Supplier. The DR Contract is structured such that the aggregate offset for electricity savings can never exceed the Net Revenue Requirement and affect a net payment from the DR Supplier to the Buyer.

The DR Strike Price is set at $350/MWh for the first year of the DR Contract and will be indexed to the year-over-year change in the average real-time market price, for each year thereafter. Proponents will be able to economically curtail the demand for electricity at lower levels of HOEP. However, there will be no offset to the NRR imputed at the lower levels. Further, during required curtailments, DR Suppliers will be compensated for the difference between HOEP and the DR Strike Price.

At the end of every month during the Term of the DR Contract, the Buyer will calculate the DR Strike Price Reduction and the DR Strike Price Payment using the real-time market prices and the three-hour ahead Pre-Dispatch Prices for the relevant periods of DR Curtailment and other information provided by the IMO. The Contingent Support Payment for each month will be adjusted for any net difference between the DR Strike Price Reduction and the DR Strike Price Payment. Examples of this calculation for a DR Project are provided in Appendix A. Prospective Proponents should refer to the DR Contract, and Exhibit J thereof in particular, as the calculation of the Contingent Support Payment involves certain other adjustments described therein.

c. Contracted Demand Reduction

Each DR Contract will, for each Season, be for a specified Contracted Demand Reduction. Under the terms of the DR Contract, the Supplier may indicate a separate Contracted Demand Reduction for each Season. This option to specify a different Contracted Demand Reduction for each Season is a recognition by the Buyer of the seasonal load profile of many potential DR Projects. The Contracted Demand Reduction must exceed 5 MW for at least one Season.

d. Operating Characteristics and Methodologies

During the Term, in any Season in which the Supplier has agreed to make Contracted Demand Reduction available, the Supplier shall be deemed to curtail the electricity demand of the load as a direct result of the operation of the Control Equipment, and hence have Imputed Curtailment, at full Contracted Demand Reduction, in each Imputed Curtailment Hour.

In addition to such Imputed Curtailment during the Term, in any Season in which the Supplier has agreed to make Contracted Demand Reduction available, the Supplier may be directed by the IMO to provide DR Curtailment not to exceed the applicable Maximum Curtailment. The IMO may issue one Operational Directive to a Supplier per day with at least three hours' advance notice requesting the Supplier to provide DR Curtailment during the Callable Hours of that day. The Supplier agrees to respond to such Operational Directives by curtailing the electricity demand of the load through the use of the Control Equipment.

The Buyer recognizes that an Operational Directive may be issued during a Callable Hour in which the Supplier has already curtailed the electricity demand of the load in response to market prices. In such circumstances, the Supplier will only be required to verify that the electricity demand of the load was curtailed as a direct result of the Control Equipment, due to actions that had already been taken by the Supplier or in response to the Operational Directive, for the duration specified in the Operational Directive. In such a circumstance the Supplier will not be required to provide any further curtailment in the electricity demand of the load beyond what was specified in the Operational Directive.

In the event that, the IMO issues an Operational Directive that results in the Supplier providing DR Curtailment during a Callable Hour in which the real-time market prices, as provided by the IMO, are less than the DR Strike Price, the Supplier will be compensated by the Buyer for all Non-Strike Curtailment provided by it during the settlement month by way of a DR Strike Price Payment from the Buyer calculated in accordance with the formula set out in the contract.

In the event that the Supplier is only partially able to curtail the electricity demand of the load as a result of a load outage or a control equipment outage, upon receiving such an Operational Directive, the Supplier will only receive a portion of the DR Strike Price Payment in accordance with the formula set out in the DR

Contract, and the Buyer shall have the right to pursue additional remedies as set out in Section V.A.3.g. below.

Prospective Proponents are advised that if the Proponent of a DR Contract shall wish to enrol the DR Project under any other demand management program during the Term of the DR Contract, it will do so in full recognition that it must continue to meet all commitments under the DR Contract and will only do so with the prior written consent of the Buyer.

The Buyer will assign to the Supplier, at no cost to the Supplier, all of the Buyer's rights existing as of September 13, 2004 in the credits and allowances provided under the Ontario Emissions Trading Program which pertain to the DR Project, and revenue arising from such OETP credits and allowances will not be included in imputed net curtailment savings.

Subject to the foregoing, the Supplier shall obtain on behalf of the Buyer, and the Buyer shall retain, all rights, title, and interest in all Environmental Attributes related to the DR Project. The Supplier shall not participate in any other programs with respect to any Environmental Attributes associated with the DR Project without the prior written consent of the Buyer, which consent may be unreasonably withheld.

If the Supplier receives any compensation for curtailing the electricity demand of the End-User load in addition to the revenues attributed to the DR Contract, then such compensation shall be shared between the Supplier and the Buyer in equal proportions.

e. Operational Directives of the IMO

In the event the amount of demand response required by the IMO in any given period of time is less than the total amount of Contracted Demand Reduction under all DR Contracts, the IMO will call on Suppliers with DR Contracts according to the priority and protocol to be specified by the IMO.

f. Measurement and Verification

The Measurement and Verification must demonstrate the use and effectiveness of the Control Equipment. There are three different types of DR Projects that would result in the need for three different Measurement and Verification Plans for DR, namely:

i. Measurement and Verification for DR Projects based on load interruption

A Proponent's Contracted Demand Reduction will be determined based on the baseline less the actual load during a DR event. The baseline for a trading hour on a business day will be based on the high ten of past eleven same trading hours on Business Days immediately preceding the provision of the DR. For Saturdays or Sundays the baseline will be based on the same trading hour in the last five Saturdays or Sundays respectively. For hours where verifiable DR occurred, the baseline will be increased by the amount of such DR.

Adjustments to the baseline may be proposed by the Proponent. An example of a possible adjustment might include but is not limited to vacation or maintenance shut downs. Acceptance of the adjustment will be solely at the discretion of the Buyer. Proponents may also propose the use of a weather correction adjustment to their baseline calculation methodology. Proponents proposing the use of a weather correction adjustment in their baseline calculation must detail the proposed method and provide the rational for it. Allowance for a weather correction adjustment and selection of the adjustment mechanism applied will be at the Buyer's sole discretion.

Preferably, interval meter data will be the basis for establishing baselines and determining the actual level of DR supplied. Proponents proposing DR from non-interval metered loads must provide a proposed Measurement and Verification Plan consistent with the Measurement and Verification Guidelines for DR.

ii. Measurement and Verification for DR Projects based on generation

When generators are the basis for the Control Equipment, then the generator must be metered, and the Measurement and Verification Plan must make the relevant metered data available to the Buyer to confirm that the demand response required to meet the Operational Directive was accomplished through the use of the generator.

iii. Measurement and Verification for DR Projects based on load shifting

When Control Equipment enables load shifting capabilities and the load shifting is routinely implemented by the load to the point where a baseline-based approach to measurement and verification is not reasonably possible, then the Measurement and Verification Plan must include provisions to demonstrate to the satisfaction of the Buyer that the Control Equipment enables the required load reduction to meet the IMO Operational Directive.

No monthly support payments shall be made by the Buyer to the Supplier until the Supplier has delivered a DR Verification Certificate in respect of a given month during the Term, which has been executed by the DR Verification Consultant.

Under the terms of the DR Contract, in order to achieve Commercial Operation, the Supplier must submit, ninety (90) Business Days prior to the Commercial Operation Date to the Buyer for its approval, a Measurement and Verification Plan for the DR Project. The Buyer will review the Measurement and Verification Plan submitted by the Supplier, and either approve the plan or provide the Supplier with its comments. The Supplier will be required to covenant to the Buyer that the Measurement and Verification Plan meets the requirements of the Measurement and Verification Guidelines for DR.

In order to be considered by the Buyer in the preparation of the statement for a given month the DR Verification Certificate must be delivered to the Buyer within ten (10) Business Days following of the end of the month. A DR Verification Certificate that is delivered more than ten, but less than ninety (90) Business Days, following the end of a month will be considered by the Buyer in the preparation of the statement for the month in which the DR Verification Certificate is received by the Buyer. Under the terms of the DR Contract the Buyer shall not make, nor shall it owe, any payments to the Supplier in respect of a month for which the Supplier fails to deliver a DR Verification Certificate for a given month before the ninetieth (90^{th}) Business Day following the end of such month.

g. Remedies for DR Contract Supplier Default

Given the importance placed by the Buyer on the Supplier attaining Commercial Operation of the facility by the corresponding milestone date set out by the Supplier, in the event that Commercial Operation is not attained by the corresponding milestone date, the DR Contract shall require the Supplier to pay to the Buyer, as liquidated damages and not as a penalty, an amount to be specified in the DR Contract. After a delay in Commercial Operation of one year, the Supplier shall be in default unless the Supplier has, on or prior to such date, paid all liquidated damages accruing to such one year date and the full amount of the required Completion and Performance Security is being held by the Buyer. However, the Supplier will be in default if Commercial Operation is delayed by eighteen months after the corresponding milestone date.

The Buyer’s rights and remedies for a Supplier Event of Default (as defined in the DR Contract) will depend on the nature of such event of default, but will include the following:

- the Supplier will forfeit the entire Contingent Support Payment otherwise payable to the Supplier for the settlement month in which such Supplier Event of Default occurs, as liquidated damages and not as a penalty;
- the Buyer may levy a performance assessment set-off as liquidated damages and not as a penalty, equal to three (3) times the average Contingent Support Payment payable to the Supplier for the most recent twelve (12) settlement months (or the number of settlement months that have elapsed from the Term Commencement Date if less than twelve settlement months have elapsed), in the event of repeated failures;
- termination of the DR Contract, at the Buyer’s option, and
- automatic termination of the DR Contract.

Also, a failure by the Supplier to achieve a minimum availability of the Control Equipment, of a percentage of the DR Contract Capacity as specified in the DR Contract, will be considered a Supplier Event of Default and shall give rise to the additional rights and remedies of the Buyer set out above, as applicable. However, if the Control Equipment is unavailable as a result of force majeure, the hours during which the Control Equipment is unavailable will not be included in the calculation of the minimum availability.

h. Declaration by Supplier

A Supplier under a DR Contract may declare that it is unavailable due to planned facility operations and maintenance, subject to certain restrictions to be set forth in the DR Contract.

Any declaration by a Supplier that it is unavailable must be made with at least one day's prior written notice to the IMO and the Buyer, and no such declaration will be valid unless supported by a verification statement from the DR Verification Consultant. The verification statement provided must demonstrate that the DR Project from which the relevant curtailment of electricity demand would otherwise have been drawn was operating below the normal load levels during the relevant period. For each day that a Supplier is validly declared unavailable, the Contingent Support Payment for that month will be reduced on a *pro rata* basis, but no other damages shall be assessed.

A Supplier must comply with the Market Rules, including outage and maintenance planning purposes.

4. Structure of DSM Contract

A Selected Proponent of a DSM Project will execute a DSM Contract, pursuant to which the Selected Proponent, as the Supplier will achieve verifiable electricity savings as a direct result of the installation of the Operating Equipment (as such term is defined in the DSM Contract), that expressed as capacity using the conversion methodology specified by the Buyer, will be equal to or greater than the DSM Project Equivalent Capacity. The DSM Contract is intended to provide Proponents with sufficient revenue to implement energy efficiency measures which would not otherwise be implemented. This incentive is the Proponent's Net Revenue Requirement. The NRR is comprised of two components: (1) the NRR(Simple Payback Period), which is intended to be the monthly payment amount that is required by the Supplier to reduce the Simple Payback Period to three years, and (2) the NRR(Variable Costs), which is intended to be the average monthly amount required by the Supplier to cover the variable costs of the DSM Project over the Term. NRR(Simple Payback Period), NRR(Variable Costs), and Variable Costs are each defined in the DSM Contract.

The DSM Contract shall be effective upon its execution, and the Term shall commence upon the Term Commencement Date and run for a Term of between five (5) and twenty (20) years. Commercial Operation shall be deemed to occur when: (a) the Measurement and Verification Plan submitted by the Supplier has been approved by the Buyer; (b) all of the meters and such other equipment as is necessary to measure and verify the electricity savings achieved by the DSM Project have been installed and are in proper working order; (c) the DSM Project commences operation in compliance with all Laws and Regulations after the completion of construction, and completion of all tests; (d) the Supplier has delivered to the Buyer a completed schedule that lists and accurately describes all of the Operating Equipment that has been installed in connection with the DSM Project; (e) the Buyer has received a certificate addressed to it from the DSM Verification Consultant attesting to matters more particularly set out in the DSM Contract including the level of completion of the DSM Project, the actual costs, the location of Connection Points, and the provision of ASVS (if applicable) and (f) the Supplier has determined the average cost of Electricity and has submitted the value along with supporting documentation and calculations to the Buyer for its review.

In the case of a DSM Project that requires the participation of third parties in respect of managing their respective loads, the Supplier must deliver to the Buyer, no less than one year prior to the milestone for Commercial Operation, proof acceptable to the Buyer of executed agreements with such third parties representing at least eighty percent (80%) of the proposed DSM Project Equivalent Capacity.

a. DSM Supplier Compensation

The payments from the Buyer to the Supplier under the DSM Contract are intended to cover, over the Term, the amount that the Supplier requires to reduce the Simple Payback Period to three years, and the variable costs that are associated with the DSM Project, which shall include O&M Costs, the administration costs, and the costs related to Measurement and Verification Activities.

As compensation, under the DSM Contract, a Supplier will receive, subject to any applicable adjustments, a monthly Contingent Support Payment equal to the Net Revenue Requirement described in Section III.E.2.b. for each MW of equivalent capacity that is attributable to the DSM Project.

b. Contingent Support Payment

The DSM Contract is intended to enable End-Users to install energy efficient equipment that exceeds the Minimum Equipment Efficiency Standard and increase their electricity efficiency to a level that would not be economical in the absence of the DSM Contract by providing Proponents with sufficient revenue to implement the measures that would not otherwise be implemented. This incentive is the Proponent's Net Revenue Requirement. The NRR is comprised of two components: (1) the NRR(Simple Payback Period), which is intended to be the monthly payment amount that is required by the Supplier to reduce the Simple Payback Period to three years, and (2) the NRR(Variable Costs), which is intended to be the average monthly amount required by the Supplier to cover the Variable Costs of the DSM Project over the Term.

Each of the Simple Payback Period and the NRR(Simple Payback Period) will be calculated by the Buyer as of the Commercial Operation Date using the methodology set out in Exhibit Q to the DSM Contract. If the calculation of the Simple Payback Period as of the Commercial Operation Date results in a Simple Payback Period for the Supplier of three years or less, then the Buyer shall have the right to terminate the DSM Contract. If the calculation of the NRR(Simple Payback Period) as of the Commercial Operation Date results in an NRR(Simple Payback Period) that is less than the NRR(Simple Payback Period) calculated during the Economic Evaluation, then the NRR(Simple Payback Period) that will be used for any calculations during the Term shall be fixed at the lesser of the two amounts.

The NRR(Variable Costs) will be calculated by the Buyer based on the information set out in the Proposal and will be fixed at the resulting amount throughout the Term. However, Contingent Support Payments in respect of Variable Costs will be adjusted throughout the Term based on the actual Variable Costs incurred by the Supplier in accordance with the terms of the DSM Contract. Under the DSM Contract the total payments to the Supplier will not be permitted to exceed a cap, which will be based on the average Actual Project Equivalent Capacity over the Term multiplied by the NRR (Variable Costs) times the number of months in the Term. Payments made by the Buyer in excess of such cap shall be recovered from the Supplier in the manner specified in the DSM Contract.

In structuring the DSM Contract, it has been assumed that: (i) efficiency improvements that are required in order to meet the current minimum efficiency requirements under the *Energy Efficiency Act* (Ontario) would have been met in the absence of the DSM Contract; and (ii) efficiency improvements that have a Simple Payback Period of three years or less are economically viable without further assistance and are likely to occur in the absence of the DSM Contract in any event. Therefore, any payments made from the Buyer to the Supplier in respect of capital costs under the DSM Contract shall be limited to such amount as is required to reduce the number of years required for the Incremental Capital Costs to be recovered through Incremental Electricity Cost Savings (as such terms are defined in the DSM Contract) to three years. That is to say only such portion of the capital costs associated with the Operating Equipment as exceeds the capital costs of comparable equipment that meets, but does not exceed, the Minimum Equipment Efficiency Standard shall be recoverable under the DSM Contract, and such portion of the capital costs shall only be recoverable to the extent that the Simple Payback Period exceeds three years.

Thus, the Incremental Capital Costs of a measure do not necessarily equal the total capital cost of the demand-side measure. For greater certainty, the capital cost of newly installed equipment exceeding the Minimum Equipment Efficiency Standard current minimum efficiency requirements prescribed by the *Energy Efficiency Act* (Ontario), can only be included in the Incremental Capital Costs for implementing the DSM Project to the extent that such cost exceeds the cost of a product of the same type which meets but does not exceed the Minimum Equipment Efficiency Standard.

Likewise, the electricity savings that will be used for the purposes of determining the equivalent capacity of a DSM Project under the DSM Contract are “incremental” in that only the electricity savings that are attributable to the increase in efficiency of the Post-Installation Consumption above the Efficiency Baseline will be considered. That is to say, there may be electricity savings achieved as a result of the implementation of a DSM Project that will not be included for the purposes of determining the equivalent capacity of such DSM Project.

The DSM Contract has also been structured to ensure that the Buyer does not make CSP payments on account of Variable Costs which exceed an amount equal to NRR(Variable Costs) multiplied by the average equivalent capacity of the DSM Project over the entire Term multiplied by the total number of months in the Term.

Under the terms of the DSM Contract, Contingent Support Payments on account of Variable Costs and the Simple Payback Period will be adjusted, as appropriate, throughout the Term to reflect: (i) the actual Variable Costs incurred by the Supplier; and (ii) the actual equivalent capacity achieved by the DSM

Project, during prior periods. Payments made by the Buyer on account of Variable Costs that exceed a cap, which shall be based on the average Actual Project Equivalent Capacity multiplied by the NRR (Variable Cost) times the number of months in the Term, shall be recovered from the Supplier in the manner specified in the DSM Contract.

c. Measurement and Verification

Under the terms of a DSM Contract, the Supplier must demonstrate to the Buyer that there has been a verifiable electricity savings attributable to the DSM Project. Each Supplier will be required to retain, at its own cost, a DSM Verification Consultant to verify, as and when required pursuant to the terms of the DSM Contract, among other things:

- the operation and effectiveness of the Operating Equipment during the relevant period;
- the DSM costs incurred by the Supplier;
- the electricity savings achieved by the DSM Project; and
- that the terms of the Measurement and Verification Plan have been complied with.

No monthly support payments shall be made by the Buyer to the Supplier until the Supplier has delivered a DSM Verification Certificate in respect of a given month during the Term, which has been executed by the DSM Verification Consultant.

Under the terms of the DSM Contract, in order to achieve Commercial Operation, the Supplier must submit, ninety (90) Business Days prior to the Commercial Operation Date to the Buyer for its approval, a Measurement and Verification Plan for the DSM Project. The Buyer will review the Measurement and Verification Plan submitted by the Supplier, and either approve the plan or provide the Supplier with its comments. The Supplier will be required to covenant to the Buyer that the Measurement and Verification Plan meets the requirements of the Measurement and Verification Guidelines for DSM.

In order to be considered by the Buyer in the preparation of the statement for a given month the DSM Verification Certificate must be delivered to the Buyer within ten (10) Business Days following of the end of the month. A DSM Verification Certificate that is delivered more than ten, but less than ninety (90) Business Days, following the end of a month will be considered by the Buyer in the preparation of the statement for the month in which the DSM Verification Certificate is received by the Buyer. Under the terms of the DSM Contract the Buyer shall not make, nor shall it owe, any payments to the Supplier in respect of a month for which the Supplier fails to deliver a DSM Verification Certificate for a given month before the ninetieth (90^{th}) Business Day following the end of such month.

d. Remedies for DSM Performance Default

Given the importance placed by the Buyer on the Supplier attaining Commercial Operation of the facility by the corresponding milestone date set out by the Supplier, in the event that Commercial Operation is not attained by the corresponding milestone date, the DSM Contract shall require the Supplier to pay to the Buyer, as liquidated damages and not as a penalty, an amount to be specified in the DSM Contract. After a delay of one year, the DSM Contract shall be in default unless the Supplier has, on or prior to such date, paid all liquidated damages accruing to such one year date and the full amount of the required Completion and Performance Security is being held by the Buyer. However, the DSM Contract will be in default if Commercial Operation is delayed by eighteen months.

The Buyer's rights and remedies for a Supplier Event of Default (as defined in the DSM Contract) will depend on the nature of such event of default, but will include the following:

- the Supplier will forfeit the entire Contingent Support Payment otherwise payable to the Supplier for the settlement month in which such Supplier Event of Default occurs, as liquidated damages and not as a penalty;

- the Buyer may levy a performance assessment set-off as liquidated damages and not as a penalty, equal to three (3) times the average Contingent Support Payment payable to the Supplier for the most recent twelve (12) settlement months (or the number of settlement months that have elapsed from the

Term Commencement Date if less than twelve settlement months have elapsed), in the event of repeated failures;

- termination of the DSM Contract, at the Buyer's option, and
- automatic termination of the DSM Contract.

Also, if the DSM Project fails to achieve Actual Project Equivalent Capacity of 5 MW or more, or if the Simple Payback Period calculated as of the Commercial Operation Date is equal to three years or less, it will be considered a Supplier Event of Default and shall give rise to the additional rights and remedies of the Buyer set out above, as applicable.

B. Counterparty

It is anticipated that if legislation establishing the OPA is enacted, the OPA will be the counterparty to the Selected Proponent under the CES, DR and DSM Contracts. If, however, the OPA has not been established at the time the CES, DR and DSM Contracts are to be executed, the counterparty will be Ontario Electricity Financial Corporation ("OEFC"). OEFC will retain the unilateral right to transfer the CES, DR and DSM Contracts to the OPA, should legislation be enacted to establish the OPA. Notwithstanding the execution of the CES, DR and DSM Contracts by OEFC, it is intended that the costs of the CES, DR, and DSM Contracts be recovered from all electricity consumers through appropriate settlement mechanisms. If the OPA is not established or legislation is not enacted to provide for the OPA to recover the costs of the CES, DR and DSM Contracts from all electricity consumers, the costs of the CES, DR and DSM Contracts will be paid from the general revenues of OEFC.

APPENDIX A: EXAMPLE OF PAYMENTS

Prospective Proponents are advised that the payment examples set out in this Appendix A are simplifications of the payment calculation provisions in the contracts, and accordingly Prospective Proponents are directed to the CES Contract, DR Contract, and DSM Contract (and Exhibit J of each of such contracts in particular), as the calculation of the Contingent Support Payment involves certain other factors and adjustments described therein.

A. PAYMENT EXAMPLE FOR A NEW GAS GENERATING FACILITY

In this example, we assume that the Supplier submitted the following values in its Proposal:

Project Size:	500 MW
Net Revenue Requirement:	$15,000/MW–month
O&M Costs:	$0.50/MWh
Specified Heat Rate:	7,500 BTU/kWh
Start-Up Costs (expressed in MMBTU/start-up):	1,800 MMBTU/start-up

We further assume that the Gas Price Index is $5.50/MMBTU for each day of the relevant month. Note for simplicity we assume the Gas Price Index, which will be applied daily, is the same each day. Figure 1 illustrates each of the five steps for calculating the Contingent Support Payment. Each of Tables A, B, C, D, and E, as described below, demonstrates a single step in such calculation.

Table A -- Total Monthly Net Revenue Requirement

The Total Monthly Net Revenue Requirement for a Proposal is determined by multiplying the Project Size by its Net Revenue Requirement. In this example, as set out in Figure 1, the Supplier had submitted a Proposal for a 500 MW New Gas Generating Facility with a Net Revenue Requirement of $15,000/MW–month, and the resulting Total Net Monthly Revenue Requirement for the Supplier is $7,500,000. Note, in future years, a portion of the Net Revenue Requirement, specified in the Proposal and between 0% and 20%, will be adjusted for changes in the Specified Index.

Table B -- Energy Cost

The Energy Cost for a Proposal is determined by multiplying the Specified Heat Rate by the Gas Price Index and adding the O&M Costs that have been provided in the Proposal. In this example, as set out in Figure 1, with a Specified Heat Rate of 7,500 BTU/kWh, a Gas Price Index of $5.50/MMBTU and O&M Costs of $0.50/MWh, the resulting Energy Cost is $41.75/MWh. In future years, the O&M Costs would be adjusted for changes in the Specified Index. The Energy

Cost will be determined for each day. In this example, it is the same each day as the Gas Price Index is assumed to be the same for each day.

Table C – Start-Up Costs

The Start-Up Costs for a Proposal are determined by first multiplying the Start Up Costs, expressed in MMBTU per start-up, by the Gas Price Index to determine the Start-Up Costs expressed in dollars per start-up. In this example, as set out in Figure 1, Start-Up Costs are 1,800 MMBTU per start-up and the Gas Price Index is $5.50/MMBTU; accordingly, the resulting Start-Up Costs, expressed in dollars per start-up, are $9,900 per start-up. Start-Up Costs are incurred for each interval of continuous deemed operation based on a comparison of the pre-dispatch prices and real-time market prices to the Energy Cost. Start-Up Costs can only be incurred a maximum of once per day. In this example, the Number of Start-ups is assumed to be 25 per month. The Total Monthly Start-Up Costs for a Proposal are then determined by multiplying the Start-Up Costs expressed in dollars per start-up by the Number of Start-ups. In this example, as set out in Figure 1, with Start-Up Costs of $9,900 per start-up and the Number of Start-ups equal to 25, the resulting Total Monthly Start-Up Costs are $247,500. Although the Start-Up Costs will be determined for each start-up as they are dependent on the Gas Price Index for that day, in this example, Start-Up Costs are the same, as the Gas Price Index is assumed to be the same for each day.

Table D -- Estimated Gross Energy Market Revenue

The Estimated Gross Energy Market Revenue is determined on the basis of information provided by the IMO. It will be assumed when calculating this value that the Supplier operated efficiently by producing during the hours in which, generally speaking, the pre-dispatch prices and the real-time market prices for electricity exceeded the Supplier's Energy Cost. This description is kept simple for purposes of this example; however, in actuality, the CES Contract will contain specific methodologies for determining when a New Gas Generating Facility would be assumed to operate that will consider both the pre-dispatch and real-time market prices in comparison to the Energy Cost and will account for outages. Based on the assumed operational pattern as developed from the methodology in the CES Contract, an Estimated Production Weighted Average Price is calculated by determining whether the New Gas Generating Facility is deemed to have produced in each hour of the month. The Estimated Gross Energy Market Revenue is calculated by multiplying the Estimated Production Weighted Average Price by the Project Size. The operational pattern will predominantly include hours when the real-time market price are higher than the Energy Cost, but it can also include hours when there is a negative profit imputation, which will be included in the calculation of the Estimated Production Weighted Average Price. However, when for any operating interval, which is defined as the operating period beginning with a deemed start-up and continuing until the New Gas Generating Facility is no longer deemed to operate, the difference between Estimated Gross Energy Market Revenue and Energy Cost plus Start-Up Costs for the interval is negative, the Estimated Net Revenue will be increased by the amount of such difference so that the impact of the negative profit imputation over such interval is zero; that is, negative profit imputations will not reduce Estimated Net Revenue for an amount less than zero for any interval. Generators will generally be able to recoup these net operating losses in these intervals from the market via features like Generator Cost Guarantee payments under the current Market Rules. This adjustment is included in Table E.

The Estimated Production Weighted Average Price is then multiplied by the Estimated Production for the New Gas Generating Facility (expressed as the New Gas Generating Facility's MWhs - month) and the resulting figure is the Estimated Gross Energy Market Revenues ($/MWh). In this example, as set out in Figure 1, the Estimated Production for the New Gas Generating Facility, based on the methodology specified in the CES Contract, is 250,000 MWh at an Estimated Production Weighted Average Price of $50.00/MWh, resulting in Estimated Gross Energy Market Revenues for the month of $12,500,000.

Table E -- Contingent Support Payment

The Contingent Support Payment is based on the Market Shortfall, which is the difference between the Supplier's Total Monthly Net Revenue Requirement set out in Table A and its Estimated Net Revenue. Calculating the Estimated Net Revenue begins with deriving the Supplier's Estimated Variable Energy Cost by multiplying the Energy Cost in Table B by the Estimated Production in Table D. The Estimated Net Revenues are then determined by first subtracting both the Estimated Variable Energy Costs and Total Monthly Start-Up Costs from Table C from the Estimated Gross Energy Market Revenues in Table D. For purposes of this example, this result includes an imputation of $32,500 in net losses incurred over one or more operating intervals for that month. As explained above, generators should generally be able to recoup these from Generator Cost Guarantee payments or other similar market-based features. Hence Estimated Net Revenues are adjusted to remove any net losses imputed over deemed operating intervals. Once the Market Shortfall has been calculated, it is converted to $/MW - month by dividing the amount of the Market Shortfall by the Project Size. The resulting figure is the Contingent Support Payment that would be paid to the Supplier. In this example, as set out in Figure 1, a Project Size of 500 MW and a Market Shortfall of $5,652,500/month will result in a Contingent Support Payment of $11,305/MW–month.

Figure 1. Payment for a New Gas Generating Facility

Table A		
Project Size (MW)		500
Net Revenue Requirement (NRR) ($/MW-month)	$	15,000
Total Monthly NRR ($/month)	**$**	**7,500,000**

Table B		
Specified Heat Rate (BTU/kWh)		7,500
Gas Price Index ($/MMBTU)	$	5.50
Fuel Cost ($/MWh)	$	41.25
O&M Costs ($/MWh)	$	0.50
Energy Cost ($/MWh)	**$**	**41.75**

Table C		
Start-Up Costs (MMBTU/start-up)		1,800
Start-Up Costs ($/start-up)	$	9,900
Number of Start-Up in month		25
Total Monthly Start-Up Costs ($/month)	**$**	**247,500**

Table D		
Estimated Production (MWh-month)		250,000
Estimated Production Weighted Avg. Price ($/MWh)	$	50.00
Estimated Gross Energy Market Revenues ($/month)	**$**	**12,500,000**

Table E		
Estimated Variable Energy Cost ($/month)	$	10,437,500
Total Monthly Start-Up Costs ($/month)	$	247,500
Imputed Net Losses Over one or more Operating Intervals in Month	$	32,500
Estimated Net Revenues ($/month)	$	1,847,500
Market Shortfall ($/month)	$	5,652,500
Contingent Support Payment ($/MW - month)	**$**	**11,305**

B. PAYMENT EXAMPLE FOR A NEW NON-GAS GENERATING FACILITY

In this example, we assume that the Supplier submitted the following values in its Proposal:

Project Size:	250 MW
Net Revenue Requirement:	$20,000/MW–month
Energy Cost:	$20/MWh
Start-Up Costs (expressed in $/start-up)	$9,900/start-up

It is important to note that the Energy Cost is fully indexed to the Specified Index. Note however, for simplicity, that we do not index the Energy Cost in this example. Figure 2 illustrates each of the five steps for calculating the Contingent Support Payment. Each of Table A, B, C, D, and E, as described below, demonstrates a single step in such calculation.

