Market Renewal Program

Energy Stream Business Case

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List of Abbreviations

Abbreviation	**Description**
CMSC	Congestion Management Settlement Credits
DAM	Day-Ahead Market
DD	Detailed Design
DSO	Dispatch Scheduling and Optimization
EDAC	Enhanced Day-Ahead Commitment Process
ERM	Enterprise Risk Management
ERUC	Enhanced Real-Time Unit Commitment
FTE	Full Time Equivalent
HLD	High-Level Design
HOEP	Hourly Average Energy Price
ICP	Intertie Congestion Price
IESO	Independent Electricity System Operator
IT	Information Technology
LDC	Local Distribution Companies
LMP	Locational Marginal Price
MCP	Market Clearing Price
MISO	Midcontinent Independent System Operator
MRP	Market Renewal Program
NPV	Net Present Value
NQS	Non Quick Start
OEB	Ontario Energy Board
RFP	Request For Proposals
RT-GCG	Real-Time Generator Cost Guarantee
SSM	Single Schedule Market

1. Executive Summary

The Independent Electricity System Operator (IESO) works at the heart of Ontario's power system. The IESO delivers key services across the electricity sector including: managing the power system, planning for the province's future energy needs, enabling conservation and designing a more efficient electricity marketplace to support sector evolution. To balance supply and demand[1] in real-time the IESO administers a wholesale electricity market to efficiently allocate resources from many suppliers under a wide range of system conditions. The design of the wholesale market is a critical factor in the ability of the IESO to meet its power system reliability objectives.

The Market Renewal Program Energy Stream presents an opportunity to implement much needed reforms to the Ontario electricity market. The expected benefits will span the sector, enabling the IESO to realize significant operational improvements, reduce costs for market participants, address known inefficiencies, and establish a robust market to integrate emerging and new technologies. A thorough financial assessment of the new market design has concluded that the program is financially viable, delivering at least $750 million in net financial benefits to Ontario consumers over the first 10 years of implementation.

Today’s Electricity Market

The wholesale electricity market was introduced in 2002 and designed to be a competitive market that would ensure power system reliability at lowest cost. The electricity market design was expected to deliver key advantages compared to the previous cost-based approach: transparent market rules to enable competition between existing and new suppliers; effective clearing prices that reflect the cost of producing power on an hourly basis; and an efficient way for the IESO to meet its reliability requirements in Ontario.

This market design has met many of its objectives and enabled the IESO to manage the grid reliably during an era of structural changes to Ontario’s supply mix including the phase-out of coal fired generation and the emergence of new technologies and participants. However, the wholesale market design remains largely unchanged since 2002 while industry best practices have advanced. The

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[1] Demand refers to the amount of electricity required in Ontario at any given moment, or over a period of time. Demand is measured at the points where the load connects to the bulk electric system.

challenges and complexity of Ontario's unique two-scheduling system results in a misalignment between price and dispatch and requires the IESO to rely on extensive out-of-market programs and payments to ensure reliability. This design has hindered opportunities to drive efficiencies and implement enhancements, including a day-ahead market that has proven effective in improving operational certainty and in reducing costs in electricity markets across North America and globally.

These market design issues are well-documented by the IESO, Ontario Energy Board's Market Surveillance Panel, Ontario's Auditor General and others. Considerable time and resources have been devoted to implementing one-off solutions that, at best, address individual issues, without fixing the underlying problem – the two-schedule system. It is for good reason that no other North American system operator uses a two-schedule system; all have implemented, or transitioned to a simpler design where prices and dispatch[2] are aligned and set by a single schedule. Without acting to fix these issues, the problems and inefficiencies associated with the current design will persist into the future, increasing costs for consumers and severely limiting the IESO's ability to effectively operate the grid.

Market Renewal Program

In 2016, the IESO launched a **Market Renewal Program** with a series of projects that will deliver a more efficient electricity market.

1. Replace the two-schedule market with a **Single Schedule Market** that will address current misalignments between price and dispatch, eliminating the need for most out-of-market payments.
2. Introduce a **Day-Ahead Market** that will provide greater operational certainty to the IESO and greater financial certainty to market participants, lowering the cost of producing electricity and ensuring we commit only the resources required to meet system needs.
3. Reduce the cost of scheduling and dispatching resources to meet demand as it changes from the day-ahead to real-time through the **Enhanced Real-Time Unit Commitment** project.

Any program that involves significant change has the potential to be both challenging and disruptive to the sector. To understand the impacts and ensure the new designs are both efficient and implementable, the IESO has worked closely with stakeholders since the program launched. A dedicated forum, the Market Renewal Working Group, was established with cross-sector participation as well as individual stakeholder engagements for each project. Education sessions, webinars, and

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[2] Dispatch indicates the process by which the IESO directs the real-time operation of registered facilities to cause a specified amount of electric energy or ancillary service to be provided to or taken off the electricity system

tailored outreach, such as the Non-Emitting Resource Subcommittee, enabled specific issues to be addressed for different stakeholder groups. The comprehensive engagement process ensured stakeholder feedback was incorporated into key design decisions and issues were addressed collaboratively.

The culmination of the high-level design phase[3] was the publication of three high-level design documents for the Energy Stream's Single Schedule Market, Day-Ahead Market and Enhanced Real-Time Unit Commitment projects. The high-level designs were developed based on agreed-upon principles to balance the best theoretical design with practical realities faced by the IESO and Market Participants.

Market Renewal Program Business Case

In 2017, the IESO commissioned an independent report[4] assessing the potential benefits for market renewal. The report drew from past Ontario studies and the experience of jurisdictions that had implemented similar market changes. The top-down report highlighted the significant potential of the market reforms but was not based on specific design decisions, or a detailed knowledge of IESO operations.

Now that the Market Renewal Program is well underway and the high-level designs are complete, the IESO is in a position to deliver a detailed MRP Business Case that assesses the operational, reliability and financial benefits and costs associated with implementing the new energy market.

The goal of the Business Case was to represent an accurate picture of the impacts of the Market Renewal Program on the electricity sector in Ontario, supported by strong and verifiable evidence. The approach started with a thorough assessment of the potential benefits and how they would impact the IESO's ability to operate the system, enhance reliability and lead to more efficient outcomes. Through this exercise it became apparent that some benefits could be quantified with a high degree of certainty, whilst other benefits were very likely but the scale of benefits was uncertain and some benefits could only be assessed on a qualitative basis. To ensure a complete analysis, both the quantitative and qualitative benefits have been comprehensively assessed.

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[3] The program is structured into three major phases: 1) high-level design; 2) detailed design; and 3) testing and implementation.

[4] The Future of Ontario's Electricity Market - A Benefits Case Assessment of the Market Renewal Project, The Brattle Group, April 20, 2017

The reader should note that many of the benefits discussed qualitatively, such as reliability risk and future opportunities for greater participation and new technologies, are essential to the IESO's core functions and the long-term health of Ontario's electricity markets.

The financial analysis focuses on a subset of benefits where there is a high degree of certainty, uses conservative assumptions, reflects stakeholder feedback, and includes characterizations of uncertainty where appropriate. The assessment also only focuses on the first 10 years of operation; however, the reforms being proposed and the corresponding benefits that will be accrued will last much longer.

Finally, unlike the 2017 report on potential benefits, this Business Case was developed by IESO staff, drawing on expertise from across the organization, ensuring the assessment was grounded using detailed knowledge and experience of the unique characteristics of the Ontario market.

Expected Benefits

The new energy market design, which moves away from the existing two-schedule market to a single schedule market with locational pricing, is expected to enhance reliability, increase operational certainty, and significantly reduce system costs paid for by consumers.

1. *Enhanced reliability*

The current two-schedule design relies heavily on two complex and costly out-of-market programs to ensure a reliable power system: the Real-Time Generator Cost Guarantee program and Congestion Management Settlement Credits. Experience from other markets shows that without these types of programs the reliability of Ontario's electricity system would be at risk[5] and North American power system reliability standards would not be met.

Although these programs are necessary for reliability they are costly and administratively complex. In December 2017, the Auditor General released a report that was critical of these two programs[6], drawing heavily from previous Market Surveillance Panel reports. Although the IESO has addressed individual issues as they have arisen, the Market Renewal Program Energy Stream is the fundamental change needed to replace these programs.

The introduction of a Single Schedule Market with locational prices aligned with dispatch will ensure resources are responding to the right incentives and price signals for dispatch, reducing costs and

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[5] W.W. Hogan, "Electricity Market Restructuring: Reforms of Reforms," 20th Annual Conference Center for Research in Regulated Industries, Rutgers University, May 25, 2001.

[6] http://www.auditor.on.ca/en/content/annualreports/arreports/en17/v1_306en17.pdf

enabling better decision-making. The new design will ensure a greater share of system costs are reflected in market prices, eliminating the need for most out-of-market payments.

2. Operational certainty for IESO and Market Participants

The implementation of a Day-Ahead Market will provide financially-binding schedules for participating resources one day in advance of operation. This will encourage all resources to participate more fully and efficiently in the day-ahead timeframe and will provide far greater clarity to the IESO on next day operations.

Enhanced Real-Time Unit Commitment will optimize the system with a look-ahead period of up to 27 hours, rather than the current 1-hour optimization, reducing the number of commitments[7] to the benefit of the IESO, Market Participants and Ontario consumers.

3. Increased system efficiency

The Market Renewal Program Energy Stream will address known inefficiencies as well as create the conditions for a more efficient bulk electrical system[8] including improved scheduling and dispatch, better use of Ontario's interties and competitive incentives for generators to reduce costs.

- Existing Ontario generators will benefit from a more transparent and competitive platform for their operating costs.
- Better scheduling and commitment of resources in the real-time operating timeframe delivering system-wide efficiency benefits of over $500 million over the first 10 years of operating the new market design.
- Elimination of approximately $450 million of unnecessary Congestion Management Settlement Credits over the first 10 years of operating the new market design. These benefits will accrue directly to Ontario consumers.

4. Address instances of gaming

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[7] Commitment is the process of deciding when and which non-quick start resources should come online in order to maintain reliability and meet demand at lowest overall cost.

[8] The Bulk Electricity System is defined as the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher.

Eliminating most out-of-market programs and payments will significantly reduce opportunities for gaming that have resulted in clawbacks[9] of over $360 million in recent years. In addition, instances of gaming have proven to be costly to recover, intrusive for business, litigious and have generally undermined confidence in the wholesale electricity market.

5. Broader market benefits

The new design will be based on accurate locational prices that will provide valuable information to system planners, potential developers and investors on the state of the local grid and the cost of supplying or consuming power. In some parts of the province, such as northwest Ontario, the low cost of local, hydro generation is not reflected in the market price today. Moving to a Single Schedule Market will provide opportunities for customers and could positively impact future investment decisions.

6. Enabling future markets

Changes introduced by the new energy market design will provide a robust platform to address emerging power system needs:

- The Single Schedule Market design changes will ensure that costs are transparently reflected in price thereby enabling resources, including new technologies such as energy storage and demand response, to more actively participate in the market and make more informed decisions when supplying and withdrawing energy.
- Increased certainty from the changes introduced by the Day-Ahead Market will help all Market Participants manage risk and costs. Locking-in prices day ahead will reduce their exposure to real-time price volatility. Large consumers will have the option to register as price responsive loads and lock-in energy prices day ahead, reducing their exposure to real-time price volatility.

Taken together, the Market Renewal Program Energy Stream changes will create a more efficient and flexible platform that allows Ontario to better utilize its existing assets. The changes will also enable existing and future Market Participants to anticipate future needs and incentivize innovative solutions to meet emerging challenges.

Financial Assessment

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[9] A clawback refers to the recovery of money that has already been disbursed. Instances of gaming in Ontario's electricity market are investigated by the Market Assessment and Compliance Division (MACD) which is a ring-fenced business unit within the IESO.

As identified above, the Market Renewal Program Energy Stream is expected to deliver a range of significant benefits. For the purpose of the analysis only the elimination of unnecessary congestion management settlement credits and the market efficiencies were included as these could be quantified with the greatest certainty. Together, these two categories of benefits are expected to total approximately $1 billion over the first 10 years of implementation.

The financial benefits associated with a day-ahead market, improved consumption and investment, hydro and system optimization, reduced gaming opportunities as well as those associated with future improvements and enabling greater and diverse market participation have not been quantified. These benefits are expected to be real, but the scale of benefits will be influenced by many factors that make them difficult to predict with certainty.

Expected Costs

The cost of implementing the Market Renewal Program Energy Stream has been estimated at $170 million (including $16 million contingency) with a range of $151 million to $194 million based on best available information.

The post-implementation costs of the program over the following 10 years are expected to be an additional $6 million. Based on a bottom-up estimating process, the Go Live date of the Market Renewal Program Energy Stream will be March 2023.

Net Present Value Calculations

The IESO developed an expected case along with low and high cases for the total expected benefits, and conducted a Net Present Value analysis using a range of benefits and costs for these cases.[10] Based on this analysis, the Net Present Value for the Market Renewal Program Energy Stream has been assessed at $290 million - $450 million with a Benefits-to-Costs Ratio of 2.7 - 4.3. A strongly positive Net Present Value and a robust Benefits-to-Costs Ratio indicate the MRP Energy Stream is a financially sound program.

The analysis uses conservative assumptions and many potential benefits have not been quantified. Overall, the IESO is confident that the realized value of the Market Renewal Program Energy Stream will exceed the benefits that are presented in this Business Case.

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[10] Please see Chapter 5 for further information on the Net Present Value calculation including key assumptions

Summary

The Market Renewal Program Energy Stream will fundamentally address long standing issues that have challenged the Ontario electricity market. Transitioning to a more efficient design will deliver benefits that far outweigh the costs of the program, even using conservative assumptions. The high-level designs are made-in-Ontario, but they are founded on proven concepts that have demonstrated their value many times over in multiple markets. The IESO is confident that implementation of the Market Renewal Program Energy Stream will benefit Ontario consumers well beyond the 10 years assessed in this Business Case.

The IESO would like to thank stakeholders for their time, commitment and dedication to developing and implementing the Market Renewal Program which has only been possible through the collective input and expertise of the sector.

2. Background and Overview

2.1 The Need for the Market Renewal Program Energy Stream

As Ontario's system operator, the IESO is responsible for the reliability and security of Ontario's electricity grid, for administering Ontario's electricity markets, and for providing businesses, communities and consumers with reliable power where and when they need it. The IESO is committed to these responsibilities and has been achieving them through an open and transparent wholesale electricity market.[11]

The fundamental objective of Ontario's electricity market, like all energy markets, is to allocate resources efficiently to maintain power system reliability at the lowest cost. This means that tools and incentives should align the physical system with market operations minimizing the need for operator intervention. However, the current tools and incentives do not effectively meet system or the IESO's requirements and have needed to be supplemented by out-of-market programs and payments.

In an ideal world, all system costs would be reflected in market prices ensuring participants can make the best possible decisions in the most transparent way. However, in practice the electricity system and all market participants cannot be perfectly modeled and there will be times when the system operator must intervene in the market for operational or reliability reasons. Despite the IESO using well defined procedures, the cost of these actions is not always visible to market participants creating uncertainty and risk. If these costs had been reflected in market prices suppliers and consumers may have made different decisions. Aside from this inefficiency, the recovery of these costs is important. In a market where the system operator makes many out-of-market actions and allocates costs after the fact, this will not incentivize participants to respond efficiently, and potentially not participate in the long run. Therefore, it is in the interest of the IESO, consumers and the province as a whole to ensure that out-of-market actions and payments are minimized and only used when absolutely necessary. By contrast, the current energy market design inherently relies on out-of-market payments, necessary for reliability, but costly to the market as a whole.

The present design has fundamental flaws:

- **Congestion Risk and Reliability:** The two-schedule design results in a risk that suppliers may not follow dispatch if prices are misaligned with offers to supply, creating an unacceptable reliability risk. In order to ensure resources follow dispatch based upon

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[11] http://www.ieso.ca/Corporate-IESO/Corporate-Strategy-and-Business-Planning/Corporate-Performance

technical constraints, the IESO has used extensive out-of-market payments known as Congestion Management Settlement Credits (CMSC);

- **Operational Certainty:** the current design provides an incomplete operational view of both the day ahead and the operating day and as a result requires out-of-market cost guarantee programs to ensure resources are available when needed.

2.2 Congestion Risk and Reliability

The current market design is based on two pricing schedules:

1. A hypothetical process to determine a uniform market clearing price that ignores most physical constraints within Ontario. The purpose of the unconstrained schedule is to determine which resources are economic, independent of system conditions; and
2. A constrained dispatch schedule for each five-minute interval for Market Participants. This schedule does consider transmission constraints and other key operational constraints such as plant operating characteristics. This schedule is used to dispatch resources based on locational prices at each node[12] but crucially the locational prices are not used for settlement.

Under the current design, Market Participants are dispatched based on a locational price, but are settled on a uniform market price. Any mismatch between locational prices and the uniform market clearing price reflects the degree of congestion on the system. Congestion introduces a risk for Market Participants since the market clearing price may or may not be sufficient to recover their operating costs. If prices generated by the two schedules deviate significantly Market Participants may be deterred from

The PJM market provides a cautionary tale on the severity of not managing congestion risk. At market opening, the original PJM market used a uniform price, like Ontario, but without constrained-off payments. Within a year the market had to be abandoned as generators self-scheduled creating a cascading effect that left the system operator unable to manage the power system reliably.

In New England, the original market based on a uniform price without constrained-off payments lasted a bit longer but only because the uniform price was set so low that no generators were constrained-off and many generators were paid to be constrained-on. New England quickly transitioned to locational pricing and a single schedule design.

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[12] The locational price at the node is sometimes referred to as a “shadow” price.

following dispatch instructions creating a serious reliability concern.[13,14]

Since Market Participants are unable to hedge differences in prices resulting from real-time congestion, the only solution under the current two-schedule design is to rely on extensive out-of-market CMSC[15] to keep them whole. These make whole payments ensure Market Participants follow dispatch instructions when pricing incentives are inaccurate and do not appropriately reflect system needs.

2.2.1 Congestion Management Settlement Credits

Since its inception, and in nearly all of its 30 monitoring reports to date, the Market Surveillance Panel of the Ontario Energy Board has commented on anomalous or unwarranted CMSC payments due to the two-schedule system and described in Section 2.2. No element of Ontario's wholesale electricity markets has attracted the attention and concern of the Market Surveillance Panel more than CMSC payments since market opening. Similar comments have been noted by the Electricity Market Forum, the IESO, stakeholders, and Ontario's Auditor General.[16,17,18]

> The current pricing design was originally intended to persist for only 18 months, as a transitional mechanism toward implementing a single-schedule system with locational marginal pricing (LMP) or "locational pricing."

It is important to note that the Market Design Committee[19] was a strong proponent for the eventual implementation of locational pricing. It emphasized that the "two-schedule" system should be temporary and had concerns that it would create inefficient and sometimes perverse incentives for generation, consumption, and investment decisions if kept in place for an extended period. It also noted that the benefits

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[13] See W.W. Hogan, "Electricity Market Restructuring: Reforms of Reforms", 20th Annual Conference Center for Research in Regulated Industries, Rutgers University, May 25, 2001, for a brief history of PJM's use of a uniform market price.

[14] See Market Surveillance Panel, "Congestion Management Settlement Credits (CMSC) in the IMO-Administered Electricity Market", for a brief discussion on New England's uniform pricing design.

[15] CMSC consists of constrained-on and constrained-off payments to dispatchable Market Participants in order to manage localized supply/demand imbalances resulting from transmission constraints. In addition, the 3- times ramp rate multiplier, slow ramping of fossil-fired units and technical / regulatory limitations can each give rise to CMSC payments. CMSC payments can also be "self-induced" through, for example, voluntary ramping actions by dispatchable loads or generators.

