EVIDENCE IN SUPPORT OF THE PROCUREMENT PROCESS

1.0 INTRODUCTION

The purpose of this exhibit is to address the Procurement Process (the "Process") described in Exhibit B-2-1. Once approved, the Process will allow the OPA to enter into procurement contracts to acquire Conservation and supply resources that will not be procured under the authority of a government directive.

2.0 OVERVIEW

Q. How did the OPA develop the Procurement Process?

A. Three activities can be identified as inputs to developing the OPA's Process. First, after its inception and prior to launching any procurements, the OPA held a broad stakeholder consultation on July 26 to 29, 2005 to discuss past (i.e., procurements launched by the government of Ontario in 2004) and future procurements (to be launched by the OPA). The OPA completed and published a report, titled "Interim Report: Summary of What We Heard in OPA's Generation Procurement Stakeholder Sessions July 26 to 29, 2005" summarizing the comments heard (see Exhibit F-1-2, Attachment 4). These comments were used by a consultant, London Economics Inc. (retained by the OPA) in preparing reports to compare procurement processes of other jurisdictions and to recommend procurement processes for OPA's consideration. As a result, two reports, (i) "Analysis of Procurement Processes for Generation Capacity, Renewables, Demand Response, and Energy Efficiency"; and (ii) "Stakeholder Consultations Regarding Centralized Power Procurement Processes in Ontario", were completed by the consultant in August and September 2005, respectively, and released publicly by the OPA.

Second, the OPA developed and launched several procurements, resulting from government directives. These procurements provided actual 'hands on' experience for the OPA to develop the Process. Examples of supply procurements are:

- Combined Heat and Power (“CHP”) RFP;
- Greater Toronto Area (“GTA”) West Trafalgar RFP;
- Goreway Station project;
- Portlands Energy Centre project; and
- Ontario Power Generation hydroelectric supply.

Examples of Conservation procurements are:

- York Demand Response (“York DR”) RFP;
- RFP for the High Performance Commercial New Construction Program ; and
- Building Owners and Managers Association (“BOMA”) project.

Third, in the early development phase of the IPSP for consultation purposes, the OPA developed and published several discussion papers, including one on procurement, entitled “Discussion Paper 8: Procurement Options” found at Exhibit C-12-1. Stakeholder comments (Exhibit C-12-2) to this discussion paper were considered by the OPA prior to developing the Process.

In summary, the OPA used all of the information outlined above to develop and finalize the Process that complies with all applicable statutory obligations of the Act and O. Reg. 424/04 and 426/04.

Q. What did the OPA learn through its various stakeholder consultations?

A. The main lesson learned by the OPA was the need for appropriate selection of a procurement type (i.e., competitive procurement, standard offer procurement, non-competitive procurement) to meet the resource needs identified by the IPSP and address the needs of proponents best able to develop these resources. In addition, it is important that the appropriate design within each procurement type is developed and implemented to ensure optimal results. For competitive procurements, the main point conveyed was the desire to have discipline and robustness in the procurement, resulting in a high quality and timely process and result. For example, where a specific need is identified in the IPSP, only similar projects/programs that meet specified criteria should participate in the procurement (i.e., “apples to apples” competition). In a circumstance where the need is not specific, a wider range of projects/programs could participate in the procurement. Furthermore, the requirements and evaluation criteria within a procurement should ensure that only qualified proponents participate and submit high-quality proposals while providing mechanisms that level the playing field between different projects/programs.

Q. What did the OPA learn from its own procurement experience?

Supply Procurements

A. The Ministry of Energy ("MOE") carried out three separate competitive supply procurements: the 2,500 MW RFP, the Renewable Energy Supply ("RES") I RFP, and the RES II RFP. The OPA, since its inception, has conducted the following competitive supply procurements:

- GTA West Trafalgar RFP (Result: TransCanada's Halton Hills Generating Station, 600 MW)
- CHP I RFP (Result: seven projects with a total capacity of 414 MW)

Since filing the original evidence, the OPA has launched several other procurement processes:

- CHP II RFP (launched December 2007)
- Northern York Region RFQ and RFP (RFQ closed March 2008; RFP launched June 2008)
- RES III RFEI and RFP (RFEI closed December 2007; RFP launched June 2008)
- CHP III RFEI and RFP (RFEI closed July 2008; RFP to be launched Fall 2008)
- Southwest GTA RFQ (to be launched Fall 2008).

The main lessons that the OPA learned from its supply procurements are as follows:

- Homogenous competitions are preferable, meaning that having similar projects compete is better than having a variety of project types (i.e., supply and Conservation, or renewables and gas-fired generation) competing. With a variety of competing projects, the procurement becomes more complex to fairly apply all requirements and criteria and to design levelized requirements and evaluation criteria, including pricing, to ensure a fair comparison. This often leads to the "lowest common denominator" solution, which, in turn, can lead to projects being included in the competition that are not well qualified and likely should not have been eligible to participate in the competition.

- Targeted procurements that outline clear requirements for the specific resource will result in a fair procurement with a good result. Where a very specific need has been identified, the procurement should outline those specific requirements. This ensures that all participating projects can provide the needed resource.
- The procurement, in particular the requirements and evaluation criteria, should lead to a robust competition with qualified proponents. The OPA will have to use its knowledge and expertise at setting the requirements and evaluation criteria at a level that ensures those proponents that can deliver the project participate and compete on an equal footing. Ensuring quality proponents and quality projects can be further reinforced through the rated evaluation criteria. In summary, the OPA has to retain the flexibility to set the requirements and criteria for each procurement on an individual basis to ensure a robust competition.
- The OPA has to provide sufficient channels to allow proponents to communicate with the OPA to provide input and ask questions. All proponents must have equal and fair access to these channels. The OPA and proponents benefit from mutual exchange and open dialogue on issues, which will ultimately lead to a more efficient design and execution of the procurement.
- The OPA needs to remain in touch with the industry and current trends and developments to ensure that the requirements and evaluation criteria reflect the needs and abilities of proponents qualified to deliver the required resource. This will ensure that the competition is open to all viable and qualified proponents to deliver a resource.
- Many multi-project procurement processes will result in attrition of some selected projects/programs. Being a successful project/program in a procurement process does not guarantee the successful development of the project/program. There are several risks that projects/programs face after contract award, especially with respect to regulatory processes for obtaining all necessary approvals or other business reasons, such as financing or labour/equipment issues. Ensuring that only qualified proponents participate in a procurement process and including an evaluation of feasibility-related criteria are some examples of achieving greater certainty that a selected project/program will deliver the intended result on time. Setting the right level of security under the procurement contract is another way to ensure that proponents fulfill the contractual obligations. Another mechanism available to the OPA is to include a "margin for error" when setting procurement targets (i.e., procuring more projects than needed). Under those circumstances, attrition of projects/programs does not trigger the OPA to commence another

procurement to obtain the “lost” capacity. Furthermore, for procurements with a sole contract award, an option might be for the OPA to continue to negotiate with another party with the intent of moving that project development forward in case the selected project does not achieve commercial operation.

The OPA has also developed a standard offer procurement, the Renewable Energy Standard Offer Program (“RESOP”). The OPA is currently developing other standard offer programs, including the Clean Energy Standard Offer Program (“CESOP”); the Northern Hydroelectric Initiative (“NHI”) for small, transmission-connected waterpower projects in northern Ontario, and an initiative to procure net electricity output from Energy From Waste ("EFW") Pilot or Demonstration Projects ("PDPs").

The main lessons that the OPA learned from its standard offer procurements are as follows:

- Contract milestones are required for standard offer program contracts – for contracts that have already been executed, there is a great deal of uncertainty whether a project will proceed and be developed. Attrition of projects is expected and more likely than with contracts executed resulting from competitive procurements.
- Uncertainty of project development creates frustration by other proponents who did not get a connection queue position.
- Challenges exist in developing standard offer program projects (that are not in the control of the OPA), such as connections, zoning, environmental and municipal approvals
- There is a wide discrepancy in proponent capability.
- Larger projects are being divided to meet the RESOP criterion of a 10 MW limit.
- Considering the high uptake in the RESOP to date, standard offer programs appear to be a viable method to develop generation projects.

Conservation Procurements

The OPA has conducted the following competitive Conservation procurements:

- York DR RFP (Result: Rodan Energy, 3 MW);
- RFP for the High Performance Commercial New Construction Program;

- RFP for the Great Refrigerator Roundup Program; and
- RFP for Aggregation Services for Residential and Small Commercial Demand Response Program

Since filing this evidence, the OPA has launched several other procurement processes:

- RFP for Multifamily Buildings Program Manager – Private Buildings Sector
- RFP for Multifamily Buildings Program Manager – Assisted and Social Housing; and Sector
- RFP for "2008 Summer Sweepstakes".

The main lessons that the OPA learned from its Conservation procurements are as follows:

- The Conservation supply chain is still developing and it is therefore difficult to acquire resources through a competitive procurement. The New Construction Program RFP yielded no compliant bids for the role of Program Manager. As a result, the OPA sole sourced the project. Procurements for Conservation resources need to be simple and, where possible, barriers to participation have to be mitigated. There is often a need to narrow the scope of the procurements, meaning that rather than seek Program Managers who will manage all elements of a project, it is sometimes preferable to divide the project into manageable pieces that allow proponents to bid on their established strengths.

The OPA recognizes the need for capability building as a priority to establish the Conservation delivery network and ensure the use of competitive procurements. The OPA has made capability building a priority in its Conservation plans.

Q. As regulated by Section 1 of O. Reg. 426/04, how will the OPA assess the likelihood of investment occurring on its own and the capabilities of the IESO-administered markets to facilitate investment?

A. Before commencing procurements to acquire the resources that will not be procured under the authority of a government directive, the OPA will have to determine whether these supply resources can be met through alternative means. The alternative means of meeting resource requirements are:

1. Whether these resources are likely to be developed without revenue guarantee or cost recovery mechanisms through contracts with other government agencies and/or regulated cost recovery through the OEB; and,
2. Whether IESO-administered markets are likely to lead to the development of the required supply resources.

The assessment will include studies, which can be conducted both by the OPA or independent experts. In addition to these studies, the OPA will consult with interested parties, relevant agencies and subject-matter experts in the field. At a stakeholder session on March 6, 2008, the OPA presented some potential approaches to assessing the capabilities of the IESO-administered markets. The OPA will continue the dialogue with stakeholders on this issue.

When assessing potential generation being developed independent of an OPA procurement contract, the OPA will not take into account the first 150 MW of renewable generation resources developed through a voluntary green market prior to 2012. Any renewable resources developed prior to that date, to a maximum of 150 MW, will not be taken into account by the OPA going forward when applying this factor.

Q. What factors will the OPA consider in determining the advisability of conducting procurement processes resulting in the execution of procurement contracts?

A. In accordance with O. Reg. 424/04 and O. Reg. 426/04, the two main factors that the OPA will assess are:

- Is the resource identified in the IPSP still required?
- Will the resource be developed independent of an OPA procurement contract?

The OPA will assess the progress of the implementation of the identified projects/programs in the IPSP, including review of any completed procurements. In the event that a resource is no longer required (for example, if another procurement provided results that also meet this identified need), the OPA will not conduct a procurement.

Regarding the second factor, it will be addressed as part of the assessment of the likelihood that resources will be developed independently of the OPA as discussed above.

Q. In accordance with O. Reg. 426/04, what are the extraordinary circumstances under which the OPA could proceed with a procurement without considering the factors?

A. The OPA would consult with the IESO, as well as other interested parties, as applicable, concerning these extraordinary circumstances. Circumstances that justify proceeding without considering the factors are those that have an urgent impact on reliability.

3.0 PROCUREMENT PRINCIPLES

Q. How does the Procurement Process reinforce environmental and sustainability elements from the IPSP? How does the OPA ensure that the environmental factors taken into account in the IPSP are actually reflected?

A. Environmental impacts and sustainability, as per the Act, Regulations and the Directive, have been addressed in the IPSP. The Process will ensure that the environmental and sustainability elements of the IPSP are reflected in the procurement by ensuring that the resources identified by the IPSP will be procured.

Q. How will the OPA meet the procurement principles listed in O. Reg. 426/04, namely (1) that the procurement process and selection criteria are fairly stated and where possible are open to a broad range of bidders; (2) the procurement process being a competitive one to the greatest extent possible; (3) there being no conflicts of interest or no unfair advantage; and (4) the procurement process not having an adverse impact on project development independent of the OPA?

A. The OPA's Process will meet the principles outlined in the regulation, as follows:

(1) *Procurement Process and selection criteria being fairly stated, open to a broad range of bidders:* all objectives, requirements, and evaluation criteria will be disclosed in the procurement documents, which will be applied and executed in an unbiased, fair and consistent manner.

For competitive procurements and standard offer procurements, the OPA will ensure that the procurements are open to a broad range of proponents by mitigating barriers to entry where needed and appropriate given the nature of the resource and the type of proponents. The OPA will endeavour to strike an acceptable balance between setting appropriate requirements and evaluation criteria and permitting a variety of capable projects/programs to participate.

For non-competitive procurements, these requirements are met by the OPA applying the Process in a fair and consistent manner. Only if the criteria in the Process are met, would a non-competitive procurement be launched. The OPA would communicate its intention and rationale for conducting a non-competitive procurement.

(2) *Preference for competitive procurements*: The OPA's default procurement type is a competitive procurement. The selection of another procurement type is based upon the conditions and circumstances outlined in the Process.

(3) *No conflicts of interest nor unfair advantage*: The procurement documents will have specific provisions to ensure that no conflicts of interest nor unfair advantages exist. Where possible, the OPA will rely on an independent evaluation team to review the proposals. An independent fairness advisor may oversee the procurement, including the evaluation and selection process.

(4) *The procurement process not having an adverse impact on project development independent of the OPA*: The OPA will undertake that its procurements will not have an adverse impact on developments taking place independent of OPA procurements. Furthermore, through its initial assessments, the OPA will ensure that where new investments/developments have taken place or likely to take place, procurements will not duplicate those efforts.

Q. How will the OPA meet the procurement principles listed in OEB Filing Guidelines, namely (1) be fair and transparent; (2) be designed to limit barriers to participation; (3) be as simple as possible; (4) restrict the use of confidentiality provisions; and (5) make provisions for the results to be disclosed?

A. (1) *Fair and transparent*:

As per the Process, the OPA is committed to fairness and transparency. For its competitive procurements, fairness and transparency are incorporated into the process as follows:

<u>Fairness</u>

- procurements are open to a broad range of proponents capable of meeting the identified resource requirement. Where barriers to entry exist, the procurement will aim to mitigate or limit these barriers to ensure broad participation;
- be responsive to the needs of proponents and the power system;
- the objective, requirements, evaluation criteria and selection process will be followed and applied in a consistent and unbiased manner; and
- there will be no conflicts of interest or unfair advantage in the procurement process.

<u>Transparency</u>

- the objective, requirements, evaluation criteria and selection process will be disclosed in the procurement documents[1], as applicable;
- engage interested parties and proponents throughout the procurement;
- provide easy and timely access to information to all proponents; and
- disclose results while safeguarding commercially sensitive information.

(2) *Limit barriers to participation*: procurements will be open to a broad range of proponents capable of meeting the identified resource requirement. Where barriers to

[1] Procurement documents refer to any documents and materials released in association with a procurement. For example, Request for Information (RFI), Request for Expressions of Interest (RFEI), Request for Qualifications (RFQ), Request for Proposals (RFP), Call for Tender (CFT) and program rules are all considered procurement documents.

entry exist, the procurement will aim to mitigate these barriers to ensure open and broad participation.

(3) *Be as simple as possible*: In the interest of having a procurement that is open to a large number of proponents, the OPA will ensure that the terms and conditions, including any qualification process, requirements and evaluation criteria, are tailored for each particular procurement. Through information gained from stakeholder activities, the OPA will design a procurement that is not overly complicated and does not limit participation. However, at the same time, the OPA will also need to ensure that the procurements target those proponents capable of delivering the needed resources.

(4) *Restrict the use of confidentiality provisions*: The OPA will restrict the use of confidentiality provisions to cover information, which is (a) internal to the proponent; or (b) could prejudice the competitive position of a proponent; and (c) is deemed to be commercially sensitive. Commercially sensitive information includes, but is not limited to:

- Detailed technical data (above what is required for EA process) with concerning:
    1. Data and methodologies
    2. Wind data/studies
    3. Fuel data/studies
    4. Energy estimates
- Fuel Supply arrangements
- Site/Project layout
- Equipment Suppliers
- Engineering, Procurement and Construction (“EPC”) Arrangements
- Off-take Agreements
- Land lease/Site control arrangements/agreements
- Site suitability studies
- Cost, price, and economic information with respect to the project/program
- Financing information:
    1. Commitment letters (debt, equity and other)

        2. Financing Plan

- Interconnection Studies:
    1. For municipal services
    2. For fuel supply
- Connection Costs
- Milestones
- Proposal Clarifications

(5) *Disclosing results*: Upon completion of any procurement, the OPA shall make appropriate announcements regarding the results. For competitive procurements and standard offer procurements, summary results will be disclosed. These results will typically include the number of executed procurement contracts, the identity of the contract counterparties, a brief description of these projects/programs, the total amount of capacity and/or energy resulting from the procurement (e.g., typically measured in MW or MWh), and average pricing. Average pricing will only be released if there are sufficient numbers of projects/programs (generally more than three). For non-competitive procurements, the announced results will include the identity of the contract counterparty, a brief description of the project/program, and the total amount of capacity and/or energy resulting from the procurement. Due to the lack of proponents in a non-competitive procurement or in a single contract award for competitive procurements, and the commercial sensitivity of the information, pricing will not be disclosed in these situations.

Q. How will the OPA ensure simpler procurements for supply from alternative and renewable supply resources, as required by Section 25.31 (2) of the Act?

A. Each procurement is specifically tailored to reflect the targeted projects/programs. In particular for renewable procurements, the OPA may use a standard offer procurement, which in itself is a simpler procurement type. Standardizing the program rules and the procurement contract including price helps remove barriers to investment in alternative and renewable supply resources by helping proponents manage project/program development efforts, attain financing, and reduce the transaction costs. These procurement elements help mitigate risks to developers of alternative and renewable supply resources.

Furthermore, where competitive procurements are executed, the requirements and evaluation criteria are tailored to best capture relevant and key elements of a project/program. This means that the requirements will be tailored to ensure that the procurement is directed at those proponents qualified and capable of delivering the project/program. Where circumstances allow for it (e.g., for procurements of renewable or alternative energy or Conservation programs), the procurement can be simplified or tailored to better capture the capability and resources of the prospective proponents. For example, the requirements and evaluation criteria can be simplified; thresholds or financial commitments (such as proposal security) can be lowered to more appropriate levels. Simplification of the procurement is generally done to ensure that a sufficient number of capable and qualified proponents participate, resulting in a robust competition.

4.0 PROCUREMENT PROCESS

Q. Can the OPA switch procurement type after a procurement has commenced?

A. Yes, if the OPA initiates a certain procurement type and through the process the OPA gains more information that would make another type a more appropriate procurement mechanism, the OPA can change types, following the criteria outlined in the Process.

Q. What is the purpose of a registration or pre-qualification process?

A. The registration step ensures that only serious proponents who are committed to the procurement participate in the procurement process. This results in greater efficiency of the process, especially regarding communication with prospective proponents. The pre-qualification phase also results in a more efficient process as the OPA will pre-screen the types of proponents and projects/programs for participation. Narrowing the number of proponents to those that are capable of delivering the needed resource will ensure that the procurement is focused and customised, resulting in a more cost effective and efficient process.

Q. What are the risks to executing a non-competitive procurement?

A. The main risk to a non-competitive procurement is the potential for a high procurement contract price. This risk exists because no competing projects/programs exist as alternatives to the resource that is to be procured through a non-competitive procurement.

Q. How will the OPA address and/or mitigate the risks associated with non-competitive procurement?

A. The OPA can address and potentially mitigate the risk of a high procurement contract price by employing some of the following means to ensure that certain controls are in place to ensure value for money:

- Open-book pricing whereby the proponent reveals all of the costs related to the project/program;
- Benchmark pricing, which sets a base amount to commence negotiations;
- Pricing caps set a top limit on the price, which is not to be exceeded;
- Independent or third party arbitration; and
- Independent expert opinion on the negotiated price (whether it reflects market pricing and provides “value for money”).

Q. How does the OPA approve and document its decision to undertake a non-competitive procurement?

A. Where a specific project/program is identified in the near-term plan in the IPSP (which leads to a non-competitive procurement), the evidence will serve as documentation. After applying the Process, the OPA will need to seek approval from the OPA Board of Directors (“BoD”) before commencing a non-competitive procurement. The OPA will document its decision and release information regarding the decision and rationale.

Q. What method will the OPA use to establish pricing for a standard offer procurement process?

A. The OPA will first look to any precedents or pricing levels that have been established as a result of competitive procurement processes. These pricing levels may be experience gained in Ontario, or, if not available in Ontario, from other relevant jurisdictions. The OPA will also quantify the price that developers will require to make the necessary investment to develop the project or program with an appropriate rate of return. The method includes a survey of any existing standard offer procurements and their pricing. To the extent that these procurements exist, and are applicable to the respective OPA standard offer procurement, they can help establish pricing. Furthermore, the accuracy of pricing can be assessed by the level of participation. The OPA will retain the flexibility to adjust pricing to react to any changes in market conditions as needed. The methodology will be finalized in consultation with an independent expert.

Q. How will the OPA avoid "hoarding" of standard offer procurement contracts by one or very few successful projects or programs?

A. To the extent that "hoarding" of standard offer procurement contracts becomes a problem, the OPA may develop rules to prevent such a result. For example, these rules may explicitly define how many procurement contracts and/or total quantity any one proponent or related entity may have.

Q. What are the risks to executing a standard offer procurement process?

A. Risks to executing a standard offer procurement include the possibility that the pricing may not be correct. If the contract price is set too low, either the procurement will have few proponents, or contract defaults will occur prior to the project or program becoming operational. If the contract price is set too high, electricity rate payers will essentially overpay for these investments, compared to what could potentially result from a competitive procurement.

Q. If risks exist, how are the risks associated with a standard offer procurement addressed and/or mitigated?

A. With respect to the risks identified above, the OPA could mitigate these risks by creating rules to adjust contract pricing under specific circumstances and staging procurements by setting an aggregate maximum quantity for designated locations in Ontario. The aggregate maximum quantity for designated locations can be revised over time as transmission and distribution are upgraded and expanded.

Q. What are the risks to executing a competitive procurement relative to other procurement options?

A. If a competitive procurement is not well designed, the result may not be optimal (i.e., the winning project/program may not be the best option to meet the needs identified in the IPSP). The OPA, in its procurement, evaluates a variety of important factors that affect the deliverability of the resources. However, despite the best knowledge and understanding of the proponents and the projects/programs, it may be difficult to guard against non-optimal results, including successful projects/programs not getting developed. Another risk to a competitive procurement is pricing. If the prices of the selected project/program are too low, project development could be jeopardized. Prices that are too high could mean that ratepayers are potentially overpaying for the procured resource.

Q. If risks exist, how are the risks associated with a competitive procurement addressed and/or mitigated?

A. Providing multiple opportunities to engage stakeholders and establish a constructive dialogue is crucial to ensuring that a competitive procurement is well designed. Furthermore, consultation and cooperation with other organizations (e.g., IESO, Hydro One, LDCs, etc.) will also minimize those risks. With respect to pricing, it is important that the OPA understands the variables that affect the economics of a project/program to judge whether or not the pricing is appropriate. Completed procurements will also provide the OPA with a benchmark to assess the economics of projects and programs. Depending on how a competitive procurement is designed, the OPA may have the ability to negotiate some or all of the pricing. In addition, all procurement contracts need to be approved by the OPA BoD which will provide an additional level of accountability.

Q. How will the OPA monitor and evaluate the efficacy of the Procurement Process?

A. The OPA will use stakeholder consultation to evaluate the efficacy of the Process. Stakeholder consultation will occur on both broad-based and target-based levels. Broad-based consultation will address general topics relating to OPA procurements. Target-based consultations will necessarily be more focused and apply to specific OPA procurements (e.g., specific competitive and standard offer procurements). During these consultations, stakeholders will have a chance to provide comments on the efficacy of the particular OPA procurement. The efficacy of a procurement process can be measured by, among other matters, assessing how robust the process was (e.g., number of proponents, capability of proponents and quality of proposals), whether the result closely matched the OPA's need and whether the result was obtained in an efficient manner.

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Stakeholder consultations regarding centralized power procurement processes in Ontario

Report prepared for Ontario Power Authority by London Economics International LLC

14 September 2005

London Economics International LLC (LEI) was engaged by the Ontario Power Authority (OPA) to observe a stakeholder consultation process related to contracting initiatives to obtain new electric generating resources in Ontario. LEI's brief was to serve as a neutral observer, to synthesize stakeholder comments, and to provide appropriate recommendations. Although all previous contracting processes reviewed took place prior to the creation of OPA, the experience provides a foundation from which OPA can learn and build. Areas in which the process may be enhanced include increasing communication, providing greater certainty as to response dates, hosting separate processes depending upon the nature of the developer (large scale, cogen, renewable, etc.), adding a possible prequalification round, and adjustments to financial security provisions. A separate paper by LEI reviews practices across North America with regards to contracting, standard offers, demand response, and renewables; we refer to findings of this companion paper where relevant to our recommendations arising from the stakeholdering exercise.

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1 Executive summary

1.1 The Stakeholder Review Process

Beginning in 2004, the province of Ontario has held four Requests for Proposals (RFPs) to encourage the development of new clean (CES), renewable (RES), combined heat and power (CHP) generation, and the implementation of conservation and demand management (CDM) programs.

In an effort to improve the process for future procurements, the Ontario Power Authority (OPA) initiated a stakeholder consultation to elicit comments about the previous RFPs and recommendations for upcoming processes. In response, OPA received 54 submissions, and viewed more than 50 presentations from interested parties including developers of conventional and renewables facilities, CDM project proponents, service providers, end-users of electricity and natural gas, industry groups, government agencies, and public interest groups.

1.2 Feedback from Stakeholders

In their submissions and presentations, stakeholders addressed a wide range of issues with the previous Ontario processes. Key areas of concern included: the financial burden of bidding (including the bid security); the way that communication was handled during the RFPs; the length of the process; the flexibility of the contract language; and the criteria used for qualifying potential bidders and evaluating project submissions.

Many stakeholders with interests in specific types of facilities also commented about issues related to specific product types.

CES - For stakeholders involved in the CES process, key concerns included: making the contract more compatible with the development of a forward market; ensuring that procurements do not favour less-prepared bidders; the treatment of a number of CES-specific issues in the contract; and concerns about the impact of new generation on Ontario’s gas infrastructure and supply.

CHP - For stakeholders involved in the CHP process, key concerns included: the flexibility of the contract with respect to the unique nature of CHP projects; the evaluation criteria for CHP projects; the timing of procurement processes for CHP; and the complexity of the RFP processes.

RES - For stakeholders involved in the RES process, key concerns included: what types of projects should qualify as renewable; the complexity and scale of the processes, which were a barrier to small bidders and projects; and issues about transmission.

CDM - For stakeholders involved in CDM projects, key concerns included: whether avoided generation would be treated symmetrically with new generation; the mechanisms that would be put in place for measuring and verifying CDM projects; issues surrounding the role of local distribution companies in CDM, questions about how the contract should treat CDM projects; and the timing of the processes with respect to CDM projects.

1.3 Recommendations for Future Processes

- **Prequalification:** Prequalification using objective criteria ensures that resources are not wasted by either bidders or evaluators, and should be implemented in the future.

- **Collusion:** The collusion requirements in future processes should be simplified, with bidders required simply to state that they have not colluded with any other bidder, and will abide by all applicable laws. Collusion requirements should not unduly restrict subcontractors from working with multiple bidders.

- **Fixed response time:** OPA should specify the length of time they will take to respond to the procurement submission, and could likely put into place a response period of no longer than 30 days.

- **Financing:** Aside from prequalification, process should not emphasize financing. After selection, bidders should be allowed a maximum time to secure financing before being disqualified. Lenders do not in any case make firm commitments to bidders prior to a bid being accepted.

- **Security:** The amount of bid security should vary with the project size and phase of development.

- **Deemed dispatch:** The contracts for differences format should be refined by refining or eliminating deemed dispatch, allowing the proponents to propose the parameters that they would be expected to meet, and requiring audits to identify any instances in which performance deviated. Contract terms should be compatible with gas markets.

1.3.1 cogeneration specific recommendations

- **Contracting:** OPA should adopt a simplified approach where proponents specify the amount of energy and the required price (categorized by peak, offpeak and seasonally). OPA would not bear fuel risk (except to allow delivery curtailment if the price exceeded a threshold).

- **Use of "Swiss challenge" approach:** In the case of unsolicited proposals, OPA should adopt the "Swiss challenge" approach of taking a proposal, and allowing other vendors an opportunity to match or beat terms on offer. The lead time should be four to six months for initial proposals, with an additional three months for competing proposals to be submitted.

- **Alternative methods:** For OPA-initiated contracting processes, OPA could also use a pre-qualification process, in which technical feasibility is reviewed, followed by a financial viability review for those projects passing the technical qualifications. Projects which are both technically and financially viable would be invited to enter into bilateral negotiations with OPA using a standard (but malleable) contract form in which dispatch orders and provisions for steam host failures would largely be the items subject to mutual agreement.

1.3.2 renewables-specific recommendations

- **Standard Offer:** Renewables should be acquired through a targeted and volume limited standard-offer process. The standard offer price should be set yearly to last the duration of any contracts signed in that year, with the price set either through a modified competitive process tailored to renewables or by establishing a premium above the previous year's average price, and the contract durations should be 10 years.

1.3.3 CDM and demand response (DR) related recommendations

- **Demand Response:** OPA should acquire a target amount of DR via a series of periodic auctions. Alternatively, DR could be procured through three-year standard offers using a percentage of a peaking plant referent price.

- **Conservation and Demand Management:** OPA should serve as a facilitator of CDM programs. Due to its complex nature, CDM should not be subject to a standardized process, nor should there be a CDM RFP process. OPA's role would be as an information clearinghouse for LDCs, providing information about best practices, a standard model set of CDM programs which LDCs could choose to adapt, and creating programs for customers not reached by LDCs.

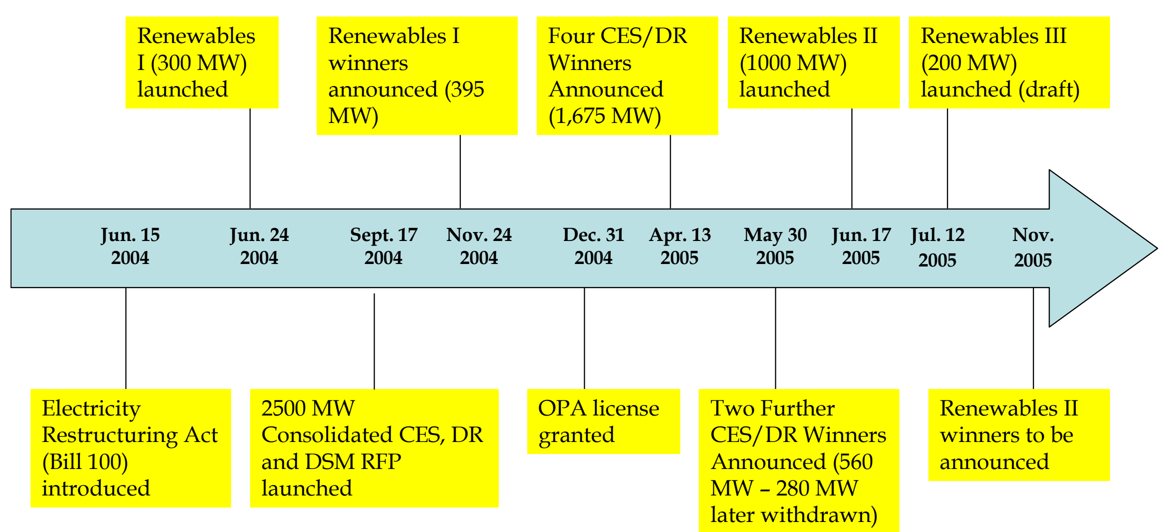
2 Study objectives

LEI was engaged to review stakeholder comments regarding contracting procedures for new generation capacity in the future, based on prior processes which took place in Ontario between June and December of 2004. Below, we describe these contracting processes in greater detail, and review our mandate.

2.1 procurement processes reviewed

Ontario's RFP contracting process began in 2004, prior to OPA being formed as a non-profit statutory corporation reporting to the Ontario legislature. The procurement process has followed a pattern to date of two RFP issuances per year, with winning projects awarded five to seven months later. Three mid-size RFPs (300 MW, 1,000 MW, and 200 MW) have focused exclusively on renewable supply, while one consolidated RFP solicited 2,500 MW of combined clean generation supply and demand side response projects. Figure 1 below shows the timeline of key events in the Ontario procurement process to date.

Figure 1: Ontario procurement timeline



As Figure 1 reveals, Ontario's RFP process has been unfolding in tandem with the definition and development of OPA's role in generation planning and procurement. Bill 100, which laid out the new institutional role for OPA and defined its planning and procurement mission, was introduced only nine days before the Renewables I RFP was launched on June 24, 2004, and the Consolidated CES and DR/DSM RFP for 2500 MW was launched only three months later, on September 17, 2004. OPA's license was granted on December 31, 2004, roughly midway through the first round of RFPs and only after the winners of the Renewables I RFP were announced. It bears mentioning that some of the issues in the Ontario procurement process are a practical consequence of this parallel evolution of both OPA and the Ontario RFP process.

2.1.1 RFP procurement results

Since the launch of the Ontario procurement process in June, 2004, a total of 2,335 MW of new generation additions have been announced: 395 MW of renewable capacity, 1,930 MW of clean generation, and 10 MW of demand-response projects. The renewables projects range in size from 2.5 MW to 99 MW; the clean generation projects range from the 90 MW Toronto Airports project to the 1,005 MW Calpine/Mitsui project; and the demand-response project is a 10 MW initiative. Figure 2 provides some data on the generation procurement results to date.

Figure 2: Ontario generation projects awarded to date[1]

RFP	Project	Capacity	Type	Location
2,500 MW CES RFP	Greenfield Energy Centre	1,005 MW	CCGT	Sarnia-Lambton
	Greenfield South	280 MW	CCGT	Mississauga
	St. Clair Power	570 MW	CCGT	Sarnia-Lambton
	Greater Toronto Airports Authority	90 MW	Cogen	Mississauga
	Loblaw Properties	10 MW	Demand Response	Province-Wide
	Subtotal	**1955 MW**		
Renewables I	Eastview Landfill Gas Energy Plant	2.5 MW	Bio Gas	Guelph
	Trail Road Landfill Gas Generating Station	5 MW	Bio Gas	Ottawa
	Glen Miller Hydroelectric Project	8 MW	Hydro	Trenton
	Umbata Falls Hydroelectric Project	23 MW	Hydro	Marathon
	Blue Highlands Wind Farm	49.5 MW	Wind	Blue Mountains
	Erie Shores Wind Farm	99 MW	Wind	Port Burwell
	Kingsbridge Wind Power Project	39.6 MW	Wind	Goderich
	Melancthon Grey Wind Project	67.5 MW	Wind	Shelburne
	Prince Wind Farm	99 MW	Wind	Prince Township
	Subtotal	**393 MW**		

From the two RFPs concluded so far, the procurement process has proceeded in a relatively timely and continuous fashion. The Renewables I RFP and the Consolidated CES, DR, and DSM RFPs have produced a set of winning projects roughly six months after the RFP launch: five months afterward for the Renewables I RFP and seven months afterward for the Consolidated CES/DR/DSM RFP. The aggregate generation awarded – roughly 2,615 MW of announcement contract capacity -- has been roughly in line with targeted levels and within the range of individual project capacity called for.

In addition to the two Renewables I and Consolidated RFPs already awarded, two additional RFPs have been launched. The third Ontario RFP, "Renewables II," was launched on June 17, 2005 in solicitation of up to 1,000 MW of new renewable energy supply from generation facilities between 20 MW and 200 MW in size. A fourth Ontario RFP, "Renewables III," was

[1] The Greenfield North project has been terminated by OPA and developer.

issued in draft form in July 2005 in solicitation of up to 200 MW of new renewable energy supply from generation facilities under 20 MW in size.

2.1.2 RFP contracts and terms

For the most part the RFP contracts issued to date exhibit a high degree of structural continuity across the process, soliciting generation projects under 20-year contracts with a single buyer structure (OPA). The mandated commercial operation dates have generally been three years from the announcement of RFP winners in the case of the renewables projects, four years in the case of the CES projects, and 2.5 years in the case of the demand-response projects.

Key RFP contract terms and conditions that were highlighted by participants in OPA stakeholder sessions are generally consistent across the RFPs: payment structures, penalties for missing milestone dates, credit and security requirements, and performance incentive payments. Contract terms and conditions are generally similar for all generation projects, regardless of size, and exhibit similar degrees of complexity. Contracts for the larger CES projects contain a payment structure based on contingent support and revenue sharing payments, while the renewables contracts call for contract price mulitiplied by delivered energy terms, with operating reserve payments in the case of the Renewables I RFP alone.

All the contracts contain the same anti-collusion conditions, which were identified by some stakeholders as cause for practical difficulties in securing consultant support for preparing responses to the RFPs. OPA retention of ownership title to the environmental attributes of renewables generation assets -- another term commonly objected to by stakeholder participants – was also common to all the RFP contracts. Finally, the credit and security requirements for the renewables RFP contracts are similar across projects, while the requirements are, as expected, somewhat higher for the larger CES contracts. Figure 3 on the following page provides some information on the RFP contract terms and conditions.

Figure 3: Selected RFP contract terms

	Renewables I	Renewables II	Renewables III [draft contract]	Consolidated 2500 MW CES, DSM, DR
Payment terms	1.contract price x monthly delivered electricity 2."constrained on" payment provision 3. above-cap energy provision 4. buyer's share: 50% of above-cap energy 5. operating reserve payment 6. performance incentive payment 7. approved incremental costs	same terms as Renewables I with these exceptions: 1. no operating reserve provisions 2. provision for the Buyer's return to the Supplier of 15% of the sale of contract-related products	same terms as Renewables II	Contingent Support payment from Buyer to Supplier; Revenue Sharing Payment from Supplier to Buyer
Environmental Attributes	buyer retains	same terms as Renewables I	same terms as Renewables I	same terms as Renewables I
Credit & Security Requrements	$33,000/MW until operational date; then $20,000/MW	$33,000/MW until operational date; then $20,000/MW -- provisions for adjusting security in case of altered contract capacity	$33,000/MW until operational date; then $20,000/MW -- provisions for adjusting security in case of altered contract capacity	$100,000/MW if commercial op. before Dec. 31, 2006; $70,000/MW if commercial op. b/n Dec. 31, 2006 and Dec. 31, 2007; $50,000/MW if commercial op. is on or after Dec. 31, 2007
Credit Evaluation	S x T S = net worth in dollars T = scale from 0.05 (S&P BBB- rating) to 0.10 (S&P A- rating)	same terms as Renewables I	same terms as Renewables I	same terms as Renewables I
Performance Incentive Payments	P x (Q-R) x S P = 25% Q = production-weighted ave. p S = monthly delivered power	same terms as Renewables I	same terms as Renewables I	no
Anti-Collusion Conditions	yes	yes	yes	yes
Capacity Adjustment Option	yes	yes	yes	yes
Milestone Date Penalties	$65/MW x contract capacity per day Maximum $33,000/MW x contract capacity	same terms as Renewables I	same terms as Renewables I	same terms as Renewables I
Contract Indexation	15% indexed; 85% non-indexed	same terms as Renewables I	same terms as Renewables I	Energy Cost, Startup Cost, and O&M Cost are indexed

2.2 process for stakeholder review

On July 8, 2005 OPA announced the stakeholder review process. OPA invited all stakeholders to submit comments and recommendations to OPA. Stakeholders were also invited to give presentations to OPA outlining their positions.

OPA staff prepared, with input from LEI staff, questionnaires for stakeholders. More than 100 questionnaires were sent to stakeholders who expressed an interest in receiving one. OPA asked that the stakeholders return their questionnaires by July 29, 2005. Separate questionnaires were created to help identify issues in the Clean Energy Supply (CES), Combined Heat and Power (CHP), Conservation and Demand Management (CDM), and Renewable Energy Supply (RES) processes. The questionnaires can be viewed in Appendix B. In response to the questionnaires, OPA received 54 written submissions.

OPA then held sessions where it met with various stakeholders. On July 26, OPA held a plenary session that was open to the public. At the plenary session OPA invited presentations from parties not directly involved in project development or the procurement process. The 27 presenters at the plenary session included industry organizations, service providers, academics, trade unions, and other interested groups. From July 27 to 29, OPA held private sessions with 31 stakeholders directly involved in the development or procurement process.

After the meetings, OPA provided LEI with the written submissions, copies of presentations made at the sessions, notes and transcripts from the sessions. These were supplemented by LEI notes and observations. LEI reviewed the stakeholder positions; LEI also reviewed best practice across North America. As a result, two reports have been created; this report, reviewing stakeholder views and presenting our recommendations, and a companion report which summarizes findings based on practices in other jurisdictions. This report synthesizes the stakeholder comments and provides recommendations based on the stakeholder input, the requirements of OPA, and the knowledge and experience of LEI.

A summary of the presentation and submission subjects is given in Figure 4 below. It is important to note that all of the participants in some form represented suppliers, and so have a particular viewpoint with regards to the process, even though their interests may diverge in specific instances. Consumers (with the exception of industrial consumers, who focused primarily on cogen issues) were not represented directly in the process. However, OPA presented comments intended to reflect the interests of consumers as well as suppliers, and LEI conclusions are also based on the need to balance the interests of suppliers against the needs of consumers.

Figure 4. Summary of Submissions and Presentations

Submissions Received						Presentations				
CES	CHP	CDM	RES	**Total**		CES	CHP	CDM	RES	**Total***
15	9	17	13	**54**		25	22	20	26	**58**

*Some presenters addressed multiple topics.

2.3 London Economics International LLC mandate

LEI was retained by OPA to serve in the capacity of observer and advisor in the stakeholdering process. LEI's role was to serve OPA and all of the stakeholders in a neutral capacity.

LEI's responsibilities leading up to the stakeholder sessions included developing a close familiarity with previous RFP processes and documents, identifying issues likely to be raised by proponents, and helping to generate the list of questions for stakeholders. LEI staff attended the stakeholder sessions to gain an understanding of the positions of the stakeholders, and debriefed with OPA staff on the results of the sessions. After the sessions LEI reviewed the written summaries and transcripts, the presentations, and the stakeholder submissions. LEI also considered the reports entitled Review of the OPA's CES Contract and Report on Large Dollar Procurement Approaches commissioned from independent consultants by OPA, and consulted with OPA staff on their views of procurement objectives.

Finally, LEI prepared this final report, which summarizes and evaluates the points raised during the stakeholdering process (including written submissions); and incorporates the input of the stakeholders, OPA, other reports commissioned by OPA, and LEI's own professional views to formulate and present conclusions, and to make recommendations about how future procurement processes could be improved.

3 OPA mandate

Stakeholders presented a range of valuable observations regarding potential improvements to the contracting process in Ontario. However, as OPA assumes responsibility for contracting on an ongoing basis for the foreseeable future, it is important to understand the boundaries within which OPA operates, as well as what the objective function is for OPA when seeking optimal outcomes. Some stakeholders views can be addressed directly by OPA, but others fall outside of OPA's purview. As such, it is useful to review OPA's mandate and objectives before identifying which aspects of the contracting process OPA can or should improve.

3.1 statutory mandate

OPA was created in 2004 by Ontario Bill 100, since passed into law as the Electricity Restructuring Act, 2004 (the "Act"). Under the law, OPA was given the following mandate:[2]

(a) to forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the medium and long term;

(b) to conduct independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario;

(c) to engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario;

(d) to engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;

(e) to establish system-wide goals for the amount of electricity to be produced from alternative energy sources and renewable energy sources;

(f) to engage in activities that facilitate load management;

(g) to engage in activities that promote electricity conservation and the efficient use of electricity;

(h) to assist the Ontario Energy Board by facilitating stability in rates for certain types of consumers;

(i) to collect and provide to the public and the Ontario Energy Board information relating to medium and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs.