Table A -- Total Monthly Net Revenue Requirement

The Total Monthly Net Revenue Requirement for a Proposal is determined by multiplying the Project Size by its Net Revenue Requirement. In this example, as set out in Figure 2, the Supplier had submitted a Proposal for a 250 MW New Non-Gas Generating Facility with a Net Revenue Requirement of $20,000/MW–month, and the resulting Total Monthly Net Revenue Requirement for the Supplier is $5,000,000. Note, in future years, a portion of the Net Revenue Requirement, specified in the Proposal and between 0% and 20%, will be adjusted for changes in the Specified Index.

Table B -- Energy Cost

The Energy Cost for a Proposal is submitted by the Supplier, which in this example is $20/MWh. In future years, the Energy Cost would be adjusted for changes in the Specified Index. In this example, the Energy Cost does not vary.

Table C – Start-Up Costs

The Total Monthly Start-Up Costs for a Proposal are then determined by multiplying the Start-Up Costs expressed in dollars per start-up by the Number of Start-ups. In this example, as set out in Figure 1, with Start-Up Costs of $9,900 per start-up and the Number of Start-ups equal to 25, the resulting Total Monthly Start-Up Costs is $247,500. Start-Up Costs are incurred for each interval of continuous deemed operation based on a comparison of the pre-dispatch and real-time market prices to the Energy Cost. Start-Up Costs can only be incurred a maximum of once per day. In future years, the value of the Start-Up Costs would be adjusted for changes in the Specified Index.

Table D -- Estimated Gross Energy Market Revenue

The Estimated Gross Energy Market Revenue is determined on the basis of information provided by the IMO. It will be assumed when calculating this value that the Supplier operated efficiently by producing during the hours in which generally speaking the pre-dispatch prices and the real-time market prices for electricity exceeded the Supplier's Energy Cost. This description has been simplified for demonstration purposes. In actuality, the CES Contract will contain specific methodologies for determining when a New Non-Gas Generating Facility would be assumed to operate that will consider both the pre-dispatch and real-time market prices in comparison to the Energy Cost and will account for outages. Based on the assumed operational pattern as developed from the methodology in the CES Contract, an Estimated Production Weighted Average Price is calculated by determining whether the New Non-Gas Generating Facility is deemed to have produced in each hour of the month. The operational pattern will predominantly include hours when the real-time market price is higher than the Energy Cost; however, it can also include hours when there is a negative profit imputation, which will be included in the calculation of the Estimated Production Weighted Average Price. However, when for any operating interval, which is defined as the operating period beginning with a deemed start-up and continuing until the New Non-Gas Generating Facility is no longer deemed to operate, the difference between the Estimated Gross Energy Market Revenue and Energy Cost plus Start-Up Costs is negative, the Estimated Net Revenue will be increased by the amount of such difference so that the impact of the negative profit imputation over the interval is zero; that is, negative profit imputations will not reduce Estimated Net Revenue to an amount less than zero for any interval. Generators will generally be able to recoup these net operating losses in these intervals from the market via features like Generator Cost Guarantee payments currently under the Market Rules. This adjustment is included in Table E.

This Estimated Production Weighted Average Price is then multiplied by the Estimated Production for the New Non-Gas Generating Facility (expressed as the New Non-Gas Generating Facility's MWhs - Month) the resulting figure is the Estimated Gross Energy Market Revenues ($/MWh). In this example, as set out in Figure 2, the Estimated Production for the New Non-Gas Generating Facility is assumed to be the maximum average monthly production of the Non-Gas Generating Facility for the purpose of simplicity and is 182,500 MWh at an Estimated Production Weighted Average Price of $45.00/MWh, resulting in Estimated Gross Energy Market Revenues for the month of $8,212,500.

Table E -- Contingent Support Payment

The Contingent Support Payment is based on the Market Shortfall, which is the difference between the Supplier's Total Monthly Net Revenue Requirement set out in Table A and its Estimated Net Revenue. Calculating the Estimated Net Revenue begins with deriving the Supplier's Estimated Variable Energy Cost by multiplying the Energy Cost in Table B by the

Estimated Production in Table D. The Estimated Net Revenues are then determined by first subtracting both the Estimated Variable Energy Costs and Total Monthly Start-Up Costs from Table C from the Estimated Gross Energy Market Revenues in Table D. For purposes of this example, this result includes an imputation of $15,000 in net losses incurred over one or more operating intervals for that month. As explained above, generators should generally be able to recoup these from market-based payments such as the Generator in the current Market Rules or other similar market-based features. Once the Market Shortfall has been calculated, it is converted into $/MW-month by dividing the amount of the Market Shortfall by the Project Size. The resulting figure is the Contingent Support Payment that would be paid to the Supplier. In this example, as set out in Figure 2, a Project Size of 250 MW and a Market Shortfall of $670,000/month will result in a Contingent Support Payment of $ 2,680/MW–month.

Figure 2. Payment for a New Non-Gas Generating Facility

Table A			**Table D**		
Project Size (MW)		250	Estimated Production (MWh-month)		182,500
Net Revenue Requirement (NRR) ($/MW-month)	$	20,000	Estimated Production Weighted Avg. Price ($/MWh)	$	45.00
Total Monthly NRR ($/month)	**$**	**5,000,000**	**Estimated Gross Energy Market Revenue ($/month)**	**$**	**8,212,500**
Table B			**Table E**		
Energy Cost ($/MWh)	**$**	**20.00**	Estimated Variable Energy Cost ($/month)	$	3,650,000
			Total Monthly Start-Up Costs ($/month)	$	247,500
Table C			Imputed Net Losses Over all Operating Intervals in Month	$	15,000
Start-Up Costs ($/start-up)	$	9,900	Estimated Net Revenues ($/month)	$	4,330,000
Number of Start-Ups in month		25	Market Shortfall ($/month)	$	670,000
Total Monthly Start-Up Costs ($/month)	**$**	**247,500**	**Contingent Support Payment ($/MW - month)**	**$**	**2,680**

C. PAYMENT EXAMPLE FOR A DR PROJECT

In this example, we assume that the Supplier submitted the following values in its Proposal:

Project Size:	100 MW
Net Revenue Requirement:	$4,500/MW–month

Figure 3 illustrates each of the five steps for calculating the Contingent Support Payment. Note that the Project Size (also known as the Contracted Demand Reduction in the context of a DR Project) may vary between Seasons and for this example, the Project Size is assumed for a given month in a given Season and may change in another Season. Each of Table A, B, C, D, and E, as described below, demonstrates a single step in such calculation.

Table A -- Total Monthly Net Revenue Requirement

The Total Monthly Net Revenue Requirement for a Proposal is determined by multiplying the Project Size by its Net Revenue Requirement. In this example, as set out in Figure 3, the Supplier had submitted a Proposal for 100 MW of Project Size with a Net Revenue Requirement of $4,500/MW–month, resulting in a Total Net Monthly Revenue Requirement for the Supplier of $450,000.

Table B – DR Strike Price

The DR Strike Price for a Proposal is $350/MWh, subject to indexation in accordance with the DR Contract. For the purposes of this example, an initial value of the DR Strike Price of $350/MWh is used.

Table C -- Estimated DR Strike Price Reduction

The Estimated DR Strike Price Reduction is determined on the basis of information provided by the IMO. It will be assumed when calculating this value that the Supplier will curtail its Contracted Demand Reduction in all hours when both the 3-hour ahead pre-dispatch price and the real-time market price are greater than the DR Strike Price and will experience savings equal to the market price less the DR Strike Price. Essentially we assume that without the equipment added to make the Project Size possible, the Supplier would have consumed and paid the market price. Based on the assumed operation pattern developed by the DR Contract, an Estimated Weighted Average Price is calculated by determining when both the 3-hour ahead pre-dispatch price and the real-time market price exceeds the DR Strike Price from Table B. The number of hours this occurs, which in this example is assumed to be seven hours, multiplied by the Project Size is then called the Estimated Curtailment. The Estimated Weighted Average Price less the DR Strike Price is then multiplied the Estimated Curtailment to determine the Estimated DR Strike Price Reduction. In this example, as set out in Figure 3, the Estimated Curtailment is 700 MWh/Month at an estimated difference of $150/MWh between the Estimated Weighted Average Price ($500/MWh) and the DR Strike Price from Table B of $350.00/MWh, resulting in an Estimated DR Strike Price Reduction for the month of $105,000.

Table D -- Estimated DR Reliability Curtailment Payment

The Estimated DR Reliability Curtailment Payment is determined on the basis of information provided by the IMO. It will be assumed when calculating this value that the Supplier will curtail its demand when specified by the IMO for reliability reasons, amongst other things, and that at times, it will do so when the real-time market price is lower than the DR Strike Price, for which the Supplier will receive compensation. An Estimated Reliability Weighted Average Price is calculated by including the real-time market prices for all hours when the IMO will call for this curtailment and the real-time market price is lower than the DR Strike Price. The number of hours this occurs, which in this example is assumed to be three hours, multiplied by the Contracted Demand Reduction, is then called the Estimated Reliability Curtailment. The DR Strike Price from Table B less the Estimated Reliability Weighted Average Price of $150/MWh is then multiplied by the Estimated Reliability Curtailment to determine the Estimated DR Strike Price Payment. In this example, as set out in Figure 3, the Estimated Reliability Curtailment is 300 MWh-month, the DR Strike Price is $350/MWh, and the Estimated Reliability Weighted Average Price is $150/MWh, resulting in a difference of $200.00/MWh between the DR Strike Price and the Estimated Reliability Weighted Average Price, and an Estimated DR Strike Price Payment for the month of $60,000.

Table E -- Contingent Support Payment

The Contingent Support Payment is based on the Estimated DR Strike Price Reduction from Table C less the Estimated DR Strike Price Payment from Table D, which will be called the Total Curtailment Cost. The Total Curtailment Cost is then subtracted from the Total Monthly Net Revenue Requirement set out in Table A to determine the Curtailment Shortfall. Once the Curtailment Shortfall has been calculated it is converted in to $/MW-month by dividing the amount of the Curtailment Shortfall by the Project Size. The resulting figure is the Contingent Support Payment that would be paid to the Supplier. In this example, as set out in Figure 3, a Project Size of 100 MW and a Curtailment Shortfall of $405,000/month will result in a Contingent Support Payment of $4,050/MW – month.

Figure 3. Payment for a DR Project

Table A

Contracted Demand Reduction (MW)		100
Net Revenue Requirement (NRR) ($/MW-month)	$	4,500
Total Monthly NRR ($/month)	**$**	**450,000**

Table B

DR Strike Price ($/MWh)	**$**	**350.00**

Table C

Estimated Curtailment (MWh-month)		700
Estimated Weighted Avg. Price ($/MWh)	$	500.00
Estimated DR Strike Price Reduction ($/month)	**$**	**105,000**

Table D

Estimated Reliability Curtailment (MWh-month)		300
Difference between DR Strike Price and Estimated Reliability Weighted Avg. Price ($/MWh)	$	200.00
Estimated DR Strike Price Payment ($/month)	**$**	**60,000**

Table E

Total Curtailment Cost ($/month)	$	45,000
Curtailment Shortfall ($/month)	$	405,000
Contingent Support Payment ($/MW - month)	**$**	**4,050**

APPENDIX B: GLOSSARY OF TERMS

The definitions of those capitalized terms and acronyms utilized in this 2,500 MW RFP, unless otherwise stated to be definitions contained in the CES, DR, and DSM Contracts, are provided below.

TERM OR ACRONYM	DEFINITION
2006 Adjustment	Means, for the sole purpose of the Economic Evaluation, a 7.0% reduction in the Real Indexed NRR of each Proposal for a New Generating Facility that will achieve Commercial Operation on or before December 31, 2006.
2007 Adjustment	Means, for the sole purpose of the Economic Evaluation, a 5.0% reduction in the Real Indexed NRR of each Proposal for a New Generating Facility that will achieve Commercial Operation after December 31, 2006 and on or before December 31, 2007.
2,500 MW RFP or this 2,500 MW RFP	Means this Request for Proposals, and all addenda to it.
Actual Project Equivalent Capacity	Means, for a DSM Project, the actual equivalent capacity of the DSM Project, as determined by the Measurement and Verification Data submitted by the Supplier for a given period, as calculated in accordance with the methodology set out in Appendix L.
Agreement on Internal Trade	Means the agreement between the federal, provincial, and territorial governments of Canada with respect to trade within Canada, executed July 18, 1995, and accessible at the Internal Trade Secretariat website www.intrasec.mb.ca.
A.M. Best	Means A.M. Best Company.
Ancillary Services	Means, as defined in the Market Rules, any services necessary to maintain the reliability of the IMO-Controlled Grid, including but not limited to frequency control, voltage control, reactive power and Operating Reserves.
Another Proponent Core Team	Means, in relation to a person or entity, a Proponent Core Team which is not the same as the Proponent Core Team to which such person or entity belongs.
Another Proponent Team	Means, in relation to a person or entity, a Proponent Team whose Proponent Core Team is not the same as the Proponent Core Team to which such person or entity belongs.
Area	Has the meaning given to it in Appendix Q.
Assigned Incremental Transmission Expansion Cost	Means the share of the Incremental Transmission Expansion Cost for a given Capacity Range assigned to a particular New Generating Facility having some or all of its CES Contract Capacity assigned to the given Capacity Range, such share being determined as the portion of the CES Contract Capacity of the particular New Generating Facility assigned to the given Capacity Range divided by the total of the CES Contract Capacities assigned to that Capacity Range from all New Generating Facilities, as more particularly described in Section III.D.2.b.ix.
Automatic System Voltage Support	Means the capability of the New Generating Facility, DR Project, or DSM Project to, both automatically and under the direction of the IMO, respond to changes in system voltage in such a manner as to control these changes within an acceptable range. This requires the automatic or manual adjustment in production or absorption of reactive power by the facility or project. as applicable. A New Generating Facility, DR Project, or DSM Project will be considered to provide Automatic System Voltage Support if the requirements set out in Sections III.C.3.a. and III.C.3.b., as applicable, are met.

Average Cost of Electricity (COD)	Means the weighted average cost of Electricity, expressed in $/kWh, associated with the Incremental Electricity Savings of the DSM Project as of the Commercial Operation Date, which shall be calculated as follows: (i) for each hour of the Hourly Electricity Savings Profile, determine the average HOEP for such hour based on historical IMO data for the two year period prior to the Commercial Operation Date; (ii) multiply the average HOEP for each hour of the Hourly Electricity Savings Profile, as determined in (i) above, by the Incremental Electricity Savings associated with such hour as set out in the Hourly Electricity Savings Profile; (iii) sum all of the amounts determined in (ii) above for all applicable hours in a year; (iv) to the amount determined in (iii) above, add the total delivery and other regulated charges avoided as a result of the DSM Project Annual Electricity Savings, based on the regulated rates applicable to such charges on the Commercial Operation Date; and (v) divide the total amount determined in (iv) above by the DSM Project Annual Electricity Savings to determine the weighted average cost of electricity, expressed in $/kWh.
Average Cost of Electricity (Proposal)	Means the weighted average cost of Electricity, expressed in $/kWh, associated with the Incremental Electricity Savings of the DSM Project as of September 13, 2004, which shall be calculated as follows: (i) for each hour of the Hourly Electricity Savings Profile, determine the average HOEP for such hour based on historical IMO data for the period from September 16, 2002 to September 15, 2004; (ii) multiply the average HOEP for each hour of the Hourly Electricity Savings Profile, as determined in (i) above, by the Incremental Electricity Savings associated with such hour as set out in the Hourly Electricity Savings Profile; (iii) sum all of the amounts determined in (ii) above for all applicable hours in a year; (iv) to the amount determined in (iii) above, add the total delivery and other regulated charges avoided as a result of the DSM Project Annual Electricity Savings, based on the regulated rates applicable to such charges on September 13, 2004; and (v) divide the total amount determined in (iv) above by the DSM Project Annual Electricity Savings to determine the weighted average cost of electricity, expressed in $/kWh.
Avoided Energy Cost	Has the meaning given to it in Section III.D.2.b.vii.
Bid Bond Form	Means the form attached as Appendix G.
Bid Repository	Means the BNY Trust Company of Canada, or such other person or entity designated by the Ministry from time to time, which shall hold the Economic Bid Statement of each Proposal in accordance with the terms of this 2,500 MW RFP.
Biomass	Means organic matter that is derived from a plant and available on a renewable basis, including organic matter derived from dedicated energy crops, dedicated trees, agricultural food and feed crops, and waste organic material from harvesting or processing agricultural products, forestry products and sewage,

	provided that: (i) waste organic material shall contain no treated by-products of manufacturing processes (e.g. treated chipwood, plywood, painted or varnished wood, pressure treated lumber, or wood contaminated with plastics or metals); and (ii) supplementary non-renewable fuels used for start up, combustion, stabilization and low combustion zone temperatures shall be no more than 3.00% of the total fuel heat input in any calendar year.
BTU	Means British thermal unit.
Business Day	Means a day, other than a Saturday or Sunday or statutory holiday in the Province of Ontario or any other day on which banking institutions in Toronto, Ontario are not open for the transaction of business.
Buyer	Means OEFC (or the OPA, if applicable), for purposes of a CES Contract, DR Contract, or DSM Contract.
Callable Hours	Means the hours, on Business Days, between 8:00 a.m. and 8:00 p.m., EST.
Capacity	Means the rated, continuous load-carrying capability, expressed in MW, of a generating facility to generate and deliver electricity at a given time.
Capacity Products	Means any products related to Capacity.
Capacity Range	Means, for purposes of the Economic Evaluation, the incremental MW of Capacity required to accommodate New Generating Facilities located in the applicable Transmission Zone, and which is determined by reference to Appendix Q. For example, the Capacity Range between “Step 1 Upgrade” and “Step 2 Upgrade” is calculated as the difference between the capacity “Max (MW)” as shown in “Step 2 Upgrade” over the capacity “Max (MW)” as shown in “Step 1 Upgrade”.
Capital Lease	Means any lease of property, personal, real or mixed, under which an equity provider is the lessee and which would be capitalized on a balance sheet of the equity provider prepared as of such date in accordance with GAAP.
Capital Lease Obligation	Means, with respect to any Capital Lease, the amount of the obligation of the lessee under such Capital Lease.
CES Contract or Clean Energy Supply Contract	Means a clean energy supply contract between a Supplier of a New Generating Facility and the Buyer, as described in this 2,500 MW RFP.
CES Contract Capacity or Clean Energy Supply Contract Capacity	Means that portion of the Nameplate Capacity that is purchased pursuant to a Clean Energy Supply Contract.
Commercial Operation	In respect of a New Generating Facility, a DR Project, and a DSM Project, has the meaning set out in Sections V.A.2., V.A.3. and V.A.4, respectively.
Commercial Operation Date	Means the date on which Commercial Operation is first attained.
Completion and Performance Security	Means the financial security that the Supplier is required to provide to the Buyer upon the execution of the CES Contract, DR Contract, or DSM Contract, as applicable, as additional assurance that, among other things, the Supplier will meet the project milestones for the New Generating Facility or Demand-Side Project as specified in its Proposal, and will diligently operate and maintain the New Generating Facility or Demand-Side Project over the Term in accordance with the CES Contract, DR Contract, or DSM Contract, as applicable.
Confidentiality Statement	Means the confidentiality statement set out in Section III.G.4.

Conflict of Interest	Includes any situation or circumstance where, in relation to this 2,500 MW RFP process, the Proponent has an unfair advantage or engages in conduct, directly or indirectly, that may give it an unfair advantage, including (i) having or having access to information in the preparation of its Proposal that is confidential to the Government of Ontario and not available to other Proponents; (ii) communicating with any official or representative of the Government of Ontario or members of the Evaluation Team with a view to influencing preferred treatment in this 2,500 MW RFP process; or (iii) engaging in conduct that compromises or could be seen to compromise the integrity of the open and competitive 2,500 MW RFP process and render that process non-competitive and unfair.
Conflict of Interest Declaration	Means the conflict of interest declaration attached as Appendix I.
Connection Costs	Means those costs which are payable by the Supplier related to the reliable connection of the Contract Facility to a Transmission System, a Local Distribution System, or an End-user, as applicable, as more particularly specified pursuant to the System Impact Assessment, Customer Impact Assessment, and Connection Impact Assessment, as applicable. For greater certainty, Connection Costs shall not include System Upgrade Costs.
Connection Impact Assessment	Means a connection impact assessment referred to in Section III.C.1.a and III.C.1.b.
Connection Point	Means: a) for a New Generating Facility, (i) where the facility is connected to the IMO-Controlled Grid, the point or points of connection, as defined in the Market Rules, between the facility and the IMO-Controlled Grid; (ii) where the facility is connected to a Local Distribution System, the embedded connection point or points, as defined in the Market Rules, between the facility and the Local Distribution System; and (iii) where the facility is connected to an End-user, the point or points where the End-user is connected to either the Transmission System or Local Distribution System; and (b) for a DR Project or DSM Project, the point or points where the Load of the project is connected to either a Transmission System or a Local Distribution System. For certainty, the Connection Point will be defined by reference to electrical connection points.
Conservation Bureau	Means the Conservation Bureau which is expected to be established as part of the proposed OPA, as described in Bill 100.
Contingent Support Payment or CSP	Means, (i) for a New Generating Facility, the CSP described in Section V.A.2; (ii) for a DR Project, the CSP described in Section V.A.3; and (iii) for a DSM Project, the CSP described in Section V.A.4.
Contracted Demand Reduction	Means, for the purposes of the DR Contract, the electricity demand, expressed in MW, that will be curtailed by the Supplier, in a given Season, based on the operation of the DR Project and as a direct result of the Control Equipment.

Control Equipment	Means, for the purposes of the DR Contract, the new capital equipment, software and associated services of the DR Project that enable the Supplier to curtail the electricity demand of the load in response to Operational Directives and the market prices for electricity.
Controlled or Controls	Means, with respect to any person at any time, (i) holding, as owner or other beneficiary, other than solely as the beneficiary of an unrealized security interest, directly or indirectly, securities or ownership interests of that person carrying votes or ownership interests sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management of that person, or (ii) the exercise of de facto control of that person whether direct or indirect and whether through the ownership of securities or ownership interests, by contract or trust or otherwise.
Cost Impact Matrix	Means the transmission expansion cost impact matrix for Transmission Zones set out in Appendix Q.
Customer Impact Assessment	Means a customer impact assessment referred to in Sections III.C.1.a. and III.C.1.b.
DBRS	Means Dominion Bond Rating Service Limited and its successors.
Debt	Means, in relation to an equity provider, means, at any time, without duplication, all debts and liabilities, present or future, to which any equity provider is or may become subject by reason of any obligations incurred on or before the time of calculation, whether contingent, unliquidated or otherwise, including, without limitation: (a) money borrowed and premiums (if any) and accrued/deferred interest (if any); (b) the principal, accrued or deferred interest, if any, and premiums, if any, in respect of any debenture, bond, note, loan stock or similar instrument; any accounts payable and accrued liabilities; (c) any deferred or future tax liabilities and deficits under any pension plans; (d) outstanding obligations in respect of any letter of credit issued on its behalf, acceptance, bill discounting or note purchase facility and any receivables purchase, factoring or discounting arrangement, which carries recourse to the equity provider; (e) all Capital Lease Obligations; (f) all marked to market amounts; (g) the amount of any recourse to any equity provider, in respect of any sale, securitization or other asset-backed financing of receivables or other assets; (h) any other transaction having the commercial effect of (1) a financial borrowing or (2) any other raising of money (other than by or in respect of the issue of share equity); and (i) all debts and liabilities of any other person referred to in this definition either (1) guaranteed directly or indirectly in any manner by an equity provider, or (2) having the commercial effect of being guaranteed directly or indirectly by an equity provider.
Deliverables	Means everything developed for or provided to the Buyer in the course of performing under a CES, DR or DSM Contract or agreed to be provided to or on behalf of the Buyer by the Supplier or its employees, volunteers, agents or subcontractors.
Demand-Side Projects	Means DR Projects and DSM Projects.
Dispatch Algorithm	Has the meaning ascribed to it in the Market Rules.
Dollar, dollars, or $	Means Canadian dollars and cents, unless otherwise specifically set out.
DR Contract or Demand Response Contract	Means the demand response contract between the Supplier of a DR Project and the Buyer as set out in this 2,500 MW RFP.

DR Project	Means, for the purposes of the DR Contract, the demand response project to be constructed, developed and operated by the Supplier under a DR Contract, and includes the Control Equipment and the Load.
DR Strike Price	Means the price in Dollars per MWh calculated and set for each contract year in accordance with the DR Contract.
DR Strike Price Payment	Means the payment that shall be made by the Buyer to the Supplier as compensation for the non-strike curtailment during non-strike Curtailment Hours in a settlement month, as more particularly calculated in accordance with Exhibit J of the DR Contract.
DR Strike Price Reduction	Means the amount by which the total monthly NRR shall be reduced as a result of the imputed savings on Imputed Curtailment of electricity demand of the Load as a direct result of the operation of the Control Equipment during Imputed Curtailment Hours, in a settlement month, as calculated in accordance with Exhibit J of the DR Contract.
DR Third Party Agreement	Means that third party agreement referred to in the third bullet point contained in Section III.C.1.b.iii.
DR Verification Certificate	Means a certificate, delivered by the DR Verification Consultant, in a form required by the DR Contract, certifying the matters described in Section V.A.3.f.
DR Verification Consultant	Means, for purposes of the DR Contract, a third party technical consultant, mutually acceptable to the Buyer and the Supplier whose role is to verify, among other things, that the requested electricity demand was curtailed by the DR Supplier, in response to an Operational Directive.
DSM Contract or Demand-Side Management Contract	Means the demand side management contract between the Supplier of the DSM Project and the Buyer as described in this 2,500 MW RFP.
DSM Costs	Has the meaning ascribed to it in Section III.D.2.b.ii.
DSM Incremental Capital Costs	Means the Incremental Capital Costs expected to be incurred in connection with the DSM Project, as specified by a Supplier in its Economic Bid Statement.
DSM Project Annual Electricity Savings	Means the annual Incremental Electricity Savings, expressed in kWh, to be achieved as a result of the DSM Project, as set out by the Proponent in Appendix E-4.
DSM Project or Demand-Side Management Project	Means projects that reduce electricity consumption during all or a significant portion of the year through energy efficient improvements and do not achieve the proposed energy savings through the substitution of new generation or generation from existing sources.
DSM Project Annual Energy Savings	Means, as set out in a Proposal for a DSM Project, the annual energy savings to be achieved by the DSM Project and expressed as electricity in kWh.
DSM Project Equivalent Capacity	Means, for a DSM Project, the equivalent value of the Peak Electricity Savings converted to capacity expressed in MW, and calculated in accordance with the methodology set out in Appendix L.
DSM Third Party Agreement	Means that third party agreement referred to in the fourth bullet point contained in Section III.C.1.c.iii.
DSM Variable Costs	Means the Variable Costs associated with a DSM Project as set in Appendix E-4.
DSM Verification Consultant	Means, for purposes of the DSM Contract, a third party technical consultant, mutually acceptable to the Buyer and the Supplier, whose role is to verify, among other things, that there has been a verifiable electricity savings attributable to the DSM Project.

EBITDA	Means, for a fiscal year for an equity provider, the aggregate of its (a) Net Income, plus (b) Interest Expense, plus (c) Taxes, plus (d) depreciation, plus (e) amortization plus (f) any extraordinary (or non-recurring) items.
Economic Bid Statement	Means the form of Economic Bid Statement set out in Appendix E-1, E-2, E-3 and E-4, as applicable.
Economic Evaluation	Means the economic evaluation set out in Section III.D.
Efficiency Baseline	Means, for a DSM Project, the electricity consumption of the DSM Project, normalized for weather (using at least the prior 10 years of weather data), occupancy and other factors, as determined in accordance with the Measurement and Verification Plan, based on the use of equipment that meets, but does not exceed, the Minimum Equipment Efficiency Standard.
End-user	Means a person who owns or operates a load facility which utilizes electricity supplied through a direct connection to the transmission system or local distribution system.
Energy Cost	Has the meaning given to it in Section III.D.2.b.iv.
Environmental Attributes	Means environmental attributes associated with a New Generating Facility having low environmental impact, and includes, without limitation, emission reduction credits and rights to any fungible or non-fungible attributes, and any and all ownership rights relating to the nature of the energy source as may be defined and awarded through applicable legislation or voluntary programs.
EPC	Means Engineering, Procurement and Construction.
EST	Means Eastern Standard Time.
Estimated DR Reliability Curtailment Payment	Has the meaning given to it in Appendix A.
Estimated Gross Energy Market Revenue	Has the meaning given to it in Appendix A.
Estimated Net Revenue	Has the meaning given to it in Appendix A.
Estimated Production	Has the meaning given to it in Appendix A.
Estimated Production Weighted Average Price	Has the meaning given to it in Appendix A.
Estimated Reliability Curtailment	Has the meaning given to it in Appendix A.
Estimated Reliability Weighted Average Price	Has the meaning given to it in Appendix A.
Estimated Variable Energy Cost	Has the meaning given to it in Appendix A.
Estimated Weighted Average Price	Has the meaning given to it in Appendix A.
Evaluated Cost	Has the meaning given to it in Section III.D.2.b.
Evaluation Team	Means, collectively, the Ministry's personnel and technical advisors.
Existing Generating Facility	Means an electricity generating facility, and ancillary lands required by such generating facility, whose generating equipment is operational and is connected to the IMO-Controlled Grid, a local distribution system or supplies electricity directly to an End-user.
Expansion	Means an addition of generating unit(s) to an Existing Generating Facility which: (i) is not intended to replace any generating equipment that operates, or had operated within twelve (12) months of the date of submission of the Proposal, at the Existing Generating Facility, (ii) generates electricity output in addition to the electricity output of other generating units that operate or operated at the Existing Generating Facility, (iii) has separate revenue grade meters that conform with the IMO metering standards and are dedicated to measuring the electrical output of the added generators and that are

	accessible to the Buyer; and (iv) results in an increase in the electricity capacity available from the Existing Generating Facility which is not greater than the capacity of the additional generating unit(s). For greater certainty, an Expansion shall not include an Upgrade of an Existing Generating Facility.
Expected Net Cost	Means the sum of all Contingency Support Payments and Transmission Integration Costs for all Suppliers' projects less any Revenue Sharing Payments.
Financial Questionnaire	Means the financial questionnaire, the form of which is set out in Appendix D.
Fitch IBCA	Means Fitch IBCA, Duff & Phelps, a division of Fitch Inc., or its successors.
Functional Change	Means a change in the electricity kilowatt-hour consumption of operating equipment used at the proposed project site(s) resultant from a change in the purpose for which a project site, or portion thereof, is utilized.
GAAP	Means Canadian or U.S. generally accepted accounting principles approved or recommended from time to time by the Canadian Institute of Chartered Accountants or the Financial Accounting Standards Board, as applicable, or any successor institutes, applied on a consistent basis.
Gas	Means natural gas as supplied by pipeline and indexed by the Union Dawn Market.
Gas Price Index	Means the Union Dawn Daily Spot Gas Price Index (day ahead) administered by NGx (the Natural Gas Exchange of the TSX). For the sole purpose of the Economic Evaluation, the Gas Price Index shall be converted from US dollars per MMBTU into Dollars per MMBTU utilizing the Bank of Canada closing exchange rate between US dollars and Dollars for 24 months, namely between August, 2002, through and including July, 2004.
Generator Cost Guarantee	Has the meaning given to it in the Market Rules.
Government of Ontario	Means Her Majesty the Queen in Right of Ontario.
HOEP	Means the arithmetic average of the uniform Ontario energy prices as defined by the Market Rules.
Hourly Electricity Savings Profile	Means, for a DSM Project, the electricity savings associated with the DSM Project, expressed in kWh for each hour, over the period specified by the Buyer.
Hydro One	Means Hydro One Inc.
IMO	Means the Independent Electricity Market Operator of Ontario, or its successor.
IMO-Administered Markets	Means the markets established by the Market Rules.
IMO–Controlled Grid	Means the IMO–Controlled Grid as defined by the Market Rules.
IMO Connection Assessment and Approval	Means the IMO connection assessment referred to in Sections III.C.1.a. and III.C.1.b.
Imputed Callable Hour	Means a Callable Hour for which the three-hour ahead Pre-Dispatch Price is equal to or greater than the DR Strike Price.
Imputed Curtailment	Means, the amount of electricity demand, expressed in MWh, that is imputed to be curtailed by the DR Project as a direct result of the operation of the Control Equipment during an Imputed Curtailment Hour.
Imputed Curtailment Hour or ICH	Means, any hour that the real-time market price (HOEP) is equal to or greater than the DR Strike Price and that the three-hour ahead Pre-Dispatch Price for the hour is equal to or greater than the DR Strike Price.
Including, or including	Means including without limitation.