[16] https://www.oeb.ca/utility-performance-and-monitoring/electricity-market-surveillance/panel-reports, Accessed June 25, 2019

[17] "3.06 Independent Electricity System Operator—Market Oversight and Cybersecurity" Office of the Auditor General of Ontario, 2017, pg. 328

[18] Reconnecting Supply and Demand: How Improving Electricity Prices Can Help Integrate A Changing Supply Mix, Increasing Efficiency and Empowering Customers, Report of the Chair of the Electricity Market Forum, George Vegh, December 2011

[19] The Market Design Committee drafted the initial comprehensive set of rules for the competitive market for electricity in Ontario from 1998 to 1999

of locational pricing could be substantial for Ontario, and developed recommendations for implementation.[20,21,22]

Some CMSC payments are necessary such as those that enhance reliability. However, the CMSC construct creates incentives for unwarranted payments, manipulation and gaming and, as such, has been questioned by the Market Surveillance Panel, Auditor General and others. CMSCs have been exploited by all segments of the market at various times – generators, loads, exporters and importers. Over the years the IESO has addressed many individual issues, often referred to as one-off solutions but the fundamental problems with the two-schedule design persist, and CMSC payments will continue to be necessary unless the current design is replaced.

Aside from CMSC issues, the two-schedule system is very complex and these complexities have proven to be a barrier to evolving the market. For example, as long as the two-schedule system is in place the IESO will not be able to implement a financially-binding day-ahead market.[23] Without a financially-binding day-ahead market, there will not be a process to provide efficient incentives that ensure that all generation resources commit to providing energy and ancillary services ahead of the operating time frame.[24]

2.3 Operational Certainty

2.3.1 Real-Time Uncertainty

When Ontario's electricity market was designed in the late 1990s, electricity markets were relatively new and day-ahead markets were not yet the common feature they are today. Although a voluntary day-ahead forward market for purely financial contracts was recommended prior to market opening[25], Ontario's electricity market was launched in 2002 without a day-ahead scheduling process.

The need for increased certainty prior to real-time emerged at the outset of the market as Ontario was facing tight supply conditions. The IESO began exploring the potential for a day-ahead market in 2003. However, despite significant effort, Ontario's unique two-schedule system proved to be a major

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[20] Market Design Committee, Second Interim Report, June 30, 1998, pg. 3-13.

[21] Market Design Committee, Final Report, January 1999

[22] First Interim Report of the Market Design Committee, March 31, 1998

[23] In 2003 the IESO did explore a day-ahead market but concluded that although it would be possible in theory, it would not be practical due to the complexity of the two-schedule design.

[24] The Future of Ontario's Electricity Market - A Benefits Case Assessment of the Market Renewal Project, The Brattle Group, April 20, 2017, pg. 2

[25] Market Design Committee, Final Report, January 1999

barrier towards its implementation. As a result, the IESO opted for a second-best solution and introduced the Day-Ahead Commitment Process in 2006.

The Day-Ahead Commitment Process was improved through the Enhanced Day-Ahead Commitment Process (EDAC) project in 2011 to address some key issues with the original design. The schedule that results from today's day-ahead commitment process provides a view of what the next day looks like; however, due to the lack of financial commitment and the lack of exports participating, the day-ahead process remains sub-optimal.

The shortcomings of the EDAC process means that control room operators only have a partial view of the next day's operation, creating significant uncertainty and a reliance on forecasts and assumptions, rather than firm commitments. Control room operators have an obligation to prepare an operating plan one day ahead and must supplement the EDAC process with additional technical assessments. Operational certainty is critical for the IESO to maintain a reliable grid, but the lack of certainty from EDAC and inefficiencies with pre-dispatch and the Real-Time Generator Cost Guarantee (RT-GCG)[26] program means that most scheduling and operational decisions need to be managed within real-time. An incomplete view of the next day's demand and supply adds administrative burden when additional operational and reserve assessments are needed. The pre-dispatch and the RT-GCG program aid with scheduling in the hours before real-time; however, these tools are inefficient and make decisions that are short-sighted and costly.

The IESO maintains reliability by supplementing current processes by operator actions and out-of-market decisions. Although these actions are vital, the lack of transparency can create uncertainty for Market Participants and limit opportunities for new and emerging participants when these conditions arise.

2.3.2 Inefficiencies Associated with Unit Commitment

When today's market was being designed, Ontario had five coal-fired generating stations, comprised of 19 units totaling about 8,800 MW.[27] Scheduling such large conventional assets with known and predictable dispatchability meant that simpler commitment and scheduling tools would suffice.

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[26] The Real Time-Generator Cost Guarantee (RT-GCG) program is a reliability measure that ensures sufficient generation is available to meet Ontario's demand for electricity. The program provides eligible resources the guaranteed recovery of certain start-up costs to the extent the costs could not be recovered through market revenues. Introduced as the Spare Generation Online Program in 2003 the program has evolved over time and is known today as the RT-GCG.

[27] "The End of Coal", Government of Ontario archived website, https://www.ontario.ca/page/end-coal, accessed August 21, 2019

Today the majority of Ontario's electricity production comes from a diversity of resources with less flexible operating characteristics and from assets that have less predictable fuel inputs (like wind and solar). Ontario's existing assets, in particular the natural gas-fired units, are able to provide the needed flexibility services in many hours, but those flexibility services often need to be handled through out-of-market mechanisms. While Ontario currently has a diverse fleet and is interconnected to access resources in neighbouring systems through interties, the current market design and tools are unable to fully utilize these resources.

A key shortcoming of the existing pre-dispatch mechanism is that it only optimizes resource scheduling over one hour at a time. This approach is sub-optimal as it fails to recognize the operational linkages from hour to hour. Furthermore, the hourly optimization does not accurately take all generator costs into account. This means that the pre-dispatch optimization falls short in accurately assessing how to best to meet system needs, which is inefficient and leads to higher system costs.

Furthermore, Non-Quick Start (NQS)[28] resources can take significant time to start-up and must remain online for a minimum amount of time to avoid damaging equipment. In order to manage the lack of financial certainty that both the current day-ahead, pre-dispatch and real-time bring, the RT-GCG program was introduced to guarantee that NQS resources, when committed, will be scheduled to meet their physical requirements and will not have to operate at a loss if conditions change in real-time.

Unit commitment decisions in the RT-GCG program are currently based on energy costs alone looking out at a single hour, while the start-up and speed no-load costs of NQS resources are not taken into account. This means that a resource with lower energy costs but higher start-up costs may be committed over resources with lower total costs, resulting in inefficient outcomes. Another key concern of the program had been that start-up costs were able to be submitted after the fact, and a substantial audit of these costs had found several systemic issues and abuses of the program. While the RT-GCG program is an essential tool for meeting reliability needs its current design has also been criticized in several Market Surveillance Panel reports, as well as an Auditor General report, due to its inefficiency, costs and lack of transparency.[29,30] Similar to the CSMCs, the IESO implemented solutions to manage and contain specific issues as they were identified. However, these changes

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[28] A Non-Quick Start resource is a generator with a lead time of at least one hour, and that must remain operating at its minimum loading point for its minimum generation block run-time.

[29] "3.06 Independent Electricity System Operator—Market Oversight and Cybersecurity" Office of the Auditor General of Ontario, 2017, pg. 328

[30] https://www.oeb.ca/utility-performance-and-monitoring/electricity-market-surveillance/panel-reports, Accessed June 25, 2019

could not address the root cause of the problem which is the current design optimizes using partial information, rather than all information. Until this fundamental issue is addressed the inefficiencies associated with unit commitment will persist.

2.4 MRP Energy Stream Scope and Structure

In 2016, the IESO committed to re-designing the market by leveraging the best practices in other jurisdictions while ensuring a made-in-Ontario approach. The MRP Energy Stream is a coordinated set of projects that will reform the electricity market with that aim to support reliable operations and address inefficiencies with the current design. It is also a unique opportunity for the IESO to use learnings from the experiences in other markets to build a more cost-effective Ontario electricity market.

MRP Mission Statement

"Deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost."

The IESO worked with stakeholders to develop a core mission statement and a number of guiding principles to provide a framework for this re-design against which the MRP Energy Stream deliverables and engagement will be measured. The guiding principles included:

- **Efficiency:** lower out-of-market payments and focus on delivering efficient outcomes to reduce system costs
- **Competition:** provide open, fair, non-discriminatory competitive opportunities for participants to help meet evolving system needs
- **Implementability:** work together with our stakeholders to evolve the market in a feasible and practical manner
- **Certainty:** establish stable, enduring market-based mechanisms that send clear, efficient price signals
- **Transparency:** accurate, timely and relevant information is available and accessible to Market Participants to enable their effective participation in the market

The MRP Energy Stream has three projects as shown below in

Figure 2-1.

Figure 2-1: The MRP Energy Stream Structure

- The Single Schedule Market (SSM) which will address misalignments between price and dispatch
- The Day-Ahead Market (DAM) which will provide greater operational certainty to the IESO and greater financial certainty to Market Participants
- The Enhanced Real-Time Unit Commitment (ERUC) which will reduce the cost of scheduling and dispatching resources to meet demand

To complete these projects, the IESO has established a dedicated internal MRP Energy Stream team, supported by a Project Management Office. For the purposes of risk management, project management, and expenditures, and to ensure a cohesive design, the MRP Energy Stream work has been broken down into three distinct phases: High-Level Design (HLD), Detailed Design (DD), and Testing and Implementation. The project design phases are shown in Figure 2-2.

Figure 2-2: MRP Energy Project Design Phases

In September and December 2018, the IESO released the HLD documents for SSM, DAM, and ERUC for stakeholder review and feedback. These projects are outlined in detail in each of the HLDs available via the Market Renewal section on the IESO website[31] and described briefly below.

The HLDs together outline the blueprint for Ontario's future market that will make the best use of resources available, where price signals are accurate and transparent and through which suppliers and users can make informed decisions and are able to respond. Though the elements of each project are unique, they are inter-related and design and implementation decisions made in each require careful coordination. All three projects have been combined into a single MRP Energy Stream for the detailed design and implementation phases in recognition of their integrated nature.

2.5 The Single Schedule Market Project

The SSM project will replace the two-schedule system with a single schedule that aligns dispatch and prices. This means that rather than a uniform market price, Ontario will implement locational prices.

In addition, the introduction of a SSM will facilitate the implementation of other important changes to the energy markets, such as the establishment of a DAM and ERUC, and set the foundation for further market enhancements in the future. By sending price signals that are accurate, the SSM project is a critical step forward in aligning our market design with operational and system needs.

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[31] http://www.ieso.ca/en/Market-Renewal/High-Level-Designs/Energy-Stream-High-Level-Designs

2.6 The Day-Ahead Market Project

The introduction of a DAM will provide financially-binding schedules for participating resources a day in advance of operation. This will encourage all resources to participate more fully and efficiently in the day-ahead timeframe. Almost all other North American electricity markets include DAMs and most of the supply is typically scheduled and settled in the DAM whereas the real-time market is used to balance deviations that occur between day-ahead and real-time. Resources that participate in the DAM benefit from a hedge against price volatility in the real-time market caused by changes in supply and demand, and consumers benefit from more efficient and cost-effective decisions overall. For the IESO it means operators will be able to rely on firm resource commitments reducing uncertainty in pre-dispatch and real-time.

2.7 The Enhanced Real-Time Unit Commitment Project

The ERUC project will be a security-constrained unit commitment process[32] that will replace both the current pre-dispatch process and the RT-GCG program and will help to ensure that when changes in system needs arise in the pre-dispatch time frame, the most cost-effective set of resources will still be available to meet demand in real-time. It will result in pre-dispatch schedules and unit commitments that better reflect the total cost of NQS resources that are based on a longer, more efficient optimization timeframe.

ERUC will introduce three-part offers into the unit commitment process including energy, start-up and speed-no-load costs which will also increase transparency and competition within the commitment process. It will improve the efficiency of commitment decisions in the intra-day timeframe by optimizing over multiple hours rather than solving for each hour independently. It will jointly optimize energy and operating reserves to determine the optimal mix of resources to meet load and it will produce binding start-up instructions and operational commitments. The differences between the existing programs and the programs under ERUC are shown below in Figure 2-3.

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[32] A security-constrained commitment process considers key system operational constraints in order to optimize dispatch while maintaining system security. These constraints include reserve requirements, transmission security constraints and generation limitations

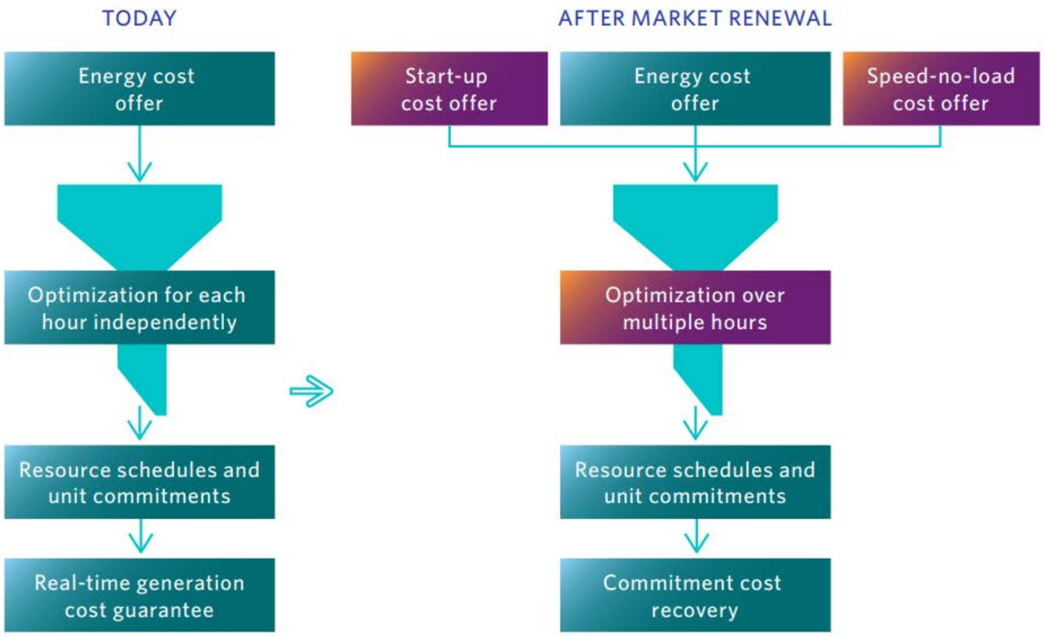

Figure 2-3: Changes to the Unit Commitment Process

3. MRP Energy Stream Benefits

3.1 Introduction

This chapter describes the key benefits associated with the MRP Energy Stream projects, and is divided into the following sections:

- Operational, Reliability and Efficiency Benefits
- Addressing Out-of-Market Payments
- Reduced Gaming Opportunities
- Enabling the Future Market
- Broader Market Benefits
- Financial Benefits

3.2 Operational, Reliability and Efficiency Benefits

The IESO is the reliability coordinator, balancing authority, transmission operator and market administrator for Ontario and is required to ensure that reliable electricity is available where and when people need it. This work has become more challenging as the supply mix has evolved in recent years. Resources are more variable and the system is less flexible, and demand profiles have been changing significantly which has made efficient operation of the system challenging.

These issues are compounded by the IESO's current market design. As described in further detail below, design changes introduced by the SSM, DAM, and ERUC projects will provide wide ranging improvements to system operations and will help to better manage reliability in the future.

3.2.1 Operational, Reliability and Efficiency Benefits from the SSM

As described in Chapter 2, the current energy market includes a number of flawed design features including the misalignment of price and dispatch, sub-optimal day-ahead scheduling and single-hour pre-dispatch optimization. During unexpected events in particular, inaccurate pricing and inefficient scheduling and commitment can exacerbate reliability concerns for the IESO. To mitigate the shortcomings of the current design, the IESO must rely on complex out-of-market programs and payments, and be prepared to manually intervene in the market if needed.

Benefits of a SSM

The SSM will provide the foundation for better market operations as it will send accurate locational prices to Market Participants (suppliers and price responsive loads) that better reflect system needs and constraints. The SSM will eliminate the two-schedule system and the need for out-of-market real time congestion payments by introducing locational prices that create alignment between pricing and dispatch on the system. Market prices will account for congestion and losses and will reflect the true costs of producing electricity at a given place and time. These transparent price signals will enhance open competition between Market Participants and therefore lead to more efficient outcomes across the system.

SSM Summary

- Better alignment of prices with system needs leads to improved operations and reliability as conditions change
- Elimination of unnecessary and unwarranted CMSC payments
- Improved visibility of operator interventions

The SSM also includes improvements to pricing signals during out-of-market operations when required. This will improve the visibility of operator interventions in the market and allow Market Participants to respond accordingly.

In addition, the introduction of a SSM will establish the foundation for the IESO to implement other important changes to the energy markets.

3.2.2 Operational, Reliability and Efficiency Benefits from the DAM

A sound operating plan is the key to being reliable in real-time. Real-time market operations begin with this operating plan and are adjusted as necessary to take into account actual and evolving system and market conditions. All market and system operators in the US[33]create an operating plan for the next day by using cleared bids and offers from day-ahead markets for

DAM Summary

- Additional operational certainty and reduced risks for the IESO
- Improved Market Participant certainty
- Better coordination with neighbouring jurisdictions
- A hedge against price volatility in the real-time market for suppliers and loads
- More efficient dispatch and lower system costs

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[33] For the purpose of the business case "system operators" refer to Independent System Operators and Reginal Transmission Operators

energy.[34,35] Planning for next day operations in many other jurisdictions involves creating an "Operating Plan Analysis" that allows for an understanding of system conditions including power flows, the identification of system operation limits that require monitoring, the development of contingencies, and coordination of mitigation plans. Resources financially commit to supply or purchase power day ahead, providing confidence to the system operator that they know which resources will be available to meet real-time demand.

The IESO, in contrast, creates its plans using the EDAC which only provides partial information in the day-ahead timeframe due to a lack of participation of some resources (e.g. exports). IESO operations must then fill in the gaps with patterns of Market Participant behaviour from previous days, but actual participation in real-time remains uncertain and there is no guarantee or incentive to ensure resources will actually be available on the next day. Since the day-ahead schedule is based upon a sub-optimal design, the IESO's real-time operational assessments consistently differ from the day-ahead schedule. When the operating plan significantly deviates from system conditions in real-time it can signal and result in operational challenges for the IESO. These challenges introduce hard to quantify risks that become more apparent when system conditions tighten or unforeseen circumstances arise. This is illustrated in the following example from the IESO Control Room.

Case Study #1

The EDAC Fails to Commit Sufficient Resources and System Conditions Change

On July 7, 2017, the EDAC process had committed only one NQS resource. The number of NQS resources committed by the EDAC is often low because exports tend not to bid in the day-ahead timeframe given that they do not receive financially-binding schedules. As such EDAC does not provide a complete picture of market demand for the following day. This can be a problem because when exports do materialize it creates uncertainty closer to real-time and the IESO Control Room has fewer internal resources that have already been committed and scheduled available that have the flexibility to respond to unanticipated system conditions. Although the IESO has many control actions it can utilize, these are typically second best options compared to using the energy market to efficiently schedule and dispatch resources.

On this day, at 08:17, only one other NQS resource had committed itself through the RT-GCG program, a pre-dispatch engine that does not optimize over the entire day and does not recognize the characteristics of NQS generators. However, system conditions had started to change significantly. Demand started to rise beyond what was forecasted and 187 MW of total reserve

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[34] The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018", 2019 FERC and NERC Staff Report, July 2019.