[2] Source: Government of Ontario Bill 100 2004: An Act to amend the Electricity Act, 1998 and the Ontario Energy Board Act, 1998 and to make consequential amendments to other Acts

3.2 currently envisioned mission

OPA currently views its mandate as fourfold:[3]

1. ***Power System Planning*** *– developing and maintaining a long-term plan for coordinating the supply and transmission of electricity in Ontario;*

2. ***Generation Development*** *– contracting for investment in new generation projects and demand management initiatives to reduce the demand-supply gap for electricity;*

3. ***Conservation Bureau*** *– facilitating the management of demand by developing conservation programs for electricity users; and*

4. ***Retail Services*** *– assuring smooth prices to residential and other designated customers, while recovering the full cost of electricity.*

OPA's groups work together to achieve the mandate. The Power System Planning group forecasts demand in the province in the medium and long term, to provide a basis for the actions of the other groups. The Generation Development Group conducts competitive and transparent procurement processes for investment in generation and demand management programs. The Conservation Bureau works to promote conservation programs in Ontario. The Retail Services works to ensure the stability of end-user prices.

OPA prepares an integrated power system plan no less than every three years, and delivers the plan to the Ontario Energy Board (OEB) and the Ministry of Energy. OPA then plans procurement processes, which are submitted to the OEB for approval. Once approved, the procurement proceeds. OPA recovers the costs through fees approved by the OEB and administered by the IESO.

It is important to note that under Ontario Regulation 424/04, a part of OPA's mandate is to include in its contracting processes consideration of long term market development implications of the contracts it issues. The Regulation states that OPA shall "identify and develop innovative strategies to encourage and facilitate competitive market-based responses and options for meeting overall system needs." It goes on to say that OPA shall "identify measures that will reduce reliance on procurement…" Both subsections suggest that OPA's ultimate goal is to withdraw from contracting in favor of market processes where appropriate, and indeed that a self-perpetuating contracting process is not part of OPA's mandate.

3.3 what OPA is not

A review of OPA's mission under the Act and subsequent ministerial directives suggests it must balance a set of related, but sometimes conflicting, objectives, including:

- supply adequacy

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[3] OPA website: http://www.powerauthority.on.ca/

- supply diversity
- promoting conservation
- providing for an appropriate amount of capacity from alternative energy sources; and
- rate stability.

The final objective constrains the previous four; OPA must find the optimum mix of generation while still seeking a degree of long term stability in rates. Note that rate design itself is outside of OPA's purview; indeed, it is not within OPA's power to assure that customers are charged the true cost of the power which it procures.

While reviewing stakeholder comments on the procurement process, it is important to bear in mind other objectives which are outside of OPA control or its objectives:

- community development or regional economic policy;
- industrial policy or the revival of specific industries;
- mitigating environmental impacts of power usage to a degree greater than required under current law;
- procuring power without regard to price impact;
- significant involvement in promoting development of gas infrastructure, or affecting the terms of gas transportation company tariffs;
- setting overall energy policy, including non-OPA charges, fees, levies, tariffs, etc. and
- ability to create favorable tax incentives.

This list of activities may contain laudable elements, and we do not intend to suggest that any or all are undesirable. However, as we will note where appropriate throughout this paper, some are simply not the responsibility of OPA as it is currently structured.

3.4 contracting process being reviewed was not an OPA process

Before moving directly to the review of stakeholder comments, it is again important to point out that the processes being reviewed were not designed by, or under the control of, OPA. The contract processes must be understood in the context of the challenges facing Ontario at the time the RFPs were issued. The unique circumstances faced by the Ministry of Energy at that time partially explain some of the more challenging aspects of the process. As the situation in Ontario stabilizes, OPA is moving to play a pivotal, if transitional over the long run, role in contracting for new generation. As such, it has the benefit of learning from, and building upon, the previous contracting experiences. The Ministry of Energy had no such luxury; even so, as our review of practices in other jurisdictions suggests, the processes it managed had elements in common with other similar procurement efforts in North America.

4 Common themes

Throughout the presentations, a number of recurring themes were hit upon by many of the stakeholders. We have included in the list of common themes those which were mentioned in relation to most or all of the processes, and those that were brought up by a diverse set of commentators. In addition, where a comment appeared to present some striking insight (even if not echoed by other stakeholders) we have made an effort to incorporate it. For purposes of this section, "stakeholders" does not imply unanimous or a majority of stakeholders, rather it implies a significant number of stakeholders. However, in the few instances were we use the word unanimous, the comment was present in all relevant responses.

4.1 bid security

Bid security was mentioned almost universally by developers of all types of facilities. In general, stakeholders felt that the security requirements were too strict, raising the level of difficulty of participating in the process. Note, however, that we found that bid security is a common feature of RFP processes in North America, and that the requirements imposed in Ontario were within the observed range from other jurisdictions.

Figure 5. Security Deposits from Selected RFPs

BC Hydro	Hydro-Quebec	**Ontario**	Puget Sound Energy	Xcel Energy
Cdn.$5 or $10/kW	Cdn.$8 to $20/kW	**Cdn. $10 or $25/kW**	$20 to $30/kW	$75/kW or $125/kW

Advocates for smaller development suggested that the bid security was especially onerous for smaller groups, and thus discouraged new entrants, smaller developer, and community-based developers from entering the market. Concern about the dampening effect of the bid security was especially widespread amongst developers of RES and CHP projects.

> *"The requirements for security bonds and full listings of equity investors preclude us from participating. A more flexible approach that recognizes the reduced risk with smaller projects that are not providing baseload electricity would more easily allow us to participate."*- Renewables Developer

A suggestion that was more directly related to encouraging smaller projects was to let bidders with fewer resources/small projects bid with less security.

> *"Lower bid security obligations to reflect size of projects and resources of bidders"* - Industry Group

> *"Specifically, we believe that the dollar value of the proposal security should reflect the different capacity factors of different renewable energy sources or should be tied to expected annual electricity production and not MW of capacity."* - Industry Group

Amongst larger developers, there was a sense that the level of bid security was appropriate, but several suggested that this part of the process could be improved by linking the amount of security required to the stage of the process, with less security required to enter the initial stages, and more to be posted as a bidder continued in the process.

> *"A very small (in the thousands of dollars) bid evaluation fee is appropriate at time of bid submission. At time of shortlisting or when the bids become binding a more significant bid bond is appropriate. The bulk of the security or collateral should be put in place when a development agreement, such as the CES contract, is executed."* – Developer

> *"A significant non-refundable security deposit should only be required at contract signing."* – Renewable Developer

> *"We also suggest that the operational performance security should be reduced as the contract proceeds through its term. At its extreme, there is no rationale for the same security to be required the day the contract starts and the day before it is to terminate."* - Developer

4.2 general financing concerns

Closely related to the bid security concerns were issues surrounding the flexibility of financing options.

Concerns about financing centered on the flexibility to adjust it during the RFP process or after the process concluded.

> *"Default cure periods very short for project financing; lender step-in rights requirement for replacement contract causes concern"* – Developer

> *"…transfer of control and ownership restrictions prevented certain types of financing from being made available."* - Industry Group

> *"The RFP process precludes sponsors from developing financing options after bid submission."* – End User

Again, advocates for the non-traditional development expressed concerns that were somewhat different from those more involved with the traditional approaches. The strict terms of the financing requirements were thought to discourage developers with non-profit structures from entering the RFPs.

> *"The stringent and excessive financial requirements, including the requirement for security bonds, and the requirement to list all the equity investors in the project, meant that co-operatives and most other small-scale generators were unable to contribute to Ontario's electricity mix."* – Industry Group

Small-project developers were very supportive of simplifying the financing process by having OPA provide standard language for financing commitment letters and allowing more debt to be used in financing. Larger developers pointed out that financing commitment letters were largely meaningless, as lenders do not actually bring projects to loan committees before the project is awarded and financing is imminent.

4.3 need for bi-directional communication during bid process

Virtually all stakeholders involved with the RFP processes felt that a more direct form of communication between OPA and the potential bidders was required.

> *"Provide some opportunities for direct communication between buyer and seller during the bid development phase, in order to allow for efficient clarification of questions and responses. This could still be accomplished in a public forum to ensure transparency and openness."* - Developer

> *"Communications being limited to written questions hampered [the] exchange of ideas and information.."*- Developer

> *"During the technical bid evaluation phase, buyer should ask follow-up questions of bidder to assure that project has been adequately planned."* - Developer

4.4 difficulty in holding bid fixed over a lengthy bid review process

The long period during which the bid had to remain valid, as long as 8 months for bidders in the CES process, created a number of risks for the bidders that were (and will be) priced into the bids.

The costs and risks imposed on bidders included:

- exchange rate risk and inflation risk;
- financing risk, especially the need to hold the security and keep financing in place over a long period of time;
- uncertainty about construction costs and commodity prices, especially steel;
- uncertainty about equipment procurement;
- issues around securing fuel sources; and
- issues with the uncertainty created for thermal offtakers.

Stakeholders recommended removing the uncertainty about the duration of bid validity by either allowing indexing of the bid to account for inflation, or having a fixed evaluation period.

> *"Proponents could be allowed to submit bids that will vary based on the exchange rate, interest rate, and steel prices as of the date the price comparisons are made. The proponent can choose to have his bid price affected by any or all of these factors based on publicly available data, such as 15/20 year government bond rate, Bank of Canada exchange rate etc. Alternatively, proponents could simply submit a firm proposal price on [deadline date], allowing appropriate time (45 days) for the review process."* – Industry Group

> *"Exposure between proposal submission and contract execution is high given inappropriately long duration."* – Industry Group

Although stakeholders make valid points with regards to the length of the evaluation period, and we indeed think some improvements can be made in this area, it is important to point out that the timing between bid submission and announcement was within North American norms. Readers can refer to our companion paper on North American best practices for more information on this issue.

4.5 anti-collusion provisions

Developers of all sizes and interests, industry groups, and service providers agreed unanimously that the anti-collusion restrictions were too strict. Many felt that these provisions reduced the number of bids in the RFPs because they limited access to providers of key services, especially when there were few providers in Ontario. Small and renewables developers identified the collusion restrictions as especially challenging, as there might be only one or very few sources of critical components and support elements available to small proponents.[4]

> *"The collusion provisions in the RES and CES RFP processes were overly cumbersome and limited the ability of proponents to assemble the most qualified teams"*- Industry Group
>
> *"Collusion provisions are difficult as written in an industry of few suppliers and knowledgeable consultants"* – Developer
>
> *"Non-collusion provisions are too strict – eliminates opportunities for synergies"* – End User

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[4] **From the 2,500 MW CES RFP Document:**

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.

4.6 contract length

Longer term contracts were cited as an important element of the procurement process. A contract length of twenty years was identified as ideal by many of the submitters, although some simply felt that longer terms were better, citing lengths of as much as forty years. Twenty-year-plus contracts were cited as facilitating financing and increasing confidence about the stability of the process over a long term. Some stakeholders believed that allowing the option of different lengths of contract would increase the flexibility of bidders.

> *"The longer the contract term, the more competitive the financing arrangements can become. This reduces the effective cost of capital and lower[s] the overall capital subsidy being sought."*- Industry Group

> *"Varying contract terms should not be solely dictated by or decided on by OPA."* – Renewable Developer

4.7 inflexibility regarding specific contract terms

The contract in the previous process generated perhaps the most comments. The comments ranged from the very general to the highly specific, with some stakeholders even offering alternate language and point-by-point critiques of the contract. Almost universally, the stakeholders felt that the contract was too inflexible.

> *"Provide a standard contract with room to negotiate."* - Developer

The inflexibility of contract provisions regarding ownership and transfer of control were a major concern. Developers believed that with more flexibility to make changes, they would be able to bid more aggressively.

> *"If the same amount, location and benefits associated with this power can be provided by another comparable plant, then OPA should recognize this and permit the transfer of the contractual arrangement to another party."* - Industry Group

> *"It may be advantageous for both parties to allow changes in the proponent team earlier in the life cycle of the project"*- Developer

Advocates for smaller projects felt that the contract inflexibility (along with its complexity) discriminated against small suppliers.

> *"Contract terms should be simple enough not to require overly onerous legal review and should not create extensive risk for facility owners…"* – Service Company

Recommendations about how to improve the contract flexibility focused on adjusting the process to add flexibility to the contracting portion, and simplifying the contract itself.

> *"High level strawman procurement process and contract should be issued before draft procurement process and contract"*- Industry Group

> *"Consider a simple tolling arrangement with capacity payments"* – Developer

> *"Converting the contract from a 'contract for differences' to a pure gas tolling arrangement with a capacity payment would significantly reduce the complexity of the contract, reduce the future administrative burden and provide a developer with a less risky investment, which would provide stable, creditworthy, reliable developers to bring their low risk (and associated low cost) approach to the table."* - Developer

4.8 pre-qualification

Developers and advocates generally favored the introduction of a pre-qualification phase for the RFPs, but there was little agreement on precisely what it should entail.

> *"More stringent selection criteria should have been established and exercised to ensure that projects and/or developers are legitimate and have a high likelihood of proceeding."* – Renewable Developer

Most suggested that pre-qualification be used to evaluate the qualifications of the development team, and their ability to see the project through to completion. Elements suitable for pre-qualification evaluation in this context included the developer's experience, financial expertise, and technical abilities.

> *"Pre-qualification criteria should be based on a developer's financial wherewithal, development experience and past track record of closing transactions. These standards should be set high to ensure that projects that are selected through a competitive process have a high probability of concluding negotiations, being developed on schedule and operating reliably over the life of the contract."* – Developer

Most stakeholders addressing this issue believed it was most appropriate to leave the details of the projects out of the pre-qualification stage.

> *"At the time of pre-qualification, a project should not be required to have completed any stage of Environmental Assessment, interconnection assessment, or permitting."* – Developer

Again, small and community-based stakeholders were concerned about the potential for being excluded by the pre-qualification results. Options for overcoming this limitation include separate processes for smaller developers and different pre-qualification standards for different sizes of projects (such as achievement-based pre-qualification for small groups).

> *"Strenuous pre-qualification would again bar new groups like a farmer's co-op from ever applying. Certainly if the directive is there with LDCs and hook up is facilitated, the perceived importance of this criteria will diminish. With small projects, it seems logical that – having gone through considerable pre-development study and using credible outside consultants – they will be more likely to deliver than less. Evidence of due diligence and meeting milestones, as well as using credible outside consultants would be sensible. Past non-delivery should be disclosed, however."* – Renewable Developer

"Pre-qualification is more effective if tied to the achievement of significant milestones instead of being restricted to those developers that can demonstrate prior experience with project development." – Renewable Developer

4.9 breadth of evaluation criteria

The narrowness of economics as the final evaluation criterion was pointed out by many stakeholders. A number suggested that using such a criterion could result in a procurement that does not meet all of OPA's goals. Many submitters suggested that an alternative was to use a more holistic evaluation of the proposed projects. Some possibilities for an alternate evaluation method included a scoring matrix that assigned numerical scores to certain attributes, a handicapping system that adjusted the value of the bid based on geographic location, and a qualitative evaluation of the project.

"The assessment of CHP projects should be based on quantitative and qualitative attributes of each particular project. Attempt[ing] to quantify qualitative benefits is very difficult and should be avoided." – Renewable Developer

The characteristics proposed for inclusion in the evaluation criteria included:

- The cost of electricity;
- The feasibility of the project;
- Maturity of the project's technology;
- Experience of the proponent team;
- Proponent's financial strength;
- Financeability;
- Deliverability;
- Online date;
- Thermal generation;
- Impact on the transmission or distribution systems (positive or negative);
- Environmental impact;
- Efficiency;
- Health impacts; and
- Economic impact.

"Evaluation should go beyond just electricity supply issues to include other benefits such as value of thermal energy, environmental attributes, avoidance of transmission congestion, job creation/retention, economic spin-offs from the host industry." - Industry Group

"A technical review as part of the evaluation of bids would be beneficial." – Developer

4.10 separate processes for each product

There was strong support among proponents for all types of projects to utilize separate processes for distinct project technologies. Given the very different characteristic of CES, RES, CHP, and CDM projects, separation would allow for the process to address the unique characteristics of the products.

> *"Use separate mechanisms for resources with different characteristics"* – Public Interest Group

> *"A separate procurement process should be developed for each with 'floor' targets."* – Industry Group

> *"Should conduct separate RFPs for clean gas fired generation and for DR/DSM."* – Developer

> *"Industrial cogeneration and district heating are conceptually similar, but different enough to require separate processes."* – Industry Group

> *"Separate renewable energy procurement processes should continue to be utilized in the future"* – Industry Group

Separate processes were also seen as a way to support smaller projects and new developers in entering the market. Many advocates for small projects believed that many of the provisions involved in the processes to date had prevented bids, due to the scale and complexity of the RFP process.

5 Additional issues specific to CES

Most of the issues raised about the CES process were related to the contract. In addition, there were significant concerns expressed about the future supply of gas in Ontario.

5.1 CES contract and competitive forward energy market

A number of developers suggested that the CES contract was not consistent with promoting the development of a market for forward contracts. These stakeholders felt that the contract was too restrictive in its terms, and would prevent the projects from participating in a forward market in Ontario. Many stakeholders suggested that OPA should encourage the development of a forward market through changes to the CES contract.

> *"CES Contract inconsistent with competitive forward energy market*
>
> – *Risk mitigation by generator precludes / strongly dis-incents forward energy contracting*
>
> – *One-way exit option strongly dis-incents exit for the sake of forward market participation*
>
> – *There should be an opportunity for beneficial energy market participation without jeopardy to underlying contract rights"* – Industry Group

> *"OPA procurement model needs to encourage market activity by making procured capacity available to third party buyers in a way that allows the ongoing development of the forward contracts market."* – Industry Group

The consensus among those who considered this a problem was to allow generators to opt out of the CES contract. Some stakeholders suggested permanent opt-out once the option was exercised, others recommended that the opt-out be temporary; another possibility advanced was to make the opt-out partial. Developers felt that this would promote the supply of competitively priced forward contracts in the market.

> *"The contracts should include incentives for generators to add value through participation in contract markets."*- Industry Group

> *"OPA should support market changes which stimulate overall market liquidity by providing more incentive for Generator to opt out of contract"* - Developer

5.2 contract structure advantaged less-prepared bids

Several CES participants noted a belief that the RFP and the contract structure actually benefited less-developed projects. The force majeure protections for approvals were noted as a contract element that biased the RFP towards less developed projects.

> *"Force majeure protection for approvals: opened doors to more proposals but lays key risk on Buyer; [provided a] potential "escape route" for developers; [and] biased outcome towards less developed projects"*- Developer

5.3 configuration of deemed dispatch

A CES participant noted that the contract deems the imputed plant to be operating at full capacity whenever HOEP is above a certain threshold, when, in fact, the specified threshold may not have fully reflected total costs of operations. The contract would offer a more realistic view of the true situation if it assumed dispatch based on realistic operational requirements.

> *"Deemed operating period based on pre-dispatch power price does not work. Facility designated operating profile should be based on operational requirements."*– End User

5.4 multiple starts

CES stakeholders believe that the contract should allow for multiple daily starts. This will allow operators to recover their true costs, and reduce the uncertainty in their bids.

> *"The imputation formula limits Start-Up Costs to one start-up per day. This means additional start-ups (or the costs of continued operations to avoid another start) are not recovered in the formula. The CES contract structure required a proponent to estimate these factors over 20 years, resulting in additional cost contingencies and higher bid costs."* - Developer

5.5 gas infrastructure issues

Stakeholders expressed strong concerns with respect to the gas infrastructure in Ontario. Stakeholders are warning of negative consequences if combined cycle gas-turbine (CCGT) generation replaces all of the coal capacity slated for retirement. In this case, the increase in gas consumption overall in Ontario would be significant, and it is unclear whether the supply of gas available to the province would be able to meet the new needs without major increases in price.

Another major concern was the ability of the transmission and distribution network to support the growth of CCGT generation without significant upgrades. If upgrades are required, it is unclear who should provide the capital expenditure. For example, should developers be responsible for pricing upgrades into their bids?

> *"The adequacy of Ontario's natural gas supply, storage and related infrastructure arising from adding approximately 2,500 MW of natural gas fired generation did not seem to be fully considered in the process."* - Developer

> *"[Stakeholder] suggests that it is premature to deal with the bidding process and details of the contracts until problems associated with the supply, transportation, distribution and storage of gas have at least been examined and questions relating to costs and who pays have been dealt with."*- Industry Group

Industrial users of gas are concerned about the potential impact of supply, transmission and distribution constraints, especially those who have interruptible contracts.

Although there are potentially major issues with the gas supply in Ontario, few of the solutions put forward were within OPA's mandate. Some are being explored though OEB initiatives, such as the recent Natural Gas Forum and the ongoing Natural Gas Electricity Interface Review. Stakeholders agree that OPA should work with gas suppliers to help ensure that the necessary supply and infrastructure will be in place.

5.6 timing of gas and electric days

Several participants mentioned concerns over the mis-alignment between the time when plants must commit to purchasing gas supplies and transportation capacity for the next day and the time at which such plants can be confident that they will be dispatched. Penalties for over and under nominating gas quantities are substantial, and can effectively wipe out any profits from operations. Again, this problem is largely outside of the control of OPA, though it is a consideration in the ongoing discussions of whether to establish a day ahead market in Ontario.

> *"Deemed operating period based on pre-dispatch power price does not work."*- End User

6 Additional issues specific to CHP

The issues surrounding CHP development focused on two major areas: the risks of gas supply, which are analogous to those involved in the CES; and the nature of CHP projects, especially the need of CHP plants to be self-dispatched or base-load to match the needs of the thermal host. In general, it was indicated that separate processes for CHP projects would likely be beneficial, as would standard offers[5] for CHP.

6.1 loss of steam host, fluctuating heat rates, changing thermal hosts, and contract flexibility in general

A number of stakeholders were worried about the potential for a fluctuating heat rate to result in a contract default. Several also mentioned the possibility that a change in the steam host could result in a default even if the project was still able to meet its other obligations. These points were related to broader (but non-specific) concerns about the inflexibility of contract terms and the possibility of inadvertently defaulting on the contract due to the special nature of CHP projects.

> *"[A CHP project] allows for creative combination bids: bricks and mortar with dispatch/financial opportunities. Extracts maximum value from assets and market at same time."* – End User

The major concern of the stakeholders involved in CHP projects was the potential for the loss of a steam host. As this is the major risk of a CHP project, most stakeholders involved in the CHP process would price this possibility into their bids, putting them at a disadvantage to non-cogen projects.

Unfortunately, there is no clear consensus about the best way to resolve the issue. Several stakeholders recommended terminating the contract in the event of a steam host defaulting. Others suggested a transfer of the contract, or conversion to a tolling arrangement.

> *"If we lost the steam host we would need to be able to terminate the electricity contract."* – Developer

> *"OPA should permit the transferability of the power purchase agreement to another party if there is a material loss of a thermal energy host, steam, heating or cooling customer. This transfer should take place on commercially reasonable terms to both OPA and the power generator suffering the loss."*- Industry Group

> *"The CHP contract could be structured as a tolling arrangement which would pay a fixed capacity payment to the project. If the steam host fails, the capacity payment would not be affected. OPA would adjust upwards the facility heat rate to a level that would*

5 Standard offers are sometimes referred to as standing offers.

> *continue to allow the project to meet its fixed cost and return obligations should the host fail."* - Developer

A number of stakeholders recommended longer contract terms (combined with cancellation provisions) as most appropriate for CHP; this recommendation, however, contradicts another's assertion that short-term contracts are most appropriate.

6.2 evaluation of CHP projects

There was a consensus that the evaluation of CHP projects should include factors other than price. Potential areas of evaluation suggested by stakeholders are:

- The location of the project;
- The benefits to local electricity distribution company infrastructure;
- Benefits to the transmission system of CHP projects;
- The level of commitment of the steam host;
- The creditworthiness of the steam host;
- Compliance with Class 43.1 of the Income Tax Act; and
- The proportions of heat and electricity generated.

> *"Non-electricity products and intangible benefits, like environmental attributes, should be used in the evaluation of different projects that are generating power through a similar process. Power projects that operate at a higher overall efficiency should be evaluated more favorably than projects that produce power at the same price, but at lower overall efficiency."* – Industry Group

6.3 time to respond to RFP not congruent with approval processes of potential hosts

Stakeholders commenting on CHP felt that the time frame for responding to an RFP was not consistent with the time that was required to negotiate an agreement with a steam host. They felt that the negotiation and approval process of the steam hosts (from opening a dialogue to receiving board approval) would tend to take several months at an absolute minimum.

There were a number of potential solutions offered to this problem, including separate processes for CHP projects, the appointment of a facilitator for CHP projects, and a standard offer for CHP.

> *"Timing must be flexible, allowing high efficiency cogen to be built on timing in synch with host…"* – Industry Group

6.4 extra charges (debt retirement, transmission, etc)

Many stakeholders expressed a desire for modifications in the debt retirement charge, transmission-related charges, and other fees. However, notwithstanding the popularity of such proposals, changes in these items are not within the authority of OPA.

> *"Subsidize rates directly or through elimination of Debt Retirement Charge, Market operations charges, Transmission & Distribution charges, etc."* – End User

> *"Debt retirement charge should be on net load only."* – End User

6.5 complexity of RFP processes

A number of CHP stakeholders felt that the RFP processes were too complex, time consuming, and expensive. The assertion was that the complexity of the process made it difficult to pursue potentially viable projects. If the process was made simpler, the range of projects would expand, as would the potential number of participants in the RFPs.

> *"Small-scale CHP projects (<25MW) are often connected to institutional thermal hosts such as municipalities, universities, schools and hospitals. These hosts are unprepared for a complex and risky procurement process."* – Industry Group

6.6 desire for standard offer

CHP stakeholders were nearly unanimous in promoting the idea of a standard offer for CHP, and none opposed the idea. They felt that standard offers would help to resolve a number of potential problems with CHP development, including the development lead times, and the concerns about the loss of the steam host. It was also expressed that a standard offer would reduce the costs of participating in the RFP process, and increase the potential for developing smaller projects. Regrettably, there was less consensus over what the definition of a "small" project should be.

> *"Create a standard offer with uniform terms and conditions for any embedded generation"* - Industry Group

7 Additional issues specific to RES

The majority of respondents who addressed RES were either community oriented groups or involved in small-scale renewables development. As such, they provided a very consistent message that OPA's processes should be adjusted to be more accessible to small and community-based developers.

7.1 definition of renewables

A number of stakeholders provided recommendations about what should qualify as renewables for OPA procurement processes. Among the fuel and generation types put forth for possible inclusion as renewable resources are:

- Black Liquor;
- Wood-Waste;
- Steel Gas;
- Zero incremental emissions technologies - fuel cells, off-gas, waste-heat recovery;
- Traditional Hydro;
- Trigen – the combination of a CHP facility with a greenhouse to consume CO_2;
- Biomass and biogas; and
- Wind.

7.2 complexity and scale of the RFP process

There was a wide-spread belief among RES stakeholders that the RFP processes to date have discriminated against small and community-based developers due to their complexity, and the financial structures required for bidding. Community-based developers believed that they were not eligible for the RFPs based on their structures and lack of equity.

> *"The Renewables I process favoured developments that have access to large amounts of private capital in order to cover the costs of security bonds, and who utilize traditional equity investment. This effectively meant that only private corporations with very deep pockets were able to participate, community power projects were effectively excluded from the process."*- Industry Group

All the smaller developers expressed the opinion that the security and financial requirements in general prevented them from competing effectively against large-scale development.

> *"The RES RFP catered to bidders who took much greater risks than is prudent to develop a sustainable wind power generation industry in Ontario."* – Green Developer

Hydro developers also highlighted the lack of coordination between contracting processes and site release and permitting programs, noting that this lack of coordination made it nearly impossible for some greenfield hydro developments to comply with the procurement schedule.

7.3 transmission issues

Several issues related to transmission were raised by stakeholders. These included the extent to which developers should be forced to pay for improvements to the transmission system associated with their projects, and whether projects which are located in a manner which reduces congestion on the transmission system (or allow the delay of future transmission system investment) should be given preference in procurement. Stakeholders also involved in CHP projects echoed the RES stakeholders' position on transmission.

> *"Proximity to electrical loads will reduce transmission losses substantially."* – Industry Group

Several stakeholders said that as investments in transmission and distribution infrastructure benefited many stakeholders, there ought to be a mechanism whereby all the beneficiaries contributed to the cost of developing the infrastructure.

> *"The RFP should allow transmission sub-zones to be expanded by proponent-led, rate-base supported, transmission upgrades"*- Industry Group

> *"If the Province wants these renewable projects to be developed then the Province and ultimately the end-use consumers should have to pay for the [transmission] upgrades."* - Developer

7.4 desire for standard offer

In contrast to an RFP process, a standard offer involves the contracting agency establishing a set price for new capacity, and accepting all technically feasible projects which are presented and which agree to accept the offered price. Stakeholders involved in the RES process agreed that a standard offer would be beneficial for them. Some argued for different standard offer levels to be set for different types of technologies or different sizes of plants. Small developers felt that a standard offer would level the playing field by reducing the costs of participating in OPA procurement.

> *"Implementing a SOC [standard offer contract] process in Ontario will facilitate the rapid development of a diverse and strong renewable energy industry in Ontario."* – Industry Group

> *"As a developer, we need some assuredness from a business planning perspective around the timing of RFPs so that we have projects ready to bid. At the same time, if the Province continues to solicit projects through an RFP process this ends up dictating the development cycle which can cause delays in bringing projects on line. This is why we would like OPA to give some serious consideration to some form of standard offer for smaller projects."* – Developer

> *"SOCs allow projects of varying sizes and from a number of different renewable energy technologies to participate in the procurement and ensure an equitable process."* – Renewables Developer

Many of the small developers supported the recommendation for standard offers put forth by the Ontario Sustainable Energy Association (OSEA). These provisions include:

- Small size – maximum of 10-20 MW;
- Open to all potential developers, including small commercial developers and community groups;
- 20 year contract terms;
- Differential pricing based on wind regimes, with higher prices for projects with less favorable wind conditions at their location; and
- OPA as counterparty.

It is important to note, however, that stakeholders associated with significant loads in the province, while attracted to the idea of a standard offer for *their* specific projects, recognized that standard offers could result in significantly increased consumer prices if oversubscribed, and could result in suboptimal allocation of contracts among project types.

8 Additional issues specific to CDM

Stakeholders addressing CDM were a very diverse group, including community groups, non-profit organizations, equipment providers, and aggregators. Their concerns and suggestions were equally diverse. One widely held view was that "smart" meters are required for effective deployment of CDM projects. They also broadly agreed that CDM has unusual characteristics and should be treated separately from other procurement processes.

8.1 megawatts versus negawatts

The question of whether a megawatt of generation should be treated identically to a megawatt of avoided generation (a "negawatt") was an area of disagreement amongst the respondents. Several asserted that avoided consumption should be valued the same as additional power generated. Some felt that "negawatts" were more valuable than a megawatt generated, others felt that "negawatts" were less valuable.

> *"A negawatt program has the same market effect as an increase in the supply of megawatts."* – Service Provider

> *"A megawatt saved is not the same as a megawatt generated. Generation and CDM/DR are subject to very different transactional, financial, and technological drivers. In particular, CDM/DR involves human behavioral parameters not present in generation capacity initiatives. This essential difference impacts both the predictability and consistency of the output from CDM/DR as compared to generation…"* – Service Provider

8.2 audit mechanism to ensure delivery

A number of stakeholders suggested that an audit mechanism should be established to ensure consistency and deliverability of CDM projects. They asserted that this would increase the certainty of CDM developers in the products that they delivered.

> *"Properly designed and applied OPA CMD/DR audit procedures and other monitoring and verification standards would bring standardization to the area, lowering lender transactional costs and thus encouraging more lenders to consider CDM/DR projects."* - Service Provider

8.3 LDC issues

Some stakeholders felt that LDCs were best positioned to deliver CDM projects. Others thought that CDM projects should be uniform across the province, and that OPA should encourage LDCs to deal uniformly with CDM providers.

> *"Up to the meter, the network needs to be implemented and managed by the LDC. The foundation needs to be provided up to the meter with the consumer building upon that*

foundation. Beyond the meter, the consumer needs to determine how best to take advantage of the information provided and respond to price signals."- Service Provider

"…[stakeholder] believes that a capacity based system paid for by a province wide commodity charges [sic] is the fairest way to deliver demand response since all electricity consumers will benefit from it." – Service Provider

8.4 contract issues

Issues raised about CDM contracts include:

- Because of the nature of CDM programs, a stakeholder suggests that OPA should develop a contract specific to CDM projects.
- Because demand response and efficiency programs often operate on different timeframes from generation projects, more flexible contract lengths may be appropriate for CDM projects.
- The counterparty to CDM contracts should be the service provider/aggregator, not the end-user. These contracts should be performance-based.
- Contract terms should be simple and should not place excessive risk on facility owners and service providers.
- OPA should reduce encumbrances, allow replacement as a cure for default, and allow a change of end-users.

8.5 time to respond to RFP not congruent with time required to aggregate CDM customers

There was a strong feeling amongst aggregators that the time constraints of the RFP process made it impossible for them to compete effectively. They felt caught – unable to sign up customers unless they won the RFP, but unable to win the RFP without having customers signed up. There was also a feeling that there were significant risks involved in the financial structures of the contracts if they were unable to sign up customers at the rates they suggested in their RFPs. Possible solutions put forth include allowing CDM providers to substitute rental generation during the initial portions of their contracts, or the use of standard offer contracts.

8.6 desire for standard offer

Most of the CDM stakeholders expressed that standard offers would be appropriate for promoting the development of CDM in Ontario. They agreed that standard offers could help address issues of timing, complexity, and financing that are otherwise difficult to overcome. There was, however, little agreement about the details of standard offers that should apply to CDM projects. It appears that any standard offer for CDM would require very flexible terms to accommodate the diversity of projects that could result in demand reductions, and creativity in terms of how these projects would be priced.

9 Observations and recommendations

Building upon the experience of the Ministry of Energy and the input from stakeholders, there are many ways in which OPA can enhance future contracting processes. These include simplifying the process, creating separate processes for specific types of projects, and creating additional contracting processes in parallel to the issuance of large scale RFPs. However, some changes to the process are not within OPA's control. Below, we first discuss the issues which stakeholders may wish to take up in other forums; we then review procedural changes which are within OPA's purview.

9.1 some stakeholder comments are outside of OPA mandate

As noted elsewhere, there are a number of stakeholder comments which, though potentially of merit, are outside of either the control or the mandate of OPA. These include, but are not limited to:

- transmission bypass;
- tax incentives;
- debt recovery charge and rate design;
- gross/net billing;
- standby costs;
- wholesale market design issues;
- industrial policy/economic development, for example as regards to the steel and timber industries in Ontario;
- gas infrastructure; and
- energy and environmental policy.

That is not to say that OPA itself is not a stakeholder in many of these processes, in particular rate design, wholesale market design, and gas infrastructure evolution. However, it has direct responsibility for none of these issues. While one would expect OPA to be an active and weighty participant in Independent Electricity System Operator (IESO) market design processes and in Ontario Energy Board (OEB) ratemaking procedures, IESO is ultimately responsible for market design and OEB for rates. Likewise, OPA itself does not make policy; concerns about the overall framework for energy and environment-related issues need to be addressed to the relevant ministries.[6]

[6] One area not strictly within OPA's mandate that may nonetheless benefit from some OPA initiative would be consideration of a single window permitting process for certain types of projects, or at least a "lead agency" approach to coordinating such processes. Any such initiative could only proceed with ministerial cooperation, however.

9.2 recommended enhancements to the contracting process

Although the contracting process was complex, and some stakeholders may have found it to be frustrating, many features of the process were not inconsistent with processes in other jurisdictions. Nonetheless, stakeholders are right that there are several areas in which improvements could be made. Many made the point that the process appeared to place great importance on adherence to procedural formalities as the definition of a "good" process, at times perhaps to the detriment of the desired outcome. Stakeholders repeatedly expressed a desire for more communication during bid processes, if possible through less formal and rigid channels. This seems reasonable, and can be accomplished without providing an unfair advantage to any bidder; the key is simply to assure that responses are consistent, and made available to all interested parties. We believe that a concerted effort can be made to simplify the process, without losing sight of either the objective of sustainable least cost procurement or of fairness to participants. In addition, we believe that the practice of providing a "take it or leave it" contract form can be modified to allow some flexibility on key terms, provided OPA deems proposed alternative language to be mutually beneficial. We present a number of specific recommendations below, as well as delving into recommendations for particular technologies and sub-groupings.

9.2.1 general procedures

There are six areas in which we think all of the contracting processes could be improved; these include five which apply across contract types (prequalification, collusion, firm response date, financing, and security), and a sixth (modification of deemed dispatch) which would require evolution should the contracts-for-differences approach be applied in the future.

Prequalification: Using a prequalification phase helps to ensure that resources are not wasted, either by bidders in preparing responses which have little chance of success, or by evaluators in examining a plethora of long shot projects. Bidders would first submit a brief description of the project or projects they intend to build; permits and land options would not be required, but a description of how such items would be obtained and the timing would be. Prequalification should be limited to a number of reasonably objective criteria. These could include the feasibility of the proposed project, a measure of bidding group net worth relative to the proposed project cost, experience in constructing similar projects of similar magnitude, record in completing projects within the time allotted, and general overall understanding of the terms of the solicitation.

Collusion: A unique feature of the Ontario contracting process was the treatment of collusion. Definitions were ambiguous, the restrictions of little relevance to the behavior they were trying to prevent, and likely were counterproductive in allowing the best, sustainable, least cost solutions to be put forward. Future contracting processes should simply require bidders to state that they have not colluded with any other bidder, have abided by all Federal and provincial laws, and have not had access to the final pricing included in any other bidder's submission. Professional services firms advising various teams are capable of putting in place an appropriate separation between team members working for different bidders; equipment manufacturers are likely to try to get the best deal for their equipment from any potential buyer. Existing laws are sufficient to guard against anti-competitive practices; there is no need to place additional burdens on bidders to comply with more restrictive definitions of collusive behavior when such behavior is neither illegal nor likely to contribute to bidding anomalies.

Fixed response date: Several bidders expressed concerns about having been forced to hold their bids fixed for a long period of time in a rising price environment. In fact, as we note elsewhere, the response time in Ontario was not particularly long when compared against processes in other jurisdictions. That is not, however, to say that the length of time that elapsed in the first processes would be appropriate in future instances. There are two aspects to the length of time until response which cause angst for bidders; this angst translates into higher bids to cover risks associated with changes in input prices. The first is the sheer uncertainty factor – processes which lack a defined and immutable response date mean that proponents must pick the longest period possible over which to fix their input prices, leading to higher costs. The second is simply with the amount of time it takes; even granting bidders some certainty, but leaving a lengthy review period, may not reduce bidder costs significantly. We believe that a well-managed procurement agency should be able to offer both a firm response date and a quick response turnaround. Provided the procurement authority is appropriately staffed, has specified the evaluation procedures clearly and in advance, and is operating within its mandate, we believe that it should be capable of promising (and delivering) a response within 30 days of receiving the proposals.

Financing: A technically feasible project sponsored by an experienced developer which receives a reasonable contract for its output from an investment grade entity is highly likely to receive financing. Aside from the net worth provisions of the prequalification phase, the contracting process should not place a major emphasis on having financing in place when the bid is submitted. Upon selection, the proponent should be given a period of time to provide evidence of firm financing; if financing is not obtained within the appropriate timeframe, the next lowest bidder would be contacted.

Security: Stakeholders made several sensible suggestions with regards to bid security. Recommendations that the amount of bid security should be proportionate to the size of the project proposed [as indeed it was in the previous processes], and decrease as construction nears completion, are both sensible, and should be adopted. However, in magnitude, the amount of security required is consistent with similar processes in other jurisdictions. Furthermore, we do not agree that certain projects should be exempt from security provisions, though certain aspects could be modified for smaller projects.

Deemed dispatch: The contracts for differences approach adopted in the initial contracting rounds had merit. However, aspects of it were unnecessarily complex. Instead, if a contracts for differences format is utilized in future procurements, we would recommend replacing the deemed dispatch with an approach in which bidders themselves would set the parameters that they would be expected to meet. Winning bidders would specify operating parameters in their proposal. They would then be required to periodically submit audited availability and bidding records, and to identify any instances in which actual performance deviated from proposed performance. Any required true-up payments would be adjusted on a pro-rata basis to reflect actual availability and bidding behavior.

9.2.2 cogeneration specific issues

Cogeneration presents a number of specific issues, some of which will be dealt with in greater detail through other OPA forums. However, OPA has already adopted the approach of procuring cogeneration in a separate process; this was one of the most common issues raised by stakeholders. Aside from the need for a separate process, the two most frequently raised issues were the incongruity between the contract response time and the time required to negotiate with steam hosts, and the provisions associated with retention of the steam host. Other comments, such as allocating a particular amount of capacity to each industry, we believe are outside of OPA's mandate. Given that OPA has been directed to procure 1,000 MW of capacity from cogeneration facilities[7], it should seek to do so in a least cost sustainable fashion, without regard to the composition of the industrial hosts within the portfolio.

We believe that although cogeneration is a complex and industry-specific process, OPA may be able to adopt a simplified approach which requires proponents to specify the amount of energy they would like to sell to OPA, divided into peak and offpeak periods, and varying seasonally if need be. We believe that where possible OPA should avoid taking on fuel supply risk; proponents bear this risk for the inside-the-fence portion of the project, and are certainly capable of managing price risk for a range of commodities in general. Instead, contracts might allow for a gas price threshold beyond which suppliers might have the option of curtailing deliveries, or differential pricing depending on whether the project sponsor or OPA takes on the fuel supply risk.

By moving to a solicitation which is predominately based on the price of the energy offered to OPA, we can minimize the issues associated with steam host retention. Sellers would have an obligation to deliver energy to OPA in the specified quantities for the duration of the contract, or face liquidated damages. Loss of the steam host would not automatically terminate the contract; instead, it would be up to the supplier to determine whether to continue to supply OPA through the existing facility, run now as a stand-alone energy generation facility, or to purchase power from third party sources to meet its obligation. However, to assure that the steam host had a reasonable chance of viability throughout the life of the contract, OPA would take into account credit ratings and other relevant financial data on the steam host when awarding the initial contract.

To meet the need for providing a timeframe consistent with negotiations with steam hosts while at the same time engaging in sensible least cost procurement practices, we suggest a modification to the "Swiss challenge" approach.[8] The "Swiss challenge" is described in the OPA commissioned "Report on *Large Dollar* Procurement Approaches". This procurement

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[7] The cogeneration directive was announced as part of the coal-plant replacement strategy. For more information, see the backgrounder on the coal replacement strategy on the MOE's website, http://www.energy.gov.on.ca.

[8] Notwithstanding the fact that each contract may be very unique, ultimately, they can each be distilled to the amount of power the sponsor wants to offer OPA and at what price. Every plant in the system is unique; each nonetheless ultimately converts into a long run marginal cost function which allows for an apples-to-apples comparison.

approach involves taking a proposal from a vendor, summarizing key points, publicizing those key points, and providing other potential vendors an opportunity for a limited period of time to match or beat the terms on offer. In the case of cogeneration procurement, we would suggest an initial call for tenders in which suppliers would name the amount of energy they would like to supply, their price, contract length, and other key contract provisions. This call for tenders would be announced with sufficient lead time (four to six months) for proponents to assemble the appropriate team members and make preliminary arrangements associated with the project.

OPA would select an initial cut of proposals which provide the required capacity at the lowest net present value of obligations. It would then publish the terms of the proposed contracts, and provide a three month period for suppliers to present alternatives that would allow OPA to achieve the same objectives at a lower cost. At the end of the three month period, OPA would finalize the list of projects, and proceed with the procurement.

9.2.3 renewables-specific issues

Renewables-specific issues fall into two broad categories: price and system integration. On price, there appears to be broad support for some sort of standard offer; our views on standard offer pricing are presented later in this document. It should be noted, however, that certain types of renewables impose costs on the system which are over and above the cost which is paid for the energy that they produce. This can include issues in dealing with intermittent resources, such as wind. The cost to procure additional ancillary services to balance certain renewable resources needs to be taken into account when examining least cost procurement alternatives. When comparing one set of renewable resources to another, those renewables with the least additional system costs clearly have an advantage.

When it comes to removing barriers to renewables at the system level, in terms of grid connection and transmission extension issues, these issues are largely outside of OPA's mandate. Adopting a standard offer gives renewables developers time to deal with any unique connection issues which arise. Transmission issues are more challenging, in that in some cases the cost of transmission to serve the renewable resources may exceed the value of the resource itself. OPA needs to walk a fine line between recognizing that renewable resources add value through portfolio diversification and their environmental attributes on the one hand, and procuring renewables regardless of cost on the other. Without in any way diminishing the role that renewables can play in the Ontario power system, stakeholders also need to recognize that not all renewables projects are worthy of funding; just because it is green does not necessarily mean it is good, at least when a project is so substantially out of the money that the added cost could be used to fund other more beneficial activities.