Incremental Capital Costs	Means the incremental portion of the capital cost, including the costs of installation, for all of the Operating Equipment associated with the DSM Project, which shall be equal to the sum of the differences for each unit of Operating Equipment between the capital cost of a unit of Operating Equipment and the capital cost, including the costs of installation, for a comparable unit of equipment that meets, but does not exceed, the Minimum Equipment Efficiency Standard.
Incremental Electricity Cost Savings	Means the portion of the Electricity savings associated with the DSM Project, expressed in Dollars, that is attributable to the installation of the Operating Equipment, which shall be equal to the portion of the total Electricity savings of the DSM Project that exceeds the savings that would have been achieved as a result of the installation of comparable equipment that meets, but does not exceed, the Minimum Equipment Efficiency Standard. For greater certainty, Incremental Electricity Cost Savings shall be calculated by multiplying Incremental Electricity Savings by the Average Cost of Electricity.
Incremental Electricity Savings	Means the incremental electricity savings of the DSM Project that are attributable to the installation of the Operating Equipment, which shall be equal to the difference, as expressed in kWh, between the Efficiency Baseline and the Post-Installation Consumption for a given period.
Incremental Transmission Expansion Cost	Means, for purposes of the Economic Evaluation, the incremental costs of transmission system upgrades that are required to transmit the incremental MW of Capacity required by New Generating Facilities located in the applicable Transmission Zone, which is determined by reference to Appendix Q. For example, the Incremental Transmission Expansion Cost between “Step 1 Upgrade” and “Step 2 Upgrade”, to increase the capacity “Max (MW)” as shown in “Step 2 Upgrade” over the capacity “Max (MW)” as shown in “Step 1 Upgrade”, is calculated as the difference between the “Total Cost” shown under the heading “Step 2 Upgrade” and the “Total Cost” shown under the heading “Step 1 Upgrade”.
Interactive Effect	Means any reduction in the electricity kilowatt-hour consumption of operating equipment used at the proposed project site(s) resultant from a change or addition of some other component or system, at the proposed project site(s) or elsewhere, that does not directly and actively control the operation of the operating equipment in order to effect the reduction in the electricity kilowatt-hour consumption. Examples of interactive effects are reduced chiller operation resulting from building envelope upgrades or as a result of conversion to more efficient lighting systems that produce less heat.
Interest Expense	Means, for any period, the sum of (a) all cash payments made on account of any interest on Debt; plus (b) all fees payable in respect of any letters of credit or guarantees; plus (c) the interest component of any payments on Capital Leases; plus (d) the discount amount of any bankers’ acceptance issued by the equity providers; plus (e) all financing, stamping, standby, commitment and other similar fees payable by the equity providers; plus (f) commitment commission; plus (g) other fees, costs and expenses in the nature of financing costs.

Intermediate Generation	Means generation from generators that can operate 16 to 24 hours during week days and shut down, if required, at night on the weekdays and on the weekends and holidays, having load factors in the range of 50 to 70 percent.
Investment Grade Credit Rating	Means a minimum credit rating of (i) BBB– with S&P, (ii) Baa3 with Moody's, (iii) BBB low with DBRS, or (iv) BBB- with Fitch IBCA, if applicable.
kW	Means kilowatt.
kWh	Means kilowatt-hour.
LDC or Local Distribution Company	Means a person licensed by the OEB as a "Distributor" in connection with a local distribution system.
Letter of Credit Form	Means the form attached as Appendix F.
Local Distribution Company or LDC	Means a Person licensed by the OEB as a "Distributor" in connection with a Local Distribution System.
Local Distribution System	Means a system for conveying electricity at voltages of 50 kilovolts or less and includes any structures, equipment or other things used for that purpose.
Management Board Secretariat	Means the Management Board Secretariat of the Province of Ontario.
Managerial Capacity	Means an assignment with the organization in which the individual personally; (i) manages the organization, department, subdivision, function or component; (ii) supervises and controls the work of other supervisory, professional or managerial employees, or manages an essential function within the organization or department or subdivision of the organization; (iii) has authority to hire and fire or recommend personnel actions or, if no other employee is directly supervised, functions at a senior level within the organizational hierarchy or with respect to the function managed; and (iv) exercises discretion over the day-to-day operations of the activity or function for which the individual has authority.
Market Rules	Means the rules made under section 32 of the *Electricity Act, 1998* (Ontario), as amended from time to time.
Market Shortfall	Has the meaning given to it in the CES Contract.
Maximum Curtailment	Means the maximum number of hours in a given Season that a Supplier may be required to curtail the electricity demand of the load as a direct result of the operation of the Control Equipment in response to Operational Directives, as set out in a DR Contract. For greater certainty, only the hours for which the Supplier has verified that it has curtailed the electricity demand of the load as a direct result of the Control Equipment in response to an Operational Directive, by delivering the appropriate DR Verification Certificate to the Buyer, will be counted as hours for the purposes of the Maximum Curtailment.
Measurement and Verification Guidelines for DR	Means Issue 1.0 of IMO_PRO_0105 – Market Manual 5: Settlements Part 5.10: Transitional Demand Response Program, Appendix C: Measurement and Verification Protocol Development.
Measurement and Verification Guidelines for DSM	Means M&V Guidelines: Measurement and Verification for Federal Energy Projects Version 2.2, dated September 2000, issued by the Office of Energy Efficiency and Renewable Energy of the United States of America Department of Energy, and referenced as DOE/GO-102000-0960, following M&V method Option B of the four M&V method Options contained therein.

Measurement and Verification Activities	All activities carried out by the DR Verification Consultant or the DSM Verification Consultant, as applicable, regarding measurement and verification of demand reduction and energy savings.
Measurement and Verification Plan	The method proposed by a Supplier to measure and verify demand reduction or energy savings.
MERX™	Means the national electronic tendering system owned and operated by Mediagrif Interactive Technologies Inc.
Minimum Equipment Efficiency Standards	Means, for a DSM Project, the efficiency level that is the higher of: (i) the current minimum equipment efficiency standards applicable to the classes of operating equipment, established pursuant to the *Energy Efficiency Act* (Ontario) and associated regulations, as contained in the guide to the *Energy Efficiency Act* (Ontario) attached as Exhibit O to the DSM Contract; or (ii) the efficiency level of the equipment that is to be replaced, or which has been replaced by, the operating equipment.
Ministry	Means the Ministry of Energy of the Government of Ontario.
Ministry of Natural Resources, Ministry of the Environment, Ministry of Finance, and Ministry of Municipal Affairs and Housing	Shall each refer to the applicable Ministry of the Province of Ontario.
MMBTU	Means one million BTUs.
Moody's	Means Moody's Investors Service, Inc. or its successor.
Municipal Solid Waste	Means: (a) any waste, whether or not it is owned, controlled or managed by a municipality, except, (i) hazardous waste, (ii) liquid industrial waste (iii) gaseous waste, and (iv) Biomass, and (b) solid fuel, whether or not it is waste, that is derived in whole or in part from the waste included in clause (a).
MVA	Means mega volt-ampere.
MW	Means megawatt.
MWh	Means megawatt-hour.
Nameplate Capacity	Means, with respect to a New Generating Facility, the rated, continuous load-carrying capability net of parasitic or station service loads, expressed in MW, of the New Generating Facility to generate and deliver electricity at a given time, and which includes the CES Contract Capacity.
NERA	Means NERA Economic Consulting.
Net Income	Means, for any equity provider for any period, net income for such equity provider for such period determined in accordance with GAAP.
Net Revenue Requirement or NRR	For a New Generating Facility, has the meaning given to it in Section III.E.1, and for a DR Project and DSM Project, has the meaning given to it in Section III.E.2.
New Gas Generating Facility	Means a New Generating Facility that uses Gas as a Primary Fuel and which is designated as such by a Proponent in its Proposal.
New Generating Facility	Means a new generating facility referred to in Section III.C.1.a.
New Non-Gas Generating Facility	Means a New Generating Facility that does not burn any coal or Municipal Solid Waste, and uses fuel(s) other than Oil as a Primary Fuel, and is designated as such by a Proponent in its Proposal.

Non-Strike Curtailment	Means the amount of electricity demand, expressed in MWh, that is curtailed by a DR Project as a direct result of the operation of the Control Equipment in response to Operational Directives during Non-strike Curtailment Hours, as set out in the DR Contract and calculated in accordance with Exhibit J of the DR Contract.
Non-Strike Curtailment Hour	Has the meaning ascribed to it in Exhibit J of DR Contract.
Notice of Intent to Proceed to Stage 3	Means the form attached as Appendix N.
NRR (Simple Payback Period)	Is the monthly payment, expressed in $/MW-month, that the Supplier will require in order to reduce the Simple Payback Period to three years calculated in accordance with the DSM Contract.
NRR (Variable Costs)	Is the simple monthly average of the total DSM Variable Costs over the Term set out in the Economic Bid Statement, expressed in $/MW-month.
O&M Costs	Means, for a New Gas Generating Facility or a DSM Project, the costs of operating and maintaining such project throughout the Term.
OEB	Means the Ontario Energy Board.
OEFC	Means Ontario Electricity Financial Corporation.
Ontario Emissions Trading Program or OETP	Means the Ontario Emissions Trading Program operating under Regulation 397/01 of the *Environmental Protection Act* (Ontario).
Oil	Means any liquid fuel derived from petroleum, including but not limited to heavy fuel oil and diesel fuel.
On-peak Hours	Means the 16 hour period between 7:00 a.m. and 11:00 p.m. local time on Business Days.
OPA	Means the Ontario Power Authority.
Operating Equipment	Means the new equipment associated with the measures to be implemented pursuant to the DSM Project the implementation of which enables the Supplier to achieve verifiable electricity savings equal to or greater than the DSM Project Annual Energy Savings, which is comprised entirely of Qualifying Equipment and Qualifying Heating and Cooling Equipment or equipment that directly controls Qualifying Equipment and Qualifying Heating and Cooling Equipment.
Operating Reserves	Means generation capacity which can be called upon on short notice by the IMO to replace electricity supply which is unavailable as a result of an unexpected outage or to augment scheduled electricity as a result of unexpected demand or other contingencies.
Operational Change	Means a change in the electricity kilowatt-hour consumption of operating equipment used at the proposed project site(s) resultant from a change in the extent to which a project site, or portion thereof, is utilized.
Operational Directive	Means, for the purposes of the DR Contract, an operational directive to curtail the electricity demand of the load, issued by the IMO to the Supplier (or to a representative of the Supplier with the authority to curtail the electricity demand of the load) a minimum of three (3) hours in advance of the time at which the curtailment of the load is to commence and which specifies the duration of the curtailment in whole hours to a maximum of six (6) hours while not exceeding the Maximum Curtailment with Callable Hours.
OPG	Means Ontario Power Generation Inc.
Other Season	Means any time of the year other than Winter or Summer.

Payback Reduction Amount	Means, for a DSM Project, the total amount, expressed in Dollars, that the Supplier requires to reduce the Simple Payback Period to three years, as determined in accordance with the methodology set out in Exhibit Q to the DSM Contract.
Peak Day	Means, for a DSM Project, a day upon which the highest demand for electricity expressed in kW is achieved in respect of the load.
Peak Electricity Savings	Means the energy savings to be achieved by a DSM Project on a Typical Peak Day in a given Season during On-peak Hours expressed as electricity in MWh and calculated in accordance with the methodology set out in Section b of Appendix L.
Peak Electricity Savings Other	Means the Peak Electricity Savings to be achieved by a DSM Project during Other Season.
Peak Electricity Savings Summer	Means the Peak Electricity Savings to be achieved by a DSM Project during Summer.
Peak Electricity Savings Winter	Means the Peak Electricity Savings to be achieved by a DSM Project during Winter.
Post-Installation Consumption	Means the electricity consumption of the DSM Project, normalized for weather (using at least the prior 10 years of weather data), occupancy and other factors as specified in the Measurement and Verification Plan as measured based on the use of the Operating Equipment.
Pre-Dispatch Price	Means the pre-dispatch price for electricity, being the hourly price determined from the Pre-Dispatch Schedule for a specified number of hours in advance of real-time market clearing, as determined by the IMO-Administered Markets.
Pre-Dispatch Schedule	Means an hourly schedule for the remaining hours of a dispatch day as determined by the Dispatch Algorithm in accordance with Chapter 7 of the Market Rules.
Primary Fuel	Means, (a) for a New Generating Facility or a DR Project that involves the generation of electricity, including any larger facility of which the New Generating Facility or DR Project forms a part, a fuel that is used for ten (10%) percent or more of the total fuel heat input of the New Generating Facility, DR Project, or for any larger facility of which the New Generating Facility or DR Project forms a part, as the case may be, over any calendar year, and (b) for a DSM Project that involves district heating or cooling equipment, a fuel used for ten percent (10%) or more of the total fuel heat input, directly or indirectly, into the district heating or cooling system during any Season.
Priority Electrical Zone	Means an electrical area identified as a Priority Electrical Zone by the Ministry as set out in Appendix O.
Priority Electrical Zone Adjustment	Means, for the sole purpose of the Economic Evaluation, a 2.0% reduction in the Real Indexed NRR of each Proposal for a New Generating Facility or DR Project, or in the DSM Cost for a DSM Project, that will be connected to a transmission system, distribution system, or End-users within either, or both, Priority Electrical Zones.
Project Stream	Means any one of following three classifications of proposed projects which are the subject matter of this 2,500 MW RFP, namely (i) New Generating Facilities, (ii) DR Projects, and (iii) DSM Projects.

Project Size	Means: (i) for a proposed New Generating Facility, the proposed CES Contract Capacity, (ii) for a proposed DR Project, the proposed Contracted Demand Reduction and (iii) for a proposed DSM Project, the DSM Project Equivalent Capacity.
Proponent	Means an entity or person that submits one or more Proposals in response to this 2,500 MW RFP. OPG may not be a Proponent.
Proponent Core Team	Means, collectively, in respect of a Proposal, each member of a Proponent Team which is not at "Arm's Length" (as that term is defined in the CES Contract, DR Contract and DSM Contract) to the Proponent of that Proponent Team, or which Controls the Proponent of that Proponent Team, but which does not include the Proponent or OPG. For purposes of this definition, any person or entity which owns an interest of 50% or more, or otherwise Controls, the Proponent of that Proponent Team or another member of the Proponent Core Team shall also be deemed to be a member of the Proponent Core Team. Notwithstanding the foregoing, OPG may not be the sole member of any Proponent Core Team, and where OPG would otherwise be one member of a Proponent Core Team with one or more members in addition to OPG, OPG shall be deemed not to be a member of the Proponent Core Team. Where a Proponent is structured as a limited partnership and where OPG owns an interest of 50% or less of the general partner of the limited partnership, the general partner shall be deemed not to be a member of the Proponent Core Team.
Proponent Non-Core Team	Means, collectively, each member of a Proponent Team other than the Proponent and the Proponent Core Team.
Proponent Team	Means, collectively, a Proponent and all entities and persons (including equity providers named in the Proposal) involved in the preparation of the Proponent's Proposal(s) for the 2,500 MW and/or required by the Proponent to successfully implement its Proposal(s) for this 2,500 MW RFP and to comply with the CES Contract, DR Contract or DSM Contract. For greater certainty, members of the Proponent Team shall include the Proponent, the Proponent Core Team, the Proponent's technical, financial and legal advisors, and any other person otherwise assisting the Proponent in the preparation of its Proposal(s), but shall not include any lenders or any technical or legal advisors to lenders.
Proposal	Means a proposal made pursuant to this 2,500 MW RFP.
Proposal Security	Means the financial security submitted with the Proposal as described in Section III.F.
Proposal Submission Deadline	Means December 15, 2004 at 3:00:00 p.m.(EST).
Prospective Proponent	Means an entity or person that submitted a Statement of Qualifications in accordance with the RFI/RFQ.
Provisional Evaluated Cost	Has the meaning given to it in Section III.D.1.a.vi.
Qualified Proponent	Means a Proponent who the Ministry has advised meets the requirements of both Stages 1 and 2 and who has submitted a Notice of Intent to Proceed to Stage 3 to the Ministry within the time specified, irrevocably confirming its intention to submit the Economic Bid Statement for evaluation in accordance with the terms and conditions of Stage 3.
Qualifying Equipment	Has the meaning set out in Section III.C.1.c.i.
Qualifying Heating and Cooling Equipment	Means district heating and cooling equipment that is replacing or used in the place of, and reduces the kWh Electricity consumption relative to, operating equipment of a type for

	which the Energy Efficiency Act (Ontario) currently prescribes a minimum efficiency.
Real Indexed NRR	Has the meaning given to it in Section III.D.2.b.1.
Related Products	Means all Capacity Products, Ancillary Services, transmission rights, any Environmental Attributes, and any other products or services that may be provided by the Contract Facility from time to time (including steam and hot water produced by a New Generating Facility), that may be traded in the IMO-Administered Markets or other markets, or otherwise sold, and which shall be deemed to include products and services for which no market may exist, such as capacity reserves.
Revenue Sharing Payment	Has the meaning given to it in Section V.A.2.c.
RFI / RFQ	Means the Request for Information / Request for Qualifications issued by the Ministry on June 25, 2004 with respect to the supply of approximately 2,500 MW of New Clean Generation and Demand-Side Projects, and all addenda to it.
S&P	Means the Standard and Poor's Rating Group (a division of McGraw-Hill Inc.) or its successors.
Season	Means each of Summer, Winter and Other Season.
Seasonal Capacity	Means the capacity to be achieved by a DSM Project on a Typical Peak Day in a given Season during On-peak Hours expressed as energy in MW in accordance with the methodology set out in Appendix L.
Seasonal Capacity Other	Means the Seasonal Capacity to be achieved by a DSM Project during Other Season.
Seasonal Capacity Summer	Means the Seasonal Capacity to be achieved by a DSM Project during Summer.
Seasonal Capacity Winter	Means the Seasonal Capacity to be achieved by a DSM Project during Winter.
Selected Proponent	Means a Qualified Proponent whose Proposal has been selected and accepted by the Government of Ontario, in accordance with this 2,500 MW RFP.
Settlement Period	Means, in respect of a DSM Contract, the six (6) month period commencing on the first day of the first full month of the Term, and each six month period thereafter.
Simple Payback Period	Means, for a DSM Project, the number of years required for the Incremental Capital Costs incurred by the Supplier to be recovered through Incremental Electricity Cost Savings, as determined in accordance with Exhibit Q to the DSM Contract.
Specified Forecast Index	Means the forecast of the inflation index set out in Appendix R.
Specified Index	Means the consumer price index for "All Items" published or established by Statistics Canada or its successor in relation to the Province of Ontario.
Specified Load	Means, for a DR Project, the amount of electricity demand that a Supplier will be capable of curtailing in accordance with the DR Contract.
Specified Heat Rate	Means the heat rate specified by the Proponent in its Proposal, which shall be subject to a minimum of 5,000 BTU/kWh and a maximum of 8,000 BTU/kWh.
Stack	Has the meaning given to it in Section III.D.1.
Stage 1	Means the stage of the Evaluation Team's evaluation of Proposals for completeness, as set out in Section III.B, and which is not intended to be a legally binding bidding process.
Stage 2	Means the stage of the Evaluation Team's evaluation of Proposals for compliance with the Technical and Financial Mandatory Requirements, as set out in Section III.C, and which is not intended to be a legally binding bidding process.

Stage 3	Means the stage of the Evaluation Team's evaluation of Proposals for purposes of the Economic Evaluation, as set out in Section III.D and which is intended to be a legally binding bidding process.
Start-Up Costs	Means the start-up costs for each imputed start-up specified by the Proponent in its Economic Bid Statement, as expressed in MMBTU per start-up, or Dollars per start-up, as the case may be.
Statement of Qualifications	Means the form attached as Appendix A to the RFI/RFQ which has been completed and delivered by an interested party to the Ministry of Energy in accordance with the RFI/RFQ.
Statutory Declaration	Means the form attached as Appendix H.
Sub-zone	Has the meaning given to it in Appendix Q.
Summer	Means all of the calendar days for the period commencing on June 16 and ending September 15.
Supplier	Means a Selected Proponent which has executed a CES Contract, a DR Contract, or a DSM Contract, as applicable.
System Impact Assessment	Means a system impact assessment referred to in Sections III.C.1.a. and III.C.1.b.
System Reliability Enhancement Adjustments	Refers to any or all of the following: Priority Electrical Zone Adjustment, Voltage Support Adjustment and Timing Adjustment.
System Upgrade Costs	Means all costs for facilities incurred by Transmitters or LDCs and invoiced to the Supplier, in relation to System Upgrades, and which may include design, engineering, procurement, construction, installation and commissioning costs, as determined in accordance with the Transmitters' or LDC's respective policies and procedures and by the OEB, if necessary. For greater certainty, System Upgrade Costs shall not include Connection Costs.
System Upgrades	Means all additions, improvements, and upgrades to the Transmission System and Local Distribution System to be built by a Transmitter or LDC that are (or will be) determined to be required to ensure the reliable delivery of electricity from new generating capacity to loads in the Province of Ontario.
Tangible Net Worth	Means, in respect of a Supplier, at any time and without duplication, an amount determined in accordance with GAAP, and calculated as (a) the sum of capital stock, preferred stock, paid-in capital, contributed surplus, retained earnings, capital reserves, and cumulative translation adjustment (whether positive or negative), minus (b) the sum of any amounts shown on account of any common stock reacquired by the Supplier, patents, patent applications, service marks, industrial designs, copyrights, trade marks and trade names, and licenses, prepaid assets, goodwill and all other intangibles.
Target Capacity	Means 2,500 MW.
Target Date	Means December 31, 2007.
Tax Compliance Declaration	Means the form attached as Appendix J.
Technical Questionnaire	Means the technical questionnaire, the form of which is set out in Appendix C-1 (for New Generating Facilities only), Appendix C-2 (for DR Projects only) and Appendix C-3 (for DSM Projects only).
Technical and Financial Submission	Means that portion of a Proposal submitted by a Proponent which comprises the documentation set out in Sections III.B.1, III.B.2, and III.B.3.
Term	Means that period of time commencing upon the later of the Commercial Operation Date and the date of the CES Contract, the DR Contract or the DSM Contract, as applicable, and

	ending: (i) on the day before the 20th anniversary date thereafter for a CES Contract and (ii) on the day before the 5th to the 20th anniversary date thereafter for a DR Contract and a DSM Contract.
Term Commencement Date	Means the first day of the Term.
Timing Adjustment	Refers to either or both of the 2006 Adjustment and the 2007 Adjustment.
Total Monthly Net Revenue Requirement	Has the meanings given to it in Appendix A, in respect to a New Generating Facility and a DR Project.
Total Resource Cost Test or TRC Test	Has the meaning given to it in Section III.D.2.b.ii.
Total Transmission Expansion Costs	Has the meaning given to it in Section III.D.2.b.ix.
Transmission System	Means a system for conveying electricity at voltages of more than 50 kilovolts and includes any structures, equipment or other things used for that purpose.
Transmission Upgrade Cost Impact	Has the meaning given to it in Section III.D.2.b.ix.
Transmission Zone	Means a transmission zone identified by the Ministry and its technical advisors that will be published in an Addendum to this 2,500 MW RFP, which shall be used for the purposes of the Economic Evaluation.
Transmitter	Means a Person licensed as a “transmitter” by the OEB in connection with a Transmission System.
Typical Peak Day	Means, for a DSM Project, the Peak Day normalized for weather (using at least the prior 10 years of weather data), occupancy and other factors determined in accordance with the Measurement and Verification Plan to represent the maximum demand during On-peak Hours for a day in a given Season.
Typical Week	Means, with respect to a given Season, a notional week that is chosen by a Proponent of a DSM Project as being representative of demand for all hours for that week, which will form the basis of an Hourly Electricity Savings Profile provided by the Proponent and to be applied to all weeks contained within such Season.
Upgrade	Includes the refurbishment or replacement of generating and related equipment at an Existing Generating Facility with equipment which provides better or improved performance, but which for greater certainty does not include an Expansion.
Variable Costs	Means the variable costs that are associated with the DSM Project, which shall include O&M Costs, the administration costs, the project delivery costs and the costs related to the Measurement and Verification Activities.
Voltage Support Adjustment	Means, for the sole purpose of the Economic Evaluation, a 5.0% reduction in the Real Indexed NRR of each Proposal for a New Generating Facility or DR Project, or in the DSM Cost for a DSM Project, that will be connected to a transmission system, distribution system, or End-user within a Priority Electrical Zone and will provide Automatic System Voltage Support in a Priority Electrical Zone.
Winter	Means all calendar days for the period commencing on December 16 and ending on March 15.
Zone	Has the meaning given to it in Appendix Q.

APPENDIX C-1: TECHNICAL QUESTIONNAIRE FOR PROPOSALS FOR NEW GENERATING FACILITIES ONLY

Proponents are required to complete this Technical Questionnaire in full, including the attachment of additional documents as and where requested. PLEASE BE ADVISED THAT INCLUDING THE NET REVENUE REQUIREMENT OR ANY OTHER INFORMATION THAT IS PART OF YOUR ECONOMIC BID STATEMENT IN THIS TECHNICAL QUESTIONNAIRE WILL LEAD TO THE DISQUALIFICATION OF YOUR PROPOSAL.

1. **Proponent Information**

   a. Proponent's full registered legal business name and any other name under which it carries on business:

   b. Proponent's address, telephone, e-mail and facsimile numbers:

   c. Name, address, telephone and facsimile numbers of the contact person(s) for the Proponent:

   d. Name of the person who is primarily responsible for the Proposal:

   e. Name of the person who will be managing the operation of the proposed Deliverables:

   f. State the legal form of the Proponent (i.e. whether the Proponent is an individual, a sole proprietorship, a corporation, a partnership, a joint venture, an incorporated consortium, or a consortium that is a partnership, or other legally recognized entity):

g. State the legal jurisdiction under which the Proponent was created (for example, the laws of Ontario):

h. Select one of the following statements, as applicable to the Proponent:

i. ☐ The Proponent is not a non-resident of Canada, as defined under the *Income Tax Act* of Canada; or

ii. ☐ The Proponent is a non-resident of Canada, as defined under the *Income Tax Act* of Canada.

i. Name(s) of the proprietor, where the Proponent is a sole proprietor; each of the directors and officers where the Proponent is a corporation; each of the partners where the Proponent is a partnership, and applicable combinations of these when the Proponent is a joint venture or consortium, whichever applies:

2. **Executive Summary of Proposal**

An executive summary of the Proposal, with a maximum length of 2 pages, must be provided which should state the following:

a. that the Proposal is for a New Generating Facility;

b. the names of the Proponent, each member of the Proponent Core Team, and each member of the Proponent Non-Core Team, and any lenders in relation to the proposed New Generating Facility;

c. a short description of the key personnel involved in the preparation of the Proposal and in the delivery and operation of the New Generating Facility;

d. an organization chart that provides a schematic representation of ownership and contractual links among all entities or individuals involved in the development, construction, financing and operation of the project;

e. a summary of the business arrangements and financing of the proposed New Generating Facility; and

f. a short description of the plant and equipment to be used in the New Generating Facility including the technology, project design, location of such plant and equipment, as well as the proposed Commercial Operation Date of the New Generating Facility.

☐ Executive summary attached.

3. **Project Information**

a. Project Name: ______________________________

____

b. Point of Connection: Indicate whether the proposed New Generating Facility is to be connected to:

i. ☐ a Transmission System;

ii. ☐ a Local Distribution System; or

iii. ☐ an End-User.

c. i. State the municipal address (including the city or town) of the New Generating Facility:

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ii. State the Environment Canada weather station that is physically nearest to the Contract Facility (or in the case of a Contract Facility that is comprised of two or more generating facilities that are aggregated, select a weather station that is physically nearest to one of the facilities so aggregated):

____
____
____
____
____

d. Attach a full description of the plant and equipment to be used in the New Generating Facility including the technology, project design, Manufacturer's Heat Rate (Higher Heating Value) in BTU/kWh, as well as the location of such plant and equipment:

☐ Description attached.

e. State whether the Proponent is aggregating two (2) or more generating facilities in the Proposal. Proponents are advised that in the event that the Proponent is aggregating two (2) or more generating facilities in the Proposal, each individual facility being aggregated must satisfy all of the requirements of the 2,500 MW RFP. Choose one:

i. ☐ Yes, the Proponent is aggregating two (2) or more generating facilities in the Proposal. The municipal address, Capacity, and a brief description of each individual generating facility being aggregated is set out in the enclosed attachment.

ii. ☐ No, the Proponent is not aggregating two (2) or more generating facilities in the Proposal.

f. Expansion of Existing Generating Facility (select one of the following):

i. ☐ The New Generating Facility is not an Expansion of an Existing Generating Facility; or

ii. ☐ The New Generating Facility satisfies the definition of an Expansion of an Existing Generating Facility. If so,

1. Name, and briefly describe, the Existing Generating Facility:

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____

2. In addition, confirm whether the Proponent for the Expansion is also the operator of the Existing Generating Facility (choose one):

a. ☐ Yes; or

b. ☐ No.

g. Type of New Generating Facility:

i. Designate whether the New Generating Facility is a New Gas Generating Facility or a New Non-Gas Generating Facility by checking the appropriate box below:

a. ☐ New Gas Generating Facility; or

b. ☐ New Non-Gas Generating Facility.

ii. Fuel Sources:

1. List all source(s) or fuel(s) consumed by the proposed New Generating Facility as Primary Fuel(s):

____
____
____
____

2. List all other source(s) or fuel(s) consumed by the proposed New Generating Facility:

____
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____
____

3. If the New Generating Facility forms part of a larger Facility, (including an Existing Generating Facility if the New Generating Facility is an Expansion) list all source(s) or fuel(s) consumed by the Facility:

____
____
____
____

h. CES Contract Capacity in MW: ____________________

i. Expected (or Actual) Commercial Operation Date (mm/dd/yyyy)

____

____

j. Nameplate Capacity in MW: ____________________

k. State the ramp rate, over a single 5 minute interval, expressed in MW/minute, being defined as the rate of increase or decrease in energy output that the New Generating Facility is capable of achieving after start-up, synchronization to the system, and technically required hold points, with such interval being between minimum load and maximum continuous rating: __________________________ MW/minute

i. Confirm whether the value of the ramping set out above for one minute, and as expressed in MW, is greater than or equal to 4% of the CES Contract Capacity:

1. ☐ Yes, the ramping value of the New Generating Facility for one minute is greater than or equal to 4% of the CES Contract Capacity.