[35] "Normal Operations Planning Process", CAISO, July 12, 2018, https://www.caiso.com/Documents/3200.pdf

shortfalls were materializing into the next hour. By 08:37, reserve shortfalls were forecasted to continue. Demand was running approximately 250 MW higher than expected and wind production was approximately 600 MW below pre-dispatch results.

The IESO Control Room did not have sufficient NQS resources readily available to mitigate the reserve shortfalls without resorting to manual control actions. It had to curtail 302 MW of exports, manually dispatch two generators, adjust the wind forecast, and increase the demand forecast by up to 500 MW for future hours. These control actions were necessary and effective in meeting demand and ensuring reliability, but costly compared to a more efficient market design. With exports committed in a DAM the IESO would have had a more complete picture of market demand for the following day, and would likely have committed and scheduled additional internal resources providing increased flexibility and operational certainty for the IESO Control Room, potentially avoiding the need for as many control actions. An improved pre-dispatch and real-time unit commitment would have also provided better tools to manage the changes from day-ahead to real-time.

The Benefits of a DAM

A DAM is a recognized best practice among other system operators for introducing additional certainty and reducing risks in operations, and a DAM will provide this same benefit to the IESO. In the future, developing a sound operational plan will largely be an outcome of the DAM.

All Market Participants, especially gas and hydro resources, will also benefit from the improved certainty provided by a DAM in their own operations. The IESO will time the completion of the DAM specifically for the timely gas nomination window to provide gas generators with more certainty on gas procurements, and hydro resources will be able to benefit from better information to support more effective water management. All resources participating in the DAM will benefit from better certainty in day-to-day operations such as other operational and staffing needs. More broadly, Ontario will also benefit from better coordination of exports and imports of electricity with neighbouring jurisdictions.[36] Under the current design, an exporter will not know the actual purchase price for power bought from the Ontario market until after it has been scheduled. This creates significant risk which must be factored into trading decisions, increasing the cost of trade and diminishing the potential benefits to the system from efficient trading.

Experience from other wholesale electricity markets shows that the introduction of a financially-binding DAM is a key tool for ensuring reliable operations and can produce significant efficiency gains. For example, Southwest Power Pool is a large market with a high penetration of intermittent

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[36] “Congestion Payments in Ontario’s Wholesale Electricity Market: An Argument for Market Reform”, Market Surveillance Panel, December 2016

wind generation and faces similar operational challenges to the Ontario market such as large swings in demand over the course of a day. Southwest Power Pool introduced energy market reforms in 2014 including a day-ahead market which has had a dramatic impact. It has been estimated that approximately 5,000 MW of generation was being inefficiently committed under the old design [37] in the absence of a day-ahead market. The new design provided a material improvement to operator certainty reducing the need to over commit resources.

3.2.3 Operational, Reliability and Efficiency Benefits from the ERUC

Ontario's electricity market uses a pre-dispatch mechanism to aid in creating scheduling certainty ahead of real-time. As such, pre-dispatch helps to transition cost-effectively from day-ahead scheduling to reliable real-time operations as conditions such as demand and supply change. Pre-dispatch does not produce a financial guarantee for most resources but provides information on how they will likely be dispatched so that they can prepare for real-time operations.

ERUC will introduce three-part offers into the unit commitment process including energy, start-up and speed-no-load costs which will increase transparency and competition within the commitment process. It will improve the efficiency of commitment decisions in the intra-day timeframe by optimizing over multiple hours rather than solving for each hour independently. Just like the DAM, it will jointly optimize energy and operating reserves to determine the optimal mix of resources to meet load and it will produce binding start-up instructions and operational commitments.

ERUC Summary

- Considers all hours in the look-ahead period
- Includes realistic resource characteristics
- Relies on internal resources first for supply and demand differences
- More efficient dispatch that reflects all supplier information including incremental energy, start-up, and speed-no-load offers

Pre-dispatch currently only looks at each hour in isolation, it does not optimize over multiple hours and it therefore does not consider critical resource characteristics such as ramp rates. This means that the current pre-dispatch process produces infeasible dispatch schedules, and IESO Operations has to do significant work to fill in the gaps. This is illustrated by an example from the IESO Control Room.

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[37] The Future of Ontario's Electricity Market - A Benefits Case Assessment of the Market Renewal Project, The Brattle Group, April 20, 2017, pg. 36.

Case Study # 2

Pre-Dispatch Produces Infeasible Schedules

January 20, 2019 was cold and windy, with temperatures forecasted to reach -20°C and a wind chill of -33°C in the Greater Toronto Area. Between 3,500 MW and 3,900 MW of wind was scheduled, and there was significant demand uncertainty as there were no similar representative days to use for demand forecasting. As a result, the IESO added 200 MW of Flex Operating Reserve to the 30 minute Operating Reserve Requirement from 08:00 to 22:00.[38] Pre-dispatch scheduled several NQS units to provide this reserve, but the current energy market algorithms scheduled these resources below their minimum load point which was technically infeasible. Units cannot operate below their minimum load point but pre-dispatch had ignored these technical constraints and scheduled them for the minimum amount necessary to satisfy the energy or operating reserve needs of the system. In order to resolve this issue and maintain reliability, the IESO Control Room was required to perform an adequacy and reliability assessment and to take manual actions to avoid any potential problems.

Pre-dispatch also showed exports to the Outaouais region of western Quebec all day. On the previous day, Hydro Quebec was experiencing tight conditions and declared an Energy Emergency Alert 3, meaning that some load shedding was in progress, and Hydro Quebec was anticipating January 20 would be another tight day. The IESO Control Room contacted Hydro Quebec to ask what impact curtailing Outaouais exports would have on them. Hydro Quebec indicated that this could potentially cause them to have to shed additional load.

In this example, the current design produced an infeasible schedule that not only impacted the Ontario market, but also had the potential to impact Ontario’s neighbours. Pre-dispatch would likely have carried on producing infeasible schedules throughout the day if the IESO operators did not take manual actions. In this case, the IESO Control Room managed the situation by constraining on one of the NQS resources to provide reserve and flexibility from 17:00 to 20:00. ERUC will avoid these types of issues by recognizing NQS characteristics and also by optimizing the schedule throughout the day, reducing the frequency of manual operator interventions.

The Benefits of ERUC

In terms of providing improved certainty to IESO Operations, ERUC has similar benefits to the DAM, but over a different time frame. ERUC will consider all hours in the look-ahead period (from the DAM

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[38] For an overview of the IESO’s Flex Operating Reserve, see “Enabling System Flexibility Using Operating Reserve”, IESO, June 27, 2019. Available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mdag/MDAG-20190627-Enabling-System-Flexibility.pdf?la=en

schedule to real-time) and will include resource characteristics including realistic ramp rates, which will create conditions that require fewer operator actions. ERUC also excludes intertie transactions more than 2 hours out unless they are scheduled in the DAM, which means that Ontario will rely on internal resources first to resolve differences in forecasted supply and demand instead of external resources, which is considered more reliable by the IESO.

This design change will result in more efficient scheduling of resources and lower system costs. As an example of this, the new look-ahead period will enable energy limited resources (e.g., hydro generators) to be dispatched at a time that is both optimal for the system and within the bounds of the resource's daily energy limits.

3.3 Hydro Modelling

Certain types of hydro resources (e.g., cascade hydroelectric generating units) have unique operating characteristics[39] which will be respected in the new energy market design. These resources represent nearly one-quarter of Ontario's available capacity and it is important for broader market efficiency that the design enables them to be effectively optimized.

In the current market, the EDAC does not recognize the unique operating characteristics of hydro resources, but it provides them a resubmission window to revise offers to allow them to manage infeasible schedules. Retaining this resubmission window in the new market design is not possible as the day-ahead is financially-binding and by allowing hydro resources to improve their DAM settlements after-the-fact, provides an unfair advantage over other resources.

To address these concerns, the new market design will model additional hydro resource characteristics in both the day-ahead and pre-dispatch timeframes. Modelling these additional resource characteristics will improve resource optimization and increase the likelihood that hydro resources receive feasible schedules. In this regard, additional modelling of hydro resources will provide a number of benefits including:

- Supporting fair competition and avoiding the requirement for a resubmission window
- Providing the IESO and Market Participants with greater operational and financial certainty
- Reducing system costs as better scheduling and dispatch of hydro resources is likely to displace higher cost resources

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[39] Hydroelectric resources have unique operating characteristics as a result of physical equipment limitations, regulatory requirements and environmental requirements

Overall, additional modelling of hydro resources will provide greater certainty and improve transparency to help reduce costs across the whole system.

3.4 Reduced Gaming Opportunities

The complexity of the current system and significant number of administrative and non-transparent workarounds creates opportunities for gaming and unwarranted transfer payments. These actions may include market manipulation or the exploitation of an existing market defect. Both the Market Surveillance Panel and the IESO have found that identifying and addressing the many types of gaming behaviour and unwarranted transfer payments is difficult and time-consuming. Since market opening, the IESO and the Market Surveillance Panel have conducted several investigations into gaming and recovered significant sums which have been returned to electricity customers. These investigations highlight the scale of gaming and of the exploitation of market defects occurring in Ontario's markets under the current market design.

Gaming Design Flaws:

- In recent years the IESO has analyzed, investigated and clawed back over $360 million in inappropriate payments from Market Participants
- These issues will persist while we rely on the current two-schedule system

The implementation of the MRP Energy Stream will eliminate the two-schedule system and the need for unnecessary CMSC payments, and it will also lead to a more transparent and competitive platform for NQS commitments by ensuring dispatch reflects incremental energy, start-up, and speed-no-load offers. By eliminating CMSC payments and by introducing energy market prices that more accurately and transparently reflect marginal production costs, the potential for gaming CMSC through inefficient bidding and from exploiting flaws in the RT-GCG program will be eliminated.

3.5 Enabling the Future Market

Changes introduced by the new energy market design will provide a robust platform to meet the uncertainty of future need to evolve the energy markets to address emerging power system needs. Policy and technological change have transformed the Ontario electricity system and further evolution can be expected with the growth of new emerging, intermittent and distributed resources. The current market design with its well documented inefficiencies is inadequate to support the future changes. The new energy design will support further market enhancement down the road regardless of how future needs evolve.

Reducing out-of-market actions and payments means that more costs flow through the market in a transparent manner. Increased transparency and operational certainty will create a better investment environment for existing and new market participants. The changes will also enable Market Participants to better anticipate future needs and incentivize innovative solutions to meet emerging challenges. Chapter 6 will further explore how these benefits are impacted under a range of potential future market scenarios.

3.6 Broader Market Benefits

Other qualitative benefits provided by the new energy market design include:

- **Supporting investment signals and competition:** transparent locational prices will provide improved signals for locating resource and infrastructure investments in areas where it can provide the most value. As an example, investment in new generation and/or transmission will be attracted by higher locational prices in zones that are import-constrained. Over time, system costs would be expected to fall as the new investment helps to reduce system constraints. More accurate and robust price signals will also help new entrants determine their competitiveness relative to conventional resources.
- **Improved price signal for flexibility:** under the current two-schedule design, price signals for resources to provide flexibility by ramping up or down to meet demand fluctuations are muted and based on an unconstrained system. With the introduction of SSM, the use of actual resource ramp rates and consideration of system constraints will produce accurate and transparent prices that will better value flexibility and incentivize resources to respond and invest to meet ramping needs.
- **Reduced curtailment and spilling:** inefficient price signals in the current market result in unnecessary curtailment and spilling of low-marginal-cost resources such as hydro, wind, and nuclear generation. More efficient pricing will better incent demand to respond to low prices and reduce curtailment and spilling, which in turn could reduce system costs. Reduced spilling from hydro resources should also increase taxpayer revenues from hydro rental charges.[40]

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[40] The Province of Ontario collects a hydro rental charge on behalf of the taxpayer for the use of water by hydroelectric resources. These charges cannot be collected when hydro resources spill water. On this basis, less hydro spilling as a result of the new market design should increase revenues from the hydro rental charge.

3.7 Financial Benefits

The IESO investigated and assessed the potential financial benefits associated with the MRP Energy Stream.[41] These assessments included the development of models to estimate improvements in market efficiencies and the reduction of CMSC payments, as well as the collection of information on issues such as gaming and the benefits achieved through similar market changes in other jurisdictions. These financial benefits are discussed in the following sections.

3.7.1 Quantifiable Market Efficiencies

The quantified market efficiencies are the reduction in total costs incurred to meet the electricity requirements of Ontario. Examples of these costs include the fuel needed to produce energy, fees incurred to acquire and store fuel, and other expenses necessary to operate a resource for electricity production.

The MRP Energy Stream aims to reduce system costs by eliminating the inefficiencies of the current market. The quantifiable system benefits of the MRP Energy Stream are derived from three main areas that remedy the sources of today's market inefficiencies:

1. More efficient unit commitment;
2. Improved intertie pricing; and
3. Locational pricing incentivizing increased resource competition

The next sections describe the approach to calculate the benefits from each of these areas.

More Efficient Unit Commitment

Resource commitment plays an important role in the electricity market as it provides time and certainty to NQS resources, such as a combined-cycle gas turbine facility, to make necessary arrangements to produce energy. As explained previously, the current commitment process does not take all this information into account when making commitments, leading to inefficient resource selections. The more efficient commitment process will be designed to consider all resource costs and respect individual operational characteristics over multiple hours of the day. As a result, the inefficiency costs associated with today's commitment process will be eliminated.

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[41] The financial benefits numbers presented in this section are on a nominal basis.

As a proxy of the inefficiency costs of today's commitment process, over 1,300 historical resource commitments were individually inspected. A re-dispatch of resources to meet demand was undertaken with each individual resource commitment removed and replaced by resources that were available and not previously scheduled. The total costs to meet demand from the re-dispatched case were compared against the total costs with the original commitment and its start-up costs. If the re-dispatched costs were lower, the inefficiency cost of the commitment was the difference between the two values, otherwise, the commitment was efficient. A rate of commitment inefficiency was calculated by summation of the costs of inefficient commitments and dividing this total cost by the total volume of energy produced by NQS in the year. The analysis indicated that about 1 in 6 commitments have been inefficient and resulted in additional $0.80/MWh costs. Based on IESO's 2019 System Planning Outlook projections of energy produced by NQS, ERUC is expected to deliver savings of approximately $190 million in its first 10 years of operation.

This saving is a conservative assessment since it did not include the inefficiencies associated with the singular hourly commitment by the pre-dispatch scheduling process compared to the multi-hour commitment under ERUC. A pre-dispatch model with multi-hour commitment is to be designed in MRP and was not available to be used to calculate these inefficiencies. For this reason it was not possible to calculate the value of this inefficiency.

Improved Intertie Pricing

Imports are efficient if it is cheaper to bring less expensive energy into Ontario from a neighbouring market than to use a resource in the province that costs more to generate the electricity. Exports out of Ontario are efficient if the price that can be received from the destination market is greater than the costs to generate the additional energy for trade across the intertie. In today's market the price of imports and exports is based on an unconstrained price that at times overvalues or undervalues the energy flowing across the intertie. The price at an intertie is calculated as the sum of Intertie Congestion Price (ICP) which represents the cost of transmission congestion through the intertie and the unconstrained Market Clearing Price (MCP) valuing energy produced or consumed in Ontario. If the locational marginal price near the intertie is different than the Ontario MCP because of internal[42] congestion, the intertie price calculated will not be accurate and may result in higher costs. The MRP Energy Stream will correct the pricing at the interties by factoring in the locational marginal price at the intertie in addition to the ICP. To further explain the inefficiency of the current calculation of

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[42] Not to be confused with congestion through the intertie valued at ICP.

intertie prices consider the proceeding example shown in Figure 3-1, which illustrates an inefficient export flowing from Ontario to the Midcontinent Independent System Operator (MISO) market:

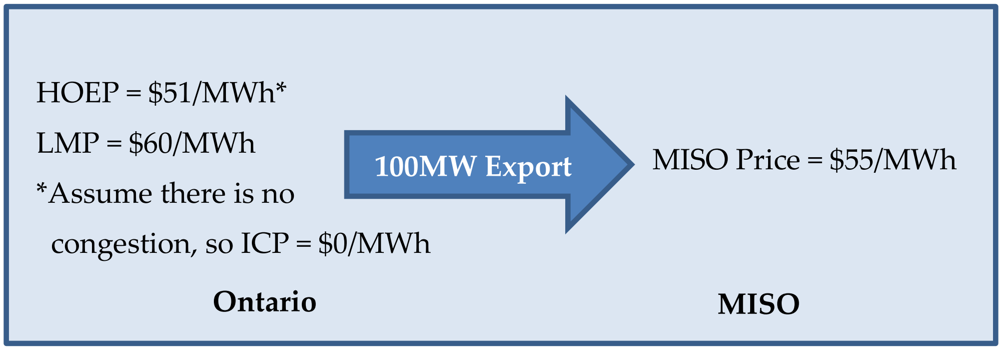

Figure 3-1: Example of Inefficient Export from Ontario to the MISO market

The Ontario unconstrained Hourly Average Energy Price (HOEP) clears at $51/MWh. There is no export congestion at the tie resulting in an ICP of $0/MWh. Exports flowing to MISO would be charged $51/MWh+$0MWh. In this case the 100MWh scheduled to flow to MISO is seemingly efficient given that the MISO price for energy flowing from Ontario would be paid $55/MWh. However, for that export, a more reflective price is the cost of generation at the locational price (LMP) adjacent to the interface. In this example the LMP is $60/MWh. Using this LMP as the correct price for the value of the export, a cost of ($60/MWh - $51/MWh) × 100MWh = $900 is incurred. If the correct intertie pricing based on the LMP was used, this export would have not occurred. This calculation does not include commitment costs that may have been incurred for the inefficient export. If the correct price was used at the intertie, this export would not have occurred and the costs of the generation needed to serve the export would have been incurred.

As the volume of intertie transactions can vary over the years, an assessment of intertie transactions of several years from 2015 to 2018[43] was done. The assessment indicated that on average 9% and 13% of net exports to MISO and the New York Independent System Operator respectively have been inefficient. These rates of inefficiency translate to about $4.60 and $3.10 of costs incurred per MWh of net exports to MISO and New York Independent System Operator respectively.

Projecting the inefficiency costs of net exports[44] avoided with improved pricing at the interties, a total of approximately $285 million is expected to be saved over the first 10 years MRP is in operation.

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[43] Intertie transactions were assessed over this time period due to availability of data

[44] Based on System Planning Outlook projections, Ontario will continue to be energy adequate and a net exporter of energy in the 10 years studied for calculation of benefits. Therefore, the analysis does not include inefficiencies associated with imports

Locational Pricing Incentivizing Increased Resource Competition

As described in section 2.2.1, CMSC is a necessary by-product of the two-schedule energy market to ensure resources follow dispatch should the unconstrained price be insufficient and result in lost operating profits. Since CMSC is settled after-the-fact and separate from the pricing signal, the value of energy production and consumption is muted. With a muted pricing signal and CMSC compensating for lost operating profits, market participants have little reason to seek additional revenue opportunities by competing against other resources. Under locational pricing, market participants would have a strong incentive to be infra-marginal (to maximize revenue/profits) and not just recover their operating costs. Studies have indicated that well-functioning organized electricity markets have incentivized resources to improve their processes to become more efficient and competitive in the market. One paper particularly relevant to Ontario given the similar shift to locational pricing is the experience in the Electric Reliability Council of Texas where moving to a LMP electricity market led to over 2% reduction in costs[45].

To calculate the impact of increased incentives for competition with LMP for dispatchable resources in Ontario, a simulation of market outcomes was performed. Since many resources in Ontario are effectively hedged and receive fixed-rates for their production of energy, the simulation performed was adjusted to only include a subset of Ontario electricity resources that have an opportunity to increase revenue by being more competitive. A simulation assuming a subset of such resources located in an uncongested area reducing their offers by 2% was performed. This is a very conservative assumption to apply the offer reduction at the low end of estimates to a few applicable resources that represent less than 10% of the total supply capacity in Ontario. The results indicated that increased competition resulting from locational pricing would deliver approximately $50 million of savings in the first 10 years.

