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Contract Savings Review

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Disclaimer

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1. Executive Summary

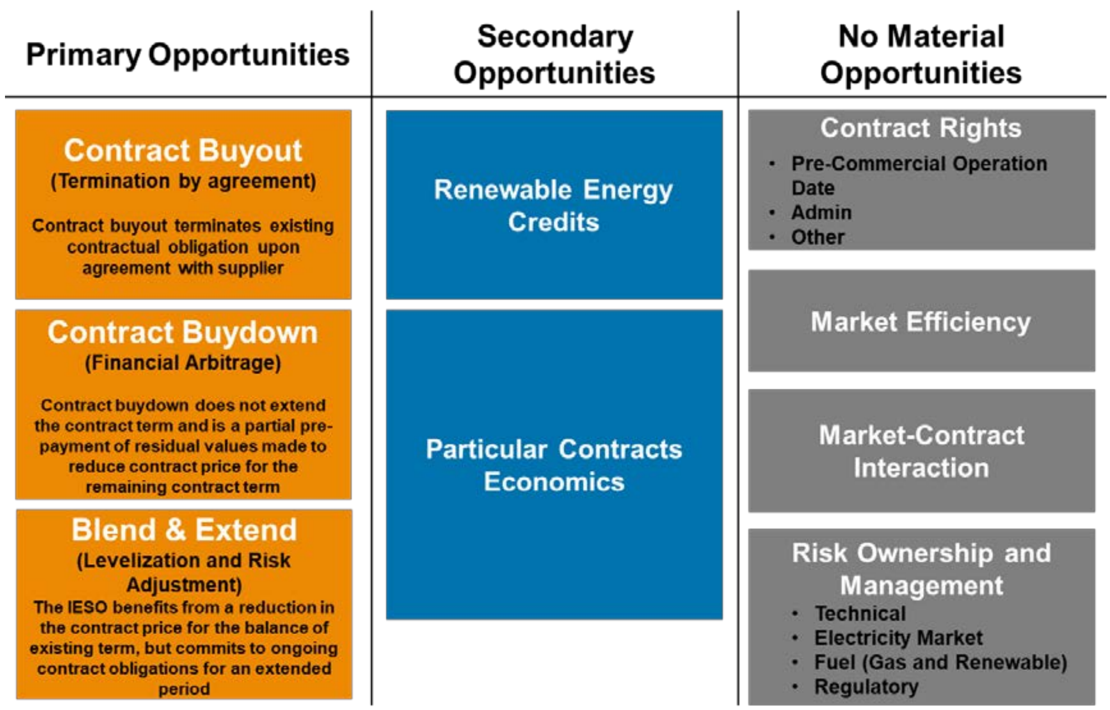
The IESO engaged Charles River Associates ("CRA") in December 2019 to provide a third-party review of its existing generation contracts to identify and quantify opportunities to reduce costs for consumers. The IESO also invited contract counterparties, referred to as "Suppliers" throughout this report, to make suggestions on potential cost-saving opportunities associated with the generation contracts.

This report sets out CRA's review and analysis of such opportunities to reduce costs, including consideration of suggestions made by Suppliers. CRA sought cost-saving opportunities that could be achieved by the exercise of readily apparent IESO rights under the contracts or by consensual changes to the contracts, as well as any supplementary revenue opportunities.

CRA did not identify any savings that could be achieved by the exercise of readily apparent IESO rights under the contracts.

In the first step of its review CRA considered a wide range of perspectives on the contracts and the associated generating facilities. CRA sought fundamental cost savings that might be achieved by reducing avoidable costs (i.e. excluding sunk costs) associated with the current contracts. This systematic review identified several opportunities that were classified as primary or secondary. Review of other perspectives revealed no material opportunities. Results are summarized in the following figure.

Figure 1 Overview of Identified Opportunities



The second step of the analysis focused on the three primary opportunities identified as contract buyout, contract buydown and Blend & Extend. Gas-fired generation is excluded from consideration for contract buyout due to the potential for jeopardizing reliability.

In a contract buyout the parties (IESO and the Supplier) agree to terminate the contract on payment of a lump sum amount by the IESO to the Supplier. In a contract buydown, the contract remains in full force for its remaining term, but the parties agree to a reduced price for the balance of the term following payment of a lump sum amount by the IESO to the Supplier. In both of those cases it is assumed that the gross savings from contract termination or price reduction would be offset by amortizing the IESO's lump sum payment amount over the balance of the contract term. The fundamental cost savings arise from the potential that the IESO's cost of finance would be less than the Supplier's cost of capital.

The Blend & Extend scenario has two conceptual steps: (i) establish an agreed price less than the present contract price that could be applicable for a contract extension period, e.g. ten years past the existing contract term; then (ii) blend the extension price with the present price to levelize a price over the extended contract period. This levelizing would reduce total costs for the remaining years of the original contract term and increase total costs in the extension period. The fundamental savings in Blend & Extend depend on monetizing Supplier's benefits in mitigating future market risks, and on a social discount rate high enough to reduce the evaluated impact of the future cost increases below the impact of immediate savings.

CRA's analysis modeled each of 45 wind projects, 15 solar projects, and 13 gas-fired projects, all of which are full participants in the IESO Administered Market. Lump-sum funding requirements and ongoing benefit and cost streams were considered for each project. CRA then estimated the % of contracts and MW capacity that would take up an offer at a particular price. This take-up rate was used to aggregate the expected funding and benefit streams for each technology. The model included assumptions about Suppliers' costs of capital, risk adjustment factors, and required benefit sharing. Modeling reflected a base case and sensitivity cases selected by CRA.

Furthermore, CRA identified a range of implementation issues that would have to be addressed in any program to realize any of these opportunities, including: timing, resource requirements, cost, legislative or regulation changes, and process. Alternative process arrangements such as auctions or standard offers are identified, and the standard offer approach is adopted as a basis for modeling without prejudice to any final selection of process.

The base case values represented a starting point for determining the ranges of likely outcomes. The sensitivity analysis takes into account uncertainties with respect to assumptions and modeling of Supplier behavior, assumptions of IESO debt interest rate, and of the normal variation between present forecasts and actual market outcomes. One of the major outcome drivers is the take-up or Suppliers' participation rate and its relationship to the IESO offer pricing. In practice, each Supplier has a unique set of parameters that it will address to arrive at a threshold transaction price, including cost of capital, risk assessment, benefit sharing requirements, and diversity of ownership and lender interests. CRA's estimation of the relationship of take-up and price has therefore taken account of reasonable expectations of these issues, but until the market is actually tested, definitive answers are unknowable, and therefore represent significant uncertainty in outcomes.

The spectrum of the sensitivity results is set out in the following table, which represents the ranges of the most likely outcomes for each category of major contracts for the three primary opportunities. The table includes both gross and net savings. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost. Note that all savings results are before accounting for any IESO program or transaction costs; such costs would need to be recognized in evaluation of any potential program.

Table 1 Overview of Results: Range of Most Likely Outcomes

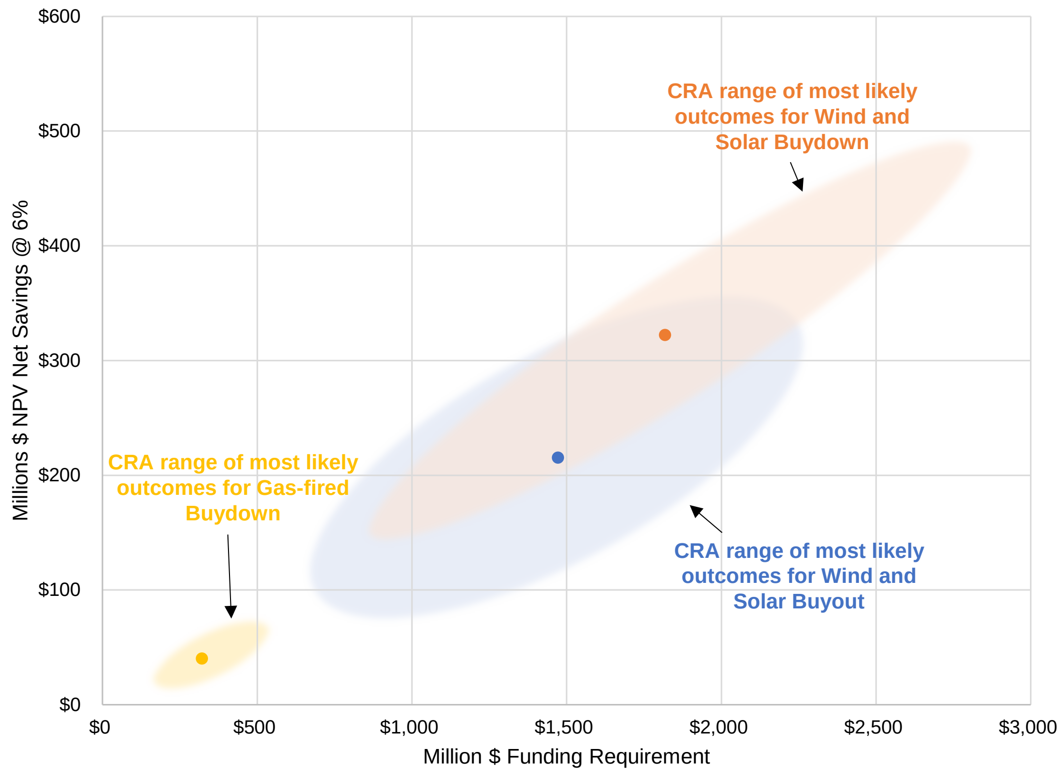
	Renewable (Wind & Solar)		Gas-fired	
Buyout				
Take-up MW	243 - 730	MW		
Take-up MW as %	5 - 14	%		
Year 1 savings - gross	86 - 258	$ Million		
% of total system costs (gross)	0.4 - 1.2	%		
Year 1 savings - net	19 - 56	$ Million		
% of total system costs (net)	0.1 - 0.3	%		
NPV net savings (@ 6% discount rate)	**108 - 323**	**$ Million**		
Buydown				
Take-up MW	426 - 1,279	MW	434 - 1,303	MW
Take-up MW as %	8 - 24	%	7 - 20	%
Year 1 savings - gross	99 - 297	$ Million	25 - 76	$ Million
% of total system costs (gross)	0.4 - 1.3	%	0.1 - 0.3	%
Year 1 savings - net	16 - 48	$ Million	3 - 8	$ Million
% of total system costs (net)	0.07 - 0.2	%	0.01 – 0.04	%
NPV net savings (@ 6% discount rate)	**161 - 483**	**$ Million**	**20 - 60**	**$ Million**
Blend & Extend				
Take-up MW	481 - 1,443	MW	803 - 2,408	MW
Take-up MW as %	9 - 27	%	12 - 36	%
Year 1 savings - gross	N/A	$ Million	N/A	$ Million
% of total system costs (gross)	N/A	%	N/A	%
Year 1 savings - net	39 - 118	$ Million	25 - 74	$ Million
% of total system costs (net)	0.2 - 0.5	%	0.1 - 0.3	%
NPV net savings (@ 6% discount rate)	**0**	**$ Million**	**1 - 2**	**$ Million**

As mentioned above, gas-fired generation is excluded from consideration for contract buyout due to the potential for jeopardizing reliability. The contract buyout or Buyout and contract buydown or Buydown opportunities are largely alternatives, as the same Suppliers would likely be candidates for each opportunity. It is possible to conceptualize a joint program in which each Supplier could select Buydown or buyout, but this would be complex and would offer little incremental benefit.

The above table does not include the significant enhancement of net year 1 savings and NPV savings that could be achieved by extending the amortization of the funding for Buyout or Buydown programs for an additional 10 years. Gross savings would be unaffected, but those net savings would increase by some 40% to 50% by deferring expense to the post-contract period.

The chart below summarizes the most likely outcomes for all Buyout and Buydown opportunities. Blend & Extend opportunities do not have initial funding requirements, and are centered on zero NPV of benefits, so do not lend themselves to this representation.

Figure 2 Case Comparison for Buyout and Buydown Opportunities



Secondary opportunities include the sale of Renewable Energy Credits, for which the benefit would likely be marginal. Individual contract opportunities are not material. It may however be possible to extend any major contract buydown program to include larger distribution-connected projects or portfolios. Considering the capacity under the larger distribution-connected renewable contracts, this could enhance the major contract buydown savings by something between 0% and 20%, but with proportionately higher IESO program and transaction costs.

2. Introduction

2.1. Background

Charles River Associates ("CRA") is pleased to provide this report to the IESO in accordance with the consulting services contract made on December 2, 2019. The report is prepared within the context of the government's directive to the IESO dated November 6, 2019, wherein the IESO was required to retain a third party to undertake a targeted review of existing generation contracts for viable cost-lowering opportunities.

2.2. IESO-CRA Interaction

The IESO provided CRA with information necessary to conduct the work, including its Annual Planning Outlook and general and specific contract information, on which CRA relied. The IESO also provided copies of contract counterparty comments and suggestions that had been received by the IESO in response to its enquiry dated November 19, 2019.

CRA met with the IESO on several occasions throughout this assignment, commencing with a kick-off call and subsequent kick-off meeting, and has continued with progress meetings and presentation of preliminary findings. CRA benefitted from IESO questions and challenges during these discussions, but maintained full independence in execution of the assignment and in the analysis and findings set out in this report.

2.3. CRA Approach

The review commenced with a contract categorization to recognize scale, market participation (all transmission-connected generators and a few others), technology and contract type. The next step focused on the systematic search to identify potential savings opportunities. Starting with certain opportunities identified in advance (Buyout, Buydown, Blend & Extend, and Renewable Energy Credits), CRA looked for any additional precedents in other markets. The results of this search identified a range of perspectives to review the contracts and their market context for possible savings opportunities.

Stakeholder comments and suggestions were also considered at this stage and included in the perspectives review. This broad review identified no major opportunities that were not identified in advance, but offered some secondary, contract-specific, opportunities worthy of consideration, even if their contributions to savings proved to be minimal.

CRA then developed its model to represent each of the primary opportunities with respect to each contract in the three main categories. Pro-forma models are provided in section 5 of this report. The applied modeling depends on estimates of various financial parameters, which were also developed by CRA, and are discussed in section 4 of this report. The model also allowed for modelling of various take-up rates followed by the aggregation of individual contracts to the category level for each opportunity to provide aggregated results.

Implementation considerations and possible approaches were identified and discussed in section 5. Base case results were struck, supplemented by various sensitivity analysis and further model refinement, all of which is addressed in sections 7 and 8 of this report.

2.4. Nature of IESO Contracts and Programs

Each of the contracts analyzed is an agreement between the IESO and a Supplier. The term "Supplier" is used extensively throughout this report. The Supplier is the IESO's counterparty in the contract. The term includes corporations, limited partnerships created for the particular projects, and for individual persons for the smaller contracts.

Many of the larger projects are part-funded using a non-recourse finance arrangement; the lenders have security rights in the project and in the contracts with the IESO. Those contracts acknowledge the secured lender rights and cannot be amended without approval by the secured lenders.

The terms of reference for this review encompass all of the IESO's procurement contracts, specifically the IESO generation contracts, except those for the Bruce Nuclear Generating Station. The baseline for the review was the IESO's contracts list[1] as of October 31, 2019. Contracts on that list have been categorized as follows:

Table 2 Overview of IESO Supply Contracts

Category	Number of Contracts	Contract Capacity (MW)	Comments
Major Opportunity Categories			
Wind	45	4,543	Accounts for 82.1% of total wind contract capacity.
Solar	15	778	Accounts for 32.2% of total solar contract capacity.
Gas-fired	13	6,620	Accounts for 89.6% of total gas contract capacity.
Other Major Contracts			
Ontario Power Generation	13	3,151	OPG and other hydroelectric contracts represent separate facilities, several of which are grouped under single contracts.
Other hydroelectric	29	981	
Other Contracts (Distribution-Connected)			
> 5 MW	228	2,461	Accounts for 84.7% of total distribution-connected capacity.
< 5 MW	1,275	446	Accounts for 15.3% of total distribution-connected capacity.
Total excl. MicroFIT	1,618	18,980	
MicroFIT	30,194	262	Contract capacity less than 0.01 MW*
Total	31,812	19,242	

* Based on IESO's Third Quarter 2019 – A Progress Report on contracted Electricity Supply

2.5. Basis of Analysis and Reporting

Fundamental cost savings and revenue enhancements are evaluated based on presently avoidable costs (i.e. excluding sunk costs) or net revenue opportunities. Except where savings can be achieved though exercise of IESO rights, it is assumed that there will be a negotiated or consensual sharing of those cost savings or net revenue enhancements between the IESO and each Supplier.

Risk management and financial engineering opportunities depend on the interplay between the IESO and each Supplier in terms of their respective cost and revenue expectations, their risk tolerances, their abilities to manage certain risks, and their effective discount rates / cost

1 The IESO publishes its contract list from time to time at: http://www.ieso.ca/en/Power-Data/Supply-Overview/Transmission-Connected-Generation

of capital. CRA modeled possible contract changes, estimated the proportion of Suppliers who may enter intro transactions at certain price levels, the stream of net IESO benefits associated with such take-up rates, and the net present value of such benefit streams. CRA's model recognized that Suppliers would expect some benefit from any transaction in determining the likely take-up rates. Therefore, all net and gross savings amounts represent savings available to the IESO on behalf of the electricity consumers.

In order to avoid dissemination of confidential information, the report uses pro-forma contract models to illustrate opportunities and includes the results from the aggregation of individual models of actual contracts. Results are presented as incremental cash flow impacts over time and include net present values at a range of social discount rates. This report does not include recommendations in matters of policy.

2.6. Incorporating Suppliers' Suggestions

CRA reviewed the submissions received by the IESO from Suppliers in response to the IESO's November 19, 2019 solicitation for ideas. Many of the Suppliers included support for considering the "blend and extend" option, although some indicated that this would be a challenge or would be precluded due to the terms of their non-recourse finance or the diversity of project ownership interests. Some Suppliers also suggested other options for cost reductions. All such ideas have been treated within section 3 below.

There was also a broad advancement of "blend and expand" concepts in various forms, and other concepts requiring incremental investment by the Suppliers. These would likely reduce the unit contract price (per MW or MWh), but would increase the overall contract payment amounts to support that incremental investment.

These changes may well provide economical options to meet requirements for additional capacity or renewable energy production, but they do not fulfil the requirement of this study to find savings in contract costs. Those proposals have therefore been treated as beyond the scope of this report.

Some other suggestions e.g. for new contracts to support existing or new facilities, for transmission investments, or for modifications to the Global Adjustment mechanism are similarly beyond the scope of this report.

2.7. Organization of the Report

The organization of the report reflects the approach described above:

Section 3 details the systematic search for potential opportunities starting with the identification of a range of different perspectives on the contracts, the contract facilities and their interaction with the electricity market. Under each perspective, the report describes and provides qualitative review of potential opportunities. Many of these are generic, with application to broad categories of contracts.

CRA's systematic search included the review of hypothetical opportunities many of which were found to offer no material benefit. At the end of section 3, the report identifies three primary opportunities, Buyout, Buydown and Blend & Extend, discussed at length in subsequent sections.

Section 4 describes the modeling construct and major inputs, with particular attention to the financial parameters like inflation / general escalation, Supplier cost of capital, IESO debt costs and social discount rate.

Section 5 describes and provides illustrative examples for each of the three primary opportunities as they apply to each of the major contract categories: wind, solar and gas-fired contracts. While wind and solar contracts are similar, their pricing and performance characteristics are sufficiently different to warrant modeling as separate categories. Their results are aggregated at the summary level.

Section 6 identifies a range of implementation considerations for the primary opportunities and explores the approaches that could be adopted: standard offer, binding auctions, or non-binding expression of interest. Without prejudice to the approach selected for each opportunity, the report then discusses the potential relationship of standard offer pricing to take-up rates.

Section 7 contains the initial results using the base case assumptions. Results are illustrated for each category of contract and for each applicable primary opportunity, on an annual basis, and are summarized as year 1 savings, initial funding requirements, and net present values at base and sensitivity social discount rates.

Section 8 extends the primary opportunity results to incorporate sensitivity cases including for cost of capital, cost of debt, pricing and take-up outcomes.

Section 9 addresses secondary opportunities, with due deferral of individual contract confidential matters.

Section 10 provides an overview of the results and conclusions, including sections on risks and uncertainties and sections setting out estimated result ranges.

The report itself is supplemented by certain appendices:

- Overview of the CRA benefit model
- CRA's internal QC report on the model used to derive the results stated herein

3. Systematic Search for Potential Savings Opportunities

3.1. Purpose and Form of Systematic Review

A systematic search is the essential first step to ensure all potential opportunities are identified for consideration and analysis. The search has four levels:

a. Informal review included in CRA's proposal preparation and discussions between the IESO and CRA in the project kick-off call and meeting;

b. Internal CRA enquiry to its consultants active in US and European electricity markets to identify any additional precedents of interest;

c. Consideration of Suppliers' comments provided in response to IESO's outreach;

d. CRA perspective-based review of the Ontario contracts. In this perspective-based review:

   i) The contract perspective identifies IESO contractual rights that can be exercised to achieve savings;

   ii) Agreed contract termination ("Buyout") is treated as a stand-alone perspective;

   iii) Finance is a perspective identified in advance as highlighting certain key opportunities; financial engineering also emerged as a focus area from those familiar with other electricity markets; finance and risk issues are closely related. Buydown and Blend & Extend opportunities are considered under this heading.

   iv) The market efficiency perspective considers whether market changes could trigger contract savings, but recognizes that significant efficiency gains are expected from the Market Renewal Program, independent of this contract savings review;

   v) The perspective of the operational and market interface seeks any inefficiencies that may result from interaction of contracts (and contract-based incentives) with the market;

   vi) Risk management and risk ownership is explored to identify any additional opportunities;

   vii) The portfolio perspective identifies certain opportunities that could emerge from the trade-off between different contracts of a single Supplier;

   viii) Some additional issues to be addressed in respect of the Smaller distribution-connected projects are considered in order to identify any additional opportunities;

   ix) And finally, we consider opportunities that arise beyond the electricity sector.