2. ☐ No, the ramping value of the New Generating Facility is not greater than or equal to 4% of the CES Contract Capacity.

4. **Additional Project Eligibility**

Indicate by checking the boxes below whether each of the following criteria are satisfied:

a. ☐ Based on the information provided in Questions 5 and 6 of this Appendix, the New Generating Facility is located in the Province of Ontario and affects supply or demand on the IMO-Administered Markets.

b. ☐ The New Generating Facility is not an Upgrade of an Existing Generating Facility.

c. ☐ The New Generating Facility Project had not attained commercial operation before September 13, 2004. For purposes of this requirement, commercial operation shall mean that the New Generating Facility commences operation in compliance with all laws and regulations after the completion of construction, completion of connection and synchronization to the IMO-Controlled Grid, Local Distribution System, or directly to an End-User, and completion of all commissioning tests.

d. ☐ The New Generating Facility is designed to operate in accordance with the CES Contract from the Commercial Operation Date until the expiry of the Term of the CES Contract.

e. ☐ The New Generating Facility does not generate electricity through a process by burning Oil as a Primary Fuel, or by burning any coal or any Municipal Solid Waste.

f. ☐ If the New Generating Facility forms part of a larger facility (referred to as in the CES Contract as the "Facility") the Facility does not generate electricity through a process by burning Oil as a Primary Fuel, or by burning any coal or any Municipal Solid Waste.

5. **Description of the Site(s) and Location(s)**

In accordance with the requirements set out in Section III.C.1.a.ii, provide a copy of each of the following:

a. A map showing the location(s) of the project site(s) in relation to neighbouring roads and lands, drawn to a scale of no less than 1:10,000 and no greater than 1:100,000, and having a size of at least 6 inches by 6 inches.

☐ Document(s) enclosed.

b. A plan of survey or its equivalent delineating the boundaries of the lands for the site(s), including any easements appurtenant to such lands.

☐ Document(s) enclosed.

6. **Control of Site(s)**

a. In accordance with the requirements set out in Section III.C.1.a.iv, provide a copy of one of the following:

i. ☐ Registered transfer, lease, licence, or other agreement permitting the use of the land for the site(s) is enclosed;

ii. ☐ Written agreement to purchase the land for the site(s) is enclosed; or

iii. ☐ Written agreement entitling the Proponent to an option to purchase, lease, licence, or use the land for the site(s) is enclosed.

Note: By checking this box ☐, the Proponent is satisfying this requirement by enclosing

a standard form lease, license or agreement that was used for more than ten (10) different sites, together with a statement by the Proponent setting out in summary form all information that is particular to each lease, license, or agreement as applicable.

b. Proponents must identify whether their proposed project involves Crown resources, including Crown land for transmission, distribution and ancillary structures. If so, Proponents must provide written confirmation from the Ministry of Natural Resources that the Proponents have been granted the opportunity to pursue development approvals for a renewable energy project in the form of a “Site Release”.

i. Proposed project involves Crown resources:

☐ Yes. Written confirmation from the Ministry of Natural Resources in the form of a "Site Release" is enclosed; or

☐ No.

7. **Documentation Relating to Environmental Assessments**

Pursuant to Section III.C.1.a.v, Proponents are to provide the following information:

a. Classification of proposed project according to the Ontario Ministry of the Environment's "Guide to Environmental Assessment Requirements for Electricity Projects" dated March 2001 as referred to in O. Reg. 116/01 to the *Environmental Assessment Act* (Ontario) entitled "Electricity Projects". Choose one of the following:

i. ☐ Category A;

ii. ☐ Category B. A copy of the published "Notice of Commencement of a Screening" is enclosed, and if not set out in the published Notice, state where and when such publication took place; or
____
____
____
____

iii. ☐ Category C. A copy of the "Terms of Reference" submitted to the Ministry of Environment is enclosed, and if not set out in the Terms of Reference, state the date of such submission if it is not already set out in the published notice.

b. In the case of a Proposal involving generating equipment that is not subject to the *Environmental Assessment Act* (Ontario), the Proponent must make the following statement:

i. ☐ Yes, all applicable Ministry of the Environment certificates of approval for air and noise emissions have been or will be applied for.

8. **Evidence of progress toward connection approvals and municipal approvals**

a. Proponents must have notified the relevant local municipality (or municipalities) or planning authority (or planning authorities) of their project in writing, and enclose the following:

i. ☐ A copy of the written notice delivered to the relevant local municipality (or municipalities) or planning authority (or planning authorities) of the Proponent's project is enclosed, and if not set out in the notice, state the date of such delivery: ____________________.

b. The Proponent must state each of the following:

i. The Proponent has:

1. ☐ notified the relevant municipalities and planning authorities of the proposed New Generating Facility;

2. ☐ sought advice from such parties about the requirements under the *Planning Act* (Ontario);

3. ☐ sought advice from such parties about which additional relevant municipalities and planning authorities should also be advised of the proposed New Generating Facility; and

4. ☐ has so advised such additional relevant municipalities and planning authorities.

c. With respect to the impact of the New Generating Facility on the electricity system, the Proponent must have initiated the appropriate assessments, and must provide the associated documentation. Specifically, details of the required assessments are described in Section III.C.1.a.viii. In relation to these requirements, the Proponent is required to submit the following, if required by the aforementioned specifications in connection with the New Generating Facility:

System Impact Assessment (by the IMO)

i. ☐ an executed copy of the System Impact Assessment (SIA) Agreement between the Proponent and the IMO for the proposed project is enclosed, or

ii. ☐ a completed System Impact Assessment report which has been prepared and issued by the IMO.

Customer Impact Assessment (by the Transmitter)

iii. ☐ a completed Customer Impact Assessment or Preliminary Customer Impact Assessment report which has been prepared and issued by the relevant Transmitter; or

iv. ☐ both of the following two (2) documents:

1. ☐ an executed copy of a "Preliminary Study Agreement" between the Proponent and the Transmitter for the "Preliminary Customer Impact Assessment" for the proposed project; and

2. ☐ a copy of a letter or other documentation from the transmitter evidencing that the application form for a "Preliminary Customer Impact Assessment" has been accepted by the Transmitter.

Connection Impact Assessment (by the Local Distribution Company)

v. ☐ a completed assessment of the project impact on the Local Distribution System, which would be an Impact Assessment, Connection Assessment, Connection Impact Assessment or Preliminary Connection Impact Assessment, or equivalent; or

vi. ☐ both of the following two (2) documents:

1. ☐ an executed copy of the "Preliminary Study Agreement" between the Proponent and the Local Distribution Company for the proposed project; and

2. ☐ a copy of a letter or other documentation from the distributor evidencing that the application form for a "Preliminary Connection Impact Assessment" has been accepted by the Local Distribution Company.

9. **Priority Electrical Zone Adjustment and Voltage Support Adjustment**

a. Identify the electrical point where the proposed New Generating Facility is to be connected to a Transmission System, a Local Distribution System, or an End-User, as follows:

☐ A single line electrical drawing which identifies the point where the New Generating Facility is expected to be connected to a Transmission system, a Local Distribution System, or an End-User, clearly showing area transmission and distribution facilities, including the transmission station that is electrically closest to the New Generating Facility, is enclosed.

b. State whether a Priority Electrical Zone Adjustment is expected to apply to the Proposal for the New Generating Facility, by selecting one of the following two options:

i. ☐ Yes, the New Generating Facility (or each individual generating facility where the Proponent is aggregating two or more generating facilities in the Proposal) is located within the Priority Electrical Zones; or

ii. ☐ No, the New Generating Facility (or each individual generating facility where the Proponent is aggregating two or more generating facilities in the Proposal) is not located within the Priority Electrical Zones.

c. State whether the New Generating Facility meets all relevant requirements for Voltage Support Adjustment under the Market Rules for a generator:

i. ☐ Yes, the New Generating Facility meets all relevant requirements under the Market Rules for a generator, whether directly connected to a Transmission System, Local Distribution System, or End-user, including the requirements described in the amendments approved by the IMO and described in http://www.theimo.com/imoweb/pubs/mr/mr_00244-ROO_BA.pdf; or

ii. ☐ No, the New Generating Facility does not meet all relevant requirements under the Market Rules for a generator, whether directly connected to a Transmission System, Local Distribution System, or End-user, including the requirements described in the amendments approved by the IMO and described in http://www.theimo.com/imoweb/pubs/mr/mr_00244-ROO_BA.pdf.

10. **Schedule of Major Project Milestones**

MILESTONE EVENT	MILESTONE DATE (dd/mm/yyyy)
Obtaining Project and Site Approvals, and Permitting	
Completion of Connection assessments (including receipt of approvals from the IMO, the transmitter, and distributor, as applicable.)	
Engineering, procurement and construction contracts executed, which shall occur no later than the later of: (i) 2 ½ years before the milestone date for Commercial Operation and (ii) six (6) months after signing the CES Contract.	
Financial Closing, which shall occur no later than the later of (i) 2 ½ years before the milestone date for Commercial Operation and (ii) twelve (12) months after signing the CES Contract.	
Equipment Order	
Equipment Delivered	
Commencement of Construction	
Completion of Construction	
Connection of generating facility to a Transmission System, Local Distribution System, or End-user	
Commercial Operation, which milestone date shall be no later than June 1, 2009.	

11. **Evidence of Proponent Team's Prior Experience**

Proponents must describe the experience that members of its Proponent Team collectively have, as required by and set out in relation to at least one (1) generating facility, other than the proposed New Generating Facility, which entered into commercial operation, by filling in the following table for each of the following areas of experience: planning, development, construction, and operating. Repeat and complete this form of table for each relevant member of the Proponent Team.

Name of member of Proponent Team:
Area of Experience:
Name of generating facility or facilities relating to said Experience:
Length of Experience:
Description of Experience:
Attach a resume, curriculum vitae, and state any professional designation:

APPENDIX C-2: TECHNICAL QUESTIONNAIRE FOR PROPOSALS FOR DR PROJECTS ONLY

Proponents are required to complete this Technical Questionnaire in full, including the attachment of additional documents as and where requested. PLEASE BE ADVISED THAT INCLUDING THE NET REVENUE REQUIREMENT OR ANY OTHER INFORMATION THAT IS PART OF YOUR ECONOMIC BID STATEMENT IN THIS TECHNICAL QUESTIONNAIRE WILL LEAD TO THE DISQUALIFICATION OF YOUR PROPOSAL.

A. Each item in the following 7 sections must be completed by all Proponents of DR Projects.

1. **Proponent Information**

a. Proponent's full registered legal business name and any other name under which it carries on business:

b. Proponent's address, telephone, e-mail and facsimile numbers:

c. Name, address, telephone and facsimile numbers of the contact person(s) for the Proponent:

d. Name of the person who is primarily responsible for the Proposal:

e. Name of the person who will be managing the operation of the proposed Deliverables:

f. State the legal form of the Proponent (i.e. whether the Proponent is an individual, a sole proprietorship, a corporation, a partnership, a joint venture, an incorporated consortium, or a consortium that is a partnership, or other legally recognized entity):

____

____

____

____

____

g. State the legal jurisdiction under which the Proponent was created (for example, the laws of Ontario):

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____

____

____

____

h. Select one of the following statements, as applicable to the Proponent:

i. ☐ The Proponent is not a non-resident of Canada, as defined under the *Income Tax Act* of Canada; or

☐ The Proponent is a non-resident of Canada, as defined under the *Income Tax Act* of Canada.

i. Name(s) of the proprietor, where the Proponent is a sole proprietor; each of the directors and officers where the Proponent is a corporation; each of the partners where the Proponent is a partnership and applicable combinations of these when the Proponent is a joint venture or consortium, whichever applies:

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2. **Executive Summary of Proposal**

An executive summary of the Proposal, with a maximum length of 2 pages, must be provided which should state the following:

a. that the Proposal is for a DR Project;

b. the names of the Proponent, each member of the Proponent Core Team, and each member of the Proponent Non-Core Team, and any lenders in relation to the proposed DR Project;

c. a short description of the key personnel involved in the preparation of the Proposal and in the delivery and operation of the DR Project;

d. an organization chart that provides a schematic representation of ownership and contractual links among all entities or individuals involved in the development, construction, financing and operation of the project;

e. a summary of the business arrangements and financing of the proposed DR Project; and

f. a short description of the plant and equipment to be used in the DR Project including the technology, project design, location of such plant and equipment, as well as the proposed Commercial Operation Date of the DR Project.

☐ Executive summary attached.

3. **Project Information**

a. Project Name: ____

b. Type of DR Project (choose one):

i. ☐ The DR Project will meet the demand response requirements through load shifting;

ii. ☐ The DR Project will meet the demand response requirements through load interruption; or

iii. ☐ The DR Project will meet the demand response requirements, either in whole or in part, through the generation of Electricity.

c. State the municipal address (including the city or town) of the DR Project:

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____

d. Expected (or Actual) Commercial Operation Date (mm/dd/yyyy)

____
____

e. Detailed description of the Control Equipment indicating how the Control Equipment will enable the Proponent to curtail the electricity demand of the load(s) and verify the load reduction as a result of the operation of the Control Equipment:

i. in response to market prices;

ii. in response to Operational Directives of the IMO; and

iii. verify the load reductions as a result of the operating of the Control Equipment.

☐ Detailed description attached.

f. State the Contracted Demand Reduction in MW, per Season, as described below:

i. Summer: ___________________

ii. Winter: ____________________

iii. Other Season: ______________

g. State whether the Proponent is aggregating two (2) or more loads in the Proposal. Proponents are advised that in the event that the Proponent is aggregating two (2) or more loads in the Proposal, each individual load must satisfy all of the requirements of the 2,500 MW RFP:

i. ☐ Yes, the Proponent is aggregating two (2) or more loads in the Proposal. The municipal address, amount of load reduction (in MW), and a brief description of each individual load being aggregated is set out in an attachment enclosed. In addition to the foregoing,

1. ☐ enclosed are letters of intent, described in Section III.C.1.b.ii and in the form provided in Appendix M of the 2,500 MW RFP, from third party loads representing at least one-fifth (1/5) of the Maximum Contracted Demand Reduction among all Seasons; and

2. ☐ enclosed is a plan with timelines for securing written agreements with such third party loads as required in Section III.C.1.b.ii.

ii. ☐ No, the Proponent is not aggregating two (2) or more loads in the Proposal.

h. Specified Load, in MW: ____

i. Description of the load(s) to be curtailed through the operation of the Control Equipment:
____
____
____
____

j. Confirm whether the DR Project has a Maximum Contracted Demand Reduction which is less than or equal to the amount of the Specified Load, and where the Contracted Demand Reduction is aggregated across two or more sites, whether the Contracted Demand Reduction at each site is less than or equal to the Specified Load at that site.

☐ Yes; or

☐ No

k. Measurement and Verification Plan

i. ☐ Outline of the Measurement and Verification Plan, as required pursuant to Section III.C.1.b.v., is enclosed.

ii. If the Control Equipment involves a generator, state the Environment Canada weather station that is physically nearest to the DR Project (or in the case of a DR Project that is comprised of two or more generators that are aggregated, select a weather station that is physically nearest to one of the generators so aggregated):

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____
____
____
____

4. **Additional Project Eligibility**

Indicate by checking the boxes below whether each of the following criteria are satisfied.

a. ☐ The DR Project is located in the Province of Ontario and affects demand on the IMO– Administered Markets.

b. ☐ The DR Project requires new capital investment in Control Equipment. In addition, check both of the boxes below:

i. ☐ The DR Project is designed to operate in accordance with the DR Contract from the Commercial Operation Date until the expiry of the Term of the DR Contract; and

ii. ☐ The Contracted Demand Reduction to be achieved by the DR Project will not be offset by, result in, or in any way cause, an increase in load elsewhere.

c. ☐ The DR Project had not attained commercial operation on or before September 13, 2004. For purposes of this requirement, commercial operation shall mean the DR Project commences operation in compliance with all laws and regulations after the completion of construction, completion of connection and synchronization to an End-User and completion of all commissioning tests of the Control Equipment.

5. **Schedule of Major Project Milestones**

MILESTONE EVENT	MILESTONE DATE (dd/mm/yyyy)
Equipment Ordered	
Equipment Delivered	
If the DR Project requires the participation of third party loads, delivery of a certificate addressed to it from the DR Verification Consultant, stating that the Supplier has executed DR Third Party Agreements as collectively represent 80% of the Maximum Contracted Demand Reduction as described in Section III.C.1.b.iii, which shall occur no later than one year prior to the Milestone Date for Commercial Operation.	
Commercial Operation, which milestone date shall be no later than December 31, 2007.	

6. **Priority Electrical Zone Adjustment and Voltage Support Adjustment**

a. Identify the electrical point where the proposed DR Project is to be connected to the End-User as follows:

i. ☐ A single line electrical drawing which identifies the point where the DR Project is to be connected to each End-user, as applicable, clearly showing area transmission and distribution facilities, including the transmission station that is electrically closest to each End-user.

b. State whether a Priority Electrical Zone Adjustment is expected to apply to the Proposal for the DR Project, by selecting one of the following two options:

i. ☐ Yes, the DR Project will affect load of an End-user that is located within the Priority Electrical Zones, where the DR Project is comprised of multiple loads, each load of an End-user is not located within the Priority Electrical Zones; or

☐ No, the DR Project will not affect load of an End-user that is located within the Priority Electrical Zones, or where the DR Project is comprised of multiple loads, each load of an End-user is not located within the Priority Electrical Zones.

c. For a DR Project that does not involve the generation of electricity, indicate by checking the boxes below whether each of the following criteria are satisfied:

1. ☐ The DR Project is equipped with facilities to provide continuously acting power factor or VAR (i.e. volt amperes reactive) control that can automatically maintain, at the Connection Point: (i) a power factor within a range of +/- 1% between power factors of 90% lagging and 95% leading, or (ii) VAR consumption within +/- 2.5% of the rated MVA of such project under steady state conditions;

2. ☐ The power factor or VAR controller has an adjustable effective response time between 10 and 60 seconds;

3. ☐ The power factor or VAR controller will automatically, and in less than 5 seconds, reduce the project's reactive power consumption by (i) 0 MVAR in response to a voltage reduction of 2 percent or less, and by (ii) an amount increasing continuously to a maximum amount equal to "X" MVAR in response to a voltage reduction at the Connection Point of 5 percent or greater, where "X" is a number equal to one-half of the Contracted Demand Reduction as expressed in MW. By way of example, if a DR Project has a Contracted Demand Reduction of 8 MW, then the maximum amount of reduction referred to in this subparagraph (ii) will be equal to 4 MVAR in response to a voltage reduction at the Connection Point of 5 percent or greater;

4. ☐ The project will operate in compliance with Market Rules associated with reactive power dispatch including, when directed by the IMO, reduce its reactive power consumption up to a maximum amount equal to "X" MVAR, where "X" is a number equal to one-half of the Contracted Demand Reduction as expressed in MW; and

5. ☐ The project will operate at all times in compliance with the load power factor requirements under the Market Rules.

7. **Evidence of Proponent Team's Prior Experience**

Proponents must describe the experience (as defined in Section III.C.1.b.vi) that members of its Proponent Team collectively have in each of the planning and development of at least one (1) demand response project, other than the proposed DR Project, which entered into commercial operation, by filling in the following table for each of the following areas of experience: Planning and Development. Repeat and complete this form of table for each relevant member of the Proponent Team.

Name of member of Proponent Team:
Area of Experience:
Name of demand response project(s) relating to said Experience:
Length of Experience:
Description of Experience:
Attach a resume, curriculum vitae, and state any professional designation:

B. Each item in the following 6 sections must, in addition to the items in A above, be completed by the Proponent of such DR Project, if the DR Project is a demand response project that will meet the demand response requirements of the DR Project in whole or in part through the generation of electricity.

8. **Project Information**

a. Source(s) or fuel(s) consumed by the proposed DR Project as its Primary Fuel(s):

____

List all other source(s) or fuel(s) consumed by the proposed DR Project:

____

b. Indicate, by checking the box, whether each of the following criteria are satisfied:

☐ The generating equipment to be used in the DR Project does not generate electricity through a process by burning Oil as a Primary Fuel, or by burning any coal or Municipal Solid Waste; and

☐ If the DR Project forms part of a larger facility, the larger facility does not generate electricity through a process by burning Oil as a Primary Fuel, or by burning any coal or any Municipal Solid Waste.

c. If the DR Project is part of a larger facility that generates electricity;

1. List all source(s) or fuel(s) consumed by the larger facility;

____
____
____
____
____

9. **Description of the Site(s) and Location(s)**

In accordance with the requirements set out in Section III.C.1.b.ix, provide a copy of each of the following:

a. A map showing the location of the project site(s) in relation to neighbouring roads and lands, drawn to a scale of no less than 1:10,000 and no greater than 1:100,000, and having a size of at least 6 inches by 6 inches.

☐ Document(s) enclosed.

b. A plan of survey or its equivalent delineating the boundaries of the lands for the site(s), including any easements appurtenant to such lands.

☐ Document(s) enclosed.

10. **Control of Site(s)**

a. In accordance with the requirements set out in Section III.C.1.b.x, provide a copy of one of the following:

i. ☐ Registered transfer(s), lease(s), licence(s), or other agreement permitting the use of the land for the site(s) is enclosed;

ii. ☐ Written agreement to purchase the land for the site(s) is enclosed; or

iii. ☐ Written agreement(s) entitling the Proponent to an option to purchase, lease, licence, or use the land for the site(s) is enclosed.

Note: By checking this box ☐, the Proponent is satisfying this requirement by enclosing a standard form lease, license or agreement that was used for more than ten (10) different sites, together with a statement by the Proponent setting out in summary form all information that is particular to each lease, license, or agreement as applicable.

b. Proponents must identify whether their proposed project involves Crown resources, including Crown land for transmission, distribution and ancillary structures. If so, Proponents must provide written confirmation from the Ministry of Natural Resources that the Proponents have been granted the opportunity to pursue development approvals for a renewable energy project in the form of a "Site Release".

i. Proposed project involves Crown resources:

☐ Yes. Written confirmation from the Ministry of Natural Resources in the form of a "Site Release" is enclosed; or

☐ No.

11. **Documentation Relating to Environmental Assessments**

Pursuant to Section III.C.1.b.xi, Proponents are to provide the following information:

a. Classification of proposed project according to the Ontario Ministry of the Environment's "Guide to Environmental Assessment Requirements for Electricity Projects" dated March 2001 as referred to in O. Reg. 116/01 to the *Environmental Assessment Act* (Ontario) entitled "Electricity Projects". Choose one of the following:

i. ☐ Category A;

ii. ☐ Category B. A copy of the published "Notice of Commencement of a Screening" is enclosed, and if not set out in the published Notice, state where and when such publication took place; or
____
____
____
____

iii. ☐ Category C. A copy of the "Terms of Reference" submitted to the Ministry of Environment is enclosed, and if not set out in the Terms of Reference, state the date of such submission if it is not already set out in the published notice.

b. In the case of a Proposal for a DR Project involving generating equipment that is not subject to the *Environmental Assessment Act* (Ontario), the Proponent must make the following statement:

i. ☐ Yes, any applicable Ministry of the Environment certificates of approval for air and noise emissions have been or will be applied for.

12. **Evidence of progress toward connection approvals and municipal approvals**

a. Proponents must have notified the relevant local municipality (or municipalities) or planning authority (or planning authorities) of their project in writing, and enclose the following:

i. ☐ A copy of the written notice delivered to the relevant local municipality (or municipalities) or planning authority (or planning authorities) of the Proponent's project is enclosed, and if not set out in the notice, state the date of such delivery: __________________________

b. The Proponent must state the following:

i. The Proponent has:

1. ☐ notified the relevant municipalities and planning authorities of the proposed DR Project;

2. ☐ sought advice from such parties about the requirements under the *Planning Act* (Ontario);

3. ☐ sought advice from such parties about which additional relevant municipalities and planning authorities should also be advised of the proposed DR Project, and

4. ☐ has so advised such additional relevant municipalities and planning authorities.

c. With respect to the impact of the DR Project on the electricity system, Proponents must have initiated the appropriate assessments, and must provide the associated documentation. Specifically, details of the required assessments are described in Section III.C.1.b.xiv. In relation to these requirements, Proponents are required to submit the following, if required by the aforementioned specifications in connection with the DR Project:

System Impact Assessment (by the IMO)

i. ☐ an executed copy of the System Impact Assessment (SIA) Agreement between the Proponent and the IMO for the proposed project is enclosed, or

ii. ☐ a completed System Impact Assessment report which has been prepared and issued by the IMO.

Customer Impact Assessment (by the Transmitter)

iii. ☐ a completed Customer Impact Assessment or Preliminary Customer Impact Assessment report which has been prepared and issued by the relevant Transmitter; or

iv. ☐ both of the following two (2) documents:

1. ☐ an executed copy of a “Preliminary Study Agreement” between the Proponent and the Transmitter for the “Preliminary Customer Impact Assessment” for the proposed project; and

2. ☐ a copy of a letter or other documentation from the transmitter evidencing that the application form for a “Preliminary Customer Impact Assessment” has been accepted by the Transmitter.

Connection Impact Assessment (by the Local Distribution Company)

v. ☐ a completed assessment of the project impact on the Distribution System, which would be an Impact Assessment, Connection Assessment, Connection Impact Assessment or Preliminary Connection Impact Assessment, or equivalent; or

vi. ☐ both of the following two (2) documents:

1. ☐ an executed copy of the “Preliminary Study Agreement” between the Proponent and the Local Distribution Company for the proposed project; and

2. ☐ a copy of a letter or other documentation from the distributor evidencing that the application form for a "Preliminary Connection Impact Assessment" has been accepted by the Local Distribution Company.

13. **Voltage Support Adjustment**

a. If a Voltage Support Adjustment is expected to apply to a Proposal for a DR Project, state whether the Proposal meets all relevant requirements under the Market Rules for a generator:

☐ Yes, the DR project meets all relevant requirements under the Market Rules for a generator, whether directly connected to a Transmission System, Local Distribution System, or End-user, including the requirements described in the amendments approved by the IMO and described in http://www.theimo.com/imoweb/pubs/mr/mr_00244-ROO_BA.pdf.; or

☐ No, the DR project does not meets all relevant requirements under the Market Rules for a generator, whether directly connected to a Transmission System, Local Distribution System, or End-user, including the requirements described in the amendments approved by the IMO and described in http://www.theimo.com/imoweb/pubs/mr/mr_00244-ROO_BA.pdf.

14. **Schedule of Additional Major Project Milestones**

MILESTONE EVENT	MILESTONE DATE (dd/mm/yyyy)
Obtaining Project and Site Approvals, and Permitting	
Completion of Connection assessments (including receipt of approvals from the IMO, the Transmitter, LDC, or Load as applicable.)	
Engineering, procurement and construction contracts executed, which shall occur no later than the later of: (i) 2.5 years before the milestone date for Commercial Operation and (ii) six (6) months after signing the DR Contract.	
Financial Closing, which shall occur no later than the later of: (i) 2.5 years before the milestone date for Commercial Operation and (ii) twelve (12) months after signing the DR Contract.	
Commencement of Construction	
Completion of Construction	
Connection of the Control Equipment to the End-user	

APPENDIX C-3: TECHNICAL QUESTIONNAIRE FOR PROPOSALS FOR DSM PROJECTS ONLY

Proponents are required to complete this Technical Questionnaire in full, including the attachment of additional documents as and where requested. PLEASE BE ADVISED THAT INCLUDING THE NET REVENUE REQUIREMENT OR ANY OTHER INFORMATION THAT IS PART OF YOUR ECONOMIC BID STATEMENT IN THIS TECHNICAL QUESTIONNAIRE WILL LEAD TO THE DISQUALIFICATION OF YOUR PROPOSAL.

1. **Proponent Information**

   a. Proponent's full registered legal business name and any other name under which it carries on business:

   b. Proponent's address, telephone, e-mail and facsimile numbers:

   c. Name, address, telephone and facsimile numbers of the contact person(s) for the Proponent:

   d. Name of the person who is primarily responsible for the Proposal:

   e. Name of the person who will be managing the operation of the proposed Deliverables:

f. State the legal form of the Proponent (i.e. whether the Proponent is an individual, a sole proprietorship, a corporation, a partnership, a joint venture, an incorporated consortium, or a consortium that is a partnership, or other legally recognized entity):

g. State the legal jurisdiction under which the Proponent was created (for example, the laws of Ontario):

h. Select one of the following statements, as applicable to the Proponent:

i. ☐ The Proponent is not a non-resident of Canada, as defined under the *Income Tax Act* of Canada; or

ii. ☐ The Proponent is a non-resident of Canada, as defined under the *Income Tax Act* of Canada.

i. Name(s) of the proprietor, where the Proponent is a sole proprietor; each of the directors and officers where the Proponent is a corporation; each of the partners where the Proponent is a partnership and applicable combinations of these when the Proponent is a joint venture or consortium, whichever applies:

2. **Executive Summary of Proposal**

An executive summary of the Proposal, with a maximum length of 2 pages, must be provided which should state the following:

a. that the Proposal is for a DSM Project;

b. the names of the Proponent, each member of the Proponent Core Team, and each member of the Proponent Non-Core Team, and any lenders in relation to the proposed DSM Project;

c. a short description of the key personnel involved in the preparation of the Proposal and in the delivery and operation of the DSM Project;

d. an organization chart that provides a schematic representation of ownership and contractual links among all entities or individuals involved in the development, construction, financing and operation of the project;

e. a summary of the business arrangements and financing of the proposed DSM Project; and

f. a short description of the plant and equipment to be used in the DSM Project including the technology, project design, location of such plant and equipment, as well as the proposed Commercial Operation Date of the DSM Project.

☐ Executive Summary attached.

3. **Project Information**

a. Project Name: ____
____

b. State the municipal address (including the city or town) of the DSM Project:

____
____
____
____
____

c. DSM Project Annual Energy Savings: __________________________ /year

d.

i. Seasonal Capacity Summer: __________________________ MW

1. Peak Electricity Savings Summer in MWh: ______________

2. ☐ Hourly Electricity Savings Profile for a Typical Peak Day of Summer enclosed.

3. ☐ Hourly Electricity Savings Profile for Typical Week of Summer enclosed.

ii. Seasonal Capacity Winter: __________________________ MW

1. Peak Electricity Savings Winter in MWh: ______________

2. ☐ Hourly Electricity Savings Profile for a Typical Peak Day of Winter enclosed.

3. ☐ Hourly Electricity Savings Profile for Typical Week of Winter enclosed.

iii. Seasonal Capacity Other: ______________________________ MW

1. Peak Electricity Savings Other Season in MWh: ________________

2. ☐ Hourly Electricity Savings Profile for a Typical Peak Day of Other Season enclosed.