Total Quantifiable Market Efficiencies

In sum, the new market design with the MRP Energy Stream in place is expected to deliver a total of $525 million in system related market efficiencies in the first 10 years and would persist thereafter.

The efficiencies are sensitive to supply and demand variations so the market efficiencies were assessed against the supply and demand outlooks contained in the IESO's System Planning Outlook. The combinations of supply and demand outlooks that bookend the high and low benefit estimates are shown in Table 3.1.

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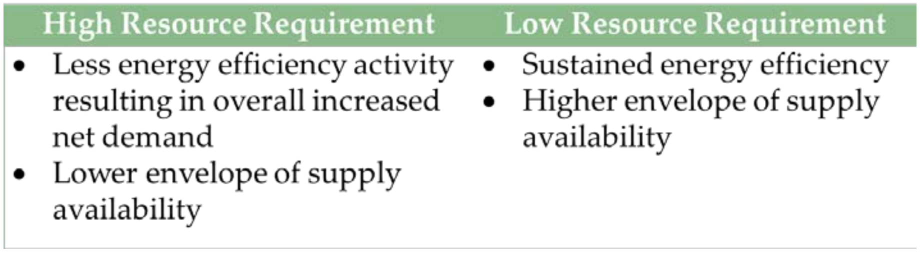
[45] Zarnikau, J., C.K. Woo, and R. Baldick. "Did the introduction of nodal market structure impact wholesale electricity prices in the Texas market?" Journal of Regulatory Economics 45.2 (2014).

Table 3-1: Combinations of Supply and Demand Outlooks



High Resource Requirement	Low Resource Requirement
• Less energy efficiency activity resulting in overall increased net demand • Lower envelope of supply availability	• Sustained energy efficiency • Higher envelope of supply availability

Using the bookend combinations of outlooks, the market efficiencies ranged from $500 million on the low end to $550 million on the high end. The narrow range of the benefits can be explained by how the variables in the models are inter-related. In the High Resource Requirement Case, the increased demand requires more supply resources to meet Ontario needs. The use of more supply requires more commitments and higher benefits would result from using improved commitments. The higher requirement of supply also means competition would be more intense. Finally, a higher demand requirement in Ontario is also likely to result in lower net exports out of Ontario. With reduced net exports, the benefits from improved intertie pricing would be lower. On balance, the High Resource Requirement case results in the lower bound of benefits. The Lower Resource Requirement has the opposite effect and this case results in the higher bound of benefits.

Both scenarios contained factors that could increase and decrease the potential benefits. On the one hand these offsetting factors results in a relatively tight range of benefits. On the other, the narrow range provides a high degree of confidence that even under different system conditions the market efficiencies would be realized. Overall, the net impact on the total market efficiencies from different supply and demand outlooks should be minimal. The cumulative total system market efficiencies are shown below in Figure 3-2.

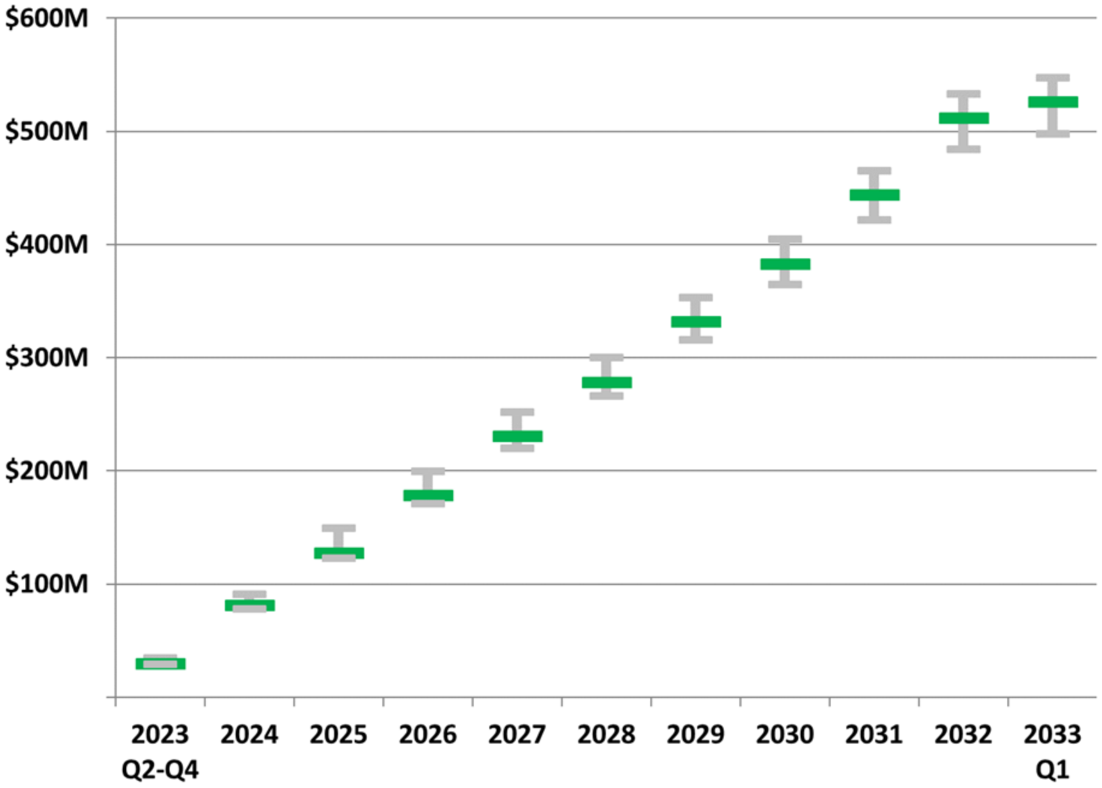
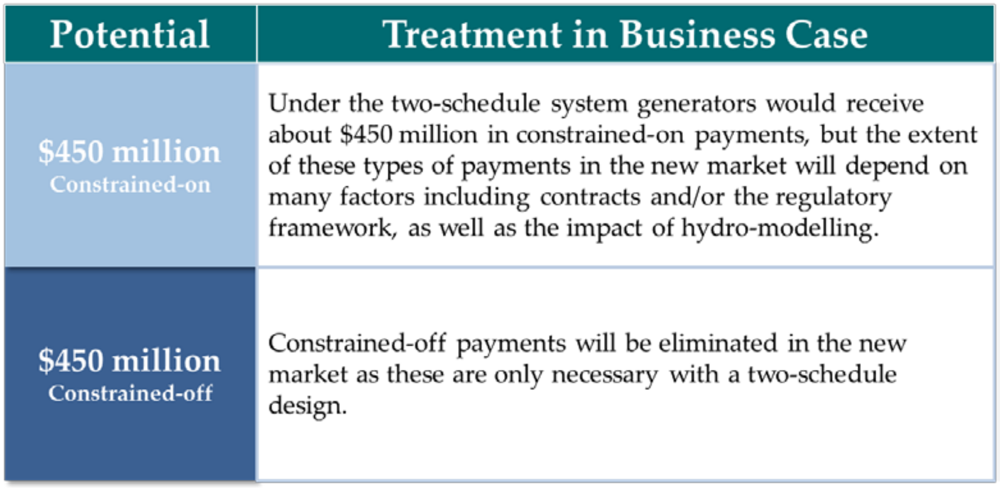


Figure 3-2: Cumulative Total Market Efficiencies

3.7.2 Quantifiable Reductions in CMSC Payments

In addition to and separate from the market efficiencies described above, the MRP Energy Stream will bring about direct customer benefits through the elimination of CMSCs, which are recovered through uplift and paid by all consumers including market participant loads. Using historical data, the IESO estimated that over the first 10 years of the new market, $900 million in CMSC payments would be incurred if Ontario kept its current market design. As shown in Figure 3-3, these consist primarily of constrained-off and constrained-on CMSC payments.



Potential	Treatment in Business Case
$450 million Constrained-on	Under the two-schedule system generators would receive about $450 million in constrained-on payments, but the extent of these types of payments in the new market will depend on many factors including contracts and/or the regulatory framework, as well as the impact of hydro-modelling.
$450 million Constrained-off	Constrained-off payments will be eliminated in the new market as these are only necessary with a two-schedule design.

Figure 3-3: Key Components of CMSC Analysis 2023-33

In the new market all of the constrained-off CMSC payments would be avoided, and the IESO has a high degree of confidence that the $450 million of constrained-off CMSC avoided represents a direct benefit to customers of the new market design.

Constrained-on CMSC payments will also be eliminated. However, some of these costs will be more transparent and represented in locational prices and others will be dependent on their treatment in contracts and the regulatory framework. Others will be reflected in make whole payments for reliability.[46] It is uncertain the exact proportion of these costs that will be incurred by customers as payments in a different form. Due to this uncertainty, the benefits from constrained-on CMSC have been excluded.

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[46] Make-Whole payments will be required under a limited set of conditions (e.g., constraint violations, co-optimization with operating reserve or emergency control actions) where locational prices are not always able to reflect the cost of balancing the system. The need for make-whole payments under the new design is expected to be infrequent and immaterial.

3.7.3 Unquantified Financial Benefits

Before describing the total financial benefits, it is worth discussing several other categories of financial benefits that are meaningful but difficult to determine with a high degree of confidence. These include the financial benefits associated with a day-ahead market in the Ontario context, the financial benefits from improved consumption and investment, as well as those associated with the availability to do future improvements in the market.

Previous IESO analysis as well as analysis from other jurisdictions points to potentially significant financial benefits associated with the implementation of a day-ahead market. In 2008, the IESO estimated that a DAM would create efficiency savings of approximately $24 million per year. [47] Experience from other jurisdictions points to even higher benefits. Southwest Power Pool's 2014 market reforms generated benefits of approximately USD $260 million per year, most of which were associated with the introduction of a DAM through a 10% reduction in the over-commitment of generating capacity. Brattle has estimated that on the high end, Ontario could realize as much as 75% of these benefits by implementing a DAM.[48]

These numbers indicate the potential magnitude of direct benefits from a DAM. Due to differences between the Southwest Power Pool market and Ontario it is unclear what share of these potential benefits would be realized by consumers. As such, they were viewed as too uncertain for inclusion in the financial analysis.

Other benefits from a day-ahead market such as improved day-ahead signaling, hedging for embedded and distributed resources, improved intertie scheduling, further improvements to in-province day-ahead dispatch, and increasing benefits at high intermittent resource levels have not been quantified and are not addressed further here.

In the renewed market, unwarranted out-of-market payments – both CMSC and the RT-GCG program and improper behaviour by Market Participants - will also be eliminated. To date, the IESO has clawed back about $360 million of unwarranted CMSC and RT-GCG associated with gaming behaviours occurring within the current two-schedule system. Actions have been taken to address inappropriate market behaviours in a variety of forms, but gaming behaviours continue and can be difficult to catch and eliminate.

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[47] IESO, "Day-ahead Market Evolution Preliminary Assessment" May 6, 2008. Converted to 2021 CAD. This value includes $5 million per year for reduced over-commitment, $16 million per year for reductions in natural gas fuel procurement costs, and an additional $3 million per year from demand response due to improved day-ahead price forecasts.

[48] The Brattle Group, "The Future of Ontario's Electricity Market - A Benefits Case Assessment of the Market Renewal Project" April 20, 2017, pg. 36 and 39.

The IESO also expects financial benefits from improved consumption and more efficient investment decisions. Without the new market, the IESO will be unable to take full advantage of new technologies, respond effectively to an evolving operating and regulatory environment, or benefit from changing technology costs that are transforming the energy sector elsewhere. However, due to the large inherent uncertainties in these benefits, they have not been quantified at this time.

3.7.4 Total Expected Financial Benefits

As described throughout this chapter, the IESO has identified a number of broad categories of potential benefits from the MRP Energy Stream. Several of these categories, such as market efficiency benefits and avoided CMSC payments, can be quantified and represent direct benefits to consumers in Ontario.

Quantifying benefits where possible has allowed the IESO to be able to estimate a conservative lower bound on the total expected financial benefits of the MRP Energy Stream. The process that the IESO used to determine this estimate is summarized below in Figure 3-4. As shown in the Figure, savings from the MRP Energy Stream were calculated by excluding benefits that cannot be quantified with a high level of confidence and only including benefits it expects to realize with a high degree of certainty.

Using certainty as a guideline, the IESO calculates that the MRP Energy Stream is expected to conservatively yield financial benefits of just under $1 billion. This consists of the full suite of market efficiency benefits ($525 million, 54% of total expected savings), and constrained-off CMSC ($450 million, 46% of total expected savings). The full amount of constrained-on CMSC, the benefits from a day-ahead market, improved consumption and more efficient investment decisions, avoided gaming, future improvements, and previously discussed qualitative benefits from multi-hour optimization, hydro modelling, have all been excluded from the estimate.

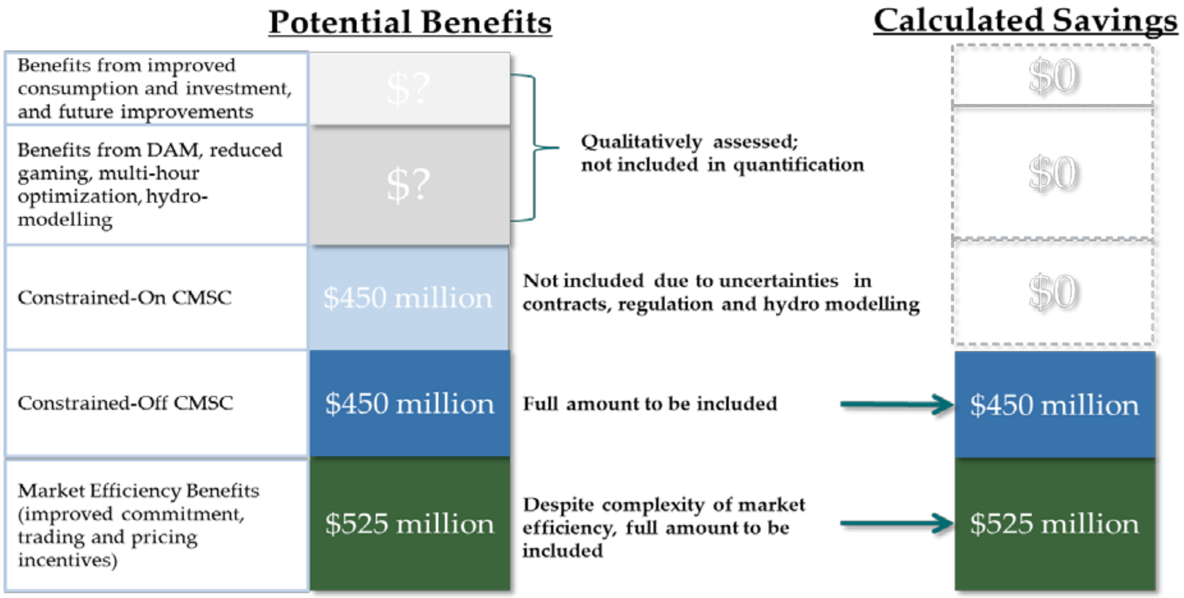

Figure 3-4: Summary of Expected Financial Benefits Included and Not Included

The source of the expected financial benefits is summarized in Figure 3-5 below. As described in this figure, constrained-off CMSC payments are separate from regulated and contract payments, and will no longer be paid in the new market. This in effect represents a direct benefit to consumers.

Finally, the IESO expects several different sources of financial savings from market efficiencies. These consist of the savings from ERUC, improved intertie pricing, and locational pricing incentivizing increased resource competition as detailed earlier in this chapter.

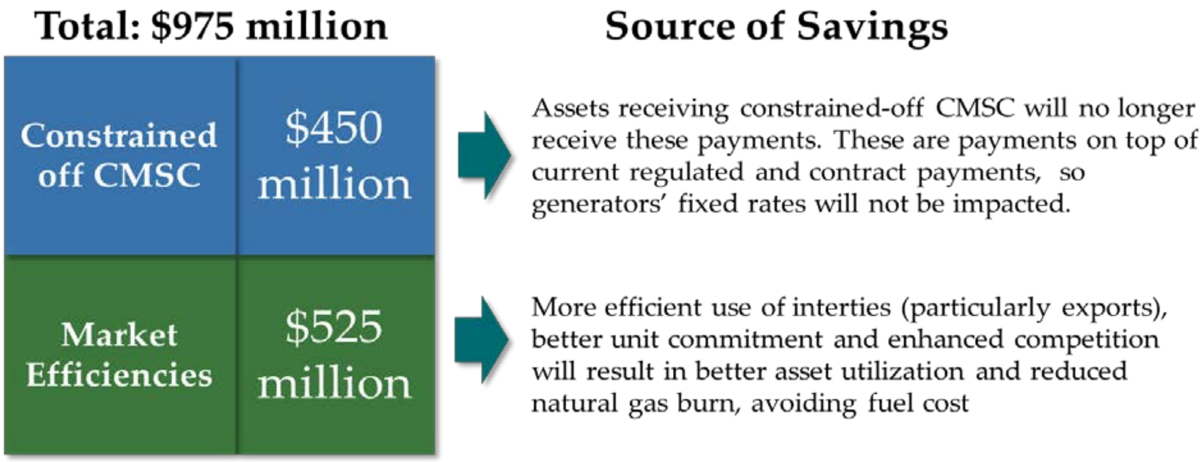

Figure 3-5: Summary of Total Benefits

4. Expected Costs and Implementation

4.1 Process

In 2019, the IESO performed a bottom-up work planning and scheduling exercise spanning the remainder of the program timeframe. This exercise allowed for greater confidence in the cost estimates than previously available through other estimating methods. With any multi-year program, detailed scheduling and planning can evolve over time so the information included in the MRP Business Case is based on the latest information available.

4.2 Schedule

The MRP Energy Stream is labour intensive throughout the program. The combination of the effort required to complete the various activities along with recruiting available resources with the requisite specialized skills (both within and external to the IESO) has had a major impact on the resulting program schedule.

This culminates in the importance of the Go Live date when the new markets are turned on and all of the supporting Information Technology (IT) solutions, systems, market rules and processes become active. The bottom-up estimating process described has resulted in a scheduled Go Live date of March 2023, and a Program closure of September 30, 2023 with six months of contingency.

Figure 4-1 provides information on the Energy Stream schedule to the Go Live date.