MicroFIT contracts are seen as having different dynamics than those covering most of the contract capacity. They are therefore kept separate throughout this review.

3.2. Contract Perspective

CRA did not review contracts from a legal perspective; such review was outside the scope of CRA's terms of reference. CRA reviewed broadly evident rights but did not identify any additional savings opportunities evident from the contract perspective.

3.3. Buyout Opportunity

There are two hypothetical forms of a Buyout transaction: contract buyout and facility buyout. This report addresses the contract buyout transaction.

In a contract buyout, the IESO would make a lump sum payment to the Supplier under a contract termination agreement. Following such agreed termination, the Supplier would bear the full market price and curtailment risks. For a wind or solar facility with zero-cost fuel and relatively low O&M costs, the market energy revenues are expected to support the continued operation of the facility for at least its asset life, which should mostly exceed the original contract term. As a result, contract buyout would not be expected to impact actual electricity supply.

A contract buyout of gas-fired facilities would present significant uncertainties. There would be no assurance that market revenues would be sufficient to support continued operation necessary for system reliability. Absent a robust and proven capacity market mechanism in which such facilities would be eligible to participate, the risks of extensive facility shutdowns are likely to be unacceptable to the IESO. Gas-fired facilities are therefore considered ineligible for Buyout.

Gross savings to the IESO represent the reduction in the total of the IESO's contract and market payments to each Supplier due to the termination of each contract. These gross savings are assumed to be offset by the amortization of debt used to fund the Buyout. That debt is amortized at the IESO debt interest cost over the bought-out term of each contact. The net IESO savings are the gross savings minus the debt amortization cost. The fundamental source of the net savings is thus the spread between the IESO cost of debt and the Supplier's cost of capital. This spread will be offset by Supplier transaction costs, Supplier risk adjustments, and Supplier retention of a share of the benefit, all of which are embedded in CRA's calculation of IESO net benefits. All IESO net benefits stated in this report are before accounting for any IESO program or transaction costs.

The contract buyout is explored in more depth in subsequent sections of this report.

The facility buyout option, which is not explored in this report, would entail the purchase by a government funded entity of the relevant facilities. This government funded entity would then own the facility and presumably allow the wind-down of the contracts. This would reflect a much broader change to the market framework than is under review in this report. Therefore, it is not considered further.

3.4. Finance and Risk Arbitrage Perspective

This perspective has been identified in advance as yielding two key opportunities with potentially broad application, recognizing that they are somewhat contrary to each other. Simplistically, to generate a savings opportunity, the Buydown model would require a government backed borrowing rate that is lower than a Supplier's cost of capital. The "Blend & Extend" model requires a social discount rate higher than a Supplier's cost of capital, and/or the transfer to the IESO of risk associated with market outcomes during the extension period.

These models are discussed in the following subsections 3.4.1 & 3.4.2. Either model could be applicable to any type of contract, subject to evaluation considerations and constraints. A hybrid of these two models, “sell an extension” is discussed in section 3.4.3. There is also a model in which the IESO would sell an option for a degree of physical expansion, e.g. by permitting repowering to increase contract energy production. This is discussed in section 3.4.4. Finally, in section 3.4.5, there is a brief discussion of a debt-displacement model in which cheaper IESO debt might be substituted for Suppliers’ debt.

Conclusions are discussed in section 3.4.6.

3.4.1. Buydown

The Buydown model is described as having the following characteristics:

- It does not change the contract term.
- It can be viewed as a contract pre-payment evaluated at a discount rate higher than the IESO’s cost of debt or as buying out of part of a potential future obligation.
- The contract would remain in full effect, unlike the Buyout option discussed in section 3.3 above.

It is assumed that Buydown would be achieved by reducing the applicable energy contract price (for wind and solar) or capacity contract price (for gas-fired). This somewhat mitigates the Supplier’s exposure to loss of revenue arising from technical risk factors or weather. It locks in any exposure that may be embedded in the historic performance used as the basis to extrapolate future performance.

The parameters that would favor viability of this model include:

- A Supplier who has a requirement for immediate cash flow and would therefore apply a high discount rate to contractually assured cash flows for the remaining term;
- A buyer who values highly the reduction of electricity costs over the remaining contract term, even to the extent it is offset by the need to amortize the initial Buydown funding over the remaining contract term;
- A contract with sufficient remaining term to provide a reasonable sustained Buydown benefit;
- A contract at a present price significantly higher than energy and/or capacity market expectations over the balance of term, so that the reduced contract payment stream would still provide sufficient incentive for Supplier’s fulfilment of its contract obligations;
- Probably balance-sheet financed; secured lenders interests in a transaction may diverge from owners’ interests and may add complexity or cost in any transaction. On the other hand, a mature contract in which secured lender finance was significantly paid down might provide an opportunity for application of the Buydown against higher cost equity.

Similar to the Buyout opportunity, the funds used by the IESO to achieve a Buydown are amortized over the remaining contract term. Total cost could be reduced by the use of lower cost IESO funds that displace the Supplier’s cost of capital. The IESO benefit would be somewhat offset by transaction cost and by Supplier retention of a share of the benefit.

CRA also considered a sensitivity case, where the amortization period is extended for an additional ten years to increase the initial savings. This occurs at the expense of increased total cost in the amortization extension period.

In any Buydown, it is necessary to define the new (bought-down) contract price that will be in effect for the remainder of the contract term. The greater the Buydown, the greater the savings. However, the contract price must not be reduced below the price available in the market because in that case, the contact ceases to have value to the Supplier. In this instance, the contract could become a liability to the Supplier (and an asset to the IESO) with the Supplier possibly seeking ways to terminate.

In CRA's model, the Buydown price floor was selected to provide adequate protection against this instance. The price was also considered in conjunction with the performance guarantees that exist in all contracts.

In order to provide reasonable assurance that the contracts can be expected to remain assets to Suppliers, the Buydown price floor for wind and solar contracts has been set to provide total "with contract" revenues no less than a multiple of the "without contract" revenues in any year. Gas-fired contracts are assumed to be bought down to a Net Revenue Requirement at an assumed floor price.

3.4.2. Blend & Extend

In the blend and extend model, the IESO benefits from a reduction in the contract price for the balance of the existing term. This is offset by the commitment to an ongoing contract obligation for an extended period. The Supplier surrenders a portion of the contract price for the balance of the existing term in exchange for increased revenue and/or increased certainty of revenue for the period of the extension.

Even though the Blend & Extend approach has established precedents when the negotiation of an existing contract is contemplated, it is difficult to identify publicly available information associated with this approach. Usually, blend and extend is considered for individual assets and not for a portfolio. The literature review indicated one portfolio-based blend and extend consideration, when the California Public Utility Commission considered blend and extend in the procurement of renewable resources for the Community Choice Aggregation structures in California.[2] The amount of MWs considered was significantly lower than the one investigated in this case.

The parameters that would favor viability of this model include:

- A Supplier with a long-term perspective and low risk tolerance, likely reflected in low discounting of contractually assured cash flows and a higher discounting of future market cash flows
- A buyer who values highly the reduction of electricity costs over the remaining contract term, the certainty of sustaining the resource after the present contract term, and sees the extension term cost as reasonable in the context of its own market expectations
- A contract with remaining term short enough that the Supplier is sensitive to post-term considerations
- A contract at a present price significantly higher than future energy (and if applicable, capacity) market expectations

2 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Costs_and_Rates/CalCCA%20R.17-06-026%20Workshop%20Presentation%2001-16-18.pdf

- Balance-sheet finance or secured lending liabilities already reduced to a level at which the lenders would accept erosion of ongoing debt service ratios within the existing contract term.

All Blend & Extend analysis assumes an extension period of ten years past the present contract term. This would be within the expected life of most assets, albeit with an expectation of some asset renewal or refurbishment costs at the start of the extension period.

Blend & Extend is not applied to contracts with a remaining term that extends past 2035. Extension of such contracts would reach more than 5 years beyond the present IESO planning horizon.

3.4.3. Sell an Extension

This is a hybrid of the Blend & Extend and the Buydown models.[3] In this model, the IESO would sell to the Supplier an option or obligation to extend the contract (at some lower price). The IESO would then apply the amortized sale proceeds directly to the reduction of the Global Adjustment. The effect of this model would be equivalent to Blend & Extend in which the contract price reduction was a predetermined annual $ amount (as opposed to a reduction in the price per MWh of production).

The parameters that would favor this model are like those for the Blend & Extend model, with the addition of a cash-rich Supplier.

While this model does achieve a one-time revenue event that could be used to offset total IESO costs, it does not actually reduce the contract costs. This model does not directly fulfil the purpose of this review and it is not further analyzed in this report.

3.4.4. Sell an Option for Physical Expansion

In this model[4], the IESO would sell to the Supplier an option to expand the contract facility by re-powering or upgrading within defined limits, e.g. to take advantage of technological advances in solar PV conversion efficiency. The IESO would apply the amortized sale proceeds directly to the reduction of the Global Adjustment. The equivalent result could be achieved by allowing the repowering expansion and blending down the contract price. This could be compounded with an extension.

This model would entail an investment by the Supplier that would not otherwise occur. Generally, no Supplier would undertake such incremental investment without an incremental return. Therefore, this model must drive an increase in total contract payments. This is contrary to the purpose of this review (to find savings) and it is not subject to further analysis.

3.4.5. Debt Substitution

In this model, the IESO would offer debt funding to Suppliers to displace their existing debt at a lower cost, and as a result allow a reduction of the contract price. This is considered impractical for several reasons:

- The IESO would enter into a significant conflict of interest as market operator and contract counterparty to an entity in which it would have a financial interest;

3 This proposed model comes from a response to the IESO's request to Suppliers for suggestions.

4 This proposed model also comes from a response to the IESO's request to Suppliers for suggestions.

- The assumption of non-recourse project debt could be complex and have high transaction costs;
- The effective interest rate at which existing debt could be repaid would likely be significantly lower than its nominal rate, limiting or eliminating any financial benefit;
- Use of the Provincial credit rating in this way might be challenged.

This is therefore not considered a viable model and it is not further analyzed in this report.

3.4.6. Conclusions Regarding Finance Perspectives

The two viable models, Buydown and Blend & Extend are analyzed further in the report. There is a possibility of finding Suppliers who would see benefit in each of such transactions.

As mentioned above, the “sell an extension” model contains elements of the Blend & Extend model, but does not directly produce contract cost savings and would likely yield lower benefits. It is not separately analyzed.

3.5. Market Efficiency Perspective

The IESO expects to achieve significant market efficiency gains through the Market Renewal Program (“MRP”). These benefits are outlined in the IESO’s MRP Business Case.

The IESO has published its principles for the amendments of contracts necessary to accommodate the MRP. Those contract amendments are expected to allow the MRP efficiency benefits to flow to electricity consumers while respecting the contracts and the amendment provisions contained therein.

The described MRP benefits and the MRP-associated contract amendments are seen as outside the scope of this contract savings review. CRA is not aware[5] of market changes beyond the scope of MRP consideration that would have an impact on the costs of generation under contract.

To the extent that savings are identified elsewhere in this report, the changes would be targeted for implementation in the existing market construct and would be expected to survive through the MRP-related amendments.

3.6. Operational and Market Interface Perspective

3.6.1. Fundamentally Uneconomic Project Operation

Fundamentally uneconomic operation of a project occurs when, as a result of obligations or economic incentives within a contract, the Supplier rationally incurs avoidable cost in excess of alternatives available to the market. Any contract that supports fundamentally uneconomic operation of a project warrants consideration.

Avoidable costs include avoidable fuel costs and avoidable fixed and variable operating and maintenance costs as well as future capital expenditures. Sunk costs are explicitly excluded from consideration, as they are by definition not avoidable. There is no fundamentally uneconomic project operation involved in continuing to operate a wind generation project in

5 Detailed analysis of MRP or other market rules changes has not been undertaken as this would be beyond the scope of this report.

an area of high curtailment or high loss penalty factors, as the avoidable cost is minimal. While the allocation of capital to such a project may in retrospect have been uneconomic, that capital is a sunk cost and is properly excluded from consideration in this review.

CRA identified no broad categories of projects whose operation is fundamentally uneconomic but identified two individual contract opportunities for consideration. One instance provides only an opportunity for short term savings, while the other can only be affected following completion of other (third party) investment and thus provides only a deferred opportunity. Both are considered as secondary opportunities without major impact.

3.6.2. Possible Perverse Market Incentives Arising From Contracts

a) *Wind and Solar*

All prior contracts for market participant (transmission connected) wind and solar projects were amended in 2013 to reflect the September 2013 market rule amendments[6]. Prior to that time, the contracts had provided a perverse incentive to generate electricity even under Surplus Baseload Generation conditions as indicated by negative prices.

The market rules and contract amendments were designed to remove the incentive for uneconomic operations. The current incentives maximize production and environmental benefits when the market prices remain positive. They are also designed to curtail production at negative prices. The Large Renewable Procurement (“LRP”) contracts were designed from the beginning to reflect the need for curtailment.

The curtailment provisions have resulted in significant payments to Suppliers in respect of curtailed production. The amount of such curtailment will likely vary over the remaining contract term in response to changes in the supply/demand balance. The IESO makes these curtailment payments pursuant to the contractual agreement. There are no identified opportunities for the avoidance of this obligation or for improvements to market efficiencies[7] under these contracts.

Furthermore, the contracts for distribution connected facilities were not amended. In general, distribution-connected projects > 5 MW capacity experience limited erosion of their revenue stream when the price goes negative. In this case, the negative price is effectively deducted from the contract price. Smaller projects experience no revenue erosion under negative market prices as well. These contracts impose some market inefficiency burden under negative price scenarios.

A possible resolution of this inefficiency would:

- Achieve some market efficiency gain through further mitigation of negative market prices, and possibly mitigation of curtailment to other negative-priced facilities
- Require that Suppliers be compensated for curtailments to which their present contracts do not render them liable

6 The amendments were related to the integration of increasing renewables on the grid and the use of curtailments to mitigate Surplus Baseload Generation (“SBG”).

7 It is expected that some amendments will be required in association with the Market Renewal Program in order to implement the efficiencies targeted by that program.

- Impose significant administration and cost burdens on the IESO
- Result in increased contract costs to support investments in monitoring, revenue metering, dispatch and control, and market and contract settlements.

The costs and benefits of this option were assessed in the 2012 and 2013 renewables integration process, and it was determined that the costs would exceed the benefits. CRA believes this assessment remains valid.

b) Gas-Fired

This analysis includes large gas-fired contracts for all modern gas-fired projects over 75 MW in contract capacity, including those under Clean Energy Supply ("CES") and similar contracts, Combined Heat and Power ("CHP") contracts, and a gas-fired peaker contract.

The common contract settlement framework is designed to avoid interference with market-profit-maximizing incentives. The determination of Imputed Net Revenue ("INR") is independent of actual operations. However, observations of actual behavior suggest that some generators are influenced in their actual market operations by their expectations of Imputed Production. It may be inferred that they ascribe disproportionate negative value to the risk of a price spike when they are imputed to run while not actually running.

From a market perspective, this represents an inefficiency. Generation units may run more than optimally, and thus incur excess fuel cost. However, after the latest round of amendments to the Generator Cost Guarantee ("GCG") programs, any such increased[8] actual production would be at the Suppliers' own net cost and should result in a reduction in total consumer cost. There is no reason to seek any changes relating to this interaction of market and the generality of gas-fired contracts.

There are several older gas-fired projects of moderate scale, the so-called Non-Utility Generators ("NUG"s) that are now operating under renewal contracts. These facilities are less efficient than the fleet of larger modern Combined Cycle Gas Turbine ("CCGT") facilities under the CES contracts and therefore operate less. The contracts were designed to expose each NUG to full market incentives, while recovering certain "windfall" gains that might arise in the event of unexpectedly high price trends. The contracts also impose certain minimum operations requirements to ensure their continued availability to serve system needs. There is no identified inefficiency at the market-contract interface for these contracts.

Finally, there are several smaller projects covered by CHP and Combined Heat and Power Standard Offer Program contracts. These contracts were designed to recognize the small scale of each facility, and to recognize complexity of optimizing facilities to serve electricity and heat requirements. While there is a theoretical opportunity to further optimize, the benefits would be very limited and the costs disproportionately high. As a result, there has been no further investigation.

8 Actual production that is matched by Imputed Production would be fully hedged against market price changes, but the observed behavior shows actual production for such generators in excess of Imputed Production, so that overproduction would result in a lowering of market price not fully offset by contract payments which would flow through to Global Adjustment.

c) *Hydroelectric Generation*

There are just three individually significant contracts for hydroelectric generation[9], and several smaller contracts. None of these appear to offer any major savings opportunities.

Other hydroelectric generation contracts (principally Hydroelectric Contract Initiative and Hydroelectric Energy Standard Offer Program) are for smaller distribution-connected facilities. They are broadly similar to the distribution-connected wind and solar projects noted under paragraph (a) above and would be subject to the similar weighting of costs vs benefits of any change.

d) *Behind-the-Meter Connections*

This is identified as a potential contract savings opportunity, but it is one that would merely transfer costs. Facility amendments that enabled this opportunity might be able to reduce nominal contract payments but would not result in overall savings. They could also reduce the efficiency of dispatch of any affected facility.

A small number of contracted facilities[10] are gas-fired cogeneration facilities, which are connected directly to their customers to provide “Behind-the-Meter” electricity to those customers. This arrangement can substantially mitigate the Global Adjustment (“GA”) that would otherwise be payable by those load customers. There may be circumstances where the location and arrangement of other contracted facilities would allow reconfiguration of the interconnections for Behind-the-Meter supply to an existing load customer.[11] This could allow the load customer to mitigate its GA cost, and that customer benefit could be recovered in whole or part by a clawback through the contract or a reduction in the contract price.

At best (from the IESO perspective), such clawback or price reduction would be expected to offset the GA avoidance by the affected load. The clawback would reduce total GA so as to mitigate but not eliminate the increase that other GA payers would otherwise experience. While potentially attractive at an individual contract level, this offers no overall cost savings and it is not further explored.

3.7. Ownership and Management of Risk

This section takes a risk-management perspective to identify any savings opportunities. It is based on the premise that controllable risk should be owned and managed by the same party. This party has the incentive to appropriately manage that risk.

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9 Each of these three contracts covers several facilities which are listed separately in the IESO contracts list.

10 Early RFPs specifically allowed such interconnection. Later standard offer programs for smaller facilities only allowed this on an exceptional basis and with full IESO clawback of the benefit.

11 The Transmission System Code (“TSC”) distinguishes between the permitted interconnection of new load to existing generation and existing load to new generation, and the non-recognized reconfiguration of connections to link existing load and existing generation behind the meter. The hypothetical opportunity in question would require any TSC restrictions to be waived, or at least not applied in respect of the GA.

3.7.1. Technical, Environmental and Similar Risks

Technical risk includes facility design, performance, operations & maintenance and the associated costs. Market participant / Supplier ownership and management of technical risk is a fundamental principle of the market and contract design.

Other risks that are inherent to facility ownership and operation include environmental compliance, weather and other environmental events, health & safety, Human Resources, and normal business risks. None of these can be appropriately separated from the facility control or ownership.

3.7.2. Electricity Market Risks

Contracts are fundamentally designed to shield Suppliers from the macro-level market risks, while leaving Suppliers exposed to certain micro-level market risks through the dispatch of their facilities. The boundaries between these two categories of market risk vary along a spectrum between different types of contracts.

Macro-level risk protection includes varying degrees of market price hedging, starting with the minimum level of IESO hedging:

- Contracts for transmission-connected wind and solar projects hedge the 5-minute electricity price whenever positive, and the exposure to curtailment in excess of annual or total caps when the price is negative.
- Distribution-connected projects over 5 MW do not provide for curtailment, and do not hedge against the negative element of market price.
- Gas-fired contracts provide a somewhat complex hedge of the market electricity price relative to gas price at a flexible granularity that relates to operating cycles, generally of a few hours. Risk allocation for distribution-connected gas fired facilities is broadly similar.
- The three individually significant hydroelectric contracts hedging arrangements.
- Distribution connected wind solar and hydroelectric facilities under 5 MW each (including microFIT), fully hedge any Supplier exposure to market outcomes.

No opportunities were identified from reducing total consumer costs by any re-allocation of electricity market risks.

3.7.3. Gas-fired Contract Imputed Net Revenue Risk

Although seen by some as complex, the determination of Imputed Net Revenue ("INR") under normal circumstances is a fairly straightforward algorithmic approach. It reflects all-or-nothing operation at contract capacity in any hour based on parameters set in the Supplier's competitive proposal or negotiated contract, using hourly parameters for electricity price and daily gas price indices. CRA's work[12] concluded that this is a reasonable hedge of gas-electric price interaction at an annual level, but the spread between Actual Net Revenue ("ANR") and INR can show significant variability at monthly or daily granularity.

12 This perspective is derived from modeling work undertaken by CRA on various prior assignments; it reflects modeled actual operations and does not reflect any particular Supplier's actual operations or financial results which may be affected by their actual operating decisions and the considerations discussed in section 3.6.2 (b) above.

A hypothetical opportunity can involve the refinement of the INR algorithm. A different approach may reduce the Suppliers' perceived risk and may enable a reduction of contract payments sufficiently to offset the transaction costs and the possible added complexity.

Hypothetical refinements to the INR calculation could include the reflection of minimum run time and part load operation in the algorithm.[13] They could also include the reflection of the timing difference between the "gas day" and the calendar day, and even the recognition that each gas turbine may be operated independently. The starting points for any discussion would be (a) that the INR should continue to be independent of actual operations[14], and (b) that Suppliers have already priced risk associated with any spread between ANR and INR into their competitive proposal prices and / or their acceptance of negotiated contract prices.

If the Suppliers were offered or accepted price reductions (or equivalent parameter changes) to reflect reduced risk from the gas day change then it would be beneficial and have minimal transaction cost. However, the expected cost reduction benefit is unlikely to be material.

Qualitative assessment of other changes suggests that the necessary changes in contract Exhibit B parameters would be very hard to evaluate, and that negotiation of those parameters would become a zero-sum game. Transaction costs would therefore be high, and outcomes uncertain.