9.2.4 CDM and demand response (DR) related issues

Although the two are often conflated, CDM and DR are two very distinct resource types and need to treated separately. As with renewables, there are attributes of demand response which may lend themselves to some form of standard offer. Demand response can play a key role in reducing super-peak prices and in mitigating market power in the wholesale generation market. Based on experience in other jurisdictions, OPA may wish to set a target for procurement of demand response. In our companion paper, we suggested a series of periodic auctions to set prices for demand response procurement. In general, we believe that this would be the best approach for addressing demand response needs in the near term.

However, should such auctions prove to not be feasible, OPA could explore using a percentage of a peaking plant referent price as a standard offer. OPA could offer to enter into three year contracts with proponents up to a total capacity threshold. OPA would pay capacity prices consistent with those it would pay to a new simple cycle gas turbine[9]; when the demand response is actually called, OPA would pay an energy price based on a formula using a relevant gas index adjusted for delivery to points in Ontario multiplied by the heat rate of a new peaking facility. Proponents would face liquidated damages should they not be able to provide the contracted load reductions when called upon. We suspect that such a standard offer could produce economics which are quite generous to demand response suppliers, which is why we prefer the auction approach. However, if the demand response standard offer were volume limited, and viewed as a means of jump-starting a promising industry, it could be a reasonable initial policy.

Conservation and demand management are a far more challenging issue from a procurement perspective. Measurement and verification can at times be highly subjective, and the baseline of what demand would have been without CDM is almost impossible to determine with any degree of precision. Such programs also risk subsidizing choices that consumers might have made anyway. CDM has been the subject of a number of OEB proceedings, which focused on the role of local distribution companies (LDCs) in providing CDM, in compensating them for it, providing incentives, and making up for lost distribution revenues on the volumes conserved.

We believe that, given the fragmented nature of the Ontario distribution system, one key role for OPA is in simply serving as a best practices clearing house on CDM, even to the point of perhaps developing a model CDM program which LDCs could choose to adapt if they wanted. By serving as a facilitator of LDC-level initiatives, OPA can avoid duplicating LDC efforts and leverage off of activities which are already taking place. If OPA identifies customers or conservation activities which are beyond the reach of LDCs, it may also want to develop programs tailored to those specific circumstances. Clearly, however, CDM is not an activity which can take place through a standardized contracting activity, and we would not envision a future RFP process based solely on CDM.

9.3 thoughts on standard offers

In our companion paper on experience in other North American jurisdictions, we presented some thoughts on applying standard offers in Ontario. Standard offers have had mixed success in other jurisdictions. While they have succeeded in encouraging the development of those resources which qualify, they have not always resulted in appropriate amounts, types, and locations for new generation. As such, we believe that any standard offer should be targeted

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[9] These reference prices would take as their basis the all in payment required to provide returns on and of capacity to a peaking facility at a zero percent load factor.

and volume limited; that there should be relatively few separate categories of pricing tiers, to avoid over-emphasizing the more expensive types of renewable resources; and that, as an alternative to a standard offer for those technologies which are significantly out-of-the-money, a series of challenge grants or other limited subsidy mechanisms be deployed.

Where possible, some form of competitive process should be deployed to set the standard offer reference price. This might take the form of an informational bidding round, in which participants submit qualifying projects and the payment they would require converted to a dollars per MWh basis. OPA would review the submissions, and set the standard offer at a level consistent with the prices submitted. Suppliers would be paid an energy price for all the energy produced, but to encourage availability, zero or limited capacity payments would be paid.

As discussed in our companion paper, an alternative approach to the standard offer would be to set the standard offer price based on a specified premium above the previous year's average hourly Ontario electricity price (HOEP).[10] The standard offer price would be set in January for all projects brought online in the subsequent year, and would be fixed for a specified period of time – we would recommend 10 years, consistent with the life of debt financing for such facilities. This would lead to different prices for resources brought online in different years, but would also serve to signal to the renewables community when new resources are needed.

9.4 OPA role in market evolution

As buyer of last resort, OPA has a substantial impact on the evolution of the Ontario electricity market. As such, any contracting exercise must take into account the impact the contracts will have on market development. It would be incorrect to refer to OPA as a single buyer, given that in Ontario's hybrid market system it remains one of many electricity purchasers; OPA is not a pure monopsonist, but is likely the most influential among the multiple buyers in the market.

It is clear, however, that there are not enough buyers in the Ontario marketplace. This leads to a lack of liquidity, particularly in forward markets. This lack of forward liquidity in turn makes it more difficult for private sector proponents to finance projects independent of OPA. Some stakeholders feel that the very structure of the CES contract contributes to the lack of liquidity in the forward markets, since under the deemed dispatch formula sellers would be penalized for entering into a long term contract which at times meant accepting less than the HOEP, even if they would otherwise as a normal commercial decision would have decided to hedge a portion of their forward sales through a medium or long term contract. As previously noted, the most straightforward way around this problem is to revise or eliminate deemed dispatch, replacing it with an audited availability standard. OPA could then rely on the incentives in the marketplace to assure that the plant runs when it is economic to do so; after all, given that the

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10 We suggested 125% of the previous year's average price; this is consistent with observed premiums paid for renewables by customers in other regions, depending on resource type and the structure of the program.

contract holder retains a portion of the profits over and above their minimum payment level, they clearly have a financial incentive to run at appropriate times.[11]

There has been discussion regarding the merits of replacing the contracts-for-differences structure of the previous contracts with a pure tolling arrangement in the next round of solicitations. A tolling agreement would effectively allow OPA to pay suppliers to operate plants and to meet certain availability targets; OPA would purchase fuel and dispatch the plant, taking on fuel supply and price risk.[12] We believe that OPA needs to carefully consider the implications of this alternative before adopting it. Administering tolling contracts would mean a significant increase in OPA's impact on wholesale electricity markets. OPA would also have a non-trivial impact on natural gas markets. OPA would need to develop a range of new skill sets, even if it were to contract out the management of the tolling arrangements. To maintain the trust of private sector players, OPA would need to develop trading protocols, and be seen to be bidding into the market in such a way that it does not artificially depress prices. In addition, public entities respond to risk management in different ways from private sector players; the discipline of the fear of going bankrupt is lacking in public sector firms. Although OPA envisions holding the tolling contracts for a period of time and then repackaging them into medium and long term contract strips to resell into the market, this transition could take time, and is unlikely to be effective in the absence of substantial buyside participation.

Regardless of whether OPA proceeds with contracts for differences or with tolling agreements, the development of additional entities who have load obligations and are exposed to price volatility is essential to the creation of vibrant, liquid, long term contract markets. A strategy of repackaging tolling agreements cannot succeed unless there are willing counterparties with a complementary need for the contracts. Although OPA cannot single-handedly create market conditions which allow the creation of alternative buyers, it can participate in the debates surrounding the creation of load serving entities, and in the evolution of the regulated rate option in Ontario. Working together with the OEB and the Ministry of Energy, it can help to put in place conditions that would lead to greater depth in long term contract markets. However, the lack of depth is less a function of the form of contracts that OPA uses, and more an indication of the lack of market participants exposed to long term price volatility.

Improvements can be made to the contracts for differences form of contract deployed to date in Ontario. Alternatively, tolling contracts can be considered. However, before making a choice in this matter, OPA should study the experience of other jurisdictions and learn from their experience. Particularly relevant is the experience of Alberta with the Balancing Pool; the Balancing Pool has evolved over time in a fashion designed to minimize any detrimental impact

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[11] It is worth noting that the amount of additional profit which current contracts allow suppliers to retain may in fact be too low, given the view of some participants that the deemed dispatch procedures failed to adequately account for start-up and other costs.

[12] A tolling arrangement, as described in the report Review of the OPA's CES Contract: "An alternative approach to the CES is to separate the risks of building and operating a power plant from those of buying fuel and marketing the energy output. The supplier is selling capacity, ancillary services and conversion services with a specific delivery point. The buyer (the OPA) assumes all risks associated with buying fuel and marketing the electricity produced i.e. managing the spark spread."; pp. 15

on the wholesale market, while at the same time contributing to liquidity by marketing forward strip products. While the Balancing Pool was created for a purpose very different from that of OPA, it too is intended as a transitional entity, and it shares certain characteristics with OPA. As such, it bears study before any final decisions are made on the format for future contracting initiatives.

9.5 concluding remarks

OPA faces a challenging task in balancing the various elements of its mandate. No matter how noble the policy objective, there needs to be some sort of cost-benefit analysis performed. Once objectives surrounding supply adequacy, diversity, renewables, and conservation have been clarified, OPA must then adopt a least cost approach to procuring resources accordingly. The evolution in the electricity supply mix in Ontario comes at a cost; this cost will appear higher to consumers for whom the price of power has been suppressed over the past two decades. Consumers already have misperceptions about the cost of power; furthermore, many underestimate the incremental cost of switching to substantial reliance on renewable resources. As OPA evolves its contracting procedures, it needs to be cognizant of the fact that it will be unable to fully meet the expectations of all stakeholders while at the same time maintaining an overall cost of electricity for the province which is competitive with other jurisdictions. However, by simplifying contracting procedures, by creating separate procurement processes for specific resources, and by exploring the possibility of time and volume limited standard offer processes, OPA can meet overall supply needs in a least cost fashion while also catalyzing a vibrant renewables and electricity conservation industry of appropriate scale.

10 Appendix A: participating stakeholders

Abitibi-Consolidated	Energy Ottawa	Pembina Institute
AES/Kingston Cogen	Energy Probe Research Foundation	Portlands Energy Centre
AMPCO	Energy Profiles Limited	Positive Power Co-op (OSEA)
APPrO	EnergyQBD	Positive Power Cooperative
Baden Community Power	EnerNOC	Power Up Renewable (OSEA)
Boralex	Enersource	Power Workers Union
Bullfrog Power	EnerSpectrum Group	Pristine Power
Calpine	GenPower/Stelco	Rentec Renewable Energy
Canadian District Energy Association (CDEA)	Green Breeze	Safety Power Inc.
Canadian Wind Energy Association (CanWEA)	Green Communities Canada CDM Presentation	Schneider Power
Chant Construction	Green Energy Coalition	Sithe Canada Holdings
City of Toronto	Helios Technologies	Sky Generation Inc
Coalition of Large Distributors	ICLEI Energy Services	Social Housing and Toronto and Region Conservation
CogenCanada	IESO	Society of Energy Professionals
CogenOntario	Imperial Oil	Superior Renewable Energy Coop (OSEA)
Comverge, Inc.	Inco Limited and IGUA	Tembec
Constellation Energy	Intelaport Network	Toromont
Countryside Energy Co-Op	International Group	Toronto Hydro Energy
Countryside Energy Co-op (OSEA)	Invenergy	Toronto Renewable Energy Co-op (OSEA)
DG Industry Task Force	Invesys Controls	Total Energy Advice and Management
Direct Energy	Johnson Controls	TransCanada Energy
Dofasco	MCW Light Heat Cool and Arbour Power	True North Energy
Durham Strategic Energy Alliance	Northland Power	University of Waterloo
EDA	NRGen	Wind Share
EKA & YES	Ontario Clean Air Alliance	Windfall Ecology Centre (OSEA)
Electric City	Ontario Greenhouse Vegetables Grower's	Windy Hills
EMIG	Ontario Sustainable Energy Association	Windy Hills Caledon (OSEA)
Enbridge Gas Distribution	Ontario Waterpower Association	Yousef Energy Services
Enbridge Inc.	OPG	
Enerconnect	Optimal Technologies	

11 Appendix B: stakeholder questionnaires

11.1 CES Questionnaire

Note: Stakeholders may present or discuss topics of their choice; however the following questions are intended to guide the discussion to ensure consistency of input into the stakeholder process. Responses by individual stakeholders will not be disclosed, however all responses will be aggregated and reported in summary without attribution.

1. Please state the name of the company or organization you are representing today.

2. Please provide a brief description of your organization.

3. a. What is your organization's past and present involvement in the development of power generation projects generally?

   b. What are your organization's future plans for participation in power generation development in Ontario?

4. a. What was your organization's or predecessor organization's involvement specifically in the 2,500MW Clean Energy Supply procurement process ("CES Process")? (Please include whether you were involved in submitting a final bid in the process.)

   b. If you did not participate in the CES Process, please indicate any impressions you may have had regarding the process, or go to question 12.

5. If you terminated your involvement in the CES Process, what was your main reason for doing so?

6. If your bid was disqualified, what was the reason given for doing so?

7. a. What was your organization's overall impression of the CES Process?

   b. In your organization's opinion, did Ontario succeed in procuring the generation it required at competitive prices pursuant to the process?

   c. Did it meet the government's goals for CES procurement?

8. What were the significant items that your organization believes could be improved in a future process in each of the four major categories below?

   a. The process itself

   b. The business and financial structure of the buyer / seller arrangement, including financial requirements

   c. Legal issues with respect to the contract form

   d. Technical issues / requirements

9. What changes to any of the four major categories could have resulted in a win-win for both the buyer and the seller? Please provide as much detail as possible.

   a. The process itself

   b. The business and financial structure of the buyer / seller arrangement, including financial requirements

   c. Legal issues with respect to the contract form

   d. Technical issues / requirements

10. a. What items of risk did the CES contract allocate to the buyer or seller that would have been more efficient to allocate to the other party?

    b. How would your pricing have changed if the risk was allocated differently?

11. In preparing your bid for the CES procurement process:

    a. How much time in person-hours did your organization devote to preparing a response to the RFP?

    b. What was your approximate cost of preparing your bid?

    c. How does this compare to other similar processes in which your organization has participated?

12. a. In what other procurement processes has your company participated?

    b. Would you regard any of these processes as a model for Ontario?

    c. If so, what aspects of these processes should be adopted in Ontario?

13. a. What is your organization's opinion on an option to bid for contracts of varying terms (i.e., 15, 20, 25 years, etc.)?

    b. How would your pricing change under different scenarios?

14. a. Would your organization be interested in a choice of either allocating the environmental attributes (i.e., NOX, SOX, GHG, Renewable Energy Credits, etc.) to OPA or retaining them within your organization?

    b. If given the choice, how would your pricing differ between transferring the attributes and retaining them (i.e., difference in price in $/MWh)?

15. How should OPA evaluate the non-electricity products and intangible benefits, including environmental attributes?

16. a. Should existing transmission restrictions limit projects in those restricted areas?
    b. If not, how should interconnection / transmission upgrades / impacts be paid for and by whom?

17. Please comment on the following potential processes each as an alternative to a competitive price bid on a fixed set of project specifications:
    a. OPA sets pricing criteria, and proponents bid what plant specifications (completion timing, plant characteristics, risk tolerance) can be offered at the set pricing criteria
    b. Standing offer procurement, based on the average results of a previous process, or other criteria. How would you propose OPA establish standing offer criteria?
    c. Sole source negotiations. When is it appropriate for OPA to enter into sole source negotiations and what controls should be in place to ensure the process results in a fair transaction for ratepayers?

18. a. How should OPA set pre-qualification criteria for its procurement processes?
    b. How should OPA evaluate developers' experience and qualifications in order to ensure proponents have the ability to deliver on their bids?
    c. When is it appropriate to restrict projects to more experienced developers versus allowing any developer to participate?
    d. What stage of Environmental Assessment, interconnection assessment or Permitting should a project have at the time of pre-qualification and at the time of bidding?

19. When and how should OPA require security or collateral during the various stages of a bidding process?

20. What other overall comments or ideas would you like to be considered for a future process?

11.2 CHP Questionnaire

Note: Stakeholders may present or discuss topics of their choice; however the following questions are intended to guide the discussion to ensure consistency of input into the stakeholder process. Responses by individual stakeholders will not be disclosed, however all responses will be aggregated and reported in summary without attribution.

1. Please state the name of the company or organization you are representing today.
2. Please provide a brief description of your organization.
3. a. What is your organization's past and present involvement in the development of power generation projects generally?
   b. What are your organization's future plans for participation in power generation development in Ontario?
4. a. What was your organization's or predecessor organization's involvement, if any, specifically in the 2,500MW Clean Energy Supply procurement process ("CES") and/or the 300 MW Renewable Energy Supply procurement process ("Renewables I") (collectively "CES/Renewables I Processes")? (Please include whether you were involved in submitting a final bid in the processes.)
   b. If you did not participate in the CES Process and/or the Renewables I Process, please indicate any impression you may have had regarding the processes or go to question 13.
5. If you terminated your involvement in the CES/Renewables I Processes, what was your main reason for doing so?
6. If your bid(s) was(were) disqualified, what was(were) the reason(s) given for doing so?
7. a. What was your organization's overall impression of the CES/Renewables I Processes?
   b. In your organization's opinion, did Ontario succeed in procuring the generation it required at competitive prices pursuant to the processes?
   c. Did they meet the government's goals for CES/Renewables I procurement?
8. a. What is your organization's overall impression of the Renewables II and III Processes currently in progress?
   b. Please provide your organization's opinion, if any, on the changes from the Renewables I Process.

9. What were the significant items that your organization believes could be improved in a future process in each of the four major categories below?
   a. The process itself
   b. The business and financial structure of the buyer / seller arrangement, including Financial requirements

c. Legal issues with respect to the contract form
d. Technical issues / requirements

10. What changes to any of the four major categories could have resulted in a win-win for both the buyer and the seller? Please provide as much detail as possible.
    a. The process itself
    b. The business and financial structure of the buyer / seller arrangement, including financial requirements
    c. Legal issues with respect to the contract form
    d. Technical issues / requirements

11. a. What items of risk did the CES/Renewables I Contracts allocate to the buyer or seller that would have been more efficient to allocate to the other party?
    b. How would your pricing have changed if the risk was allocated differently?
12. In preparing your bid(s) for the CES/Renewables I procurement processes:
    a. How much time in person-hours did your organization devote to preparing response(s) to the RFPs?
    b. What was your approximate cost of preparing your bid?
    c. How does this compare to other similar processes in which your organization has participated?
13. a. In what other procurement processes have you participated?
    b. Would you regard any of these processes as a model for Ontario?
    c. If so, what aspects of the process should be adopted in Ontario?
14. a. What is your organization's opinion on an option to bid for contracts of varying terms (i.e., 15, 20, 25 years, etc.)?
    b. How would your pricing change under different scenarios?
15. a. Would your organization be interested in a choice of either allocating the environmental attributes (i.e., NOX, SOX, GHG, etc.) to OPA or retaining them within your organization?
    b. If given the choice, how would your pricing differ between transferring the attributes and retaining them (i.e., difference in price in $/MWh)?
16. How should OPA evaluate the non-electricity products and intangible benefits, including environmental attributes?

17. a. Should existing transmission restrictions limit projects in those restricted areas?

    b. If not, how should interconnection / transmission upgrades / impacts be paid for and by whom?

18. What procurement methods should OPA use to procure "up to 1,000 MW of high efficiency combined heat and power projects across Ontario including industrial co-generation projects and district energy projects"?

19. Should there be one single process or multiple processes with different parameters for different fuel-types, industries, sizes, heat rates, thermal efficiency, etc.?

20. If there are multiple processes, how should the 1,000 MW target be divided amongst various types of CHP projects, industries, fuel-types, heat rates, thermal efficiency, etc.?

21. a. How should OPA evaluate CHP projects, especially the non-electricity products and intangible benefits?

    b. If a CHP project is a district energy project replacing the need for additional megawatts, how should the avoided MWs be measured?

    c. Should OPA utilize the same methods deployed by the OEB when making considerations regarding CDM initiatives?

22. How should the overall efficiency of a plant be evaluated against other benefits that may be provided by plants that have lower overall plant efficiencies?

23. a. How should OPA evaluate different projects with different power to heat ratios?

    b. Should there be different valuation parameters for projects that follow power demand more closely versus those that follow heat demand more closely?

24. a. What projects and technologies should qualify as "high efficiency" CHP projects for future CHP generation procurement processes?

    b. What projects should not?

    c. Should, for example, qualification for Class 43.1 be a test?

25. Should non-CHP distributed generation be allowed to compete with CHP due to the system benefits distributed generation provides?

26. What are the remaining barriers to CHP projects assuming OPA serves as a long-term counterparty?

27. a. How long should OPA continue entering into contracts for CHP projects?

    b. Should the support be different for different projects or products (i.e., electricity, steam)?

    c. If a steam host fails, what support role should OPA play?

28. a. What roles should OPA not assume for these projects?

    b. What roles should other stakeholders play?

29. Please comment on the following potential processes each as an alternative to a competitive price bid on a fixed set of project specifications:

    a. OPA sets pricing criteria, and proponents bid what plant specifications (completion timing, plant characteristics, risk tolerance) can be offered at the set pricing criteria

    b. Standing offer procurement, based on the average results of a previous process, or other criteria. How would you propose OPA establish standard offer criteria?

    c. Sole source negotiations. When is it appropriate for OPA to enter into sole source negotiations and what controls should be in place to ensure the process results in a fair transaction for ratepayers?

30. a. How should OPA set pre-qualification criteria for its procurement processes?

    b. How should OPA evaluate developers' experience and qualifications in order to ensure proponents have the ability to deliver on their bids?

    c. When is it appropriate to restrict projects to more experienced developers versus allowing any developers to participate?

    d. What stage of Environmental Assessment, interconnection assessment or Permitting should a project have at the time of pre-qualification and at the time of bidding?

    e. Should the financial viability of the thermal host be one of the pre-qualifications for CHP procurement processes?

    f. Are there any attributes of the US PURPA efficiency standards for cogeneration which should be adopted by OPA?

31. When and how should OPA require security or collateral during the various stages of a bidding process?

32. What measures can be taken to increase the awareness of OPA processes such that potential projects that might not proceed but for the benefit from OPA procurement processes are given a higher probability of proceeding?

33. How should the issues of system bypass be addressed for embedded generation projects, including, for example, the debt reduction, transmission and IESO charges?

34. Should existing district energy systems be allowed to bid into an RFP against proposed new projects?

35. What other overall comments or ideas would you like to be considered for a future process?

11.3 CDM Questionnaire

Note: Stakeholders may present or discuss topics of their choice; however the following questions are intended to guide the discussion to ensure consistency of input into the stakeholder process. Responses by individual stakeholders will not be disclosed, however all responses will be aggregated and reported in summary without attribution.

1. Please state the name of the company or organization you are representing today.
2. Please provide a brief description of your organization.
3. a. What is your organization's past and present involvement in the development of CDM and power generation projects generally?

   b. What are your organization's future plans for participation in CDM in Ontario?
4. What are the barriers to implementing CDM in Ontario assuming OPA provides support, including for example regulatory, legislative, interconnection charges, etc.?
5. Broadly speaking, what are the realistic opportunities for CDM in Ontario?
6. In your organization's opinion, what is the best method(s) of payment for CDM (i.e., taxpayer, ratepayer through LDC distribution charges, ratepayer through province-wide commodity charge, etc.)?
7. a. Should a distinction be made between in front of and behind the meter investments?

   b. Should reductions in line losses be included in the evaluation?
8. In you opinion, is CDM best delivered at a local or regional level, or a combination thereof?
9. What organizations are in the best position to deliver CDM programs (centralized, LDC/regional groups, NGOs, electricity retailers, OPA, etc.)?
10. a. What was your organization's or predecessor organization's involvement specifically in the 2,500MW Clean Energy Supply procurement process ("CES Process")? (Please include whether you were involved in submitting a final bid in the process.)

    b. If you did not participate in the CES Process, please indicate any impressions you may have had regarding the process, or go to question 18.
11. If you terminated your involvement in the CES Process, what was your main reason for doing so?
12. If your bid was disqualified, what was the reason given for doing so?
13. a. What was your organization's overall impression of the CES Process?

    b. In your organization's opinion, did Ontario succeed in procuring the CES it required at competitive prices pursuant to the process?

    c. Did it meet the government's goals for CES procurement?

14. What were the significant items that your organization believes could be improved in a future process in each of the four major categories below?

    a. The process itself

    b. The business and financial structure of the buyer / seller arrangement, including financial requirements

    c. Legal issues with respect to the contract form

    d. Technical issues / requirements

15. What changes to any of the four major categories could have resulted in a win-win for both the buyer and the seller? Please provide as much detail as possible.

    a. The process itself

    b. The business and financial structure of the buyer / seller arrangement, including financial requirements

    c. Legal issues with respect to the contract form

    d. Technical issues / requirements

16. a. What items of risk did the CES contract allocate to the buyer or seller that would have been more efficient to allocate to the other party?

    b. How would your pricing have changed if the risk was allocated differently?

17. In preparing your bid for the CES procurement process:

    a. How much time in person-hours did your organization devote to preparing a response to the RFP?

    b. What was your approximate cost of preparing your bid?

    c. How does this compare to other similar processes in which your organization has participated?

18. a. In what other procurement processes have you participated?

b. Would you regard any of these processes as a model for Ontario?

c. If so, what aspects of the process should be adopted in Ontario?

19. a. What is your organization's opinion on an option to bid for contracts of varying terms (i.e., 15, 20, 25 years, etc.)?

    b. How would your pricing change under different scenarios?

20. a. Would your organization be interested in a choice of either allocating the environmental attributes (i.e., NOX, SOX, GHG, etc.) to OPA or retaining them within your organization?

    b. If given the choice, how would your pricing differ between transferring the attributes and retaining them?

21. How should OPA evaluate the non-electricity products and intangible benefits, including environmental attributes?

22. Please comment on the following potential processes each as an alternative to a competitive price bid on a fixed set of project specifications:

    a. OPA sets pricing criteria, and proponents bid what project specifications (completion timing, project characteristics, risk tolerance) can be offered at the set pricing criteria

    b. Standing offer procurement, based on the average results of a previous process, or other criteria. How would you propose OPA establish standing offer criteria?

    c. Sole source negotiations. When is it appropriate for OPA to enter into sole source negotiations and what controls should be in place to ensure the process results in a fair transaction for ratepayers?

23. a How should OPA set pre-qualification criteria for its procurement processes?

    b. How should OPA evaluate proponents' experience and qualifications in order to ensure proponents have the ability to deliver on their bids?

    c. When is it appropriate to restrict projects to more experienced proponents versus allowing any proponent to participate?

    d. What stage of Environmental Assessment, interconnection assessment or Permitting should a project have at the time of pre-qualification and at the time of bidding?

24. When and how should OPA require security or collateral during the various stages of a bidding process?

25. What other overall comments or ideas would you like to be considered for a future process?

11.4 RES Questionnaire

Note: Stakeholders may present or discuss topics of their choice; however the following questions are intended to guide the discussion to ensure consistency of input into the stakeholder process. Responses by individual stakeholders will not be disclosed, however all responses will be aggregated and reported in summary without attribution.

1. Please state the name of the company or organization you are representing today.
2. Please provide a brief description of your organization.
3. a What is your organization's past and present involvement in the development of power generation projects generally?
   b. What are your organization's future plans for participation in power generation development in Ontario?
4. a. What was your organization's or predecessor organization's involvement specifically in the 300 MW Renewable Energy Supply procurement process ("Renewables I Process")? (Please include whether you were involved in submitting a final bid in the process.)
   b. If you did not participate in the Renewables I Process, please indicate any impression you may have had regarding the process, or go to question 13.
5. If you terminated your involvement in the Renewables I Process, what was your main reason for doing so?
6. If your bid was disqualified, what was the reason given for doing so?
7. a. What was your organization's overall impression of the Renewables I Process?
   b. In your organization's opinion, did Ontario succeed in procuring the generation it required at competitive prices pursuant to the process?
   c. Did it meet the government's goals for Renewables procurement?
8. a. What is your organization's overall impression of the Renewables II and III Processes currently in process?
   b. Please provide your organization's opinion, if any, on the changes from the Renewables I Process.
9. What were the significant items that your organization believes could be improved in a future process in each of the four major categories below?
   a. The process itself
   b. The business and financial structure of the buyer / seller arrangement, including financial requirements
   c. Legal issues with respect to the contract form
   d. Technical issues / requirements

10. What changes to any of the four major categories could have resulted in a win-win for both the buyer and the seller? Please provide as much detail as possible.
    a. The process itself
    b. The business and financial structure of the buyer / seller arrangement, including financial requirements
    c. Legal issues with respect to the contract form
    d. Technical issues / requirements
11. a. What items of risk did the Renewables I Contract allocate to the buyer or seller that would have been more efficient to allocate to the other party?
    b. How would your pricing have changed if the risk was allocated differently?
12. In preparing your bid for the Renewables I procurement process:
    a. How much time in person-hours did your organization devote to preparing a response to the RFP?
    b. What was your approximate cost of preparing your bid?
    c. How does this compare to other similar processes in which your organization has participated?
13. a. In what other procurement processes have you participated?
    b. Would you regard any of these processes as a model for Ontario?
    c. If so, what aspects of the process should be adopted in Ontario?
14. a. What is your organization's opinion on an option to bid for contracts of varying terms (i.e., 15, 20, 25 years, etc.)?
    b. How would your pricing change under different scenarios?
15. a. Would your organization be interested in a choice of either allocating the environmental attributes (i.e., NOX, SOX, GHG, etc.) to OPA or retaining them within your organization?
    b. If given the choice, how would your pricing differ between transferring the attributes and retaining them (i.e., difference in price in $/MWh)?
16. How should OPA evaluate the non-electricity products and intangible benefits, including environmental attributes?
17. a. Should existing transmission restrictions limit projects in those restricted areas?
    b. If not, how should interconnection / transmission upgrades / impacts be paid for and by whom?
18. Should there be one process for all renewable projects, or multiple processes with different parameters for different technologies, sizes, etc.?

19. Should renewable projects with the ability to be dispatched be included in the same process with other renewable projects, or should there be a separate process for these, or should they be included with non-renewable generation development?

20. Please comment on the following potential processes each as an alternative to a competitive price bid on a fixed set of project specifications:

    a. OPA sets pricing criteria, and proponents bid what plant specifications (completion timing, plant characteristics, risk tolerance) can be offered at the set pricing criteria

    b. Standing offer procurement, based on the average results of a previous process, or other criteria. How would you propose OPA establish standard offer criteria?

    c. Sole source negotiations. When is it appropriate for OPA to enter into sole source negotiations and what controls should be in place to ensure the process results in a fair transaction for ratepayers?

21. How should OPA set pre-qualification criteria for its procurement processes?

    a. How should OPA evaluate developers' experience and qualifications in order to ensure proponents have the ability to deliver on their bids?

    b. When is it appropriate to restrict projects to more experienced developers versus allowing any developers to participate?

    c. What stage of Environmental Assessment, interconnection assessment or Permitting should a project have at the time of pre-qualification and at the time of bidding?

22. When and how should OPA require security or collateral during the various stages of a bidding process?

23. a. What projects and technologies should qualify for future renewable generation procurement processes?

    b. What projects should not?

    c. Should, for example, qualification for Class 43.1 be a test?

24. a. How long should OPA continue entering into contracts for renewable projects?

    b. Should the support be different for different technologies?

25. Should non-renewable distributed generation be allowed to compete with Renewables due to the system benefits distributed generation provides?

26. What other overall comments or ideas would you like to be considered for a future process?

12 Appendix C: Class 43.1

Class 43.1 refers to a provision of the Income Tax Act that entitles taxpayers to an accelerated write-off of efficient or renewable-fueled generation equipment, and the deduction of certain expenses related to establishing and operating the equipment.

The following systems qualify for class 43.1[13]:

- *Certain cogeneration and specified-waste fuelled electrical generation systems;*
- *small-scale hydro-electric installations (not exceeding 15 megawatts of average annual capacity);*
- *wind energy electrical generation systems;*
- *enhanced combined cycle systems;*
- *expansion engines;*
- *photovoltaic electrical generation systems (three kilowatts capacity or larger);*
- *geo-thermal electrical generation systems;*
- *electrical generating systems using solution gas that would otherwise be flared during the production of crude oil;*
- *active solar systems (including groundsource heat pumps);*
- *heat recovery systems;*
- *specified-waste fuelled heat production equipment (Thermal energy systems qualify only if their primary purpose is to produce thermal energy for use directly in an industrial process).*

Compliance with Class 43.1 is often recommended as a possible evaluation criterion for CHP and RES projects.

[13] Source: Natural Resources Canada publication: "Tax Incentives for business investments in energy conservation and renewable energy."

13 Appendix D: stakeholder process documents

13.1 Letter to Stakeholders and Stakeholder Consultations Terms of Reference

Please see the following page.

Ontario Power Authority

175 Bloor Street East
North Tower, Suite 606
Toronto, Ontario M4W 3R8

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

July 8, 2005

Dear Stakeholder,

The Ontario Power Authority will be holding stakeholder consultations on the procurement processes for electricity resources to be conducted by the OPA. This will be an information gathering exercise that will, in conjunction with other studies being commissioned by the OPA, shape the OPA's future procurement processes and contracting structures for electricity resources. Stakeholder input is sought on the procurement process itself, as well as the commercial arrangements and contract structures between Buyer and Seller for electricity resources including renewable energy supply (RES), clean energy supply (CES), conservation and demand management projects (CDM) and high efficiency combined heat and power projects (CHP).

The Terms of Reference and an Application Form for the stakeholder consultation sessions are included in this package. Stakeholders who are interested in participating in this consultation are asked to indicate their interest by completing the Application Form and faxing it to the OPA at 416-967-1947, or by e-mailing a scanned copy of the completed application form to generation.procurement@powerauthority.on.ca by no later than the close of business on Friday July 15, 2005. The OPA will inform the stakeholders of their presentation or meeting time and date, and send the appropriate stakeholder questionnaire by Wednesday July 20. As it may not be possible to hear from all parties in this consultation, the OPA may ask some Stakeholders to provide their views through the written submissions.

The plenary session will be held on Tuesday July 26, 2005 from 9:00am to 6:00pm at a downtown Toronto location, to be announced. The individual sessions will be held from Wednesday July 27 through Friday July 29.

We look forward to hearing your views on this critically important issue.

Yours truly,

Paul J. Bradley
Vice President
Generation Development
Ontario Power Authority

Ontario Power Authority

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Stakeholder Consultations
OPA Procurement Process for Electricity Resources

Terms of Reference

Objective: To collect and document Stakeholders' views on the procurement processes to be conducted by the OPA for electricity resources. In particular, stakeholder input is sought on the procurement process itself, as well as the commercial arrangements and contract structure between the Buyer and Seller for electricity resources development – renewable energy supply (RES), clean energy supply (CES), Conservation and Demand Management initiatives (CDM), and high efficiency combined heat and power project (CHP). Stakeholders may present topics of their choice to the OPA; however a Stakeholder questionnaire will be provided for each of the CES/RES, CDM and CHP sectors in order to guide stakeholders.

The results of this stakeholder process as well as other research and consulting on generation procurement will be used by the OPA in establishing appropriate procurement processes and procurement contracts in future. Stakeholder input will be a key element for the OPA in establishing its procurement framework for its near-term and long-term mandates.

Process:

1. Written submissions from Stakeholders on the OPA's procurement processes are welcome at any time through July 29, 2005.

2. Stakeholders directly involved in power generation development (CES/RES), conservation and demand management project (CDM) development, and high efficiency combined heat and power project (CHP) development, and stakeholders directly involved in the procurement process, are invited to attend individual 1-hour sessions (Individual Sessions) with OPA representatives. These Individual Sessions have been structured to allow stakeholders to provide candid and detailed information to the OPA on its procurement process. As there are a limited number of time slots, the OPA may be required to limit time slots to stakeholders directly involved in the procurement or project development process. Individual Sessions are scheduled for July 27-29 at a location to be announced in downtown Toronto.

3. Stakeholders not directly involved in project development or the procurement process, including industry organizations and service providers, will be invited to attend a plenary session. At the Plenary Session, each stakeholder will be allowed a 15 minute block of time to present to the OPA, and entertain questions from the OPA and/or other attending stakeholders. The Plenary Session is scheduled for July 26 at 9:00 a.m. at a location to be announced in downtown Toronto. Stakeholders participating in the Individual Sessions may also apply to present to the Plenary Session; however first preference will be given to applicants not participating in Individual Sessions.

4. Stakeholders interested in presenting to either session should complete the Application for Presentation Appointment attached to this document. Applications must be received by fax, mail or e-mail by the close of business on July 15, 2005 as indicated on the form. Notification of Stakeholders' appointments will be communicated by e-mail or fax.

5. The OPA will retain one or more advisors to attend all sessions. Advisors will be responsible for collecting information from all stakeholders' presentations and comments. No comments will be attributed to individual organizations, but will be presented in a summary fashion.

6. Stakeholders attending Individual Sessions may present or discuss topics of their choice; however they are encouraged to consult the relevant Stakeholder Questionnaire to guide the input process. The appropriate Stakeholder Questionnaire will be sent to Stakeholders at the time the OPA notifies Stakeholders of their appointed time slot. Stakeholders presenting to the Plenary Session may present on the same items or items of their choice related to CES, RES, CHP, CDM and the procurement process.

7. All stakeholders may submit separate written presentations in addition to presentations made at Individual Sessions or the Plenary Session. All written submissions will be considered in the OPA's stakeholdering process, and may be posted on the OPA website and/or included in one or more OPA reports.

8. The OPA expects to report back to stakeholders as follows:

   a. A report summarizing the presentations to the OPA during private sessions and the Plenary session is expected to be posted on the OPA website by August 15, 2005.

   b. A second report incorporating the first report, written presentations, and other consultations commissioned by the OPA is expected to be posted by August 31, 2005.

   The OPA will attempt to notify all participating stakeholders when reports are posted to its website.

9. A list of the names of stakeholder organizations attending the Individual Sessions or the Plenary Sessions, submitting written submissions, or otherwise participating in the consultation process will be made available at the conclusion of the sessions or at the end of the stakeholder consultation process.

OPA Procurement Process Stakeholder Consultations

Application for Presentation Appointment

Organization Name:

Primary Contact:
Phone:
E-mail:
Mailing Address:

Alternate Contact:
Phone:
E-mail:
Mailing Address:

Session Preference: Please check one or both of the following:

_____ Individual 1hr. session with the OPA:

- **Number of persons attending ____**

_____ 15 minute presentation to Plenary Session:

- **Number of persons attending ____**

Scope of Presentation:

_____ Non-renewable power generation development (CES)

_____ Renewable power generation development (RES)

_____ Conservation and demand management projects (CDM)

_____ High-efficiency combined heat and power project development (CHP)

(note: an organization may present to the OPA in one or more of these scopes)

Preferred Date/Times: (optional)*

1.

2.

3.

4.

5.

The OPA will make every effort to accommodate applicant's preferred date/time; however no guarantees can be made

- Plenary Session: 15 minute slots from 9:00 a.m. to 4:45 p.m., Tuesday, July 26
- Individual Sessions: 1 hour slots from 9:00 a.m. to 5:00 p.m., Wednesday, July 27 through Friday, July 29

Please return completed applications no later than the close of business, Friday July 15, 2005 to:

Ontario Power Authority

Attn: Generation Procurement

175 Bloor St. West, Suite 606 North Tower

Toronto, ON M4W 3R8

E-mail: generation.procurement@powerauthority.on.ca

Fax: 416-967-1947

Questions or Comments should also be directed to the address listed above.

Ontario Power Authority

175 Bloor Street East
North Tower, Suite 606
Toronto, Ontario M4W 3R8

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

Sept. 9, 2005

Re: OPA Stakeholder Consultations – Procurement Process for Electricity Resources

Dear Stakeholders:

On July 8, 2005 the Ontario Power Authority announced a stakeholder consultation process to be held between July 26, 2005 and July 29, 2005. The stakeholder consultation was an information gathering exercise that, in conjunction with other studies commissioned by the OPA, will help shape the OPA's future procurement processes and contracting structures for the procurement of electricity resources. Stakeholder input was sought on the procurement process itself, as well as the commercial arrangements and contract structures between Buyer and Seller for electricity resources including renewable energy supply (RES), clean energy supply (CES), conservation and demand management projects (CDM) and high efficiency combined heat and power projects (CHP).

The OPA invited over 100 stakeholders to participate in the process. We received presentations from approximately 65 stakeholders over the course of a four day period, and received written presentations from a number of stakeholders that did not make presentations. Many of these presentations can be found on our website www.powerauthority.on.ca along with the additional reports commissioned by the OPA.

The presentations and submissions from stakeholders were highly informative and very thought provoking. We believe that we heard in the aggregate, balanced points of view on most of the topics on which consultation was sought. There were a number of recurring themes and positions that came through to us quite clearly. Many of these common themes are summarized in the report by London Economics International "Stakeholder Consultations for Centralized Power Procurement Processes in Ontario" as well as our internal "Interim Report - Summary of What We Heard in Stakeholdering Sessions" report.

The OPA would like to make several concluding comments on this stakeholder consultation process:

1. First and foremost, we would like to thank the stakeholders that participated in the consultations for the substantial time and effort that went into the presentations and submissions. Virtually all of the presentations and submissions reflected careful thought

and attention to the subjects at hand. These presentations were of great value in understanding the ideas and needs of all sides of the interests associated with procuring generation resources.

2. The interests in the electricity sector are complex and require a delicate balance of the competing objectives. Changes to the industry, however small, impact some stakeholders much more than others. For every progressive project or technology that requires additional funding from electricity rates above current levels, there are consumers and industries that feel the impact of every small increase in power prices. The OPA must weigh each of its actions with care, in order to ensure that each procurement has an appropriate and measured effect on all stakeholders.

3. Communications with stakeholders is perhaps the most significant component of ensuring an appropriate balance of interests going forward. We consistently heard from stakeholders that increased dialogue, especially during the procurement processes, is necessary to increase the effectiveness of the procurement initiatives. The OPA will structure its procurement processes beginning in the Fall in a manner that allows increased and consistent dialogue with proponents in a fair and transparent manner.

4. The OPA was urged to strike a better balance between the requirement for robust processes to allow for fairness and transparency, and the complexity of the process to avoid making them expensive, cumbersome and inefficient. We heard that a robust process is not an end to itself – the process must lead to the selection of sound, reliable projects that make economic sense. The OPA has already begun to evaluate various options for creating more manageable processes in the future. These options include more targeted solicitations by geography, size and type or technology of the required resources.

5. We heard overwhelming support for a "Standard Offer Contract" structure to allow small and renewable projects to be developed without the complexity, cost and schedule of typical RFP processes. The OPA has embarked on an effort with the OEB to develop an appropriate Standard Offer program to aid in removing certain barriers for small and renewable generators.

6. Cogeneration and Combined Heat and Power stakeholders provided a number of suggestions to address the barriers they face in implementing fuel efficient and environmentally responsible energy production. The OPA will announce by the end of September 2005 its plans for procurement for cogeneration and CHP, including a stakeholder workshop and tailored process for project proponents.

7. Lastly, the OPA heard a number of comments and suggestions from stakeholders that fall outside of the OPA's mandate. Such items included the need to address net versus gross metering, transmission charges, debt retirement charges, distribution charges, other thermal energy purchases, and tax incentives. The OPA that these complex matters all have an impact on the climate for investment in new generation in Ontario. However the OPA may only act within its mandate as defined by *The Electricity Restructuring Act, 1998.*

We look forward to introducing more streamlined, efficient and effective procurement processes this fall to address Ontario's electricity supply gap. This will require some give and take from all sides, to ensure the right resources are procured at the right prices and within the required time.

Once again, we sincerely thank all of the participating stakeholders and look forward to working with you more closely in the future.

Yours truly,

Original Signed by

Paul J. Bradley
Vice President
Generation Development
Ontario Power Authority

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Ontario Power Authority (OPA)

Stakeholder Consultations - General Procurement Database
Presentations July 26-29, 2005 (Includes Observers)

Company	
Aegent Energy Avdisors	Observer
AES North America East	
APPrO	Observer
Barker Dunn & Rossi (BDR)	Observer
Blake, Cassels & Graydon LLP	
Boralex	Observer
Bullfrog Power	
Calpine	
Canadian Urban Institute	
Cascades	
Chant Construction	
City of Toronto	
Coalition of Large Distributors	
CogenCanada	
Comverge	
Constellation Energy	
Countryside Energy Co-operative Inc.	
Direct Energy	
Dofasco	
Electricity Distributprs Association (EDA)	Observer
Enbridge Inc.	
Energy Profiles Limited	
EnergyQBD	
Enerlife Consulting	
Enersource	
EnerSpectrum Group	
EnerSpectrum Group	
GREEN (Grand River Eco Energy Network)	Observer
Green Breeze	
Hawkestone Communications	
Hearthmakers Energy Cooperative	
Helios Technologies	Observer
ICLEI Energy Services	
Imperial Oil	
Independent Electricity Market Operator (IMO)	
Independent Electricity System Operator (IESO)	
Industry Task Force	
Invensys	
Ivaco Rolling Mills	Observer
John Wolnik & Associates Inc.	Observer
Kingston Cogen Limited	
Ministry of Agriculture and Food	
Navigant Consulting	
Northland Power Inc.	
Ontario Clean Air Alliance	

Ontario Energy Board (OEB)	Observer
Ontario Power Generation	
Optimal Technologies	Observer
Optimira Cinergy	Observer
Ontario Sustainable Energy Association (OSEA)	
Peat Resources Limited - Clean Fuel	Observer
Positive Power Co-Op	
Power Up Renewable Energy Co-Op	
Prentice Yates & Clark	Observer
Pristine Power Inc.	
Regional Municipality of Durham (The)	
Rentec Renewable Energy Technologies Inc.	
Robert Cary & Associates Inc.	
Safety Electric Power	Observer
Safety Power Inc.	
Schneider Power	
Sherritt International	Observer
Sithe Canada Holdings	
Smart Synch	
SMS Energy Engineering Inc.	
Society of Energy Professionals (The)	
Stanton Bros.Limited	
Stelco Inc.	
Stratico	Observer
Superior Renewable Energy Co-Op	
Tembec Inc.	
Toromont Energy Ltd.	
Toronto Renewable Energy Co-operative	
Total Energy Advice & Management Ltd. (TEAM)	Observer
TransCanada Energy Ltd.	
True North Energy	
University of Waterloo	
West Wind Development Inc.	Observer
Wind Share	
Windfall Ecology Centre	
Windy Hills Caledon	

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Interim Report
Summary of What We Heard
in OPA's Generation Procurement Stakeholdering Sessions
July 26-29, 2005

As part of its mandate with respect to procurement of electricity resources, Ontario Power Authority (OPA) sought stakeholder comment and input on the procurement process to be utilized. As well, opinions were solicited on the commercial arrangements and contract structures between the buyer and the seller for electricity development for renewable energy supply (RES), clean energy supply (CES), conservation and demand management initiatives (CDM), and high efficiency combined heat and power projects (CHP).