3. ☐ Hourly Electricity Savings Profile for Typical Week of Other Season enclosed.

e. DSM Project Equivalent Capacity in MW (as converted in accordance with the formula set out in Appendix L): ______________________________________

f. Expected (or Actual) Commercial Operation Date (mm/dd/yyyy): _________________

g. Operating Equipment

Indicate by checking the boxes below whether each of the following criteria are satisfied:

i. ☐ A list of equipment which is to be used at the proposed project site(s) during the Term of the DSM Contract is attached.

ii. ☐ All of the equipment listed in the list of equipment provided in Question 3.g.i of this Appendix currently has a prescribed minimum efficiency under the *Energy Efficiency Act* (Ontario).

iii. ☐ The DSM Project achieves a direct reduction in electricity (kilowatt-hours) consumption through the equipment listed in the list of equipment provided in Question 3.g.i of this Appendix.

iv. ☐ The DSM Project does not include Interactive Effects, voltage reduction, and Operational Changes or Functional Changes to equipment or facilities.

v. ☐ The DSM Project does not directly or indirectly burn Oil as a Primary Fuel or burn any coal or any Municipal Solid Waste, if the DSM Project includes district heating or cooling equipment.

vi. ☐ List all fuel(s) used by the DSM Project

____
____
____
____
____

h. Description of the load from which the DSM Project Annual Energy Savings are going to be achieved as a result of the DSM Project:

i. Confirm whether the DSM Project Annual Energy Savings are derived entirely from load other than residential load; for greater certainty, residential load is the load of a dwelling, property as defined in the *Condominium Act, 1998* (Ontario), a residential complex as defined in the *Tenant Protection Act, 1997* (Ontario), or a property that includes one or more dwellings and that is owned or leased by a co-operative as defined in the *Co-operative Corporations Act* (Ontario):

1. ☐ Yes; the DSM Project Annual Energy Savings are derived entirely from load other than residential load; or

2. ☐ No; the DSM Project Annual Energy Savings are not derived entirely from load other than residential load.

i. State whether the Proponent is aggregating two (2) or more sites and measures in the Proposal. Proponents are advised that in the event that the Proponent is aggregating two (2) or more sites or measures in the Proposal, each individual site or measure must satisfy all of the requirements of the 2,500 MW RFP:

i. ☐ Yes, the Proponent is aggregating two (2) or more sites or measures in the Proposal. The municipal address, amount of DSM Project Equivalent Capacity, and a brief description of each individual site or measure being aggregated is set out in the attachment enclosed. In addition to the foregoing:

1. ☐ enclosed are letters of intent, described in Section III.C.1.c.ii and in the form provided in Appendix M of the 2,500 MW RFP, from third party sites or measures representing at least one-fifth (1/5) of the DSM Project Equivalent Capacity; and

2. ☐ enclosed is a plan, with timelines for securing written agreements with such third party sites or measures, as required in Section III.C.1.c.ii.

ii. ☐ No, the Proponent is not aggregating two (2) or more sites or measures in the Proposal.

j. Measurement and Verification

Check each of the following boxes:

☐ The methodology to be used to determine the DSM Project Annual Energy Savings is enclosed.

☐ The outline of a Measurement and Verification Plan, as required in Section III.C.1.c.vi, for the electricity savings that the Proponent is intending to achieve by virtue of the DSM Project is enclosed.

4. **Additional Project Eligibility**

Indicate by checking the boxes below whether each of the following criteria are satisfied:

a. ☐ The DSM Project is located in the Province of Ontario, will affect demand in the IMO-Administered Markets, and achieves DSM Project Annual Energy Savings entirely from loads located in the Province of Ontario.

b. ☐ The DSM Project does not derive any consumption reduction or portion of the DSM Project Annual Energy Savings through any manner of transfer of electricity consumption to a location at which the change in electricity consumption is not accounted for and otherwise included in the determination of DSM Project Annual Energy Savings.

c. ☐ The DSM Project requires new capital improvement or equipment, including related control equipment, having a Simple Payback Period of more than three (3) years.

d. ☐ The DSM Project was not in commercial operation on or before September 13, 2004, and is expected to achieve Commercial Operation no later than December 31, 2007. For purposes of this requirement, commercial operation shall mean the DSM Project commenced operation in compliance with all laws and regulations after the completion of construction, completion of connection and synchronization to an End-User and completion of all commissioning tests.

5. **Schedule of Major Project Milestones**

MILESTONE EVENT	MILESTONE DATE (dd/mm/yyyy)
Equipment Ordered	
Equipment Delivered	
If the DSM Project requires the participation of third party sites or measures, delivery of executed DSM Third Party Agreements as collectively represent 80% of the DSM Project Equivalent Capacity, as described in Section III.C.1.c.iii, which shall occur no later than one year prior to the Commercial Operation Date.	
Commercial Operation, which milestone date shall be no later than December 31, 2007	

6. **Priority Electrical Zone Adjustment and Voltage Support Adjustment**

Indicate by checking the boxes below whether each of the following criteria are satisfied:

a. Identify the electrical point where the proposed DSM Project is to be connected to the End-User as follows:

i. ☐ A single line electrical drawing which identifies the point where the DSM Project is to be connected to each End-user, as applicable, clearly showing area transmissions and distribution facilities, including the transmission station that is electrically closest to each End-user.

b. State whether a Priority Electrical Zone Adjustment is expected to apply to the Proposal for the DSM Project, by selecting one of the following two options:

i. ☐ Yes, the DSM Project will affect load of an End-user that is located within the Priority Electrical Zones, or where the DSM Project is comprised of multiple loads, each load of an End-user is not located within the Priority Electrical Zones; or

☐ No, the DSM Project will not affect load of an End-user that is located within the Priority Electrical Zones, and where the DSM Project is comprised of multiple loads, each load of an End-user is located within the Priority Electrical Zones.

c. Indicate by checking the boxes below whether each of the following criteria are satisfied:

1. ☐ The DSM Project is equipped with facilities to provide continuously acting power factor or VAR (i.e. volt amperes reactive) control that can automatically maintain, at the Connection Point: (i) a power factor within a range of +/- 1% between power factors of 90% lagging and 95% leading, or (ii) VAR consumption within +/- 2.5% of the rated MVA of such project under steady state conditions;

2. ☐ The power factor or VAR controller has an adjustable effective response time between 10 and 60 seconds;

3. ☐ The power factor or VAR controller will automatically, and in less than 5 seconds, reduce the project's reactive power consumption by (i) 0 MVAR in response to a voltage reduction of 2 percent or less, and by (ii) an amount increasing continuously to a maximum amount equal to "X" MVAR in response to a voltage reduction at the Connection Point of 5 percent or greater, where "X" is a number equal to one-half of the Seasonal Capacity as expressed in MW. By way of example, if a DSM Project has a Seasonal Capacity of 8 MW, then the maximum amount of reduction referred to in this subparagraph (ii) will be equal to 4 MVAR in response to a voltage reduction at the Connection Point of 5 percent or greater;

4. ☐ The project will operate in compliance with Market Rules associated with reactive power dispatch including, when directed by the IMO, reduce its reactive power consumption up to a maximum amount equal to "X" MVAR, where "X" is a number equal to one-half of the Seasonal Capacity as expressed in MW; and

5. ☐ The project will operate at all times in compliance with the load power factor requirements under the Market Rules.

7. **Evidence of Proponent Team's Prior Experience**

Proponents must describe the experience (as defined in Section III.C.1.c.vii) that members of its Proponent Team collectively have in each of the planning and development in relation to at least one (1) demand-side management project other than the proposed DSM Project, which entered into commercial operation, by filling in the following table for each of the following areas of experience: Planning and Development. Repeat and complete this form of table for each relevant member of the Proponent Team.

Name of member of Proponent Team:
Area of Experience:
Name of demand-side management project relating to said Experience:
Length of Experience:
Description of Experience:
Attach a resume, curriculum vitae, and state any professional designation:

APPENDIX D: FINANCIAL QUESTIONNAIRE

Proponents are required to complete this Financial Questionnaire in full, including the attachment of additional documents as and where requested. PLEASE BE ADVISED THAT INCLUDING THE NET REVENUE REQUIREMENT OR ANY OTHER INFORMATION THAT IS PART OF YOUR ECONOMIC BID STATEMENT IN THIS FINANCIAL QUESTIONNAIRE WILL LEAD TO THE DISQUALIFICATION OF YOUR PROPOSAL.

1. **Complete Description of the Financing Plan of the Project**

   a. Using the table below, repeated for each source of financing, funding or credit support, set out all sources of current and future financing, funding or credit support for the project, including the names of all sources and the amounts of (i) debt, (ii) equity and (iii) other funds being provided. Loans from affiliated entities, project partners, and loans that are subordinated to the primary or senior project financing should be reported as equity.

Name of Entity providing Financing:
Type of Financing [i.e. equity, debt, or other (if other, describe source)]:
Amount of Funds to be Provided:

☐ Description is continued on the attached.

   b. State the total amount of financing for the project provided from each of: (i) equity, (ii) debt, and (iii) other sources, and the total amount of financing for the project, based on the information set out in Question 1.a. above.

Total Equity Financing:

Total Debt Financing:

Total Financing from Other Sources:

Total of All Sources of Financing:

2. a. If, and to the extent that, equity is a source of financing for the proposed project but such equity is not in place as of the date of the Proposal, the Proponent shall provide a

commitment letter from each equity provider stating its agreement in principle containing the required elements below, to put its equity in place by the milestone date for financial closing set out in the Technical Questionnaire, and the amount of its equity contribution.

For greater certainty, an agreement in principle by an equity provider must state, at a minimum, that such equity provider has reviewed the 2,500 MW RFP, one of the CES Contract, DR Contract or DSM Contract as applicable to the Proponent's Proposal, and the financial model (including projected costs and revenues) of the proposed project, and that it agrees in principle to advance, provide or underwrite the amount of equity financing specified in the commitment letter by the milestone date for financial closing specified by the Proponent in response to the Technical Questionnaire, subject to the satisfaction of specific objective conditions. The commitment letter must disclose any and all of such objective conditions. A commitment to simply arrange the equity financing will not be considered sufficient to satisfy the Minimum Mandatory Financial Requirements of the 2,500 MW RFP.

☐ Commitment letters from equity providers, if any, proposing to provide equity are enclosed.

b. If, and to the extent that, the equity structure of the Proponent is in place as of the date of the Proposal, the Proponent must submit a letter from each equity provider confirming that its equity is in place and the amount of its equity contribution.

☐ Commitment letters from actual equity providers, if any, are enclosed.

3. If, and to the extent that, equity is a source of financing for the proposed project, then:

c. Provide the name, percentage of total project equity held, and Tangible Net Worth of any one equity provider who accounts for 35% of the total project equity, or if applicable, any group of equity providers who together account for the 35% or more of the total project equity, together with each such equity provider(s)' percentage contribution of total project equity. Each such equity provider must have a Tangible Net Worth which satisfies the applicable criteria set out in Questions 3.b.i, 3.b.ii, and 3.b.iii of this Appendix, as applicable. In addition, describe the methodology by which the stated Tangible Net Worth for each equity provider was calculated:

____

d. Check one of the following:

i. ☐ with respect to a New Generating Facility, such one equity provider, or group of equity providers on a collective basis, has a Tangible Net Worth of at least $500,000/MW of CES Contract Capacity;

ii. ☐ with respect to a DR Project, such one equity provider, or group of equity providers on a collective basis, has a Tangible Net Worth of at least $500,000/MW of Maximum Contracted Demand Reduction; and

iii. ☐ with respect to a DSM Project, such one equity provider, or group of equity providers on a collective basis, has a Tangible Net Worth of at least $500,000/MW of DSM Project Equivalent Capacity.

e. For each such equity provider named in Question 3.a. of this questionnaire, provide the audited annual financial statements of such equity provider for the most recently completed fiscal year. If audited annual reports or financial statements are not available, then an officer of the equity provider must confirm, to the best of his or her knowledge, that such financial statements present fairly, in all material respects, the financial position of the equity provider in conformity with generally accepted accounting principles in Canada or the United States consistently applied. Also, whether the financial statements are audited or unaudited, an officer each applicable equity provider must confirm, to the best of his or her knowledge, that there are no facts or circumstances that would materially adversely affect the equity provider's financial condition as set out in the annual reports or financial statements described above. Check the following box:

☐ Documentation for each such equity provider, or group of equity providers, including the required confirmations by the officer of the equity provider, is enclosed.

f. In addition, for each such equity providers named in Question 3.a of this questionnaire, provide the documentation required from one of the following three options, as set out below:

i. Investment Grade Credit Rating

All available credit ratings of the equity provider, if the equity provider has an Investment Grade Credit Rating which satisfies the minimum Investment Grade Credit Rating requirement from the following agencies: Standard and Poor's Rating Services (S&P), Moody's Investors Services Inc. (Moody's), Dominion Bond Rating Service Limited (DBRS), and Fitch IBCA if applicable.

☐ Investment Grade Credit Ratings enclosed.

ii. If the equity provider does not have an Investment Grade Credit Rating, then provide a confirmation letter from a financial institution that the equity provider(s) has credit available under an approved facility. Check the following box:

☐ Confirmation letter for each such equity provider enclosed; or

iii. Provide a certificate of an officer of the equity provider setting out the debt coverage ratio of the equity provider, which shall be calculated as at the last day of the most recently completed fiscal year, by dividing (a) Debt, by (b) EBITDA, which ratio must be no greater than 7:1. The certificate of the officer shall also set out the calculations of Debt and EBITDA.

Debt:____

EBITDA:______________________________________

Ratio of Debt to EBITDA is _________________to 1.

☐ Certificate enclosed.

4. a. If, and to the extent that, debt is a source of financing for the proposed project, then provide a commitment letter from each lender stating its agreement in principle containing the required elements set out below, to provide the necessary debt financing for the project by the milestone date for financial closing set out in the Technical Questionnaire, and the amount of its proposed credit facility or loan.

For greater certainty, an agreement in principle by a lender must state, at a minimum, that such lender has reviewed the 2,500 MW RFP, one of the CES Contract, DR Contract or DSM Contract as applicable to the Proponent's Proposal, and the financial model (including projected costs and revenues) of the proposed project, and that it agrees in principle to advance, provide or underwrite the amount of debt financing specified in the commitment letter by the milestone date for financial closing specified by the Proponent in response to the Technical Questionnaire, subject to the satisfaction of specific objective conditions. The commitment letter must disclose any and all of such objective conditions. A commitment to simply arrange the debt financing will not be considered sufficient to satisfy the Minimum Mandatory Financial Requirements of the 2,500 MW RFP.

i. ☐ Commitment letters for all lenders enclosed.

b. For each lender, describe lender type as described below, and provide credit rating if requested below:

i. ☐ A lender who is a financial institution listed in Schedule I or II of the *Bank Act* (Canada); or

ii. ☐ A lender who is a financial institution not listed in Schedule I or II of the *Bank Act* (Canada). State credit rating(s) of such lender; or

iii. ☐ A lender who is not a financial institution. State credit rating(s) of such lender. If credit rating(s) of such lenders are not publicly available, then letters are enclosed from the applicable rating agencies confirming the credit rating(s) of such lenders.

5. a. If, and to the extent that, the financing plan specifies a source of financing for the proposed project other than debt or equity, provide a commitment letter from each such source of financing stating its agreement in principle to provide such financing by the milestone date for financial closing as set out in the Technical Questionnaire and the amount of its proposed financial contribution.

For greater certainty, an agreement in principle by such other source of financing other than debt or equity must state, at a minimum, that such other provider has reviewed the 2,500 MW RFP, one of the CES Contract, DR Contract or DSM Contract as applicable to the Proponent's Proposal, and the financial model (including projected costs and revenues) of the proposed project, and that it agrees in principle to advance, provide or underwrite the amount of financing specified in the commitment letter by the milestone date for financial closing specified by the Proponent in response to the Technical Questionnaire, subject to the satisfaction of specific objective conditions. The commitment letter must disclose any and all of such objective conditions. A commitment to simply arrange the financing will not be considered sufficient to satisfy the Minimum Mandatory Financial Requirements.

i. ☐ Commitment letters from all sources of non-debt and non-equity financing are enclosed.

APPENDIX E-1: ECONOMIC BID STATEMENT (FOR NEW GAS GENERATING FACILITIES ONLY)

NOTE TO PROPONENTS: For instructions and assumptions regarding the completion and submission of this Economic Bid Statement, please refer to Section III.E. of the 2,500 MW RFP.

Name of Proponent: ____
____

Name of Project: ____
____

Net Revenue Requirement: $______________.______/MW-month

Adjustment of NRR:

(i) Percentage of NRR to remain level: _________% (between 80% and 100%)

(ii) Percentage of the NRR to be adjusted for changes in the Specified Index: _________% (between 0% and 20%)

Note: Percentages in (i) and (ii) above must total 100%.

Connection Costs: $______________.______

which are composed of the following, if applicable:

(i) $____________.____ for improvements or modifications to the existing facilities of the relevant transmitter required to connect the New Generating Facility;

(ii) $____________.____ for improvements or modifications to the existing facilities of the relevant distributor required to connect the New Generating Facility; and

(iii) $____________.____ for any new dedicated radial facilities that may be required to connect the New Generating Facility.

Name of Entity Preparing Estimate of Connection Costs: ____________________

Specified Heat Rate: ________________ BTU/kWh (between 5,000 and 8,000 BTU/kWh)

O&M Costs: $_________._____/MWh

Start-Up Costs: __________MMBTU/start-up

Dated at ● this ● day of ● 2004.

[*Insert name of Proponent*]

By: ______________________________

Name: ●

Title: ●

____

Name: ●

Title: ●

I/we have the authority to bind the Proponent.

APPENDIX E-2: ECONOMIC BID STATEMENT (FOR NEW NON-GAS GENERATING FACILITIES ONLY)

NOTE TO PROPONENTS: For instructions and assumptions regarding the completion and submission of this form, please refer to Section III.E of the 2,500 MW RFP.

Name of Proponent: ____
____

Name of Project: ____
____

Net Revenue Requirement: $______________.______/MW-month

Adjustment of NRR:

Percentage of NRR to remain level: _________% (between 80% and 100%)

Percentage of the NRR to be adjusted for changes in the Specified Index: _________% (between 0% and 20%)

Note: Percentages in (i) and (ii) above must total 100%.

Connection Costs: $______________.______

which are composed of the following, if applicable:

(i) $__________.__ for improvements or modifications to the existing facilities of the relevant transmitter required to connect the New Generating Facility;

(ii) $__________.__ for improvements or modifications to the existing facilities of the relevant distributor required to connect the New Generating Facility; and

(iii) $__________.__ for any new dedicated radial facilities that may be required to connect the New Generating Facility.

Name of Entity Preparing Estimate of Connection Costs: ____________________

Energy Cost: $_________.___/MWh

Start-Up Costs: $_________.___/start-up

Dated at ● this ● day of ● 2004.

[*Insert name of Proponent*]

By: ______________________________

Name:

Title:

____

Name:

Title:

I/we have the authority to bind the Proponent.

APPENDIX E-3: ECONOMIC BID STATEMENT (FOR DR PROJECTS ONLY)

NOTE TO PROPONENTS: For instructions and assumptions regarding the completion and submission of this form, please refer to Section III.E of the 2,500 MW RFP.

Name of Proponent: ______________________________
____

Name of Project: ______________________________
____

LENGTH OF TERM
(a whole number between 5 and 20 years): ______________________________ years

NET REVENUE REQUIREMENT: $__________.______/MW-month

Dated at ● this ● day of ● 2004.

[***Insert name of Proponent***]

By: ______________________________
Name:
Title:

____
Name:
Title:

I/we have the authority to bind the Proponent.

APPENDIX E-4: ECONOMIC BID STATEMENT (FOR DSM PROJECTS ONLY)

NOTE TO PROPONENTS: For instructions and assumptions regarding the completion and submission of this form, please refer to Section III.E of the 2,500 MW RFP.

Name of Proponent: ____

Name of Project: ____

Using the methodology set out in Appendix L to the 2,500 MW RFP calculate the DSM Project Equivalent Capacity: ________________ MW

Using the methodology set out in Exhibit Q to the DSM Contract calculate the DSM Incremental Capital Costs: $_____________.______

Using the methodology set out in Exhibit Q to the DSM Contract calculate the DSM Project Annual Electricity Savings: ________________________kWh / year

Using the methodology set out in the DSM Contract calculate the Average Cost of Electricity (Proposal): ________________$/kWh

LENGTH OF TERM
(a whole number between 5 and 20 years): ______________________________________ years

Total annual DSM Variable Costs (add additional rows as necessary):

Year of the Term of the DSM Contract	DSM Variable Costs ($ / MW - year)
Year 1	
Year 2	
Year 3	
Year 4	
Year 5	

Dated at ● this ● day of ● 2004.

[*Insert name of Proponent*]

By: ________________________________

Name: ●

Title: ●

____

Name: ●

Title: ●

I/we have the authority to bind the Proponent.

APPENDIX F: PROPOSAL SECURITY (LETTER OF CREDIT FORM)

DATE OF ISSUE:	**[Insert Date]**
APPLICANT:	**[Insert Proponent's Name]**
BENEFICIARY:	Ontario Electricity Financial Corporation or, Ontario Power Authority, if established
AMOUNT:	●
EXPIRY DATE:	**[Insert Expiry Date, being a minimum of six (6) months after the Proposal Submission Deadline]**
EXPIRY PLACE:	Counters of the issuing financial institution
CREDIT RATING:	**[Insert credit rating only if the issuer is not a financial institution listed in either Schedule I or II of the *Bank Act* (Canada)]**
TYPE:	Irrevocable and Unconditional Standby Letter Of Credit Number: ●

We hereby authorize you to draw on **[insert name of Bank and Bank's address]** in respect of irrevocable and unconditional standby letter of credit No. ● (the "Credit"), for the account of the Applicant up to an aggregate amount of $● (Canadian dollars) available by your drafts at sight, accompanied by the Beneficiary's signed certificate stating that:

> "[The Applicant has made a material misrepresentation in the Proposal,] or [the Applicant, in relation to a New Generating Facility, DR Project or DSM Project, as applicable, has become a Selected Proponent and has failed to sign the CES Contract, DR Contract or DSM Contract, as applicable, within ten (10) Business Days of the date on which the Applicant was given the final CES Contract, DR Contract or DSM Contract, as applicable, to sign], and therefore the Beneficiary is entitled to draw upon the Credit in the amount of the draft attached hereto. All capitalized terms used in this certificate that have not been defined herein have the meanings ascribed to them in the 2,500 MW RFP."

Drafts drawn hereunder must bear the clause "Drawn under irrevocable and unconditional Standby Letter of Credit No. **[insert number]** issued by **[the bank]** dated **[insert date]**".

This Credit is issued in connection with the Request for Proposals for 2,500 MW of New Clean Generation and Demand-Side Projects issued by the Ministry of Energy (Ontario) dated September 13, 2004 as amended (the "2,500 MW RFP") and the Proposal dated [insert date of proposal] submitted by the Applicant in response thereto (the "Proposal").

We engage with you that all drafts drawn under, and in compliance with the terms of this Credit will be duly honoured, if presented at the counters of **[insert the bank and bank's address]** at or before 5:00 p.m. (EST) on **[insert the expiry date]**.

It is a condition of this Credit that if there should be an interruption of the issuing bank's business upon the expiry date, arising out of any of the circumstances provided for in Article 17 of the Uniform Customs and Practice for Documentary Credits (1993 Revision), International Chamber of Commerce Publication No. 500, this Credit shall automatically be extended to the first following day on which the issuing bank resumes business. This Credit is subject to the Uniform Customs and Practice for Documentary Credits (1993 Revision), International Chamber of Commerce Publication No. 500. This Credit shall be governed by and construed in accordance with the laws of the Province of Ontario, without regard to principles of conflict of laws. The place of jurisdiction shall be the Courts of the Province of Ontario.

[BANK OR QUALIFIED FINANCIAL INSTITUTION]

By: ____

Authorized Signatory

APPENDIX G: PROPOSAL SECURITY (BID BOND FORM)

BID BOND

Bond No.: ●

Bond Amount: $(●)

[Insert Proponent's name] as Principal, hereinafter called the Principal, and **[insert Surety's name]** a corporation created and existing under the laws of **[insert originating jurisdiction]** and duly authorized to transact the business of Suretyship in the Province of Ontario as Surety, hereinafter called the Surety, are held and firmly bound unto Ontario Electricity Financial Corporation (or the Ontario Power Authority, if created) as Obligee, hereinafter called the Obligee, in the amount of ●/100.00 Dollars ($●) of lawful money of Canada, for the payment of which sum the Principal and the Surety bind themselves, their heirs, executors, administrators, successors and assigns, jointly and severally.

WHEREAS, the Principal has submitted a written proposal to the Obligee dated the **[insert date of Proposal]**, hereinafter called the Proposal, for the development and operation of a new generating facility or demand-side project in the Province of Ontario, in response to a Request for Proposals for 2,500 MW of New Clean Generation and Demand-Side Projects issued by the Ministry of Energy (Ontario) dated September 13, 2004, as amended, hereinafter called the 2,500 MW RFP.

> The condition of this obligation is that the Principal has made a material misrepresentation in its Proposal, or the Principal, in relation to a New Generating Facility, DR Project or DSM Project, as applicable, has become a Selected Proponent and has failed to sign the CES Contract, DR Contract or DSM Contract, as applicable, within ten (10) Business Days of the date on which the Principal was given the final CES Contract, DR Contract or DSM Contract, as applicable, to sign, in which case the Principal and the Surety will pay unto the Obligee the entire amount of the Bid Bond; otherwise, this obligation shall be null and void. All capitalized terms used in this condition that have not been defined in this Bid Bond have the respective meanings ascribed to them in the 2,500 MW RFP.

The Principal and the Surety shall not be liable for a greater sum than the Bond Amount.

Any suit under this Bond must be instituted before the expiration of twelve (12) months from the date of this Bond.

No right of action shall accrue hereunder to or for the use of any person or corporation other than the Obligee named herein, or the successors or assigns of the Obligee.

The Surety confirms that, as of the date of this Bond, it has a financial strength rating of A- or higher by A.M. Best in financial size category VIII or higher.

IN WITNESS WHEREOF, the Principal and the Surety have Signed and Sealed this Bond this ● day of ● , 2004.

[PRINCIPAL]

By: ________________________________
Name: ●
Title: ●

I/we have the authority to bind the Principal.

[SURETY]

By: ________________________________
Name: ●
Title: ●

I/we have the authority to bind the Surety.

APPENDIX H: STATUTORY DECLARATION

PROVINCE OF ONTARIO TO WIT	IN THE MATTER OF a proposal dated ●, 2004 to which this Declaration forms an integral part (the "Proposal") prepared by ● (the "Proponent"), and submitted in response to a Request for Proposals issued by the Ontario Ministry of Energy dated September 13, 2004, as amended, regarding the supply of approximately 2,500 MW of New Clean Generation and Demand-Side Projects (the "2,500 MW RFP")

I, ●

OF THE ●

IN THE ●

SOLEMNLY DECLARE THAT

1. I am the ● of the Proponent and as such, have knowledge of the matters declared below, and am duly authorized by the Proponent to execute this declaration. All capitalized terms used in this declaration, unless otherwise stated, have the meanings ascribed to them in the 2,500 MW RFP.

PROPOSAL VALIDITY AND PROPOSAL SECURITY

2. All statements, specifications, data, confirmations, and information that have been set out in the Proposal are complete and accurate in all material respects.

3. The Proponent has consented, pursuant to subsection 17(3) of the *Freedom of Information and Protection of Privacy Act* (Ontario), to the disclosure, on a confidential basis, of the Proposal by the Ministry to the Evaluation Team and the Ministry's other advisers retained for the purpose of evaluating or participating in the evaluation of the Proposal.

4. The Proponent has received and reviewed the 2,500 MW RFP issued by the Ministry, together with any and all addenda thereto either posted on the www.ontarioelectricityrfp.ca website or mailed to the Proponent from time to time, up to and including the Deadline for Issuing Addenda on November 15, 2004.

5. If the Proponent is a Proponent of a New Generating Facility or a DR Project, then the Proponent has received and reviewed the final CES Contract or DR Contract, as applicable, issued by the Ministry, together with any and all addenda thereto posted on the www.ontarioelectricityrfp.ca website from time to time, up to and including the Deadline for

Issuing Addenda on November 15, 2004, and has agreed to be bound by the terms of the CES Contract or DR Contract, as applicable, including the requirement to provide the Completion and Performance Security.

6. Neither the Proponent, the proposed New Generating Facility or Demand-Side Project (as applicable) described in the Proposal, nor any member of the Proponent Team is the subject of any bona fide legal proceedings, investigation or regulatory hearings that could materially impact the financial condition of the Proponent or any of the entities involved in financing and operations for the proposed New Generating Facility or Demand-Side Project (as applicable).

7. The Proponent has agreed that: (i) if the Proponent becomes a Qualified Proponent, then Ontario Electricity Financial Corporation (or the Ontario Power Authority, if established), as directed by the Ministry, shall be able to draw upon the full amount of the Proposal Security if the Proposal contains any material misrepresentation, or (ii) if the Proponent is a Proponent of a New Generating Facility, DR Project or a DSM Project, becomes a Selected Proponent, and fails to sign the CES Contract, DR Contract or DSM Contract, as applicable, within ten (10) Business Days of the date on which the Selected Proponent is given the applicable finalized CES Contract, DR Contract or DSM Contract to sign.

NON-COLLUSION

8. In preparing its Proposal(s), no member of the Proponent Team has discussed or communicated any information relating to its Proposal(s) with Another Proponent Team.

9. The Proponent:

   a. is not a member of any other Proponent Team, except as a Proponent of a Proponent Team that is not Another Proponent Team;

   b. has not coordinated its Economic Bid Statement or any other aspect of any of its Proposal(s) with Another Proponent Team;

   c. has no knowledge of the contents of the Proposal(s) submitted by Another Proponent Team; and

   d. has kept and will continue to keep its Proposal(s) confidential until the Selected Proponents are publicly announced.

10. No member of the Proponent Core Team has entered into any agreement or arrangement with any member of Another Proponent Core Team, which may, directly or indirectly, affect the Economic Bid Statement or any other aspect of the Proposal(s) submitted by the Proponent and/or Another Proponent Team.

11. No member of the Proponent Core Team has provided advice or assistance in the preparation of the Proposal(s) of Another Proponent Team.

12. No member of its Proponent Non-Core Team has provided any advice or assistance in the preparation of the Proposal(s) of Another Proponent Team. In the alternative, if such person has provided such advice or assistance to Another Proponent Team, or if such person will be privy to information relevant to Another Proponent Team's Proposal(s), then the Proponent has taken and/or put in place, or caused to be taken and/or put in place, appropriate measures or protections to ensure that such person does not serve as a conduit for the exchange, sharing or comparison of information relating to any Proposal between multiple Proponent Teams.

13. Only one Proposal has been entered by the Proponent for this project.

AND I make this solemn declaration conscientiously believing it to be true, and knowing that it is of the same force and effect as if made under oath.

DECLARED BEFORE ME at the ● of ●, in the County/Region of ●, on ●. ____________________ Commissioner for Taking Affidavits	____________________ Name

APPENDIX I: CONFLICT OF INTEREST DECLARATION

PROVINCE OF ONTARIO TO WIT	IN THE MATTER OF a proposal dated ● , 2004 to which this Declaration forms an integral part (the "Proposal") prepared by ● (the "Proponent"), and submitted in response to a Request for Proposals issued by the Ontario Ministry of Energy dated September 13, 2004, as amended, regarding the supply of approximately 2,500 MW of New Clean Generation and Demand-Side Projects (the "2,500 MW RFP").

I, ●

OF THE ●

IN THE ●

SOLEMNLY DECLARE THAT

1. I am the ● of the Proponent and as such, have knowledge of the matters declared below, and am duly authorized by the Proponent to execute this declaration. All capitalized terms used in this declaration, unless otherwise stated, have the meanings ascribed to them in the 2,500 MW RFP.