This opportunity is therefore not subject to further analysis at this time.

3.7.4. Fuel-Related Risks

a) Gas-Related Risk

Gas management and risk allocation has been identified in informal discussion as a hypothetical opportunity worthy of exploration.

i. Commodity Price

Contracts for gas-fired facilities incorporate the day-ahead gas price at the Dawn trading hub[15] into the gas-electric price hedge arrangements. It is understood that most of the large gas fired generators have established gas commodity purchase arrangements based on this index, so their direct price risk is minimal. There is no apparent opportunity for risk mitigation to reduce contract payments in this area.

ii. Gas Delivery and Management ("GD&M")

Gas-fired generators do not receive any physical or financial commitment schedule from the electricity market in time to define daily commodity needs or delivery nomination in the day ahead gas market time frame. As a result, they are exposed to risk in managing that uncertainty and in paying for the services required. The portfolio of services to be managed may include Dawn storage (including injections and withdrawals), Dawn-Parkway gas transmission, TCPL gas transmission, Enbridge delivery arrangements, and associated balancing services. The actual requirements will vary from facility to facility. Currently, the nature of services (e.g. Short-Term

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13 CES contracts Exhibit B sets out the contract parameters based on the competitive proposals and any subsequent negotiations. Implementation of either minimum run time or part load operation would entail revision of and / or addition to these fundamental contract parameters

14 The preservation of full market incentives is particularly important for the fleet of large gas fired generation as this will be the marginal tranche of supply for most high-demand hours.

15 There is at least one exception to the use of the Dawn hub price, but this is not material to this discussion.

Firm, Firm, Interruptible) and the volume are decisions generally made by each Supplier separately and at the Supplier's cost.

Nature and volume of services are a matter of each Supplier's expectations and risk preferences. Generally, Suppliers do not contract firm service sufficient to support full output for 24 hours per day, as this requirement would be so rare. At least one Supplier has in the past elected fully interruptible delivery service.

There are several facilities that have full or partial exceptions to the Supplier's responsibility for GD&M cost and the associated risk. In such cases, the IESO reimburses the Supplier for the relevant GD&M costs.

Moreover, there is a range of options for Supplier GD&M risk mitigation to achieve cost reduction:

- In order to mitigate ongoing (but not historic) divergence of regulated gas service rates from the consumer price index embedded in the contract, the Supplier's cost of firm delivery services could be backed out of the Net Revenue Requirement. They can be subject to an escalation factor directly related to regulated gas transportation and delivery service rates. However, risk transfer savings would likely be minimal.
- The IESO could negotiate that the Supplier should reduce firm gas delivery commitments below the level that Supplier would have otherwise selected. This can occur on the basis that production would not be imputed to the extent that the reduced services limit actual production.[16] However, such change could reduce system adequacy and reliability.
- The IESO could assume cost responsibility for GD&M services, subject to conflict of interest as discussed below;
- The IESO could actually acquire those services on a portfolio basis and allocate use of those services on e.g. a daily basis or an hourly basis in order to implement gas deliveries to each facility.

The last two options are fraught with potential conflicts of interest. If Suppliers were to be provided these services for free, in return for a contract price reduction, they would have little incentive to minimize cost beyond that necessary to demonstrate some degree of prudence. There would be pressure for increases in volumes of procured firm services available to each facility. Since rates for most of the needed services are regulated, there would be no volume discount.

Any assumption by the IESO of a central portfolio management role would tend to separate gas management operations from the electricity market interface, possibly adding friction in risk management. It would also impose on the IESO the obligation to acquire and pay the overhead cost for a gas management team, recognizing that this is not an area in which the IESO would claim prior expertise.

This opportunity is therefore not subject to further analysis at this time.

b) Wind and Solar

Suppliers generally bear the risks of volume and timing of wind and sunshine. Payment is based on the volume of actual production, plus the volume foregone as a

16 A variant of this, using shared GD&M services to serve a portfolio of the Supplier's contracted facilities was proposed in a Supplier's Dec14 responses.

result of curtailment. This is designed to maximize production from these resources and to minimize the need for production from emitting resources. This incentive structure remains valid, and there is no need for change.

A Supplier's volume risk could be mitigated by converting all or part of the contract payment stream into a fixed payment.[17] This would possibly reduce lender's assessment of Supplier's risk and thus reduce financing costs. This would be unlikely to have material cost impact as a stand-alone change, but a partial adjustment could enhance any cost savings being achieved by other changes such as a partial buy-down or a Blend & Extend amendment.

c) Hydrological Risk

Suppliers generally bear the risks of volume and timing of water. Considerations for smaller facilities are similar to those for wind and solar, but with less total materiality.

3.7.5. Regulatory risk

All contracts include carefully considered provisions that provide certain protections to Suppliers with respect to legislation, regulation and market rules. Allocation of any associated regulatory risks is not an issue addressed in this report.

3.7.6. Post-Term Risks

Post-term risks are intentionally outside contract scope of any contract. The Blend & Extend opportunity makes these risks relevant to the present discussion. Any contract extension would significantly mitigate Suppliers' post-term risks and add to the attractiveness to Suppliers of this opportunity.

3.8. The Portfolio Perspective

Suppliers who hold contract portfolios may be of interest due to the potential opportunities for trade-offs within the portfolios. For example, by extending one contract as consideration for a price reduction or termination of another.[18]

The Ontario electricity market, excluding Ontario Power Generation and Bruce Power, is highly fragmented. Very few Suppliers own significant portfolios, without minority interests, in diverse resource types. An additional small number of Suppliers own portfolios of partial interests in wind, solar or a combination thereof.

There may be circumstances in which a portfolio approach can bring extra benefits over those available from individual contracts. If the IESO were to be seeking early retirements of particular facilities (e.g. of coal facilities for environmental reasons), then such portfolio exchanges might be significant.

In the present context where the primary opportunities are centered on financial and risk arbitrage, the portfolio exchanges offer little apparent gain. To the extent that any may arise during the implementation phase, they may be worthy of consideration for incremental benefit within established approaches.

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17 This was included in the Supplier suggestions received on December 14. Volume risk reduction also occurs in a contract Buydown transaction.

18 This proposed model also comes from a response to the IESO's request to Suppliers for suggestions

Portfolios of distribution-connected facilities may provide incremental opportunities for economical extension of approaches that are developed and implemented for large facilities. Overall impacts would be small.

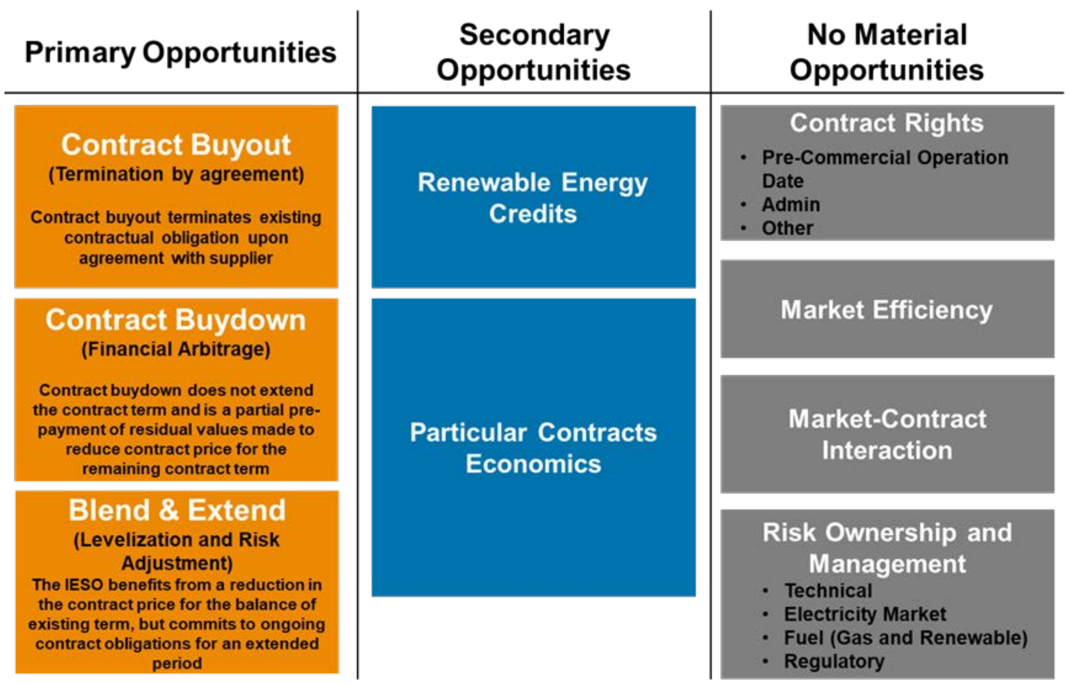
3.9. Special Opportunities

Special opportunities are all contract-specific and considered confidential. They are not addressed in this report. CRA has also identified an opportunity related to Renewable Energy Credits that is further discussed in Section 9.2.

3.10. Table of Opportunities – Larger Facility Contracts

The following table summarizes opportunities linked to contracts for transmission-connected facilities into primary opportunities warranting further analysis; secondary opportunities warranting some consideration; and possible opportunities investigated and found to provide no material savings value:

Figure 3 Identified Opportunities for Transmission Connected Facilities



3.11. Distribution-Connected Facility Contracts

This review has not identified any material savings opportunities unique to distribution-connected facility contracts.

There may be some potential to extend to the larger distribution-connected facilities an opportunity to participate in any program designed for larger facilities of each technology. Please refer to section 9.1 for discussion.

3.12. MicroFIT

Total microFIT contract capacity for the 30,194 microFIT contracts is 261.54 MW. Ownership is diverse by design.

MicroFIT generation is designed for passive operation, without any response to market signals. All electricity produced is metered separately from any load and is treated for settlement purposes as being injected into distribution systems.

It can be expected that there will be a certain amount of attrition in aggregated microFIT production and contract payments due to slow technical degradation and other damaging events. There may also be a certain amount of administrative attrition on sales of property or defaults, but these are unlikely to be material.

Opportunities for any restructuring (Buyout, Blend & Extend, etc.) are just not realistic for this scale of contract. Review of the form of contract has not indicated any other opportunities for savings within the microFIT program.

3.13. Summary of Primary Opportunities

The primary opportunities are considered in the context of each major category of larger contracts, and are summarized in the following table:

Table 3 Primary Opportunities for Large Contracts

Category	Size	Options		
		Buyout	**Buydown**	**Blend & Extend**
Wind *Large transmission-connected facilities, 19 MW to 300 MW*	**45 Contracts** **4,543 MW** (82.1% of total wind) **$ 1,696 M / yr total cost (2021)**	**Yes**	**Yes**	**Some** *Contracts with term past 2035 not considered eligible*
Solar *Large transmission-connected facilities 10 MW to 100 MW* *Potential to consider larger portfolios of smaller contracts*	**15 Contracts** **778 MW** (32.23% of total solar) **$ 413 M / yr total cost (2021)**	**Yes**	**Yes**	**Some** *Contracts with term past 2035 not considered eligible*
Gas *Excludes Ontario Power Generation's 2,000 MW gas / oil fired Lennox facility (close to the end of contract term) and all distribution-connected facilities*	**13 Contracts** **6,620 MW** (89.62% of total gas) **$ 1,095 M / yr total cost (2021)**	**No** *Would create a threat to system adequacy*	**Some** *Others have present price below our buydown floor or have term past 2035*	**Some** *Others have low present price that would be increased by blending or have term past 2035*

The table provides details on the opportunities for all three major categories of Supplier contracts and what size of the exiting operational fleet they represent. For example, the 45 wind contracts that represent 4543 MW of wind resources are close to 82% of the total wind resources in Ontario. Similarly, the 778 MW of solar contracts represent 32.23% of the solar resources and the 6620 MW of gas-fired contracts represent close to 90% of gas fired resources (excluding Lennox) that are under contract.

4. Modeling and Evaluation Inputs and Parameters

4.1. Framework for Evaluating Primary Opportunities

All analysis is carried out using nominal dollars. An annual escalation and inflation rate of 2% is used to determine escalated contract prices and to adjust the cost projections in the IESO's Annual Planning Outlook to nominal market prices for each year.

It is expected that Suppliers will each evaluate the available opportunities offered by the IESO, and will establish whether such opportunity could be attractive, and at what threshold price. To determine that threshold price, each Supplier is expected to consider its base cost of capital, the increase or mitigation of risk, the transaction cost, and the net gain or benefit share required to warrant allocation of resources to a transaction. Each of these parameters will vary among Suppliers. Any reasonable price offered by the IESO is likely to exceed the threshold price of a certain number of Suppliers and as a result those Suppliers would then take up the offer.

The higher the IESO price offer, the higher the take-up rate, but the lower the net benefit retained by the IESO. CRA's modeling of take-up rate versus price starts by establishing as a baseline the median Supplier cost of capital. This is expected to be close to the average. Individual Suppliers' cost of capital will vary around this. This is discussed in section 4.2 below.

The potential IESO net savings in Buyout and Buydown transactions arises from the difference between IESO cost of borrowing to fund the transactions, and the discount rate implicit in the transaction price. This discount rate is referred to as the IESO pricing rate. Actual Buyout or Buydown transaction prices offered by the IESO would be determined by the IESO's assessment of the Supplier's foregone revenue to contract term, discounted at the IESO's pricing rate. Individual contract offer prices would thus depend on contract capacity / extrapolation of historic production capability, contract price, and contract term date. Market revenue streams post Buyout would be based on the IESO's market price projections including locational impacts when these become applicable, and expected levels of curtailment. The IESO pricing rate is discussed in section 4.3 below.

A second starting point is to establish as a baseline the IESO cost of debt funding. This is discussed in section 4.4 below.

Each transaction exhibits a different savings and cost profile over time. The net present value ("NPV") of each opportunity is determined by discounting the annual impacts to 2021 using a discount rate representative of the value to society of those future impacts, the social discount rate. The social discount rate is discussed in section 4.5 below.

These and other modeling assumptions are summarized in the table in section 4.6 below.

4.2. Suppliers' Cost of Capital

4.2.1. General Principles

Selection of Supplier-focused parameters (discount rate in particular) was a matter of judgment and was tested with sensitivity cases.

CRA also considered the tax code implications in this effort. However, none of the proposed transactions would include a transfer of physical assets or of ownership interest in shares or partnership units. All payments to Suppliers for Buyout or Buydown are therefore assumed to be treated as revenue, and not eligible for treatment as capital gains. The contract revenues foregone by such a transaction would also have been revenue, and therefore subject to equivalent tax treatment. As a result, there is no obviously apparent difference in the tax treatment of Buyout or Buydown and contract revenues, and no need to make any special adjustment for tax impact.

From a Supplier's perspective, the IESO contract buyout has broadly comparable (but not identical) impact to a private sale of the underlying assets and contract interests or of partnership units. A prudent Supplier would thus evaluate contract buyout against a full asset or unit sale, recognizing the valuations that may be available in the market for such a private sale. Such private sales of partnership units may also be available to part-owners of facilities in which other owners wish to maintain their existing interests for the full contract term.

4.2.2. Determination of Pro-Forma Cost of Capital

It is customary to establish an appropriate discount rate for translating uncertain future cash flows at an after-tax weighted average cost of capital when deriving the net present value of a contract. The appropriate discount rate should reflect systemic financial market risks and project-specific risks of a Supplier participating in the Ontario wholesale markets and the return required by investors to compensate for those risks. CRA recognizes that generation projects can be financed under a project financing or balance sheet financing approach.

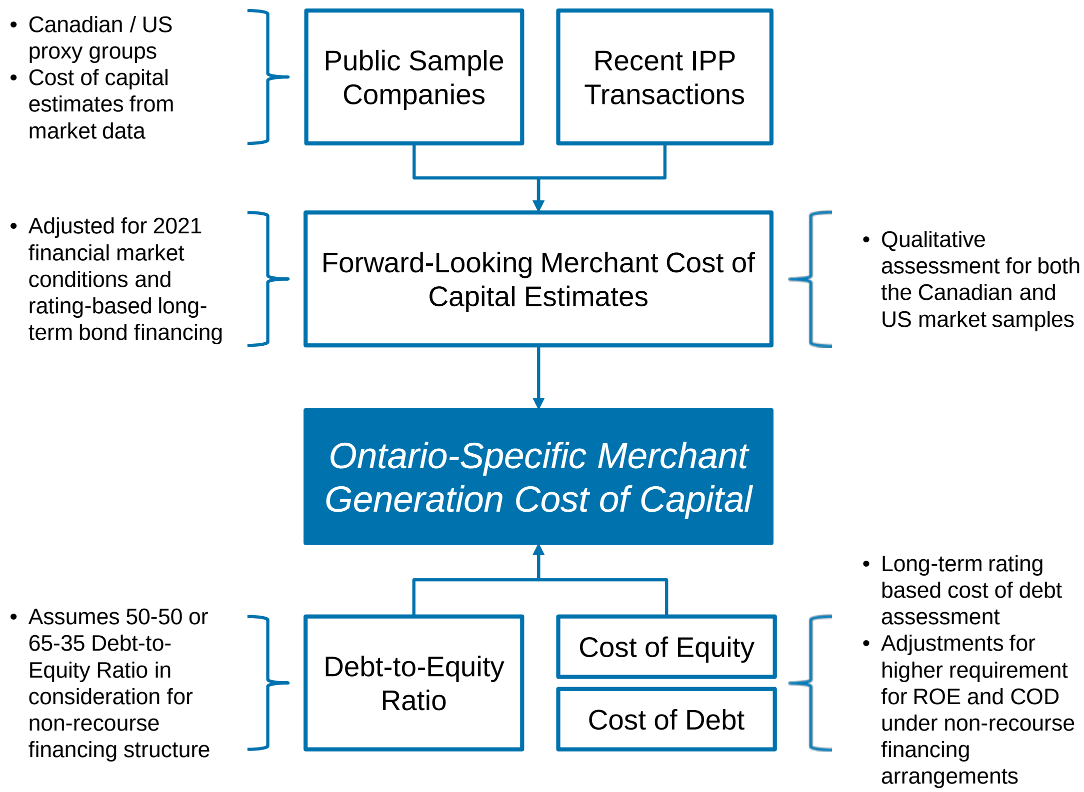
Generally, project financing considers project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a new power plant. Non-recourse debt is not backed by a guarantee from the equity investor – in most cases the larger parent company - above the value of the individual power plant. For these projects, senior lenders look solely to the assets and cash flows of the projects for repayment. They are considered higher risk financing and usually assigned a higher cost of capital than balance sheet projects.

Balance sheet financing employs debt backed by the project owner itself, which may have significant and diverse resources and assets beyond the individual power plant. Therefore, the cost of capital for such assets is lower since it carries less risk. Based on reviewed information, the majority of the projects in Ontario are financed on a "stand-alone" or project-specific basis. Specifics around these financing structures are not publicly available, not uniform, and thus not easily encapsulated.

Due to this, CRA's analysis focuses on the review of a peer group of publicly traded independent power producers ("IPPs"), and uses their financial parameters to inform calculations of the recommended cost of capital. This approach provides the most reasonable cost of capital, and will be considered as the base case in this effort. As mentioned above, the report provides results of different sensitivities on the cost of capital to identify directionally the impact on benefits realized by the various primary opportunities.

The figure below provides in more detail the approach for estimating the Supplier's Cost of Capital.

Figure 4 Approach for Estimating the Supplier's Cost of Capital



CRA's approach considered publicly available information on various companies in the US and Canada and recent applicable transactions to estimate the applicable cost of capital in this analysis. The collected information was incorporated in widely adopted methods described below.

Firstly, the cost of capital for an investment can be estimated by the Weighted Average Cost of Capital ("WACC") that represents the blend of rates paid on equity and debt specific to that investment's capital structure and can be expressed by the following equation:

$$\text{WACC} = \text{ROE} * \text{Weight of Equity} + \text{COD} * \text{Weight of Debt}$$

Where:
ROE = Return on Equity, and
COD = Cost of Debt

The cost of equity (or Return on Equity, ROE) can be estimated using the Capital Asset Pricing Model (CAPM). In this effort, CAPM was applied to samples of U.S. and Canadian generation companies. In brief, the cost of equity for each company is derived as the applicable risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta."

CAPM is expressed by the following equation:

$$R_e = R_f + \beta\,(R_m - R_f)$$

Where:

R_e= Required return on equity

R_f = The risk-free rate

β = Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific security, and

R_m = The return required of the market as a whole – market risk premium

The “beta” describes the correlation of the company’s performance with the market – in this instance described as the Standard & Poors (“S&P”) TSX index for Canadian generation companies and the S&P 500 index for U.S. companies.

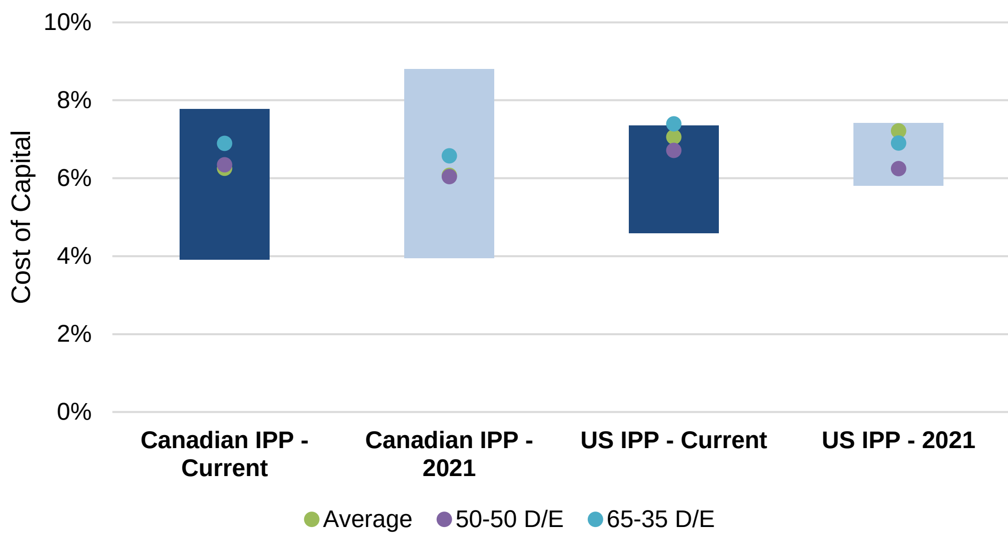
CRA assumed capital structure of 50/50 or 65/35 (Debt /Equity) and an observed risk-free rate of 1.9% in Canadian markets and 2.5% in U.S. markets which is based on the market yields for 10-year Treasury bonds in each market as of the date of the analysis. Taxes were factored into the cost of debt.