Over the course of four days (July 26-29, 2005) OPA heard presentations from more than 65 companies, associations, organizations and industry groups. The OPA panel consisted of Paul Bradley, Vice President, Generation Development, with alternating assistance from Paul Shervill, Vice President, Retail Services, Peter Love, Chief Energy Conservation Officer, Mary Ellen Richardson, Vice President, Corporate Affairs, and Amir Shalaby, Vice President, Power System Planning. Representatives from London Economics acted as attendant advisors to OPA, and Gia DeJulio, OPA Communications, recorded comments.

OPA's panel was very pleased and encouraged with the level of effort and the quality of material compiled and presented by the stakeholders, particularly in light of the tight timeframe in which to prepare. While many stakeholders had already visited with certain OPA staff prior to this process, there was additional significant and valuable information to be learned from these formal presentation sessions. As well, certain parties, who had not had the chance to talk with OPA in earlier meetings, took advantage of the opportunity to share their opinions and, in some cases, provide information on some unique applications for electricity generation and conservation.

The comments below represent highly summarized comments from a very diverse range of interests. Therefore, certain of the comments may be in conflict with each other. The reader is encouraged to review the actual presentations and responses to questionnaires submitted by proponents on OPA's website http://www.powerauthority.on.ca/ . OPA has commissioned London Economics to provide a final report which will weight these comments according to the interests represented, and consider additional information and consultations to the stakeholder consultation process.

Many recurring comments and themes were delivered to OPA. These are addressed below.

1. Procurement Process (past and future)

General Comments on Past Government RFP Processes

Positive feedback regarding the past government Request for Proposals (RFP) processes included the following comments:

- The process was relatively transparent, which was good, and inspired trust
- The issue of level playing field, i.e., concerns with respect to OPG's role in generation were addressed
- Separate renewable energy procurement processes should continue

The bulk of the comments regarding the government's RFP processes described the challenges encountered by stakeholders. Observations included:

- legal and financial terms were too restrictive or too heavy
- Security deposit and contract signing required one developer to spend about $500,000 to prepare for one bid of 50 MW even though the project may not even succeed
- Bidding costs were very large compared to similarly sized projects in other jurisdictions
- RFP timelines were unrealistic for the many decisions required of third party customers in the case of aggregation requirement
- Process for CHP/cogeneration proponents did not achieved required results (i.e., generation in Downtown Toronto and West Greater Toronto Area)
- It was hard to bid on the RFP due to difficulty in signing a long term contract with the steam host and taking on risk to be dispatched like a combined cycle gas turbine plant
- Issue of rigour regarding the stage 3 process; strength of some of the successful proponents questionable
- Often difficult to get clarification on key items (e.g., bi-fuel eligibility)
- Proponents went up a steep learning curve, with considerable investment of time and effort by all
- Complexity of process/legal obligations/financial security scared off potential applicants; this was really designed only for 'serious players', not to entice new entrants or encourage project development; this was not a project development vehicle
- The long bid validity period with an uncertain award date imposed risks that could not be hedged; uncertainty regarding equipment procurement scheduling; uncertain construction shipping season; interest rate risk; currency risk
- Renewable procurement processes to date have excluded dispatchable hydroelectric generation, despite its significant value to the electricity system
- Process was unfriendly to developers, and risk allocation was inappropriate, especially with respect to natural gas supply and gas transportation
- The focus of the solicitations was too broad to assess a proponent's competitive position (i.e., comparing generation with Demand Response and Demand Side Management)
- Geography issue was too heavily weighted versus other generation location investment criteria such as gas issues and transmission issues

General Comments on Future OPA RFP Processes

There is a need for OPA to be balanced in its procurement efforts (i.e., not abuse its market power and impose non-commercial provisions on proponents). There is also a concern for the potential of OPA to unwittingly influence the market if it becomes too involved in manipulating the forward markets. Parties indicated the need for some body to be accountable for achieving lowest cost of delivered electricity in Ontario, until the Province has a workable competitive market, and it was suggested that this should be OPA's mandate.

The following is a list of general suggestions made about the OPA's generation procurement processes:

- Need an overall generation strategy, in the long term context
- Diverse supply is critical
- Engage government and energy leaders
- A predefined tendering process is inadequate
- View energy generation as an investment opportunity
- Renewable energy targets are aggressive: 2008 and 2009 dates for the RFPs can be a challenge for some of our industry (e.g., demand for wind turbines has driven prices significantly high)
- Narrow the focus of the solicitations by type of resource, size, location, etc., to make it easier to assess the probability of success, and then decide whether or not to proceed
- Sustainability of the process: rules should endure but include continuous improvement
- Balanced procurement across all sectors
- Ensure early identification of issues and potential delays to ensure recovery action or adjustments to overall plan
- Include effective assessment of project delivery risks
- Increase the importance of non-price factors, although price is still the most important
- Ensure projects have been adequately planned; ask follow-up questions
- Move fairly quickly via test systems to get programs in place before next summer's season
- Strategy must consider capitalizing on existing strengths in Ontario and on strategic partnerships
- Should be more ambitious to reflect Ontario's potential requirements, and the speed with which projects can be commissioned
- Allow OPA to weigh the project risk in the final selection process along with the price
- Continue to recognize future market mechanisms, e.g., the Day Ahead Market (DAM)
- a comprehensive DAM is needed by generators and by gas industry
- Target sustainability versus renewable
- Evaluation criteria depends on situation e.g., reserve margins, criticality of supply
- Maturity of the bid is important
- In more critical situations "intangible" criteria become more important: financial wherewithal, experience, track record, viability and probability of closing negotiations which result in a project that is developed on time and operates reliably
- Communicate with bidders consistently throughout process, and keep communications open

Transparency as a Recurring Theme

Not unexpectedly, many participants provided comments on the need for OPA's processes and decision-making to be transparent. Here are some related statements:

- Decisions should be fair in fact and in appearance; disclosure to the maximum extent possible respecting confidentiality
- Ensure any incentive in place is clear and upfront, eliminating unnecessary work by proponents
- Bids with contract terms of different lengths may be considered as long as method for valuing bids of varying lengths is clearly identified
- Additional evaluation criteria may be added for environmental attributes, as long as a transparent method for evaluating these benefits is established
- Require transparent rules to ensure OPG is not getting an unfair advantage in accounting for its costs in small hydro electricity projects

Lessons learned in other procurement processes

Several presentations referred to the BC Hydro RFP process and recommended the OPA consider its successes:

  - aspects of the B.C. model may be good for Ontario; see website http://www.bchydro.com/
  - fixed price tenders, subject only to permits for plant and associated facilities; penalty for failure to achieve permits
  - Two stage process, allows attrition early in the process before too much time and money spent; allows more effective collaboration in light of stringent non-compete provisions
  - Power Smart type of program is encouraged; Lyle McClelland is in charge of the industrial program in B.C.; buy or borrow from them, don't reinvent the wheel

Timing

Participants had some comments regarding RFP process schedules and timelines:

- Request for longer planning horizon for procurement, which accommodates development timelines, and a "cushion" for project failures; especially important for aggregators and large industrial cogen
- Locational and schedule requirements must be better defined and prioritized, and reflected in risk
- Consider the length of time between final bids and awards, and thus the need to hold bids fixed for a long period of time
- Fixed end dates would be nice to see
- Ensure proponents are meeting their schedules, as off-coal program targets are dependent upon this

Bidder Pre-Qualification

A few suggestions were made with respect to submitting bidders to a pre-qualification process:

- Implement a bidder pre-qualification step that assesses the financial strength and ability of a bidder which would result in a short list of bidders who can then submit a binding bid
- Follow a fair pre-qualification process that focuses on technical and financial strength as well as progress in project development; focus on a subset of potential projects which will improve the efficiency of the process by reducing the workload for all parties involved
- Participant qualifications: look to technical capability, experience, licensing as applicable, and evidence of real customer commitment

Geographic Considerations

Some participants had opinions regarding the effect of geographic considerations in generation procurement:

- Target future processes geographically to where power is needed
- Ensure evaluation bonus to projects meeting geographic target; i.e., gas transportation costs less to put a plant in south-western Ontario where power supply is not critical
- Be more specific with respect to deliverability, location and desired operational characteristics, e.g., serious Toronto area problem; off-coal program requires significant transmission investments to compensate for the location of new generation
- Limit project locations to specific areas if generation additions have been deemed to be the only viable solution to reliability issues

Transmission Issues

Include the cost of transmission as a component of overall project evaluation:

- Projects need to be valued on "delivered power" including upstream and capital costs
- Identify transmission constraints and upgrade costs early on in the RFP process as they have a significant impact on project location
- RFP should allow transmission sub-zones to be expanded by proponent-led, rate-base supported, transmission upgrades
- Important to consider the transmission cost of any proponent responding to an RFP
- Seller financing of transmission system upgrades is not workable

Natural Gas Issues

Recurring comments were expressed with respect to the effect natural gas pricing, infrastructure and nomination timing have on electricity generation:

- Consider the OEB's gas/electricity interface recommendations when developing future procurement processes
- Gas infrastructure risk/return considerations could be made clearer to bidders, including load balancing costs, terms, limitations, risks
- Bid requirement not in synch with gas infrastructure offerings

Need for different RFPs for different generation types

Most participants recognized the need to acknowledge different generation procurement solutions via different RFP processes. Comments included:

- Procurement process must be open and encourage competition; need separate processes for smaller, one-off and specialized technology projects
- Significant new generation and DSM are both required but do not procure them in the same RFP
- New base-load and peaking generation should not be procured in the same RFP; very different financial models are required for these different products
- Separate RFPs are required for each of Combined Cycle (CC), simple cycle peaking plants, cogeneration/CHP, DR and DSM

- There should be a separate process to support small (2-10 MW) hydro-electric development and create a power purchase mechanism that recognizes the hurdles of transmission costs and regulatory permitting
- Future RFPs should accommodate energy storage and peak shifting technologies

Pricing to be Paid to Generators

Participants had some helpful suggestions regarding the pricing structure or mechanisms that OPA should consider in future arrangements. The following comments addressed these pricing issues:

- Pay a premium for speed of bringing on new supply e.g., via load shifting
- Assume the marginal market effect in the valuation of peak shaving
- The current round of RFPs should provide a pricing benchmark; the uptake by generators will provide signals on required changes in pricing in future RFPs
- Pricing should consider system optimization i.e., Locational Marginal Pricing (LMP) and delivered cost (which might favour embedded generation)
- Consider the profitability index used by France and by the banking industry, i.e., discounted cash flow by dollar of cost; use this as the price setting mechanism which incorporates a fair rate of return for the investor and precludes windfall profits
- There needs to be different prices for different technologies
- Implement one fixed price proposal for 5 years for wind generation; set a price and projects will either be able to meet it or not; if they do get built they may not survive at the price, but that is not the risk of OPA
- Pricing should assume fuel risk, at least for the electrical portion of the output
- Top-up the rate for all CHP electrical power produced to 7.5-9.5 cents per kilowatt-hour (kWh) (on-peak); the top-up is commensurate with benefits delivered; it is not a subsidy but is a monetization of the benefits the project will deliver for the benefit of the entire system; if the project does not meet the reliability benefit expectation then it must pay back its top-up premium
- Proponents should be able to choose non-dispatchable or dispatchable, fixed or floating (natural gas) fuel pricing

Communication

A vast majority of participants commented on the need for good communication between OPA and future proponents. There is a need for bi-directional communication during the RFP process. Many participants praised the government's existing RFP website which accompanied the process, but would have preferred to also have had a more interactive means of communicating.

Listed below are comments on where OPA can improve on the communication aspects of government's past procurement processes, for application in OPA's future RFPs:

- What not to do: no public consultation; no cost/benefit analysis; incomplete information for consumers on the true costs of the plan
- What to do: transparency, and balance between consumer's right to know and commercial confidentiality; timely, understandable information about price impacts for consumers; regular reporting on all aspects of the performance of Ontario's electricity system by an independent third party
- It's important to learn who the short listed competitors are; proponents should be given an avenue to ask "process" questions at any time, even after question and answer (Q&A) phases are complete

- Website is a good communication tool, but need face to face opportunities too
- Direct communication to the extent possible in order to allow for efficient clarification of Q&As; still could be accomplished in a public forum to ensure transparency and openness; website with Q&As was very effective, but magnitude of questions raised was huge and the timeframes were tight

One good communication-related suggestion was the recommendation that, after awarding procurement contracts, OPA representatives and other provincial authorities should follow up by championing the process within the communities affected by the awarded projects.

Non-Collusion Restrictions

For those who expressed opinions on non-collusion provisions, there was unanimity regarding the difficult restrictions limiting the involvement of consultants and experts to assist proponents. To make an effective point about the difficulty of these restrictions, one participant brought to the attention of the panel Non-Collusion declaration language from the final RFP for RES II, Page 40 section 1, whereby the proponent must declare that it: "Is not a member of any other Proponent Team, except as a Proponent of a Proponent Team that is not Another Proponent Team". Much head shaking followed this recitation.

Further comments from participants included:

- With so few players in such a small market, non-collusion provisions limit the involvement of these players; there are so few parties with the skill set and capability to help prepare a bid, who are not already working on other projects
- Non-collusion provisions are too strict, eliminating opportunities for synergies between financiers
- These provisions should be limited to pricing
- Use of a Fairness Officer would be better for collusion issues
- Non-collusion language made it difficult for the partners of projects to reply to the RFP as a combined entity and then to apply as proponents of other projects
- Allow advisors and consultants to participate in multiple bids

Sole Source Negotiations

Some participants had opinions regarding sole source negotiations, i.e., the process of certain parties entering into bilateral negotiations with OPA instead of bidding into a more generic supply RFP.

Understandably, some believe that the RFP process is not well suited to all projects, but may be good particularly for small projects. Hence, it was recommended that in order for parties to be considered for such bilateral negotiations, project viability thresholds should be established. Also suggested was a hybrid process where a final contract would be based on price competition, but complemented with a bilateral contract negotiation to address barriers.

Sole source negotiations work in the natural gas industry:

  - Gas pipelines routinely use open season processes with some standard features and some negotiated elements
  - Pre-qualifications of parties are important; experience is preferable with a scoring matrix such as credit agencies use

The panel was reminded that OPA's enabling regulations contemplate the need and role for sole-sourcing negotiations. It is justified when comparators are not available.

Another hybrid situation was suggested whereby OPA would have full knowledge but could pick the parties to provide each aspect of the project; e.g., fuel supply, financing, etc. It may be that a bilateral negotiation process with clear and public evaluation criteria is the only way that industrial cogeneration projects will be "kick-started" in the near future.

Between RFPs there may be a chance or opportunity to bring in some additional projects via sole source negotiations due to projects possibly falling off or being disqualified from the RFPs. The panel was warned that investment won't come into Ontario without some form of bilateral contracting.

Other proponents commented:

- Dispatchable hydro-electric generation may require a separate process or a sole source negotiation that considers the value of peaking energy and ability to follow load (to help replace the dispatchability currently offered by Ontario's coal-fired fleet)
- Unique projects such as expansions to existing hydro facilities should be separately negotiated

Combined Heat and Power (CHP) Procurement Processes

CHP proponents advised that this form of electricity generation is very different from other generation types, thus requiring different treatment. A process targeted specifically at CHP/cogeneration is generally regarded as a positive move. However, parties want a simple process that can be relatively easily understood. It was recommended that OPA review Alberta's energy industry for the CHP market infrastructure, and the economic and social drivers.

Some participants believe that each natural gas fired plant should include a significant cogeneration component; single purpose thermal plants should not be built until cogen potential is assessed. Most recommended OPA procurement via direct sole-source negotiations, following a pre-qualification process.

Proponents had the following comments to make:

- Need an independent monitor of negotiations
- A premium should be paid for increased power generated during on-peak hours
- OPA should be indifferent to the project ownership structure and should not specify an industry
- Selection criteria should be based on competitiveness
- Developers and system planners should work together to create networks; take advantage of synergies
- Arrangements should be made retroactive for the past few years to accommodate Early Mover cases, i.e., plants which were built subsequent to the Electricity Act, 1998 but before the government's recent generation procurement RFPs were issued; this would result in increased operation of existing assets which are now sitting idle
- The renewable RFP process is more appropriate to industrial cogen because it allows projects to simply bid a price; this could take the form of a Standard Offer Contract that would achieve the needed level of price certainty for the project
- Scale of some cogen (i.e., district energy) is not large enough to compete on price alone, with large scale Combined Cycle

Need for Definition

An industry standard definition for high efficiency CHP doesn't exist; a proper definition should be established at the start of this process**.** Parties were polarized: some said Class 43.1 is not sufficient to qualify cogen projects while others said Class 43.1 is useful for defining such projects.

Contract Specifics

Below are suggestions received regarding the specific contract terms for CHP arrangements:

- Embedded load needs to continue to have dispatchable flexibility
- 6500 Btu/kWh was a recommended project heat rate
- The power contract should include a provision for base-loading the true cogen component
- Utilize a Matrix Grid for heat rate and output: ambient temperature and relative humidity should be applied
- 20 year contracts to match assets
- One industrial proponent gave an example that a $35 per MWh premium would make its proposed CHP project viable versus its current forecast
- A CHP Power Purchase Agreement (PPA) should lock in the value of power, provide exemptions from network and line connection charges and the Debt Retirement Charge (DRC); should also assign the tax incentives i.e., Capital Cost Allowance, and the Kyoto/GHG credits generated from the shutdown of coal plants; this will allow CHP to bid for more realistic prices
- Apply net load billing to CHP projects, no stand-by charges, as well as LRAM mechanism to offset the lost revenue to the Local Distribution Company

Comments on Fuel Issues

There was a criticism of the government's RFP being biased toward natural gas-fired combined cycle projects, as evidenced by the heat rate and indices utilized. However, while the majority of CHP plants are gas-fired, some participants addressed the topic of other fuels. The suggestions included:

- Consider a diverse fuel mix for the CHP generation portfolio; biomass, and by-product fuels should be included
- Projects should be evaluated and selected by fuel types on a competitive basis
- A separate procurement process should be developed for each of cogen and district energy with floor targets; e.g., industrial cogen 850 MW fossil fuel, biomass and by-product gases; District Energy; and Distributed Generation 150 MW gas fired

Ancillary Benefits and Value

Most proponents requested consideration be given to the indirect and non-financial attributes of CHP. (Although one party said OPA should leave environmental attributes undetermined at this time.) The procurement process should recognize the benefits and unique nature including generation efficiency, environmental emissions reductions, economic (for both the host industrial and electricity consumers), increased Canadian industry competitiveness, transmission and distribution avoidance.

Specific comments included:

- Place value on having a diversified portfolio of industrial cogen projects

- Employ a multi-process approach and apply a methodology to value other benefits besides electricity and to compare dissimilar projects: recognize and compensate for all the benefits of CHP and DG including transmission grid relief, diversification of demand side, dispatchability, proven technologies; take into account location, scale, efficiency, societal costs test, reduced burden on LDC infrastructure
- Establish clear project ranking system based on:
    - Environmental benefits
    - Industry benefits
    - Transmission and distribution benefits
    - Economic benefits
    - Product flexibility
    - Address traditional CHP challenges such as thermal host bankruptcy and loss of thermal load, etc.

Steam Host Issues

One of the elements which make CHP different from other generation types is the existence of a Steam Host. Industrial steam hosts operate on a 7 day per week, 24 hour per day basis and require a constant and stable flow of steam, even during hours when it is uneconomic to baseload gas fired power plants. This is a barrier as market rules don't recognize the inherent nature of a cogen plant to be a must run basis (baseload) and cannot be dispatched to meet balancing requirements of the power system.

Some participants expressed concern about the lack of understanding by parties that CHP may ultimately increase the financial heat rate due to the benefits or subsidies enjoyed by the steam host, ultimately paid by the ratepayers. Here are some further comments:

- Fundamental issue is the credit worthiness of thermal off takers (thermal or steam hosts)
- Loss of thermal host exposes cogen project investor to reduced revenues from lost heat sales and reduced electricity revenue due to higher heat rates
- Highly efficient cogen projects properly sized to match the host (i.e., high heat to electricity ratio) are especially exposed

Proponents had useful suggestions to make regarding the risks associated with the reduction or loss of steam host load. To compensate, the CHP project proponent may need more than one process or host taking steam. There should be as long a commitment as possible from the steam host(s), although most are unable or reluctant to commit to a long term guaranteed load. The evaluation process should be an economic analysis assuming steam usage is minimal, and then actual operation will likely be better than the analysis. Proponents made the following recommendations regarding contract provisions:

- Should the host suffer a permanent or prolonged shutdown, OPA should allow proponents' heat rate to rise well above the established; also allow more flexibility with regards to the cure period for loss of steam host
- OPA guarantee of revenue should apply whether owned by an Independent Power Producer or the steam user
- There should also be a way to exit from the contract if heat rate becomes an issue
- Host heat requirements fluctuate daily which will affect heat rate; proposed solution: OPA contract that provides back-stop to loss of thermal off-taker (short term and long term); also provide for a change in heat rate following change of thermal load
- Capacity payments under a tolling arrangement with baseload component
- May include front load payments to accelerate debt payment

- Risk of steam host is proponent's, hence, do not expect a price adjustment as a result of inefficiencies; proponents would expect to get paid for what they are able to generate; would not want to be penalized further for not being able to generate as expected

Timing may not align with RFP

CHP project proponents often target a window to capture economic benefits of avoided capital. These industrial parties have to attend to their business which may not align with OPA's RFP process. Hence, an RFP with a specific window is not preferred; instead proponents suggested OPA create a standing-offer open window for about 5 years to match CHP development. Then a steam host will be more likely to consider a CHP project when the opportunity arises. A volume limitation might make it too restrictive and brings an added element of risk. Comments about the government's RFP project:

- The RFP was too complex: timing was too rigid and certain cogen projects are ineligible for the simpler Renewables
- The RFP did not recognize that cogen projects might ramp up with power supply over time, and cannot bid a single price/volume
- Incongruence between timing of RFP and timing of customer approvals

In the future, OPA:

- Needs flexibility in terms of the RFP timelines and processes
- Timing not to be based on an arbitrary RFP timeframe but on timing in synch with a steam host, e.g., a new hospital being built
- Utilize an open bid period and a formulaic method for price determination

Small Distributed Generation (DG)

Most potential DG sites were not represented in the government's past RFP processes because of the complexity, and because the RFPs appeared to be designed for larger projects. A barrier to implementing is that there is still a concern with respect to connection requirements.

There were some specific comments within the CHP proponent group regarding small DG:

- Do not tilt the playing field to the small CHP projects
- Use separate RFP processes or sub-processes for projects with different capacities
- Group technologies into peaking, mid-merit and baseload, and into different sizes
- Make a simpler process for smaller projects for proponents with fewer resources
- Create a Standard Offer Contract (SOC) with uniform terms and conditions for any embedded generation; include hidden benefits of DG and make the process available for a period that will recognise host approval and development times
- Remove the current stipulation that proponents must be IESO market participants; no real need for a minimum size
- Desire a dedicated procurement process for a combined supply of 150-250 MW of high efficiency CHP less than 25 MW each plant
- Adopt an RFP "lite", to pre-qualify bids and reduce bid risks and costs

2. Contract

Participants in the stakeholdering consultations were asked about their views on contracts for generation procurement. Responses were very constructive, with specific examples and suggested provisions to improve upon the government's RFP contracts.

Comments on Past RFP Contracts

On a positive note, the term of the Clean Energy Supply contract was considered appropriate in ensuring the necessary financing of new generation and satisfied the risk profile. Also, certain participants said that the CES contract was acceptable; there was fair apportionment of risk between buyer and generator; the force majeure provided appropriate share of risk; and transmission upgrade costs were split appropriately between buyer and generator. What else was right: OPA now carries most of the risk associated with the political impact on the market.

Comments on the past arrangements included a lament about the lack of ability to negotiate on key terms. The contract was described as very one-sided in favour of the buyer, and that the CES contract in particular was inconsistent with a competitive forward energy market. The permitting risk between buyer and seller was particularly unfair in the recent York Region terms of reference. The force majeure provisions were insufficient to reflect the realities of permitting.

CES contracts put the "cart before the horse", as the government will be implementing those contracts without addressing who will pay for the increased costs (i.e., gas costs). Contract for differences was not typical, not transparent, and not easy to determine what is being paid for power; it will require auditing.

A start up energy value at a fixed price was not appropriate for a 20 year term, and long term contracts without any inflation adjustment are difficult if not unrealistic. The indexation provision tied to 15% of the bid price for renewable contracts does not adequately cover inflationary risks and instead resulted in inflated bid prices in order to manage the risks of foreign exchange and changing commodity prices. There was no reference to Location Marginal Pricing (LMP) in the contracts, which should be included.

A plant only being allowed to serve Ontario demand is not helpful as exports could be lifeblood for a generation plant. The arbitration process defaulting to courts is inefficient; some said "let OPA do it". The remedy for the third Capacity Test Check Failures was too punitive.

Recommended Contract Provisions

Participants had many suggestions on what provisions should be included in future OPA contracts for generation procurement.

Timing Issues

There were several consistent messages with respect to the term of the contract. Many participants expressed the need for a longer term fixed commitment in order to achieve an acceptable economic return on installation, particularly for hydro-electric facilities. Not inconsistent, however, was the desire to see in contracts the ability to "opt-out" (completely, partially or temporarily) in favour of alternative, market-based risk management mechanisms. Parties who see the role of OPA as transitional believe contract structure should facilitate economically rational forward contracting alternatives to long term public support of generation investment. "Ensure there are forward market options in long term contracts", it was implored. One recommendation was that OPA should support market changes which stimulate overall market liquidity by providing more incentive for the generator to opt out of the contract. A few participants suggested that there is an advantage in limiting the extent of these contracts in order to phase into an orderly market in the near term. Specifically, the agreement should be limited to the definitive contract (CES for example); the complete deal should be embodied in the contract.

Compensation

The panel was advised that prices set by OPA's contracts (including Standard Offer Contracts) will set the pricing for the entire market and for buyers in the market, suggesting that the compensation aspect of the contracts is the most critical. Participants would like to see compensation provisions in these contracts reflect the benefits inherent in various features of the different electricity supply arrangements. Some of these benefits include:

- Early commissioning e.g., pay higher price for early period
- Generators contracting for upstream supply and related transportation
- High level of supply availability
- Deemed operation reflecting actual IESO dispatch instructions
- Multiple starts in a day

Tolling Model

Many participants raised the idea of a tolling model in contract compensation provisions. The panel and certain participants discussed, in the context of CES, the possibility of splitting the "hardware" and marketing functions of generators via the use of tolling agreements, in order to have generation built and operated efficiently. Marketing rights could be sold separately without OPA being in a "market power" position similar to the Alberta Balancing Pool.

Here were some of the discussion points:

- Create a load serving entity (LSE) model to create aggregated buyer "pools", and to attract sellers to enter the market
- Force the market into a longer term merchant market, not just the spot market
- "Park" or delay the call option on the dispatch rights until there is greater market liquidity, then strip off the future merchant rights; OPA to hold this function until merchants take up the role
- If possible, this will not be a "20 year, government-backed, PPA world"
- Might need to tweak the tolling arrangement; baseload versus peaking plant may need to be structured differently; need to get demand into the forward market; the structured wholesale market might take some time, but need to put the option into these contracts
- A simple tolling arrangement with capacity payments would be preferred and is a lower risk for the seller; better return expectations for OPA too
- Use conventional tolling contracts as the basis for gas fired RFPs
    - Capacity payment to recover financing and fixed operating costs
    - Gas price and deliverability risk passed on to off-taker, heat rate stays with owner

Legislative and Regulatory Risk

Experienced parties are wary of changes in law and/or regulations which have the potential for enormous risk. The following suggestions were made in this context:

- Put values on issues which may not be controllable or changeable by OPA e.g., DRC, transmission issues, etc.
- Better apportion of regulatory risk on gas side between OPA and generator
- Changes in law that would normally be reflected in the market price of electricity should be recoverable by CES suppliers
- Regulatory risk re fuel supply issues, should be borne by OPA, including change in law

It was suggested to limit a buyer's total contract liability to a percentage of total contract price.

Other Contract Provisions

Comments on other provisions within electricity procurement contracts included references to full cost assessment, renewable classification and changing parties. Here is a sampling of these:

- Need to assess and disclose the full costs: contracted output, premiums, penalties, transmission upgrades (at site and for the grid), tax incentives, new tariffs
- Renewables classification should include zero incremental emissions technologies, i.e., fuel cells, off-gas, waste-heat recovery
- Green attributes: community power projects need choice in assigning green attributes; much depends on how they are quantified
- Class 43.1 test should be applied; i.e., should be approved by NRCan at the time of the bid
- Adjust tests for ambient conditions
- It may be advantageous for both parties to allow changes in the proponent team (e.g., equity) earlier in the life cycle of the project
- Contracting with an entity other than OPA may be possible as long as does not result in an unfair advantage to either party in the open marketplace
- Anything that can help manage the spark spread risk is good

Merchant Renewable Projects

Certain retailers expressed concern about this particular situation:

- If the Merchant Renewable Projects all choose to bid into RFP III and are successful, there will not be any green power for retailers until new projects can be built
- Resolution: OPA could guarantee retailers' contracts for a small portion of the output rather than becoming the primary obligor for Merchant Renewable power; this would allow the OPA to avoid the cost of a portion of this particular power source and encourage a green market, with the only risk being that the retailer defaults in which case the OPA would be in no worse a position than currently envisaged

Financial Requirements

Many participants expressed strong criticisms of the past government RFP processes regarding financial requirements including security deposits, foreign exchange and interest rate risk, project financing, guarantees, insurance, and penalties. Here are some of those criticisms:

- Project timeframes should have been constant; slippages caused issues with financing and foreign exchange and resulted in a requirement for the bid window to stay open

- Deposit was tied up for such a long time without knowing if and when process was proceeding
- Onerous penalties and insurance requirements were out of scope; commercial insurance would not typically go down to such a low level deductible for such expensive projects; insurance requirement was not industry norm
- Too harsh judgments for automatic defaults even if changes were to their benefit
- Financing commitment was relied on in lieu of buyer's due diligence, but was not subjected to testing in Stage 2; no means for evaluating completion risks
- Limitations on facility changes were unnecessarily restrictive
- Default cure periods were very short for project financing
- From bid submission to PPA signature and financial close there was no practical way to mitigate interest rates, foreign exchange, cost of equity, construction costs, etc.
- RFP II was very onerous e.g., 17 pages of financial questions; RFP III seems to have the same onerous requirements
- Financial security requirement, onerous bidding process and the criterion of lowest cost were all in particular barriers to community wind generation:

Fortunately, most parties had suggestions on how to improve the future OPA processes regarding financial requirements. Their comments include:

- Security should be in place when firm bid is to be relied upon; should be posted upon signing; reduce bid deposits to nominal amounts
- Would like to have seen in the Conditions Precedent examples of desired or unacceptable language e.g., the commitment letter
- Perhaps OPA should write the exact language needed in the financial letters from bankers
- Focus on assurances associated only with equity commitments
- Focus on the equity component; net worth 30-35% of the estimated capital cost should be adequate, given that security is in place
- Need for flexibility in the extent to which a full financing plan is in place
- If the sponsor of the project is prepared to be financially at risk for the bid and performance bonds, the specific details should be the sole responsibility of the sponsor; the RFP process should not preclude the sponsors from developing financing options after bid submission
- Performance security requirements should be amended to consider contractor security during construction, the creditworthiness of guarantors and the total liability exposure a CES supplier may have to the Buyer

Where prices are versus where they should be

Many parties including consumer groups implored OPA to balance the need to keep Ontario competitive (particularly for industrials), while also accounting for the true value of electricity. In this exercise economics should be a major consideration, as well as considering "pain threshold" pricing. If done right, the ratepayers should accept the outcome.

Standard Offer Contracts

A great number of participants in all sectors expressed interest in establishing some type of Standard Offer Contract (SOC). The creation of SOCs for embedded generation largely requires the support of the Ontario Energy Board (OEB), and OPA was asked by the OEB to poll these stakeholders on their views regarding SOCs. Many participants did have opinions to share, whether subject to these types of arrangements or not.

There are examples of proposed SOCs available including one by the Renewable Energy Task Team (RETT). Also, the Ontario Sustainable Energy Association produced a report (sponsored by the MOE) on this subject, which can be found on the association's website http://www.ontario-sea.org/pdf/PoweringOntarioCommunities.pdf

One participant listed the following potential features of SOCs:

- Size up to 10 MW; open to all players;
- 20 yr contract between generator and OPA;
- price: set to encourage project development where there is community support and sufficient resource e.g., wind greater than or equal to 5.6 m/s;
- guaranteed within reason and established safety guidelines;
- access to grid;
- 5 year pilot suggested 2005-2010 (no artificial cap such as the IESO's 100 MW); review in 2007

Some participants suggested treading carefully with respect to criteria for being eligible, and others said SOC should be available to all players, not just local community developers.

Some producers have said SOC should be implemented immediately for small projects (up to 20 MW) and that contracts should be with OPA (not the LDCs) for the sake of simplicity, although LDCs will manage the contracts and be involved. One contract which is between the generator and OPA offers:

- Ease of administration, without unnecessary bureaucracy
- Facilitates participant entry
- Ensures oversight of process

Others said it must be central agency designed. Provincially applicable rulemaking is preferable versus giving the role to LDCs; however, it is fine for LDCs to implement or handle settlement. When pushed further on this issue, parties admitted that it is largely an issue of LDC creditworthiness, as well as a desire to not have a range of procurement agencies. Parties are willing to consider an SOC process whereby the LDC becomes a "one stop shop" to sign the contract, with OPA as backstop.

Here are some further suggestions made by participants regarding SOCs:

Pricing

- Standard Offer price for CHP with a premium based on efficiency
- One fixed price (not a market price plus a premium) and purchase all power offered at that price
- SOC price once established should be reviewed annually and take uniqueness of water power projects into consideration
- Premium is appropriate
- Value delivery on peak
- Value line loss reductions, production in peak demand periods and other benefits

Other Issues

- Be rigorous but make it simple
- Distinguish between projects behind the meter and connecting to the grid; should be a detail as part of the implementation stage

- See DR a part of this as well; need alternate channels; allow for retailers, aggregators; need standardized and simplified assessments, interconnectivity, contracts, etc.
- Create a SOC for embedded generation
- Implement a SOC only if the necessary standard settlement system is also built; change only one settlement system, don't change 91 LDC systems
- Contracting structure should ensure procured capacity is available to forward energy markets; need to accommodate the fact that cost of entry is still greater than energy market value
- LDC entities are supportive and see their role as facilitating this for both the generator and the customers but have concerns about how to manage risks on bill financing
- SOC for small hydro is needed immediately coincident with Ministry of Natural Resources site release process, as these sites are already under development
- SOC that recognizes a different business model, will allow for smaller more diverse projects, and lower financial barriers to participating
- SOCs to emphasize simplified grid connection process
- SOC may address the issue that the current RFP mechanism is not accessible enough for farmers' renewables projects, which must have consultants to manage

3. Conservation and Demand Management

The issue of Conservation and Demand Management (CDM) was distinct from the other issues addressed during the four days of presentations. Suggestions made were specific to CDM and its components including Demand Response (DR). The government's Conservation Action Team (CAT) defines Conservation as the application of measures and practices to reduce the amount of energy consumed, and to increase the efficiency of energy consumption in equipment, buildings etc., in order to reduce the amount of energy consumed. CAT defines Demand Side Management (DSM) as measures and activities taken by a distribution utility and/or consumers to affect the amount and timing of electricity demand; usually this means decreasing the level of demand (through conservation or more efficient use of energy) or shifting consumption to some other time period when demand is typically lower. CAT defines Demand Response (DR) as actions voluntarily taken by a consumer to adjust the amount or timing of their electricity consumption. Actions are usually in response to price signals or utility incentives. Load shifting is an example of DR.

General Comments

Some parties recommended that the OPA proceed with caution as there is a lot of hype in this field, and many good ideas but not many that have been implemented. CDM must be part of the market, not running parallel and separate, and OPA must build a complementary framework to what already works.
It needs to be sure of getting the power reductions that are "for real" and it needs to know that they will happen by a given date.

Regarding the government's RFP, certain parties claimed that the CES process was designed for large scale generation. DSM and DR were forced to fit as an afterthought. As well, the DSM financial structure was a complete non-starter; i.e., considering only incremental dollars and incremental energy savings, and then a buy-down to 3 year pay-back. One party stated that the CDM market is missing a counterparty: it's like asking an end-user to contract with a generator directly where few have the sophistication to do it.

Following below are some of the many further suggestions from participants regarding CDM:

- Do not lump Distributed Generation (DG) and CDM together
- Increase funding for incentive-based programs which can and should be market-based
- Need to be able to target best "integrated" CDM programming efforts
- A MWh saved is less valuable than a MWh produced due to the risk of uncertainty that the initiative will produce any real results, the uncertainty of the magnitude of results, the savings claimed are real, and that early results will be sustained
- Difficulty prioritizing competing investments (lack of evaluation standards)
- No confidence in information (low credibility of vendors' claims)
- No management support or internal marketing
- Lack of incentives, uncertainty of return as it is a business case
- Illiquid forward markets, high bid/ask spreads mask accurate price signals
- Continued regulatory uncertainty (rebates, adjustments, etc.) what is my true price?; this is a concern and a distraction
- Need to re-establish and grow the industry
- Allow cross-subsidization of long term paybacks with short term paybacks
- Tap into history and success of companies like gas utilities; see also NRCan's best practices
- What's missing is a simple understandable market or procurement process particularly for small (e.g., 1 MW) projects
- Format for contracts for CDM and generation should be different; CDM should be a performance contract; OPA should not contract with end user but instead with the service provider
- Pre-qualify those service providers
- CDM bidders into the RFP process would bring the capacity not the end users
- Audits to ensure ability to deliver and to ensure savings are in fact delivered

Centralized System

One of the consistent messages from most presenters was the need for centralization or widely applicable programs. There were suggestions for a centralized body to stitch together coordinated plans, remove duplication, and establish province-wide and regional programs. Specific recommendations and comments included:

- Central database application is a possible tool for use by all CDM stakeholders; it helps in audit process and data/information management
- Multi-location businesses face a challenge without a centralized approach
- Replace the CDM RFP process with CDM "umbrella programs"; program parameters need to address the need for certainty of unit cost; allowing OPA to rely on a portfolio of CDM projects that become "self-insuring"
- Increasing value of CDM is found in the "standard" as it lower costs for participation, and lubricates the process; increases the value of savings; less room for misunderstanding
- Want a consistent approach to conservation; want a co-coordinated approach when piloting new technologies

LDC Plans

Others criticized that there are too many LDCs and too many CDM plans. Presenters questioned the efficacy of subsidized utility programs, and pointed to the grossly inflated programs in the gas industry e.g., water heater set back program from Enbridge whereby a tiny fraction of savings were realized versus those reported. Specifically, a gap exists in many LDC territories between the needs of Commercial and

Institutional (C&I) customers and the LDCs' plans. Current CDM plans too often emphasize residential information programs. Different tools are needed for the C&I customers who need actual incentives.

Distribution System Optimization (DSO) is the planned intervention by LDCs to recapture system losses through system enhancements and managing peak demand, which saves the real cost of losses without putting pressure on revenues. DSO contributes to CDM efforts by reducing the need for system capacity expansion, and it provides sustainable benefits. OPA needs to include a focus on line loss reduction either as a key program in itself or as part of customer centric programming.

It was recommended that embedded market participants should register with the LDC thereby ensure LDCs are made aware of possible CDM program implementation. The LDCs can help OPA in monitoring and ensuring compliance with OPA RFPs. "Establish an LDC registry to manage CDM programs in the area", suggested one presenter. However, another party stated that the LDC does not need to be involved with market participants. There was a request for OPA to support the facilitation of utility bill data retrieval and installation of interval /smart meters.

Demand Response Issues

Participants had many specific comments to make regarding DR issues and opportunities. The interest in DR is significant, suggesting that the potential for these types of programs is also significant in the resolution of generation procurement. However, there is still a lack of awareness, and a need for "proof of concept". DR is largely unexploited, in its early steps, but has promise. It was recommended that OPA develop mechanisms via pilot programs, for example, northeast York region for about 10 MW.

Contract Specifics

Several parties had experience or were familiar with the existing IESO Transitional DR Program (TDRP), citing the rules are problematic. For example, an asset owner can't engage with the IESO for many technical reasons e.g., 5 MW minimum. As well, the IESO TDRP focuses on peaking relief, whereas certain plants would reduce demand almost 100% of the time. Thus, for OPA programs, baseload DR should be considered. DR should stand alone as part of a conservation program.

Listed below are several suggestions on what would be required in contract arrangements between OPA and DR proponents:

- Two parameters, timing and risk, need to be addressed
- Use market forces for DR and pay at the same price as generation via competitive bidding process; however the opposite comments were also heard such as a MW saved (a "negawatt) is not the same as a MW generated, and negawatts have different technical and financial bases from megawatts generated
- Parameters for new generation are not correct for negawatt initiatives
- Embedded loads need continued flexibility to be dispatchable
- Industrial DR should be through open-ended process via Conservation Bureau; not with generation procurement
- Owners are willing to invest in upgrades or DR but require a reasonable sense of payback
- DR and DG schemes require an aggregator, which is difficult with current IESO rules
- RFP required signed contracts with end customers (100% for an aggregator is an impossibility), but proponents can't sign with customers until have some high probability of proceeding, so a "chicken and egg" situation developed

- Recommend a step build up of committed customers signed with proponent, e.g., 10% by a certain point, 25% by the next stage, etc.
- Liquidated damages for failures; every aspect of mix must be metered and monitored knowing exactly how many watts are being offset using internet technology; when IESO triggers, such technology will know within seconds the amount of power being offset
- Long term vision: if building owners know about the potential DR revenue stream they will be inclined to put in natural gas fired backup units now instead of diesel units
- Regulated tariff should be offered to participants; recommended that OPA RFP would ask for aggregators to be the program operators who would create and prepare the marketing program
- Consider an agreement like an SOC, e.g., if aggregator can offer committed MW per month, then will be offered an SOC program from the utility; customers could work with the LDCs directly but there's still a role for knowledgeable aggregators to advise and manage less sophisticated customers
- Another function of the aggregator is to ensure each location is environmentally compliant
- Timing for RFPs that look at DR and efficiency initiatives: different in what they deliver compared to generation plant; shorter lived commitments e.g., isolate the capacity and possibly discount due to its variability but consider that it can come on quickly
- If implemented as an incentive program it must compete against other incentive plans available from LDCs or NRCan

4. OPA Mandate

The OPA panel heard a lot of comments from stakeholders regarding issues OPA cannot change, although it can be a proponent of such change. Examples include financial issues around the applicability of transmission bypass, Debt Retirement Charge, gross load versus net load billing issues, standby costs, Load Serving Entities, forward markets and a Day Ahead Market. As well, OPA was asked to address the need for market evolution in Ontario, and to work its way out of a "hybrid" market.

There is a struggle between what responsibilities the Ontario electricity ratepayer should have versus the taxpayer, and the panel sometimes asked presenters their opinions on these issues. Other participants addressed the gap between the public's perception of what electricity costs and the true cost of electricity, while the OPA panel pushed back on the price at which technologies such as wind, solar, photovoltaic and others become commercial. Certain ideas that sound so logical cannot be automatically undertaken by OPA unless the full economics are understood and do not put undue upward pressure on rates.