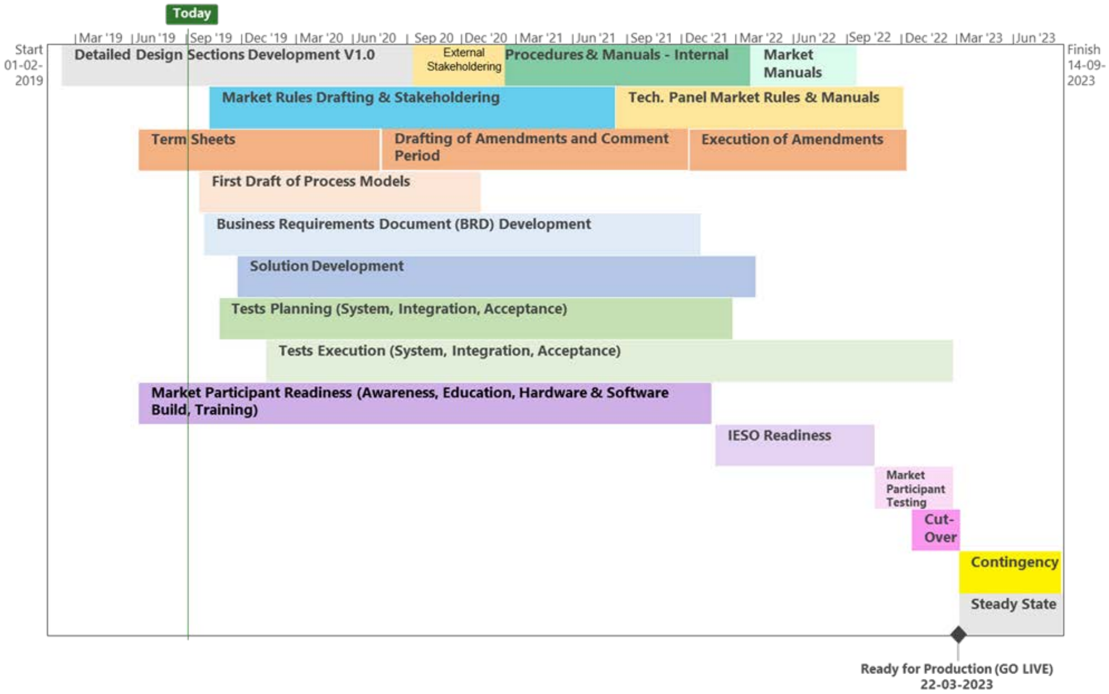

Figure 4-1: MRP Energy Stream Schedule

4.3 Included Costs

For the purposes of this business case, the IESO examined direct program-related costs incurred by the IESO associated with designing, implementing, testing and operationalizing the new market structures. Actual costs incurred cover the period from January 1, 2017 – June 30, 2019. Estimates of future costs cover the period from July 1, 2019 through to Go Live in March 2023.

For the purposes of the Net Present Value (NPV) calculation, an examination of IESO avoided costs has been performed. This looked at both the period during which the program is under development, as well as the 10-year period following Go Live coincident with the benefits modelling.

The result of this work revealed that during development of the program, there was no significant net avoided cost to capture. While the IESO may have some avoided costs by not pursuing otherwise regularly scheduled IT maintenance or changes, those cost savings would be offset by costs associated with implementing ad hoc fixes during the period until the new systems were in place. While there may be some minor savings and costs, the net result of combining the two was negligible, and not material to the costs otherwise presented.

For the period following Go Live, the IESO included costs associated with the steady state period, up to one year following Go Live. Those costs are captured in the direct program costs. For the remainder of the post Go Live benefits modelling period, the IESO looked for avoided costs to capture, but similar to the program development period, did not identify any significant avoided costs to include in the NPV calculations.

4.4 Identified Impacts Not Included

Throughout the high-level design phase, stakeholders have expressed diverse views and varied expectations as to what costs they feel should be included in the MRP Energy Stream business case. The IESO acknowledges that Market Participants may need to make changes to IT hardware or software, change existing processes, and add new processes or retire old processes.

At the time of developing the business case, as a result of the detailed design phase being under development, there was not enough information available for stakeholders to fully assess how they might be impacted either through increased costs or realized savings.

The IESO looked to other system operators who have completed significant market change programs to determine if they had any insight into participant costs that might be leveraged. For various reasons, including the nature of the market change programs completed and different market participation models, it was found that market participant costs varied considerably.

As a result, the IESO has no effective way of estimating potential cost or saving impacts to stakeholders at this time. The IESO cannot track Market Participant costs and therefore these impacts have not been included as part of the costs in the business case.

4.5 Market Renewal Cost Accounting

The MRP Energy Stream uses an activity-based accounting framework. There are core resources assigned to the program, and there are various corporate shared services (e.g. administration, procurement and resourcing/recruiting) that charge their costs to the program for the direct support they provide. Support provided to facilitate the extensive stakeholder engagement activities and communications required are also included. These costs include IESO labour, rental fees for stakeholder engagement venues, audio visual equipment rental and support to facilitate interactive web-participation and recording as required.

The MRP also required additional office space to be leased for the dedicated program team to work out of. Physical overhead costs including rent, furniture, relocation, and telephone/IT assets have all been included in the program costs. In cases where the IESO has incurred or plans to incur incremental costs above and beyond our normal level of operation, those incremental costs have been captured in the MRP cost estimates.

4.6 Date for Cost Estimates

The cost estimate portion of the MRP Energy Stream Business Case has been prepared as of June 30, 2019. All costs covering the period of January 1, 2017 – June 30, 2019 are actual costs directly attributed to the MRP Energy Stream and costs that were previously shared between the Energy Stream and Capacity Stream, the latter of which is no longer part of the Market Renewal Program[49]. For 2019, these shared costs were referred to as the General stream. For the period of January 1, 2017 – June 30, 2019, all common shared MRP costs not directly captured under Energy or Capacity have been apportioned to the MRP Energy Stream at 50%.

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[49] In July 2019, the IESO announced it would stop further work on the current High-Level Design for the Capacity Stream. For further information please see: http://ieso.ca/-/media/Files/IESO/Document-Library/engage/ica/2019/MRP-20190716-Communication.pdf?la=en

4.7 Estimating Uncertainty

Estimating uncertainty reflects the fact that costs are being estimated over the next 4 years with imperfect information. The HLD's were finalized and published on August 8, 2019, and the detailed design engagement process will begin during Q3-Q4 2019. Figure 4-2 highlights some of the key MRP Energy Stream milestones against a *Cone of Uncertainty*.

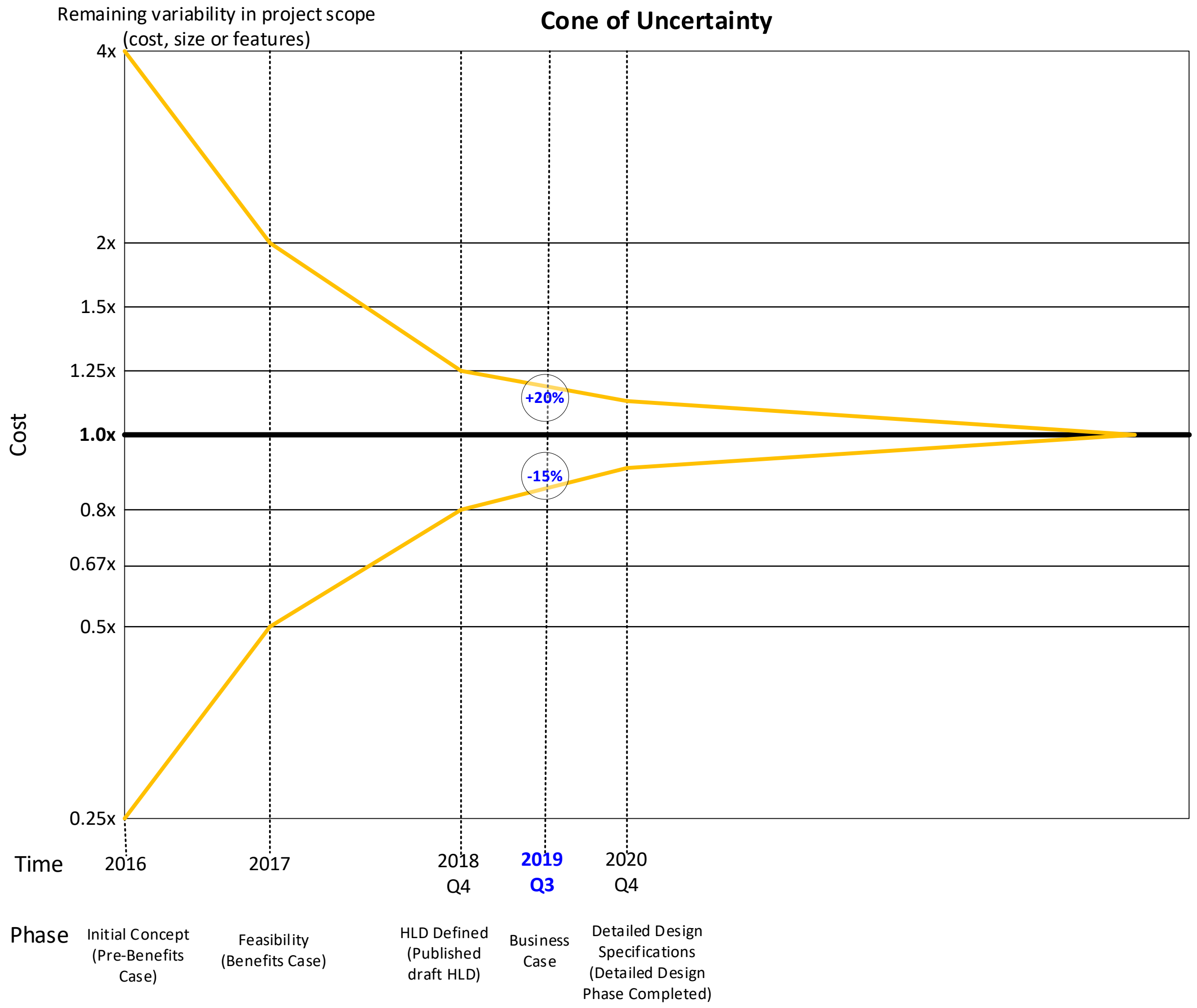

Figure 4-2: MRP Energy Stream Cost Category

The inclusion of a range of estimated costs is prudent for this business case and consistent with industry practice.

4.8 Program Cost Summary

The Market Renewal Program will cost $170 million (including $16 million contingency) in capital and operating funds, and will be implemented over of seven years (includes 6 months contingency) from January 2017 to September 2023.

The budgeted cost of the program ranges from $151 million to $194 million based on an uncertainty cost estimation tolerance of ***- 15% to +20%***,[50] due to the Detailed Design phase targeted to be completed in 2020. The summary details are shown in Figure 4-3.

The capital component of the program cost is $131 million (excludes $15 million contingency). The operating component of the program cost will be $23 million (excludes $1 million contingency).

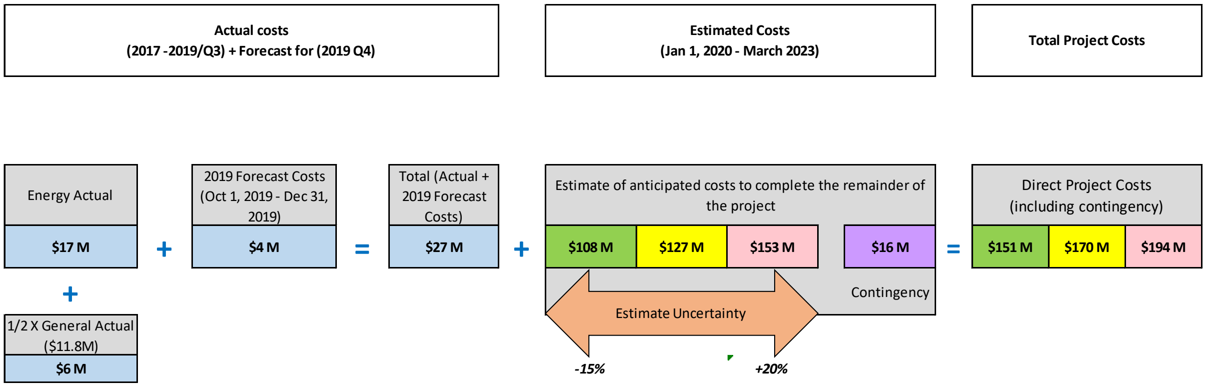

Figure 4-3: MRP Energy Stream Cost Summary

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[50] The range of -15% to +20% is consistent with the current level of uncertainty, see Figure 4-2.

4.9 Program Cost Details

4.9.1 Capital and Operating cost breakdown

Based on the approval for $170 million (including $16 million contingency) of capital and operating funds to implement MRP. The program costs are comprised of both capital and operating components as shown in Figure 4-4.

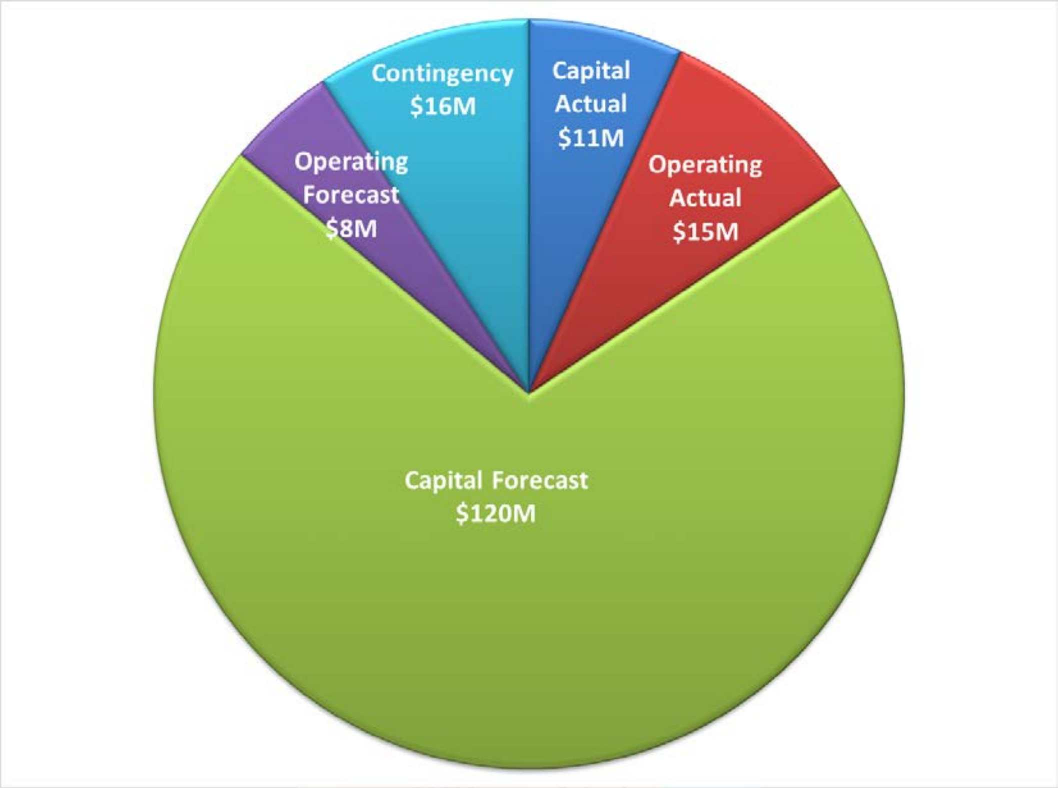

Figure 4-4: MRP Energy Stream Capital and Operating Costs Summary

4.9.2 Annual Capital and Operating Cost Breakdown

These costs cover the period from January 1, 2017 through to September 30, 2023. The annual breakdown of costs is shown in Figure 4-5.[51]

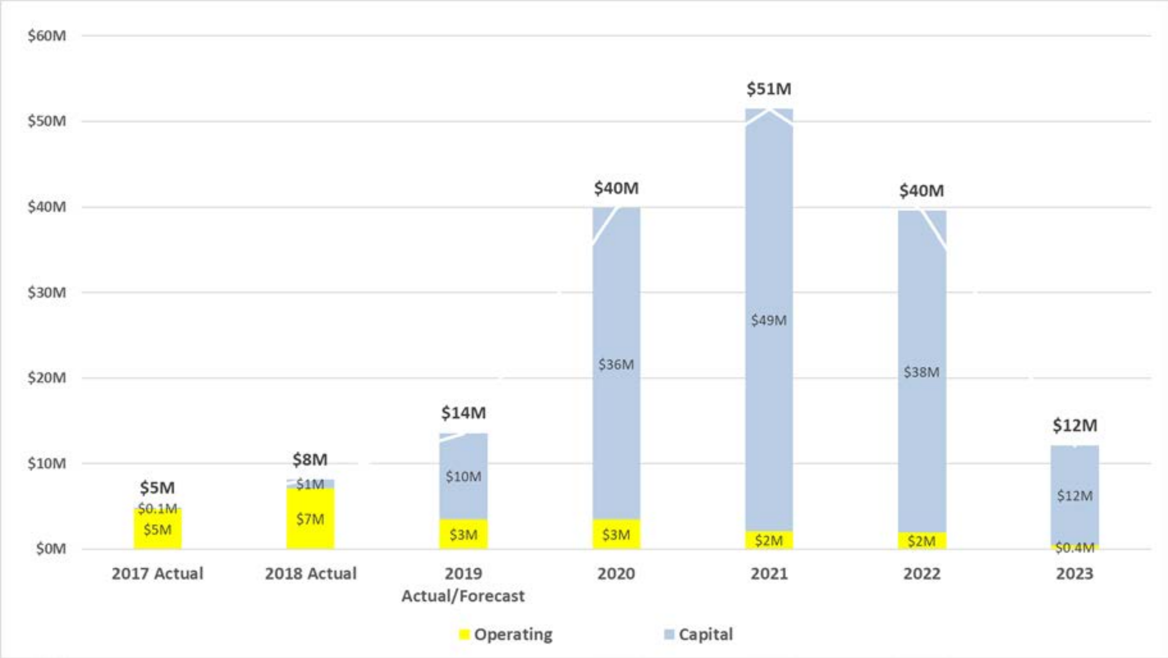

Figure 4-5: MRP Energy Stream Annual Cost Breakdown

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[51] Note that the summary numbers in Figure 4-5 are rounded.

4.9.3 Program Phase Cost Breakdown

The costs have also been allocated by program phase as shown in Figure 4-6.[52] The implementation phase is estimated to be the largest phase with investment costs at $111 million, accounting for 65% of the total program estimate, followed by the detailed design phase estimated at $28 million which accounts for 16%.

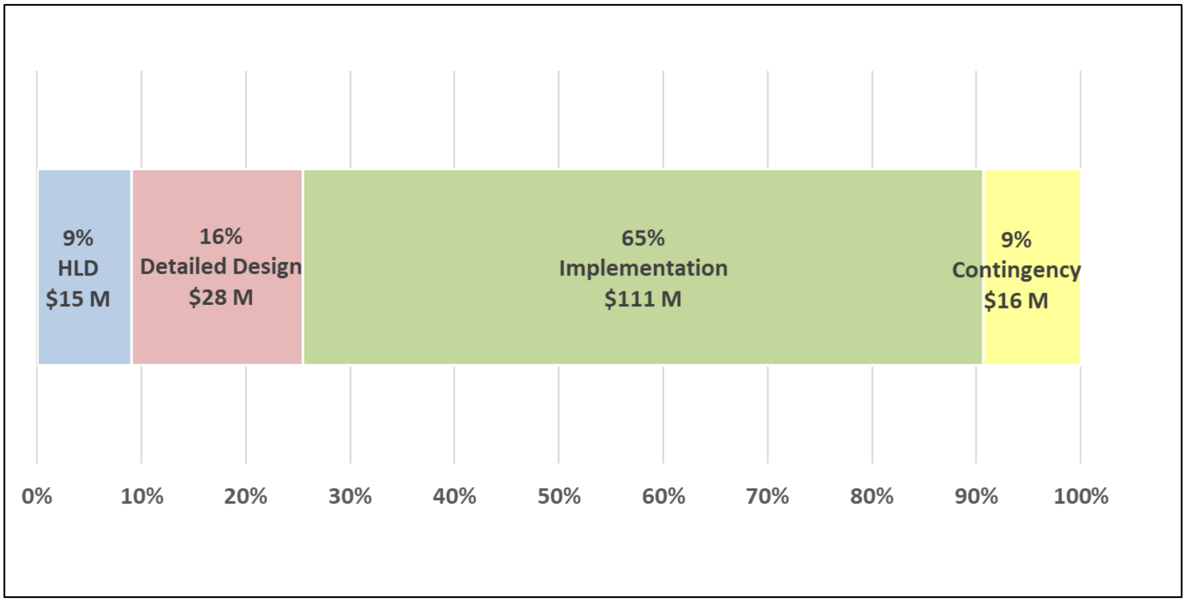

Figure 4-6: MRP Energy Stream Cost per Phase

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[52] Note that the numbers have been rounded

4.9.4 Program Cost Category Components

The program costs are divided into five category components namely: IESO Labour, IT (Hardware and Software), Professional and Consulting, Contingency and Other (Interest and Rent) as shown in Figure 4-7.