The expected market risk premium is around 5.5% based on the historical long-term average for the Canadian market and the long-term average for the U.S. market, and the forecasted market risk premiums (MRPs) for both markets.

To reflect forward looking considerations, CRA consulted OECD on the 2021 interest rate outlook and used 1.6% and 2.0% for Canada and US respectively. The consideration of forward risk free rates required the adjustment of the CAPM resulting in updated cost of equity and as result cost of capital.

The figure below depicts the results of CRA analysis for both current and 2021 market conditions. The 2021 year was considered to align with the assumptions of Section 3.6. After these assumptions are incorporated, the average the cost of capital of public IPPs in Canada and US falls in the 6-8% range under current market conditions.

Figure 5 Average Cost of Capital for Public IPPs in Canada and US



As explained above, non-recourse financing arrangements typically demand higher cost of capital, reflected through increased level of debt leveraging. As a base case, CRA assumed the Supplier's cost of capital to be 6% representing a reasonable average for the two types of financing.

4.3. IESO Pricing Rate

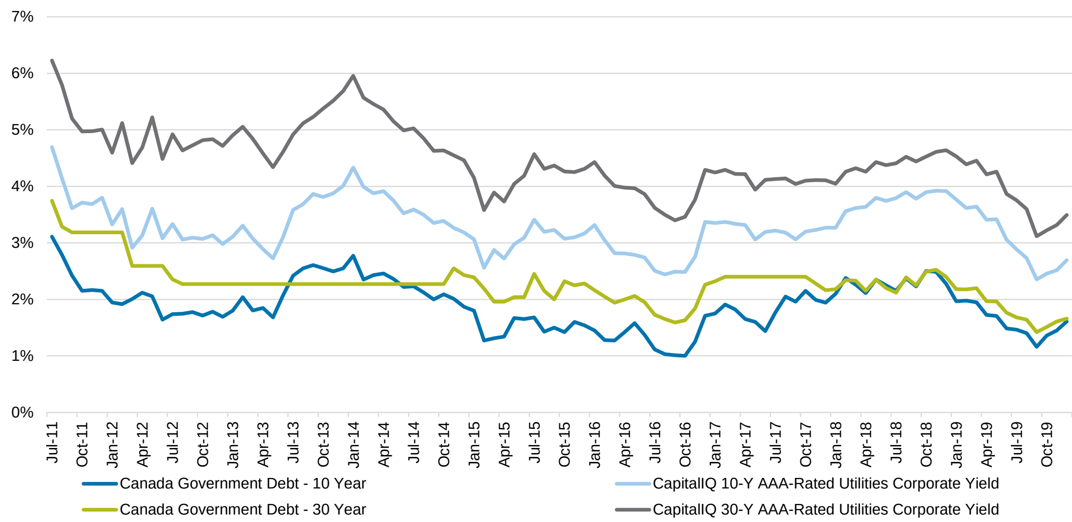
The IESO pricing rate is the discount rate used by the IESO and applied to Suppliers' foregone revenue streams in order to determine the transaction price. The IESO would be expected to select a pricing rate that would maximize overall benefit according to the specific program objectives, likely including a balance between maximizing total net savings as aggregated to Net Present Value, and maximizing the efficiency in the use of funds to achieve those savings, all with due regard to risk and uncertainty over take-up and other factors.

As discussed in section 6.4.2, below, the base case modeling assumption for IESO pricing rate is 6%, which is the same as the estimated Supplier median cost of capital as discussed in section 4.2 above. The base case take-up rate reflects this base case IESO pricing rate. Take-up for Buyout or Buydown would thus be limited to the subset of Suppliers whose individual cost of capital is sufficiently above this median value.

4.4. IESO Cost of Debt Funding

The IESO cost of debt required for the financing of the potential opportunities is assumed to be tied to the highest rated class. Under current market conditions, the AAA-rated Utilities Corporate Yields have been trading at around 1.4%-2.1% premium over the Canada Government Bonds. These spreads have remained relatively stable over the past 5 years while the OECD forecasts the 2021 interest rate to be around 1.60% for Canada – this implies that when combining the two assumptions, the range of the IESO's cost of debt should fall in 3-4% range.

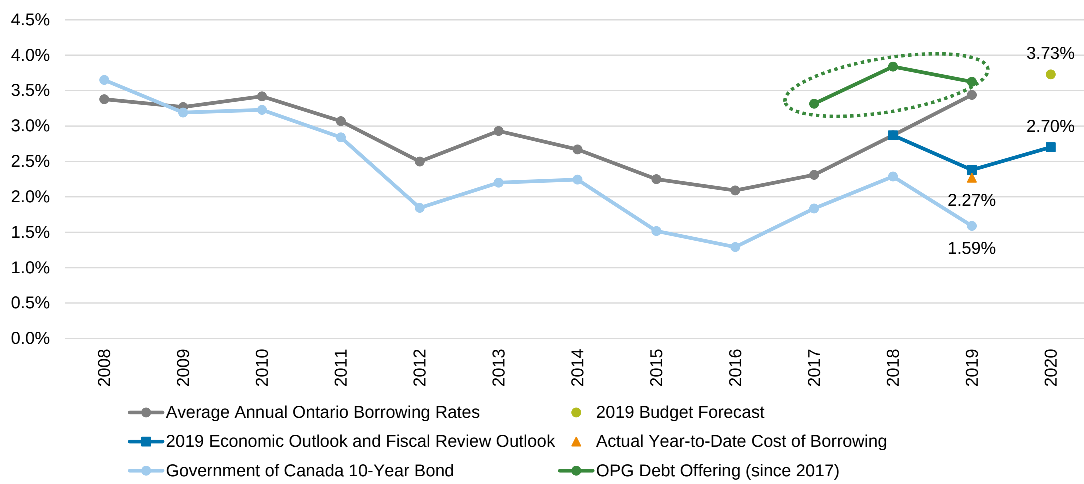
Figure 6 Cost of Debt Range for IESO (1)



- This range is also confirmed by current examples. According to Ontario Financing Authority, the Government has been able to borrow in the range of 2.0% - 3.5% over the past decade confirmed by the OPG's issuance of $1.7 billion with an average realized rate of 3.61%

The provincial government is able to borrow at a discount to BBB+ rated or above corporate debt offerings.

Figure 7 Cost of Debt Range for IESO (2)



CRA's assessment assumed 3.0% as the IESO cost of debt in this analysis and considers sensitivities around this number. Based on historical performance and expected market conditions, CRA does not expect the IESO cost of debt to trend lower than 3.0%. Therefore, CRA's sensitivity analysis did not consider such case.

4.5. Social Discount Rate

The social discount rate is used to establish the net present value to society of future cost and revenue streams of a project. Since there is no definitive method for estimating the social discount rate, CRA relied on literature review and industry reports. CRA understands that a 6% social discount rate, applied to nominal cash flows, has been widely used in the Ontario electricity sector and historically has been used in IESO's analysis. Therefore, it was adopted as the mid-point value in CRA's analysis. CRA also considered a range for stating net present value results at alternative rates of 3% and 9% to capture the entire spectrum of potentially adopted social discount rates.

4.6. Other Modeling Assumptions

The table below provides an overview of the additional assumptions considered in the modeling of various opportunities.

Table 4 Summary of Modeling Assumptions

Category	Assumptions
Implementation date	January 1, 2021
Real or Nominal	Analysis assumed nominal dollars
Inflation / Escalation Rate	2%
Supplier Cost of Capital	6%
IESO Cost of Capital / Cost of Debt	3%
Social Discount Rate	Base 6%
Effective Average Peak Capacity Contribution	Wind: 15% Solar: 35% Gas: 93%
Exchange Rate	USD/CAD = $0.8
Renewables contract Buydown Floor	Assumed 1.5x – ratio of bought-down contract revenues over the sum of market energy and capacity revenue
Gas contract Buydown Price Floor	Assumed $8,000-9,000/MW-month – floor of bought-down contract Net Revenue Requirement
Energy and Capacity Price	• IESO's Annual Planning Outlook Marginal Costs 2019, APO Reference Case, as proxy for Energy Price outlook; • IESO's Annual Planning Outlook Marginal Capacity Costs, APO 2019 Reference Case, as proxy for Capacity Price outlook
Blend & Extend Term	10 Years
Buydown / Buyout Debt Amortization Term	• Base Case: Remaining contract life • Sensitivity on extension: 10 years past contract term
Renewables Extrapolation	Production Capability = Annual average over 2014 (or 1st full year of operation) - 2018 Annual Curtailment = Annual average over 2014 (or 1st full year of operation) – 2018 Unpaid Curtailment = Minimum of Annual Curtailment, Annual Cap and Remaining Total Cap
Gas-fired Generation Extrapolation of Actual Net Revenue	Extrapolate Imputed Net Revenue based on the cumulative price setting outlook summarized from the Base Case Hourly IESO Annual Planning Outlook Marginal Costs analysis. Actual Net Revenue assumed equal to Imputed Net Revenue.

4.7. Impacts Not Considered

This analysis addresses IESO costs and benefits. IESO program and transaction costs are not included, so all benefits are before recognizing such costs. The analysis does not recognize any potential for broader Provincial impacts such as on tax or on borrowing programs.

5. Primary opportunities: individual Contract Modeling

5.1. General Principles

Modeling of the primary opportunities reflects individual parameters for each of 45 wind, 15 solar, and 13 gas-fired contracts, simplified somewhat by rounding each term date to the closest calendar year end.

In the “existing” case, the total annual Supplier revenue stream from each facility under contract is modeled. This equals the total cost to the IESO of production from that facility.

For wind and solar contracts, the modeled revenue stream comprises:

a. During the contract term:
   - i.) Actual production at contract price (a portion of which will flow as market energy revenue)
   - ii.) Contract payments in respect of curtailment, also at the contract price

b. After the contract term date
   - i.) Actual production at market price
   - ii.) Capacity revenue based on the assumption that structured capacity payments will be available to non-contracted generators equivalent to the marginal cost of capacity[19]

For gas-fired contracts, the modeled revenue stream comprises:

a. During the contract term:
   - i.) The fixed capacity payment equal to the contract Net Revenue Requirement x the Contract Capacity[20]
   - ii.) The estimated cost of fuel consumed

b. After the contract term date
   - i.) Actual net market energy revenue
   - ii.) The estimated cost of fuel consumed
   - iii.) Capacity revenue based on the assumption that structured capacity payments will be available to non-contracted generators equivalent to the marginal cost of capacity

In order to accommodate and properly reflect impacts that could arise for up to 10 years after existing term dates, the model extends to 2050. Discounting of results and the tailing-off of possible impacts over that period limits the materiality of the assumptions made to extrapolate impacts past the end of the IESO’s Annual Planning Outlook projections in 2040.

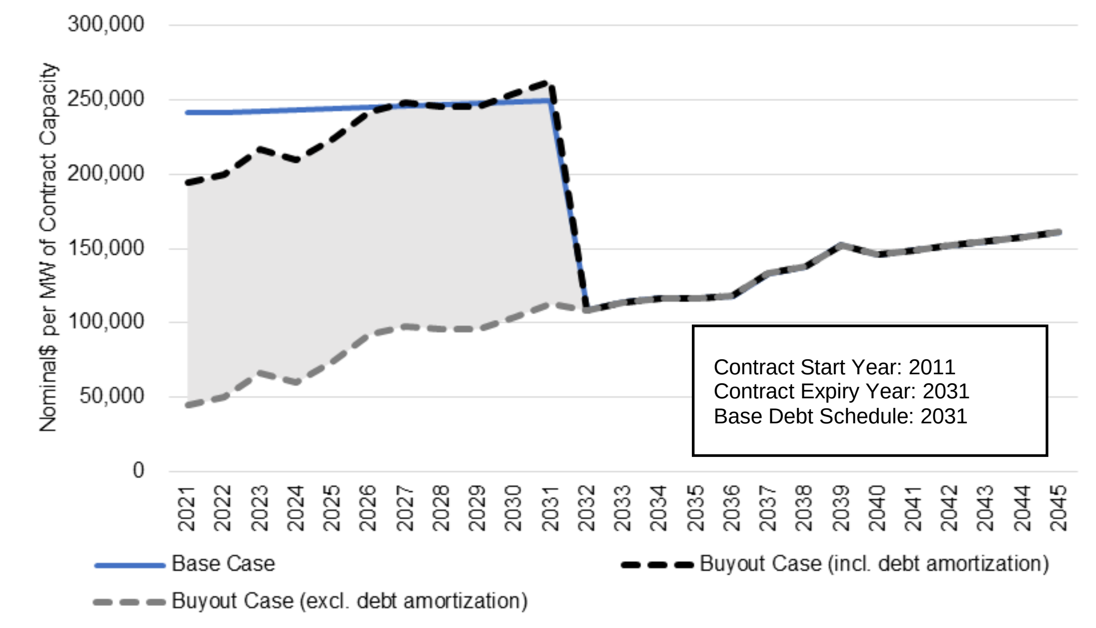
19 Please refer to further discussion of capacity elements in sections 6.2 (c) and 7.1

20 Note the implicit assumption that, at the precision required for this analysis, each gas-fired generator’s actual net revenues are equal to their Imputed Net Revenues.

5.2. Pro-forma Buyout Transaction

The example below provides information on a pro-forma wind contract. The cash flows represent the total market costs and contract costs with both with and without debt amortization.

Figure 8 Buyout Example for Wind Contracts



For this pro-forma transaction, the results would be:

Table 5 Savings Results for Wind Contract Buyout Example

Funding Requirement	1,386	
Year 1 Gross Savings before Debt Amortization and IESO Program and Transaction Costs	197	
Year 1 Net Savings after Debt Amortization and before IESO Program and Transaction Costs	47	
NPV Gross Savings @ Various Social Discount Rates	3%	1,533
	6%	1,320
	9%	1,151
NPV Net Savings @ Various Social Discount Rates	3%	147
	6%	139
	9%	131

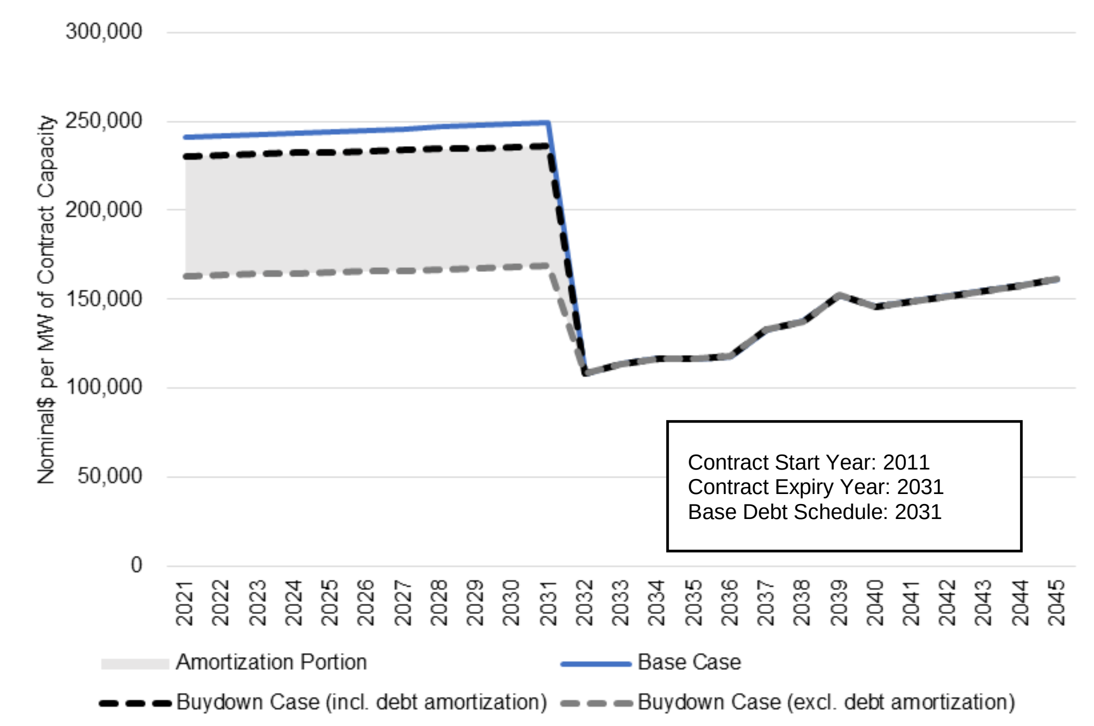
Note: values presented in the table above are in 2021 $000s per MW of Contract Capacity; NPVs are derived based on each of the stated Social Discount Rates. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

A pro-forma solar contract buyout would look similar to the wind project buyout, but with a higher premium of contract price over market price.

5.3. Pro-forma Buydown Transaction

Pro-forma wind contract example

Figure 9 Buydown Example for Wind Contracts



Note that the extent of Buydown is limited in order to support ongoing operation and fulfilment of present contract commitments:

For this pro-forma transaction, the results would be:

Table 6 Savings Results for Wind Contracts Buydown Example

Funding Requirement	624	
Year 1 Gross Savings before Debt Amortization and IESO Program and Transaction Costs	78	
Year 1 Net Savings after Debt Amortization and before IESO Program and Transaction Costs	11	
NPV Gross Savings @ Various Social Discount Rates	3%	733
	6%	624
	9%	538
NPV Net Savings @ Various Social Discount Rates	3%	109
	6%	92
	9%	79

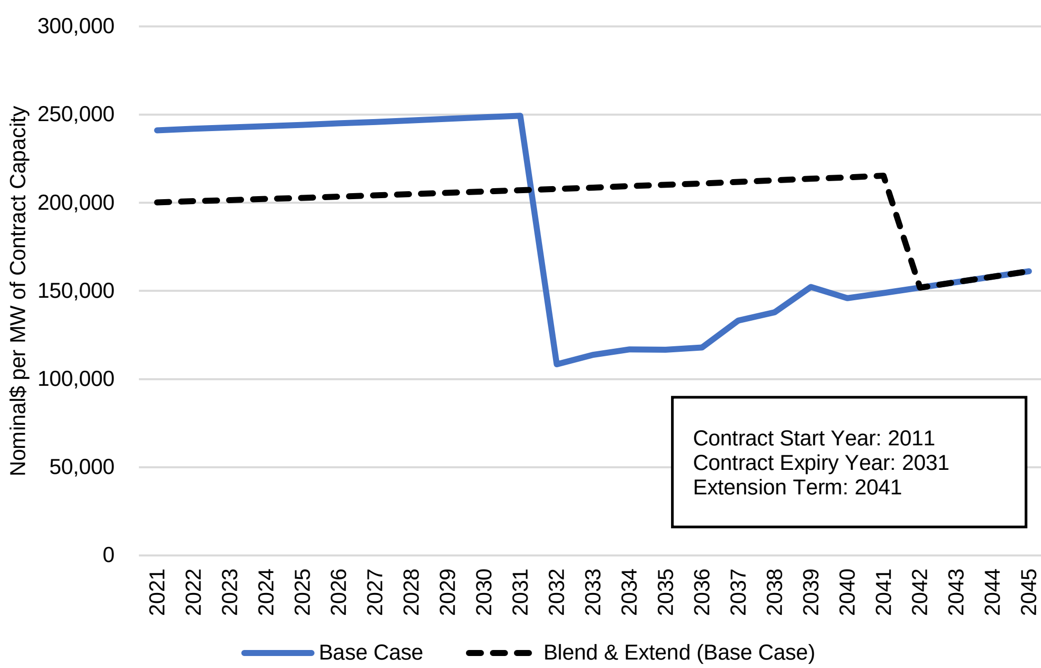
Note: values presented in the table above are in 2021 $000s per MW of Contract Capacity; NPVs are derived based on each of the stated Social Discount Rates. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

A solar or gas-fired contract Buydown would look similar to the wind project Buydown. The solar contract would show a higher premium of contract price over market price. The gas contract would show a lower premium of contract price over market price due largely to the greater impact of assumed market capacity revenues.

5.4. Pro-forma Blend & Extend Transactions

Pro-forma wind contract example is provided below. The figure compares the Blend and Extend transaction with the base case.