Some parties wanted to discuss external socialization mechanisms, including the effect of coal closure on rates, as an example. Gas infrastructure and pricing will likely be issues for some time to come, with no easy solution, and not within the purview of OPA.

While OPA may not have direct responsibility, it was important to include many of the important and valid comments made below:

- OPA is a transitional agency, not a permanent solution; following the transition OPA should no longer need to procure capacity and DR
- Take a long term perspective; set a goal for an open and competitive electricity industry with multiple sellers and buyers
- OPA has an obligation to the ratepayer who seems to bear the ultimate cost
- OPA's mandate needs to be expanded in order to bring in policy elements: e.g., DRC and transmission exemption, tax incentives, assignment of GHG permits

- Transmission and Distribution utilities (T&D): concerns with potential interference by OPA re bypass issue; T&D utilities must remain solvent and access has to be funded
- Let IESO run spot market and DAM to ensure operational efficiency; want long term migration back to IESO for market operation
- Set renewable portfolio standards
- New nuclear generation should bear the same risks as other resource alternatives; avoid transfer of risk to the non-nuclear market
- “NIMBYism” (Not In My Back Yard) is an issue coming up; must think about how to involve the government and communicate to the public to get these projects done
- OPA must promote the creation of LSEs
- OPA needs to influence:
  - IESO action on DAM
  - Improvements in gas/electric interfacing; going so far as to contracting in relation to, say, tolling agreements
  - Commitments to gas infrastructure
- Regulated gas industry infrastructure costs/rates could be structured as a pass-through; OEB would have to approve this concept
- OPA models need to encourage market activity by making procured capacity available to third party buyers in a way that allows the ongoing development of the forward contracts market
- Add sellers and shift risk from publicly supported contracts to private market participants
- Procurement process should be disentangled from privatization
- OPA has a conflict of interest by contracting for power and yet being responsible for Regulated Price Plan for consumers
- Coal replacement plan and by extension the generation procurement process is an undertaking which should be submitted to environment ministry for an environmental assessment
- Allow for green power marketing to customers
- Bypass plans should not be allowed
- Net metering should be brought in as soon as possible to help promote DSM
- Distribution system code needed in order to facilitate small DG
- Steel gases are sustainable and inexhaustible and replaceable so should qualify as renewable
- Desire for OPA to consider bids from Ontario based proponents; consider the social and economic benefits to the province versus giving the business to non-Ontario and non-Canadian proponents
- Approvals processes for hydro sites are complex and cumbersome and uncoordinated among the different departments and governments

Analysis of procurement processes for generation capacity, renewables, demand response, and energy efficiency

Report prepared for the Ontario Power Authority by London Economics International LLC

31 August 2005

To develop an effective total electricity procurement strategy for the province of Ontario, the Ontario Power Authority ("OPA") must balance several somewhat opposing needs. First, OPA must ensure that the province has an adequate amount of generation capacity to meet the electricity needs of Ontario in a cost-effective manner. Second, OPA must take into consideration political, environmental, and social policies advocated by the Ontario government. Finally, OPA needs to be sure that it creates a process that is not administratively onerous and expensive. In support of this process, we have conducted an analysis of procurement processes in other North American jurisdictions for generation capacity, renewable resources, demand response, and energy efficiency to review common practices for OPA. This report is a companion to a separate report prepared by London Economics International LLC which reviews comments of stakeholders regarding recent requests for proposals (RFPs) for new capacity and presents recommendations for process improvements.

Our assessment of generation capacity procurement processes indicates that Ontario's new capacity procurement processes had many common elements with other jurisdictions; indeed, Ontario has managed to complete its procurement processes faster than many of the utilities that we analyzed, though some aspects of the process appear to have been anomalous. While standard offer contracts have been recommended as a way for the province to increase its renewable generating capacity as per government targets, our assessment of such programs in other jurisdictions reveals several potential challenges in implementing them in the long run. As such, we have identified key issues that OPA should be aware of when considering standard offer contracts as well as highlighting alternative policy options to encouraging the development of additional renewable generation, such as Renewable Portfolio Standards, technology specific grants and subsidies, and encouraging green marketing efforts.

In addition, we evaluated conservation and demand side management procurement efforts in North America. Both have proved to be effective at addressing short term reliability issues, as illustrated in the California crisis, as well as serving as an economic way to avoid building new peaking facilities and, if structured correctly, could complement the province's procurement efforts.

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1 RFP processes in other regions

1.1 Jurisdictions and processes reviewed

To determine the extent to which recent Ontario practice differed from other jurisdictions, we reviewed several recent procurement processes for new generation capacity in North America. We selected two Requests for Proposals ("RFPs") from Canada, issued by BC Hydro and Hydro-Quebec, and six from the US, issued by Xcel Energy, Progress Energy Carolinas, Arizona Public Service Co., Puget Sound Energy, Long Island Power Authority, and New York Power Authority. Except for the RFP by Hydro-Quebec, all were issued in 2005.

In the subsections below, we give a brief context for each of the procurement processes, describing the utility, the type of supply sought, and the procurement process. We then discuss important components of the procurement process in a comparative manner, addressing issues such as process length, bidder pre-qualification, use of third party evaluators, registration fees, and security deposits. The figure below provides an overview of the RFPs we cover in this section.

Figure 1. Overview of RFPs examined

RFP	Issue Date	Utility	Jurisdiction	Size
2006 Open Call for Power	July, 2005	BC Hydro	British Columbia Utilities Commission	800 GWh/year from projects 10 MW and larger; 200 GWh/year from projects 1 MW and larger, but less than 10 MW
2003 RFP electricity supply from wind power for 1,000 MW	May, 2003	Hydro-Quebec Distribution (HQ Distribution)	Quebec's Regie de l'energie	1,000 MW of wind power starting December 2006 through December 2012, contracts to last between 15-20 years
RFP for 2009 Western Region Power Supply Resources	May, 2005	Progress Energy Carolinas	North Carolina Utilities Commission; the Public Service Commission of South Carolina	240 MW
RFP for Long-Term Capacity Supply	May, 2005	Arizona Public Service Co	Arizona Corporation Commission	1,000 MW
RFP from All Generation Sources (DRAFT)	July, 2005	Puget Sound Energy	Washington Utilities and Transportation Commission	233 MW to 1,500 MW
2005 Dispatchable/ Nondispatchable Resource RFP	February, 2005	Xcel Energy	Colorado Public Utilities Commission	2,500 MW
RFP to Provide Off-Island Capacity and/or Energy	March, 2005	The Long Island Power Authority (LIPA)	New York Public Service Commission	1,030 MW
Long-Term Supply of In-City Unforced Capacity and Optional Energy	March, 2005	New York Power Authority (NYPA)	New York Public Service Commission	500 MW

1.1.1 BC Hydro

RFP: *2006 Open Call for Power*

Issuer: BC Hydro

Issue Date: July 2005

Jurisdiction: British Columbia Utilities Commission ("BCUC")

Size: A minimum of 800 GWh/year of firm electrical energy supply and up to 800 GWh/year of associated non-firm electrical energy supply from projects 10 MW and larger ("Large Projects") built and operated by Independent Power Producers ("IPPs"), and a minimum of 200 GWh/year (based on a 50 MW portfolio at approximately 50% capacity factor) of electrical energy supply from projects 1 MW and larger, but less than 10 MW ("Smaller Projects") built and operated by IPPs

BC Hydro serves more than 1.6 million customers in British Columbia, Canada. It operates 30 hydroelectric facilities, two gas-fired thermal power plants and one combustion turbine station. BC Hydro's plants generate between 43,000 to 54,000 GWh annually, of which 80% is produced by major hydroelectric generating stations on the Columbia and Peace rivers.

BC Hydro recently launched a "Call for Tender" ("CFT") process for at least 800 GWh/year of firm electricity supply and up to 800 GWh/year of non-firm supply. Unlike other recent calls by BC Hydro, the CFT consists of only a single phase, which eliminates the pre-qualification phase for bidders or for projects. This is intended to shorten the procurement period to approximately six to seven months and reduce the cost for both parties. The CFT will have two separate streams, one for "Large Projects" and one for "Small Projects." Each stream will have a different Electricity Purchase Agreement ("EPA") and a similar, but not identical, evaluation methodology.

Mandatory requirements and evaluation criteria are set out in the CFT. This will enable bidders to determine at an early stage whether or not they wish to participate. The evaluation process for both streams includes the following steps:

- Initial Assessment:
  - Conformity review
  - Mandatory requirements assessment
  - Bidder and project risk assessment
- Price levelization
- Determination of adjusted bid prices
- Determination of optimal portfolio

Additionally, a bidder tendering a project that meets the "BC Clean Electricity" definition will be given a preference in the evaluation process.

1.1.2 Hydro Quebec

RFP: *2003 RFP electricity supply from wind power for 1,000 MW*

Issuer: Hydro-Quebec Distribution ("HQ Distribution")

Issue Date: May 2003

Jurisdiction: Quebec's Régie de l'énergie

Size: 1,000 MW of wind power starting December 2006 through December 2012, contracts to last between 15 and 20 years

Hydro Quebec ("HQ") generates electricity and sells it on wholesale markets both inside and outside of Quebec. HQ owns 52 hydropower stations, five thermal generating stations, and one wind farm, totaling 333,892 MW of installed capacity in 2004.

HQ's distribution arm, Hydro Quebec Distribution ("HQ Distribution"), has access to a heritage pool of up to 165 TWh of electricity per year, at a fixed price of 2.79¢/kWh (Canadian). However, demand in the province is growing quickly and additional supply is already needed.

In order to meet the needs of the Quebec market, HQ Distribution is authorized enter into power supply contracts on an as-needed basis. In 2003, HQ Distribution launched an RFP for the procurement of 1,000 MW of wind-powered supply, which we use as the basis of our discussion in this document. HQ Distribution has launched several other RFP processes since then, all very similar in form, for 350 MW of cogeneration (2004) and most recently for 2,000 MW of wind power (June 29, 2005).[1]

The RFP process has five steps: (1) issuing the RFP; (2) receiving and opening the bids; (3) selecting the bids; (4) preparing the contracts; and, (5) award of the contracts. The contracts are awarded based on the lowest price, taking into account the applicable cost of transmission and any other requirements specified in the RFP. The selection process has three phases. In the first phase, bids that do not meet the minimum requirements for bidding are discarded. In the second stage, bids are divided into categories according to the features of the products offered (in the case of the 2003 wind RFP, based on the year in which supply will start). An evaluation of the financial and non financial components (bidder's financial capacity, experience, technological risk, etc.) of the bid is conducted. In the third phase, the financial issues are more closely examined, and the impact of the bid on HQ Distribution's supply portfolio is assessed. Ultimately, the bid that meets all the conditions at the lowest cost wins.

Bidders are required to submit registration forms and a registration payment in order to participate in the bidding process. A pre-bid conference is held a few weeks after the RFP is issued, although attendance is not mandatory.

The RFP process for 1,000 MW of wind power resulted in 32 bids being received from nine different bidders totaling 4,292 MW. The winning bidders were Cartier Energie Eolienne and Northland Power, resulting in expected new build of 990 MW.

1 The amount of information available for the 2003 RFP far exceeded the other more recent RFPs, hence our use of the 2003 RFP as our example.

1.1.3 Xcel Energy (Public Service Company of Colorado)

RFP: *2005 Dispatchable/Nondispatchable Resource RFP*

Issuer: Xcel Energy (PSCo)

Issue Date: February 2005

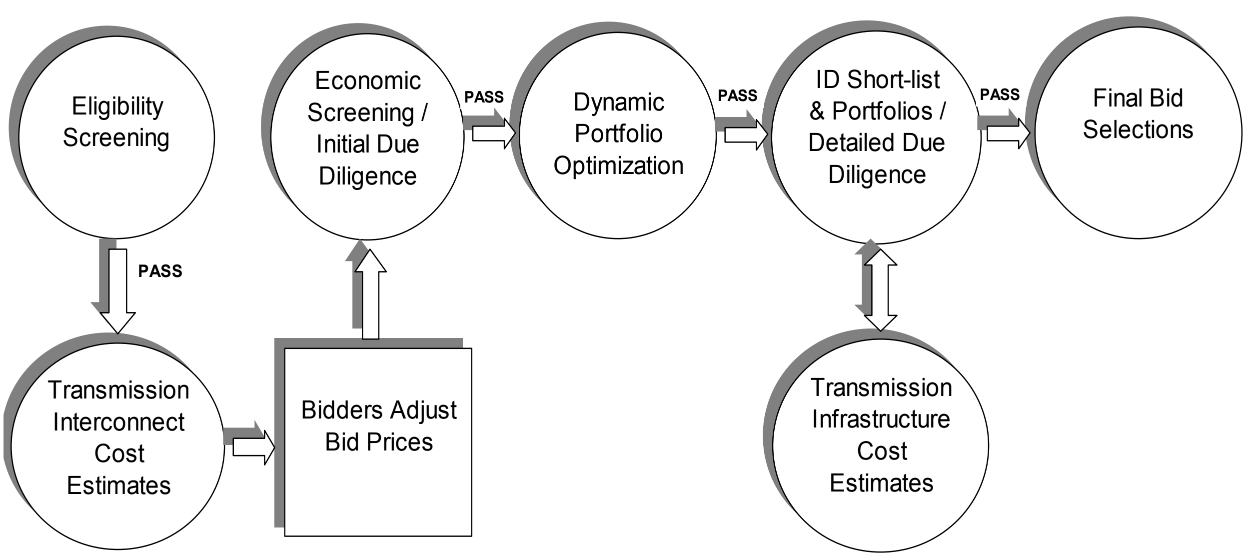
Jurisdiction: Colorado Public Utilities Commission ("COPUC")

Size: 2,500 MW of additional electric supply and demand side resources that would commence to provide service during the resource acquisition period ending October 31, 2013

Xcel provides services to 3.3 million electricity customers and 1.8 million natural gas customers in Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin. With annual revenue of $8 billion, Xcel owns over 260,000 miles of electricity transmission and distribution lines, and more than 33,000 miles of natural gas pipelines, and operates 15,200 MW of electric generation capacity. Public Service Company of Colorado ("PSCo") is an operating company subsidiary of Xcel Energy Inc ("Xcel") servicing the state of Colorado.

In February 2005, PSCo launched an RFP for 2,500 MW of additional electric supply and demand side resources to provide supply through 2013. PSCo aims to complete contract development and sign purchase contracts by the beginning of 2006.

Figure 2. Xcel Energy's Bid Evaluation Process



Source: Xcel Energy

After a pre-bid conference, interested bidders were encouraged to submit a Notice of Intent to Bid form before submitting a proposal. Proposals were evaluated with an assessment of both economic and non-economic criteria (as shown in Figure 2) by a bid evaluation team from Xcel and PSCo. After the deadline passed in May 2005, Xcel received 89 proposals for about 17,000

MW with a substantial diversity of resources, which will enable Xcel to select from a wide array of projects. There are 15 offers for coal-fired generation, of which half the capacity is from new plants proposed in Colorado, with the other half coming from projects in Kansas and Wyoming. Additionally, wind developers offered 3,370 MW in Colorado and 1,200 MW in Wyoming and New Mexico. Xcel expects to announce winning bidders by the end of the year.[2]

1.1.4 Progress Energy Carolinas

RFP: *RFP for 2009 Western Region Power Supply Resources*

Issuer: Progress Energy Carolinas ("PEC")

Issue Date: May 205

Jurisdiction: North Carolina Utilities Commission ("NCUC") and the Public Service Commission of South Carolina ("PSCSC")

Size: 282 MW winter rating (240 MW summer) of combined-cycle capacity in PEC's Western Region service territory

Progress Energy Carolinas ("PEC") provides electric power to approximately 1.3 million customers in a 34,000-square-mile service territory in eastern and western North Carolina and central South Carolina. PEC owns and operates 18 power plants with a total summer generating capacity of 12,482 MW. These resources include 832 MW of coal, hydro, and combustion turbine capacity in PEC's Western Region, which covers a portion of western North Carolina in and around the city of Asheville.

PEC recently launched a tender process for 240 MW summer rating of combined cycle capacity required by 2009. The process is scheduled to be completed in approximately nine months (by February 2006), which includes pre-submission activities, the evaluation process, and contract negotiations. In the pre-submission activities, bidders are supposed to submit a Notice of Intent to Bid Form before submitting the proposal. The evaluation process will consist of eight steps, which are shown in Figure 3. In the event the PEC self-build alternative is superior to the short-listed proposals, the Final List announcement and Contract Negotiations steps of the process will not take place.

The RFP deadline passed in July 2005 and did not draw any responses. PEC is currently evaluating its next steps.[3]

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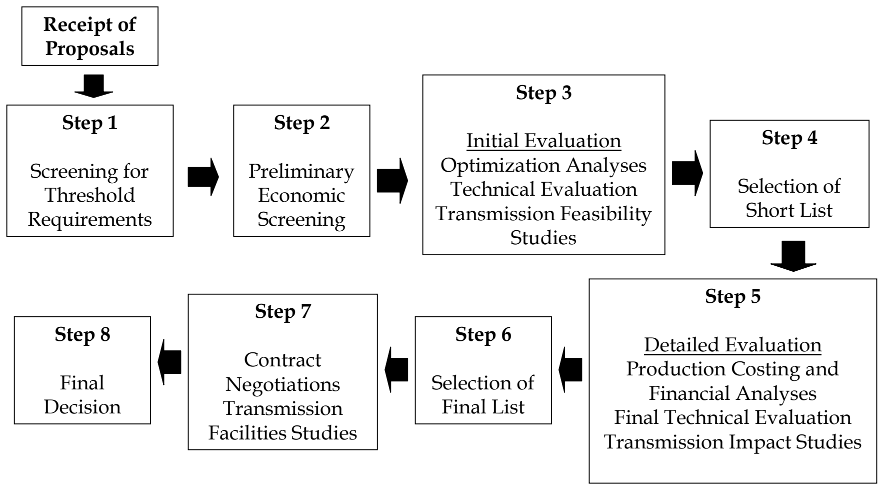
2 Megawatt Daily, July 7, 2005.

3 Megawatt Daily, July 21, 2005.

Figure 3. PEC's Evaluation Process



Source: PEC

1.1.5 Arizona Public Service Co.

RFP: *RFP for Long-Term Capacity Supply*

Issuer: Arizona Public Service Co. ("APS")

Issue Date: May 2005

Jurisdiction: Arizona Corporation Commission ("AC")

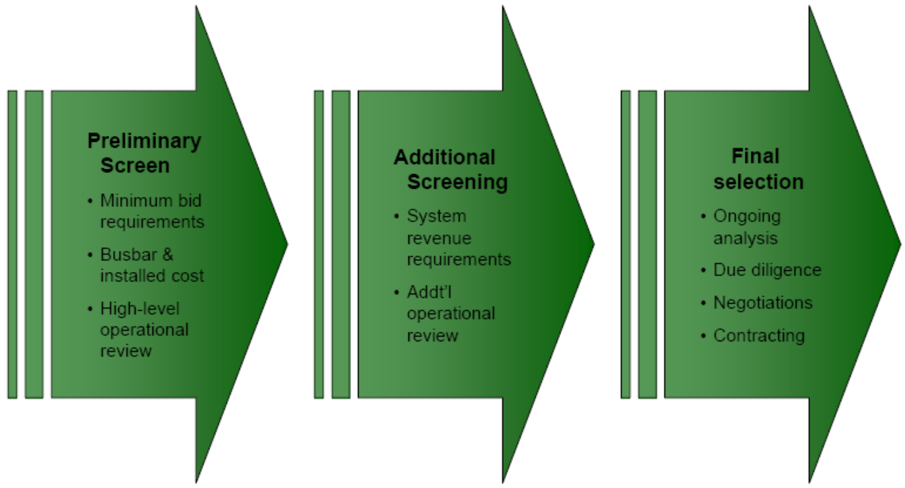
Size: Summer capacity totaling at least 1,000 MW for a period of not less than five years beginning with deliveries between June 2007 and June 2008

Arizona Public Service Company ("APS") is a utility with retail load in 11 of Arizona's 15 counties, with approximately 70-80% of its load located in the Phoenix metropolitan area. APS is anticipating customer growth of nearly 4% per year and needs approximately 1,300 MW of (summer) generation capacity by 2007.

APS recently issued an RFP for 1,000 MW of capacity starting between June 2007 and June 2008. Interested bidders were requested to submit a Notice of Intent to Bid Form to assure that they would receive information distributed in the RFP process.

The evaluation will be based on compliance with threshold requirements, price competitiveness, and non-financial considerations. Among these factors, price (which includes all delivered costs to APS service territory) will be the most important factor. The summary of the process is shown in Figure 4. The RFP process is scheduled to be completed within five and half months (by November 2005).

Figure 4. APS' Bid Evaluation Process



Source: APS

1.1.6 Puget Sound Energy

RFP: *RFP from All Generation Sources (DRAFT)*

Issuer: Puget Sound Energy ("PSE")

Issue Date: July 2005

Jurisdiction: Washington Utilities and Transportation Commission ("WUTC")

Size: Approximately 233 MW in the 2006/07 winter period increasing to over 1,500 MW by the 2014/15 winter period

Puget Sound Energy ("PSE") is a subsidiary of Puget Energy Inc. PSE serves nearly 1 million electric customers and more than 650,000 natural gas customers, primarily in the Puget Sound region in the state of Washington. The utility owns 1,813 MW of installed capacity in the region. Due to growing demand and the forthcoming expiration of long term Power Purchase Agreements ("PPAs"), PSE has started to expand its supply sourcing.

PSE recently released a Draft RFP soliciting additional generation capacity in the region. The process started with a workshop with potential respondents on July 15, 2005 prior to the issuance of the draft RFP at the end of July. There will be a public meeting and comment period before the approval of Final RFP by the Washington Utilities and Transportation Commission ("WUTC") in three to four months.

After issuing the Final RFP, a Pre-Proposal Conference will be held for questions and answers. Proposals will initially be evaluated based on the cost of each proposal and on qualitative criteria. After examining the individual proposals, PSE will determine a preliminary short list made up of the most attractive proposals to continue with portfolio evaluation and additional due diligence based on the same primary criteria. The portfolio evaluation will focus on assessing the risk levels of the most promising resources and determining the interaction with existing resources within PSE's power portfolio. Proposals that have the lowest impact on PSE's revenue requirements and rates will be given preference.

As part of the evaluation process, PSE may require the final short-listed respondents to fund the fees and costs of a third party selected by PSE to perform "fatal flaw" analyses and initial due diligence of the selected projects. The maximum level of funding will be specified at the time of any such request.

The post-proposal negotiations will be held with the leading respondent(s) on the short list. However, PSE has no obligation to enter into definitive agreements with any respondent and may terminate or modify the RFP at any time without liability or obligation to any respondent. PSE estimates that the entire process will take eight to twelve months.

1.1.7 Long Island Power Authority

The Long Island Power Authority ("LIPA"), a non-profit electric utility since May 1998, provides electric service to customers in Nassau County, Suffolk County, and the portion of Queens County known as the Rockaways in the State of New York. LIPA provides electric service via 1,300 miles of underground and overhead transmission lines to over one million electric customers. LIPA encourages its customers to purchase energy from green power generation resources and provides energy conservation products and services, as well as incentive programs.

RFP: *RFP to Provide Off Island Capacity and/or Energy*

Issuer: Long Island Power Authority ("LIPA")

Issue Date: March 2005

Jurisdiction: New York Public Service Commission ("NYPSC")

Size: Capacity and/or energy of:

- ✓ 10 MW to 345 MW (10 MWh to 345 MWh/hr) over the Cross Sound Cable ("CSC") for a term of five to 20 years beginning no earlier than May 1, 2006
- ✓ 10 MW to 685 MW (10 MWh to 685 MWh/hr) over the Neptune Cable for a term of five to 20 years beginning the later of the commercial operation date for the Neptune Cable or July 1, 2007

LIPA issued an RFP to solicit power from both new and existing generations that use the existing Cross Sound Cable ("CSC") from the ISO-NE region or the proposed Neptune Cable from PJM. The solicited amount of power is 345 MW for the generation using CSC, and 685 MW using Neptune, with commercial on-line dates of May 2006 and July 2007, respectively. According to the schedule by LIPA, the proposal was due a month after the RFP was revised, with a workshop held after the RFP was issued. LIPA is planning to select winners by the end of this year.

Proposals are reviewed by a Selection Committee consisting of LIPA staff and consultants. Proposals were supposed to offer non-tolling arrangements except for natural gas-fired plants, which could offer LIPA a tolling arrangement as an option. LIPA's quantitative and qualitative assessment will use the following criteria:

- All-in cost to LIPA's customers;
- Operational and scheduling flexibility of generator(s) supplying products (e.g. ramp rates, firm advance reservation requirements, minimum run times);

- Fuel assurance and deliverability;
- Risk of cost increases to LIPA's ratepayers resulting from factors such as firmness of fuel transportation, technical attributes of project, and contractual obligations imposed on LIPA;
- Respondent's experience in developing and/or operating generating projects;
- Respondent's creditworthiness;
- Improvement to local reliability;
- Ability of the products to meet LIPA's load growth requirements;
- Product deliverability;
- Increased supplier diversity;
- Increased fuel diversity;
- Impact on the environment;
- Respondent's ability to permit project (new or repowered project only);
- Ability to meet proposed start dates for the sale of products; and,
- The degree of acceptance of the terms and conditions in the LIPA PPA including acceptance of LIPA's standard contract terms and conditions.

1.1.8 New York Power Authority

New York Power Authority ("NYPA") is a state entity focused on wholesale power, although it also supplies power to some government accounts, such as the Metropolitan Transportation Authority, the New York City Housing Authority, and the Port Authority of New York and New Jersey. NYPA operates 17 generating facilities and more than 1,400 circuit-miles of transmission lines in New York.

RFP: *Long-Term Supply of In-City Unforced Capacity and Optional Energy*

Issuer: New York Power Authority ("NYPA")

Issue Date: March 2005

Jurisdiction: New York Public Services Commission ("NYPSC")

Size: 500 MW of Unforced Capacity ("UCAP") and energy in New York City (Zone J), starting as early as February 1, 2008

Because of the requirement from the New York ISO to have enough installed capacity to cover its energy deliveries, and also to replace aging plants, NYPA issued a long-term RFP to solicit 500 MW of Unforced Capacity ("UCAP") and energy for New York City – Zone J, starting as early as February 1, 2008, preferably for a term lasting through December 31, 2017. UCAP is based on the capability of a generating plant after adjusting for the monthly forced-outage rate under NYISO rules. Generating facilities that are located outside of Zone J, but can deliver power to the area, are also encouraged to bid.

Interested parties must contact appropriate personnel at NYPA to get a copy of the RFP since detailed information is not publicly available.[4] Proposals will be evaluated based on, but not limited to, the following criteria:

- Evaluated price of bidder's proposal;
- Extent to which offered pricing is economical, stable, and predictable over the offered contract term;
- Overall portfolio cost and risk, including project and financing risk;
- Construction and performance guaranties;
- Creditworthiness;
- Contribution to system reliability;
- Contribution to the overall reduction of electricity costs citywide;
- Contribution to increasing electric in-city capacity;
- Contribution to the diversification of the total number of electricity supply sources and creditworthy counterparties;
- Contribution to the diversification of physical locations of electricity supply sources;
- Contribution to the diversification of fuel supply of electricity supply sources;
- Contribution to policy objectives, including environmental and health quality; and, enhancements, and consistency with the City of New York's land-use policies and rezoning plans.

NYPA notes that preference will be given to proposals with minimum risk to NYPA and its customers.

1.2 Characteristics of generating capacity procurement processes

As detailed in Section 1.1, the supply sought in our case studies varies by type, by time frame, and by contractual terms. Likewise, there are several different characteristics of each utility's RFP process. In this section, we take a step back to compare the RFP processes and to assess several important components of the RFP process in a comparative fashion.

1.2.1 Length of process

The length of the RFP process varies extensively among the different case studies that we assessed, with the shortest being APS's RFP which is supposed to take four and one half months from the issuance of the RFP through to the selection of the final winners to the longest being Xcel's RFP, which ultimately will take about one year.

The main difference in the length of the process is due largely to the amount of time each utility takes to select the winning bids. The amount of time between the issuance of the RFP and the due date for proposals is relatively similar, around two and a half months on average, with

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4 LEI obtained the RFP documents from the Director of Supply Planning, Jordan Brandeis, at New York Power Authority on August 17, 2005.

some utilities on the low end at one and a half months (APS) and others at the high end with three months (NYPA and Xcel). It is the period of time from when the proposals are due until when a final bidder(s) is(are) selected where there are substantial differences. Indeed, the amount of time to determine the winning bidder(s) ranges from three months (APS) to nine months (Xcel).

It is unclear why some utilities have such lengthy selection times, given that the actual analysis of bids should not take longer than one to two months. Bids that are ultimately evaluated based on their optimization of the utility's total portfolio might require a more complex assessment process than a basic assessment of an individual project's merit and economics. However, there appears to be little organizational basis for why utilities such as LIPA and Xcel would require seven to nine months for the evaluation process. Both utilities explicitly state that pricing must remain firm during the evaluation bid or proposals will be disqualified.

Figure 5. Comparison of length of RFP processes

Utility	Period from RFP issuance to proposal due date	Period from proposal due date to short list selection	Period from proposal due to final selection	Total process: RFP issuance to final selection
APS	1.5 months	1.5 months	3 months	4.5 months
LIPA	2.5 months	n/a	7-8 months	10-11 months
NYPA	3 months	n/a	n/a	n/a
PEC	2 months	2 months	4 months	6 months
PSE	2.5 months	3 months	6 months	8.5 months
Xcel	3 months	5 months	9 months	12 months

1.2.2 Bidder prequalification and screening

Except for the most recent RFP by BC Hydro and the 2003 RFPs issued by HQ Distribution, the RFP process usually requires a bidder prequalification and screening stage. However, there is a trend for bidders to examine the prequalification criteria by themselves at a bidder's conference or workshop. The screening process is then often integrated into an early stage of the evaluation process.

In order to increase the diversity of proposals, utilities are setting the eligibility requirements of potential respondents broadly. Respondents could be electric utilities, marketers, exempt wholesale generators, or merchant generators. However, some RFPs disqualify respondents from affiliated generating companies of the utility who is issuing the RFP (e.g., PSE and APS). In addition, some utilities provide even broader guidelines. Some RFPs define the range of the size of each project, while others do not.[5]

[5] E.g. BC Hydro defines the sizes in two streams; NYPA set a minimum bid size of 25 MW; Xcel solicits bids of any size.

Bidders' financial and creditworthiness information is a factor for either the qualification or evaluation process. Bidders are required to provide detailed credit and financial information, such as a letter of credit. Some utilities, like PEC, use a respondent's credit rating by S&P or Moody's. If companies are not rated by S&P or Moody's, a respondent's financial statements are quantified into a credit score for in-house analysis. An example of such a methodology is shown in Figure 6. If a company is rated by both S&P and Moody's, the lesser of the two ratings is used to determine a PEC equivalent rating.

Figure 6. PEC's in-house analysis for financial viability (if bidder not rated)

Measure	Weight	Credit Score						
		-1	0	1	2	3	4	5
Debt/Capital	0.25		≥ .75	.74-.71	.70-.65	.64-.60	.59-.55	≤ .55
Tot Debt/FFO	0.05		≥ 5	5 - 4	3 - 4	2 - 3	1 - 2	≤ 1
FFO/Interest Expense	0.23		≤ 1.25	1.25-2	2-2.5	2.5-3	3 - 4	≥ 4
Fixed Assets/Total Assets	0.1		≤ .1	.1-.2	.2-.3	.3-.4	.4-.5	≥ .5
Fixed Assets/Equity	0.02		≤ 1	1-1.5	1.5-2	2-2.5	2.5-3	≥ 3
Net Worth (in Millions)	0.17		≤ 11	11 - 50	50-200	200-500	500-1,000	> 1,000
Financial Statements	0.02		Qualified or Outdated	Unaudited	Compiled	Statutory Filing	Unqualified (Not Big 4)	Unqualified (Big 4)
Income Trend	0.1		Downward			Mixed		Upward
Years in Business	0.02		Less than 2	2 - 3	3 - 4	5 - 6	7 - 8	Over 8
Type of Business	0.02		Merchant Generator	Small Marketer	Large Marketer	Co-Op	Utility	Municipality
Ratings Outlook	0.02	Negative		Stable	Positive			

Source: PEC

Generally, a preliminary evaluation starts with screening for the minimum requirements set in the RFP, including operational performance, reliability, fuel supply plan, deliverability, financial strength, and environmental impacts. The bidder's experience in developing projects is also assessed; a bidder's ability to build on schedule within budget is heavily weighted.

1.2.3 Bid fees (registration fees)

Based on the case studies we examined, bid/registration fees for large scale capacity procurement processes range from $1,000 to $10,000, as shown in Figure 7. Some RFPs set a uniform fee, while others set varied prices depending on the registration date. HQ Distribution has uniform fees and for its 2003 RFP required that all bidders pay a registration fee of Cdn. $1,000, including taxes. BC Hydro sets a varied registration fee based on the timing of the proposal submission. In its recent RFP, BC Hydro originally set a discounted fee for early registration, which was Cdn. $2,500, as compared to the full registration fee of Cdn. $7,500. Later, the price for remaining submissions was revised to Cdn. $5,000.

The bid fee can also be determined by the size of a project. For example, Xcel Energy and LIPA set a different bid fee based on the size of the proposed facility as shown in Figure 8 and Figure 9.

In addition, the fee can also be based on how many bid variations are offered. Under Xcel's procurement process, a single proposal would consist of a single total capacity level, a single contract term length, a single set of prices, and a single location. Proposals that vary any of these conditions would constitute a separate proposal and, as such, would require an additional bid evaluation fee, although a single proposal may offer up to two in-service years for one bid evaluation fee. Likewise, PEC charges $1,000 for additional variations in project terms and/or pricing, although two variations in these components are granted for free. In some limited cases, when other RFPs are proposed simultaneously, and the bidder has submitted a proposal and paid, the second registration fee may be waived.

A registration fee is usually nonrefundable, as seen in the BC Hydro, HQ Distribution, APS, and LIPA processes. However, other utilities sometimes provide a refund under certain circumstances. For example, Xcel Energy refunds 75% of the fee, if, after completing the initial eligibility screening, a proposal is determined to be non-responsive, incomplete, or otherwise ineligible to participate in the solicitation.

Figure 7. Bid fees by RFPs

	BC Hydro	Hydro-Quebec Distribution (HQ Distribution)	Progress Energy Carolinas	Arizona Public Service Co.	Xcel Energy	LIPA
Amount	Cdn.$5,000	Cdn. $1,000	$10,000	$5,000	$2,000 - $10,000	$2,000 - $5,000
Refundable?	No	No	NA	No	75%	No

Figure 8. Xcel Energy's fee schedule

Proposal Size	Bid Evaluation Fee
Less than or equal to 2 MW	$2,000
Greater than 2 MW and less than or equal to 20 MW	$6,000
Greater than 20 MW	$10,000

Figure 9. LIPA's fee schedule

Proposal Size	Bid Evaluation Fee
Less than 50 MW (50MWh/hr)	$2,000
50 - 100 MW (50 - 100 MWh/hr)	$3,500
Greater than 100 MW (100MWh/hr)	$5,000

Given the different parameters that determine the bid fee, we have used a sample proposal of 100 MW in size to illustrate on an apples to apples basis the difference in bid fees as seen in our examples. We have kept the registration fees in their respective currencies given that there has been substantial movement in the US-Canadian exchange rate. As shown in Figure 10, the lowest fees are from HQ Distribution's RFP at Cdn. $1,000 with the highest fees being Xcel's RFP at US$10,000.

Figure 10. Comparison of bid fees using example of 100 MW plant

Utility	Bid Fee
APS	US$ 5,000
BC Hydro	CDN $5,000
HQ	CDN$ 1,000
LIPA	US$ 5,000
PEC	US$ 10,000
Xcel	US$ 10,000

1.2.4 Project security deposit

In order to ensure that bidders are able to develop a project under a legally binding contract, a project security payment is required once the contracts have been signed in the amount and form required by the utility. A common medium for such a security payment is in the form of an irrevocable standby Letter of Credit, cash, or government bonds. Some RFPs require a minimum rating for issuers of credit or bonds (e.g., A- or better for Xcel) or require that the bond must be issued for a minimum term (e.g., two years for PEC) and must be renewed every year.

The amount of the security payment is typically set in a form of dollars per capacity; we show a comparison of security deposits in Figure 11. The actual price differs depending on the size of the facility, the bidder's credit rating, and the timing of project development. The amount and structure of the security payment differ significantly by utility.

Figure 11. Security deposit amounts

BC Hydro	Hydro-Quebec Distribution (HQ Distribution)	Puget Sound Energy	Xcel Energy
Cdn.$5/kW or Cdn.$10/kW	Cdn.$8 to $20/kW*	$20 to $30/kW*	$75/kW or $125/kW

*Actual deposit required varies depending on the phase of development and contracts.

Note that the deposit for BC Hydro varies by stream (Cdn. $5/kW for small projects and Cdn. $10/kW for large projects).

BC Hydro sets the amount of the security deposit based on its two procurement streams: Cdn. $10,000/MW for "Larger Projects" and Cdn.$ 5,000/MW for "Smaller Projects". In contrast, PEC's security deposit amount varies by a number of factors such as the bidder's credit rating, the structure of capacity payments, and the mark-to-market value of the contract, and is determined through a negotiation process. In general, the amount required increases with the development of the project and decreases during the term of the PPA as illustrated in PEC's process, which is shown in Figure 12. PEC also adjusts the amount of security based on a credit ranking. HQ Distribution uses a structure that is dependent on (1) the size of the project (by kW) and (2) the phase of the project, differentiating the security required at the signing of the contract (Cdn. \$10/kW), 18 months before the guaranteed date of delivery (Cdn. \$20/kW), as of the date of delivery once the regional content requirements have been verified (Cdn. \$12/kW), and at the 10th anniversary of the start of deliveries (Cdn. \$8/kW).

Generally, the security deposit must be provided after the PPA's execution date. Our examples show the period ranges between 15 days to two months after the effective date. The funds will be released at the end of the PPA term or a few days after the end of the PPA term.

Figure 12. PEC's security deposit schedule

Timing	Amount (Cash Equivalent Value)	Cumulative (Cash Equivalent Value)
30 days after contract signing	\$20/kW	\$20/kW
18 months before Scheduled Commercial Operation Date	\$10/kW	\$30/kW
12 months before Scheduled Commercial Operation Date	\$20/kW	\$50/kW
Commercial Operation Date	\$20/kW	\$70/kW
2 Years After Commercial Operation Date	\$30 /kW	\$100/kW
5 Years After Commercial Operation Date	\$(50)/kW	\$50/kW
10 Years After Commercial Operation Date	\$(30)/kW	\$20/kW

Source: PEC

As it is difficult to compare these amounts on an apples to apples basis, we have taken a sample power plant of 100 MW in size with a BBB- rating as a way to compare the different security deposits required. Again, we have not converted the currencies. The security deposits range from Cdn. \$1 million (HQ Distribution and BC Hydro) to US\$ 12.5 million (Xcel). Note that the US\$ 12.5 million is for dispatchable capacity; the deposit drops to US\$7.5 million for non-dispatchable capacity. However, it is clear that Xcel remains an outlier as compared to our other examples, which all range in the \$1 to \$2.5 million range for a 100 MW facility. For higher credit ratings, some companies, such as PEC, give a reduction in the amount of credit rating required.

Figure 13. Comparison of security deposit for 100 MW plant day after contract signed

Utility	Security payment
BC Hydro	CDN\$ 1,000,000
HQ	CDN\$ 1,000,000
PEC	US\$ 2,000,000
PSE	US\$2,500,000
Xcel	US\$ 12,500,000

1.2.5 Indexation of proposal items

Indexation of variables in the bid formula is common and mainly applies to the term of the PPA, rather than the period between the bid submission and acceptance. These types of indices apply to fuel costs or inflation indices in general, or any other elements that are likely to change over a lengthy period of time. For example, PEC allows bidders to propose using a price index or a formula based on an index to automatically update fuel prices. Formulas and escalation rates, if used, must be specified in the bidder's proposal.

Xcel also allows bidders to propose alternative pricing tied to a general inflation index for the capacity payment, variable operating and maintenance costs, or fixed operating and maintenance costs. According to Xcel's "Corporate Escalation Rate", the general inflation rate will use an annual escalation factor of 2.36% for the 30-year planning period from 2004 to 2034, which is a weighted rate that is based on PSCo's projection of regional trends for labor and non-labor rates. It assumes an average breakdown of approximately 40% labor and 60% non-labor costs.

LIPA requires bidders to offer an energy price using an index or another method designed to provide value and predictability of pricing to LIPA. Likewise, HQ Distribution allows for a variety of different inflation, currency, and interest rate indices to be applied in bids. HQ Distribution also allows bidders to consider other indices but bidders must obtain approval for these indices prior to their being submitted in an official bid.

1.2.6 Anti-collusion provisions

Some RFPs include anti-collusion provisions to prevent bidders from jointly determining their bids, thereby disrupting the competitive nature of the bidding process. Among our examples, PSE, APS, and LIPA have such provisions. In a proposal for PSE, the respondent must certify that "the respondent has not sought by collusion to obtain for itself any advantage over any other respondent."

Likewise, APS states the following in its "Contract and Regulatory Approval" clause: "by submitting a Proposal to APS in response to this RFP, the Respondent certifies that the Respondent has not divulged, discussed or compared its Proposal with other Respondents and has not colluded whatsoever with any other Respondent or parties with respect to this or other Proposals."

LIPA asks bidders to sign in Non-Collusive Bidding form. In addition, LIPA and NYPA both ask whether the bidders were convicted of anti-competitive acts or omissions, or collusive bidding or other procurement- or sale-related irregularities in the last five years.

It is important to note, however, that although we observe non-collusion provisions in many jurisdictions, such provisions apply exclusively to the bidder. They do not seek to further interfere in the structuring of the bidder's advisory team, or prohibit advisors from working with other bidders.

1.2.7 Ownership of environmental attributes

Environmental attributes generally refer to credits, benefits, reductions, offsets, and other beneficial allowances, which result from the use of certain (non or low emission) resource generation. Bidders can retain, offer, or transfer such attributes to the utility, depending on the specifications in the RFP. The positions of the utilities on this issue vary, as we describe below.

BC Hydro provides two options for bidders regarding environmental attributes: one option is to tender "green attributes" to BC Hydro and receive the green credit of $3.00/MWh for purposes of tender evaluation only. These bidders would still be eligible for government programs such as the federal Renewable Power Production Incentive ("RPPI") or Wind Power Production Incentive ("WPPI"). The other option is for the developer to retain the "green attributes" for sale to third parties or other uses, but to receive no green credit.

In contrast, PSE and HQ Distribution claim the possession of all environmental attributes associated with the project and offer no other option to bidders.

1.2.8 Role of third party evaluators

Some of the utilities managing RFPs reserve the right to use a third party evaluator in order to determine the final selection. Only LIPA states that it definitely will use an outside entity, while PEC and Xcel reserve the right to do so. The remaining utilities do not state their intention of using an outside consultant to assist in the bid evaluation process.

For state-owned utilities, such as BC Hydro and HQ Distribution, it could be argued that there is no need for external assessment given that the owner of these utilities (the government of the province) is responsible to the utilities' ratepayers (its citizens and voters). Thus, in theory, the utility's owner has an interest in correctly motivating the utility's managers to select least cost bids, regardless of whether those bids are from the generation arm of the utility or from an outside company.

Figure 14. Comparison of whether or not third party evaluator used in procurement process

Utility	Consultant used
APS	no
BC Hydro	no
LIPA	yes
NYPA	no
PEC	maybe
PSE	no
Xcel	maybe

In other jurisdictions, where the interests of utility's owners and governments are not aligned, and the utility running the RFP has an affiliate bidding in the RFP, one could very easily defend the need for a third party evaluator to ensure the fairness and the appearance of fairness of the procurement process. This is the case in many of the auctions in the Northeast for default supply, where it is mandated that a third party evaluator assess any auction where a utility's affiliate is bidding. Note that the appearance of fairness is an important point: when bidders fear that the process is subject to manipulation, they are less likely to participate in the process.

1.3 Overall complexity of process

The complexity of the procurement process is largely a function of the length and complexity of the RFP, the evaluation methodology, and any changes that occur midstream. As detailed below, these characteristics vary substantially among the procurement processes we assessed. However, the PEC procurement process was generally the most complicated while the processes run by BC Hydro and HQ Distribution were the least complicated.