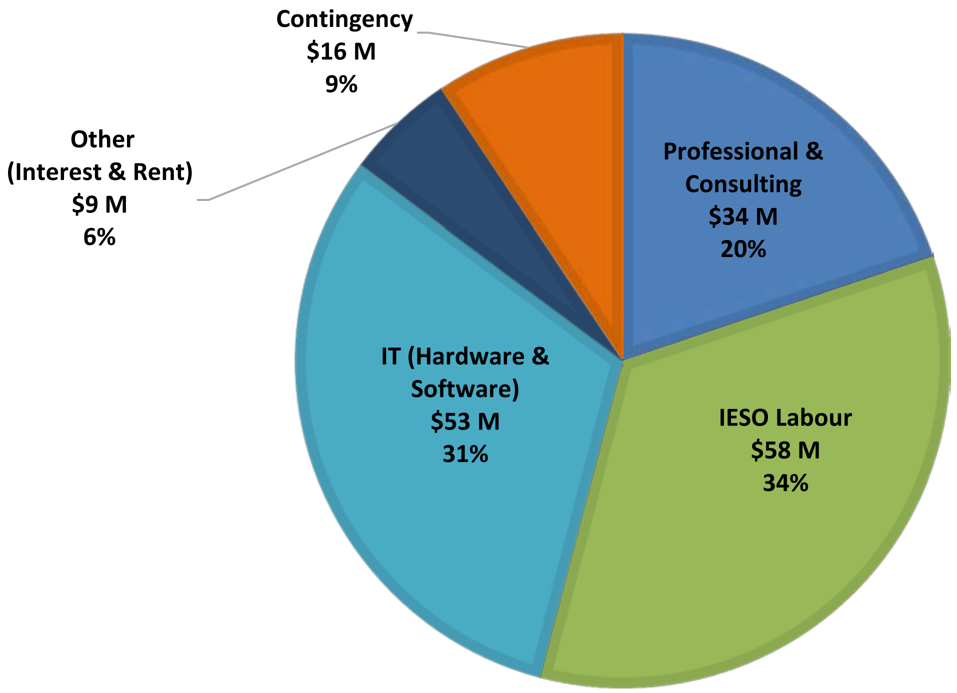

Figure 4-7: MRP Energy Stream Cost per Category

IESO Labour Costs

The total labour cost of $58 million is comprised of the actual labour costs to date plus the annual average full time equivalent (FTE).

The IESO does not have sufficient specialized resources to implement a program on the scale of the MRP Energy Stream while at the same time continuing to deliver on our core mandate obligations. IESO labour costs described above include both full time regular staff and temporary contract staff. Even with the addition of temporary staff, the IESO requires specialized knowledge and skills which are not available through a temporary employment relationship.

Professional and Consulting Costs

The estimated costs for professional and consulting support are $34 million, which is further broken down in Figure 4-8.[53]

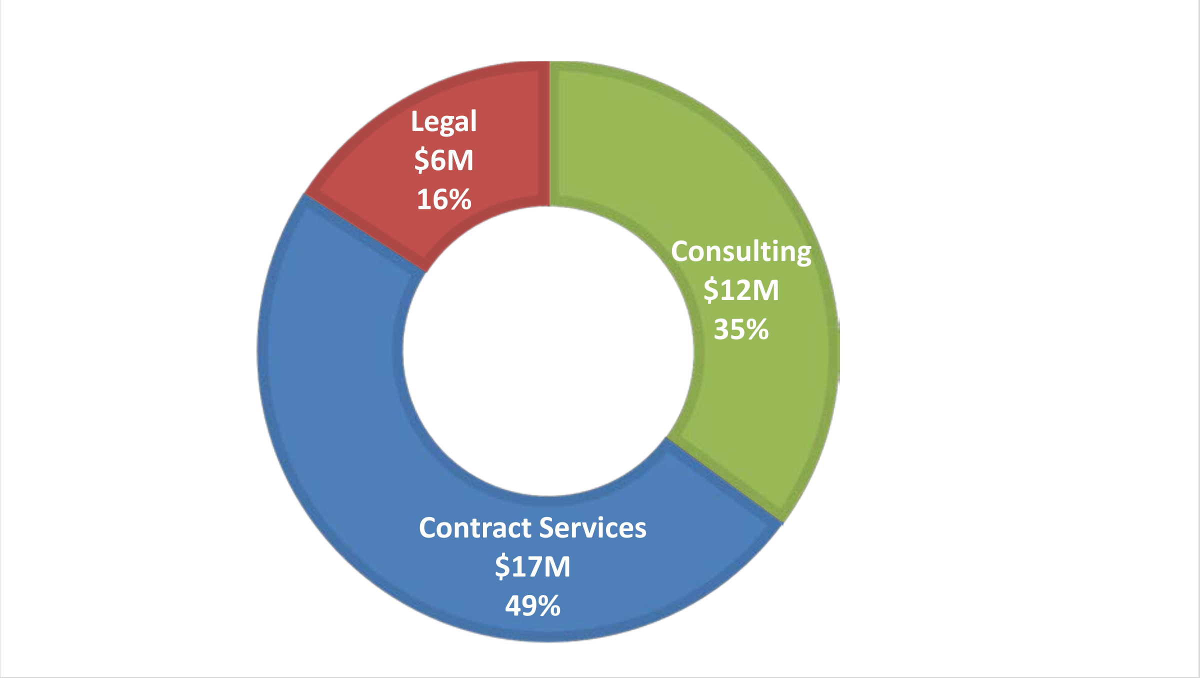

Figure 4-8: MRP Energy Stream P&C Breakdown

The consulting category includes North American or global consulting firms specializing in energy market design. This expert support augments the IESO labour effort. Contract Services includes areas where the IESO can augment its team with outsourced or insourced contractors. Examples of the

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[53] Note that the summary numbers in Figure 4-8 are rounded.

services include specialist contractors covering topics such as optimization, Ontario energy market participation, electricity grid and market operation, generation operation, design and system integration, and market rules drafting. Resources such as project management support, business analysis, quality assurance and testing will be secured on short-term arrangements through agencies to augment IESO temporary direct hires and offer temporary surge capacity for program peaks. Various audit services including risk, Dispatch Scheduling and Optimization (DSO) calculation, and settlement calculation are included. Legal services include: Legal Support for MRP designs, electricity supply contract changes and governance.

IT (Hardware/Software) Costs

IT costs for both hardware and software comprise $53 million of the program costs for a total of 18 systems. The largest single cost component is the DSO solution, representing 58% of the total IT costs. Figure 4-9 provides a breakdown of the various components of this cost category.

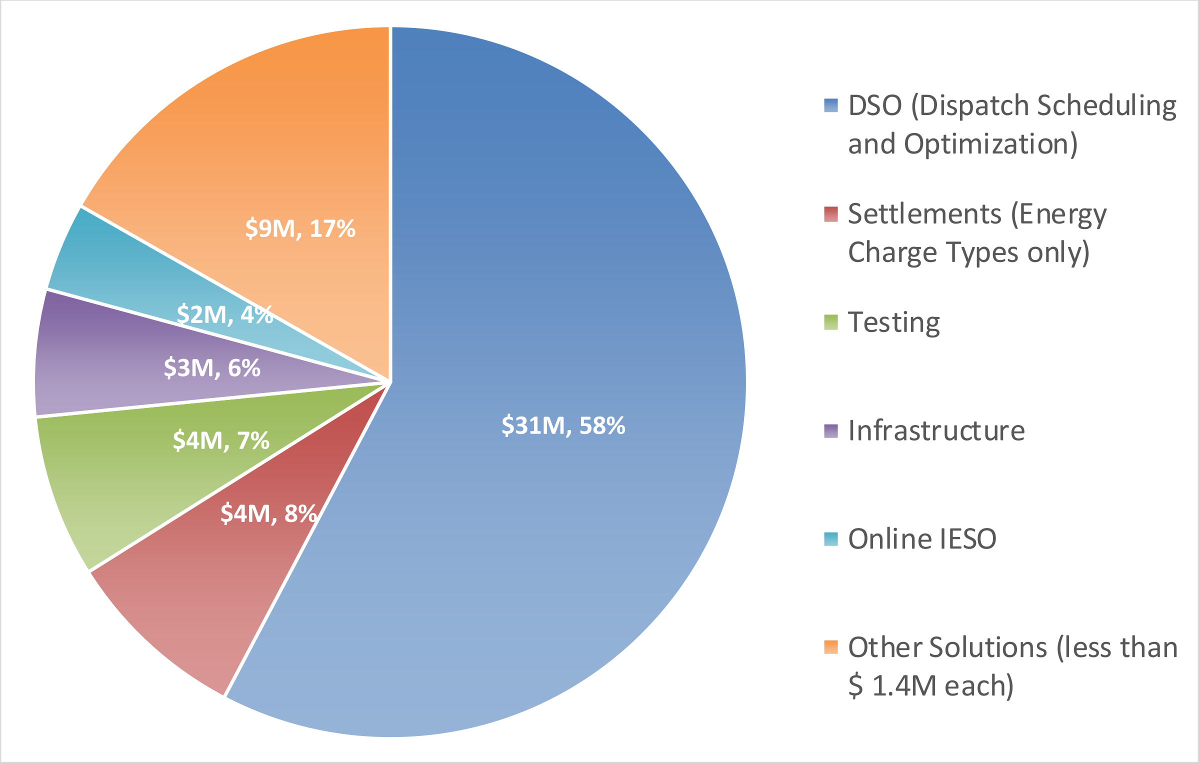
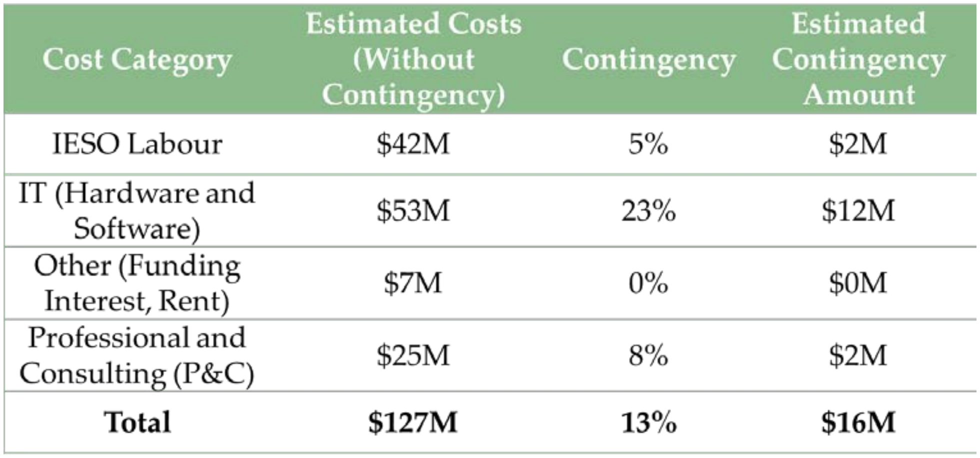


Figure 4-9: MRP Energy Stream IT (Hardware/Software) Breakdown

Contingency Costs

Contingency is a sum of money set aside at the start of a program to be used in case of need, for example, to offset unforeseen increases in costs. The amount of contingency carried depends on the level of risk the program faces and also on the overall program budget itself. Contingency has been examined based on the different cost categories, and is summarized in Table 4-1.

Table 4-1: MRP Energy Stream Contingency Breakdown



Cost Category	Estimated Costs (Without Contingency)	Contingency	Estimated Contingency Amount
IESO Labour	$42M	5%	$2M
IT (Hardware and Software)	$53M	23%	$12M
Other (Funding Interest, Rent)	$7M	0%	$0M
Professional and Consulting (P&C)	$25M	8%	$2M
Total	**$127M**	**13%**	**$16M**

The MRP Energy Stream has three overlapping phases. There is not a hard line delineating the detailed design and implementation phases. In order to effectively manage both the work and the resources required to complete it, some implementation activities will begin during the detailed design phase, while some detailed design activities will continue into the implementation phase.

An example of this is creation and finalization of the detailed design document. The schedule identifies that the first complete version of the detailed design document will be available for stakeholder review by the end of March 2020. The IESO is currently planning that in the weeks and months following, the IESO and stakeholders will work together to further explain and address any issues or concerns identified with the detailed design document. By September 2020, the IESO expects to have a final detailed design complete that incorporates any changes resulting from the detailed design process. This time period would effectively be identified as falling within the detailed design phase.

At the same time, there are elements of the detailed design that may not have any impact on Market Participants, but rather impact internal IESO processes or systems. Subject to resource availability, the IESO will look to begin work on implementation activities where practicable during the detailed design phase in order to help expedite the schedule.

The implementation phase will commence in 2020 and is anticipated to take approximately 36 months, concluding with the MRP Energy Stream Go Live estimated in March 2023.

4.10 IESO Implementation

The implementation phase of the MRP Energy Stream will include development of market rules, development of market manuals, development of internal or external facing processes and procedures, development or modification of IT systems and solutions, including software and hardware, testing, preparation for Go Live and system “cut-over”, and finally Go Live with all of the new tools and processes.

The IESO will also be engaging with Market Participants and stakeholders throughout this phase. Market rules will be developed and shared with stakeholders as they move from drafting through to the technical panel review process. Similarly, the IESO will be engaging Market Participants specifically with respect to how IESO system and process tool changes will affect them, and what Market Participant changes may be required in order to participate effectively with the new markets. Plans and details on how this stakeholder engagement will unfold will be shared with stakeholders once they have been sufficiently developed.

4.11 Market Participant Support and Readiness

In addition to the implementation activities for the IESO set out in the previous section, Market Participants will need to have their own individual plans to prepare their organizations and facilities for the new energy market. Similar to the IESO, Market Participants will need to understand how the market changes may impact their own IT solutions (hardware, software), internal processes and procedures and other areas of interest to their businesses.

While the IESO is not in a position to develop or execute these Market Participant plans, the IESO has a responsibility to ensure that we are providing Market Participants with timely, relevant information to allow Market Participants to implement their own plans on a timeline that is consistent with the IESO’s activities and ultimately the Go Live date.

This will be a highly interactive process. It will start during the Detailed Design, with the work on specifying data requirements, and will continue with work on technical IT interfaces, and finish with multiple stages of testing.

The IESO will be providing test environment(s) for Market Participant testing and market trials. The IESO will also be supporting and coordinating the testing. There will be multiple stages of testing, starting from basic connectivity testing, through more complex test cases, to end-to-end testing.

4.12 Contract Management

The IESO acknowledges that there are many stakeholders with IESO contracts where specific details or provisions in those contracts will need to change as a result of the changes contemplated by the MRP Energy Stream. An example is the elimination of the HOEP with the introduction of the SSM.

While the contract management processes, including amending contracts, are not formally part of the MRP Energy Stream scope, the IESO acknowledges that the two processes – energy design and implementation, and contract management, need to move together in a coordinated fashion in order for the IESO and stakeholders to be ready for Go Live. As a result, the IESO has shown contract management activities on the overall program schedule, as they are of significant interest to stakeholders.

4.13 Post-Implementation Costs

After the program has been implemented there is expected to be some additional ongoing incremental maintenance costs. These post-implementation costs over the first 10 years following implementation have been estimated to be an additional $6 million.

The total of the program and post-implementation costs taken together have been estimated at $176 million, with a range of $157 million to $200 million. Chapter 5 uses these totals in the financial assessment of the MRP Energy work stream.

5. MRP Energy Stream Financial Assessment

5.1 Introduction

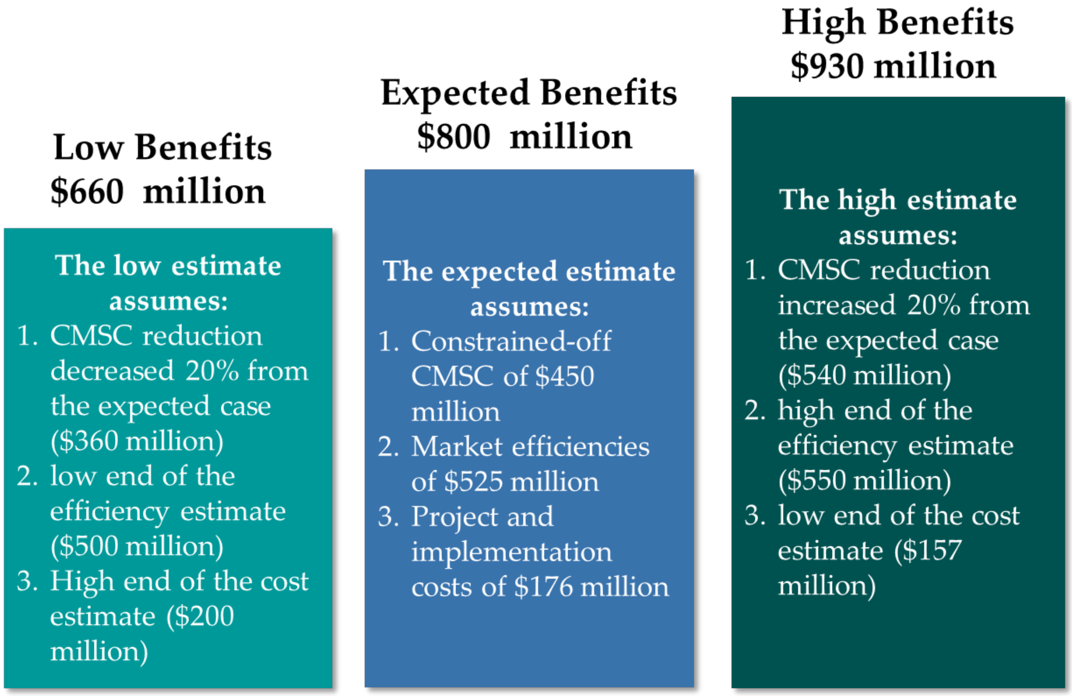
The expected financial benefits of the MRP Energy Stream were outlined in Chapter 3, and the associated costs of the program have been described in Chapter 4. In this chapter, these benefits and costs have been incorporated together in an NPV analysis to estimate the net financial benefits of the program.

NPV analysis is a valuation tool used for determining the value of a capital program. It calculates the difference between the present value of all future financial benefits and costs of a program. If the NPV is positive, it indicates that the financial value of the benefits in today's dollars is greater than the program costs. While other unquantified benefits and costs or non-financial factors need to be considered, a strongly positive NPV and associated benefit-to-cost ratio is often a good indication that a program makes financial sense.

This Business Case has recognized the importance of uncertainty in estimating the benefits and costs in previous chapters, and the financial assessment presented in this chapter takes a similar approach. The IESO has developed an Expected NPV Case along with a Low NPV Case and a High NPV Case for the costs and benefits in order to determine a realistic range for the total net benefits of the MRP Energy Stream, as well as for the NPV analysis. To quantify the sensitivity to key inputs and capture the potential for lower probability outcomes, a Monte Carlo simulation was conducted to further stress test these results.

5.2 NPV Results

Three cases were developed to capture the potential ranges of the benefits and costs of the MRP Program as well as the NPV results including: 1) an Expected NPV Case, 2) a Low NPV Case and 3) a High NPV Case. The Expected NPV Case represents the IESO's best estimate of the net financial benefits from the MRP Energy Stream, while the Low NPV Case and the High NPV Case were developed to capture the potential ranges for market efficiencies, program and implementation costs and savings from constrained-off CMSC presented in previous chapters. The resulting range of total net benefits is shown in Figure 5-1. As shown in the figure, this range is $660 million to $930 million.