Figure 10 Blend and Extend Example for Wind Contracts



For this pro-forma transaction, the results would be:

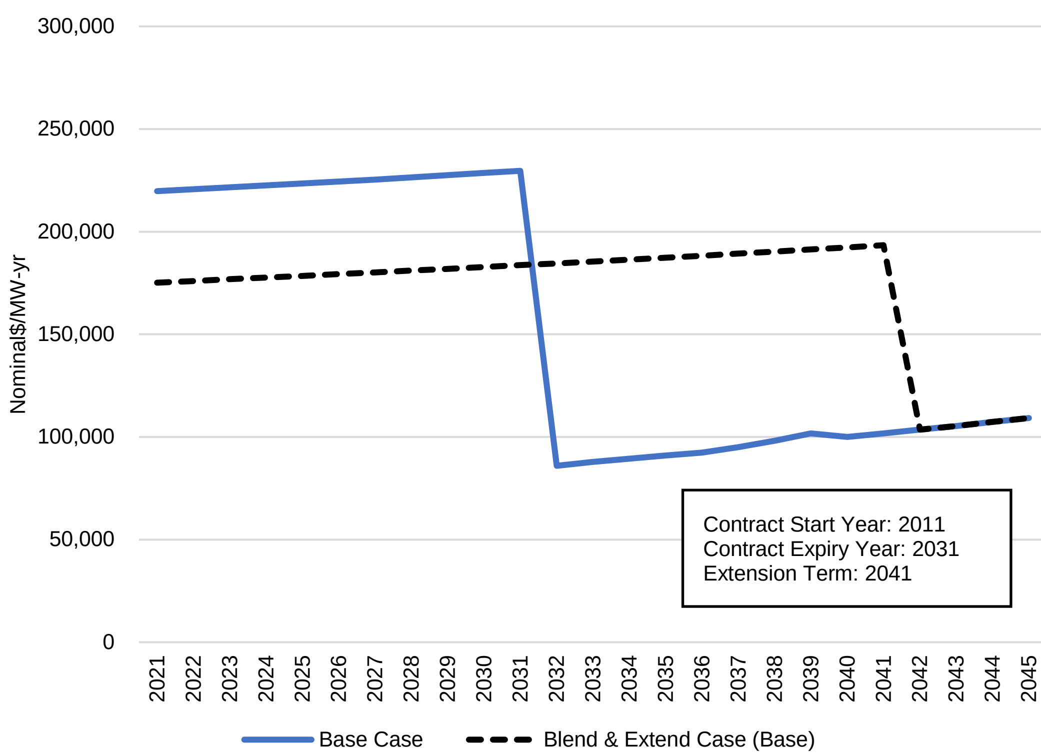
Table 7 Savings Results for Wind Contracts Blend and Extend

Funding Requirement	N/A	
Year 1 Gross Savings before Debt Amortization and IESO Program and Transaction Costs	N/A	
Year 1 Net Savings after Debt Amortization and before IESO Program and Transaction Costs	41	
NPV Gross Savings @ Various Social Discount Rates	3%	N/A
	6%	N/A
	9%	N/A
NPV Net Savings @ Various Social Discount Rates	3%	(131)
	6%	(0)
	9%	71

Note: values presented in the table above are in 2021 $000s per MW of Contract Capacity; NPVs are derived based on each of the stated Social Discount Rates. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Pro-forma gas-fired contract example is as follows:

Figure 11 Blend and Extend Example for Gas-Fired Contracts



For this pro-forma transaction, the results would be:

Table 8 Savings Results for Gas-Fired Contracts Blend and Extend Example

Funding Requirement	N/A	
Year 1 Gross Savings before Debt Amortization and IESO Program and Transaction Costs	N/A	
Year 1 Net Savings after Debt Amortization and before IESO Program and Transaction Costs	45	
NPV Gross Savings @ Various Social Discount Rates	3%	N/A
	6%	N/A
	9%	N/A
NPV Net Savings @ Various Social Discount Rates	3%	(150)
	6%	(0)
	9%	80

Note: values presented in the table above are in 2021 $000s per Contract MW-year; NPVs are derived based on each of the stated Social Discount Rates. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

6. Implementation Considerations and Costs

6.1. General Implementation Considerations

Specific program design is beyond the scope of this assignment, but will need to include consideration of:

a. Selection and sequencing of the opportunities to pursue per category;

b. Selection of the broad approach per opportunity / category (standard offer / auction / certain cases of individual negotiation / other), all based on prioritized objectives;

c. Program development resources, costs and time;

d. Realistic implementation timetable;

e. Legislative or regulation changes needed for implementation, including issues related to any required funding, borrowing and accounting for debt, and any allocation of debt amortization cost to electricity customers;

f. Inclusion of appropriate stakeholder consultations about program and transaction design;

g. Individual contract transaction costs expected to be borne by the IESO and by Suppliers;

h. Recognition in design of probable aversion to the assumption of additional risk by many Suppliers, and of the important role and rights of secured lenders in non-recourse financed projects;

i. Appropriate balance between transparency and the confidentiality necessary to preserve negotiating positions; and

j. Approach to the potential interaction with the Market Renewal Program and any associated contract amendments.

6.2. Primary Opportunities: Pricing and Benefit Sharing Approaches

There are options for pricing and benefit sharing within any of the primary opportunities.

a) Suppliers' Transaction Costs

The Suppliers' costs of negotiating and implementing this transaction could be treated as reimbursable costs outside any Buyout, Buydown or blended contract prices; or they could be deemed to be included in those transaction prices. Deemed inclusion enhances initial savings by spreading this cost over the term of the savings, and it eliminates a conflict of interest over control of those costs. Modeling is based on deemed inclusion. Each Supplier would therefore be responsible for its own transaction costs and would presumably include these in its threshold transaction price.

b) Market Outcome Impacts

The actual savings achieved in a wind or solar Buyout transaction will depend on actual market price and curtailment outcomes over the bought-out term of the contract, and will almost certainly differ from the current projections that form the basis of any Buyout transaction. One option would be to include a savings adjustment provision in any Buyout transaction. Such a provision would:

- establish a new form of contractual relationship between the bought-out Supplier and the IESO over the bought-out term; and
- to some degree hedge the Suppliers' market risk and have the IESO re-assume that portion of the market risk.

Such a transaction would thus include strong elements of the Buydown transaction. Modeling is therefore based on a simple Buyout transaction with no subsequent adjustment for actual market outcomes.

The savings in a Buydown transaction are not dependent on market outcomes as the existing contract price hedge remains in place.

The actual savings achieved in a Blend & Extend transaction will depend on actual market outcomes over the extension period of the contract, and will almost certainly differ from current projections. One of the key features of a Blend & Extend transaction, particularly attractive to Suppliers, is the added hedging of the future market price in the extension period. Dilution of this by a savings adjustment mechanism would weaken the incentive to transact and likely reduce early savings. Modeling is therefore based on a simple Blend & Extend transaction for the full contract capacity and energy production with no subsequent savings adjustment for actual market outcomes.

c) ***Policy and Regulatory Impacts***

The actual savings in any Buyout of Blend & Extend transaction will depend on policy and regulatory decisions that will affect market outcomes. Suppliers are likely to view these as quite distinct from normal market risks. For example:

- Hypothetical policy-level decisions with respect to nuclear refurbishment or life extension could have a significant impact on some wind project curtailment over the bought-out contract term.

- Modeling assumes that all non-contracted generators will be able to monetize the value of capacity that they provide at a level equal to the IESO's marginal cost of capacity. It is not yet clear what mechanism may be available for this. Because of this uncertainty, the expectation of capacity revenues is not reflected in the calculation of Buyout prices.[21]

Suppliers can be expected to price any Buyout or Blend & Extend transactions on the basis of their perceived risks arising from policy or regulatory outcomes. Suppliers' assumption of these risks outside any contract may reduce the savings available in Buyout transactions and increase those available in Blend & Extend transactions. Modeling makes indicative allowance for these impacts, but Suppliers can be expected to raise the issues in stakeholder consultations for implementation design. The IESO will need to consider how to approach or respond to such concerns.

d) Modeling Treatment of Supplier Pricing

It is assumed that each Supplier interested in any of the primary opportunity transactions would develop its threshold price to transact at auction, or would have to evaluate any IESO standard offer against a notional threshold.

It is assumed that a willing Suppliers' threshold price for Buyout or Buydown would reflect the reduction in future cash flows discounted at their individual cost of capital, adjusted in the case of Buyout for the additional risks assumed, adjusted to include transaction costs and adjusted to include a certain minimum acceptable share of savings. Under a standard offer or clearing price auction approach (as noted in section 6.3 sub (a) and (b) below) the Supplier would also achieve a net overall benefit equal to the excess of the standard offer or clearing price over its threshold. Under a pay-as-bid implementation (possible under a sealed bid auction section 6.3 sub (c) below) the Supplier would receive only the savings share built into its bid price, and would thus likely increase its bid price above that which would apply in a clearing price auction.

Suppliers' threshold pricing for Blend & Extend would be at a price reflective of (a) the extension period market revenue expectation or Cost of Life Extension (whichever is higher), (b) blending existing price and extension period expectation at its cost of capital, (c) reduction to reflect the extension period risk being hedged, and (d) addition of transaction costs. The minimum benefit share included by a Supplier would likely depend on the implementation approach adopted by the IESO.

6.3. Primary Opportunities: Implementation Approaches

The starting point of implementation is the decision to select which opportunities to develop for each category of generation (e.g. Buyout for wind, Buydown for solar, Blend & Extend for gas) and which approach to adopt for each.

Whatever approach(es) is (are) selected, the IESO would need to provide for each facility certain information. This would probably need to include the energy and capacity price

21 This adds a certain degree of conservatism into the buyout analysis as market capacity revenue that subsequently becomes available to wind and solar projects could be viewed as a double payment with respect to the buyout price. This degree of conservatism, or potential savings understatement, is considered appropriate pending clarification of what capacity mechanisms can be assured to be available and recognizing the conservative approach likely to be taken by Suppliers to future price uncertainty.

projections that the IESO would be using to evaluate the offers received. In addition, for all wind and solar Suppliers, the IESO would probably need to provide to each Supplier the projections of annual production and paid curtailments on which the IESO would base its evaluation or determination of the Buyout amount. For gas-fired generators the IESO would probably need to provide projections of Imputed Net Revenue that it would assume to equal Suppliers actual net revenue.

Each Supplier would be able to make its own forecasts which would likely differ from the IESO's projections. Such differences could contribute to variation in Supplier perception of the value attached to any particular IESO price point, and thus to the variation in Supplier threshold pricing. Other differences in Supplier perspectives would also contribute to differences in Suppliers' transaction price thresholds, including: Cost of Capital; perceptions of risk; expected transaction costs; benefit thresholds to overcome comfort with status quo; differences amongst project stakeholders including equity partners and secured lenders; etc.

Four main approaches have been identified for illustration of the Buyout opportunity at this stage:

a. Standard offer approach to target a fixed rate of IESO savings per MW
b. Descending clock auction approach to target the most beneficial (to the IESO) "X" MW
c. Sealed bid auction approach to target the most beneficial "X" MW
d. Expression of Interest approach

Without prejudice to implementation decisions that may require to be made, the modeling is based on a default IESO standard offer approach for each primary opportunity.

6.4. Primary Opportunities: Category Modeling of Implementation

6.4.1. Modelling Framework and Suppliers' Threshold Pricing

For purposes of modeling, it is assumed that each Supplier will evaluate the IESO's standard offer, and that any transaction would proceed at a standard offer price that meets or exceeds the Supplier's threshold criteria. There is no additional sharing of Supplier costs. And there is no adjustment to reflect actual realized savings after that transaction is closed.

The Supplier's threshold is conceptually expressed as a transaction discount rate.

- For Buyout or Buydown, if the IESO's standard offer is at a higher price than (i.e. at an implicit discount rate below) the Supplier's threshold, the Supplier could transact.
- For Blend & Extend, if the IESO's standard offer is at an implicit discount rate higher than the Supplier's threshold, the Supplier could transact.

The conceptual framework for each primary opportunity transaction is as follows:

a) Buyout

Supplier's threshold transaction discount rate =

Weighted Average Cost of Capital

– adjustment to recover Supplier transaction costs over the bought-out term

– adjustment to recover any secured lender penalties

– adjustment to reflect market risk being assumed

– required benefit adjustment (i.e. incentive to transact)

b) Buydown

Supplier's threshold transaction discount rate =

Weighted Average Cost of Capital

– adjustment to recover Supplier transaction costs over the term

– adjustment to recover of any secured lender penalties

+ a small adjustment to reflect that the lower price reduces Suppliers exposure to operational risk

– required benefit adjustment (i.e. incentive to transact)

c) Blend & Extend

Supplier's threshold transaction discount rate =

Weighted Average Cost of Capital

+ adjustment to recover Supplier transaction costs over the extended term

+ adjustment to recover any secured lender penalties

– premium to reflect market risk being hedged

+ required benefit adjustment (i.e. incentive to transact)

6.4.2. Take-up rate Assumptions: Buyout and Buydown

Applying a notional distribution of cost of capital, and starting with the base case in which the IESO's standard offer is based on a 6% IESO price rate, we assume take-up rates among eligible projects[22] as follows:

Table 9 Independent Take-Up Rate Assumptions

	For Buyout (separately)	For Buydown (separately)
Balance sheet finance	12 %	26 %
Non-recourse finance	8 %	12 %

The above table sets out take-up rates for Buyout and Buydown if either one is selected by the IESO and Suppliers are not given an option to select between them. Take–up rates for Buyout are lower than for Buydown due to the inclusion of the adjustment to reflect market risk being assumed by the Supplier.

Specifically, a Buyout, if taken by the Supplier, would eliminate the Supplier's contract safeguards around future market revenue. Therefore, Buyout represents a higher risk to Suppliers, and would have a lower take-up than Buydown at the same IESO pricing rate. The

22 Eligibility for wind and solar Buyout and Buydown is assumed to be broad, without restriction as to remaining term. Gas-fired projects are not eligible for buyout, and those gas fired projects under acquisition by OPG are not treated as eligible for Buydown.

set of wind and solar Supplies modeled as taking up a Buyout option is a subset of those taking up a separate Buydown option. Therefore, these results cannot be added to each other.

The IESO could decide to offer a joint program in which each Supplier could take up either Buyout or Buydown. This is illustrated by considering the result if half of those who qualify for Buyout elect Buydown instead. This results in joint implementation take-up rates for wind and solar as follows:

Table 10 Joint Take-Up Rate Assumptions

	For Buyout (with option)	For Buydown (with option)
Balance sheet finance	6 %	20 %
Non-recourse finance	4 %	8 %

6.4.3. Take-up Rate Assumptions: Blend & Extend

Applying a notional distribution of cost of capital, and starting with the base case in which the IESO's standard offer is based on a 6% IESO pricing rate, we assume take-up rates among eligible projects[23] as follows:

Table 11 Blend and Extend Take-Up Rate Assumptions

	For eligible Blend & Extend contracts
Balance sheet finance	33 %
Non-recourse finance	18 %

6.4.4. Joint Take-Up

There is no opportunity to combine a contract Buyout (by which the contract is terminated) with Buydown or with Blend & Extend (which requires the persistence of the contract).

There is technically an opportunity to combine a Blend & Extend transaction and a Buydown transaction. This is, however, unlikely to enhance the real savings opportunity, as the Blend & Extend transaction is designed to appeal to Suppliers with low cost of capital, and the Buydown is designed to appeal to those with high cost of capital. Also, once a contract had been bought down to the floor price dictated by market price expectations, there would not be room for additional savings from price blending. This type of joint take-up is therefore not analyzed.

23 All contracts with remaining term exceeding 15 years from Jan 1, 2021 are treated as ineligible for blend & extend. Gas fired contracts with current pricing too low to achieve material reduction from the blending process are also treated as ineligible.

7. Base Case Results by Contract Category

This section of the report sets out the framework for aggregating the portfolio of contracts in each category for each applicable opportunity, as summarized in the chart below:

Table 12 Primary Opportunities Contracts Overview

Category	Size	Options		
		Buyout	Buydown	Blend & Extend
Wind *Large transmission-connected facilities, 19 MW to 300 MW*	**45 Contracts** **4,543 MW** (82.1% of total wind) **$ 1,696 M / yr total cost (2021)**	**Yes**	**Yes**	**Some** *Contracts with term past 2035 not considered eligible*
Solar *Large transmission-connected facilities 10 MW to 100 MW* *Potential to consider larger portfolios of smaller contracts*	**15 Contracts** **778 MW** (32.23% of total solar) **$ 413 M / yr total cost (2021)**	**Yes**	**Yes**	**Some** *Contracts with term past 2035 not considered eligible*
Gas *Excludes Ontario Power Generation's 2,000 MW gas / oil fired Lennox facility (close to the end of contract term) and all distribution-connected facilities*	**13 Contracts** **6,620 MW** (89.62% of total gas) **$ 1,095 M / yr total cost (2021)**	**No** *Would create a threat to system adequacy*	**Some** *Others have present price below our buydown floor or have term past 2035*	**Some** *Others have low present price that would be increased by blending or have term past 2035*

For each contract, for each year, the model determines the change in total cost to the IESO that would arise by implementing the relevant opportunity before (gross) and after (net) accounting for amortization of the debt that may be incurred to fund the Buyout or Buydown. Each contract is assigned a base case take-up rate that represents a probability that an IESO standard offer for that particular opportunity would be taken up by the Supplier[24]. Ineligible contracts are excluded or assigned a zero take-up rate. The annual results for each category are aggregated to show the category impact, and the present value of those annual category savings is calculated using each of three social discount rates. The base case result for each parameter is thus a single point value at each social discount rate for each of gross and net savings around which the appropriate range is developed, as discussed in later sections.

7.1. Buyout and Buydown for Wind and Solar

In considering Buyout or Buydown transactions, it is expected that the IESO could choose to make lump sum payment offers on a higher basis or lower basis. Higher basis offers would allocate a greater share of the savings to Suppliers, leading to a higher take-up rate. The

24 Take-up is based solely on the transaction proposed, the pricing of the opportunity, and whether each contract has activated the secured lender provisions applicable to non-recourse financing. There is no assessment or judgment of individual Suppliers or contracts.

IESO's total funding requirement would increase slightly more than in proportion to the MW take-up in each category, but the IESO's net savings per MW taken up would be reduced. The IESO's transaction costs would also increase with increased take-up. Increased take-up has diminishing returns, particularly in relation to capital employed. All the uncertainties and the need to balance total benefits and the efficient use of capital employed would render any attempt to fine tune the pricing redundant. CRA has however selected a base case that appears to achieve a reasonable balance between maximizing total IESO net savings and the efficient use of capital employed.

Results for the various opportunities base case are summarized in the following tables:

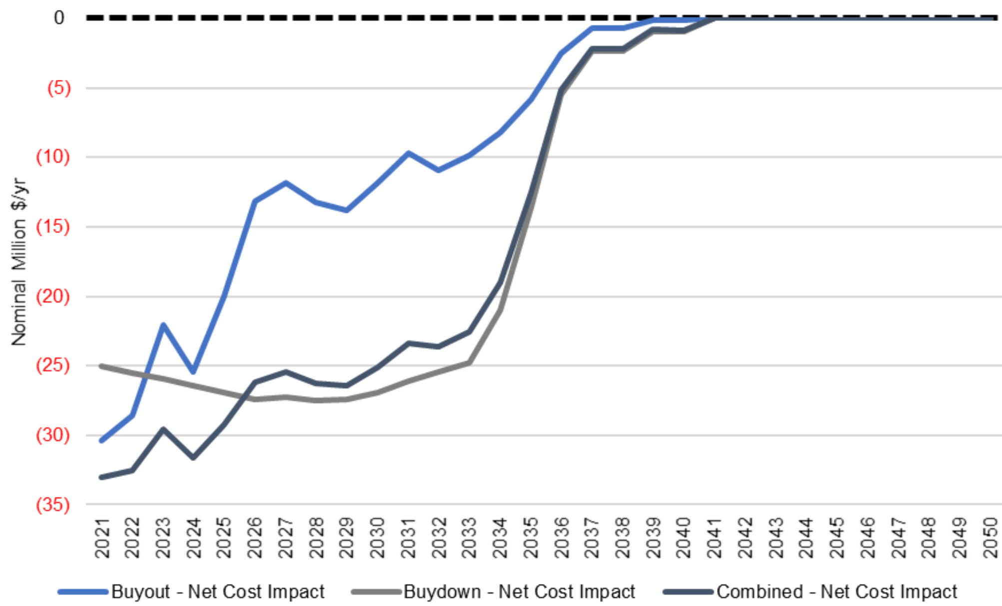
Table 13 Summary of Base Case Results for Large Wind Contracts

Base Case Large Wind Generation		Buyout	Buydown	Combined
Take-Up MW	MW	421	745	745
Take-Up MW as %	%	9%	16%	16%
Initial Debt	$ million	1,156	1,447	1,612
Gross Yr 1 Savings (1)	$ million	139	160	184
Net Yr 1 Savings (1)	$ million	30	25	33
NPV Gross Savings @ Various Social Discount Rates	3%	$1,356	$1,757	$1,934
	6%	$1,126	$1,447	$1,597
	9%	$952	$1,214	$1,344
NPV Net Savings @ Various Social Discount Rates	3%	$200	$310	$322
	6%	$171	$253	$266
	9%	$148	$210	$224

(1) Gross & net savings are all both stated before IESO program and transaction costs; NPVs are derived based on each of the stated Social Discount Rates and are provided in the table above in 2021$ million. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Net impact on total consumer costs for large wind projects are:

Figure 12 Base Case Net Cost Impacts for Large Wind Contracts Buyout and Buydown



Note that savings are represented in this and subsequent charts as negative cost impacts.

In reviewing these results, it is notable that:

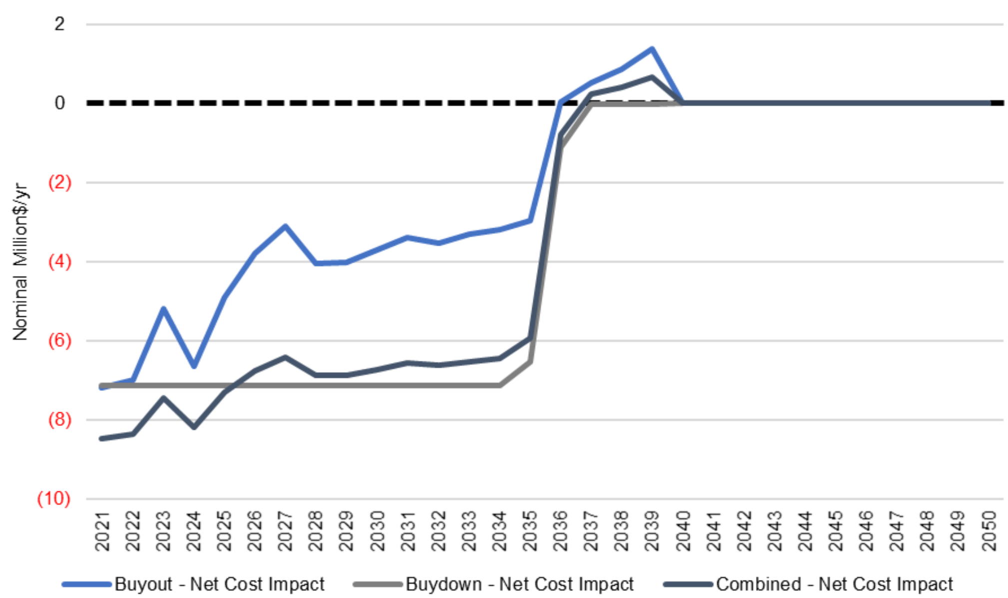
- Buyout savings are eroded over time by expected market price escalation, and so are less sustained than Buydown savings. Buyout savings thus have a higher year 1 value per $ of debt, but a lower full life value (NPV).
- Buyout has greater uncertainty than Buydown due to the uncertainties about perceived risk transfer associated with this transaction.
- The combined approach offers small gains over the Buydown approach and could add significant complexity.