The complexity and length of the RFPs, which could be used as a proxy for the complexity of the process, varied among the case studies. The average length of the RFP was 27 pages, with NYPA being at the low end with 10 pages and PEC being at the high end with 52 pages. While using the length of pages of the RFO could be used as a more objective measure of complexity, we ultimately found that some simple processes were described in a lengthy manner (HQ at 38 pages) while relatively complex processes were described quickly (PSE in 18 pages). We then analyzed the number of pages that were dedicated to explaining the evaluation process. This provided a more useful understanding of RFP complexity. While some utilities managed to explain the evaluation process in as little as three pages (NYPA and LIPA), others took as many as 12 pages (PEC). The average seemed to be in the five to seven page range (Xcel, PSE, APS, and BC Hydro).

The complexity of the actual evaluation process is also crucial. PEC had a complicated methodology to value the creditworthiness of bidders that were not rated by major agencies, which might have discouraged bidders.[6] In addition, PEC's security amount was defined by the phase of project development, which at one point accumulated to $100/kW. Although this amount could be reduced as a function of the bidder's credit rating, the complexity of the formula could have made it difficult to determine this. At the same time, other RFPs did not provide much detail on how they will be rating the bids, making it more difficult for bidders to evaluate their chances of success.

Changing the RFP process midstream is another way that can complicate the RPF process in that it requires bidders to re-evaluate their chances of success as well as potentially requiring them to do additional work on their proposal. However, it is also a way for utilities to avoid unattractive or disqualifying proposals being submitted. BC Hydro, LIPA, and PSE revised their RFPs during the process. BC Hydro changed and lowered the bid fees and security amounts, and other terms were also simplified or eliminated. LIPA increased the solicited capacity amounts by 40 MW in total. PSE is still in process of finalizing the RFP after communicating with various entities and public. The intension is to draw more and highly qualified proposals, as well as to develop publicly-supported projects. The impact of such revisions could be positive, if the changes are made according to the participants' comments in previous RFP

6 The PEC process would have been more familiar to loan officers than to project developers.

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processes, such as in the case of BC Hydro.[7] However, as these RFPs are still in process, the actual impact of these changes is unknown at the moment.

One way to provide support to bidders during any, but especially complex, RFP processes is to conduct workshops to explain the RFP and to answer potential bidder questions. Almost all RFPs except the ones issued by PEC and NYPA had workshops to explain the RFPs in advance. This type of opportunity not only enables the utility to communicate with bidders about the concept of RFPs and their goals, but also allows bidders to assess their qualifications and their likelihood of success by asking the issuer questions directly. Overall, such opportunities reduce the cost and save time for both parties by increasing the quality of submitted proposals.

1.4 Implications for OPA

There are a number of similarities in the RFP process in general and in the approach toward selecting winning bidders. All procurement processes involved releasing a relatively detailed RFP, proving time for questions to the utility, and setting a fixed due date for proposals to be submitted. While some utilities developed short lists that were announced to bidders before determining winning bids, other utilities preferred to keep their short lists private and announce only winning bidders. The selection of winning bidders was largely based on the lowest cost bid (including required additional infrastructure such as transmission and distribution lines), using a technically feasible approach, that met all of the RFP requirements.

At the same time, there were aspects of the RFP and the RFP process that were handled very differently by utilities. The timing of the procurement process was one of these. The quickest RFP processes were more than twice as fast than the slowest, indicating a very big gap in approach and process. The time for the assets to be on line varied from a mandatory on-line date within 18 months to the possibility to come on-line by 2013. Contract lengths ranged from five years to 25 years – some were explicitly mandated, while others were open to the bidders' choice. Sometimes the utilities kept all environmental attributes to the generation; other times, they were left with the bidders. While there were general ranges of registration fees and security deposits around which many of the RFPs averaged, there were also outliers, such as Xcel on the high end and HQ Distribution on the low end.

Ontario's RFPs in 2004 and 2005 had aspects that were consistent with the processes and criteria that we observed in other jurisdictions. The main differentiating factor is that Ontario (despite concerns expressed by stakeholders) was relatively efficient in completing its RFP processes – indeed Ontario would rank among the top two in the case studies we assessed for the fastest process from release of RFP to announced project winners. While some of the characteristics of Ontario's RFP process were not seen across the board in all of the RFPs that we assessed (contract length of 25 years, assets to be on-line within three years on average, environmental attributes to be owned by OPA), these were observed in some of the RFPs we analyzed. Key

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7 Note that not all of BC Hydro's RFPs have been successful. On June 17, 2005, BC Hydro announced that it was abandoning the proposed Duke Point Power Project following a lengthy legal struggle.

differences included treatment of anti-collusion provisions, financing support letters[8], reduction in the level of communication as the process evolved, and the far more dynamic policy environment in which the RFPs were issued. Arguably, this last factor is the largest distinction between Ontario and the jurisdictions we surveyed, where the RFPs were part of a normal and ongoing supply process.

8 While none of the RFPs we assessed in detail required financing support during the proposal evaluation process, we are aware of other examples where this is the case. For example, in a recent RFP by Southern California Edison ("SCE"), a deposit of the greater of $25,000 or $5/kW was required from the time when the proposal was submitted until when SCE made a determination of winning bids. The deposit is returned once the bid has been rejected or, if the bid has been accepted, once the Development Fee (or project security deposit) has been given to SCE.

2 Standard offer contracts and other methods for renewable energy development

2.1 concept definition

Standard offer contracts[9] generally involve procuring and encouraging the development of renewable energy by providing a minimum price guarantee (usually by technology and/or size of generation asset) for renewable energy through a long term contract (typically 15 to 20 years). Unlike an RFP process, standard offer processes operate through a published price, which is then offered to all resources which qualify. A standard contract document is provided for all qualifying applicants, reducing the need for negotiations. Standard offer contracts were originally used in the US in California and New York in the wake of Federal legislation encouraging clean energy, though were ultimately replaced by other approaches which we will discuss later in this section. The standard offer contract is regularly employed in Europe, where it is generally referred to as a feed-in tariff, in order to meet the EU and Kyoto renewable energy production targets. Countries such as Austria, Spain, France, Denmark, and Germany, use different variants of a standard offer contract in order to ensure adequate renewable energy generation.

Tariffs under a standard offer contract are generally based on the amount of electricity generated by an allowed renewable technology. The standard offer price is a regulatory determined minimum unit based price (i.e., $/MWh price) that an electric utility has to pay the generator for the amount of electricity it supplies to the grid. The tariffs can be based on the avoided cost of non-renewable generation plus a premium to account for the social and environmental benefits of renewable power or they can be based solely on the production costs of the renewable technology. The tariffs can be fixed for a number of years or they can be updated regularly to account for technological improvements or a general shift in market prices. We provide more detail on actual structures of standard offer contracts in the subsections below.

2.2 key issues

Experience with standard offer contracts for renewable energy has been mixed. While the US experience in the early 1980s was relatively negative and ultimately resulted in uneconomic contracts, many European countries have managed to put in place effective standard offer contracts which have increased the amount of renewable energy capacity while not resulting in out of the money contracts for extended periods of time. It is possible that some of the success seen in European standard offer contracts can be attributed to the fact that there has been a learning curve of how to effectively implement a standard offer contract program, building upon previous US experience. More likely, however, is that in the regions of Europe where

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[9] The standard offer contracts we refer to in this section refer only to the long term tariffs offered to renewable generation. They do not refer to the default supply contracts used in the US Northeast, which are also sometimes called Standard Offer contracts.

they have been used most, there is a lack of baseload resources and a heavy reliance on gas and oil fired plants, which makes renewable energy more competitive. Note, however, that standard offer contracts are still relatively young in Europe and thus their long term impacts have not yet been assessed.

Standard offer contracts have a clear attraction for generators. Given their long term contractual nature, they give investors a high level of certainty regarding their capital investment, without the time-consuming process of negotiating a power purchase agreement (PPA). As a result, standard offer contracts have been relatively successful in increasing the amount of renewable capacity in a given region. This was the case in New York and California, as well as in many jurisdictions in Europe.

On the other hand, there are numerous criticisms of standard offer programs. They are not seen as being economically efficient. Because the price is guaranteed for all electricity production, there are no incentives for operators to compete, to become more efficient, or to reduce their costs over time. Second, while the ongoing administration costs are low, the up front challenge of determining the actual tariff for the standard offer is very challenging – especially when set at a fixed price for a long term contract. Finally, standard offer contracts are at odds with the tenets of full-fledged wholesale competition as seen in deregulated markets as they ultimately result in a distortion of market behavior.

Thus, while standard offer contracts can offer some solutions to the policy challenges faced by Ontario, the implementation of such a program must be conducted very carefully, mindful of some of the weaknesses of such a system. Importantly, the Province would have to balance the potential risk that using a standard offer process would result in too much of the wrong capacity in the wrong place with the potential benefits of bringing on-line a number of innovative renewable projects.

The Ontario government has currently set a target of having 5% of its capacity (1,350 MW) be renewable by 2007 and 10% (2,700 MW) by 2010, which could ultimately serve as a cap in the procurement processes for renewable capacity. With this in mind, the Province should focus on identifying the most effective way to procure these amounts.

2.3 Prior experience in the US

In the US, the development of renewable energy was accelerated by 1978 Public Utilities Regulatory Policies Act ("PURPA") due to the high oil prices in 1970s. PURPA required state regulatory commissions to establish procedures to require utilities to purchase from non-utility owned facilities, so-called Qualifying Facilities ("QF"), whose technology was cogeneration, hydro (less than 80 MW), or fueled by other renewable sources.[10] However, PURPA left it to

10 A size limit of 80 MW on Small Power QFs was waived by Congress in 1990 for all facilities (except hydro-power plants) that requested QF status by December 31, 1994. A qualifying cogeneration facility must produce both useful steam and electricity and must meet PURPA-specified efficiency standards if it is fueled by oil or natural gas. PURPA also specifies that a QF cannot be more than 50% owned by or controlled by an electric utility or an electric utility holding company.

states to determine the price to pay for the energy produced by QFs. Pricing was generally based on "avoided cost," a measure of the cost of the next MW of energy and capacity which would otherwise have needed to have been procured.

Comparing definitions of qualifying renewable energy projects according to US's PURPA and Canada's Class 43.1 regulations:

- ✓ Cogeneration facilities (PURPA specifies minimum efficiency standards whereas Class 43.1 does not)
- ✓ Small hydro (less than 80 MW under PURPA and less than 15 MW under Class 43.1)
- ✓ Wind energy systems (both PURPA and Class 43.1)
- ✓ Photovoltaic systems (above 3 kW under Class 43.1)
- ✓ Other renewable energy sources (for PURPA)
- ✓ Enhanced combined cycled systems (Class 43.1)
- ✓ Expansion engines (Class 43.1)
- ✓ Waste fuelled systems using municipal waste, wood waste, landfill gas or digestor gas (Class 43.1)
- ✓ Geothermal systems (Class 43.1)

Note that PURPA has other restrictions such as ownership.

Although PURPA did not require states to offer long-term contracts to QFs, some states, including New York and California, implemented legislation to mandate that QFs receive long-term contracts. These efforts resulted in increasing the number of QFs and renewable capacity, but the long term contracts in particular have not had a huge amount of success. Challenges have included the high energy cost paid for QFs as compared to market prices, difficulty in fuel price projections, lack of cap or target capacity, and the evolution of electricity markets over time. Instead, over the last ten years many states in US have started to use alternative approaches to renewable procurement, such as renewable portfolio standards, tax exemptions and other production incentives, which we discuss in more detail in Section 2.5. In this section, we provide more context on the two states that attempted to implement long term contracts for QFs, New York and California.

2.3.1 Six-Cent Law in New York

The New York Public Service Commission ("NYPSC") passed legislation in 1981 designed to encourage the development of QFs by requiring utilities to offer long-term contracts at "rates just and reasonable to electric and steam corporation ratepayers".[11] The so-called "Six-Cent Law" was effective in attracting QFs, and resulted in significant growth of cogeneration and

11 New York State Consolidated Laws, Public Service, Article 4, S 66-c.

small hydro facilities in New York state. Key points of the Six-Cent Law are summarized as follows:

- **Eligibility**: small hydro, co-generation, and other alternative energy facilities with capacity of up to 80 MW;
- **Mandatory purchase:** Utilities were obligated to purchase all power produced by eligible QFs in their service territories;
- **Price:** minimum sale price of six cents per kWh, excluding transmission and distribution costs;
- **Target:** no specific aggregate capacity target was set for the state; and,
- **Contract length:** Length of contracts ranged between 10 and 20 years.

The price of 6 c/kWh was the administratively determined avoided cost of power, as calculated in 1981. However, a decade later, prevailing wholesale prices remained much lower than the six-cent level, and the volumes that the utilities were required to purchase from the QFs generally exceeded demand. New York utility Niagara Mohawk, in particular, faced a dilemma in that its obligation to purchase power from QFs was substantially in excess of its peak demand of 6,093 MW in 1991.[12] The utility threatened to declare bankruptcy in order to restructure some of the QF contracts. The "Six-Cent Law" was repealed by the NYPSC in 1992. However, the 1992 amendment grandfathered existing contracts executed and filed with the NYPSC on or before 1992.

2.3.2 Standard Offer 4 in California

In response to PURPA, the California Public Utilities Commission ("CPUC") passed Decision 83-10-093 to require utilities to offer long-term contract to QFs in 1983. Interim Standard Contract No.4 ("SO4") was established to provide QFs with guaranteed payments that increased over time. The payments consisted of both a capacity payment and an energy payment. Contracts under SO4 ranged from 15 to 30 years. The energy payment was based on the forecasted price of fuel and was fixed for the first ten years of the contract. After 10 years, the energy payment was replaced by "short run avoided costs" ("SRACs"), which is a variable energy payment. The capacity payment was provided in addition to the energy price payment and was based on the forecasted cost of capacity. An example of schedules from a 1983 contract with Southern California Edison ("SCE") is shown below. The forecast was estimated assuming a high growth rate due to an anticipated increase in oil and gas prices at the time.

After the initial ten years, however, the energy price that ranged from 5.7 to 8.1 cents/kWh in late 1980s dropped to about 3 cents/kWh in the mid-1990s when converted to SRAC pricing. This sharp decline in payment on the 11th year was described as a "price cliff", and resulted in

12 Niagara Mohawk, 10K, 1997.

financial hardships for QFs. This phenomenon resulted from the high forecasts of gas and oil prices, on which energy prices were based for the first ten years.

The SO4 Program was in place from May 1983 to May 1985. Combined with federal and state tax incentives[13], SO4 resulted in a significant number of QF projects being brought on-line in California, including the construction of some 1,200 MW of wind energy capacity. In 1990, California had 98% of the country's wind capacity. Between 1985 and 1990, about 5,000 MW of renewable capacity was added to California's electricity system as a result of standard offer contracts, including SO4.[14]

Figure 15. SCE's payment schedule - Forecast of annual marginal cost of energy (first ten years only) & as-available capacity

Year	Annual Marginal Cost of Energy (¢/kWh)
1985	5.7
1986	6
1987	6.4
1988	6.9
1989	7.6
1990	8.1
1991	8.6
1992	9.3
1993	10.1
1994	10.9
1995	11.8
1996	12.6
1997	13.6
1998	14.6
1999	15.6

Year	As-Available Capacity ($/kW-year)
1985	81
1986	87
1987	94
1988	101
1989	109
1990	117
1991	126
1992	148
1993	158
1994	169
1995	180
1996	194
1997	206
1998	221
1999	235

Source: SCE "Standard Contract Long Term Power Purchase Power Purchase Contract" in 1983 (revised in 1984)

As oil and gas prices declined in the mid 1980s, the CPUC started to phase out the SO4 program. SO4 was permanently suspended in 1985.[15]

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13 In 1980, the Crude Oil Windfall Profits Tax Act increased the business energy tax credit to 15%. Combined with an investment tax credit passed earlier, the total federal tax credit for a wind turbine was 25%. In addition, California had a 25% state tax credit in the early 1980s, bringing the effective tax credit to nearly 50%. (from EIA, "Wind Power Milestone") http://www.eia.doe.gov/cneaf/solar.renewables/renewable.energy.annual/backgrnd/chap10l.htm)

14 California Energy Commission, "Investing in Renewable Electricity Generation in California", June 2001.

15 Through Decision 85-04-075, 85-07-021.

2.4 European case study

Having nearly two-thirds of the world's wind capacity, Europe has been advanced in developing of renewable energy, accelerated by its commitment to Kyoto Protocol. Many European countries use feed-in tariffs, such as Austria, France, Germany, and Spain as well as Renewable Portfolio Standards. To illustrate how feed-in tariffs work, we describe Austria's system below.

2.4.1 European context

The encouragement to use renewable energy sources has long been a goal of the European Union, and this was translated into law in 2001 (2001/77/EG) by creating the goal of increasing the production of electricity from renewable energies from 14% to 22% and the share of consumption to 12% by 2010. However, in 2004, a first report on the progress of implementation revealed that many Member States are not on track to meet the targets, except Germany, Denmark, Finland, and Spain.[16]

2.4.2 Austrian renewable regulations

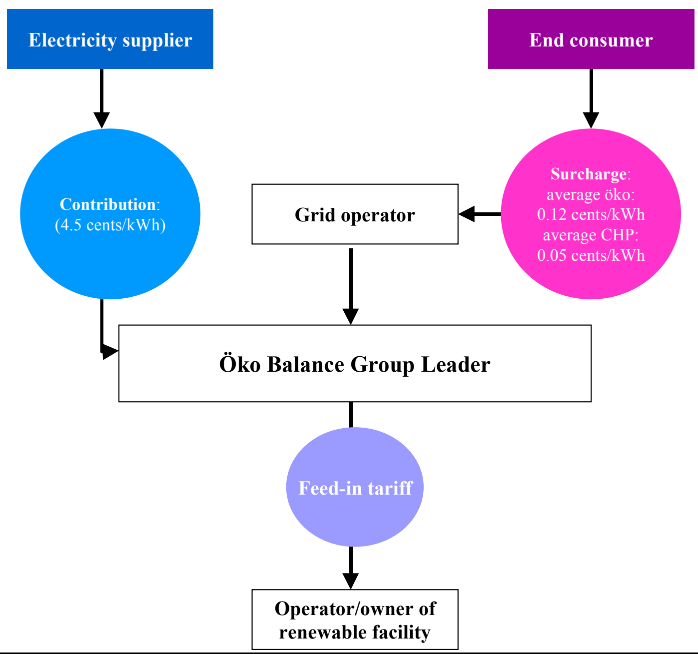
In the interest of refining its previous regulation and making its policies coherent with EU policy, Austrian authorities in 2002 passed the *Ökostromgesetz*, also known as the Green Electricity Act (BGBI. I Nr. 149/20029), which came into effect on January 1, 2003. This law regulates the subsidy mechanisms for renewable generation, such as wind, biomass, and solar power, in addition to small hydro (currently defined as those units that are less than 10 MW in capacity) and cogeneration. The fundamental objectives of the *Ökostromgesetz* are listed below:

- 78% of electricity production must come from renewable sources by 2010 (achievable because Austria already has substantial hydro resources);
- the target increase for non-hydro renewable sources of electricity generation will be 4% by 2008;
- the 2008 electricity generation target for small hydro will be increased to 9%;
- small hydro will now be compensated by the regulated "feed-in" tariff structure that other renewable generators operate under;
- "feed-in" tariffs will be set at the federal, rather than provincial, level and are the minimum compensation for renewable generation;
- cost efficiency of renewable electricity generation would thus be improved; and
- modernization of cogeneration equipment encouraged (although refurbishment of cogeneration will not contribute to the overall 78% target).

16 "Commission Communication: the share of renewable energy in the EU" May 26, 2005.

Financial support for this targeted increase in renewable electricity use (and the "feed-in" tariff) comes from a dual fee mechanism. The funds necessary to finance the "feed-in" tariffs are generated from a direct levy on consumers and an obligatory purchase at a fixed price on retail suppliers. The "feed-in" tariffs are, in principle, supposed to compensate (subsidize) the generators of renewable electricity for the difference between the market price of electricity (that they would have otherwise earned in the deregulated market) and the all-in cost of generating electricity from renewable resources. However, the program, as it currently stands, does not adjust with market dynamics. Rather, it pays all renewable generators a pre-determined tariff.

Figure 16. Flow of funds for renewable electricity subsidies payment



The grid operators for each grid zone also represent an *Ökobilanzgruppe* (environmental balancing group), and each of the grid operators (or, in this context, known as the *Öko Balance Group Leader*) is responsible for administering the subsidy payment based on the flow of funds illustrated in the figure below. First, the system operator collects 4.5 Euro cents from each retail supplier for each kilowatt-hour of renewable electricity they sell. Retail suppliers are obliged to purchase 9.5% of renewable electricity in proportion to their total electricity sales.[17]

Second, the grid operator charges end-consumers a levy based on their total electricity consumption for renewable and cogeneration energy, which is then funneled back to the grid operator. The *Ökostromgesetz* limits the amount that can be directly levied on consumers, although each Austrian province determines the actual amounts of the levy. The maximum levy for non-hydro renewable generation that can be charged to end-users is 0.22 Euro cents/kWh;

17 Information compiled from an interview with Christian Schönbauer, E-Control, July 2003.

the maximum for small hydro is 0.16 Euro cents/kWh; and the maximum for cogeneration is 0.15 Euro cents/kWh.[18]

The grid operators then purchase electricity from renewable electricity facilities, paying them the federally-established tariff, often referred to as "feed-in" tariffs (shown in Figure 17) instead of the market price.[19] The current "feed in" tariffs for hydro and non-hydro renewable electricity were developed by the Minister of the Economy, in conjunction with the Justice Minister and the Environmental Minister in 2002.

Although the feed-in tariff system may be appropriate for Austria, it has some drawbacks which make it less attractive as a model for Ontario. First, it is complicated to administer, involving multiple actors and agencies. Second, it sets feed-in tariffs at high rates, and does not encourage competition among various renewables providers. Third, market conditions for Austria are quite different from those in Ontario; consumers in Austria are habituated to paying higher tariffs, which can cover the cost of subsidizing renewables. In general, we find European models to be less attractive for Ontario, and believe any definition of "success" should incorporate not only a measure of the resources mobilized, but also the cost involved to do so.

Figure 17. "Feed-in" tariffs paid to renewable generators (Euro cents per kWh)

Type of energy	Size	Price (cents/kWh)
Wind	all	7.80
Biomass (strong, high fuel quality)	<2 MW	16.00
Biomass (strong, high fuel quality)	2-5 MW	15.00
Biomass (strong, high fuel quality)	5-10 MW	13.00
Biomass (strong, high fuel quality)	>10 MW	10.20
Fluid Biomass	<200 kW	13.00
Fluid Biomass	>200 kW	10.00
Biogas from agricultural products	<100 kW	16.50
Biogas from agricultural products	100-500 kW	14.50
Biogas from agricultural products	500 kW-1 MW	12.50
Biogas from agricultural products	>1 MW	10.30
Geothermal	all	7.00
Existing small hydro	first 1 mil. kWh	5.68
Existing small hydro	next 4 mil. kWh	4.36
Existing small hydro	next 10 mil. kWh	3.63
Existing small hydro	next 10 mil. kWh	3.28
Existing small hydro	more than 25 mil. kWh	3.15
New small hydro	first 1 mil. kWh	6.25
New small hydro	next 4 mil. kWh	5.01
New small hydro	next 10 mil. kWh	4.17
New small hydro	next 10 mil. kWh	3.94
New small hydro	more than 25 mil. kWh	3.78
Photovoltaic	<20 kW	60.00
Photovoltaic	>20 kW	47.00

Source: Feed-in tarrifs from 2003 (http://www.e-control.at), Verordnung des Bundesministers für Wirtschaft und Arbeit, BGBI. II Nr. 508/2002; these tariffs were still valid as of August 2005.

18 Note that the actual levy is calculated using the total kilowatt-hours consumed by the customer.

19 Note that the feed-in tariffs are currently higher than market prices; should this change, renewables generators are allowed to sell at market-based rates if they so desire.

2.5 Alternative approaches to renewable procurement

Other approaches to procure renewable energy include the Renewable Portfolio Standard ("RPS"), state and federal incentives programs, and green marketing.[20] The following sections will examine three alternative approaches with several case studies in North America.

2.5.1 Renewable portfolio standards

Generally speaking, RPS sets an objective of increasing renewable capacity, generation, or consumption to a certain level, which in North America is often implemented through an RFP process. However, eligible renewable systems and technologies differ by jurisdiction.[21] Nearly half of the states in US have adopted an RPS target, and almost all of them have set mandatory objectives. In Canada, five of the provinces have put in place an RPS program although not all have completed the implementation process.[22] This section examines three RPS examples from North America: Alberta, New York, and California.

2.5.1.1 Alberta

While the province of Alberta has not set a fixed mandatory Renewable Portfolio Standard, it has set targets for renewable energy capacity. In October 2002, the government proposed a target of 3.75% of total generation capacity being from renewable energy sources by 2008. This would amount to approximately 600 MW of capacity.

In addition, Alberta's Small Power Research and Development ("SPRD") Act, enacted in 1988, encouraged the development of renewable energy by encouraging renewable energy projects to sell power to electric utilities at a regulated price for a contract period of ten to 20 years. The Act set a cap of total capacity to be developed this way of 125 MW. Ultimately, 108 MW of capacity was built under the provisions of the Act. When Alberta deregulated its market in the late 1990s, it structured the process such that when power pool prices are below the prices of the SPRD contracts, the Balancing Pool pays the difference to the producers.

Transalta, one of the main Alberta utilities, supported Alberta's RPS target by announcing in 2003 that it had a goal of having 10% of its generation capacity be from renewable energy by 2010. At the end of 2003, Transalta acquired Vision Quest, a wind energy developer that owned 82 MW in Alberta. Transalta currently owns almost 200 MW of wind power in Alberta. It is worth pointing out that, despite the lack of any sort of standard offer or binding mandate,

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20 Integrated Resource Planning ("IRP") is also a potential alternative to RPS and other approaches, as indicated on a study on utilities in the Western US. Seven of the 12 utilities analyzed do not operate under an RPS, yet of the 8,000 MW of renewable capacity expected to be brought on line by the utilities, half was by utilities not under an RPS. (From Bolinger, Mark and Ryan Wise, "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plants," Ernesto Orlando Lawrence Berkeley National Laboratory, August 2005.)

21 In the US, jurisdiction is by state and in Canada, jurisdiction is by province.

22 Alberta, Ontario, New Brunswick, Nova Scotia and Prince Edward Island have developed RPS programs.

Alberta currently has an additional 440 MW of wind power in development, due to be on-line by 2006.[23]

2.5.1.2 New York

Due to concerns about the state's dependence on fossil-fired generation and environmental implications, the NYPSC started to develop an RPS in 2003. New York's RPS program (effective since 2004) targets increasing the percentage of electricity derived from renewable resources from the current 19.3% to at least 25% by 2013. It is envisioned that most of this goal – 24% out of 25% - will be achieved through a newly established central procurement program administered by the New York State Energy Research and Development Authority ("NYSERDA"). The remaining 1% of the goal is expected to be attained through the initiatives of power marketers in a voluntary green power market.

The structure of the RPS program is based on two tiers of eligible renewable resources: a Main Tier and a Customer-Sited Tier. The Main Tier consists of medium to large facilities (such as utility scale projects) and encompasses wind, hydro, biomass, biogas, liquid bio-fuel, and tidal power facilities. The Customer-Sited Tier consists of small on-site systems and includes fuel cells, solar, and wind among its eligible technologies.

Figure 18. Basic goals and eligible systems under the New York RPS

Program	Basic provisions	Eligible renewables
Renewable Portfolio Standard (RPS)	To increase the percentage of electricity derived from renewable resources to 25% by 2013	**Main Tier:** wind, hydro, biomass, biogas, liquid bio-fuel, and tidal power facilities **Customer-Sited Tier:** small on-site systems that include fuel cells, solar, and wind

The NYPSC RPS order limits qualified hydro resources to:

(1) ***hydroelectric upgrades*** with no new storage impoundments and with eligibility limited solely to the incremental production associated with the upgrade,[24]

(2) ***new low-impact run-of-river hydro*** with rated capacity of 30 MW or less and with no new storage impoundment, and

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23 AESO 10 year Transmission System Plan (2005-2014).

24 Based on the September 24, 2004 *Order Approving Renewable Portfolio Standard Policy* and confirmed through personal communication with the NYSERDA staff.

(3) ***existing small hydro facilities*** of less than 10 MW, and with existing contracts at or below market prices as well as small hydro facilities with expiring above-market energy contracts.

Once project eligibility has been established, the generation project can enroll to obtain support through a central procurement process administered by NYSERDA. The procurement mechanism was set in motion only three months following the announcement of the new state RPS goal. In December 2004, NYSERDA, responding to the NYPSC to accelerate the process, released its first solicitation for the procurement of 1.4 million MWh of renewable power. NYSERDA committed to purchase the qualified renewable generation under fixed rate contracts to sell energy into the NYISO spot market, with varying terms but not exceeding ten years. By the end of January 2005, NYSERDA received over 20 bids from renewable generators in total accounting for 1.2 million MWh. NYSERDA ultimately entered into seven contracts (including wind, biomass, landfill gas, and small hydro) covering over 820,000 MWh in the first contract year. All contracts were for energy from new renewable generation projects, all of which are expected to be completed by the end of December 2005.[25]

NYSERDA is planning on expanding its central procurement program to cover utility scale projects with an RFP expected to be issued by the end of 2005. It is also considering other procurement alternatives including standard offer contracts and auctions as well as the possibility of longer term contracts (12-15 years) and ability to sell energy under bilateral contracts.

The program is funded by revenues derived from a non-bypassable volumetric charge levied on the delivery portion of customers' electric bills, the collection of which is expected to begin by the end of 2005. The charge, collected by utilities, will then be transferred to NYSERDA which is responsible for selecting qualified projects. The NYPSC expects that the charge will not have a significant impact on the final consumer bill. For residential customers, the NYPSC estimated that the cumulative bill impact could range from a reduction of 1% to an increase of 1.7%. The impact on commercial customers' bills is forecasted to range between a 0.8% reduction and a 1.8% increase, while industrial consumers' bills are expected to be reduced by 1.5% or, if increased, by no more than 2% over the life of the program. One driving factor in cost containment is that NYSERDA is not making an open-ended commitment to renewables; instead it is procuring only as much energy as is required to fulfill its mandate, and it is doing so through least cost solicitations.

2.5.1.3 California

California has among the most aggressive RPSs in North America: it requires retail sellers of electricity to purchase 20% of their electricity from renewable sources by 2017. The eligibility requirements and basic goals of California's program are summarized in the chart below.

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25 If the developer fails to honor its commitment and is not ready to commence operation by January 2006, NYSERDA will retain a $3/MWh deposit.

Electricity sales from renewable sources are required to increase by at least 1% per year through an official procurement process. The issuances of RFPs started in 2004 and are scheduled to continue. Should the utilities not meet the 1% minimum level increase of renewable energy, the CPUC will impose penalties. While there is some leeway for utilities to carryover a certain amount of RPS deficit (ultimately determined by the CPUC), for unallowable RPS deficiencies, the CPUC levies an upfront and automatic penalty of 5 c/kWh up to a maximum penalty of $25 million per utility for the amount of RPS not covered.

Figure 19. Basic goals and eligible systems under California RPS

Program	Basic provisions	Eligible renewables
Renewable Portfolio Standard (RPS)	Electricity sales from renewable sources increase 1% per year beginning in 2003 to reach at least 20% by end of 2017	biomass, solar thermal, photovoltaics, wind, geothermal, fuel cells using renewable fuels, small hydropower of 30 MW or less, digester gas, landfill gas, ocean wave, ocean thermal, and tidal current

The California RPS also requires the CPUC and the California Energy Commission to adopt a Market Price Referent ("MPR") methodology to estimate the long-term market price of electricity for use in evaluating bid products received during renewable solicitations. The "market price" must reflect the long-term market price of electricity a utility would need to purchase to meet its capacity and energy needs from conventional fossil fuel resources instead of the renewable resources proposed under the RPS bidding process. [26] The MPR should also consider "the value of different products including baseload, peaking, and as-available output."[27]

The MPRs will establish a benchmark at or below which approved contracts will be considered reasonable and above which contracts will be eligible to receive Supplemental Energy Payments ("SEPs"). The MPR will be determined by the CPUC after the closing date of the RFPs. In July 2005, 2004 MPR values were finalized and are shown in the graphic below.

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26 CPUC, "Market Price Referent ("MPR")"

27 Ibid.

Figure 20. 2004 MPR values

Adopted 2004 Market Price Referents At Specified Zonal Delivery Points (e.g., NP15 or SP15) **(cents/kWh - 2005$)**			
Resource Type	**10-Year**	**15-Year**	**20-Year**
Baseload MPR	5.78	5.88	5.99
Peaking MPR	11.02	11.17	11.33

Source: CPUC, "Energy Division Resolution E – 3942", July 21, 2005

2.5.1.4 Massachusetts

Started in 1997 through the Electric Utility Restructuring Act of 1997, Massachusetts Division of Energy Resources ("DOER") finalized its regulations for a Renewable Portfolio Standard in 2002. It required that all retail electricity providers use renewable energy sources to supply an increasing amount of their load, starting at 1% in 2003 and increasing to 4% in 2009. After 2009, suppliers will be obliged to increase renewable supply by 1% per annum until DOER sets a date for freezing the minimum percentage.

Eligible renewable technologies include solar, wind, tidal, fuel cells, landfill gas, and low emission biomass. New renewable sites must have been installed after December 31, 1997. Systems that meet the technical qualifications but were installed before that date may qualify under the Vintage Waiver Provision.

The Massachusetts Technology Collaborative ("MTC") administers the program. The program relies on the New England General Information System ("GIS") which separates new renewable generation attributes from the actual electricity generated by a qualifying generation unit. The new renewable attributes are granted an on-line, serial numbered, electronic certificate, similar to the Renewable Energy Certificates that are used in Europe. The GIS creates a certificate for every MWh of electricity generated and classifies the non-energy attributes of the electricity, including the unit ID of generation plant and whether it classifies as a new renewable generation unit under MA RPS. Other information contained on the GIS certificate include the unit's fuels, air emissions, and whether it qualifies for CT and ME RPS. This system is intended to enable DOER (and other regulatory entities) to reliably track the purchase and sale of renewable certificates. All generation units and all suppliers in New England have an electronic account in the GIS and every quarter the GIS creates and deposits in to each generation account the certificates for the renewable electricity generated. Each supplier receives in its account the total retail load obligation for the same period. Two months of trading ensue during which suppliers can purchase certificates from generators to comply with regulatory obligations or market claims (green power products). At the end of the year, suppliers must have enough certificates to account for the minimum percentage of RPS required.

Suppliers are required to submit Annual Compliance filings to DOER to document their RPS compliance. Moreover, generation owners have to obtain Statements of Qualification from DOER to formally recognize their "new renewable" sites. All fourteen suppliers active in the MA market met their obligation in 2003. [28] Of the almost 500 GWh of renewable electricity sales in MA in 2003, 304 GWh came from new renewable generation, mainly from landfill (56%) and biomass (36%) sources. Note that 40% of new renewable generation in 2003 was from MA, with Maine contributing 36% and New Hampshire contributing 14%. Most of the remaining renewable energy required came from 2002 Banked Compliances. (A Banked Compliances allows a supplier that had more RPS certificates than it needed for a given year to reserve those certificates to apply to RPS needs over the next two years.) It is also possible to meet the RPS obligation through an Alternative Compliance Payment ("ACP") to MTC. As such, the ACP serves as an effective cap on the price of RPS certificates.[29] The ACP in 2003 was $50/MWh. ACPs in 2003 were negligible.

The 2004 RPS requirement is approximately 762 GWh and DOER has estimated total new renewable generation of about 401 GWh for 2004. About 60.4 GWh will be covered by Banked Compliances from 2003, leaving about a 300 GWh shortfall, which will be met through ACPs. The ACP for 2004 was set at $51.41/MWh[30], indicating that likely payments to MTC of at least $15 million.[31] The ACPs will be used by DOER, in conjunction with MTC, to fund additional new renewable generation.

2.5.2 Technology jump-start grants

In the US, many states offer grants and tax credits to purchase and install renewable energy systems. Typically, the eligible technologies involve new wind, solar, or geothermal generation systems. The grants (often called "incentives") are usually tied to the size of the system and paid in a lump sum, although there is a pilot program in California that is using a performance based production payment for the first three years of the installation's operation. This section describes grant programs to encourage the development of new renewable installations in New York, California, Vermont, and Massachusetts.

2.5.2.1 New York

The New York State Energy Research and Development Authority ("NYSERDA") is a public benefits corporation created in 1975 by the New York State Legislature. NYSERDA administers

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28 Massachusetts Division of Energy Resources, "Annual RPS Compliance Report for 2003," February 15, 2005.

29 On July 1, 2005, the DOER announced a Notice of Inquiry ("NOI") regarding renewable generator eligibility. Specifically, the DOER is considering more broadly defining the category of low emission biomass to include additional facilities, a proposal that has many generators concerned that the RPS certificate market could be flooded if hundreds of megawatts of existing plants are granted eligibility.

30 The ACP is calculated according to changes in the Consumer Price Index.

31 Massachusetts Division of Energy Resources, "Annual RPS Compliance Report for 2003," February 15, 2005. All figures are DOER estimates as final 2004 figures will be published in early 2006.

the New York Energy $mart program, which provides energy efficiency services, and focuses on developing and bringing into use innovative energy-efficient, and environmentally beneficial products, services, and processes.

NYSERDA provides grants to developers of certain renewable energy systems in order to encourage the development and commercialization of such technologies. There are currently two such programs run out of NYSERDA: the Wind Incentives for Eligible Installers and Photovoltaic Incentives for Eligible Installers Program. Both programs are managed in a similar manner. A certain amount of funding, called "incentives" by NYSERDA, is set aside for a specific type of renewable technology. Incentives are paid to the installers and are intended to benefit both the installer for business development and the system owner. The installer must pass incentives directly through to end users.

The Photovoltaics ("PV") Incentive Program provides an incentive in the form of a $4 - $4.50/Watt rebate (paid in increments with terms linked to project timeline milestones) for the installation of grid-connected PV systems with a rated capacity not exceeding 50 kW. The rebate cap is set not to exceed 60% of the total system installation. The program, with a $12 million budget, is set to expire in June 2006.

The Wind Incentive Program offers a rebate incentive of either 50% of the wind system installation costs for 500 W-10 kW systems or 15% of costs for systems larger than 80 kW, but not to exceed $100,000 per single system installation costs. $2.5 million in funds is available to system installers for the Wind Incentive Program.

The process for obtaining a grant from NYSERDA for both programs is organized through the installers. Installers must apply for eligibility for specific equipment from NYSERDA based on their professional experience. Once deemed eligible, the installers apply for and reserve on a first-come first-served basis NYSERDA incentive awards for approved new projects. An installer can apply for one or more incentive awards up to a maximum of either 10 reservations or incentives totaling $400,000.

NYSERDA also offers below market interest rate loans to encourage investment in renewable resources. The loans are available for both the newly constructed systems and to cover renovation and improvement expenses for already existing qualified systems. This program offers a 10 year loan at 400 basis points below the lending rate and, for the borrowers in the Manhattan and the Canal Street regions, at 650 basis points below the lending rate. The loan amounts for these favorable terms are capped at $1 million for non-residential borrowers, $5 million for multi-family borrowers, and at $20,000 for residential borrowers.

The Long Island Power Authority ("LIPA") also launched a rebate program focused on solar energy. The so-called Solar Pioneer Program offers a rebate for the installers of new PV systems. The rebate starts with $5/Watt (up to a maximum of $50,000) for the first 1 MW of PV installed, with an additional $4.50/Watt for the next 1 MW of installation, with an additional $4/Watt for the next 1 MW. Throughout the six year life of the program, LIPA has issued rebates for over 500 PV systems.

2.5.2.2 California

The California Energy Commission ("CEC") runs a program called the Emerging Renewables Program ("ERP"), which was created to help develop a self-sustaining market for renewable energy systems. Through this program, the CEC provides funding to offset the cost of purchasing and installing new renewable energy systems using emerging technologies. The goal of ERP is to decrease the cost of on-site renewable energy systems to end users and thereby stimulate and increase their adoption. Funding for the program comes from the ratepayers of California's four IOUs.

The ERP provides end consumers with a financial incentive to purchase and installed a renewable energy system on their property. The incentive is based on the size of the installation and its technology and is paid once the system is operational. The end consumer must receive electricity service from one of the four main IOUs in California that fund the project to qualify for the program. The renewable energy system must use one of the following renewable technologies: photovoltaics, solar thermal electric systems, fuel cells using renewable fuels, or small wind turbines. The system must be interconnected to the grid, use new components, come with a five year warranty, and generate electricity to offset the end consumer's on-site load.

The program offers two types of incentives. The first is a rebate based on the generating capacity of the system, which is paid in a lump sum. The second is a performance based incentive based on the amount of electricity generated by the system and is paid over a three year period. There is a cap on the total incentive paid to any one end consumer of $400,000. The program has has about $118 million in funding for 2002 through 2006.

The rebate incentive payments differ based on the technology used and the size of the installation:

- Photovoltaics receive $2.80/W;
- Wind installations receive $1.70/W for first 7.5 kW and $0.70/W thereafter; and,
- Solar and fuel cells receive $3.20/W for all systems that are less than 30 MW.

The performance-based incentive option is limited to photovoltaic installations. The end user is paid based on actual production from the installation, as compared to the capacity payment under the rebate incentive. This is currently a pilot program and pays $0.50/kWh for each kilowatt-hour produced over a three year period. As of January 2005, over 11,000 new systems have been installed since the rebate program began in 1998.

California also provides tax credits for the purchase and installation of renewable systems. Tax credits are given for systems with certified photovoltaic or wind generating capacity up to 200 kW and installed in California between January 1, 2004 and December 31, 2005. The amount of the tax credit is 7.5%, or $4.50/W of rated peak generating capacity, whichever is less.[32]

Finally, the CEC also has another program to provide grants to geothermal capacity developers. Up to $3.9 million is available from the Geothermal Resources Development Account ("GRDA") to fund projects that directly relate to geothermal development, planning or mitigation. Projects must be located in California or be sponsored by a California-based company. Funding assistance is available as a grant or a loan and there are no pre-determined limits on project funding requests. The CEC will allocate at least 25% of the GRDA funding to each of the three project categories (development, planning, and mitigation). A matching contribution is required to participate in the solicitation, which could be cash, equipment, and/or in-kind services provided by the applicant or other sources secured by the applicant toward completion of the awarded project. All applicants must submit a pre-application. Those applicants who meet the minimum criteria and who have submitted an eligible pre-application will be allowed to submit a final application. The deadline for final applications is October 31, 2005 and the CEC anticipates approving the awards on February 8, 2006.

2.5.2.3 Vermont

Vermont's Solar and Small Wind Incentive Program was originally established through legislation passed by the Vermont State Legislature in the spring of 2003. The goal of the program is to quickly increase market demand for solar and wind systems. The initial program, which funded the installation of more than 200 renewable energy systems, was fully subscribed in the summer of 2004, with all installations completed by the summer of 2005. $840,000 was funded during this first round. The second round of the program will open for incentive reservations in late 2005. Funding for the second round will use US DOE funds for wind projects ($460,000) as well as funds from Vermont utilities for solar projects ($280,000).

The Renewable Energy Resource Center ("RERC"), a project of the Vermont Energy Investment Corporation ("VEIC"), administers the program. The incentives cover about 25% of the total installed cost for eligible systems and are expected to leverage approximately $3 million in private investment. The program offer incentives on renewable energy systems installed by Vermont Solar and Wind Partners. There will be additional incentives available for systems that use components manufactured in Vermont by a Vermont-based company. Total electricity savings are estimated to be 540 MWh for both wind and solar electric systems in the second round of the project.

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32 Note that a 15% tax credit was available for the same technologies from January 1, 2001 through December 31, 2003.

Figure 21. Vermont Solar & Small Wind Incentive Program

System	Solar electric system	Solar hot water system	Wind sysetm
Incentive amount	$2.00/Watt	$2.00/hundred Btu/day	$2.00 to $3.50 for individuals and businesses;$4.00 for schools and municipalities
Maximum incentive	$10,000	$10,000	$10,000 for individuals and schools: The lesser of $20,000 or 50% of total installed cost for schools and municipalities

Source: Renewable Energy Resource Center

2.5.2.4 Massachusetts

The Massachusetts Technology Collaborative ("MTC") is the state's development agency for renewable energy. MTC brings together leaders from industry, academia, and government to develop technology-based solutions for economic growth and a cleaner environment in MA. The MTC administers the Renewable Energy Trust, a program that promotes clean energy technologies and fosters the emergence of sustainable markets for electricity from renewable sources.