Low Benefits
$660 million

The low estimate assumes:

1. CMSC reduction decreased 20% from the expected case ($360 million)
2. low end of the efficiency estimate ($500 million)
3. High end of the cost estimate ($200 million)

Expected Benefits
$800 million

The expected estimate assumes:

1. Constrained-off CMSC of $450 million
2. Market efficiencies of $525 million
3. Project and implementation costs of $176 million

High Benefits
$930 million

The high estimate assumes:

1. CMSC reduction increased 20% from the expected case ($540 million)
2. high end of the efficiency estimate ($550 million)
3. low end of the cost estimate ($157 million)

Notes: figures rounded

Figure 5-1: Total Expected Net Benefits Range

To calculate the NPV of these benefits, a financial model was developed. The model uses a time frame that captures all the relevant costs for the program life cycle from 2017-2023, and the first 10 years of estimated benefits from 2023-2033, along with associated incremental implementation costs for these years. The model also uses weighted average cost of capital assumptions for different years as the discount rate used to assess the present value of future benefits and costs. The IESO's actual weighted average costs of capital for years in which MRP has already been in development (2017-2019) ranges from 1.8% to 2%. A cost of borrowing of 4% is used for the years remaining until implementation of MRP is completed (2020-2022). Finally, a higher discount rate of 6% is used for later years consistent with longer term borrowing costs (2023-2033).[54] These assumptions are outlined in Table 5-1.

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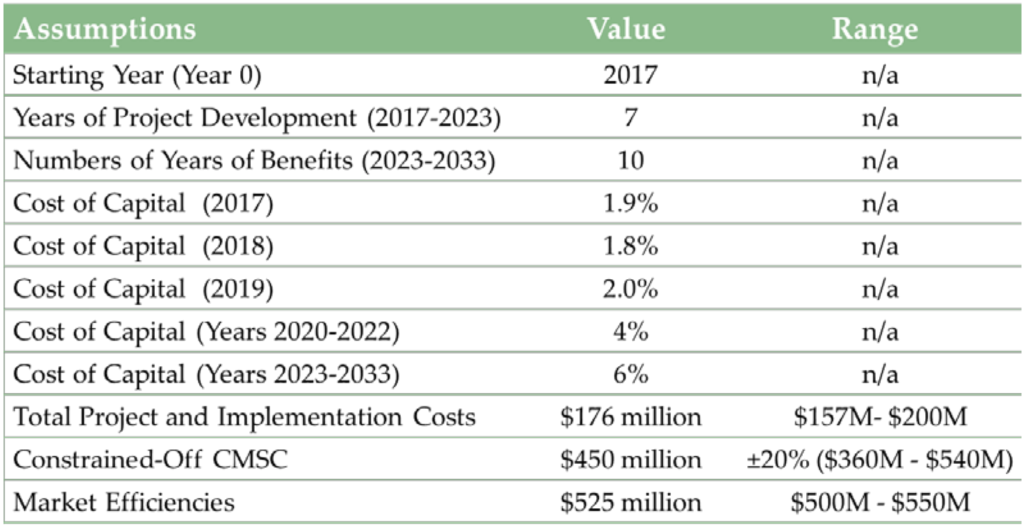
[54] A discount rate of 6% is consistent with the social cost of capital used by the province for large capital projects in the public sector by non-profit entities. Commercial entities typically use a higher discount rate to reflect the higher costs of borrowing and profit expectations.

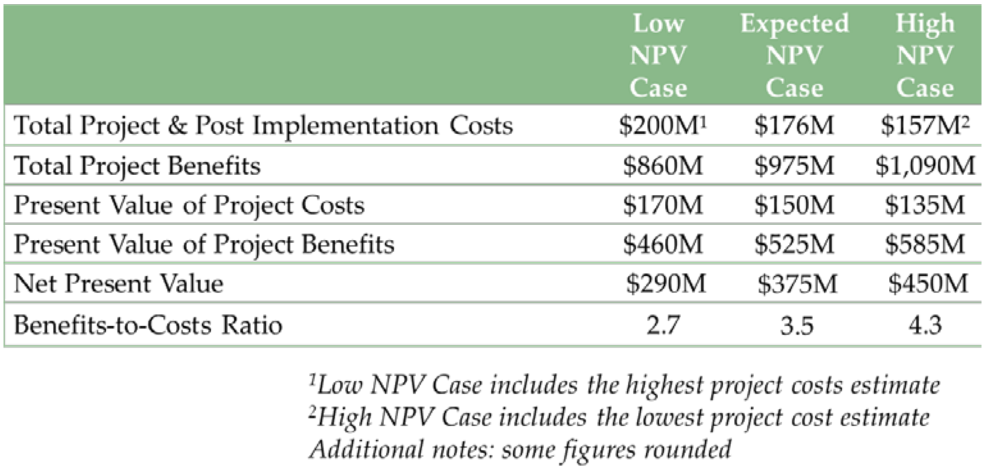
Table 5-1: Assumptions Used in the NPV Analysis



Assumptions	Value	Range
Starting Year (Year 0)	2017	n/a
Years of Project Development (2017-2023)	7	n/a
Numbers of Years of Benefits (2023-2033)	10	n/a
Cost of Capital (2017)	1.9%	n/a
Cost of Capital (2018)	1.8%	n/a
Cost of Capital (2019)	2.0%	n/a
Cost of Capital (Years 2020-2022)	4%	n/a
Cost of Capital (Years 2023-2033)	6%	n/a
Total Project and Implementation Costs	$176 million	$157M- $200M
Constrained-Off CMSC	$450 million	±20% ($360M - $540M)
Market Efficiencies	$525 million	$500M - $550M

The calculated NPV results of the three cases are shown in the Table 5-2 below. Based on this analysis, the NPV range for the MRP Energy Stream has been assessed at approximately $290 million - $450 million with a Benefits-to-Costs Ratio of 2.7-4.3.

Table 5-2: NPV Summary



	Low NPV Case	Expected NPV Case	High NPV Case
Total Project & Post Implementation Costs	$200M[1]	$176M	$157M[2]
Total Project Benefits	$860M	$975M	$1,090M
Present Value of Project Costs	$170M	$150M	$135M
Present Value of Project Benefits	$460M	$525M	$585M
Net Present Value	$290M	$375M	$450M
Benefits-to-Costs Ratio	2.7	3.5	4.3

[1] *Low NPV Case includes the highest project costs estimate*

[2] *High NPV Case includes the lowest project cost estimate*

Additional notes: some figures rounded

The range of estimated benefits from low to high reflects uncertainty around future market conditions and Market Participant behaviour. For example, the benefits arising from reduced CMSC will be determined by a range of considerations such as the wholesale market clearing price and the supply mix. Payments of CMSC are directly related to the amount of transmission congestion in the system. Transmission and supply outages, growth in demand in a local zone with limited supply can exacerbate the bottling of supply causing constrained-off payments to increase. Conversely, transmission upgrades or growth in demand in an area with excess supply can decrease the amount of constrained-off payments reducing the potential benefits.

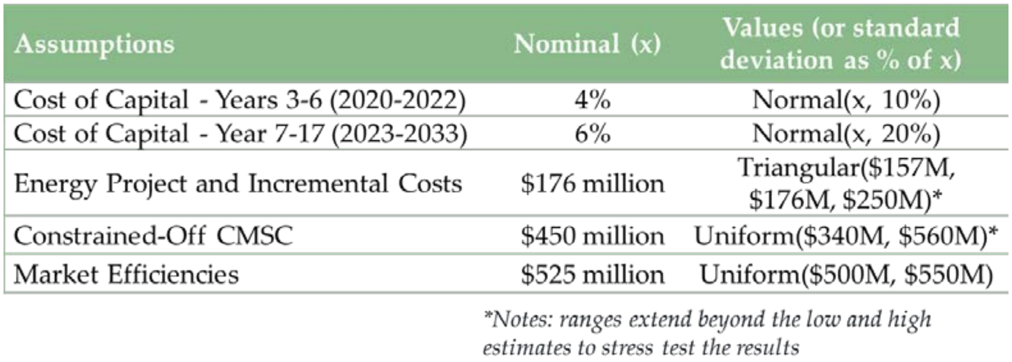
Variability in the efficiency benefits is explained by the different market outcomes as discussed in section 3.7.1. The benefits associated with a Day-Ahead Market and the broader market benefits are expected to be considerable but not quantified as part of the NPV assessment. In practice, the IESO is confident that the value of the MRP Energy Stream is at least as high as calculated in the Business Case and likely to be higher which would be consistent with the experience of other system operators who implemented similar reforms.

5.3 Monte Carlo Simulation of the NPV Calculation

The low and the high NPV values were derived using best estimates of the variables, including their ranges. However, in practice, some variables are more uncertain than others and have low probabilities at even higher or lower values.

A probabilistic analysis using a Monte Carlo model was undertaken to more realistically characterize the impact of uncertainty on the NPV calculation. The intent of this analysis was to stress test the NPV results. Probability distributions were used to represent the uncertainty for key variables, as shown in the Table 5-3 below:

Table 5-3: NPV Assumptions - Monte Carlo Simulation



Assumptions	Nominal (x)	Values (or standard deviation as % of x)
Cost of Capital - Years 3-6 (2020-2022)	4%	Normal(x, 10%)
Cost of Capital - Year 7-17 (2023-2033)	6%	Normal(x, 20%)
Energy Project and Incremental Costs	$176 million	Triangular($157M, $176M, $250M)*
Constrained-Off CMSC	$450 million	Uniform($340M, $560M)*
Market Efficiencies	$525 million	Uniform($500M, $550M)

**Notes: ranges extend beyond the low and high estimates to stress test the results*

The simulation used 10,000 runs and the resulting probability distribution of the program NPV was calculated as shown in Figure 5-2 below. This probability distribution indicates that there will be a 90% probability that the program NPV will be between $250 million and $490 million. A key take-away from the Monte Carlo simulation is that the net benefits are strongly positive under assumptions that have been stress tested, which is a good indication of the financial viability of MRP.

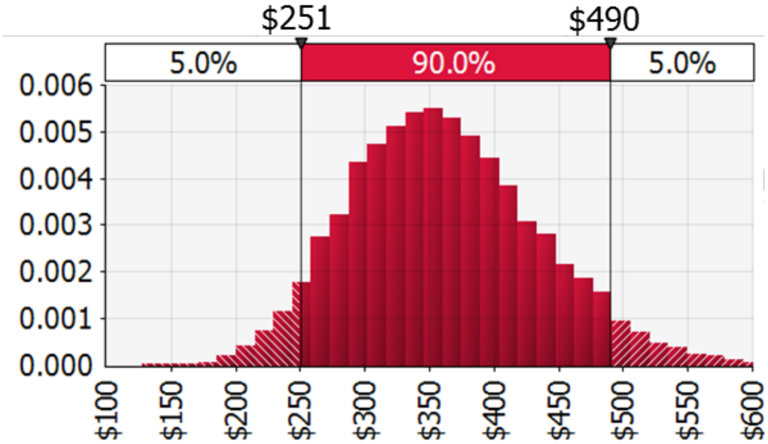


Figure 5-2: Probability Distribution of the NPV ($M)

A tornado graph of this Monte Carlo distribution was also produced, which ranks the impact of the variables on the NPV results. As shown in Figure 5-3, assumptions on cost of capital and constrained-off CMSC have the most impact on the results, in both the negative and positive directions.

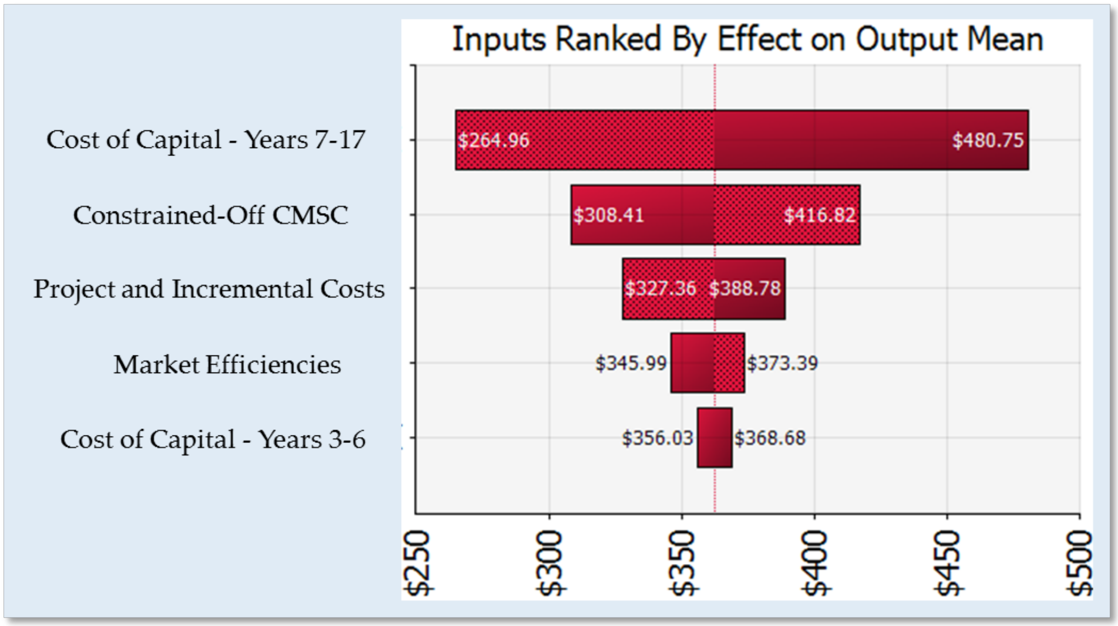


Figure 5-3: Tornado Graph Ranking the Impact of the Variables on the NPV Results ($M)

5.4 Conclusion

This chapter has presented results of a financial assessment on the MRP Energy Stream, including an NPV analysis on low and high cases, and a corresponding Monte Carlo simulation to stress test the results. The Low and High cases indicate that the NPV has a range of $290 million to $450 million with a Benefits-to-Costs Ratio of 2.7-4.3. The Monte Carlo simulation further indicates that the NPV will be between $250 million and $490 million with a 90% probability. These cases and the Monte Carlo simulation taken together indicate with a high likelihood that the MRP Energy Steam will return a significant net benefit within this range.

6. Future Market Assessment

6.1 Introduction and Context

The MRP Energy Stream represents a significant advancement and modernization for Ontario's electricity market. It is needed, in part, in response to the rapid transformation of the broader electricity sector that continues to impact Ontario and neighboring jurisdictions.

Large changes to the supply mix have occurred through the phase out of coal and introduction of renewables. The costs for distributed energy resources are declining, and the emergence of new technologies and other innovations are disrupting traditional models of generating and distributing electricity. Further, structural change in Ontario's economy is shifting where and when demand occurs, as well as the overall demand for electricity.[55] In the future, new technologies will enable consumers to take a more active role in the market, becoming "prosumers" and blurring the lines between distributors, producers and consumers. With this changing landscape in mind, it is important that the benefits of the MRP Energy Stream are robust and enduring even as the sector evolves.

6.2 Approach

The Future Market Assessment assesses the benefits of the new market design, relative to the Business Case expectations, across three potential future market scenarios. The future market scenarios have been defined to cover a range of outcomes and are informed by previous IESO analysis and stakeholder engagements including the Non-Emitting Resources Subcommittee. The assessment groups the new market design benefits into three categories including: 1) Operational, Reliability and Efficiency Benefits, 2) Broader Market Benefits and 3) Financial Benefits. The Future Market Assessment exercise qualitatively assesses the impact of the three future market scenarios, relative to the Business Case expectations, across each of benefit categories.

6.3 Future Market Scenarios

The benefits of the MRP Energy Stream have been assessed across three potential future market scenarios: 1) Low Net Demand, 2) Low Cost Clean Grid and 3) Decentralized Future. These scenarios

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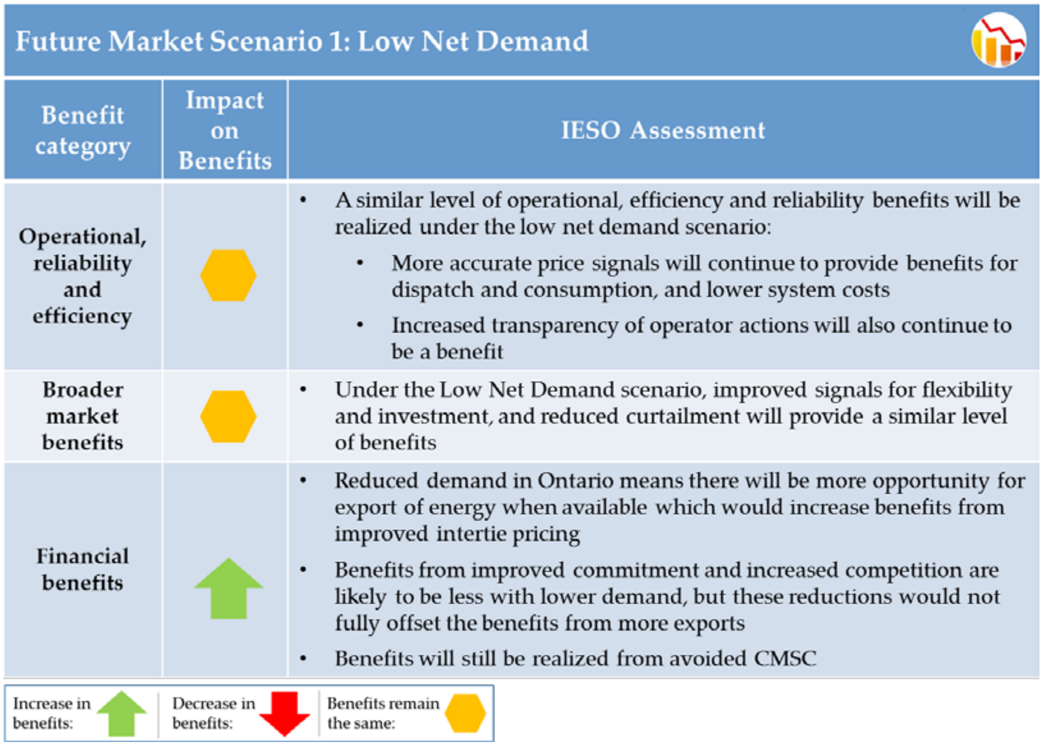
[55] The overall demand for electricity in Ontario has declined significantly. Historic data from IESO indicates that in 2005, the annual demand was 157 TWh, whereas in 2018 the annual demand was 137.4 TWh. For details please review http://www.ieso.ca/en/Power-Data/Demand-Overview/Historical-Demand

are not intended to be an exhaustive set of potential outcomes but rather have been selected to represent a range of possibilities. A description of each scenario is presented below in the Figure 6-1

Figure 6-1: Future Market Scenarios

6.4 Future Market Outcomes

The three future market scenarios have different impacts on the different benefit categories of the MRP Energy Stream. These impacts are presented below in Figure 6-2, Figure 6-3 and Figure 6-4 for each future market scenario. The impact on each benefit category is illustrated as an increase, decrease or remains the same as that projected in the Business Case. The tables also include an explanation of the key impacts on benefits in each category.