Table 14 Summary of Base Case Results for Large Solar Contracts

Base Case Large Solar Generation		Buyout	Buydown	Combined
Take-Up MW	MW	66	108	108
Take-Up MW as %	%	9%	14%	14%
Initial Debt	$ million	315	372	411
Gross Yr 1 Savings (1)	$ million	33	38	42
Net Yr 1 Savings (1)	$ million	7	7	8
NPV Gross Savings @ Various Social Discount Rates	3%	$368	$457	$496
	6%	$300	$372	$403
	9%	$249	$308	$335
NPV Net Savings @ Various Social Discount Rates	3%	$53	$86	$85
	6%	$45	$70	$70
	9%	$39	$58	$59

(1) Gross & net savings are all both stated before IESO program and transaction costs; NPVs are derived based on each of the stated Social Discount Rates and are provided in the table above in 2021$ million. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Figure 13 Base Case Net Cost Impacts of Solar Contracts Buyout and Buydown



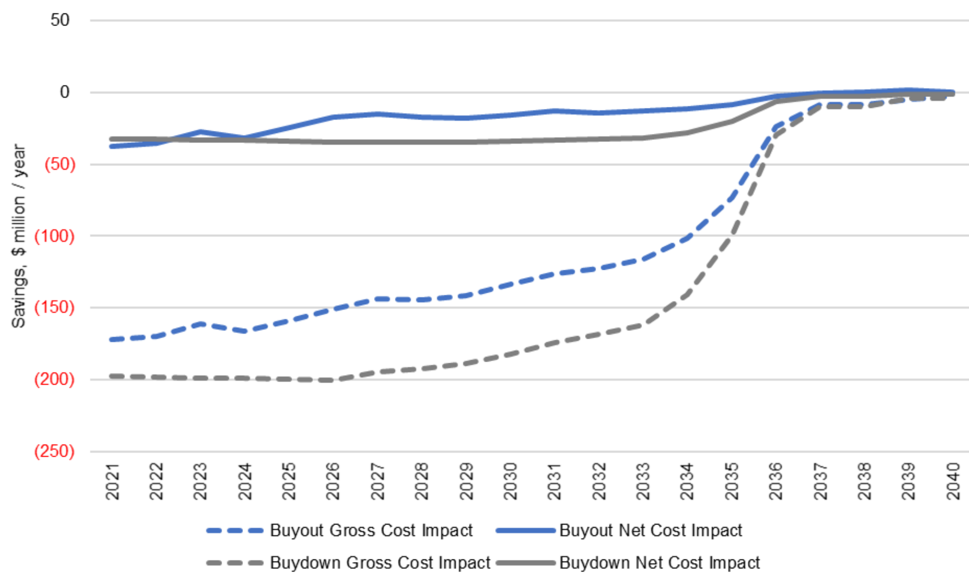
The results for solar generation are broadly similar to for wind. Differences arise from:

- The higher contract price for solar generation relative to market price, which tends to allow a greater Buydown %
- The commercial operations dates and contract term dates for the solar fleet are generally later than for most of the wind fleet, which correspondingly extends the amortization period for IESO debt.

- Solar contract prices are not subject to any price escalation, which tends to level the nominal value of savings during contract term.

The phasing of gross and net savings over the next 20 years is shown for wind and solar combined on the following chart for each of Buyout and Buydown:

Figure 14 Wind and Solar Contract Gross and Net Cost Impact



7.2. Buydown for Gas-Fired Generation

Results for gas-fired generation are summarized in the following table:

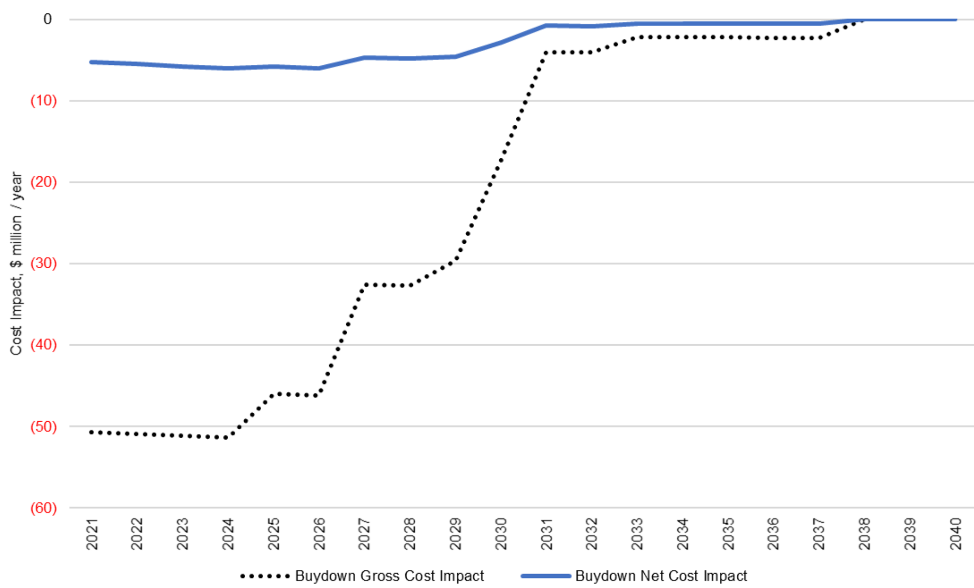
Table 15 Summary of Base Case Results for Major Gas-Fired Contracts

Base Case Gas-fired Generation		Buyout	Buydown	Combined
Take-Up MW	MW	N/A	869	N/A
Take-Up MW as %	%	N/A	13%	N/A
Initial Debt	$ million	N/A	322	N/A
Gross Yr 1 Savings	$ million	N/A	51	N/A
Net Yr 1 Savings	$ million	N/A	5	N/A
NPV Gross Savings @ Various Discount Rates	3%	N/A	$368	N/A
	6%	N/A	$322	N/A
	9%	N/A	$284	N/A
NPV Net Savings @ Various Discount Rates	3%	N/A	$47	N/A
	6%	N/A	$40	N/A
	9%	N/A	$35	N/A

Note: NPVs are derived based on each of the stated Social Discount Rates and are provided in the table above in 2021$ million. Gross savings represent the total reduction in the IESO's *contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.*

The phasing of gross and net savings over the next 20 years is shown for gas-fired contracts on the following chart for Buydown:

Figure 15 Base Case Net Cost Impacts for Buydown of Gas-Fired Contracts



Results are broadly equivalent to those for wind and solar Buydown, recognizing the differences between the energy basis of those contracts and the capacity basis of the gas-fired contracts.

7.3. Blend & Extend for Wind, Solar and Gas-Fired

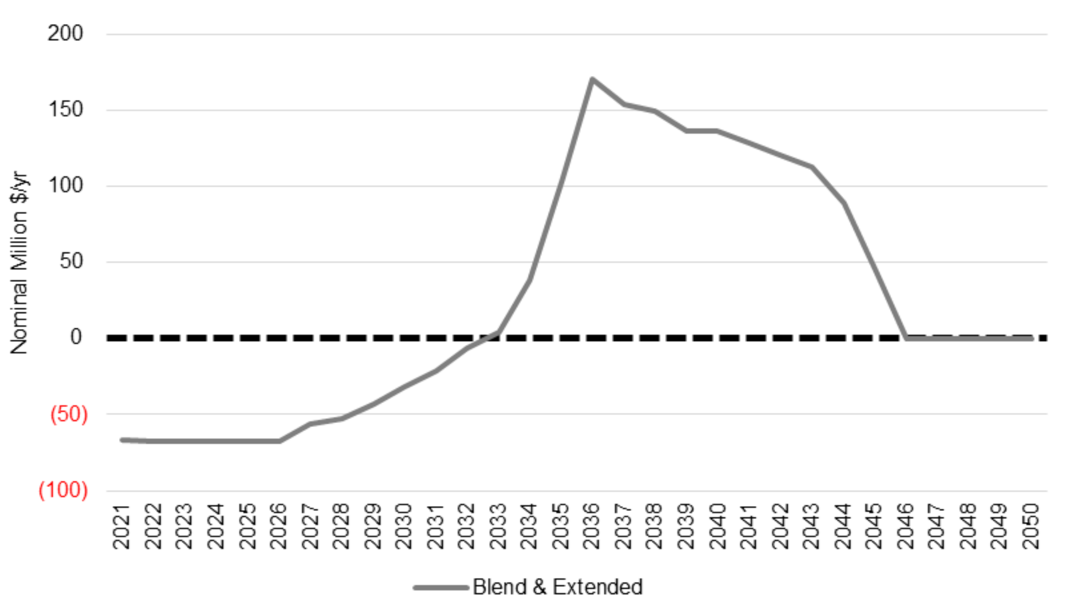
Results for large wind generation are summarized in the following table:

Table 16 Summary of Base Case Results for Large Wind Contracts

Base Case Large Wind Generation		Blend & Extend
Take-Up MW	MW	910
Take-Up MW as %	%	20%
Initial Debt	$ million	N/A
Gross Yr 1 Savings	$ million	N/A
Net Yr 1 Savings	$ million	67
NPV Gross Savings @ Various Social Discount Rates	3%	N/A
	6%	N/A
	9%	N/A
NPV Net Savings @ Various Social Discount Rates	4%	($260)
	6%	($0)
	8%	$130

Note: NPVs are derived based on each of the stated Social Discount Rates and are provided in the table above in 2021$ million. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Figure 16 Base Case Net Cost Impacts for Blend & Extend of Major Wind Contracts



The Supplier's cost of capital is recognized in equalizing the present value of the blended price with that of the separate current and extension prices. The nominal cost increase in the extension period is thus significantly higher than the nominal savings within the contract term. This is evident on visual examination of the above chart: the enclosed area above the X axis post 2033 is clearly larger than the enclosed area below the X axis pre 2033. In the base case, at a 6% social discount rate, these effects offset each other to yield 0 net present value.

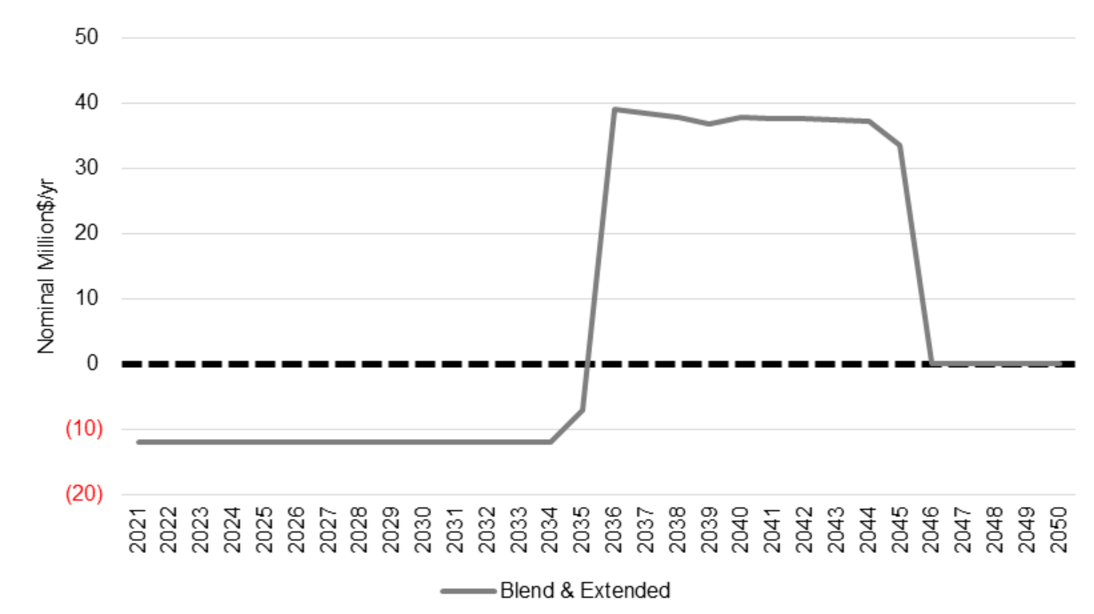
Results for large solar generation are summarized in the following table:

Table 17 Summary of Base Case Results for Large Solar Contracts

Base Case Large Solar Generation		Blend & Extend
Take-Up MW	MW	52
Take-Up MW as %	%	7%
Initial Debt	$ million	N/A
Gross Yr 1 Savings	$ million	N/A
Net Yr 1 Savings	$ million	12
NPV Gross Savings @ Various Social Discount Rates	3%	N/A
	6%	N/A
	9%	N/A
NPV Net Savings @ Various Social Discount Rates	3%	($64)
	6%	$0
	9%	$30

Note: NPVs are derived based on each of the stated Social Discount Rates and are provided in the table above in 2021$ million. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Figure 17 Base Case Net Cost Impacts of Blend & Extend for Large Solar Contracts



Results for solar generation differ from those for wind generation due to the grouping of commercial operation dates in the period 2014 to 2015, compared with the diversity of wind projects commercial operation dates over a longer period.

The NPV of Blend & Extend is zero when the discount rate assumed for IESO pricing equals the social discount rate, is negative at lower social discount rate and positive at higher social discount rate.

Results for gas-fired generation are summarized in the following table:

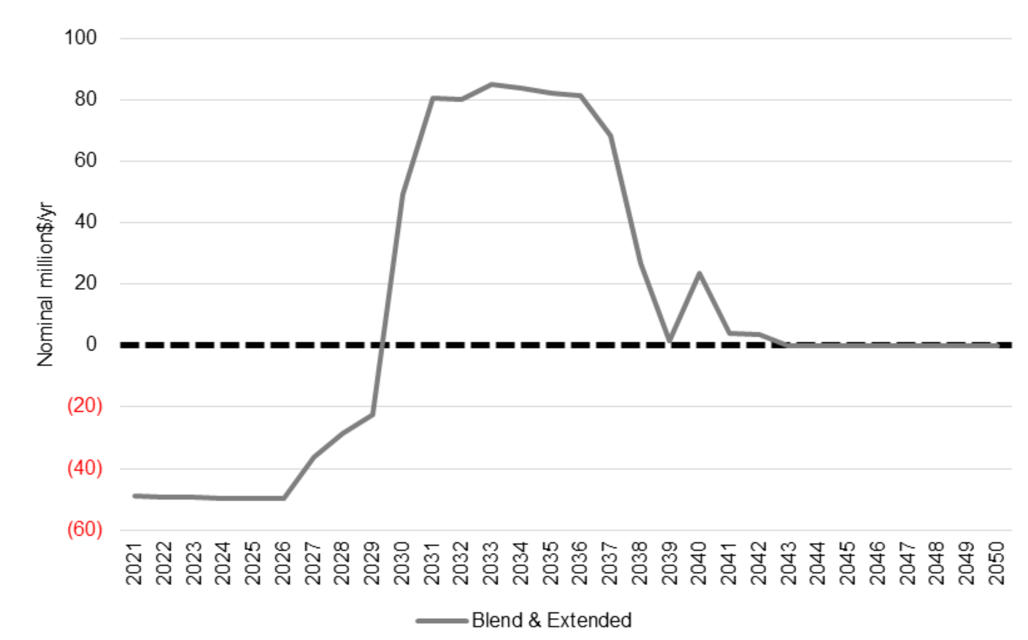
Table 18 Summary of Base Case Results for Gas-Fired Contracts

Base Case Gas-Fired Generation		Blend & Extend
Take-Up MW	MW	1606
Take-Up MW as %	%	24%
Initial Debt	$ million	N/A
Gross Yr 1 Savings	$ million	N/A
Net Yr 1 Savings	$ million	49
NPV Gross Savings @ Various Social Discount Rates	3%	N/A
	6%	N/A
	9%	N/A
NPV Net Savings @ Various Social Discount Rates	3%	($105)
	6%	$1
	9%	$63

Note: NPVs are derived based on each of the stated Social Discount Rates and are provided in the table above in 2021$ million. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Results over time are shown in the following chart.

Figure 18 Base Case Net Cost Impacts for Blend & Extend of Gas-Fired Contracts



8. Sensitivity Cases and Range of Results

This section contains a brief description of each of the sensitivity cases analyzed and a description of the results. The report addresses the opportunities under the following main headings:

- Buyout and Buydown of wind and solar,
- Buydown for gas-fired, and
- Blend & Extend for wind, solar and gas-fired.

8.1. Buyout & Buydown for Wind and Solar

8.1.1. Sensitivity to IESO Pricing Approach

As noted in section 6, CRA has tested the case in which the IESO elects to use a lower pricing discount rate to determine Buyout or Buydown price, resulting in higher offer price and a higher expected take-up. This also results in a lower rate of saving per MW. CRA has also tested the case in which the IESO elects to use a higher pricing discount rate, resulting in a lower offer price and a lower take-up rate, which also results in a higher rate of saving per MW. These cases tested and validated the selection of the base case IESO pricing rate.

As expected, the reduction of the IESO pricing rate increases the IESO's offer prices and thus increases the funding requirements per MW taken up. Take-up is also increased, further increasing the total funding requirement. Net savings per MW are reduced: for Buydown, this reduction is broadly in proportion to the reduced spread between IESO pricing rate and IESO debt interest rate; for Buyout it is steeper. For both transactions, the accounting of IESO program and transaction costs would tend to amplify the rate of benefit reduction per MW taken up. While total net savings increase as the IESO's pricing rate is reduced, the incremental gain shows significantly diminishing returns on the funding required. Preliminary testing indicated that further reductions in the IESO pricing rate would yield reductions in the total value of net savings even before recognizing IESO program and transaction costs.

All of these effects are reversed in the opposite case of increased IESO pricing rate. But as the take-up rates reduce further, the loss of take-up outweighs the improvements in benefit per unit of funding required.

Eventual selection of pricing policy for any program of Buyout or Buydown will require careful weighing of the benefits against the funding requirement and the IESO program and transaction costs, all in the light of prioritized policy objectives. Pending such further analysis, and without prejudice to its outcome, CRA considers that these sensitivity case results reasonably validate the use of 6% as the base case IESO pricing rate.

8.1.2. Sensitivity to IESO Debt Funding Cost

There is a risk that the IESO's debt funding costs will be higher than the base case modeled 3.0%. It is also possible that program and IESO transaction costs could be added to program debt funding and increase the total cost of its amortization. These possibilities are tested by considering an increase in the interest assumed in the amortization of Buyout or Buydown debt to 3.5%.

When the IESO's debt funding costs are increased by 0.5%, both Buyout and Buydown approaches for wind and solar showed less benefits. NPVs of net savings of Buyout reduced by around 20%, while NPVs of net savings of Buydown reduced by around 16%.

CRA also tested higher IESO's debt funding costs in conjunction with sensitivity to IESO's pricing approach. The diminishing returns on increased funding and per MW became more pronounced.

8.1.3. Uncertainty of Take-Up Rates

There is considerable uncertainty in the estimation of take-up rates at any given IESO offer price. Sensitivity cases are therefore considered at +/- 50% of the base case take-up rate. Results vary in direct proportion to the take-up rates over this range. Program costs would likely be unaffected by actual take-up; only IESO transaction costs would vary with take-up.

8.1.4. Changes in Forecast Market Costs

Cases are considered in which forecasts used as a basis for the IESO's offers and for transactions are different from the present Annual Planning Outlook projections.

Sensitivity cases considered included +/- 33% of the base case Annual Planning Outlook projections for energy and capacity. Directionally, a reduction in the planning outlook prices led to greater realizable benefits in both Buyout and Buydown case, and vice versa. In the Buyout case, reducing forecast prices increases the Suppliers' foregone revenue streams and the IESO savings. In the Buydown case, the reduction reduces the Buydown floor price, enabling greater Buydown.

When CRA reduced the base case Annual Planning Outlook prices by 33%, the amount of borrowing requirements increased by around 6% and 22% in the Buyout and Buydown case respectively for wind and solar. NPVs of net savings increased by some 14% and 22% in the Buyout and Buydown case respectively for wind and solar.

8.1.5. Variation in Actual Market Price Outcomes

Cases are considered in which actual price outcomes differ from the projections on which transactions are based. Buyout is transacted on the basis of the Annual Planning Outlook price projections, but market price outcomes are either higher or lower than those price projections by the same % every year; i.e. this is modeled as a single % step change and not as a steady divergence. Increases in actual price outcomes result in reduced IESO savings and increased Supplier benefit of the transaction. Reductions in actual price outcomes result in increased IESO savings and reduced Supplier benefit of the transaction. Some version of this difference is therefore likely to be considered by any Supplier seeking to establish a threshold price and risk profile for a Buyout transaction. Results from this analysis are reasonably aligned with assumptions built into the take-up vs pricing model used in the overall analysis.

For Buydown, the post-transaction price changes can have no impact on savings outcomes. The only input from price projections into the Buydown model is in fixing the Buydown floor. Once the transaction is complete, this cannot change.

8.1.6. Buyout Capacity Treatment

In this case, applicable to wind and solar Buyout only, the somewhat conservative treatment of capacity revenue identified in section 6.3 (c) and footnote 21 is reversed to reflect a hypothetical and optimistic assumption that expected capacity revenue stream would be fully recognized by Suppliers in evaluating their Buyout option.

The gross savings are unchanged, and the Buyout funding requirement is reduced. Debt amortization is therefore reduced, so net savings are increased. Even in the most optimistic case, results remain within the range of most likely outcomes arising from other sensitivity considerations.

8.1.7. Test of Extended Amortization

Finally, there is a case to test the impact on net savings of extending the Buyout or Buydown debt amortization period for 10 years past the term date of each contract, so that additional in-term savings are offset by post-term cost increases. This option is shown in the following charts (revised from those in Section 7 for the Buyout and Buydown transactions.

Extending the amortization period of initial borrowing would not impose any change in the gross savings pattern. Due to reduced annual debt obligations, this option shows significantly larger net savings for the remaining term of the original contract. Total consumer costs are increased for the 10-year extension of the debt amortization. The NPV of net savings increases as the debt repayments are deferred at the IESO's 3% interest rate, and then discounted to present value at the higher 6% social discount rate.