An important program run out of the Renewable Energy Trust is the Small Renewables Initiative Rebate ("SRIR"). This program grants rebates of up to $50,000 for the design and construction of customer-sited renewable energy projects that are less than 10 kW in size. Eligible technologies include micro-hydro[33], solar photovoltaic, and wind systems. The goal of the SRIR is to support the installation of 500 systems statewide. There are $5 million of Renewable Energy Trust funds available for this program. Currently the first Block of the funds, totaling $1 million, is available to applicants. Additional blocks of funding will be made available over the coming years. The baseline rebate rates are expected to decrease with each subsequent funding block.

There are several requirements to be eligible for the SRIR:

- The projects must be connected to one of the MA IOU distribution networks.
- Projects must be less than 10 kW in capacity.
- 90% of the renewable energy produced must be consumed onsite.

33 Hydro projects must use naturally flowing water and involve renovation or development at existing dams or use flow of river technologies.

- The applicant must document its efforts over the previous four years to participate in utility-sponsored energy efficiency programs. Alternatively, the applicant must commit to meet such energy efficiency requirements within one year of installation.

- Applicants must be pre-approved prior to installation.

- Applicants have to installed equipment to track electricity production, which will be reported to MTC on a monthly basis. 10% of the rebate is withheld at the time of installation and is released as a production rebate after a minimum level of production is completed within a 12 month period.

The incentive level for each project is based on the technology and the size of the asset. Wind power installations receive $2/W, solar PV receives $3/W, and micro-hydro receives $4/W. The rebate can be increased by $0.10/W to $2/W by adding features such as MA manufactured components ($0.50/W to $0.75/W), public buildings ($1.00/W to $2.00/W), economic targeted areas ($0.35/W to $0.75/W), low income housing ($0.35/W to $0.75/W), back up for critical load ($0.10/W to $0.50/W), and building-integrated PV ($1.00/W). Note that the maximum rebate cap of $50,000 remains even with the add-on incentives.

There are also other programs in MA that encourage the development of additional renewable generation. These include the **Large Onsite Renewable Energy Initiative**, run by the Renewable Energy Trust. This initiative is for projects that are larger than 10 kW. These grants, capped at $650,000, are offered twice per year through a competitive solicitation process for any renewable technology. The **Clean Energy Choice program**, run by MTC, matches household and small business support for renewables with clean energy grants for the local community. Finally, the **Commercial, Industrial, and Institutional Initiative** ("CI3"), run by MTC, is a program offering $6 million in grant funding to expand the use of distributed renewable energy generation at commercial, industrial, and institutional facilities in MA.

2.5.3 Green power marketing and premiums

Complementing the federal and state renewables-friendly policies and programs, many electric utilities and marketers began to offer customers a wider array of renewable energy service options starting in the early 1990s in US, albeit at premium pricing to regular retail products. These programs have been called a variety of terms, such as green power program or green pricing. Green pricing generally refers to green power programs in regulated markets. Other green power programs are also offered by green power marketers.

Renewable products offered by green power marketers differ from those offered by utilies in the mix of electricity generated from new versus existing renewable resources. Since competitive suppliers typically compete on price, the products they offer tend to contain a mix of new and pre-existing resources and are generally offered at a lower price. Utilities, on the other hand, tend to rely more on new renewables projects and commensurately price in higher premiums for those products.

2.5.3.1 Green power marketing

Today, approximately 15% of utilities offer green power programs to customers in 34 states, and more than 50% of all customers in the US have the option to purchase some type of green power product from a retail electricity provider. In addition, there are also more than 20 companies marketing green power through renewable energy certificates ("RECs"), which all customers are eligible to purchase. [34] Figure 22 lists the top 10 utility green power programs in terms of kWh/year sales as of December 2004.

Figure 22. Green Power Program Renewable Energy Sales (as of December 2004)

Rank	Utility	Resources Used	Sales (kWh/year)	Sales (Avg. MW[a])
1	Austin Energy	Wind, landfill gas, small hydro	334,446,101	38.2
2	Portland General Electric[b]	Existing geothermal, wind, small hydro	262,142,564	29.9
3	PacifiCorp[cd]	Wind, biomass,solar	191,838,079	21.9
4	Sacramento Municipal Utility District[e]	Landfill gas, wind, small hydro, solar	176,774,804	20.2
5	Xcel Energy	Wind	137,946,000	15.7
6	National Grid[fgh]	Biomass, wind, small hydro, solar	88,204,988	10.1
7	Los Angeles Department of Power & Water	Wind and landfill gas	75,528,746	8.6
8	OG&E Electric Services	Wind	56,672,568	6.5
9	Puget Sound Energy	Wind, solar, biogas	46,110,000	5.3
10	We Energies[e]	Landfill gas, wind, small hydro	40,906,410	4.7

Note:

a An "average megawatt" (aMW) is a measure of capacity equivalent that assumes the capacity operates continuously.

b Some products marketed in partnership with Green Mountain Energy Company.

c Includes Pacific Power and Utah Power.

d Some Oregon products marketed in partnership with 3 Phases Energy Services.

e Product is Green-e accredited (www.green-e.org).

f Includes Niagara Mohawk, Massachusetts Electric, Narragansett Electric, and Nantucket Electric.

g Marketed in partnership with Community Energy, CET & Conservation Services Group, EnviroGen, Green Mountain Energy Company, Mass Energy, People's Power & Light, and Sterling Planet.

h Some products are Green-e certified (www.green-e.org).

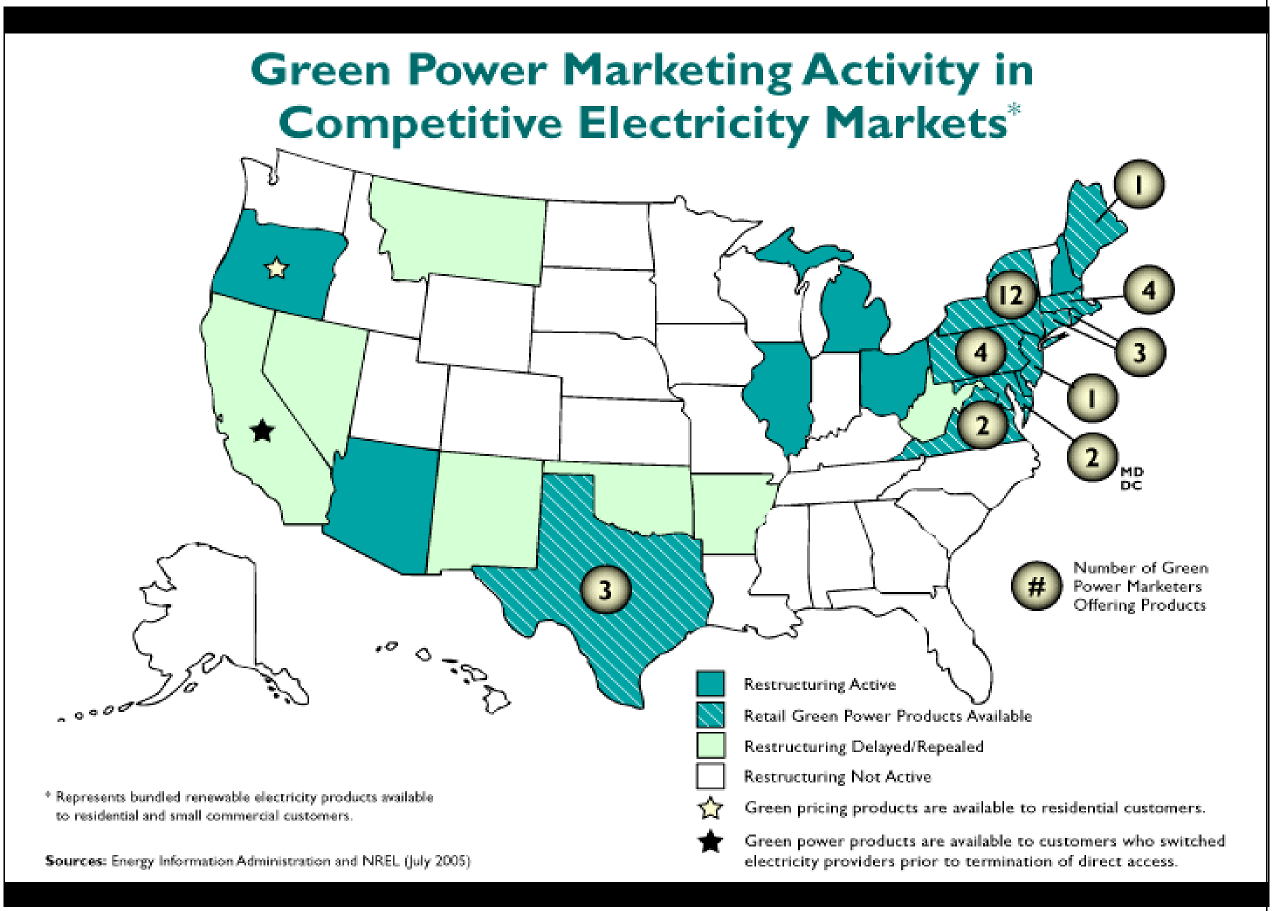
Source: NREL

To be able to take advantage of these options in deregulated markets, customers do not necessarily have to switch suppliers. Instead, a variety of green power options are available through default suppliers which, if they do not offer their own green power products, generally

34 NREL, "Green Power Marketing in the United States: A Status Report." September 2004.

allow customers to choose from green power options offered by competing green power marketers. The map below shows the states with green power market activities.

Figure 23. Map of Green Power Marketing Activity (2005)



Source: EIA and NREL (July 2005)

In the US, sales of green power continue to grow. This is due to the increase in demand by non-residential customers for such programs as well as the increase in the amount of green power purchased by residential customers.

2.5.3.2 Green Premium

Based on a database of more than 600 surveys, 56% to 80% of US voters expressed their willingness to pay more for renewable energy.[35] 68% of respondents in a Canadian survey showed a strong support for the use of green energy.[36] For green pricing provided by utilities

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35 American Wind Energy Association, "Green Pricing Resource Guide", 2004.

36 Oracle poll Research "National Survey Report", October 2004. Canadian Wind Energy Association "Wind Energy in Canada, Market Research Briefing Document", February 2005.

in regulated markets, the price premium is based on the difference in cost between a least-cost case and a case with more renewables. Thus, the utility's avoided cost is a proxy for setting the premium. The ranking for the price premiums charged for new renewable power is shown in the table below.

Figure 24. Ranking for Price Premium Charged for New, Customer-Driven Renewable Power[a] (As of December 2004)

Rank	Utility	Resources Used	Premium
1	Avista Utilities	Wind	0.33¢/kWh
2	Austin Energy[b]	Wind, small hydro, landfill gas	0.50¢/kWh
3	Edmond Electric[b]	Wind	0.68¢/kWh
4	Clallam County Public Utility District	Landfill gas	0.70¢/kWh
5	Eugene Water and Electric Board[b]	Wind	0.71¢/kWh
6	PacifiCorp[c]	Wind, biomass, solar	0.78¢/kWh
7	OG&E Electric Services[b]	Wind	0.88¢/kWh
8	Wabash Valley Power Association[d]	Landfill gas	0.90¢/kWh
9	Roseville Electric	Geothermal, small hydro, solar	1.00¢/kWh
9	Sacramento Municipal Utility District[e]	Landfill gas, wind, small hydro	1.00¢/kWh
9	Southern Minnesota Municipal Power Agency	Wind	1.00¢/kWh

Note:

a Includes only programs that have installed or announced firm plans to install or purchase power from 100% new renewable resources.

b Premium is variable; customers in these programs are exempt or otherwise protected from changes in utility fuel charges.

c Pacific Power product marketed in partnership with 3 Phases Energy Services.

d The premium charged by participating member distribution utilities varies from 0.9¢/kWh to 1.0¢/kWh.

e Product is Green-e accredited (www.green-e.org). d Program offered in association with Wisconsin Public Power Inc.

Source: NREL

The average premiums for utility green pricing have been decreasing since 2000, and currently are about 2.44 cents/kWh with a wide range of 0.33 to 17.6 cents/kWh. The historical and current price premiums in green pricing are shown in the table on the following page.

On the other hand, competitively marketed green power is generally priced at a premium of between 1 cent/kWh and 2.5 cents/kWh. Some marketers charge a monthly service fee or offer a fixed price to protect customers against price volatility. The price premium is based on several factors, such as the price of default service, the availability of incentives to marketers, and the cost of renewable generation in the regional market. New York state offers the largest number of such programs and its green premium ranges from 0.5 cents/kWh to 2.5 cents/kWh.

Figure 25. Historical Price Premiums for Utility Green Pricing (¢/kWh)

	1999	2000	2001	2002	2003	2004 - May 2005
Average Premium	2.15	3.48	2.93	2.82	2.62	2.44
Median Premium	2	2.5	2.5	2.5	2	2
Range of Premiums	0.4-5.0	(0.5)-20.0	0.9-17.6	0.7-17.6	0.6-17.6	0.33-17.6
10 Programs with Lowest Premiums*	0.4-2.5**	(0.5)-2.5	1.0-1.5	0.7-1.5	0.6-1.3	na
Number of Programs Represented	24	50	60	80	91	145

Note: *Represents the 10 utility programs with the lowest price premiums for new customer-driven renewable energy. This includes only programs that have installed—or announced firm plans to install or purchase power from—new renewable energy sources. In 2001 the discrepancy between the low end of the range for all programs and the Top 10 programs results from the fact that the program with the lowest premium (0.9¢/kWh) was not eligible for the Top 10 because it was either selling existing renewables or had not installed any new renewable capacity for its program.

**Data for April 2000.

Source: NREL, "Green Power Marketing in the United States: A Status Report"

Green products in other Northeastern states, such as Connecticut, Massachusetts, Maine, and New Jersey have a similar range of price premiums, except for Maine which offers green products at above 2.5 cents per kWh level.[37]

2.6 OSEA Recommendations

In 2005, the Ontario Sustainable Energy Association ("OSEA") submitted a report of recommendations with respect to the criteria for a pilot program offering standard supply contracts to small or community-based renewable power projects.

OSEA's conclusion focused on the terms of renewable contracts under the pilot and included recommendations regarding the eligibility of renewables, the length of contracts, price mechanism, as well as the limitation on capacity target.

OSEA recommended that eligible renewables be limited to wind, solar PV, low-impact hydro and biomass, and suggested that tariffs or standard offer contracts should differ by technology. OSEA recommended that the length of contract be 20 years, with higher prices for the first five to 10 years in order to recover capital cost, then lower prices for the remainder of the contract.

Wind facilities were divided into three categories: low, medium, and high wind, according to the following characteristics;

- Low wind = <600 kWh/m2/yr
- High wind = >800 kWh/m2/yr
- Medium wind = 600-800 kWh/m2/yr

37 Please see the Appendix, which starts on page 68, for details.

OSEA recommended that wind tariffs be fixed for all tranches for the first 10 years, then be based on relative productivity in units of annual specific yield (kWh/m2/yr) averaged over eight years after high and low years were removed.

OSEA recommended that contracts be allocated on a "first come, first served" basis, and there be no cap or limitation on target capacity to avoid gaming and hoarding.

2.7 Implications for OPA

The development of additional renewable capacity in order to meet environmental policy goals is of growing importance in many markets around North America and in Europe. Numerous different programs and policies have been put in place to facilitate and encourage the development of renewable capacity with varying degrees of success. In developing its policy for procuring renewable energy projects, the Province will have to balance the political support for renewable generation with economic and market considerations.

Standard offer contracts for renewables have had mixed results. In the US, they resulted in the development of a substantial amount of new renewable generation in a relatively short period of time but under pricing schemes that ultimately proved uneconomic. US practice has been to move away from standard offers for renewables in favor of competitive procurement through RFPs and grants. In Europe, where they are still being used, they have been relatively successful in bringing significant amounts of capacity on line, but at great cost. However, the main critique of standard offer contracts is that they are not a cost-effective or efficient way to encourage renewable generation and that they ultimately result in distortions in a competitive market. Poorly designed standard offer contracts can result in an entitlement culture in which projects with minimal beneficial impact are pursued at great expense to the ratepayer. As OPA coordinates in conjunction with the Ontario Energy Board to cooperate in developing a standard offer program, it must be very careful to develop an appropriate pricing strategy that does not result in out of the money contracts and encourages improved cost efficiency from these sites over time.

Given the mixed results from standard offer programs, the province of Ontario may also want to consider also deploying some of the alternative approaches to encouraging renewable generation, such as RPS, technology incentives, or the encouragement of green marketers. Many North American jurisdictions have put in place an RPS, which starts at a relatively low point and increases over time. Market participants that do not meet the RPS are penalized. So far, the mandatory RPS programs have been relatively effective at mobilizing the development of renewable resources. Grants paid to specific renewable technologies are another way to encourage the development of such projects. Such grants are usually paid for the installation of such technologies and thus do not interrupt the competitive nature of the market subsequently. Indeed, the grants process itself is competitive, with the projects requiring the least amount of subsidy awarded grants. Moreover, these programs can be targeted to specific technologies, specific regions, or specific types of customers, making them a powerful tool for policy makers.

3 Demand response procurement

Demand response is an approach that utilities and regulators sometimes use as a way to address capacity or transmission/distribution shortages in a given area. Demand response is usually considered to be a program that encourages consumers to reduce their consumption at certain periods in exchange for economic (or other) benefits from its supplier. Such contracts are relatively common for large industrial customers, for whom electricity represents a significant percentage of their costs. However, demand response contracts are increasingly being developed for large commercial customers, who can coordinate the consumption of numerous sites, thereby resulting in a meaningful decrease in consumption. Demand response programs are sometimes negotiated on a one-on-one basis with each customer or, increasingly, can also be procured through a competitive Request For Proposals process. We discuss examples of both below.

In addition, there are also programs that leverage the existing generation that exists at industrial or other sites, using them as full time generators during crucial periods. Standby generators are categorized as distributed generation, which refers to any small scale generation unit close to the point of consumption. Many procurement processes for localized generation refer to distributed generation in general, which includes standby generation units. The programs for utilizing these generators are varied and we discuss some recent examples in Section 3.3.

3.1 demand response programs in key markets

Demand response and demand side management are becoming increasingly important. Indeed, in the US in 2003, $1.45 billion was spent on such initiatives by utility ratepayers and states.[38] The regions with a tight supply-demand balance or where building new infrastructure is difficult are contributing the most to such programs. Approximately $500 million was spent on demand response programs in the Northeast and more than $400 million was spent in California. In the subsections below, we discuss demand response programs in New York, California, and Alberta, providing information on the types of demand response programs that are run in these areas and the impact they have had on load reduction.

3.1.1 New York

The New York Independent System Operators ("NYISO") runs two reliability programs that are controlled by the NYSIO – Emergency Demand Response and ICAP Special Case Resources- and one economic program that is controlled by the customer – the Day Ahead Demand Response program. All three programs are targeted at wholesale market participants, aggregators, and direct customers.

- **Emergency Demand Response Program:** A reliability program activated in response to forecast or actual operating reserve deficiencies. The minimum size for participation is

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38 American Council for an Energy Efficient Economy.

100 kW although participants may aggregate within a zone to reach the threshold. Customers are paid for energy reduction (kWh). Interruptible load and emergency back-up generation can participate, as well as Load Serving Entities, direct customers, and aggregators. This is a voluntary response program and there are no penalties for not participating. The payment is the greater of the real-time marginal price or $500/MWh and is guaranteed for four hours.

- **ICAP Special Case Resources:** A reliability program that is activated in response to forecast or actual operating reserve deficiencies. The minimum size for participation is 100 kW although participants may aggregate within a zone to reach the threshold. Unlike the Emergency Program, participation is mandatory and resources are penalized and de-rated for non-compliance. Participants receive a capacity payment plus an energy payment. The energy payment is the greater of the real-time marginal price or the amount that the bidder contractually agreed to bid into the market when signing up for the program[39] (any amount up to $500/MWh) and is guaranteed for four hours. Interruptible load and emergency back-up generation can participate, as well as Load Serving Entities, direct customers, and aggregators. Participants receive a day-ahead warning that the program may be activated.

- **Day Ahead Demand Response:** This is an economic program that allows participants to be paid for reducing their supply. The minimum participation size is 1 MW although participants can aggregate within zones to meet the threshold. Load bids into the day ahead market like a generator with a minimum bid of $75/MWh and receives the greater of marginal price or its bid.

New York has had significant success with its demand response programs, reducing peak load by as much as 800 MW during reserve shortages. More than 2,300 large commercial and industrial customers have participated.[40] As of February 2005, the NYISO has more than 1,000 MW of capacity registered in the Emergency and ICAP Special Case Resource Programs and more than 350 MW registered in the Day Ahead Program. The cost benefit ratios for New York's demand response programs are impressive. In 2003, the Reliability Programs had total costs of $7.2 million and benefits of $54 million (7.5 to 1 ratio) and the Economic Program had total costs of $0.2 million and benefits of $2.2 million (10 to 1 ratio).[41] Note that these costs are far cheaper than building a new peaking facility, which would cost about US $2 million per year for 25 MW of capacity.

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39 Dispatchers can thus rank the bids in terms of offer price when determining which bids to dispatch.

40 Breidenbaugh, Aaron, Presentation of NYISO's Demand Response Program by NYISO Demand Response Coordinator, "Reduce Energy and Get Paid 2005," March 15, 2005.

41 Ibid.

3.1.2 California

Following its energy crisis in 2000 to 2001, California launched a number of demand response initiatives. As part of its *Energy Action Plan 2003*, the California government has targeted peak demand reduction of 1% per year through demand response initiatives when power is expensive or reliability is an issue. Most of these programs are run through the individual IOUs as well as the California Power Authority, and thus the number of programs originally sponsored by the California Independent System Operator ("CAISO") has been reduced to only the Voluntary Load Reduction Program. This program, as its name implies, is a purely voluntary one that relies on its participants to reduce their energy consumption by an amount of their choosing when the CAISO declares a power emergency. The objective of this program is to prevent further escalation of an emergency to higher levels that could require more severe action by the CAISO, such as interrupting load. There is no payment for this participation. The CAISO does not provide any information on the amount of demand that this program aggregates and activates.

The California Power Authority ("CPA") runs a program called the Demand Reserves Partnership Program, which encourages businesses to reduce power usage when supplies are low. This program provides load reductions of between 500 MW and 1,000 MW of power. Businesses are compensated by the CPA for participating in this program through a monthly reservation fee for making the capacity available and through an energy payment for actual reductions. The entire program is automated using an Internet-based system enabling the state to dispatch commercial and industrial power curtailment just like generation. The fees for this program are based on a capacity payment and energy payment for specific kinds of response and vary substantially depending on the season. The capacity payments range from $330/MW month for non summer Replacement Capacity or Day Ahead Reserves Replacement[42] to $14,000/MW month for summer Non Spinning Capacity[43]. The energy payments are the same for all types of service and during all seasons at $80/MWh. [44]

Finally, the California utilities also all run their own demand reserve programs consisting of numerous individual programs. As an illustration of the extensive nature of these programs, we use Southern California Edison ("SCE") as an example. SCE has ten demand response programs, which we briefly describe below. Note that more information is provided on these programs on each of the utilities websites. Many of the programs also incorporate a penalty component for non-compliance, which we do not list here.

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42 Replacement capacity that can be scheduled or dispatched up to 1 ½ hours after notification if the capacity was reserved by CAISO and/or the Authority by the end of the previous day.

43 Any capacity that can be scheduled or dispatched on not more than 10 minutes basis and can be used for any type of service. No reservation required.

44 All pricing information from template contract for DR service for 2005 available at: http://www.caldrp.com/Documents/CPA-DRProvider_Agreement.pdf.

- **Base Interruptible Program ("BIP"):** Pays participants to reduce their load to a pre-determined level when CAISO calls a load curtailment notice. Must commit to curtail at least 15% of average monthly load or a minimum of 100 kW, whichever is greater. Participants are paid $7/kW/month.

- **I-6:** Provides lower energy and time-related demand charges for the portion of power usage that a customer is willing to interrupt when requested by SCE. The number of interruptions are limited to 25 events per year.

- **Demand Bidding Program ("DBP"):** This program offers a credit to qualifying SCE bundled service customers with a demand of at least 200 kW who voluntarily commit to reduce at least 10% of their annual average demand during a DBP event. Incentives range from $0.15/kWh to $0.50/kWh.

- **Critical Peak Pricing ("CPP"):** Allows participants to lower their business' electricity bills by shifting or reducing electricity consumption during critical peak summer afternoons.

- **Optional Binding Mandatory Curtailment Plan:** Lets participants avoid curtailments by implementing load reductions of 5% to 15% increments on their entire circuit.

- **Scheduled Load Reduction Program ("SLRP"):** Participants identify one to three four-hour periods during the week when they are willing to curtail their electric load. They must commit at least to 15% of their average monthly load with a minimum of 100 kW per event. Participants are paid $0.10/kWh. Must curtail load once each week for each period they choose through the summer season (June 1 through September 30).

- **Schedule 20/20:** This program is geared at small commercial and residential customers and grants them a 20% discount for reducing their load by 20% from the previous year.

- **Summer Discount Plan:** SCE provides and installs a cycling device on the participant's air conditioner which is activated by remote control when needed. Participants receive a credit on their summer season electric bill based on their current rate schedule, whether they have chosen the base or enhanced discount plan, and the calculated tonnage of air conditioner participating in the program. Individuals or entities participating in the enhanced program are subject to an unlimited number of events per year for a maximum of six hours per day and receive twice the credits under the base program.

- **Energy$mart Thermostat SM Program:** This is a pilot program that is testing a new technology for controlling air temperature and reducing bills. Participants receive a cash incentive of up to $150 and also receive a fee digital programmable thermostat.

- **Agriculture and Pumping Interruptible Service Program:** Provides lower energy and or time-related demand charges to customers who are willing to interrupt power usage at SCE's request. Events are limited to one event per day, four events per week, or 25 events per year and will not exceed six hours per day, 40 hours per month, and 150 hours per year. Participants receive a credit of $0.00827/kWh.

In addition, the CPUC and CEC are also working to expand the possibilities for using demand response programs within the residential and small commercial customer segment and are in the process of refining these programs through a series of workshops and pilots.

3.1.3 Alberta

The Alberta Energy System Operator[45] ("AESO") has a voluntary load reduction program where payment is made to customers based on actual curtailments. This program tends to be used on an off-on basis when supplies are tight, and was of particular use during the shortages in 2000-2001. The program is not currently in use.

The first major RFP for curtailable load was issued in December 2000 in Alberta and solicited load reduction within one hour for a minimum four hour duration following instructions from the dispatcher. Compensation is based on the $/MWh price proposed by the supplier and is paid based on actual curtailment. Note that the prices bid by load are not considered to be a bid for the purposes of setting the marketing clearing price in the spot market and, as such, have no impact on the market price. The program was designed so that the AESO can issue an RFP each month for the following month.

There are certain requirements for this program. The minimum load for the program is 1 MW. Smaller loads may aggregate to meet this requirement but must have a single point of contact for dispatch to qualify. The participants must have time interval metering and must be able to provide the AESO with 15 minute data.

The AESO evaluates all of the proposals and determines which meet the minimum eligibility requirements. Those that do are ranked according to price, whether they can be reduced "down by" a certain amount or "down to" a certain amount, the availability of curtailable load, and deviation from the standard contract. The bidders are then chosen in order of their position on the ranked list on an "as-needed" basis.

3.2 use of standard offers in demand response programs

As we have described above, demand response programs are usually structured in a manner where a pool of qualifying assets agree to provide demand response services for a set fee. This fee sometimes consists of a capacity payment for the amount of capacity that the bidder is willing to participate with as well as an energy payment for the actual amount by which the bidder is required to reduce its consumption. Capacity payments are set in advance (for the next year or season), and the energy price is either set in advance or has a pre-existing minimum level (i.e., such as in New York where energy payments are often the greater of the marginal energy price or $500/MWh, effectively guaranteeing a minimum payment of $500/MWh). As such, one might argue that these programs are similar to a standard offer in that the bidders have (in the short term) an understanding of the payment that they might

45 Note that the AESO was formerly called the Alberta Power Pool. We refer to its current name in this report even when making references to time periods when it was called the Alberta Power Pool.

expect under such a program. However, because the payment is largely contingent on being "called" by the system operator (or the utility), there is little certainty for bidders in programs where there is no (or only a small) capacity payment.

3.3 programs involving standby generators

Standby generators, a type of distributed generation[46], are increasingly being used as a short-term fix to challenges in developing generation capacity or transmission and distribution infrastructure to address growing demand or load pockets. Unlike central power plants, which are typically located far from load centers, distributed generation can produce electricity at or near the place it is consumed. Distributed generation can run on fossil fuels, renewable energy resources, or waste heat and the sizes of such equipment range from less than one kW to hundreds of MW. The use of distributed generators has been particularly prevalent in areas of tight supply-demand balances, or where Not-In-My-Backyard ("NIMBY") sentiments are strong, such as New York, California, and New England.

For example, in Decision 03-02-068, the California Public Utilities Commission ("CPUC") concluded: "Distribution system planning must consider distributed generation alternatives to wires upgrades as part of the normal planning process and non-utility distributed generation solutions should be actively solicited through the distribution planning process."[47] As such, California utilities, San Diego Gas & Electric and South California Edison, are seeking vendors to supply turnkey distributed generation alternatives to distribution upgrades. (We provide information on the procurement processes for such technology in the next subsection.)

Likewise, the New York State Public Service Commission ("NYPSC") began a three year pilot program in October 2001 requiring New York utilities to develop and issue RFPs for customer-side distributed generation to meet specific capacity needs on their systems. Each utility was obliged to identify areas in its distribution service territory where distributed generation might be applied and to issue two RFPs in each planning year to potential distributed generators.

Other utilities in the US also have programs that rely on distributed generators to provide reliable electricity to their customers. Portland Gas & Electric ("PGE") has a program that operates standby generators, less than 250 kW in size, to meet peak demand load. The generators are monitored and dispatched from PGE's demand center and PGE assumes all costs for upgrading equipment and for operations and maintenance.

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46 Distributed generation refers to all types of localized generation near the site of consumption and can include standby generators as well as small renewable units. Because more of the programs that we assessed referred to the general category of distributed generator and did not specify standby generators we use the term distributed generation as well.

47 See www.cpuc.ca.gov/word_pdf/FINAL_DECISION/24136.pdf.

3.3.1 procurement processes

Thus far, the procurement of distributed generation (including standby generators) to use for peak or localized demand by utilities has occurred through formal RFP processes.

In December 2003, the Independent System Operator of New England ("ISO-NE") issued an RFP for 300 MW of emergency generation capacity in Southwest Connecticut to alleviate localized load pockets and ensure reliability over the next four years. The RFP was targeted at generation resources, demand response, or standby generators located in Southwest Connecticut. The minimum load for standby generators was 100 kW. Payments are through a capacity payment. The decision on winning bids was based to lowest total cost using technically feasible equipment.

Of the 260 MW awarded under the contract, almost 100 MW were provided by distributed generators. 125 MW of additional capacity was available as of June 1, 2004 and about 255 MW will be available by the summer of 2007. The contracts for the awarded bids, which were submitted to FERC for approval, were all standard contracts with specifications altered to suit the technology of the winning bidders (i.e., standby generation, demand response, distributed generation, etc.). The initial term for all contracts lasted from 2004 through 2008[48], with the option to extend the contract for one year. The winning bidders included conservation providers (Conservation Services Group and NXEGEN), demand response providers (Comverge, Connecticut Municipal Electric Energy Cooperative ("CMEEC"), EnerNOC, United Illuminating ("UI"), Pinpoint Power, and Honeywell DMC Services), and emergency generators (CMEEC, EnerNOC, NXEGEN, UI, and Pinpoint Power). While most of the contracts were redacted so that specific information related to exact capacity commitments and bidder compensation were not available, the Pinpoint Power contract was not redacted. Average prices for capacity ranged from $31,000/MW-month to $33,000/MW-month for the months of June through September. ISO New England estimated that the cost of the total amount provureed through the RFP will be approximately $125 million over the four year term.[49]

In British Columbia, BC Hydro over the last couple of years regularly organized competitive tenders for distributed generation. As a result, BC Hydro has facilitated the development of cogeneration projects at industrial facilities in its service territory by providing much of the capital investment.[50] There are two such projects to date. First, BC Hydro contributed almost half of the $35 million investment required for a 30 MW hog-fuel generator at the Weyerhaeuser pulp mill in Kamloops. In exchange, the contract guarantees BC Hydro 155 GWh of load displacement for 10 years. Excess energy is sold on the wholesale market. The other project is similar. BC Hydro has contributed $49 million of the $81 million required for a 48 MW generator to be installed at one of Canadian Forest Product's sites. BC Hydro will supply the

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48 Exact dates varied by contract.

49 ISO New England press release, "ISO New England Secures Resources to Help Maintain Reliable Power Supplies for Southwest Connecticut this Summer," April 16, 2004.

50 Those capital investments are included in its rate base.

company with all the electricity it needs as well as supply power for other consumers in the area for a 15 year period.[51] The incentive level for these projects is about Cdn. c 1.5/kWh. The utility typically provides payments in three installations: 25% at the beginning of construction, 50% once the project is fully operational, and 25% after measurement and verification a year later. The customer must meet an annual generation target and refund a pro-rated portion of the payments if it switches to another supplier within 10 years of the project completion date. In addition, BC Hydro has also obtained other customer based generation projects through its 2002 RFP process, which will result in 500 GWh of new electricity to the BC system. The adjusted bids for the successful projects did not exceed Cdn. c 5.5/kWh, which is BC Hydro's long-run marginal cost for electricity.[52]

San Diego Gas & Electric ("SDG&E") is currently in the process of seeking vendors to pre-qualify for possible turnkey distributed generation alternatives to distribution system upgrades. SDG&E will identify the capacity projects where it thinks that distributed generation could serve as a good alternative to a distribution grid investment and will approach pre-qualified vendors, who will then be required to provide information on size, quantity, reliability, O&M responsibility, and other issues. SDG&E will then compare this solution to its other options and select the solution that provides the lowest total cost to SDG&E. Likewise, Southern California Edison ("SCE") has conducted a pilot program in conjunction with the Distributed Energy Resources ("DER") Partnership, which entailed identifying several distribution areas that were facing significant upgrades that might be deferrable using distributed generation. An RFP is being issued this year which is expected to target 10-25 MW of distributed generation capacity. The objectives of the procurement process will be to have a solicitation that is easy to understand and respond to and to encourage many bidders to submit innovative options to the utility.

While, in theory, customer sited generation can compete in full fledged utility solicitations, there are a number of challenges. Sometimes the minimum size requirements (such as 5 MW in a recent PGE RFP) can prevent smaller projects from participating. In addition, negotiating rates and other contractual terms with the utility can be burdensome and challenging for customers, whose core activity is not in the electricity sector. Some industry participants have recommended that a third party entity, such as an aggregator, play a pivotal role in aggregating different standby generators and other distributed generators into a portfolio and assisting or managing negotiations with the local distribution companies.

3.3.2 environmental issues regarding diesel generators

Emissions of greenhouse gases and other pollutants from standby generators depend on the technology used and range from zero to quite high. Because the generators are small, they

51 All information from the BC Hydro projects from the Oregon PUC, "Distribution Generation in Oregon: Overview, Regulatory Barriers and Recommendations," February 2005 and confirmed in telephone interview with Richard Marchante of BC Hydro on July 12, 2005.

52 BC Hydro press release, "Customers to provide BC Hydro with 500 GWh/year of electricity" April 14, 2003.

generally are not covered by the same regulations that cover central power plants. In developing a total electricity procurement strategy, addressing how to balance the need for additional supply with the potential environmental impacts is of crucial importance.

A template already exists for developing regulations for small scale generators, including diesel generators. In the US, a group of 30 state utility regulators, state environmental regulators, representatives from the distributed generation industry, environmental advocates, and federal officials developed model rules for states for emission standards for distributed and other generation facilities that are not regulated directly by the Federal Clean Air Act. This was called the Regulatory Assistance Project, and resulted in "Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources," published October 31, 2002.[53] The rules regulated five emissions: nitrogen oxides, particulates, carbon monoxide, sulfur dioxide, and carbon dioxide. Standards are based on the output of the facility rather than fuel consumed as well as whether the output is intended for baseload, peaking, or emergency needs[54]. The general premise is that the more a generator operates, the less polluting it must be. Emissions limits are based on what current technologies are capable of and then are decreased over time.

In reality, the need for capacity has often outweighed environmental considerations. In the New York pilot program in 2001, additional environmental assessments were not required by the NYPSC, who stated, "We agree…that it would not be fruitful, and could be counter-productive at this time, to introduce environmental impacts as an evaluation factor in the bid analysis."[55] Thus the bids under the pilot program are required only to obtain the required environmental permits required of all distributed generation units in the state. At the same time, the NYPSC required that appropriate environmental information and characteristics of the bids should be submitted and evaluated by the utilities in their assessments of the programs. Note that some of the participants to the proceedings had argued for adding a pre-qualification requirement imposing emission restrictions designed to disqualify the most polluting technologies. Likewise, the current RFPs for distributed generation in California specify no environmental characteristics and the evaluation process are based mainly on the technical abilities of the unit and the economics as compared to CA utilities' procurement alternatives.

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53 More information is available on the following website dedicated to the topic: http://www.raponline.org/Feature.asp?select=8. The report is available at the following link: http://www.raponline.org/showpdf.asp?PDF_URL=%22ProjDocs/DREmsRul/Collfile/ReviewDraftModelEmissionsRule.pdf%22.

54 Emergency generators are not allowed to generate more than 300 hours per year and have emissions limits that are equal to EPA standards for off-road engines.

55 New York Public Service Commission, Opinion No. 01-5, Case 00-E-0005: Proceeding on Motion of the Commission to Examine Costs, Benefits and Rates Regarding Distributed Generation. October 26, 2001.

3.4 Implications for OPA

Demand response programs are a key way for all markets to reduce demand at crucial periods by providing economic incentives to consumers. Demand response has proved to be effective at addressing reliability issues as well as providing an economic way to avoid building additional capacity to address peak needs. Demand response can be a cost-effective policy tool, as illustrated by the high ratio of benefits to costs as measured by the NYPSC. Indeed, on a per kW basis, demand response is much cheaper than installing new peaking facilities.

Based on our assessment of different programs, an institutionalized long term approach to large scale demand response procurement is most effective. A centralized approach, run by the ISO or by an entity dedicated to such efforts, makes it easier to quantitatively evaluate the costs and benefits of the program. Even in the most active jurisdictions, demand response programs have only scratched the surface of what is possible; most customers are unaware of how they could participate or how they could reconfigure their operations to benefit. Note that smaller demand response programs, such as those focused on residential and small commercial customers, can be coordinated by aggregators, as was observed in Connecticut and elsewhere.

The use of standby generators, or other distributed generation, can also be very helpful in times of tight supply-demand conditions. Indeed, jurisdictions such as New England, New York, and California have all mobilized distribution generation resources as a way to address supply shortages, transportation infrastructure needs, or localized generation needs. As seen in these markets, it is possible to utilize a traditional RFP based procurement process to acquire distributed generation, even in a short time frame as demonstrated by the ISO-NE process for Southwest Connecticut. However, given Ontario's commitment to the environment, OPA will have to determine an appropriate way to address potential negative environmental externalities from such an approach on an ex ante basis. It has several options in this regard, including requiring the integrating of some form of streamlined environmental assessment as part of the RFP process, requiring that distributed generation assets meet certain minimum environmental criteria (which for certain areas could be in excess of current statutory requirements), or structuring the payments to generators in such a way that rewards those that are environmentally friendly or neutral.

4 Energy efficiency procurement in other provinces

Energy efficiency programs usually run independently of other capacity solicitations and, in many jurisdictions, are strongly encouraged or required by the local regulator. Often, conservation goals are jointly set by the regulator and the utility, and funding that is generally integrated into ratebase is set aside to cover the costs of such programs. Energy efficiency programs differ in the incentives that utilities face to go beyond minimum requirements and in the actual activities funded by these programs. We discuss several of the more prominent programs below.

First, however, it is important to address the issue of monitoring and verification of energy efficiency programs as this is of crucial importance in undertaking and assessing such initiatives. There is an international monitoring and verification standard, called the International Performance Measurement & Verification Protocol ("IPMVP")[56], which was based on work originally funded by the US Department of Energy and now maintained by IPMVP Inc., a non profit organization[57]. The IPMVP standardizes the methods for quantifying energy savings and help to assess projects consistently. The IPMVP provides detailed documentation to the public regarding the development of a comprehensive monitoring and verification ("M&V") program and serves as a reference internationally. Some utilities rely exclusively on the IPMVP approach, while others use it more as a reference in conjunction with their individual M&V plans.

4.1 British Columbia Hydro's "Power Smart" program

4.1.1 Program goals and accomplishments

In 2001, British Columbia Hydro ("BC Hydro") launched a Conservation Potential Review to estimate the realistic potential for electricity conservation in British Columbia by 2016. The study was completed in 2002 and concluded that British Columbia ("BC") customers could reduce their electricity consumption by 5,800 GWh by 2016 by implementing a variety of cost-effective energy efficiency measures.[58] The total cost savings were estimated at Cdn. $255 million.[59] The Review focused on technologies that were already commercially viable or would be so by 2005. The information used to calculate the potential for energy conservation was based on sales data, energy efficiency upgrade options, and estimates of economic energy

56 We provide a brief summary of the International Performance Measurement & Verification Protocol in the Appendix. The full protocol is available at: http://www.ipmvp.org/download.php.

57 IMVP, Inc. is dedicated to serving the energy and water efficiency market place. Its goals are the development of Monitoring and Verification protocols, relevant training and educational materials, and a community of IPMVP users focused on advancing the state of Monitoring and Verification worldwide.

58 Current discussions at BC Hydro are focused on a new goal of having consumption in 20 years be equal to today's level, should this be formalized.

59 BC Hydro, "Conservation Potential Review Overview," December 6, 2003.

savings potential, as well as assumptions regarding the proportion of consumers that would be likely to install the relevant technologies.

The Review divided BC consumers into three categories: residential, commercial, and industrial. The Review estimated that residential consumers could realistically achieve aggregate electricity savings of 1,333 GWh per year by 2016. The savings potential was largely driven by lighting (49%) and home appliances (38%), with the remainder being met by efficient new apartments, water heating, heat pumps, and weatherization techniques. The Conservation Potential Review calculated that the commercial sector could save an aggregate 1,128 GWh by 2016, which would be driven by lighting (45%), small commercial retrofit and design (23%), and high performance large commercial buildings (12%). Finally, the Review determined that the industrial sector could save an aggregate 3,374 GWh by 2016. These savings could be realized by improvements to pump systems, mechanical pulping systems, and steam cycle optimization, which together represent 74% of the potential savings.[60]

According to BC Hydro's 2005 Annual Report, current savings from the Power Smart program totaled 1,355 GWh, above the target of 1,315 GWh for 2004-2005, and a large increase from the previous year's 834 GWh. The target for 2005-2006 is 1,886 GWh.[61]

4.1.2 Specific projects

The BC Hydro's Power Smart program has numerous different programs that focus on different consumer segments.

- **Power Smart Residential Program** targets small residential customers with a variety of energy efficiency techniques and applications. Some of the programs within the residential program include the refrigerator buy back program, which has collected more than 39,000 second operating refrigerators for which customers were paid Cdn. $30 each; the compact fluorescent light ("CFL") bulb giveaway campaign, which resulted in 1.8 million CFLs being distributed to almost 650,000 customers; the renovation rebate program; Power Smart packages of energy efficient products for new homes (more than 1,100 homes built in 2004 and over 2,200 more under construction); and, substantial on-line information about ways to make existing residential heating, water, lighting, and appliances more energy efficient.

- **Power Smart Business Program** targets businesses and commercial customers through a variety of different approaches and programs, including the product incentive program, which provides financial incentives to business customers to replace existing inefficient products with energy efficient technologies; Power Smart Partner Program, where BC Hydro partners with eligible businesses who make a commitment to energy efficiency;

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60 All savings estimates were from: BC Hydro, "Conservation Potential Review Overview," December 6, 2003.

61 BC Hydro 2005 Annual Report.

Power Smart Green Power Certificates; and a host of on-line information about ways to make existing commercial buildings and businesses more energy efficient.

- **Power Smart Certified Program:** Power Smart Certified customers represent a group of the most energy efficient customers within their respective industries. Three additional companies received certification in 2004, bringing the total number of Power Smart Certified Companies to nine in BC.

- **Power Smart School Program:** BC Hydro provides energy conservation education to schools at a number of grade levels, reaching almost 60,000 students in 280 schools over the last year. The program focuses on encouraging behavioral change campaigns, energy audits of schools, and interactive games that demonstrate how individual efforts can lead to significant energy savings.