2. There is not nor was there any actual or potential Conflict of Interest relating to the preparation of the Proposal.

[Note to Proponent: or if applicable, replace that portion of paragraph 2 above with the following:]

The following is a list of actual or potential Conflicts of Interest relating to the preparation of the Proposal or the performance of the contractual obligations contemplated in the 2,500 MW RFP:

____

____

____

____

In submitting the Proposal, the Proponent has/has no **[Note to Proponent: strike out the inapplicable portion]** knowledge of or ability to avail the Proponent Team of confidential information of the Crown in right of Ontario (other than confidential information which may have been disclosed by the Ministry to the Proponents in the normal course of the 2,500 MW RFP) which is relevant to the 2,500 MW RFP or the Proposal.

3. The following individuals, as employees, advisors, or in any other capacity (a) participated in the preparation of the Proposal; AND (b) were employees of the Ontario Public Service ("OPS") and have ceased that employment since April 23, 1997:

Name of Individual:
Job Classification (of last position with OPS):
Ministry/Agency (where last employed with OPS):
Last Date of Employment with OPS:
Name of Last Supervisor with OPS:
Brief Description of Individual's Job Functions (at last position with OPS):
Brief Description of Nature of Individual's Participation in Preparation of Proposal:
(Repeat above for each identified individual)

4. The Proponent has agreed that, upon request by the Ministry, the Proponent shall provide the Ministry with a Conflict of Interest Declaration from each individual identified in paragraph 3 above in the form prescribed by the Ministry.

AND I make this solemn declaration conscientiously believing it to be true, and knowing that it is of the same force and effect as if made under oath.

DECLARED BEFORE ME at the ● of ●, in the County/Region of ●, on ●.	
______________________________ Commissioner for Taking Affidavits	______________________________ Name

APPENDIX J: TAX COMPLIANCE DECLARATION

The Government of Ontario expects Proponents to pay their provincial taxes on a timely basis. In this regard, Proponents are advised that the Government of Ontario requires a declaration from the Proponent that the Proponent's provincial taxes are in good standing.

In order to be considered for an award of a CES Contract, DR Contract, or DSM Contract, as applicable, the Proponent must submit the following tax compliance status statement and the following consent to disclosure:

Declaration

The Proponent hereby certifies that ________________________________

(legal name of Proponent)

at the time of submitting its Proposal is in compliance with all of the tax statutes administered by the Ministry of Finance for Ontario and that, in particular, all returns required to be filed under all provincial tax statutes have been filed and all taxes due and payable under those statutes have been paid or satisfactory arrangements for their payment have been made and maintained.

Consent to Disclosure

The Proponent consents to the Ministry of Energy releasing the taxpayer information described in this Declaration to the Ministry of Finance as necessary for the purpose of verifying that the Proponent is in compliance with all of the tax statutes administered by the Ministry of Finance.

Dated at this day of 2004.

[Proponent]

____
Per: (authorized signing officer)

____
(Print Name)

____
(Title)

____
(Phone Number) (Fax Number)

APPENDIX K-1: TECHNICAL AND FINANCIAL SUBMISSION RETURN LABEL

AFFIX THIS LABEL TO YOUR TECHNICAL AND FINANCIAL SUBMISSION PACKAGE ENVELOPE

Prospective Proponent to complete the following:
(Full Legal Name and Address)

NAME ______________________________________

(In addition, set out name of Proponent named in the Statement of Qualifications, if different from the above)

NAME ______________________________________

ADDRESS____________________________________
____
____

CONTACT ___________________________________

PHONE NO. _________________________________

FAX NO. ____________________________________

E-MAIL ADDRESS ____________________________

RFP NO. SSB-069092

PROPOSAL SUBMISSION DEADLINE:

Date: December 15, 2004

Time: 3:00:00 pm (EST)

Shared Services Bureau
Strategic Procurement Branch
Tenders Office
56 Wellesley St. West, 2nd Floor
Toronto, Ontario, M5S 2S3
Attention: 2,500 MW RFP

I. IMPORTANT INSTRUCTIONS

The Technical and Financial Submission must be submitted in a sealed package(s) to the address indicated on this Technical and Financial Submission Return Label between the hours of 9:00 a.m. and 5:00 p.m. (EST), Monday through Friday (excluding Statutory Holidays), AND NO LATER THAN THE PROPOSAL SUBMISSION DEADLINE NOTED ABOVE.

The Shared Services Bureau/Ministry of Energy does not accept responsibility for any Technical and Financial Submission directed to any location other than the Shared Services Bureau address indicated on the label above.

Failure to affix this Technical and Financial Submission Return Label to your submission envelope/ package may also result in submissions not being recognized as a Technical and Financial Submission. This could result in your Technical and Financial Submission arriving late at the Tenders Office resulting in the Proposal being deemed late, disqualified and returned to the Prospective Proponent.

Technical and Financial Submissions received by Fax or any other kind of electronic transmission will be rejected.

APPENDIX K-2: ECONOMIC BID STATEMENT RETURN LABEL

AFFIX THIS LABEL TO YOUR ECONOMIC BID STATEMENT PACKAGE ENVELOPE

Prospective Proponent to complete the following:
(Full Legal Name and Address)

NAME ______________________________________

(In addition, set out name of Proponent named in the Statement of Qualifications, if different from the above)

NAME ______________________________________

ADDRESS____________________________________
____
____

CONTACT ___________________________________

PHONE NO. _________________________________

FAX NO. ____________________________________

E-MAIL ADDRESS ____________________________

RFP NO. SSB-069092

PROPOSAL SUBMISSION DEADLINE:

Date: December 15, 2004

Time: 3:00:00 pm (EST)

BNY Trust Company of Canada
4 King Street West
Suite 1101
Toronto, Ontario
M5H 1B6

Attention: Senior Trust Officer
Re: 2,500 MW RFP

I. IMPORTANT INSTRUCTIONS

The Economic Bid Statement must be submitted in a sealed package(s) to the address indicated on this Economic Bid Statement Return Label between the hours of 9:00 a.m. and 5:00 p.m. (EST), Monday through Friday (excluding Statutory Holidays), AND NO LATER THAN THE PROPOSAL SUBMISSION DEADLINE NOTED ABOVE.

The Shared Services Bureau, Ministry of Energy, and the Bid Repository do not accept responsibility for any Economic Bid Statement directed to any location other than the Bid Repository's address indicated on the label above.

Failure to affix this Economic Bid Statement Return Label to your Economic Bid submission envelope/package may also result in submissions not being recognized as a Economic Bid Statement. This could result in your Economic Bid Statement arriving late at the address set out above resulting in the Proposal being deemed late, disqualified and returned to the Prospective Proponent.

Economic Bid Statements received by Fax or any other kind of electronic transmission will be rejected.

APPENDIX L: METHODOLOGY FOR CONVERTING PEAK ELECTRICITY SAVINGS TO DSM PROJECT EQUIVALENT CAPACITY

Proponents of DSM Projects are required to provide Hourly Electricity Savings Profiles which support the Peak Electricity Savings stated by the Proponent in its answer to the Technical Questionnaire attached as Appendix C-3. The Peak Electricity Savings, expressed in MWh, will be converted to DSM Project Equivalent Capacity, expressed in MW, using the calculations and methodology described below.

a. Calculate the Hourly Electricity Savings Profiles for a Typical Peak Day of each Season

For each Season, provide Hourly Electricity Savings Profiles of the DSM Project. Calculate the Hourly Electricity Savings Profiles using methodologies outlined in the Measurement and Verification Guidelines for DSM. Data should be presented graphically and summarized in a table.

b. Calculate Peak Electricity Savings for a Typical Peak Day of each Season

Based on (a) above, calculate the total MWh saved during the On-peak Hours for a Typical Peak Day in each Season. Data should be presented in a table as follows:

Peak Electricity Savings for a Typical Peak Day in Summer (in MWh)

Peak Electricity Savings for a Typical Peak Day in Winter (in MWh)

Peak Electricity Savings for a Typical Peak Day in Other (in MWh)

c. Determine the Seasonal Capacity

For each Season, determine the Seasonal Capacity of the DSM Project for each Season by dividing the Peak Electricity Savings from (b) above by the number of On-Peak Hours (16hrs).

Peak Electricity Savings for a Typical Peak Day in Summer (MWh) / 16hrs = Seasonal Capacity Summer (MW)

Peak Electricity Savings for a Typical Peak Day in Winter (MWh) / 16 hrs = Seasonal Capacity Winter (MW)

Peak Electricity Savings for a Typical Peak Day in Other (MWh) / 16 hrs = Seasonal Capacity Other (MW)

d. Determine the DSM Project Equivalent Capacity

The DSM Project Equivalent Capacity is the sum of 40% of the Seasonal Capacity Summer, 40% of the Seasonal Capacity Winter, and 20% of the Seasonal Capacity Other, and calculated as follows:

  Seasonal Capacity Summer (MW) x 40%
\+ Seasonal Capacity Winter (MW) x 40%
\+ <u>Seasonal Capacity Other (MW) x 20%</u>
= DSM Project Equivalent Capacity (MW)

APPENDIX M: FORM OF LETTER OF INTENT FOR DR OR DSM AGGREGATION

[insert full mailing address of the Undersigned]

[insert Date]

[insert Addressee]

Re: Development of [**insert either "DR Project" or "DSM Project"**] by **[insert Name of Proponent**]

This letter is to confirm that the undersigned is the [**insert either "owner" or "operator"]** of the property located at [**insert municipal address, including City/Town**] and associated electrical load (the "**Load**"), which comprises a [**insert brief description of the Load (e.g. an office building, a restaurant)].**

The undersigned has reviewed the relevant portions of the 2,500 MW RFP issued by the Ontario Ministry of Energy on September 13, 2004 and associated appendices, a copy of which is posted on the internet at www.ontarioelectricityrfp.ca (the "**2,500 MW RFP**") which pertain to the **[insert either "DR Project" or "DSM Project"]**, together with **[insert "the DR Contract" or "the DSM Contract", as applicable]** (a copy of which is posted on such website), and the proposed **[insert "DR Third Party Agreement" or DSM Third Party Agreement", as applicable]** and confirms that the undersigned:

has the authority to permit the Proponent to install all necessary measures and equipment on the undersigned's property and Load in connection with the development and the operation of the [**insert "DR Project" or "DSM Project", as applicable**]; and

agrees in principle to permit the Proponent, under a [**insert "DR Third Party Agreement" or "DSM Third Party Agreement", as applicable]** with the undersigned, to control the Load in order to enable the Proponent to meet the obligations of the [**insert "DR Contract" or "DSM Contract", as applicable**];

The undersigned acknowledges that the Proponent is required to submit this letter as part of its Proposal and that the Ontario Ministry of Energy has the right to contact the undersigned for the purposes of verifying the information set out in this letter.

__________________________ _________________________________

[Witness] **[insert name and title of Authorized Person]**

[Note: Amend signature lines as appropriate to reflect the identity of the third party.]

APPENDIX N: NOTICE OF INTENT TO PROCEED TO STAGE 3

This Notice of Intent to Proceed to Stage 3 must be completed and delivered by the Proponent to the Ministry on or before the deadline date, and in the manner, specified in such notice by the Evaluation Team to the Proponent failing which the Proponent shall automatically be deemed to have revoked and withdrawn its Proposal.

Name of Proponent: ___________________________________

Name of Project: ___________________________________

CHECK ONE OF THE FOLLOWING BOXES

☐ **YES,** the Proponent irrevocably authorizes the Bid Repository holding the Economic Bid Statement in relation to the above-noted Project to deliver the Economic Bid Statement to the Evaluation Team, and agrees to submit the Economic Bid Statement for evaluation in accordance with the terms and conditions of Stage 3 of the 2,500 MW RFP. The Proponent acknowledges and agrees that Stage 3 of the 2,500 MW RFP constitutes a legally binding bidding process and the Proposal shall be irrevocable by the Proponent from the commencement of Stage 3 until 5:00 p.m. (EST) on the one hundred and eightieth (180th) day after the Proposal Submission Deadline.

OR

☐ **NO,** the Proponent irrevocably revokes and withdraws the Proposal for the above-noted Project from the 2,500 MW RFP, and requests the return of the Proposal Security submitted in relation to the above-noted Project in accordance with the terms and conditions of the 2,500 MW RFP.

Dated at this day of 200__

[Insert name of Proponent]

By: ___________________________________

Name: ●

Title: ●

By: ___________________________________

Name: ●

Title: ●

I/We have authority to bind the Proponent.

APPENDIX O: BOUNDARIES OF PRIORITY ELECTRICAL ZONES

The Priority Electrical Zones are defined as follows:

a. **Priority Electrical Zone 1: Downtown Toronto – Leaside Sector**

Priority Electrical Zone 1 is comprised of parts of the Hydro One 115kV network (and connected to the Toronto Hydro distribution system), including all facilities, connected between and among: Charles TS, Cecil TS, Terauley TS, Esplanade TS, Hearn TS, Basin TS, Gerrard TS, Carlaw TS, and Main TS. These stations are supplied via transmission connected to Leaside and Cherrywood TS.

b. **Priority Electrical Zone 2: GTA West of Toronto**

Priority Electrical Zone 2 is comprised of the Hydro One 115kV and 230kV network (and connected distribution systems of Toronto Hydro, Oakville Hydro, Enersource Hydro Mississauga Inc, PowerStream and Hydro One Brampton) bounded by Wiltshire TS, John TS, Oakville TS, Ford TS, Lorne Park TS, Cooksville TS, Lakeview GS, Horner TS, Finch TS, Rexdale TS, Goreway TS, Bramalea TS, Woodbridge TS, Kleinburg TS, Vaughan MTS1, Vaughan MTS2, Vaughan MTS3, Tomken TS, Goreway TS, and Claireville TS.

The determination of whether a New Generating Facility, DR Project, and DSM Project is located within a Priority Electrical Zone shall be made in accordance with the following:

- a New Generating Facility will be considered to be located within a Priority Electrical Zone if it is connected directly to the aforementioned stations or to transmission or distribution facilities connected directly between and among the stations, or if the New Generating Facility is connected to End-user(s) that is connected directly to the aforementioned stations or to transmission or distribution facilities connected directly between and among the stations. A direct radial connection to any one of the aforementioned stations or to any point within these electrical boundaries is considered to be within the zone, and;

- a DR Project will be considered to be located within a Priority Electrical Zone if the generation, load reduction or load shifting associated with the DR Project is connected to End-user(s) that are connected directly to the aforementioned stations or to transmission or distribution facilities connected directly between and among the stations. A direct radial connection to any one of the aforementioned stations or to any point within these electrical boundaries is considered to be within the zone, and;

- a DSM Project will be considered to be located within a Priority Electrical Zone if the load reduction associated with a DSM Project is achieved at End-user(s) connected directly to the aforementioned stations or to transmission or distribution facilities directly between and among the stations. A direct radial connection to any one of the aforementioned stations or to any point within these electrical boundaries is considered to be within the zone.

APPENDIX P: ECONOMIC EVALUATION OF AN ILLUSTRATIVE PROPOSAL FOR EACH OF A NEW GAS GENERATING FACILITY AND A NEW NON-GAS GENERATING FACILITY, A DR PROJECT AND A DSM PROJECT

This Appendix provides examples of the calculations to be performed in the Economic Evaluation of an illustrative Proposal for each of a New Gas Generating Facility and a New Non-Gas Generating Facility, a DR Project and a DSM Project. Examples of the remaining steps in the Economic Evaluation that involve the interrelationship between the various Proposals, such as stacking and the calculation of Transmission Upgrade Cost Impact, will be presented at Technical Consultation Session #2, referred to in Section IV.A.1.

As per Section III.D.2.a., the following data will be used in conducting the Economic Evaluation:

b. The relevant one, two and three hour ahead pre-dispatch data for each hour during the period from and including August 1, 2002 through July 31, 2004;

c. HOEP supplied by the IMO during the period from and including August 1, 2002 through July 31, 2004;

d. The Gas Price Index during the period from and including August 1, 2002 through July 31, 2004; and

e. The Specified Index, and the Specified Forecast Index as set out in Appendix R, together covering the years 2002 to 2030, inclusive.

A. A PROPOSAL FOR A NEW GAS GENERATING FACILITY

Parameters of an example of a New Gas Generating Facility

Project Size, MW	500
NRR $/MW-month	$11,500
% of NRR adjusted	20%
Specified Heat Rate, BTU/kWh	7,500
O&M Costs, $/MWh	$2.50
Start-Up Costs, BTU/start-up	2,000,000,000
Priority Electrical Zone	1
Voltage Support Adjustment	yes
Commercial Operation Date	August 1, 2007
Term of CES Contract, years	20

Other Evaluation Data

Escalation for inflation 2003-2007	8.6%
Inflation de-escalation factor for Commercial Operation Date, to July 2003	0.915
O&M Costs at July 2003, $/MWh	$2.29

Specified Forecast Index	2.0%
Date for 2007 inflation adjustment	July 1, 2007
Real discount rate	5.0%

1. **Calculating the Real Indexed NRR**

In order to determine the initial Evaluated Cost of a Proposal for a New Gas Generating Facility (i.e. the Evaluated Cost based on the Economic Bid Statement before considering any applicable System Reliability Enhancement Adjustments) it is necessary to calculate the Real Indexed NRR ("RINRR") for such Proposal. This process of levelizing the NRR serves to make Proposals that are based on differing term lengths equivalent for the purposes of the Economic Evaluation by establishing a real annual cost for each Proposal.

This process of levelization begins with a calculation of the net present value ("NPV") of the NRR, which as per Section III.D.2.b.i. is calculated at a nominal discount rate of 7.0% (such percentage being equal to a real rate of 5.0% plus a projected annual inflation rate of 2.0%). The nominal NRR is converted into an annual value for the first year of the proposed CES Contract by multiplying by 12. For each subsequent year, to account for inflation, the portion of the NRR that has been specified by the Proponent will be adjusted by the Specified Forecast Index. In this example the Proponent has specified that 20% of the NRR is to be adjusted for inflation. The NPV of these adjusted annual amounts is then calculated as in the table below.

Year of Term	Nominal annual NRR adjusted by Specified Index ($)
1	69,000,000
2	69,276,000
3	69,557,520
4	69,844,670
5	70,137,564
6	70,436,315
7	70,741,041
8	71,051,862
9	71,368,899
10	71,692,277
11	72,022,123
12	72,358,565
13	72,701,737
14	73,051,772

15	73,408,807
16	73,772,983
17	74,144,443
18	74,523,332
19	74,909,798
20	75,303,994
NPV @ nominal discount rate, $	$754,806,402

In order to convert the NPV of the Proposal into the RINRR the following formula is used, where r_n is the nominal discount rate (7.0%), r_i is the inflation rate (2.0%), and *per* is the number of periods (20).

$$RINRR = NPV \times \left(\frac{r_n - r_i}{1 - \frac{(1+r_i)^{per}}{(1+r_n)^{per}}} \right) \quad = \$61,266,459$$

In this example the RINRR of the Proposal is equal to $61,266,459. That is to say the real dollar equivalent of the NRR in the proposed first year, accounting for inflation over the term of the CES Contract is $61,266,459, which for the purposes of the Economic Evaluation is the real annual cost of this Proposal.

Once the RINRR has been determined it is converted to 2007 dollars as of July 1, 2007, using monthly compounding of the Specified Forecast Index. In this example the Proponent has indicated a Commercial Operation Date of August 1, 2007 and as such the RINRR must be adjusted for one month. The adjusted RINRR for this Proposal in 2007 dollars would be:

$61,165,440

This adjusted figure is then converted into a monthly value by dividing by 12, for a monthly RINRR of:

$5,097,120

Finally, in order to create a value expressed in $/MW-month the monthly RINRR is divided by the Project Size. In this example the Proponent has specified a Project Size of 500 MW and as such the RINRR for the Proposal expressed in $/MW-month is:

$10,194 /MW-month

At this stage of the Economic Evaluation it is necessary to adjust the RINRR for any applicable System Reliability Enhancement Adjustments.

2. Reducing the RINRR for System Reliability Enhancement Adjustments (or "SREA")

In this example there are three System Reliability Enhancement Adjustments that apply to the Proposal. The RINRR for the proposed New Gas Generating Facility in this example will be reduced by 12% in accordance with the table below as it will be located in Priority Electrical Zone 1, will provide Automatic System Voltage Support, and will achieve Commercial Operation prior to December 31, 2007.

Priority Electrical Zone Adjustment	2%
Voltage Support Adjustment	5%
Timing Adjustment	5%
Total SREA	12%
Adjusted NRR – RINRR reduced by total SREA, $/MW-month	$8,971

Once this reduced RINRR has been determined, a nominal Contingent Support Payment for the proposed first month of the Term will be calculated by subtracting from this amount the monthly average Estimated Net Revenue of the proposed New Gas Generating Facility as more particularly described below.

3. Calculating the Nominal Contingent Support Payment

In order to calculate a nominal Contingent Support Payment for the purposes of the Economic Evaluation it is necessary to determine the average monthly Estimated Net Revenue for the proposed New Gas Generating Facility, which is the net revenue that the proposed New Gas Generating Facility would have been expected to earn on average per month according to the past 24 months of data for the Gas Price Index, Pre-Dispatch Prices and HOEP.

For a New Gas Generating Facility, the O&M Costs submitted by the Proponent are adjusted for inflation at the midpoint of the first 12 months of Commercial Operation, to July 2003, which is the midpoint of the historical data series. In this example, this adjustment for inflation would bring the value of the O&M Costs down from $2.50/MWh to $2.29/MWh.

For this example according to the data series and the Specified Heat Rate, O&M Costs, and Start-Up Costs provided, the monthly average Estimated Net Revenue for the proposed New Gas Generating Facility is $5,415 /MW-month, which, adjusted to 2007 dollars (escalated by 8.6%), is equal to $5,881/MW-month. The nominal Contingent Support Payment for this example is calculated as follows:

$8,971/MW-month (RINRR as reduced by SREA)
- $5,881/MW-month (monthly average Estimated Net Revenue)
= $3,090/MW-month (nominal Contingent Support Payment)

This nominal Contingent Support Payment is the provisional Evaluated Cost for the proposed New Gas Generating Facility, which may require further adjustment depending on the result of the allocation of the Transmission Upgrade Cost Impacts described in Section III.D.2.b.ix.

B. A PROPOSAL FOR A NEW NON-GAS GENERATING FACILITY

Parameters of an example of a Proposal for a New Non-Gas Generating Facility

Project Size, MW	250
NRR, $/MW-month	$17,000
% of NRR adjusted	10%
Energy Cost, $/MWh	$42.00
Start-Up Costs, $/start-up	10,000
Priority Electrical Zone	1
Voltage Support Adjustment	yes
Commercial Operation Date	November 1, 2008
Term of CES Contract, years	20

Other Evaluation Data

Inflation escalation for 2003-2007	8.6%
Inflation de-escalation factor for Commercial Operation Date to July 2003	0.884
Energy Cost at July 2003, $/MWh	$37.13
Start-Up Costs at July 2003, $/start-up	$8,840
Forward-looking inflation rate	2.0%
Date for 2007 inflation adjustment	July 1, 2007
Real discount rate	5.0%

1. Calculating the Real Indexed NRR

In order to determine the initial Evaluated Cost of a Proposal for a New Non-Gas Generating Facility (i.e. the Evaluated Cost based on the Economic Bid Statement before considering any applicable System Reliability Enhancement Adjustments) it is necessary to calculate the Real Indexed NRR (“RINRR”) for such Proposal. This process of levelizing the NRR serves to make Proposals that are based on differing Term lengths equivalent for the purposes of the Economic Evaluation by establishing a real annual cost for each Proposal.

As with a Proposal for a New Gas Generating Facility, the NRR submitted by a Proponent of a New Non-Gas Generating Facility will be calculated at the nominal discount rate of 7.0% and converted into an annual value for the first year of the proposed CES Contract by multiplying by 12. For each subsequent year, to account for inflation, the portion of the NRR that has been specified by the Proponent will be adjusted by the Specified Forecast Index. In this example the Proponent has specified that 10% of the NRR is to be adjusted for inflation. The NPV of these adjusted annual amounts is then calculated as in the table below.

Year of Term	Nominal annual NRR adjusted for escalation ($)
1	51,000,000
2	51,102,000
3	51,206,040
4	51,312,161
5	51,420,404
6	51,530,812
7	51,643,428
8	51,758,297
9	51,875,463
10	51,994,972
11	52,116,872
12	52,241,209
13	52,368,033
14	52,497,394
15	52,629,342
16	52,763,929
17	52,901,207
18	53,041,231
19	53,184,056
20	53,329,737
NPV @ nominal discount rate, $	$549,097,555

In order to convert the NPV of the Proposal into the RINRR the following formula is used, where r_n is the nominal discount rate (7.0%), r_i is the inflation rate (2.0%), and *per* is the number of periods (20).

$$RINRR = NPV \times \left(\frac{r_n - r_i}{1 - \frac{(1+r_i)^{per}}{(1+r_n)^{per}}} \right) \quad = \$44,569,393$$

In this example the RINRR of the Proposal is equal to $44,569,393. That is to say the real dollar equivalent of the NRR in the proposed first year, accounting for inflation over the term of the CES Contract is $44,569,393, which for the purposes of the Economic Evaluation is the real annual cost of this Proposal.

Once the RINRR has been determined it is converted to 2007 dollars as of July 1, 2007, using monthly compounding of the Specified Forecast Index. In this example the Proponent has indicated a Commercial Operation Date of November 1, 2008 and as such the RINRR must be adjusted for sixteen months. The adjusted RINRR for this Proposal in 2007 dollars would be:

$43,408,005

This adjusted figure is then converted into a monthly value by dividing by 12, for a monthly RINRR of:

$3,617,334

Finally, in order to create a value expressed in $/MW-month the monthly RINRR is divided by the Project Size. In this example the Proponent has specified a Project Size of 250 MW and as such the RINRR for the Proposal expressed in $/MW-month is:

$14,469 /MW-month

At this stage of the Economic Evaluation it is necessary to adjust the RINRR for any applicable System Reliability Enhancement Adjustments.

2. **Reducing the RINRR for System Reliability Enhancement Adjustments (or "SREA")**

In this example only two System Reliability Enhancement Adjustments apply to the Proposal. The RINRR for the proposed New Non-Gas Generating Facility in this example will be reduced by 7% in accordance with the table below as it will be located in Priority Electrical Zone 1 and will provide Automatic System Voltage Support, but will not achieve Commercial Operation in time for a Timing Adjustment to apply.

Priority Electrical Zone Adjustment	2%
Voltage Support Adjustment	5%
Timing Adjustment	0%
Total SREA	7%
Adjusted NRR -- RINRR reduced by total SREA, $/MW-month	$13,456

Once this reduced RINRR has been determined, a nominal Contingent Support Payment for the proposed first month of the Term will be calculated by subtracting from this amount the monthly average Estimated Net Revenue of the proposed New Non-Gas Generating Facility as more particularly described below.

3. Calculating the Nominal Contingent Support Payment

In order to calculate a nominal Contingent Support Payment for the purposes of the Economic Evaluation it is necessary to determine the average monthly Estimated Net Revenue for the proposed New Non-Gas Generating Facility, which is the net revenue that the proposed New Non-Gas Generating Facility would have been expected to earn on average per month according to the past 24 months of data for Pre-Dispatch Prices and HOEP.

For this calculation, both the Energy Cost and the Start-Up Costs are adjusted for inflation at the midpoint of the first 12 months of Commercial Operation, to July 2003, which is the midpoint of the historical data series. In this example, this adjustment for inflation would bring the value of the Energy Cost down from $42.00/MWh to $37.13/MWh and the Start-Up Costs down from $10,000/start-up to $8,840/start-up.

For this example according to the data series and the Energy Cost and Start-Up Costs provided, the monthly average Estimated Net Revenue for the proposed New Non-Gas Generating Facility is approximately $11,049/MW-month, which, adjusted to 2007 dollars (escalated by 8.6%), is equal to $11,999 /MW-month. The nominal Contingent Support Payment for this example then is calculated as follows:

$13,456/MW-month (RINRR as reduced by SREA)
-$11,999/MW -month (monthly average Estimated Net Revenue)
= $1,457/MW-month (nominal Contingent Support Payment)

This nominal Contingent Support Payment is the provisional Evaluated Cost for the proposed New Non-Gas Generating Facility, which may require further adjustment depending on the result of the allocation of the Transmission Upgrade Cost Impacts described in Section III.D.2.b.ix.

C. A PROPOSAL FOR A DR PROJECT

Parameters of an example of a Proposal for a DR Project

Seasonal Capacity Summer, MW	100
Seasonal Capacity Winter, MW	60
Seasonal Capacity Other Season, MW	50
NRR, $/MW-month	$4,500
Priority Electrical Zone	2
Voltage Support Adjustment	Yes
Commercial Operation Date	May 1, 2006
Term, years	5

Other Evaluation Data

Inflation escalation for 2003-2007	8.6%
Inflation de-escalation factor for Commercial Operation Date to July 2003	0.900
Forward-looking inflation rate	2.0%
Date for 2007 inflation adjustment	July 1, 2007
Real discount rate	5.0%
DR Strike Price, $/MWh	$350
Average Equivalent Capacity, MW	62.9

The Contracted Demand Reduction for a Proposal for a DR Project will be adjusted to an equivalent average monthly capacity by multiplying the Contracted Demand Reduction for each Season by 85% and then applying weighting factors of 40% for each of Summer and Winter, and 20% for Other Season. Based on the seasonal Contracted Demand Reduction specified by the Proponent of this DR Project the equivalent average monthly capacity is as follows:

0.85 [(100x0.4) + (60x0.4) + (50x0.2)] = 62.9 MW

1. Calculating the Real Indexed NRR

As with Proposals for New Generating Facilities the net present value (NPV) of the NRR of a DR Project is calculated at the nominal discount rate of 7.0%. In order to derive the first year annual cost for the proposed DR Project the NRR is multiplied by the Contracted Demand Reduction for each Season, in MW, and the number of months in each period:

$4,500 x (4x100 + 4x60 + 4x50) = $3,780,000

The NPV of this annual amount is then calculated as in the table below.

Year of Term	Nominal annual cost ($)
1	3,780,000
2	3,780,000
3	3,780,000
4	3,780,000
5	3,780,000
NPV @ nominal discount rate, $	$15,498,746

In order to convert the NPV of the Proposal into the RINRR the following formula is used, where r_n is the nominal discount rate (7.0%), r_i is the inflation rate (2.0%), and *per* is the number of periods (5).

$$RINRR = NPV \times \left(\frac{r_n - r_i}{1 - \frac{(1+r_i)^{per}}{(1+r_n)^{per}}} \right) \qquad = \$3,641,526$$

In this example the RINRR of the Proposal is equal to $3,641,526. That is to say the real dollar equivalent of the NRR in the proposed first year, accounting for inflation over the Term of the DR Contract is $3,641,526, which for the purposes of the Economic Evaluation is the real annual cost of this Proposal.

Once it has been determined the RINRR is converted to 2007 dollars as of July 1, 2007, using monthly compounding of the Specified Forecast Index. In this example the Proponent has indicated a Commercial Operation Date of May 1, 2006 and as such the RINRR must be adjusted for fourteen months. The adjusted RINRR for this Proposal in 2007 dollars would be:

$3,726,636

This adjusted figure is then converted into a monthly value by dividing by 12, for a monthly RINRR of:

$310,553 /month

Finally, in order to create a value expressed in $/MW-month the monthly RINRR is divided by the equivalent average monthly capacity. In this example the equivalent average monthly capacity is 62.9 MW and as such the RINRR for the Proposal expressed in $/MW-month is:

$4,937 /MW-month

At this stage of the Economic Evaluation it is necessary to adjust the RINRR for any applicable System Reliability Enhancement Adjustments.