Example wind contract Buyout:

Figure 19 Extended Debt Amortization for Wind Contract Buyout Example

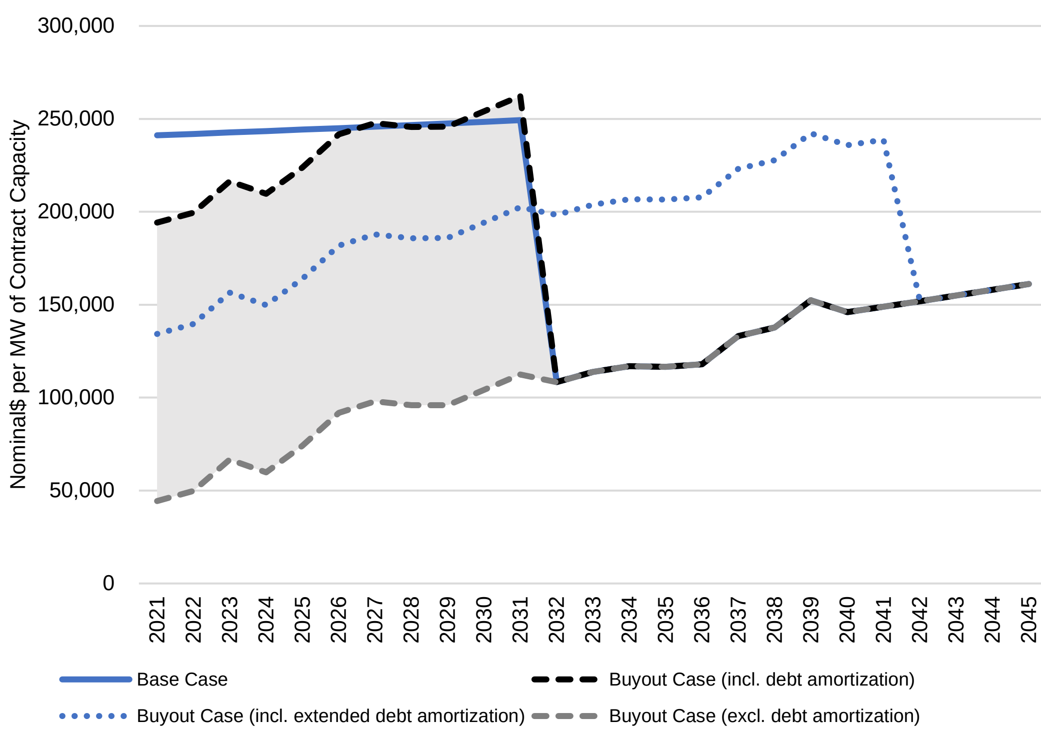
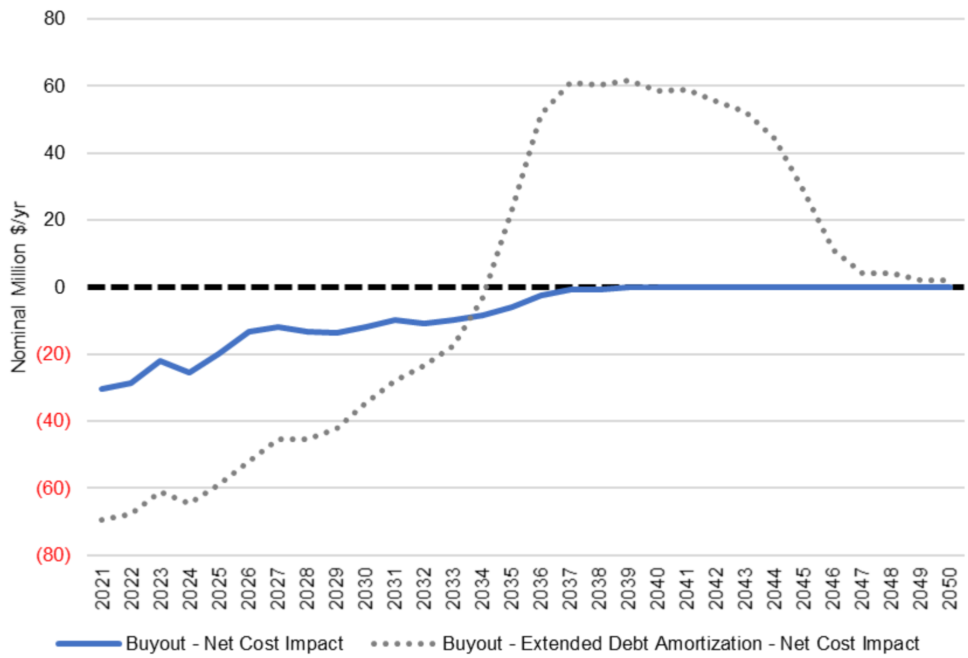


Figure 20 Net Annual Impact on Consumer Costs of Extended Debt Amortization for Buyout of Large Wind Generation Contracts



Example wind contract Buydown:

Figure 21 Extended Debt Amortization for Wind Contract Buydown Example

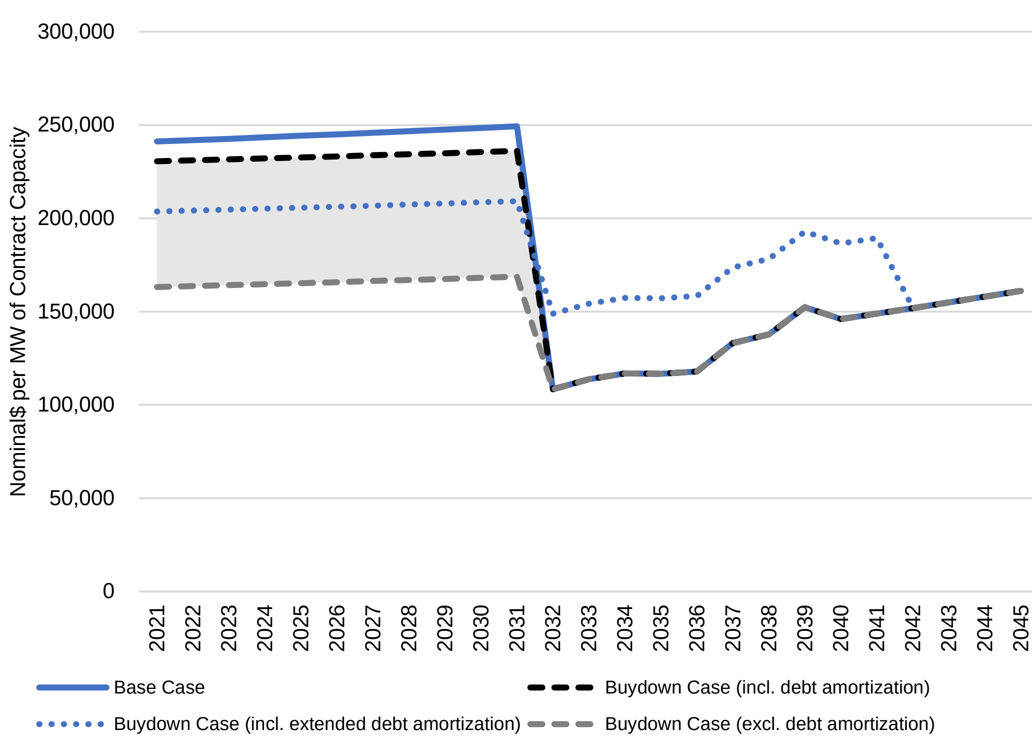
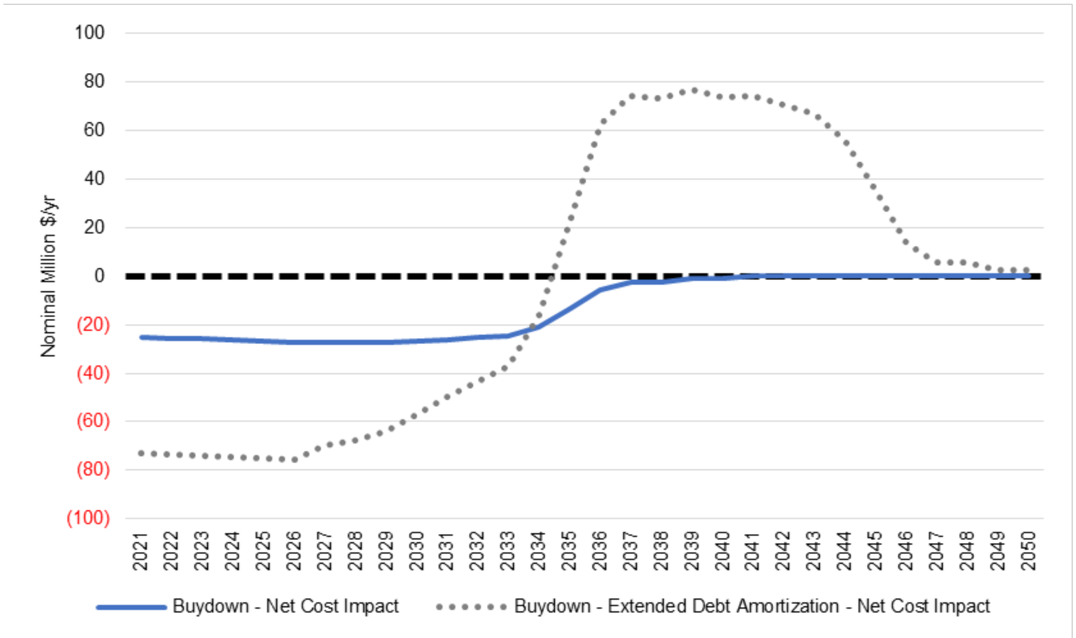


Figure 22 Net Annual Impact on Consumer Costs of Extended Debt Amortization for Buydown of Large Wind Generation Contracts



8.2. Buydown for Gas Fired Resources

8.2.1. Sensitivity to IESO Pricing Approach

Please refer to the description in section 8.1.1 above. For gas-fired generation contracts, the impacts were similar to those for wind and solar.

8.2.2. Sensitivity to IESO Debt Funding Cost

Please refer to the description in section 8.1.2 above. Gas-fired contracts experienced similar impacts under the same sensitivities.

8.2.3. Uncertainty of Take-Up Rates

Please refer to the description in section 8.1.3 above. Results were equivalent.

8.2.4. Changes in Forecast Market Costs

Please refer to description in section 8.1.4 above. Due to a different construct in estimating potential savings from gas-fired contracts, results of the - 33% sensitivity of the base case Annual Planning Outlook projections did not have equivalent impact on potential net savings. In the case of 33% increase in the Annual Planning Outlook projections, there was a reduction in extent of Buydown possible, and consequent reductions in gross savings, funding requirement and net savings.

8.2.5. Variation in Actual Market Price Outcomes

Please refer to the description in section 8.1.5 above.

8.2.6. Buyout Capacity Treatment

Not applicable (Buyout not considered for gas-fired generation contracts.)

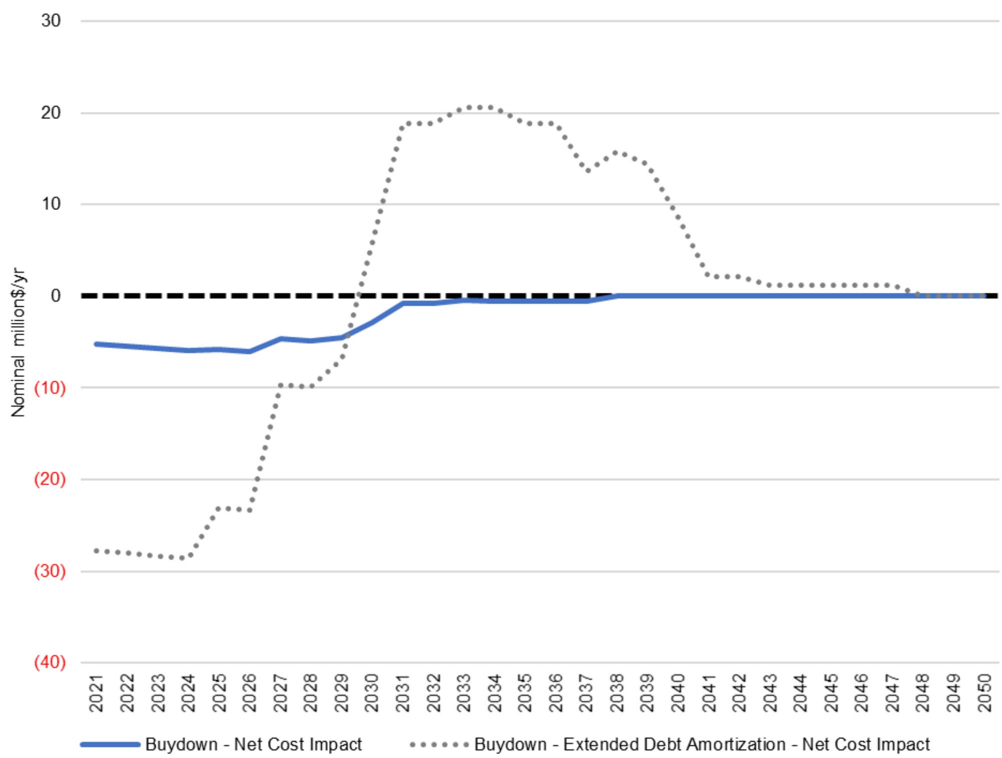
8.2.7. Test of Extended Amortization

Please refer to the description in section 8.1.7 above. Results are similar.

Extending amortization period of initial borrowing would not impose any change in gross savings pattern. Due to reduced annual debt obligations, this option shows significantly larger net savings through expiry of the original contract. The NPV of net savings increases as the debt repayments are deferred at 3% interest, and then discounted to present value at the higher 6% social discount rate.

Results for the aggregation of gas-fired contract Buydowns are summarized in the following figure:

Figure 23 Net Annual Impact on Consumer Costs of extended amortization for Buydown of Gas-fired Generation Contracts



8.3. Blend & Extend for Wind, Solar and Gas-Fired

8.3.1. Sensitivity to IESO Pricing Approach

Please refer to the description in section 8.1.1 above. It should be noted that the direction of sensitivity for Blend & Extend is the reverse to that for Buyout and Buydown. A higher IESO pricing rate to establish the Blend & Extend pricing would increase the effective offer price and increase take-up.

- Expected take-up MW and year 1 net savings increase or decrease in direct proportion to the change in take-up rates
- NPVs would increase in response to lower IESO pricing rate, and vice versa

8.3.2. Sensitivity to IESO Debt Funding Cost

This is not applicable to Blend & Extend.

8.3.3. Uncertainty of Take-Up Rates

Please refer to the description in section 8.1.3 above. Impacts are in direct proportion to the take-up.

8.3.4. Changes in Forecast Market Costs

Please refer to the description in section 8.1.4 above.

- Changes in year 1 savings (and proportionate later cost increases)
- Over the course of study period 2021-2050, sensitivity cases around forecast market costs did not have a material impact on NPVs of net savings for wind, solar and gas-fired contracts at 6% social discount rate.

8.3.5. Variation in Actual Market Price Outcomes

Please refer to the description in section 8.1.5 above.

This sensitivity considers the impacts of unforeseen market price changes in the contract extension period, i.e. post-contract term. For the renewable projects which are largely dependent on energy price, such uncertainty carries lower risk than gas fired generation which are more strongly affected by capacity price.

8.3.6. Buyout Capacity Treatment

This is not applicable to Blend & Extend.

8.3.7. Test of Extended Amortization

This is not applicable to Blend & Extend.

8.4. Comparison of Base Case with Various Take-Up Rates

The IESO has requested that CRA analyze a sensitivity case using CRA base case parameters but with take-up assumed at various levels up to 100% under three different social discount rates. The following charts provide the NPV results for both Buyout and Buydown when the take-up rates are increased to 100% for the applicable wind and solar projects under the 6% social discount rate only. All other assumptions remain constant at the levels used for CRA's base case.

Figure 24 Base Case vs Various Take-Up Rates Comparison for Wind and Solar Buyout

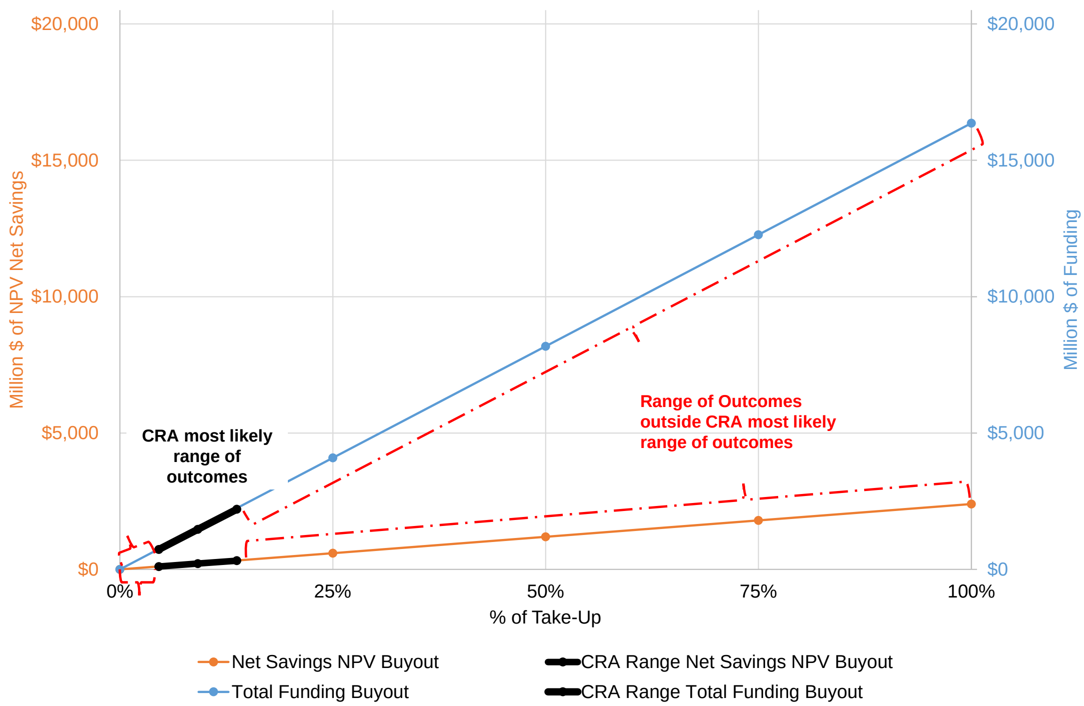
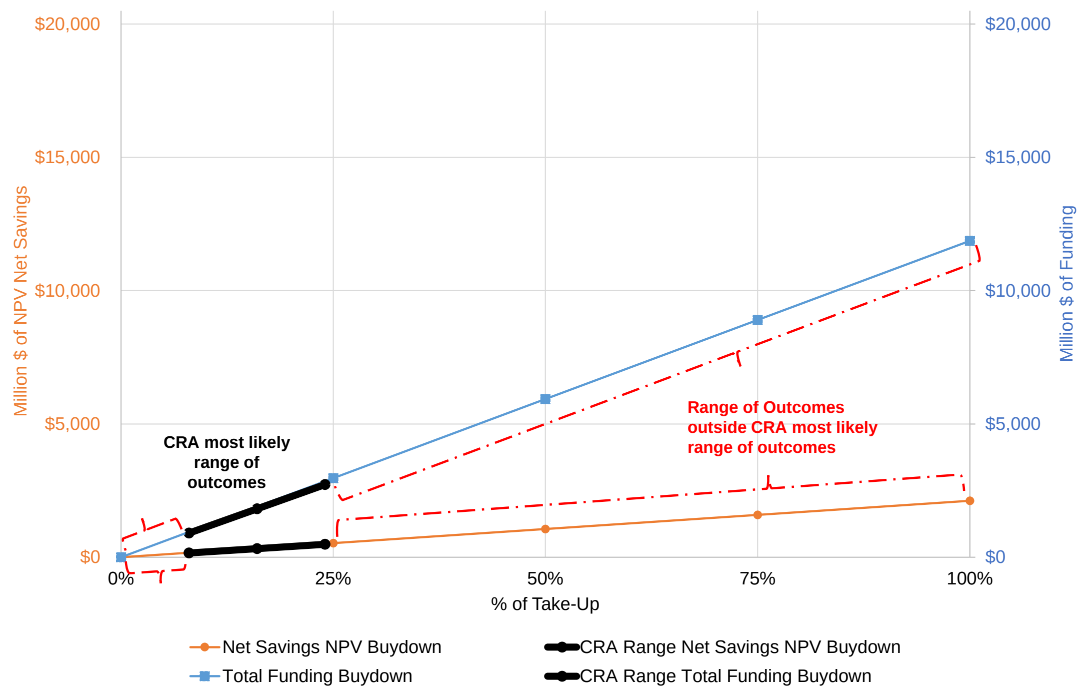


Figure 25 Base Case vs Various Take-Up Rates Comparison for Wind and Solar Buydown



The tables below depict the requested analysis for all three social discount rates.