- **Power Smart Prince George Pilot Street Lighting Program:** The project uses a new technology that allows streetlights to be dimmed at certain times of the night, day, week, or season to save energy and money for the city.

4.1.3 Program management and funding[62]

BC Hydro currently has a Cdn. $125 million annual budget for all conservation and demand side management programs, including educational endeavors. This budget is included in their ratebase, as long as the regulator approves the expenses as reasonable and just. There is no requirement for BC Hydro to have a conservation program under BC's provincial laws and regulations and there is no incentive payment associated with the program. Note however that as the conservation and demand side management program goals are integrated into BC Hydro's Integrated Resource Plan, there could be long term negative consequences for the firm for not meeting targeted consumption reductions.

The utility sets its targets, based on its Conservation Potential Review, which are updated and revised in their ten year plans. These targets are then translated into specific targets for program managers and key account managers (for the larger commercial and industrial accounts).

About 150 people within BC Hydro work on conservation and energy efficiency issues.

BC Hydro's energy efficiency programs are evaluated after implementation to determine their full impact. The Evaluation Oversight Team consists of representatives from different lines of business and the chair of the team is designated by someone outside of distribution activities. BC Hydro prepares an evaluation plan in advance and actual evaluations are conducted at major project milestones or at the end of the program. Process, market, and impact evaluations are conducted and are overseen by the Evaluation Oversight Team. BC Hydro also benchmarks itself against other utilities by comparing its energy efficiency investments as a percentage of revenues and the resulting electricity savings as a percentage of sales.

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62 All information obtained by telephone interview with BC Hydro's Richard Marchante on July 12, 2005.

4.2 other North American jurisdictions

Many other utilities in North America also have successful energy efficiency programs that could provide insight or guidance to the Ontario Power Authority in its reflections on this topic. Programs, as in BC, are often run by the utility. The financing for such programs is either spending based or set up in a performance-based incentive manner, depending on the sophistication and objectives of the regulator. In the US, there is a trend toward incentive-based programs. For example, in Massachusetts, utilities can claim an after-tax reward of 5%-5.5% of the conservation budget for savings achievements of 75% to 110% of targets. In Connecticut, utilities can earn a pre-tax reward of 2% to 8% of the conservation and load management budget for savings achievements of 70% to 130% of targets.[63] Competitive bidding for the procurement of such projects is starting to become more popular. Indeed, at least 20% of California's $325 million budget for energy efficiency measures will be put out to competitive tender.[64] We provide two case studies below to provide more detail on the ways that utilities can promote energy efficiency and how they are compensated for this.

4.2.1 California: San Diego Gas & Electric ("SDG&E")

San Diego Gas & Electric ("SDG&E") started to actively promote conservation programs and to receive incentives for doing so starting in 1989. Current programs include the 20/20 Program, which gives customer a 20% credit on their next bill for reducing their consumption by 20% from the same period during the previous year. All residential customers can participate and commercial customers that consume 20 kW or less per month can also participate. Another program is the residential rebate program, which provides a rebate to consumers who purchase and install qualifying energy saving measures. SDG&E also provides numerous on-line interactive tools for both residential and business consumers geared at helping them identify potential energy saving techniques and technologies, such as the Energy Smart Home and the Business Energy Analyzer.

California is currently in the process of restructuring how it compensates utilities for energy efficiency programs. There have been three critical phases in the state's development on this topic, which we describe briefly below.[65]

- **Pre-restructuring Era (1990-1997):** The California Public Utility Commission ("CPUC") put in place a system of financial rewards and penalties (shareholder incentive mechanisms) for energy efficiency programs in order to reconcile the financial conflicts that IOUs faced under Cost of Service regulation regarding conservation. Under this system, IOUs earned a fixed percentage of the net savings to ratepayers (energy savings

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63 Shirley, Wayne, "Surveying DSM Programs Nationwide: Is there Money on the Table?" *The Regulatory Assistance Project*, A presentation to NAESCO Mid-Year Conference, May 19, 2005.

64 Ibid.

65 Information on these historical phases comes from Decision 05-01-055 January 2005, "Interim Opinion on the Administrative Structure for Energy Efficiency: Threshold Issues"

minus costs) after a threshold level of savings was achieved. For example, during this period, the threshold for SDG&E was 50%. SDG&E was subject to a penalty if net benefits fell below 50% of the forecasts but they were also rewarded if they achieved benefits in excess of 50% of the forecast. At higher benefit levels, the savings share increased steeply at first, then at a slower rate, finally leveling off when benefits reached 130% of the forecast. There was no cap on the total amount that SDG&E could earn.

- **Restructuring Era (1997-2000):** During the process of restructuring, the CPUC acknowledged the continued need for energy efficiency programs, but shifted away from programs that provided financial incentives to individual consumers toward programs that had broader transformational impacts, such as education outreach and incentives to manufacturers. The funding for such programs was to be collected directly from ratepayers in the form of a non-bypassable charge (Public Goods Charge – ("PGC")) on local distribution service. An independent organization, the California Board for Energy Efficiency ("CBEE") was formed to oversee contracts for the administration of such contracts. However, following a slew of legal and administrative problems, in 1999, through AB 1393, control for such programs was given back to the IOUs although funding was still generated through the PGC.

- **Post Energy Crisis Structure (summer 2000 - 2005):** In response to the supply shortage, the CPUC launched the Summer 2000 Energy Efficiency Initiative, which solicited program proposals from the IOUs and other interested parties to quickly reduce demand in the state, resulting in $72 million in expenditures over the following 18 months. This marked a new administrative structure for energy efficiency programs in California. The CPUC established evaluation criteria for reviewing program proposals, solicited proposals, and made final program selections each funding cycle. In short, the CPUC took over full control of all energy efficiency programs during this period.

The new structure of administering such a program is currently being designed and as such the details of the programs functioning are not yet fully determined. The new program is expected to be in place by 2006. The IOUs will take over control once again of project administration based on CPUC-set goals. This decision was based on the fact that "experience has demonstrated to us that IOUs can meet aggressive savings goals under an administrative structure that holds them directly accountable for program results….we estimate that IOU administrators….produced $1.4 billion in net benefits to ratepayers (savings minus costs, including shareholder incentives) for programs implemented or initiated over the 1994-1997 period."[66] The CPUC will still maintain oversight responsibility: it will review IOU proposals, funding and assess the cost effectiveness of such programs. There will be a competitive bidding minimum requirement (20%) as well as a ban on affiliate transactions between IOU administrators and program implementers. The program will also integrate performance based incentives but the details of how this will work have not yet been determined.[67]

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66 Decision 05-01-055 January 2005, "Interim Opinion on the Administrative Structure for Energy Efficiency: Threshold Issues."

67 Based on telephone interview with Peter Lei, California Public Utility Commission, on July 12, 2005.

The new program will also put in place an extensive monitoring and verification structure. The Energy Division of the CPUC will assume responsibility for managing and contracting all M&V studies from 2006 onward. The studies will be used to measure and verify energy and peak load savings for individual programs, to generate the data for savings estimates and cost-effectiveness inputs, to measure and evaluate the achievements of energy efficiency programs, and to evaluate whether or not program and portfolio goals are met. The development of M&V protocols is being determined in a public workshop-based process. M&V plans and budgets will be determined during each program planning cycle. Study results will be available for public review and comment. In conducting these activities, the Energy Division will rely on an ad hoc committee of technical experts, such as CEC staff members, IOU experts, and other field experts.

4.2.2 Minnesota: Northern States Power (Xcel Energy)

Northern States Power ("NSP"), which is owned by Xcel Energy, is an IOU in Minnesota that provides gas and electric services to 1.3 million customers in five states in the Midwest. NSP started its conservation program in the early 1990s. The program is currently is focused largely on providing useful information to residential and commercial customers. The residential program includes a home energy analyzer, a set of energy calculators to evaluate appliances, and the Energy Smart University and Library, which serve as tools and resources to customers looking to learn more about conservation and energy issues. Services for business customers include an on-line energy assessment as well as detailed information about heating, HVAC, lighting, refrigeration, and other applications commonly used in commercial units.

In Minnesota, the financing for energy efficiency programs has varied over the years.[68] Utilities are obliged by state statute to spend a certain amount on energy efficiency and conservation. (Xcel's obligation is 2% of gross revenue for electric demand side management programs.) In addition, as part of the state's resource planning requirement, demand side approaches are also required to represent a certain percentage of long term planning depending on comparative cost effectiveness with other possible resources.

In addition, there are other incentive structures that encourage the utilities to go above and beyond the minimum criteria set out in regulations. In Minnesota, there have been several different approaches to structuring these incentives. These projects were originally structured using a bonus rate of return mechanism. The utility capitalized and amortized all allowed conservation expenses over a five year period and was allowed to earn a 5% bonus on the unamortized portion of capitalized expenses. In order to receive the bonus, NSP had to show cost effectiveness equal to at least 50% of its target net avoided revenue requirement, a concept similar to avoided costs. The actual bonus payment was directly tied to the level of goal achievement, with 0% granted as a bonus when 50% of the target was achieved to the full 5% for 100% or more of goal achievement.

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68 All information on these programs was provided in an interview with Xcel executive, Gray Staples, on July 10, 2005.

Then, for a brief period of time in the late 1990s, the regulator used a lost margin compensation structure. However, this proved to be very lucrative for the utility[69] and the compensation approach was ultimately changed in 2001 to a performance based structure. The current structure is designed to encourage the utility to spend more on conservation and energy efficiency than the minimum and is structured in a way that rewards the utility for cost-effective investments. As such, every two years, conservation goals are set for each utility. The bonus compensation to utilities is calculated in two steps. First, the PUC determines the percentage above the goal that the utility has achieved. Second, the PUC uses a formula that grants a certain percentage bonus (based on percentage of goal achieved) times the avoided costs of the utility (referred to as the net benefit). The total bonus is caped at 30% of total spending. Xcel hit the cap in 2002 but has not reached it since.[70]

4.3 Implications for OPA

Energy efficiency programs offer potential for load reduction and constitute an important policy initiative for the province of Ontario. There are two crucial components to implementing a successful energy efficiency program: achieving actual energy savings in a cost effective manner and encouraging utilities to go above and beyond minimum energy efficiency program requirements. Achieving actual energy savings requires that appropriate and realistic targets be set and that an effective monitoring and verification process to ascertain actual accomplishments is designed. Exaggerated claims of potential savings need to be avoided, as does a mentality of "savings at any cost." External evaluation of the program, whether it be through a committee of utility executives from other business lines, the regulator, or a third party, is essential to developing confidence that the program is being run effectively and that target results are being achieved in a cost-effective manner. Second, it is important to appropriately encourage the implementing agency to exceed minimum targets, though such incentives are at least in part under the purview of the Ontario Energy Board, at least if they are included in distribution company rates.

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69 In 1999, the utility actually earned $35 million using this approach, which was close to the amount that the program cost. The Minnesota PUC attempted to deny this level of incentive payment but was ultimately forced to allow it due to a state supreme court decision. Following this, the Minnesota PUC changed the system of compensating utilities for energy efficiency and conservation programs.

70 Xcel's average budget in Minnesota for conservation and demand side management is currently approximately $40 million, effectively setting a cap of $12 million. Recent bonus payments since 2002 have been in the $7-8 million range.

5 Concluding remarks

Our analysis in this report is intended to supplement the comments from the stakeholder process and to provide a cross-jurisdictional picture of different policy alternatives available to OPA as it develops a total electricity procurement strategy for the province. In this process, it is essential for OPA to keep in mind several important characteristics of a successful procurement strategy:

- **Economically rational:** for the sake of ratepayers and taxpayers, the provinces' procurement strategy should be economically rationale, allocating costs for energy to the customers than caused them and encouraging the development of cost-effective programs.

- **Compatibility with a competitive market:** procurement strategy and policies should not inhibit the development of a competitive market or distort competitive dynamics in the market.

- **Long term sustainability:** the procurement strategy must be sufficiently flexible as to be able to adapt to changes in market structure, government policies, and other unforeseen events.

- **Consistent with the province's environmental and social policies:** for a procurement strategy to be accepted and long lasting, it must be grounded in and consistent with the province's environmental and social policies.

- **Ease of administration:** procurement policies must be straight forward to administer and have relatively low administration costs.

With the above principles in mind, we summarize our recommendations in each of the four areas of study below.

<u>RFP processes</u>

Characteristics of successful RFPs in other jurisdictions include:

- frequent, open, and fair communication with bidders;
- clear identification of bid evaluation criteria;
- limited time between bid submission and decision;
- flexibility in means chosen to meet the need being procured with regards to technologies and locations, provided transmission was available; and,
- procurement consistent with political realities.[71]

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71 Arguably, the failure of recent BC processes has been due to the inconsistency between RFP results and what certain stakeholder groups viewed as acceptable.

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We provide further recommendations with regard to procurement processes in the companion report on the views of stakeholders, which is being issued simultaneously with this report.

Standard offer procurement

OPA is coordinating with the Ontario Energy Board to develop a standard offer procurement process for qualifying renewable resources. We believe that such programs should be developed with care, and should be part of a range of procurement approaches designed to contract for an appropriate amount of renewable electricity at least cost. The following approaches may be worthwhile:

- capacity to be procured at the standard offer price should be limited to the mandated procurement amount; additional renewable resources would remain eligible to bid into standard RFP processes;
- pricing should be limited to a specified premium to market-based prices; for example, the standard offer rate could be fixed at the beginning of each year for the next twelve months at 125%[72] of the average hourly Ontario electricity price for the previous three years;
- pricing should be standardized across renewable resources; OPA's objective should be to procure the mandated amount of renewable capacity at least cost, rather than to micromanage the choice of renewables to be deployed; and,
- if necessary, OPA could set aside a small budget for challenge or innovation grants, in which developers whose projects remain uneconomic at the standard offer price would compete based on the least cost additional subsidy required.

Demand response

Designing effective demand response programs requires close coordination with the IESO, as well as significant outreach. Demand response programs may be appropriately designed as a series of annual auctions, with a total capacity to be procured set in advance by the IESO. OPA would commit to holding the auctions annually for at least five years, and in each auction would offer 3 year contracts commencing six months from the date of the auction. The contracts would feature a capacity payment, and an avoided energy payment when called upon. Aggregators would not be required to list all available resources in advance, but would be required to demonstrate sufficient capacity to meet the contract within three months of having been awarded it. Liquidated damages would be set in such a way that it would be up to the aggregator to determine how much additional capacity it would need to have available in reserve to cover reliability issues among their portfolio. Bidders would be required to meet all existing environmental standards.

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72 This premium is more or less consistent with the observed premium for renewables products offered by retailers across North America.

Energy efficiency procurement

Substantial commentary on procurement of energy efficiency programs is beyond the scope of this paper. However, at a minimum we believe that OPA can serve as an enabler of local distribution company (LDC) programs, providing templates, serving as an information clearing house, assisting with measurement and verification protocols, providing model contracts for third party conservation contracts, and generally serving as both a resource and a motivator to the LDCs. Ontario's current situation is distinct from that of BC, in that the direct link to the customer is fragmented among many entities. Thus, OPA faces a choice of three roles: facilitator of LDC activities; focus on efficiency programs in areas where LDCs are not able to reach; or to take on the role of a central efficiency agency, in which OPA is the sole entity engaged in efficiency activities which are then funded directly through OPA's tariff instead of through the LDCs (who may nonetheless need lost revenue adjustment mechanisms). Practically speaking, we suspect that the first two roles are where OPA will end up focusing.

6 Appendix

6.1 Green product pricing

Figure 26. Retail Green Power Product Offerings in New York State (as of July 2005)

Company	Product Name	Residential Price Premium[1]	Fee	Resource Mix[2]	Certification
ConEdison Solutions (3) / Community Energy	GREEN Power	0.5¢/kWh	–	25% new wind, 75% small hydro	Green-e
ECONnergy	Keet It Clean	$.10/day for 100kWh $.20/day for 200kWh	–	100% new wind	–
Energy Cooperative of New York (4)	Renewable Electricity	0.5¢/kWh to 0.75¢/kWh	–	25% new wind, 75% existing landfill gas	–
Long Island Power Authority / Community Energy	New Wind Energy	2.5¢/kWh	–	new wind	–
Long Island Power Authority / Community Energy	New Wind Energy and Water	1.3¢/kWh	–	60% new wind, 40% small hydro	–
Long Island Power Authority / EnviroGen	Green Power Program	1.0¢/kWh	–	75% landfill gas, 25% small hydro	–
Long Island Power Authority / Sterling Planet	New York Clean	1.0¢/kWh	–	55% small hydro, 35% bioenergy, 10% wind	–
Long Island Power Authority / Sterling Planet	Sterling Green	1.5¢/kWh	–	40% wind, 30% small hydro, 30% bioenergy	–
NYSEG/Community Energy	Catch the Wind/New Wind Energy	2.5¢/kWh	–	100-kWh blocks of new wind	–
Niagara Mohawk / Community Energy	60% New Wind Energy and 40% Small Hydro	1.0¢/kWh	–	60% new wind, 40% hydro	–
Niagara Mohawk / Community Energy	NewWind Energy	2.0¢/kWh	–	new wind	–
Niagara Mohawk / EnviroGen	Think Green!	1.0¢/kWh	–	75% landfill gas, 25% hydro	–
Niagara Mohawk / Sterling Planet	Sterling Green	1.5¢/kWh	–	40% wind, 30% small hydro, 30% bioenergy	Environmental Resources Trust
Niagara Mohawk/Green Mountain Energy	Green Mountain Energy Electricity	1.3¢/kWh	–	50% small hydro, 50% wind	Green-e
Rochester Gas & Electric/Community Energy	Catch the Wind/NewWind Energy	2.5¢/kWh	–	100-kWh blocks of new wind	–
Suburban Energy Services /Sterling Planet	Sterling Green Renewable Electricity	1.5¢/kWh	–	40% new wind, 30% small hydro, 30% bioenergy	–

Note:

1 Prices may also apply to small commercial customers. Prices may differ for large commercial/industrial customers and may vary by service territory.

2 New is defined as operating or repowered after January 1, 1999 based on the Green-e TRC certification standards.

3 Price premium is based on a comparison to ConEdison Solutions' standard electricity product in the ConEdison service territory.

4 Price premium is for Niagara Mohawk service territory. Program only available in Niagara Mohawk service territory. Premium varies depending on energy taxes and usage.

Source: NREL

Figure 27. Retail Green Product Offering in CT, MA, NJ (as of July 2005)

State	Company	Product Name	Residential Price Premium[1]	Fee	Resource Mix[2]	Certification
CT	Community Energy (CT Clean Energy Options Program)	CT Clean Energy Options 50% or 100% of usage	1.1¢/kWh	–	50% new wind, 50% landfill gas	–
CT	Levco	100% Renewable Electricity Program	0.0¢/kWh	–	98% waste-to-energy and hydro (Class II), 2% new solar, wind, fuel cells, and landfill gas	–
CT	Sterling Planet (CT Clean Energy Options Program)	Sterling Select 50% or 100% of usage	1.15¢/kWh	–	33% new wind, 33% existing small low impact hydro, 34% new landfill gas	–
ME	Maine Renewable Energy/Maine Interfaith Power & Light (3)	Maine Clean Power	2.37¢/kWh	–	100% low impact hydro	–
ME	Maine Renewable Energy/Maine Interfaith Power & Light (3)	Maine Clean Power Plus	2.87¢/kWh	–	80% low impact hydro, 20% wind	–
MA	Cape Light Compact (4)	Cape Light Compact Green 50% or 100%	1.768¢/kWh (for 100% usage)	–	75% small hydro, 24% new wind or landfill gas, 1% new solar	–
MA	Massachusetts Electric/Nantucket Electric/Community Energy	New Wind Energy 50% or 100% of usage	2.4¢/kWh	–	50% small hydro, 50% new wind	Green-e
MA	Massachusetts Electric/Nantucket Electric/Mass Energy Consumers Alliance	New England GreenStart 50% or 100% of usage	2.4¢/kWh (for 100% usage)	–	75% small hydro, 19% biomass, 5% wind, 1% solar (≥25% of total is new)	–
MA	Massachusetts Electric/Nantucket Electric/Sterling Planet	Sterling Premium 50% or 100% of usage	1.35¢/kWh	–	50% small hydro, 30% bioenergy, 15% wind, 5% new solar	Environmental Resources Trust
NJ	Green Mountain Energy Company (5)	Enviro Blend	1.0¢/kWh	$3.95/mo.	5% new wind, 0.4% solar, 44.6% captured methane, 50% large hydro	–

Note:

1 Prices may also apply to small commercial customers. Prices may differ for large commercial/industrial customers and may vary by service territory.

2 New is defined as operating or repowered after January 1, 1999 based on the Green-e TRC certification standards.

3 Price premium is for Central Maine Power service territory based on standard offer of 7.13¢/kWh.

4 Price premium is based on a comparison to the Cape Light Compact's standard electricity product.

5 Green Mountain Energy offers products in Conectiv, JCPL, and PSE&G service territories. Product prices are for PSE&G (price to compare of 6.503¢/kWh).

Source: NREL

6.2 International Performance Verification & Measurement Protocol

The International Performance Monitoring & Verification Protocol ("IPMVP") is a framework of definitions and methods for assessing energy savings. It was designed to allow users maximum flexibility in developing a Monitoring and Verification ("M&V") plan to meet the need of their individual projects, but that also adheres to the principles of accuracy, transparency, and repeatability.

Energy savings are determined by comparing measured energy use or demand before and after implementation of an energy savings program after adjusting for conditions such as weather occupancy, plant throughput, and equipment operations required by these conditions. Determining the actual savings is a necessary part of the savings program design. Thus, the basic approach to savings assessment is closely linked to the savings program design.

According to IPMVP, there are eight main steps in developing an appropriate M&V approach.[73]

1. Depending of the scope and type of project, an IPMVP option to calculate energy savings must be chosen. There are four principal options: Partially Measured Retrofit Isolation; Retrofit Isolation; Whole Facility; and, Calibrated Simulation. For utility programs, usually the Whole Facility option or the Calibrated Simulation model is most appropriate.

2. Gather relevant energy and operating data from the base year and record it.

3. Design the energy savings program, including both the design intent and methods to be used for demonstrating achievement of the design intent.

4. Prepare a Measurement Plan and a Verification Plan, which will define the actual savings for each project.

5. Design, install, and test and special measurement equipment needed for the M&V plans.

6. After the energy savings program is implemented, inspect the installed equipment and operating procedures to be sure they conform with the design in Step 3.

7. Gather energy and operating data from the year after the savings program has been in place, consistent with the data collected in Step 2 and as defined in the M&V plan.

8. Compute and report savings in accordance with the M&V plan.

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[73] Note that this is simply a brief summary of the approach. The actual IPMVP documentation provides extensive detail about the actual implementation of such processes. The IPMVP is available at: http://www.ipmvp.org/download.php.

Note that Steps 7 and 8 are repeated periodically when a savings report is required. Savings are considered to be statistically valid if the results of the savings are greater than the expected variances in the base year data. Once a savings report has been prepared, a third party may verify that it complies with the M&V plan. The third party can also assess whether or not the M&V plan is consistent with the objectives of the underlying project.

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Ontario Power Authority (OPA)

Report on *Large Dollar* Procurement Approaches

September 6, 2005

Purpose of this Report

- This report briefly describes approaches to competitive as well as non-competitive procurements including the relative advantages and disadvantages of each.

- In addition, there may be occasions when only one qualified supplier is capable of delivering a project.

- Within this context, the primary focus of this report is to provide the OPA with guidance as to the measures that it might take to respond to any concerns or risks that may arise when the OPA finds it necessary to expedite large dollar procurements using a non-competitive approach i.e. sole source contracting.

- The report recognizes that the OPA may need to expedite large dollar procurements, for example the pressing need for supply of electricity to address a critical demand situation and secure a stable source of power to the Province and avert current risks of failure of the system.

The OPA's Procurement Governance

- The OPA is an Ontario Government-mandated organization with an independent governing board and as such is <u>not</u> required to follow any Ontario Government procurement directives or policies except as provided below.

- The OPA is governed by the Electricity Restructuring Act, 2004, S.O. 2004, c.23 – Bill 100

- The OPA is required to respect the procurement principles and processes set out in the *Ontario Regulation 426/04* under the *Electricity Act, 1998* which provides that:
  - *Procurement processes and selection criteria must be fair and clearly stated and wherever possible be open and accessible to a broad range of interested bidders;*
  - *To the greatest extent possible, procurement processes must be competitive;*
  - *There must be no conflicts of interest or unfair advantage allowed in the selection process;*
  - *to the greatest extent possible, the procurement process must not have an adverse impact on investment in electricity supply or capacity or in measures that will manage electricity demand.*

Overview of *Competitive* Approaches for Large Dollar Procurements

Request for Information (RFI)

- Used when there is uncertainty about the capability of potential suppliers to provide a particular product or service and/or their interest in responding to a competitive process to acquire the product or service. The OPA prepares and publishes a document that sets out details about its goals and requirements; the proposed procurement process including the selection methodology and contracting approach; and seeks comments from potential suppliers typically in the form of written comments.

Request for Qualification (RFQ)

- Used when it is the goal of the OPA to pre-qualify suppliers for a subsequent competitive process (i.e. Request for Proposal) based on the suppliers' capability to demonstrate that they can provide the required product or service at a price that is acceptable to the OPA. An RFQ sets out the criteria that must be met by suppliers and the process by which their submissions will be evaluated and selected. From the perspective of potential suppliers, an RFQ enables potential suppliers to demonstrate their capability in a manner that is more cost-effective than responding to an RFP i.e. if a supplier is not pre-qualified for the subsequent RFP, they avoid incurring the cost of responding to the subsequent RFP.

... Overview of *Competitive* Approaches for Large Dollar Procurements

Request for Proposal (RFP):

- Used when the goals and objectives of a project are known, but there are different approaches to reaching the result; where the primary selection consideration is best value (combination of qualifications and experience, approach, cost, etc.); there may be a requirement to allocate risk between the public and private sector. An RFP typically includes a three-stage evaluation – selection process which includes evaluation of the written proposals against the mandatory requirements, the point rated criteria and pricing requirements.

Limited Competition Procurements:

- Used when there is written justification and prior approval to limit the procurement to two or more potential suppliers (the written justification should be able to withstand to an independent examination of the material facts of the procurement).

...Overview of *Competitive* Approaches for Large Dollar Procurements

Unsolicited Proposals (Swiss Challenge):

- Provides the OPA with a method for receiving unsolicited proposals for projects and then offering other suppliers with an opportunity to improve on the unsolicited proposal while at the same time protecting the ability of the original proponent to match any other competing proposals.

Request for Information (RFI)

Purpose:

- Primarily used to assess the capability and the interest of potential suppliers to respond to a competitive process for particular products or services and to access information on the latest product and service offerings from the industry.

Expected Results:

- Potential suppliers have an opportunity to submit a response to an RFI demonstrating their capability and experience and interest in responding to a subsequent competitive process. Potential suppliers may also be asked to provide feedback concerning the proposed procurement process including the proposed evaluation and selection processes. This process enables the OPA to asses the probability that it will receive a meaningful quantity of quality proposals in response to a subsequent competitive process. An RFI also provides potential suppliers with advanced notice of a possible competitive process and allows the OPA to refine its requirements based on the latest product and service offerings available from suppliers.

...Request for Information (RFI)

Obligation to Complete the Process:

- Undertaking an RFI process does not obligate the OPA to undertake a subsequent competitive process. Nor does it obligate any of the respondents to the RFI to participate in a subsequent competitive process.

Examples of Use:

- Typically used when there is uncertainty about the capability of potential suppliers to provide a particular product or service and/or their interest in responding to a competitive process to acquire the product or service. The OPA prepares and publishes a document that sets out details about its business goals and requirements; the procurement outcomes and objectives; the proposed procurement process including the evaluation and selection processes and the proposed contracting approach; and seeks feedback from potential suppliers typically in the form of written comments however formal one-on-one consultation sessions with interested suppliers may also be undertaken which can be an extremely helpful exchange of information that greatly improves the quality of the outcome.

...Request for Information (RFI)

Pros:

- Assesses the potential success of a competitive process in advance of undertaking the competitive process
- Provides the OPA with up to date information on available product and service offerings
- Provides advance notice to suppliers of a potential competitive process
- Reduces the cost to suppliers to participate in a competitive process
- Improves the quality of proposals
- Demonstrates probity in use of public funds

Cons:

- Increases the overall procurement timeframe by the time required to undertake the RFI process

Request for Qualification (RFQ)*

Purpose:

- Primarily used to establish a list of qualified suppliers that will receive a Request for Proposal for a particular product or service. This is generally considered to be a two-stage procurement process in that there is a qualification stage in advance of a competitive or RFP stage.

Expected Results:

- Potential suppliers are invited to submit a written response to the RFQ demonstrating their capability to provide the required product or service. The OPA evaluates the responses against the published evaluation criteria (mandatory requirements and rated criteria) and the published basis of selection. Following the evaluation effort, the OPA creates a list of suppliers that are then qualified, on the basis of the selection methodology published in the RFQ, to receive the subsequent solicitation document i.e. an RFP.

* Sometimes referred to as a "Request for <u>Pre</u>-Qualifications".

...Request for Qualification (RFQ)

Obligation to Complete the Process:

- Although an RFQ stage is most typically followed by an RFP stage, there may be reasons why the OPA is unable to undertake the competitive stage. However once the RFP is released, the OPA is obligated to complete the process except to the extent that it exercises its right or privilege to cancel (re-issuing at its discretion) in accordance with the terms of the solicitation.

Examples of Use:

- Typically used when the OPA wants to limit the competitive process to a list of suppliers that have the demonstrated capability of providing the required product or service.

...Request for Qualification (RFQ)

Pros:

- Increases the probability of a successful procurement outcome since the RFP will be forwarded to suppliers who, as a result of the RFQ stage, are qualified to provide the required product or service
- Provides advance notice to pre-qualified suppliers of a subsequent competitive process
- Eliminates the risk that unqualified suppliers will participate in a competitive process
- Eliminates the cost to suppliers to participate in a competitive process for which they are not qualified
- Improves the quality of proposals
- Demonstrates probity in use of public funds

Cons:

- May increase the time and cost to complete a procurement

Request for Proposal (RFP)

Purpose:

- Primarily used when the OPA knows what it wants, but cannot or does not want to describe or prescribe an exact manner or method of how the need is to be fulfilled. Rather the OPA wants to undertake a competition to have suppliers propose how to achieve the desired result and make a selection based on price, abilities and qualifications of the bidder (i.e. best overall value).

Expected Results:

- Potential suppliers submit a response that identifies how they propose achieving the result. Proposals are evaluated and a winner is identified and receives an award in accordance with the terms and conditions of the RFP.

Obligation to Complete the Process:

- The OPA is obligated to complete the process except to the extent that it exercises its right or privilege to cancel (and re-issue) in accordance with the published rights or privileges.

…Request for Proposal (RFP)

Examples of Use:

- Typically used when the OPA knows what results it wants to achieve or be delivered, but it wants to leave it up to the bidders to propose how to achieve the results and there is more than one supplier who has the abilities and qualifications to achieve the results.

Pros:

- Promotes competition
- Provides clarity
- Standardizes evaluation & selection
- Reduces bias and favourtism
- Improves the quality of proposals
- Promotes best value
- Increases the potential for supplier innovation
- Demonstrates probity in use of public funds
- Proposes distribution of risk, as applicable

Cons:

- Increases time to complete the procurement (vs. Sole Source)
- Increases cost to undertake the procurement (vs. Sole Source)

Limited Competition Procurements

Purpose:

- A process similar to a Request for Proposal (RFP) process except that the competition is limited to only a few specific bidders. The bidders that receive the RFP may have been qualified as a result of a previous competitive process e.g. Request for Qualification.

Expected Results:

- Specific bidders are asked to submit a response that identifies how they propose achieving the result together with the proposed price. Proposals are evaluated and a winner is identified and receives an award in accordance with the terms and conditions of the RFP.

Obligation to Complete the Process:

- The OPA is obligated to complete the process except to the extent that it exercises its right or privilege to cancel (and re-issue) in accordance with its rights or privileges provisions as setout in the RFP document.

... Limited Competition Procurements

Examples of Use:

- Typically used when the OPA knows specifically which bidders are qualified to propose how to achieve the required results.

Pros:

- Promotes competition
- Provides clarity
- Standardizes evaluation & selection
- Reduces bias and favourtism
- Improves the quality of proposals
- Promotes best value
- Increases the potential for supplier innovation
- Demonstrates probity in use of public funds
- Proposes distribution of risk, as applicable

Cons:

- Increases time to complete the procurement (vs. Sole Source)
- Increases the cost to undertake the procurement (vs. Sole Source)

Unsolicited Proposals – Swiss Challenge

Purpose:

- Unlike competitive approaches, the idea generally originates with a private sector supplier when the supplier seeks to negotiate directly with the public sector entity for a sole source contract. This method, referred to as a "Swiss Challenge procurement procedure", has become an alternative to traditional procurement methods by taking advantage of the best aspects of the various other procurement methods while, at the same time, maintaining transparency in the process.

Expected Results:

- The OPA and the supplier would enter into a Swiss Challenge agreement giving the OPA the right to use the technical information contained in the unsolicited proposal as input to a public tender (i.e. RFP) to prospective bidders (but excluding any proprietary information). The supplier then has the right to match any competitive offer to maintain its sole source position. The successful bidder is selected and the details of the contract are finalized. The successful supplier may or may not be the initiating supplier.

...Unsolicited Proposals – Swiss Challenge

Obligation to Complete the Process:

- Under the Swiss Challenge procurement method, the OPA should follow through with a competitive process unless any of the pre-conditions for Sole Source contracting are met.

Examples of Use:

- Typically used in the procurement of large capital infrastructure projects.

Pros:

- Expedites the procurement timeframe and process
- Requirements for competition are met
- Promotes best value
- Increases the potential for supplier innovation
- Suppliers are better able to determine if they can meet the technical requirements before investing time to prepare a response
- Demonstrates probity in use of public funds

Cons:

- May be viewed / challenged as unfair (primarily a result of lack of familiarity with the process)

Measures to Reduce Risks of Complaints in *Competitive* Procurements

- Encourage dialogue with the supplier community early on and often in the process

- Full disclosure of information about the process and the project, including:
  - Any information regarding any known dangers regarding the work
  - Evaluation criteria
  - The qualification and selection process
  - The terms and conditions of the procurement process and the terms and conditions of the contract that will be awarded to the successful proponent
  - Published evaluation and selection processes
  - Contract terms and conditions

- Fair and equal treatment of all proponents

- Absence of conflicts of interest or unfair advantage

- Adherence to the published evaluation and selection process

… Measures to Reduce Risks of Complaints in *Competitive* Procurements

- Debriefing of unsuccessful bidders
- Provision of OPA processes that could be initiated by a bidder/competitor complaint e.g. the matter is referred to senior general counsel of the OPA or a senior executive not involved in the procurement who will review the complaint and who may assign an independent reviewer to investigate the complaint
- Provision of dispute resolution measures or mechanisms
- Involvement of a Fairness Commissioner/Monitor

Overview of *Non*-Competitive Approach for Large Dollar Procurements - Sole Source

Purpose:

- Typically used to purchase goods, services and construction services from a single bidder where one or more of the following conditions apply:
  - There is an emergency situation.
  - There is only one supplier able to supply e.g. unique or uncommon product or service, geography.
  - There are pre-requisites to bidding e.g. the existence of an operational power generation facility with excess capacity.
  - The time frame for delivery is urgent and cannot be stretched to allow the time needed for a competitive process.
  - The required good or service is not in common commercial supply.
  - The project is a follow-on assignment most appropriately undertaken by the original contractor.
  - The OPA (or the board or some other senior entity) considers that a pressing public interest requires the OPA to proceed with the procurement on a sole source basis.

…Overview of *Non*-Competitive Approach for Large Dollar Procurements - Sole Source

Expected Results:

- A single bidder is awarded a contract to deliver the required goods and services.

Obligation to Complete the Process:

- The OPA is obligated to complete the process unless no suppliers submit a proposal or no supplier is deemed successful. The OPA can cancel the process in accordance with any published privileges or rights to cancel under specific circumstances.

- The OPA should make a public announcement of its intent to make a single source award with the objective to determine if such an award is appropriate.

Examples of Use:

- This non-competitive approach is best used and should only be used if any of the conditions exist that are set out under "Purpose".

...Overview of *Non*-Competitive Approach for Large Dollar Procurements - Sole Source

Pros:

- Expedient
- Cost-effective
- Predictable outcome

Cons:

- Eliminates or reduces competition
- May give rise to concerns of bias or favourtism
- May not result in best value
- Unfair to other equally qualified bidders if other bidders exist
- Inconsistent with government commitments

Measures to Reduce Risks of Complaints in *Non*-Competitive Procurements

- Establish and publish (on the OPA web site) a written policy and procedure for awarding sole source contracts.
- For each sole source contract award, prepare written documentation to justify the decision including:
  - A definition of the requirements;
  - The results of market research (market research should be extensive for large contracts);
  - The results of stakeholder consultations;
  - An explanation (justification) as to why this product or service is the only one that can meet the requirement of the OPA;
  - Establish an open-book procurement process and final contract;
  - An explanation as to why there is only one supplier able to supply the required product or service;
  - An explanation as to why the price is considered reasonable (critical to demonstrate value for money);

... Measures to Reduce Risk of Complaints in *Non*-Competitive Procurements

- A description of the approach to be taken to conduct a non-competitive negotiation to get the best possible price;
- The number and value of any contracts previously awarded to the same supplier;
- An assessment of any potential complaints from the supplier community and a plan for managing and responding to such complaints;

- Adherence to clear approval authorities at a management level, executive level or board level as applicable depending on the prescribed thresholds;
- Public notice of intent to make a single source award with the objective to determine if such an award is appropriate (***Optional step*** - if this action is taken it should be done very early in the process. The risk of taking this action is that it may attract complaints from other bidders who may attempt all available means to sabotage sole source contract awards.);
- Maintain a written record of every single sole source award – the supplier's name, the amount of the contract; the type of contract (goods, services or construction); what was procured under the contract.
- **NOTE**: the amount of written justification will depend on the value of the contract but in all cases it must stand up to an independent examination of the material facts of the procurement.

… Measures to Reduce Risks of Complaints in *Non*-Competitive Procurements

- Provision and publication (on the OPA web site) of OPA processes that could be initiated by a complainant concerning a sole source contract award, for example the matter is referred to senior general counsel of the OPA or a senior executive not involved in the procurement or an independent third party such as a Fairness Monitor who will review the complaint and who may assign an independent reviewer to investigate the complaint;

- Provision of dispute resolution measures or mechanisms;

- Involvement of a Fairness Commissioner/Monitor as an external independent observer to ensure no conflicts of interest or other biases were at play in the decision.

Summary

- A fundamental principle of the OPA should be to procure goods and services through a competitive procurement.

- However, where certain conditions exist for which a non-competitive process is acceptable and allowable, a sole source contract may be awarded recognizing the critical necessity to maintain documentation that justifies the decision.

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REDUCING RELIANCE ON PROCUREMENT

1.0 INTRODUCTION

This exhibit addresses how the OPA has met the requirements in section 2(1), paragraphs 4 and 5 of Ontario Regulation ("O. Reg.") 424/04 to:

4. Identify and develop innovative strategies to encourage and facilitate competitive market-based responses and options for meeting overall system needs.
5. Identify measures that will reduce reliance on procurement under s. 25.32 of the Act.

2.0 REDUCING RELIANCE ON OPA CONTRACTS

Q. How will the Integrated Power System Plan and/or the Procurement Process facilitate evolution towards a workably competitive electricity market that will reduce reliance on procurements by the OPA?

A. Both the Integrated Power System Plan (the "IPSP" or the "Plan") and the Procurement Process (the "Process") will help facilitate evolution of Ontario's electricity sector towards a workably competitive market. The IPSP will provide a broad plan to develop and maintain Ontario's electricity system. This Plan provides necessary information to developers of Conservation, generation and transmission resources in order to undertake investments in Ontario.

The Process will facilitate evolution of Ontario's electricity sector in two ways. First, prior to initiating the Process, an assessment of investment occurring in the market will be conducted. In accordance with O. Reg. 426/04, the OPA, with the assistance of the IESO, will assess the capabilities of the IESO-administered markets to facilitate new investment, and the likelihood of this investment occurring on its own. Therefore, OPA procurements and their resulting contracts should be viewed as 'last resort' procurement measures.

Second, in accordance with O. Reg. 426/04, the Process is to use competitive procurement to the greatest extent possible Competitive, market-based responses outside of the OPA, and competitive procurement, with the ability to assign the procurement contract to a third party, both work to increase the number of Conservation and generation projects/programs. As further outlined in Exhibit D-4-1, the OPA has identified capability building as an essential approach to achieving the Directive's long-term Conservation goals. By increasing the "supply" of service providers (i.e., the number and proficiency of the service providers) it will lead to increased competition among suppliers, lower costs, more innovation and greater Conservation offered to customers to support achievement of targets in the long-term.

Q. What key features are necessary for a robust, transparent and liquid forward market for electrical energy and reliability products to evolve in Ontario?

A. There are three key features needed for this evolution to occur in Ontario. First, there needs to be load that is at risk to supply and price in the real-time hourly market. Second, there is a need for generation that is at risk to price and dispatch in the same hourly market. Finally, there is a need for a forward market with a range of tradable contracts that converge to a day-ahead market ("DAM") that can facilitate both buyers and sellers in managing these risks.

Q. What measures and innovative strategies has the OPA identified in order to reduce reliance on OPA procurements, and to encourage and facilitate competitive market-based responses and options for meeting overall system needs?

A. The OPA has identified two innovative strategies that it will continue to develop:

Load Serving Entities

First, the OPA will continue its work on Load Serving Entities ("LSEs") in Ontario. LSEs act as intermediaries between loads and the wholesale marketplace, and they take on the responsibility for managing the risks of serving this load. As such, the development of LSEs would result in less future OPA procurement activity over time, as LSEs would have the ability and the incentive to contract for their own supply. In many other jurisdictions, LSEs contract with generators and demand response providers to ensure reliable supply for their load customers.

Forward contracting activity by LSEs will add liquidity and length of term to the market, and ultimately provide a competitive alternative to an OPA contract for generation developers. For buyers of electricity, long-term contracts provide a fixed and predictable price for a pre-determined period of time. Therefore, electricity buyers would not be subject to short-term price volatility and could then plan their consumption of electricity with greater certainty. The evolution to LSEs in Ontario would help increase market liquidity through increased contracting activity, while transferring risk from electricity consumers to the LSEs and ultimately the generators themselves.

Forward Price Curve Development

Second, the OPA will continue its work to develop the forward price curve. One way that it will do this is by increasing liquidity in the forward electricity market through .facilitation of forward auctions. Forward electricity auctions can provide future price signals to potential Conservation and generation developers. These auctions result in forward price discovery, which facilitates marketplace contracting, and increases the number of buyers and sellers. This, in turn, would help support new market-based resource investment without the need for long-term contracts with the OPA.

The OPA worked with the Natural Gas Exchange (“NGX”), in the development of its first three forward auctions. NGX has taken over management of these auctions and turned them into regular market-pricing events. In addition, NGX is offering over-the-counter clearing services, and has listed standard tradable electricity products for use in Ontario.

In addition to NGX’s role in providing a trading platform and clearinghouse service, liquidity in these forward auctions is required to make them truly successful. Liquidity is dependent on effective competition which requires both multiple buyers and multiple sellers each respectively motivated to mitigate exposure risk in the real-time market.

Increased liquidity strengthens the price signals resulting from these forward transactions, and induces merchant investments rather than dependence on OPA contracts.

Q. Are there any measures being pursued by other electricity agencies in Ontario that can reduce reliance on OPA procurement?

A. Yes. The OPA continues to support the IESO's initiative in the development of the Day Ahead Market to ensure that it functions as an effective risk transference mechanism for forward transactions, and that it provides the necessary intra-day risk mitigation and reliability contracts to enable effective convergence between the day ahead market and the real-time dispatch of generation and Conservation resources.

Q. Is the OPA identifying any innovative strategies that are alternatives to the OPA Procurement Process for Conservation in the Near-Term Plan? Will the OPA be identifying innovative strategies to help facilitate development of Conservation projects and programs?

A. The OPA sees the development of Conservation projects and programs as long-term and short-term alternatives to generation supply. These programs will develop the necessary demand-based price elasticity that is essential to any functional and competitive market. Conservation products are designed to provide load-based alternatives to generation supply along the entire time spectrum.

Q. Do any barriers exist to implementing innovative strategies to procure Conservation and/or generation resources?

A. The primary barriers to implementing the market-based elements of the Conservation program strategy include (i) the continued need for evolution of a forward price curve that reflects the appropriate scarcity value of electricity; and (ii) the need to get load represented in the forward market. The development of LSEs and the forward price curve will contribute to the elimination of these barriers.