2. **Reducing the RINRR for System Reliability Enhancement Adjustments (or "SREA")**

In this example there are two System Reliability Enhancement Adjustments that apply to the Proposal. The RINRR for the proposed DR Project in this example will be reduced by 7% in accordance with the table below as it will be located in Priority Electrical Zone 2 and will provide Automatic System Voltage Support.

Priority Electrical Zone Adjustment	2%
Voltage Support Adjustment	5%
Total	7%
Adjusted RLC -- RLC reduced by total SREA, $/MW-month	$4,592

Once this reduced RINRR has been determined, a nominal Contingent Support Payment for the proposed first month of the Term will be calculated by subtracting from this amount the monthly average DR Strike Price Reduction of the proposed DR Project as more particularly described below.

3. **Calculating the Nominal Contingent Support Payment**

In order to calculate a nominal Contingent Support Payment for the purposes of the Economic Evaluation it is necessary to determine the monthly average DR Strike Price Reduction for the proposed DR Project according to the past 24 months of data for Pre-Dispatch Prices and HOEP.

The monthly average DR Strike Price Reduction is evaluated at the DR Strike Price of $350/MWh, as adjusted from July 2007 to July 2003 (divided by 1.086), resulting in an adjusted DR Strike Price of $322/MWh. The DR Strike Price Reduction for this value is approximately $234 /MW-month which, adjusted to 2007 dollars (escalated by 8.6%), amounts to a reduction of $254 /MW-month. The nominal Contingent Support Payment for this example then is calculated as follows:

$4,592/MW-month (RINRR as reduced by SREA)
-$ 254/MW -month (monthly average DR Strike Price Reduction)
=$4,338/MW-month (nominal Contingent Support Payment)

The nominal Contingent Support Payment is the Evaluated Cost for the DR Project.

D. A PROPOSAL FOR A DSM PROJECT

Parameters of an example of a Proposal for a DSM Project

		Annual Adjustment
Incremental capital costs, NPV, $	$12,000,000	
O&M Costs, $/MW-month	$400	0.8% year 1 0.4% thereafter
Administrative costs, $/MW-month	$400	0.8% year 1 0.4% thereafter
Program delivery costs, $/MW-month	$400	0.8% year 1 0.4% thereafter
Costs of measurement & verification, $/MW-month	$400	0.8% year 1 0.4% thereafter
DSM Project Equivalent Capacity	6 MW	
Priority Electrical Zone	2	
Voltage Support Adjustment	No	
Commercial Operation Date	November 1, 2007	
Term, years	5	

Other Evaluation Data

Inflation escalation for 2003-2007	8.6%
Forward-looking inflation rate	2.0%
Date for 2007 inflation adjustment	July 1, 2007
Real discount rate	5.0%

1. Calculating the DSM Cost

For the purposes of the Economic Evaluation DSM Projects will be evaluated according to the Total Resource Cost Test. This will be implemented by computing an Evaluated Cost for a DSM Project that is equivalent to that for New Generating Facilities and DR Projects, and including the DSM Project in all Stacks and Combinations in the Economic Evaluation based on this Evaluated Cost. The first step of calculating the Evaluated Cost for a DSM Project that will be used to implement the Total Resource Cost Test is to determine the total cost associated with the implementation of the DSM Project according to the data submitted by the Proponent in the Economic Bid Statement.

Please note that the NRR set out in the Economic Bid Statement is not used in the Economic Evaluation of a DSM Project. The NRR is the value to be paid to a Supplier under a DSM Contract with the Buyer, which will be limited to the lower of the amount specified by the Proponent in its Economic Bid Statement and the amount that will provide for recovery of the investment based on a three year Simple Payback Period.

In order to determine the NPV of the total cost of a DSM Project each of the monthly per MW costs specified by the Proponent are multiplied by 12 and the resulting figure is multiplied by the DSM Project Equivalent Capacity. For the first year, this annual cost is added to the incremental capital costs specified by the Proponent, which is considered to be given as a NPV in the first year. For each subsequent year the annual costs (not including the incremental capital costs) as specified by the Proponent in their Economic Bid Statement are used. The NPV of this annual amount is then calculated as in the table below.

Year of Term	Nominal annual cost adjusted for escalation ($)
1	12,115,200
2	116,123
3	116,588
4	117,054
5	117,523
NPV @ nominal discount rate, $	$11,692,306

The NPV is then converted into a real levelized DSM Cost ("RLC") using the following formula, where r_n is the nominal discount rate (7.0%), r_i is the inflation rate (2.0%), and *per* is the number of periods (5).

$$RLC = NPV \times \left(\frac{r_n - r_i}{1 - \frac{(1+r_i)^{per}}{(1+r_n)^{per}}} \right) \qquad = \$2,747,179$$

In this example the RLC of the Proposal is equal to $2,747,179. That is to say the real dollar equivalent of the annual cost in the proposed first year, accounting for inflation over the term of a DSM Contract is $2,747,179, which for the purposes of the Economic Evaluation is the real annual cost of this Proposal.

Once the RLC has been determined, it is converted to 2007 dollars as of July 1, 2007, using monthly compounding of the Specified Forecast Index. In this example the Proponent has indicated a Commercial Operation Date of November 1, 2007 and as such the RLC must be adjusted for four months. The adjusted RLC for this Proposal in 2007 dollars would be:

$2,729,105

This adjusted RLC is then converted into a monthly value by dividing by 12, so that the monthly RLC is:

$227,425 /month

Finally, in order to create a value expressed in $/MW-month the monthly RLC is divided by the DSM Project Equivalent Capacity. In this example, the DSM Project Equivalent Capacity is 6 MW and as such the RLC for the Proposal expressed in $/MW-month is:

$37,904 /MW-month

At this stage of the Economic Evaluation it is necessary to adjust the RINRR for any applicable System Reliability Enhancement Adjustments.

2. **Reducing the RLC for System Reliability Enhancement Adjustments (or "SREA")**

In this example only one System Reliability Enhancement Adjustment applies to the Proposal. The RLC for the proposed DSM Project in this example will be reduced by 2% in accordance with the table below as it will be located in Priority Electrical Zone 2.

Priority Electrical Zone	2%
Voltage Support Adjustment	0%
Total	2%
Adjusted RLC – RLC reduced by total SREA, $/MW-mo	$37,146

Once this reduced RLC has been determined it is necessary to determine the Avoided Energy Cost associated with the DSM Project. This process is described below.

3. **Adjustment for Avoided Energy Cost**

Once determined the RLC is reduced by an amount equal to the monthly average avoided energy, which is calculated based on the Hourly Electricity Savings Profile for a Typical Week in each Season and the past 24 months of data for HOEP. The load profile for the DSM Project is evaluated according to the historical HOEP, assuming no variable O&M Costs (O&M Costs are taken as a total monthly cost from the Economic Bid Statement). The Hourly Electricity Savings Profile will be multiplied by HOEP and summed in the month. The resulting sum will be divided by 24 and further divided by the DSM Project Equivalent Capacity.

For this example according to the data the average monthly Avoided Energy Cost for the DSM Project is $30,833/MW-month (based on calculated savings for the load profile of about $4.5 million over 24 months), which, adjusted to 2007 dollars (escalated by 8.6%), amounts to a reduction for Avoided Energy Cost of $33,938/MW-month. The resulting DSM Cost is calculated as follows:

$37,146/MW-month (RLC as reduced by SREA)
-$33,938/MW -month (monthly average Avoided Energy Cost)
=$3,209/MW-month (resulting Evaluated Cost)

It is this resulting value that is the Evaluated Cost for a DSM Project and which will in all Stacking analyses and all evaluations of combinations be compared to, or combined with, the Evaluated Cost (as adjusted to account for Transmission Upgrade Cost Impacts as applicable) of New Generation Facilities and DR Projects. This translates the DSM Cost of a DSM Project into the Evaluated Cost for the DSM Project so that the Evaluated Costs of each of New Generating Facilities, DR Projects, and DSM Projects are all representative of the resource costs of developing and maintaining the relevant facilities less the net resource costs savings of the associated energy savings or energy production resulting from the facilities of each type.

Inflation Assumptions

The following is the reported CPI (All-Items) index from Statistics Canada. For purposes of this Appendix P, the projected index is based on the Specified Forecast Index from August 2004, but Proponents are advised that the actual Economic Evaluation will be conducted based on the Specified Forecast Index commencing on December 15, 2004 as noted in Appendix R.

Month	Reported Index	Month	Projected Index	Month	Projected Index
Jan-02	117.3	Aug-04	126.3	May-07	133.8
Feb-02	118.2	Sep-04	126.4	Jun-07	133.5
Mar-02	119.5	Oct-04	126.1	Jul-07	133.7
Apr-02	119.5	Nov-04	126.4	Aug-07	134.0
May-02	119.5	Dec-04	126.7	Sep-07	134.1
Jun-02	119.9	Jan-05	126.7	Oct-07	133.8
Jul-02	120.8	Feb-05	126.9	Nov-07	134.1
Aug-02	121.7	Mar-05	127.4	Dec-07	134.4
Sep-02	121.2	Apr-05	127.6	Jan-08	134.4
Oct-02	121.5	May-05	128.6	Feb-08	134.6
Nov-02	121.8	Jun-05	128.3	Mar-08	135.2
Dec-02	120.6	Jul-05	128.5	Apr-08	135.5
Jan-03	122.4	Aug-05	128.8	May-08	136.5
Feb-03	123.4	Sep-05	128.9	Jun-08	136.2
Mar-03	123.5	Oct-05	128.6	Jul-08	136.4
Apr-03	122.3	Nov-05	128.9	Aug-08	136.7
May-03	122.7	Dec-05	129.2	Sep-08	136.8
Jun-03	122.9	Jan-06	129.2	Oct-08	136.5
Jul-03	123.1	Feb-06	129.4	Nov-08	136.8
Aug-03	123.8	Mar-06	129.9	Dec-08	137.1
Sep-03	123.9	Apr-06	130.2	Jan-09	137.1
Oct-03	123.6	May-06	131.2	Feb-09	137.3
Nov-03	123.9	Jun-06	130.9	Mar-09	137.9
Dec-03	124.2	Jul-06	131.1	Apr-09	138.2
Jan-04	124.2	Aug-06	131.4	May-09	139.2
Feb-04	124.4	Sep-06	131.5	Jun-09	138.9

Mar-04	124.9	Oct-06	131.2	Jul-09	139.1
Apr-04	125.1	Nov-06	131.5	Aug-09	139.4
May-04	126.1	Dec-06	131.8	Sep-09	139.5
Jun-04	125.8	Jan-07	131.8	Oct-09	139.2
Jul-04	126.0	Feb-07	132.0	Nov-09	139.5
		Mar-07	132.5	Dec-09	139.8
		Apr-07	132.8		

APPENDIX Q: COST IMPACT MATRIX

This Appendix Q sets out the information and methodology required to determine the Transmission Upgrade Cost Impact, if any, for Proposals for New Generating Facilities, for purposes of conducting the Economic Evaluation as described in Section III.D of the 2,500 MW RFP. In particular, this Appendix expresses the Transmission Zones as Areas, Zones, and Sub-Zones and provides a cost impact matrix (the "Cost Impact Matrix") outlining the Capacity Ranges and the Incremental Transmission Expansion Costs in relation to each Area, Zone, and Sub-Zone.

The information and methodology in this Appendix has been developed by the Ministry, in consultation with its technical advisors, the IMO, and Hydro One, and is provided for the express use of this 2,500 MW RFP and for no other purpose. Prospective Proponents are advised that the Cost Impact Matrix contained in this Appendix is a model that has been developed to ensure that the Economic Evaluation is as clear and transparent as possible, and that the capacity, cost, and other values or descriptions contained in the Cost Impact Matrix should not be relied upon by Prospective Proponents as being definitive of the actual capacity, cost, or other values or descriptions that may be payable or applicable.

Background

The capacity of New Generating Facilities being proposed in response to this 2,500 MW RFP must be able to be reliably delivered to loads in the Province of Ontario. The costs of transmission system expansions or reinforcements to ensure such reliable delivery will be part of the overall costs of providing new supply to the province's customers, and will therefore be considered in the Economic Evaluation of Proposals for New Generating Facilities.

The information and methodology set out in this Appendix, which will be applied to the Economic Evaluation, is a simplification which attempts to address material effects on the transmission system as well as to keep the Economic Evaluation as simple, transparent, and manageable as possible. For example, the transmission system has been assessed to estimate what levels of new capacity would likely require incremental investments of $25 million dollars or more. However, the Ministry recognizes that the ability of the transmission system to deliver new generation to loads varies significantly with the location of new generation on the transmission system and by the amount of new capacity, as well as the fact that certain locations may have spare capacity due to the retirement of coal-fired generation facilities.

As a result, there are locations throughout the province that can accommodate additional new generation capacity without substantial transmission upgrades, while there other locations throughout the province which require transmission upgrades to accommodate even relatively small amounts of new capacity. Given this diversity, the province has been divided into six (6) separate Areas, and each Area has been separately assessed to estimate the investment in the transmission system that would be required to be able to accommodate the development of New Generating Facilities which may be located within each such Area for all ranges of capacity additions up to the Target Capacity. However, it is also recognized that transmission capacity is not equally distributed within a given Area, and so the assessment of investments in the transmission system has also been further defined by reference to each Zone and Sub-Zone with such Area.

Definition of Areas, Zones, and Sub-Zones

The Areas, Zones and Sub-Zones are defined in terms of the transmission stations and circuits which are associated with them, and are set out in Tables 1b, 2b, 3b, 4b, 5b, and 6b. The Areas are:

1. West of London;
2. London to West GTA;
3. West-Central GTA;
4. East GTA and Eastern Ontario;
5. Simcoe to Deep River; and
6. North of Barrie Area.

The Areas, Zones, and Sub-Zones are defined based on electrical system considerations and the point of connection of a New Generating Facility, as set out in the Proposal, will be uniquely assigned to one Area, Zone and Sub-Zone. For certainty, circuits defined with only an originating station include the circuit section up to the next station or the entire circuit if the circuit is radically connected. The exception to this are those circuits which are connected to an isolation switch, which under normal operations is opened. In such cases where a circuit is sectionalized by a "normally open switch", only the circuit length from the originating station to the "normally open switch" applies. As noted below, Prospective Proponents are advised to consult the IMO and Hydro One for specific determination of the electrical location for the purposes of this allocation.

Illustrative Maps of Areas, Zones, and Sub-Zones and Determining the Applicable Area, Zone and Sub-Zone for a given New Generating Facility

Overview maps are provided illustrating the geographic and high level transmission facilities encompassed by the Area, Zones and Sub-Zones and are set out in Figures 1, 2, 3, 4, 5, and 6. However, Prospective Proponents are advised that while these overview maps are representative, the definitions of Areas, Zones and Sub-Zones set out in Tables 1b, 2b, 3b, 4b, 5b, and 6b will be utilized, together with the information provided in the Proposal as to the applicable point of connection of the New Generating Facility (including the single-line electrical diagram provided in response to the Technical Questionnaire), in order to determine the Area, Zone, and Sub-Zone of the New Generating Facility for purposes of this Appendix.

Prospective Proponents are advised that confirmation of the name of the circuit or station set out in Tables 1b, 2b, 3b, 4b, 5b, and 6b to which the New Generating Facility will be connected is available through Hydro One and the IMO as part of the Connection Assessment Process and Customer Impact Assessment managed by the IMO and Hydro One, provided that the necessary information related to the proposed point of connection has been provided to Hydro One or the IMO. Prospective Proponents seeking this confirmation prior to initiating the Connection Assessment Process or the Customer Impact Assessment are advised to request this information from the IMO or Hydro One, provided that the necessary information related to the proposed point of connection has been provided.

Cost Impact Matrix

A Cost Impact Matrix has been prepared for each Area, which contains the following information:

1. *Area* of the province. The six Areas collectively cover the entire province.

2. *Zone(s)*, within an Area.

3. *Sub-Zone(s)*, within a Zone.

4. *Max without upgrades (MW)* – Represents the maximum capacity that the transmission system in the applicable Area, Zone, or Sub-Zone, as the case may be, is assumed to bear without transmission upgrades.

5. *Step 1 Upgrade* :

   Total Cost (M$) – Total cost in millions of dollars that is assumed to be required in order to upgrade the transmission system in the applicable Area, Zone, or Sub-Zone to accommodate new capacity from the existing level (as set out in the column entitled "Max without Upgrades") to the capacity set out in "*Max (MW)"* under Step 1 Upgrade*.*

6. *Step 2 Upgrade :*

   Total Cost (M$) – Total cost in millions of dollars to upgrade the transmission system in the applicable Area, Zone, or Sub-Zone to accommodate new capacity from the existing level (as set out in column entitled "Max without Upgrades") to the capacity set out in the column entitled *"Max (MW)"* under Step 2 Upgrades. For certainty, Step 2 Upgrades include Step 1 Upgrades.

7. *Step 3 Upgrade :*

   Total Cost (M$) – Total cost in millions of dollars to upgrade the transmission system in the applicable Area, Zone, or Sub-Zone to accommodate new capacity from the existing level (as set out in the column entitled Max without Upgrades) to the capacity set out in the column entitled *"Max (MW)"* under Step 3 Upgrades. For certainty, Step 3 Upgrades include Step 1 Upgrades and Step 2 Upgrades.

8. Step 4 Upgrade :

Total Cost (M$) – Total cost in millions of dollars to upgrade the transmission system in the applicable Area, Zone, or Sub-Zone to accommodate new capacity from the existing level (as set out in the column entitled Max without Upgrades) to the capacity set out in the column entitled *"Max (MW)"* under Step 4 Upgrades. For certainty, Step 4 Upgrades include Step 1 Upgrades, Step 2 Upgrades, and Step 3 Upgrades.

Application of Cost Impact Matrix

Proponents are advised that the Transmission Upgrade Cost Impact to be allocated to a Proposal for a New Generating Facility, will be calculated based on the Incremental Transmission Expansion Costs required to transmit all incremental Capacity of the proposed New Generating Facilities from the particular Sub-Zones in which they will be located out to the boundary of such Area. Furthermore, the Incremental Transmission Expansion Costs and the maximum existing capacities of a given Sub-Zone, Zone, and Area set out in the Cost Impact Matrix are interdependent within each Area and component Zone and Sub-Zone such that a Proposal for a New Generating Facility located within a Sub-Zone will use up existing transmission capacity and potentially attract Incremental Transmission Expansion Costs attributed to the Sub-Zone, the Zone containing the Sub-Zone, and the Area containing the Zone.

TABLE 1a

Area: West Of London

Cost Impact Matrix:

Area	Zone	Sub-Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
				Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
West of London			2,000	$50	2,500						
	London to Sarnia		2,000	$50	2,500						
		London	100	$25	300	$75	800	$175	2,500		
		Sarnia	100	$25	300	$100	800	$300	2,500		
		Lambton	2,000	$25	2,500						
	London to Windsor		1,000	$100	1,500	$200	2,500				
		Lauzon-Kent	200	$25	400	$75	800	$175	2,500		
		Keith	0	$50	600	$100	800	$200	2,500		

Note: Prospective Proponents are advised that the Cost Impact Matrix set out above sets out total costs and total capacities (under the headings "Total Cost" and "Max (MW)" respectively) and does not specifically set out incremental costs and incremental capacities. Accordingly, Incremental Transmission Expansion Costs and Capacity Ranges are to be calculated by comparing the various columns against each other. For example, the Incremental Transmission Expansion Cost between "Step 1 Upgrade" and "Step 2 Upgrade", to increase the capacity "Max (MW)" as shown in "Step 2 Upgrade" over the capacity "Max (MW)" as shown in "Step 1 Upgrade", is calculated as the difference between the "Total Cost" shown under the heading "Step 2 Upgrade" and the "Total Cost" shown under the heading "Step 1 Upgrade".

TABLE 1b

Area: West Of London

Definition of West of London Area, Zones, and Sub-Zones:

AREA	***ZONE***	**SUB-ZONE**	**Definition**
West of London			• All circuits and stations defined in the London to Sarnia Zone • All circuits and stations defined in the London to Windsor Zone
	London to Sarnia		• Network Stations: Scott TS and Lambton TS • 230kV circuits from – Buchanan TS to Scott TS – Buchanan TS to Longwood TS – Buchanan TS to Clarke TS – Longwood TS to Lambton TS – Lambton TS to Scott TS • All 115kV circuits and stations defined in the Sarnia and London Sub-Zones
		Sarnia	• Network Stations: Scott TS • 230kV circuits N6S and N7S • All 115kV circuits connected from Scott TS
		London	• Network Stations: Buchanan TS 115kV • All 115kV circuits connected from Buchanan TS
		Lambton	• Connection at the 230kV switchyard at Lambton TS
	London to Windsor		• Network Stations: Chatham SS, Lauzon TS, Keith TS, Essex TS • 230kV circuits from – Buchanan TS and Longwood TS to Chatham SS – Chatham SS to Lambton TS – Chatham SS to Lauzon TS – Chatham SS to Keith TS • All 115kV circuits and stations defined in Lauzon-Kent and Keith Sub-Zones
		Lauzon – Kent	• Network Stations: Lauzon TS 115kV, Essex TS • All 115kV circuits connected from Lauzon TS to Essex TS and Lauzon TS to Kent TS • 115kV circuit N5K from Kent TS
		Keith	• Network Stations: Keith TS • 230kV circuits from Keith to Chatham • All 115kV circuits connected from Keith TS

FIGURE 1

Illustrative Map of West of London Area, Zones, and Sub-Zones:

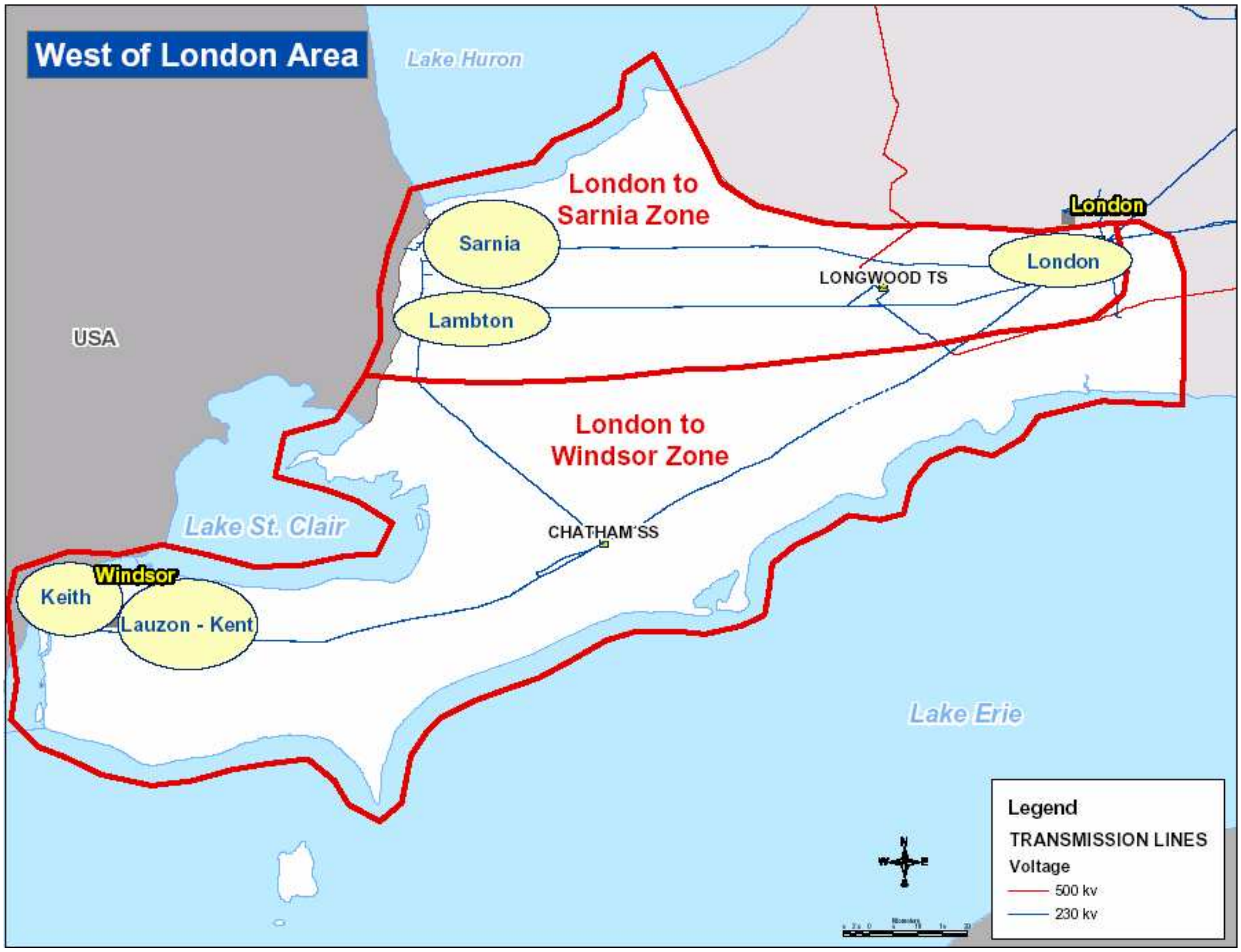


TABLE 2a

Area: London to West GTA

Cost Impact Matrix:

Area	Zone	Sub-Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
				Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
London to West GTA			2,500								
	Bruce		1,000	$50	1,500	$450	2,500				
	East of Bruce		500	$50	1,000	$100	1,500	$500	2,500		
		Hanover	100	$50	600	$350	2,500				
		Seaforth	50	$50	200	$150	600	$450	2,500		
	Waterloo		300	$50	1,000	$100	1,500	$200	2,500		
	Hamilton-Burlington		200	$50	400	$100	800	$400	2,500		
	Niagara		100	$100	300	$150	800	$250	1300	$450	2,500
	East of London		500	$50	1,000	$100	1,500	$500	2,500		
	Nanticoke		2,500								

Note: Prospective Proponents are advised that the Cost Impact Matrix set out above sets out total costs and total capacities (under the headings “Total Cost” and “Max (MW)” respectively) and does not specifically set out incremental costs and incremental capacities. Accordingly, Incremental Transmission Expansion Costs and Capacity Ranges are to be calculated by comparing the various columns against each other. For example, the Incremental Transmission Expansion Cost between “Step 1 Upgrade” and “Step 2 Upgrade”, to increase the capacity “Max (MW)” as shown in “Step 2 Upgrade” over the capacity “Max (MW)” as shown in “Step 1 Upgrade”, is calculated as the difference between the “Total Cost” shown under the heading “Step 2 Upgrade” and the “Total Cost” shown under the heading “Step 1 Upgrade”.

TABLE 2b

Area: London to West GTA

Definition of London to West GTA Area, Zones, and Sub-Zones:

AREA	*ZONE*	SUB-ZONE	Definition
London to West GTA			• All network stations and circuits defined in the following Zones: – Bruce Zone – East of Bruce Zone – Waterloo Zone – Hamilton-Burlington Zone – Niagara Zone – East of Buchanan Zone – Nanticoke Zone • 500 kV circuits from Middleport TS to Milton TS
	Bruce		• Network Stations: Bruce Complex • 500 kV circuits from – Bruce Complex to Milton SS – Bruce Complex to Longwood TS • 230kV circuits from – Bruce Complex to Hanover TS – Bruce Complex to Seaforth TS – Bruce Complex to Owen Sound TS
	East of Bruce		• Network Stations: Hanover TS, Orangeville TS, Seaforth TS, Owen Sound TS • 230kV circuits from – Hanover TS to Orangeville TS – Orangeville TS to Essa TS – Orangeville TS to Detweiler TS (up to Fergus TS) – Seaforth TS to Detweiler TS • Includes all 115kV circuits and stations defined in Hanover and Seaforth Sub-Zones
		Hanover	• Network Stations: Owen Sound TS 115kV and Hanover TS 115kV • All 115kV circuits connected from Owen Sound TS and Hanover TS
		Seaforth	• Network Stations: Seaforth TS 115kV • All 115kV circuits connected from Seaforth TS
	Waterloo		• Network Stations: Detweiler TS • 230kV circuits from – Detweiler TS to Orangeville TS up to and including Fergus TS – Detweiler TS to Middleport TS up to and including Galt Junction and tap to Preston TS • All 115kV circuits connected from Detweiler TS

AREA	***ZONE***	**SUB-ZONE**	**Definition**
	Hamilton - Burlington		• Network Stations: Burlington TS, Middleport TS, Beach TS • 230kV circuits from – All circuits between Middleport TS, Beach TS, Burlington TS – Circuits Q23BM, Q24HM, Q25BM and Q29HM includes sections up to and including Hannon Junction – Burlington TS to Trafalgar TS up to Lantz Junction • All 115kV circuits connected from Burlington TS and Beach TS
	Niagara		• Network Stations: Beck 2 TS, Beck 1 SS, Allanburg TS, Decew Falls SS • 230kV circuits from – Beck 2 TS to Beach TS up to Hannon Junction – Beck 2 TS to Burlington TS up to Hannon Junction – Beck 2 TS to Allanburg TS – Allanburg TS to Middleport TS • All 115kV circuits connected from Allanburg TS, Beck 1 SS, and Decew Falls SS • 25 Hz system
	East of London		• 500 kV circuits from – Longwood TS to Nanticoke TS • 230kV lines from – Buchanan TS to Detweiler TS – Buchanan TS to Middleport TS – Middleport TS to Galt Junction
	Nanticoke		• Network Stations: Nanticoke TS, Middleport TS, Caledonia TS • 500 kV lines from – Nanticoke TS to Middleport TS • 230kV lines from – Nanticoke TS to Middleport TS • All 115kV circuits connected from Caledonia TS

FIGURE 2

Illustrative Map of London to West - GTA Area, Zones, and Sub-Zones:

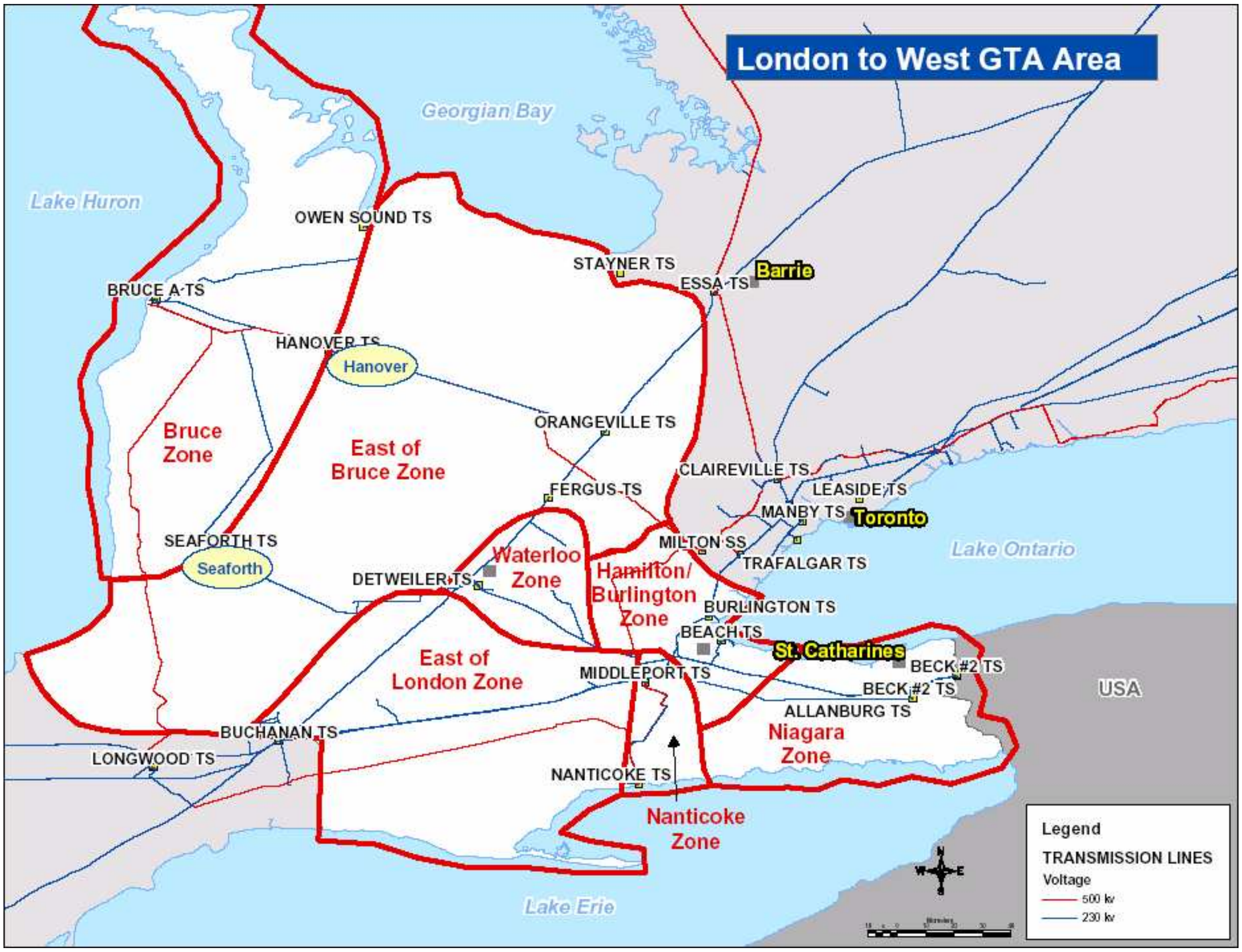


TABLE 3a

Area: West – Central GTA

Cost Impact Matrix:

Area	Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
			Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
West – Central GTA		2,000	$100	2,500						
	Manby West	0	$50	1,000	$350	2,500				
	Manby East	0	$50	1,000	$350	2,500				
	Newmarket	500	$100	1,500	$300	2,500				

Note: Prospective Proponents are advised that the Cost Impact Matrix set out above sets out total costs and total capacities (under the headings "Total Cost" and "Max (MW)" respectively) and does not specifically set out incremental costs and incremental capacities. Accordingly, Incremental Transmission Expansion Costs and Capacity Ranges are to be calculated by comparing the various columns against each other. For example, the Incremental Transmission Expansion Cost between "Step 1 Upgrade" and "Step 2 Upgrade", to increase the capacity "Max (MW)" as shown in "Step 2 Upgrade" over the capacity "Max (MW)" as shown in "Step 1 Upgrade", is calculated as the difference between the "Total Cost" shown under the heading "Step 2 Upgrade" and the "Total Cost" shown under the heading "Step 1 Upgrade".