Table 19 CRA Base Case vs Various Take-Up Rates Comparison for Wind and Solar Buyout

Take-up Rates	Total Funding 2021$ billion			Gross Savings NPV 2021$ billion			Net Savings NPV 2021$ billion		
	3%	6%	9%	3%	6%	9%	3%	6%	9%
0%	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
CRA Lower Bound - 5%	$0.7	$0.7	$0.7	$0.9	$0.7	$0.6	$0.1	$0.1	$0.1
CRA Base Case - 9%	$1.5	$1.5	$1.5	$1.7	$1.4	$1.2	$0.3	$0.2	$0.2
CRA - Upper Bound - 14%	$2.2	$2.2	$2.2	$2.6	$2.1	$1.8	$0.4	$0.3	$0.3
25%	$4.1	$4.1	$4.1	$4.8	$4.0	$3.3	$0.7	$0.6	$0.5
50%	$8.2	$8.2	$8.2	$9.6	$7.9	$6.7	$1.4	$1.2	$1.0
75%	$12.3	$12.3	$12.3	$14.4	$11.9	$10.0	$2.1	$1.8	$1.6
100%	$16.4	$16.4	$16.4	$19.2	$15.8	$13.3	$2.8	$2.4	$2.1

Note: NPVs in table above are derived using various social discount rates at 3%, 6% and 9%. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

Table 20 CRA Base Case vs Various Take-Up Rates Comparison for Wind and Solar Buydown

Take-up Rates	Total Funding 2021$ billion			Gross Savings NPV 2021$ billion			Net Savings NPV 2021$ billion		
	3%	6%	9%	3%	6%	9%	3%	6%	9%
0%	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
CRA Lower Bound - 8%	$0.9	$0.9	$0.9	$1.1	$0.9	$0.8	$0.2	$0.2	$0.1
CRA Base Case - 16%	$1.8	$1.8	$1.8	$2.2	$1.8	$1.5	$0.4	$0.3	$0.3
CRA Upper Bound - 24%	$2.7	$2.7	$2.7	$3.3	$2.7	$2.3	$0.6	$0.5	$0.4
25%	$3.0	$3.0	$3.0	$3.6	$3.0	$2.5	$0.6	$0.5	$0.4
50%	$5.9	$5.9	$5.9	$7.2	$5.9	$5.0	$1.3	$1.1	$0.9
75%	$8.9	$8.9	$8.9	$10.9	$8.9	$7.4	$1.9	$1.6	$1.3
100%	$11.9	$11.9	$11.9	$14.5	$11.9	$9.9	$2.6	$2.1	$1.8

Note: NPVs in table above are derived using various social discount rates at 3%, 6% and 9%. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost.

9. Secondary Opportunities

9.1. Extend Primary Opportunities to Slightly Smaller Contracts

This review has not flagged any beneficial opportunities that are unique to distribution-connected contracts.

There is some potential that a Buyout or Buydown program that has been proven through large project implementation could be extended to distribution-connected projects over a certain threshold, say 5 MW. As noted in section 2.4, there are 228 contracts for a total of 2461 MW that meet this threshold, mostly wind, solar and gas-fired but including some hydroelectric and biomass projects. This represents a reasonable scale, being some 20% of the total large contract capacity analyzed above, and a higher proportion within that of renewable generation. Take-up rates for Buyout would likely be minimal in view of the risk transfer and the Suppliers' incremental costs in managing market risk. For Buydown CRA would expect take-up to lower than for major projects, and program / transaction costs per MW significantly higher. It may be possible to design an extension of any large project Buydown program to include at least the larger of the distribution-connected renewable generation contracts, and those held as a portfolio by single owners. The savings from large renewable contract Buydown might thus be amplified by 0% to 20% before IESO program and transaction costs. Any such smaller contract program would likely need to lag a year behind any equivalent large contract program.

9.2. Opportunities that Arise Beyond the Electricity Sector

Renewable Energy Credits ("REC"s) are instruments recognized in some jurisdictions to provide a market-based price premium to energy from qualifying renewable resources. There is an existing market for such instruments in New York; RECs can be sold in conjunction with the underlying energy from an identified renewable generating station that was placed in service after 2015. The opportunity is limited by several factors:

- Size (demand) of the NY market and price sensitivity to any increasing supply
- Transmission costs and constraints, as well as energy price risks, associated with the export of electricity, tagged as from a particular generator, from Ontario to relevant zones in NY State
- Overhead costs associated with such trading
- Benefit sharing between Supplier and the IESO

The IESO reports that it has commenced a pilot project with one generator to test viability of such trading. This opportunity seems conducive to development by pilot and evolution rather than strategic initiative.

9.3. Special Opportunities

None of the contract-specific opportunities identified offered any material savings opportunity.

10. Overview and Commentary

10.1. Risks

It is appropriate for an assessment as this to provide an overview of the potential risks related to the transactions analyzed.

10.1.1. Reliability Risks

Reliability risk has been considered in this review, but detailed reliability analysis is beyond scope. Buyout of gas-fired generation contracts is excluded in order to avoid the apparent reliability risk that it might impose. The transactions that are analyzed are not identified as imposing any reliability risk. Reliability risk should be subject to appropriate full technical review by the IESO within any implementation process.

10.1.2. Planning Risks

Planning risk is an issue that needs to be addressed for any Blend & Extend program. Such a program could extend contract commitments for energy and capacity within the years 2029 to 2045. Planning uncertainties increase over this period. There is a potential that alternative supply costs will increase and that these commitments will prove to have saved more than presently expected. But there is also a risk that long-term commitments made now for the latter years of the IESO's Annual Planning Outlook and beyond, will reduce flexibility of response to changing circumstances, particularly if demand reduces below present expectations or if technology advances to provide less costly supply. Such risk would increase as Blend & Extend take-up rates increase and economic retirement opportunities are deferred.

10.1.3. Financial Risks

The financial risks are comprised of two aspects: (i) market price and (ii) financing costs. The analysis utilized market prices from APO's most probable scenario Even though this market outlook is considered the most probable, there is a significant uncertainty on whether it will be realized. Furthermore, there is a risk of Supplier's not adopting the IESO's market price forecast further complicating the negotiations of applying each of the opportunities. CRA expects – especially for projects financed through non-recourse financing – the Suppliers to provide their own outlook of market prices to eventually be compared with the IESO's.

Financing cost risk must be considered for both Suppliers and the IESO. Even though current market conditions appear stable the assumption that these opportunities – if considered – will be in place by 2021 add a considerable timing risk to the debt financing component of the established program. Macro and geopolitical risks that affect both the risk-free rate and the market premium may be altered significantly if the Province or Canada enters into a more unstable market condition. As an example, increased investment risk may result in increased cost of debt that will reduce any realized benefits from the primary opportunities all else being equal.

10.2. Uncertainties of Results

CRA's analysis has considered a significant range of sensitivities to assess directionality of costs and benefits in order to establish a likely range of outcomes. One of the major drivers of outcome is the take-up rate and its relationship to IESO offer pricing as embodied in the IESO pricing rate. In practice, each Supplier has a unique set of parameters to address in order to arrive at a threshold transaction price, including:

- Cost of capital and of distribution around that
- Supplier risk transfer premium / discount
- Minimum benefit sharing requirement
- Non-recourse lender impact on transaction pricing and / or take-up
- Potential for market power perceptions to influence Supplier decision making or pricing

This review has not sought, nor would it have been appropriate to seek, Supplier inputs on these parameters. CRA's estimation of the relationship of take-up and price has therefore taken account of reasonable expectations of these issues, but until the market is actually tested, definitive answers are unknowable, and therefore represent significant uncertainty in outcomes.

10.3. Buyout and Buydown Conclusions

The sensitivity analyses have identified ranges of the most likely outcomes centered on the base case results for each opportunity. These are presented in the following three charts in respect of wind & solar Buyout, wind & solar Buydown, and gas-fired Buydown. Each chart shows base case and individual sensitivity case outcomes and the range of the most likely outcomes centered on the base case. Gross savings represent the total reduction in the IESO's contract and market payments to each Supplier due to the modification of the contract. Net Savings represent gross savings minus the debt amortization cost. Savings are all stated before accounting for any IESO program or transaction costs, and are plotted against the initial funding requirements.

Figure 26 Case Comparison for Renewables Buyout

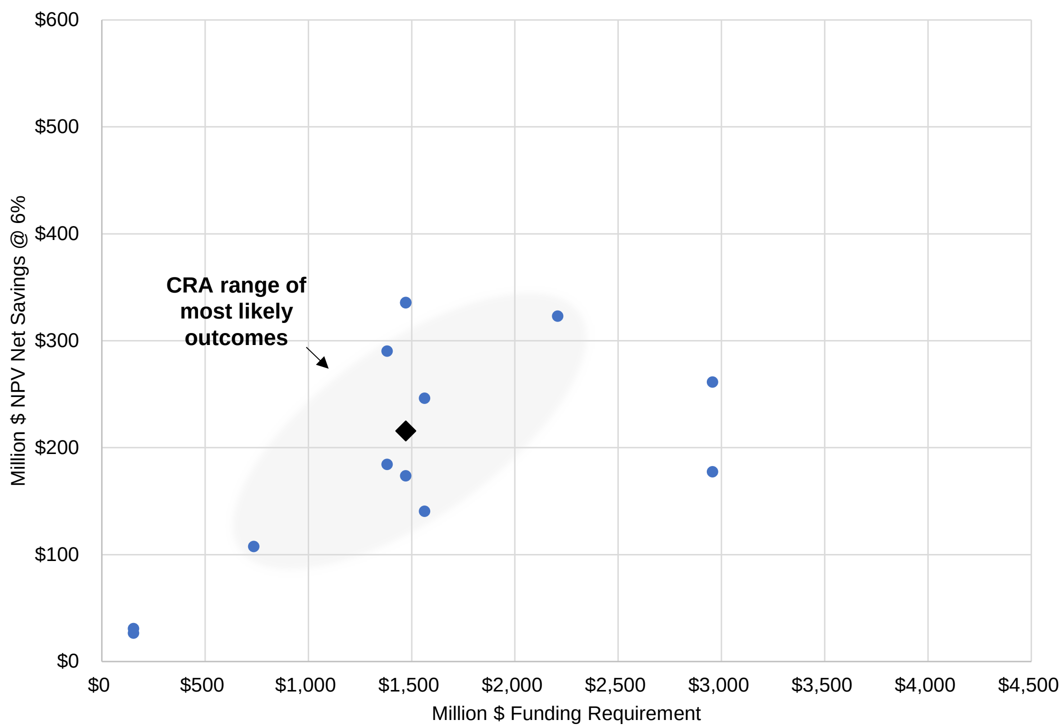


Figure 27 Case Comparison for Renewables Buydown

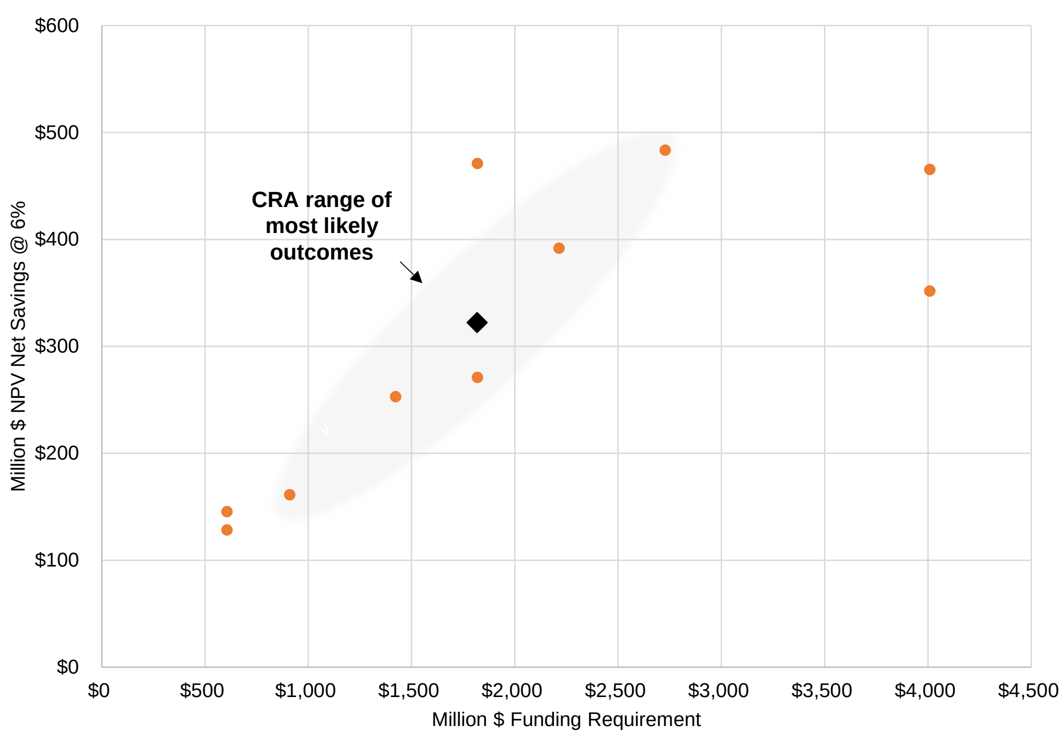
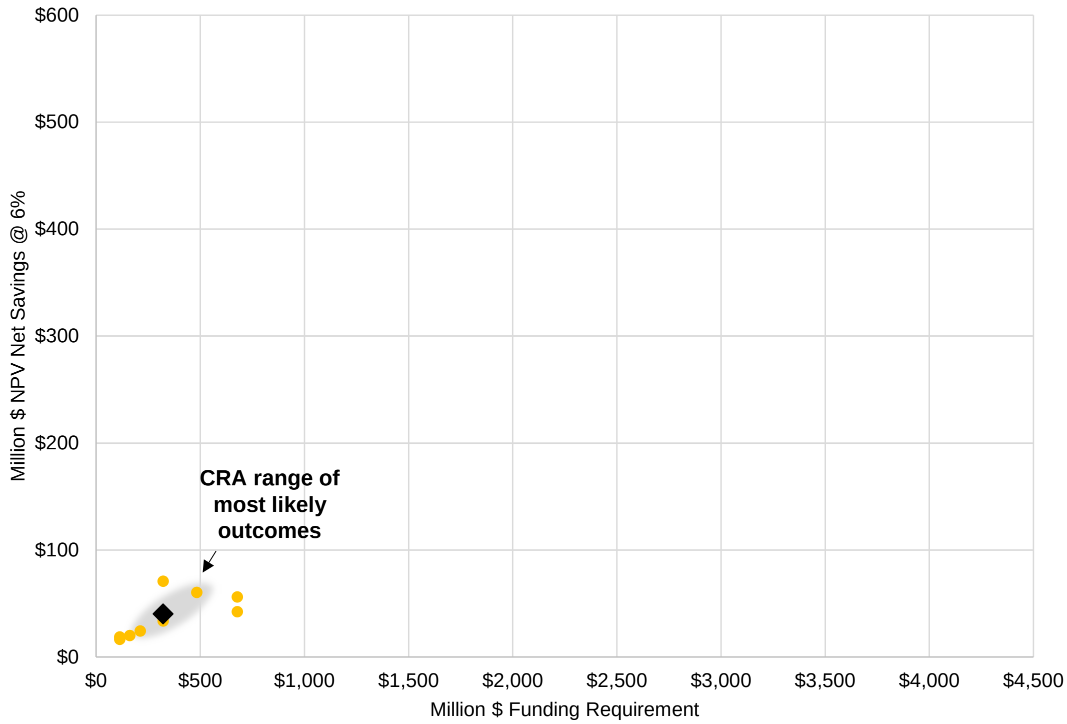


Figure 28 Case Comparison for Gas Fired Buydown



The following table summarizes those ranges:

Table 21 Sensitivity Cases Overview for Buydown and Buyout

	Renewable (Wind & Solar)		Gas-fired	
Buyout				
Take-up MW	243 - 730	MW		
Take-up MW as %	5 - 14	%		
Year 1 savings - gross	86 - 258	$ Million		
% of total system costs (gross)	0.4 - 1.2	%		
Year 1 savings - net	19 - 56	$ Million		
% of total system costs (net)	0.1 - 0.3	%		
NPV net savings (@ 6% discount rate)	**108 - 323**	**$ Million**		
Buydown				
Take-up MW	426 - 1,279	MW	434 - 1,303	MW
Take-up MW as %	8 - 24	%	7 - 20	%
Year 1 savings - gross	99 - 297	$ Million	25 - 76	$ Million
% of total system costs (gross)	0.4 - 1.3	%	0.1 - 0.3	%
Year 1 savings - net	16 - 48	$ Million	3 - 8	$ Million
% of total system costs (net)	0.07 - 0.2	%	0.01 – 0.04	%
NPV net savings (@ 6% discount rate)	**161 - 483**	**$ Million**	**20 - 60**	**$ Million**

In comparing the wind and solar Buyout and Buydown opportunities we note that:

- Buyout has greater uncertainty than Buydown due to the uncertainties about perceived risk transfer.
- The Buydown opportunity offers higher NPV net savings per $ of funding requirement due to the difference in risk profiles and the sustainment of the savings rate over a longer period.

10.4. Blend & Extend Conclusions

The Blend & Extend opportunity represents savings within the term of existing contracts, traded off against later cost increases. Blend & Extend also bears a risk of reducing flexibility in response to future changes in planning expectations.

Net savings are zero when evaluated at the base 6% social discount rate. Net savings are negative at lower social discount rates and positive at higher social discount rates.

Table 22 Sensitivity Cases Overview for Blend and Extend

	Renewable (Wind & Solar)		Gas-fired	
Blend & Extend				
Take-up MW	481 - 1,443	MW	803 - 2,408	MW
Take-up MW as %	9 - 27	%	12 - 36	%
Year 1 savings - gross	N/A	$ Million	N/A	$ Million
% of total system costs (gross)	N/A	%	N/A	%
Year 1 savings - net	39 - 118	$ Million	25 - 74	$ Million
% of total system costs (net)	0.2 - 0.5	%	0.1 - 0.3	%
NPV net savings (@ 6% discount rate)	**0**	**$ Million**	**1 - 2**	**$ Million**

10.5. Secondary Opportunity Conclusions

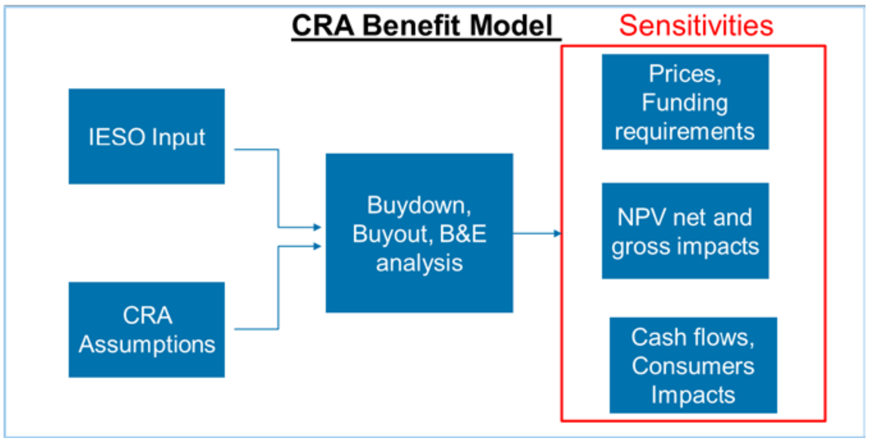
CRA investigated at high level the secondary opportunities described in section 9.

The only potentially material opportunity is the extension of any large contract Buydown program to include the larger distribution-connected contracts or portfolios. The savings from large renewable contract Buydown might thus be amplified by 0% to 20% before IESO program and transaction costs. Any such smaller contract program would likely need to lag a year behind any equivalent large contract program.

Appendix A - Overview of the CRA Benefit Model

CRA has developed a model to analyze the applicable contracts for the three primary opportunities: Buyout, Buydown and blend and extend. The model considers input provided by the IESO and information based on CRA's judgment as described in the assumptions sections. The graph below provides a schematic of the model's architecture.

Figure 29 CRA Benefit Model Structure



Information provided by the IESO includes the following:

- Wind, solar and gas contract data comprised of the contract term, price and other
- Wind, solar and gas contract asset specific information such as historical production, curtailment and other
- APO related prices for both energy and capacity

Information considered in the model based on CRA's analysis and judgement include the assumptions described in section 4 of the main body of the report.

The main body of CRA's model consists of two parts. The first evaluates the Buyout, Buydown and blend and extend prices for wind and solar and the second conducts a similar evaluation for the gas project. Each of the three primary opportunities employs a different logic.

For Buyout, the model calculates a price that reflects the residual contract revenue for the project over the remaining term discounted at the Supplier's pro-forma cost of capital.

For Buydown the model develops a price that reflects the following approach:

- Wind & solar
  - o Contract price should remain above expected market price so that the contract does not become a liability for the Supplier.
- Gas contracts
  - o Contract price should remain above expected energy & capacity market price and above expected avoidable cost so that the contract does not become a liability for the Supplier.

The Buydown is based on the portion of the contract revenue stream over the remaining term discounted at the Supplier's cost of capital.

Lastly, for blend and extend the extension price is evaluated to be the greater of:

- Expected realizable energy and capacity market net revenues in the extension period, and
- For gas-fired facilities, the expected avoidable cost for the extension period including return on life extension investments

The model can produce prices and both net and gross impacts to the Ontario consumers for all assessed contracts.

In order to estimate the sensitivities and their impact at an aggregated level, the CRA benefits model included functionality that provided information on annual basis, NPV and funding requirement levels for each of the contract classes for all three primary opportunities.

Appendix B - CRA's Internal Quality Control Report

Quality assurance is an integral part of the culture at CRA and an important function that we believe underlies excellence in the execution and delivery of our work. For this effort, CRA's energy practice was assisted by an independent quality assurance function unaffiliated with the service line that was tasked with performing the work within the RFP for the engagement.

The CRA Forensic Solutions, Investigations Practice ("CRA Forensics"), performed a quality assurance ("QA") of the Contract Pro-forma Model ("Model") developed by the Energy and Environmental Group ("Engagement Team") during the course of their engagement by the Independent Electricity System Operator of Ontario, Canada ("IESO").

In the core of the Quality Control effort was the development of a process that took input from the project team and performed the review and quality control of the work to achieve the goals of IESO.

CRA Forensics has developed a comprehensive QA plan and has completed the following:

- Met with members of the Engagement Team on multiple occasions to gain an understanding of the modeling process, critical inputs driving the Model results, the assumptions used, and the intended function of various pieces of the Model.
- Reviewed the Model at multiple stages of development to understand the impact of changes made by the Engagement Team during the progression of the engagement and to provide real time feedback.
- Performed a detailed review of the Wind & Solar and CES Representative sections of the Model.
- Verified that the aggregated results reported in this Independent Electricity System Operator – Contract Review as of February 14, 2020 match the results derived from the Model.

CRA Forensics did not perform work to validate the theory used in arriving at the assumptions presented to the IESO on January 23, 2020, including the work performed to derive the Base Case Assumptions.

Based on the work performed, the Model appears to be generating results as intended.