TABLE 3b

Area: West – Central GTA

Definition of West – Central GTA Area, Zones, and Sub-Zones:

AREA	*ZONE*	SUB-ZONE	Definition

West – Central GTA			• Network Stations: Milton SS, Trafalgar TS, Claireville TS, Richview TS, Manby TS
			• 500kV circuits from
			  – Milton SS to Claireville TS (includes this section of B560V)
			  – Milton SS to Trafalgar TS
			  – Claireville TS to Essa TS
			  – Claireville TS to Parkway TS
			• 230kV circuits from
			  – Richview TS to Claireville TS
			  – Richview TS to Trafalgar TS
			  – Richview TS to Oakville TS
			  – Richview TS to Manby East TS
			  – Richview TS to Manby West TS
			  – Richview TS to Cherrywood TS up to Leaside Jct
			  – Richview TS to Parkway TS up to Leaside Jct
			  – All circuits from Claireville TS
			  – Manby East TS and Manby West TS
			  – Trafalgar TS to Burlington up to and including Lantz Junction
			• All 115kV circuits defined in Manby East Zone
			• All 115kV circuits defined in Manby West Zone

	Manby East		• Network Stations: Manby East TS 115kV • All 115kV circuits from Manby East TS
	Manby West		• Network Stations: Manby West TS 115kV • All 115kV circuits from Manby West TS
	Newmarket		• 230kV circuits from Claireville TS to Beaverton TS

FIGURE 3

Illustrative Map of West-Central GTA Area, Zones, and Sub-Zones:

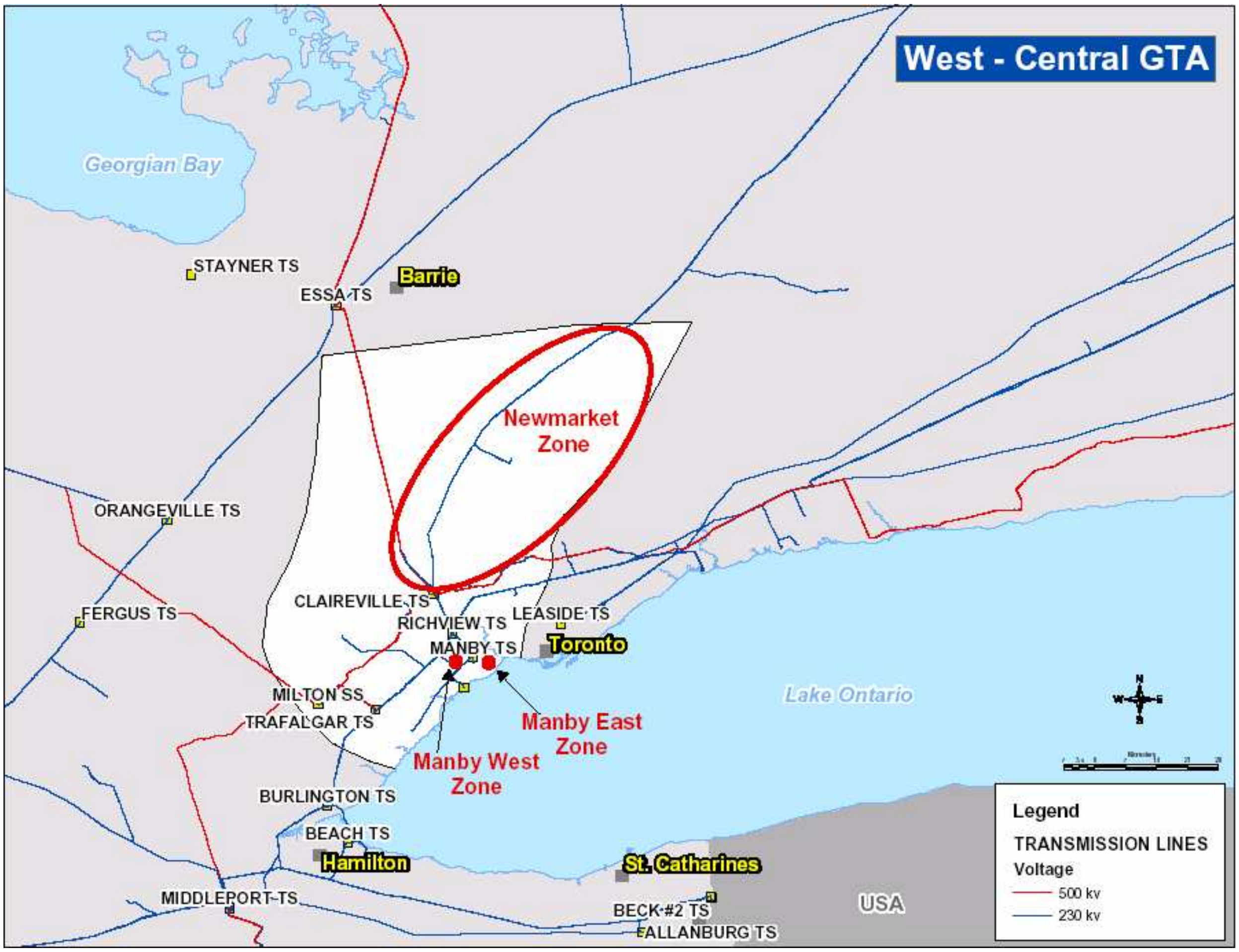


TABLE 4a

Area: East GTA and Eastern Ontario

Cost Impact Matrix:

Area	Zone	Sub-Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
				Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
East GTA and Eastern Ontario			1,500	$150	2,500						
	Cherrywood to Leaside		200	$100	1,500	$200	2,500				
	Leaside		0	$100	1,500	$200	2,500				
	Hearn		600	$150	1200	$650	2,500				
	Chenaux		100	$50	300	$125	700	$425	2,500		
	St Lawrence		200	$150	500	$350	800	$550	2,500		
		Brockville	30	$25	200	$75	400	$125	800	$425	2,500
	Kingston		300	$40	1,000	$90	2,500				
	Belleville		150	$50	400	$100	800	$400	2,500		
	Ottawa		200	$30	1,000	$80	2,500				
		Ottawa 115kV	50	$30	200	$60	500	$90	800	$390	2,500
	St. Isidore		0	$50	500	$100	1,000	$200	2,500		
	Lennox 500 kV		2,000	$250	2,500						
	Other Eastern Ontario		200	$50	400	$250	1,500	$450	2,500		

Note: Prospective Proponents are advised that the Cost Impact Matrix set out above sets out total costs and total capacities (under the headings "Total Cost" and "Max (MW)" respectively) and does not specifically set out incremental costs and incremental capacities. Accordingly, Incremental Transmission Expansion Costs and Capacity Ranges are to be calculated by comparing the various columns against each other. For example, the Incremental Transmission Expansion Cost between "Step 1 Upgrade" and "Step 2 Upgrade", to increase the capacity "Max (MW)" as shown in "Step 2 Upgrade" over the capacity "Max (MW)" as shown in "Step 1 Upgrade", is calculated as the difference between the "Total Cost" shown under the heading "Step 2 Upgrade" and the "Total Cost" shown under the heading "Step 1 Upgrade".

TABLE 4b

Area: East GTA and Eastern Ontario

Definition of East GTA and Eastern Ontario Area, Zones, and Sub-Zones:

AREA	***ZONE***	**SUB-ZONE**	**Definition**
East GTA and Eastern Ontario			• All network stations and circuits defined in the following Zones: – Cherrywood to Leaside Zone – Leaside Zone – Hearn Zone – Chenaux Zone – St. Lawrence Zone – Kingston Zone – Belleville Zone – Ottawa Zone – Lennox 500 kV Zone – St. Isidore Zone – Other Eastern Ontario Zone • 500 kV circuits from Cherrywood TS to Parkway TS • 230 kV circuits from – Cherrywood TS to Parkway TS – Parkway TS to Richview up to Leaside Junction
	Cherrywood to Leaside		• Network Stations: Cherrywood TS • 230kV circuits from Cherrywood TS to Leaside TS
	Leaside		• Network Stations: Leaside TS 115 kV • All 115kV circuits from Leaside TS
	Hearn		• Hearn TS 115kV switchyard
	Chenaux		• Network Stations: Chenaux TS • 230 kV circuits from Chenaux TS to Dobbin TS • 115kV circuits from Chenaux TS
	St. Lawrence		• Network Stations: St. Lawrence TS, Hinchinbrooke SS • 230kV circuits from – St. Lawrence TS to Hinchinbrooke SS – St. Lawrence TS to Hawthorne TS – St. Lawrence TS to Beauharnois up to inter-provincial boundary
		Brockville	• Network Stations: St. Lawrence TS 115kV • All 115 kV circuits from St. Lawrence TS
	Kingston		• Network Stations: Lennox TS 230kV bus • All 230kV circuits from Lennox TS

AREA	*ZONE*	SUB-ZONE	Definition
	Belleville		• Network Stations: Dobbin TS, Port Hope TS, Sidney TS, Cataraqui TS, Frontenac TS • 115kV circuits from – Dobbin TS to Sidney TS – Sidney TS to Cataraqui TS – Cataraqui TS to Frontenac TS (not including B5QK section to Barrett Chute GS
	Ottawa		• Network Stations: Hawthorne TS and Merivale TS • 230kV circuits from – Hawthorne TS to Merivale TS – Merivale TS to Chats Falls
		Ottawa 115 kV	• All 115 kV circuits from Hawthorne TS • All 115 kV circuits from Merivale TS
	St. Isidore		• Network Stations: St. Isidore TS, Longueuil TS • 230kV circuits from – Hawthorne TS to St. Isidore TS to Longueuil TS – St. Isidore TS to Beauharnois GS up to the inter-provincial boundary
	Lennox 500 kV		• All 500 kV circuits from Lennox TS
	Other Eastern Ontario		• All other 115 kV and 230kV stations within East GTA and Eastern Ontario Area

FIGURE 4

Illustrative Map of East GTA and Eastern Ontario Area, Zones, and Sub-Zones:

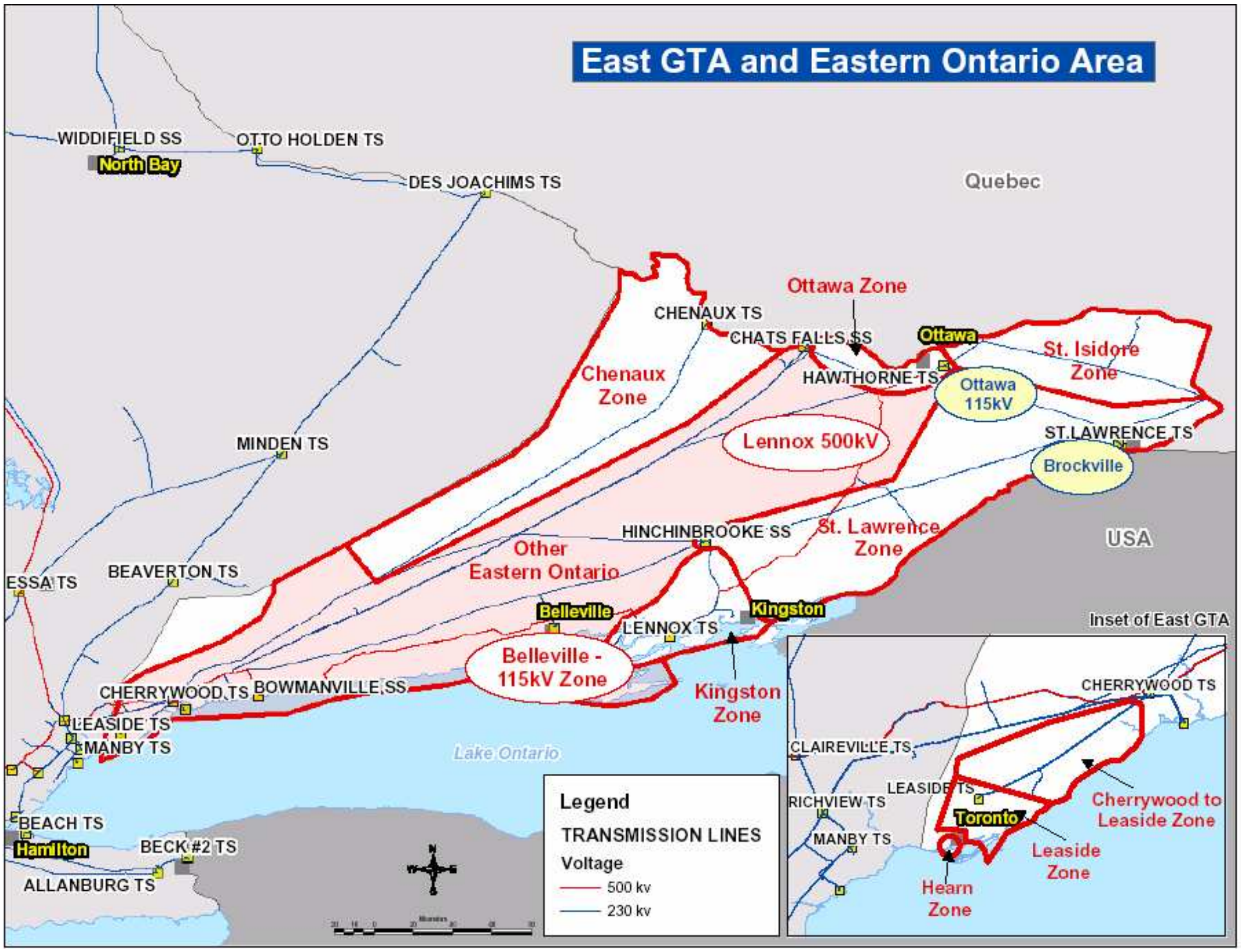


TABLE 5a

Area: Simcoe to Deep River

Cost Impact Matrix:

Area	Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
			Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
Simcoe to Deep River		500	$50	1,000	$150	1,500	$250	2,500		
	Barrie	200	$50	400	$100	800	$400	2,500		
	Deep River	50	$25	150	$125	400	$425	2,500		

Note: Prospective Proponents are advised that the Cost Impact Matrix set out above sets out total costs and total capacities (under the headings "Total Cost" and "Max (MW)" respectively) and does not specifically set out incremental costs and incremental capacities. Accordingly, Incremental Transmission Expansion Costs and Capacity Ranges are to be calculated by comparing the various columns against each other. For example, the Incremental Transmission Expansion Cost between "Step 1 Upgrade" and "Step 2 Upgrade", to increase the capacity "Max (MW)" as shown in "Step 2 Upgrade" over the capacity "Max (MW)" as shown in "Step 1 Upgrade", is calculated as the difference between the "Total Cost" shown under the heading "Step 2 Upgrade" and the "Total Cost" shown under the heading "Step 1 Upgrade".

TABLE 5b

Area: Simcoe to Deep River

Definition of Simcoe to Chalk River Area, Zones, and Sub-Zones:

AREA	*ZONE*	SUB-ZONE	Definition
Simcoe to Deep River			• Network Stations: Essa TS, Beaverton TS, Minden SS, Des Joachim TS • 230kV circuits from – Essa TS to Parry Sound TS – Essa TS to Minden SS – Beaverton TS to Minden SS – Minden SS to Des Joachims SS • All 115kV circuits defined in Barrie Zone • All 115kV circuits defined in Deep River Zone
	Barrie		• Network Stations: Essa TS 115kV • All 115kV circuits connected from Essa TS
	Deep River		• Network Stations: Des Joachim TS 115kV • All 115kV circuits connected from Des Joachim TS

FIGURE 5

Illustrative Map of Simcoe to Deep River Area, Zones, and Sub-Zones:

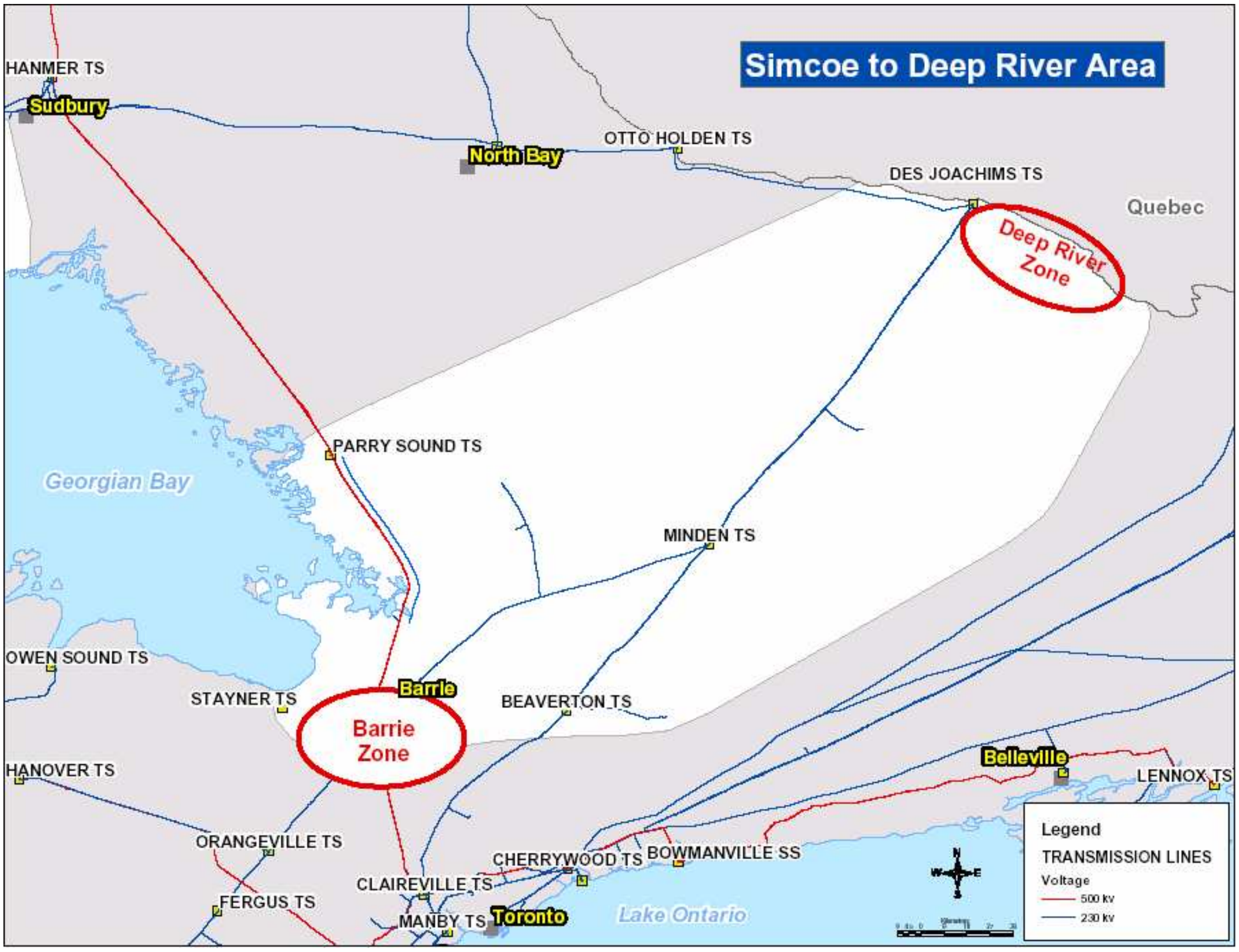


TABLE 6a

Area: North of Barrie

Cost Impact Matrix:

Area	Zone	Sub-Zone	Max without upgrades (MW)	Step 1 Upgrade		Step 2 Upgrade		Step 3 Upgrade		Step 4 Upgrade	
				Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)	Total Cost (M$)	Max (MW)
North of Barrie			500	$60	1,000	$460	2,000	$660	2,500		
	North of Sudbury		0	$250	1,500	$310	2,000	$560	2,500		
		North of Timmins	0	$200	1,500	$260	2,000	$460	2,500		
	East of Sudbury		100	$25	200	$75	400	$125	800	$425	2,500
	Sudbury to Marathon		200	$100	1,000	$200	2,000	$300	2,500		
		Mississagi to Marathon	300	$100	1,000	$200	2,000	$300	2,500		
	Northwest		500	$700	1,500	$1400	2,500				
		Thunder Bay	400	$50	1,000	$100	1,500	$200	2,000	$300	2,500
		Atikokan	250	$100	1,000	$200	1,500	$300	2,000	$400	2,500
		Other Northwest	100	$50	500	$200	1,500	$300	2,000	$400	2,500

Note: Prospective Proponents are advised that the Cost Impact Matrix set out above sets out total costs and total capacities (under the headings "Total Cost" and "Max (MW)" respectively) and does not specifically set out incremental costs and incremental capacities. Accordingly, Incremental Transmission Expansion Costs and Capacity Ranges are to be calculated by comparing the various columns against each other. For example, the Incremental Transmission Expansion Cost between "Step 1 Upgrade" and "Step 2 Upgrade", to increase the capacity "Max (MW)" as shown in "Step 2 Upgrade" over the capacity "Max (MW)" as shown in "Step 1 Upgrade", is calculated as the difference between the "Total Cost" shown under the heading "Step 2 Upgrade" and the "Total Cost" shown under the heading "Step 1 Upgrade".

TABLE 6b

Area: North of Barrie

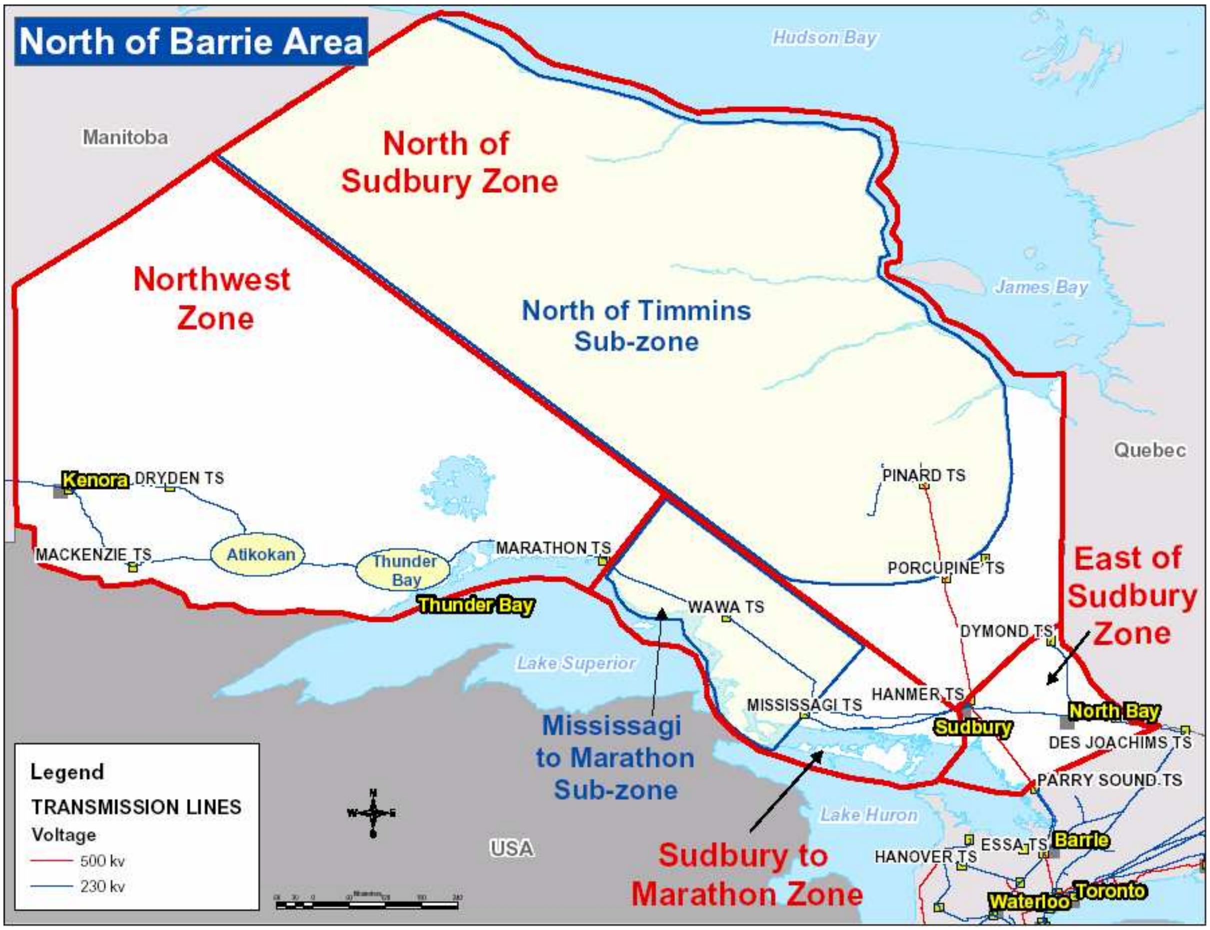
Definition of North of Barrie Area, Zones, and Sub-Zones:

AREA	*ZONE*	SUB-ZONE	Definition
North of Barrie			• All network stations and circuits defined in the following Zones: – North of Sudbury Zone – East of Sudbury Zone – West of Sudbury Zone
	North of Sudbury		• Network stations: Porcupine TS, Kirkland Lake TS, Ansonville TS • 500 kV circuit from Hanmer TS to Porcupine TS • 230kV circuits from – Porcupine TS to Ansonville TS • 115kV circuits from – Kirkland Lake TS to Ansonville TS – All network stations and circuits defined in the North of Timmins Sub-Zone
		North of Timmins	• Network stations: Pinard TS, Kapuskasing TS • 500 kV circuits from Porcupine TS to Pinard TS • 230kV circuits from – Pinard TS to Otter Rapid GS, Harmon GS and Kipling GS – Little Long GS to Spruce Falls TS • 115kV circuits from – Ansonville TS to Hunta SS – Porcupine and Timmins TS to Hunta SS – Hunta SS to Hearst TS – Hunta SS to Abitibi Canyon TS – 115 kV circuits north of Abitibi Canyon TS to Attawapiskat TS
	East of Sudbury		• Network stations: Martindale TS, Widdifield SS, Otto Holden TS and Dymond TS • 230kV circuits from – Martindale TS to Widdifield SS – Widdifield SS to Otto Holden TS – Widdifield SS to Dymond TS – Otto Holden TS to Des Joachims TS • 115kV circuits from – Martindale TS to Otto Holden TS – Crystal Falls SS to Dymond TS – Dymond TS to Kirkland Lake TS • 25 Hz system connected to Martindale TS
	Sudbury to Marathon		• Network stations: Algoma TS, Mississagi TS • 230kV circuits from – Hanmer TS to Mississagi TS – Martindale TS to Algoma TS

AREA	*ZONE*	SUB-ZONE	Definition
			– Algoma TS to Mississagi TS • 115kV circuits from – Martindale TS to Algoma TS – Algoma TS to Elliot Lake TS – Algoma TS to Ryner GS • All network stations and circuits defined in Mississagi to Marathon Sub-Zone
		Mississagi to Marathon	• Network stations: Wawa TS, Third Line TS • 230kV circuits from – Mississagi TS to Wawa TS – Wawa TS to Marathon TS – Mississagi TS to Third Line TS – Wawa TS to Third Line (under construction) • All 115 kV circuits in Great Lakes Power and 115 kV line to Chapleau TS
	Northwest		• All 230 kV and 115 kV stations and circuits west of and including Marathon TS
		Thunder Bay	• Network stations: Thunder Bay GS • 115 kV line from Thunder Bay GS to Birch TS
		Atikokan	• Network stations: Atikokan GS • 230 kV line from Mackenzie TS to Atikokan GS
		Other Northwest	• All other 230 kV and 115 kV stations or circuits in the Northwest Sub-Zone not defined by the Atikokan GS and Thunder Bay GS Sub-Zone

FIGURE 6

Illustrative Map of North of Barrie Area, Zones, and Sub-Zones:



APPENDIX R: SPECIFIED FORECAST INDEX

The Specified Forecast Index is as follows:

Period	Index (Per Annum)
2004	1.8%
2005 to 2030, inclusive	2.0%

Note: For purposes of the 2,500 MW RFP, the Specified Forecast Index shall be applied from and after December 15, 2004, and shall be pro-rated for the 2004 period.