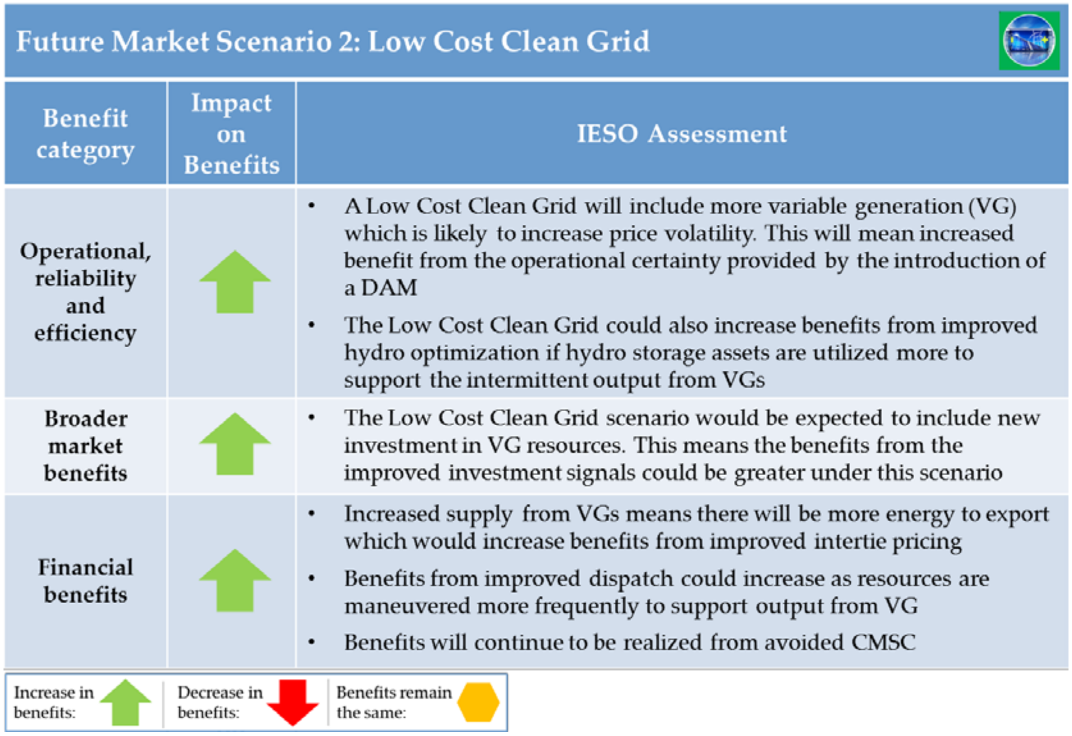


Future Market Scenario 1: Low Net Demand

Benefit category	Impact on Benefits	IESO Assessment
Operational, reliability and efficiency	⬢	• A similar level of operational, efficiency and reliability benefits will be realized under the low net demand scenario: • More accurate price signals will continue to provide benefits for dispatch and consumption, and lower system costs • Increased transparency of operator actions will also continue to be a benefit
Broader market benefits	⬢	• Under the Low Net Demand scenario, improved signals for flexibility and investment, and reduced curtailment will provide a similar level of benefits
Financial benefits	⬆	• Reduced demand in Ontario means there will be more opportunity for export of energy when available which would increase benefits from improved intertie pricing • Benefits from improved commitment and increased competition are likely to be less with lower demand, but these reductions would not fully offset the benefits from more exports • Benefits will still be realized from avoided CMSC

Increase in benefits: ⬆	Decrease in benefits: ⬇	Benefits remain the same: ⬢

Figure 6-2: Low Net Demand Scenario

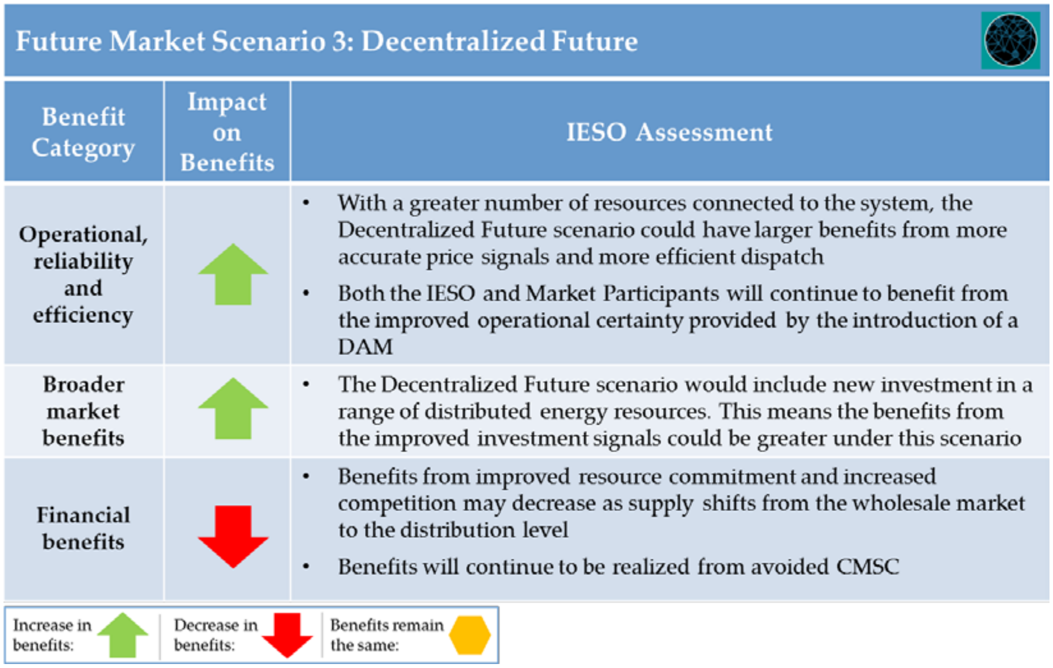


Future Market Scenario 2: Low Cost Clean Grid

Benefit category	Impact on Benefits	IESO Assessment
Operational, reliability and efficiency	⬆	• A Low Cost Clean Grid will include more variable generation (VG) which is likely to increase price volatility. This will mean increased benefit from the operational certainty provided by the introduction of a DAM • The Low Cost Clean Grid could also increase benefits from improved hydro optimization if hydro storage assets are utilized more to support the intermittent output from VGs
Broader market benefits	⬆	• The Low Cost Clean Grid scenario would be expected to include new investment in VG resources. This means the benefits from the improved investment signals could be greater under this scenario
Financial benefits	⬆	• Increased supply from VGs means there will be more energy to export which would increase benefits from improved intertie pricing • Benefits from improved dispatch could increase as resources are maneuvered more frequently to support output from VG • Benefits will continue to be realized from avoided CMSC

Increase in benefits: ⬆	Decrease in benefits: ⬇	Benefits remain the same: ⬢

Figure 6-3: Low Cost Clean Grid



Future Market Scenario 3: Decentralized Future

Benefit Category	Impact on Benefits	IESO Assessment
Operational, reliability and efficiency	⬆	• With a greater number of resources connected to the system, the Decentralized Future scenario could have larger benefits from more accurate price signals and more efficient dispatch • Both the IESO and Market Participants will continue to benefit from the improved operational certainty provided by the introduction of a DAM
Broader market benefits	⬆	• The Decentralized Future scenario would include new investment in a range of distributed energy resources. This means the benefits from the improved investment signals could be greater under this scenario
Financial benefits	⬇	• Benefits from improved resource commitment and increased competition may decrease as supply shifts from the wholesale market to the distribution level • Benefits will continue to be realized from avoided CMSC

Increase in benefits: ⬆ Decrease in benefits: ⬇ Benefits remain the same: ⬢

Figure 6-4: Decentralized Future

6.5 Summary of Findings

The Future Markets Assessment illustrates there may be some variation in magnitude of benefits across the different scenarios:

- Under the Low Net Demand scenario, financial benefits could be higher than expected as there would be opportunity to export more energy and therefore derive greater value from improved intertie pricing.
- Under the Low Cost Clean Grid scenario, benefits could be higher than estimated for several reasons, including that with changes in the supply mix output could become more variable resulting in more prices volatility. Increased price volatility will mean more benefit attributable to the operational certainty that is provided by the introduction of a DAM. Infrastructure spending to transition to the Low Cost Clean Grid could also mean higher than expected benefits from improved investment signals under this scenario.
- For the Decentralized Future scenario, benefits could be higher than expected across several benefit categories. In particular, with a higher number of resources connected to the system the benefit of more accurate price signals and efficient dispatch could be greater than expected. Equally, the financial benefits from improved commitment and competition could be lower than expected as the expansion of distributed resources reduces the role of traditional generators from which these benefits are attributable.

In summary, the future market assessment demonstrates that whilst the extent of some individual benefits may vary by scenario, overall the benefits of the new market design are relevant and robust across a range of realistic scenarios.

7. Program Risks

7.1 Key Program Risks and Mitigation Plans

The MRP Energy Stream leverages IESO's Enterprise Risk Management (ERM) framework to proactively identify, analyze, monitor and mitigate risks as they arise. The ERM framework is embedded within an overall enterprise planning framework to enable risk-informed inputs into integrated organizational planning, risk and performance management to map key elements required to implement the program's strategic objectives - including key annual priorities, resource allocation, and detailed budgets, as encompassed in IESO's three-year business plan.

MRP Energy risks have been catalogued into strategic and project categories, with recommendations for risk remediation developed for each risk. Strategic risks are overarching risks that impact the overall success of the MRP Energy program. Their interdependent nature requires they be addressed strategically and remediation strategies are developed and implemented in an integrated fashion. The establishment of the Program Governance Framework, which outlines where types of decisions should be made, supports this risk mitigation.

The following four strategic risks have been identified in relation to MRP Energy execution:

- Delivery Risk
- Resourcing Risk
- Regulatory and Public Policy Risk
- Stakeholder Risk

Each of these risks have been assessed and their mitigation plans have been defined and are being actively executed. These strategic risks will be the focus of quarterly risk updates provided to the Market Renewal Executive Steering Committee and the IESO's board to support a disciplined, structured and accountability based approach for achieving MRP objectives.

The sections below provide an overview of mitigations plans at the end of Q3, 2019.

7.1.1 Delivery Risk

Table 7-1: Key Strategic Delivery Risk

Risk Grouping	Strategic Risk Description	Risk Owner	Residual Risk Impact	Residual Risk Likelihood	Risk level	Mitigation Plans (based on Contributing Factor)
Delivery Risk	IESO does not have recent demonstrated capability to deliver highly complex transformational programs of similar size to MRP	Leonard Kula	Significant	Possible	High	IESO mitigating actions include the onboarding of a Program Delivery Executive as part of implementing a Program Governance Framework. Further, the IESO will integrate its IT Strategy, including IT resourcing within its program plans. Impact assessments for MRP Energy have been completed, with associated resourcing requirements identified. Resourcing remains to be deployed.
	Market participants are unprepared for system operation at go-live date	Terry Young	Significant	Possible	High	IESO will develop and implement a Market Participant Readiness Plan to ensure effective and timely engagement that will allow market participants to secure funding and resources to implement required changes.

7.1.2 Resourcing Risk

Table 7-2: Key Resourcing Risk

Risk Grouping	Strategic Risk Description	Risk Owner	Residual Risk Impact	Residual Risk Likelihood	Risk level	Mitigation Plans (based on Contributing Factor)
Resourcing Risk	Inability to secure qualified external resources for detailed design and Implementation	Robin Riddell	Moderate	Possible	Medium	The challenges of a constrained labour market are mitigated by the IESO through a strategic talent acquisition process including a competitive value proposition for temporary resources. Procurement for specialized resources such as Project Manager, Business Analyst and Quality Assurance staff and others is supported through a Vendor of Record (VOR) for appropriate agencies to efficiently onboard staff.

7.1.3 Regulatory and Public Policy Management Risk

Table 7-3: Key Regulatory and Public Policy Management Risk

Risk Grouping	Strategic Risk Description	Risk Owner	Residual Risk Impact	Residual Risk Likelihood	Risk level	Mitigation Plans (based on Contributing Factor)
Regulatory and Public Policy Risk	Government and/or regulator (OEB) does not support IESO's direction, resulting in non- approval of IESO's funding or other barriers	Terry Young	Significant	Unlikely	Medium	IESO continues outreach and education to support its demonstrated value for money in the MRP Energy business case. Additionally, the IESO delivers a strong implementation plan and effective execution of MRP to ensure government/regulator continues to prioritize MRP within IESO's portfolio of funded priorities.

7.1.4 Stakeholder Management Risk

Table 7-4: Key Stakeholder Management Risk

Risk Grouping	Strategic Risk Description	Risk Owner	Residual Risk Impact	Residual Risk Likelihood	Risk level	Mitigation Plans (based on Contributing Factor)
Stakeholder Risk	Stakeholders' dissatisfaction results in lack of support of MRP initiative	Terry Young	Significant	Unlikely	Medium	In response to stakeholder disagreement with IESO's approach, load pricing issues were addressed by the IESO in June. To increase its effective participation with stakeholders so they feel heard or responded to clearly, IESO is preparing specific outreach plans for impacted stakeholders as potential issues are identified. Specific examples include contract management, OPG.

7.1.5 Risk Monitor and Control

The ERM framework also entails effective project governance that continuously monitors progress of program initiatives and reports updates accordingly on a timely basis to the Market Renewal Executive Steering Committee along with consistent and repeatable risk identification and prioritization to uncover and address risk root causes. Project risks include events that have an effect on one or more project outcomes such as:

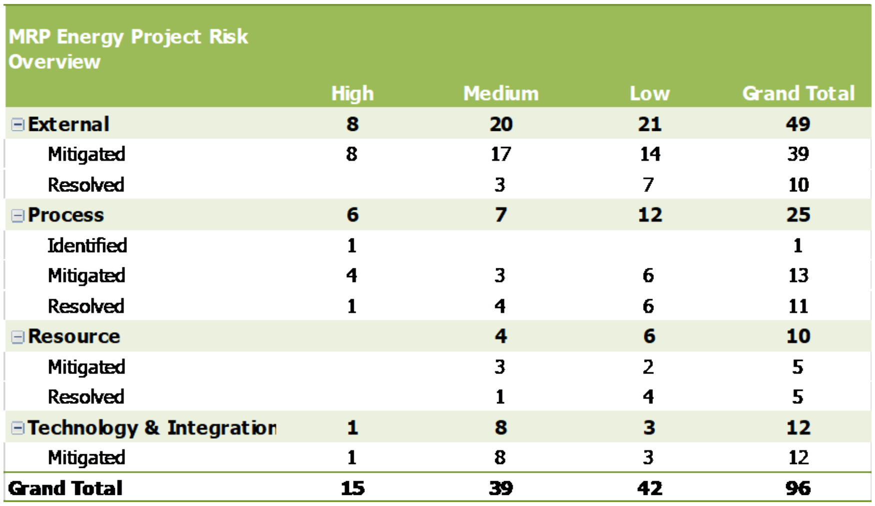
- Project objectives met within approved project parameters
- Achievement of benefits/payback
- Stakeholder engagement and support
- Integration/interdependencies with other projects

- Change management
- Resourcing

7.1.6 Project Level Risk

The project level risks have also been identified and assessed, with mitigation plans prepared and executed for each of the risks. The program Project Management Office maintains a detailed log of project risks and mitigation plans. All risks are monitored and managed, with high or critical-rated risks reported regularly to Market Renewal Executive Steering Committee on a quarterly basis. A summary of the project risk log count is provided below:

Table 7-5: Project Risk Count Summary



MRP Energy Project Risk Overview	High	Medium	Low	Grand Total
⊟ External	**8**	**20**	**21**	**49**
Mitigated	8	17	14	39
Resolved		3	7	10
⊟ Process	**6**	**7**	**12**	**25**
Identified	1			1
Mitigated	4	3	6	13
Resolved	1	4	6	11
⊟ Resource		**4**	**6**	**10**
Mitigated		3	2	5
Resolved		1	4	5
⊟ Technology & Integration	**1**	**8**	**3**	**12**
Mitigated	1	8	3	12
Grand Total	**15**	**39**	**42**	**96**

Legend	
Identified	A discovered risk which could potentially prevent the project from achieving its objectives. Risk response are yet to be developed.
Mitigated	Specific measures have been established to potentially minimize the likelihood or severity of the risk.
Resolved	Risk is closed and is no longer a concern.

At the end of Q3, 2019, 16 percent of the project risks have a residual rating that is ‘high’. Project risks are monitored and reported on through a project status summary, including progress updates on project objectives, financial and schedule health. Risks are reported at initially assessed levels, detailed mitigation plans are addressed and a residual risk level is then reflected. Updates are provided to the Market Renewal Executive Steering Committee on a monthly basis, with critical/high-rated risks and mitigation activities being a focus area for management discussion. Finally, in addition to the internal review and monitoring of risks, the IESO has also engaged a third party to review different areas of the program to provide insight with respect to existing as well as emerging risks across the program. All findings are actively addressed.

8. Stakeholder Engagement Summary

8.1 Engagement Description / Background

The IESO is committed to giving stakeholders access to engagement opportunities in order to provide input into the review and decision-making process for facilitating required changes.

Active stakeholder participation and perspectives are used to inform IESO decision-making. As a result, a defined engagement process with a clear set of principles exists to ensure inclusiveness, sincerity, respect and fairness in IESO engagement initiatives. There are seven core principles that guide the engagement process at the IESO, which include: analyze opportunities for engagement, ensure inclusive and adequate representation, provide effective communication and information, promote openness and transparency, provide effective facilitation, communicate outcomes and measure satisfaction.

With the launch of the MRP Energy Stream, this stakeholder engagement process and principles were implemented to guide the manner in which interaction with stakeholders would take place.

Since May 2017, the IESO has been leading an active stakeholder engagement process on the development of the MRP Energy Stream design phase and will continue through to implementation.

The first phase of engagement on the MRP Energy Stream set out to develop the high-level design for SSM, DAM, and ERUC. These HLDs were required to establish the foundation for the detailed design sections that are the necessary for implementing the new design constructs into the IESO Administered Market. Over the course of the HLD phase of the engagement from May 2017 to August 2019, the IESO hosted 29 formal engagement sessions, with an average of almost 50 attendees per session. In addition to these formal engagement sessions open to all stakeholders, the IESO also took part in a number of one-on-one meetings to help inform and clarify design concepts for specific stakeholders from across the sector. The IESO also established the Market Renewal Working Group to help the IESO maintain the progress of the MRP Energy Stream high-level design phase. The HLD engagement process was considered complete with the release of the finalized HLDs on August 8, 2019.

The detailed design engagement process begins in Q3-Q4 2019 with an engagement plan shared with stakeholders in August 2019 that outlined the approach and main objectives of engaging on the detailed design sections of the MRP Energy Stream. This engagement will continue through to the development of draft market rules and manuals that will be reviewed at the engagement level with proposed rule amendments submitted for review through the Technical Panel process.

The IESO required a separate engagement process to consult with stakeholders on the MRP Energy Stream Business Case for the period between the HLD and detailed design phases. As a result, the IESO utilized its MRP Update Meetings to bring the Business Case discussion to stakeholders and seek input and perspectives on the development of the document. Meetings on the MRP Energy Stream Business Case took place monthly from April 2019 through to the completion of the MRP Energy Stream Business Case in October 2019.

In the future, the IESO will lead engagement and training to prepare for the implementation of MRP to ensure that Market Participants are prepared for the changes that accompany the renewed market. The IESO will begin a Market Participant support and readiness initiative which includes engagement and awareness with stakeholders and will focus on training, market trials and IT changes that will be required to understand and ensure that all active participants in the IESO Administered Market are prepared for implementation.

8.2 Engagement Objective

8.2.1 Engagement Approach

In order to achieve the objectives set out in the engagement phases of the MRP Energy Stream, a series of in-person engagement sessions, webinars, one-on-one stakeholder meetings, direct stakeholder emails, IESO Bulletins, recorded and printed information packages were all utilized to provide an accessible engagement opportunity for stakeholders on the MRP Energy Stream.

Throughout the MRP Energy Stream engagement process, stakeholders relied on meeting materials in advance of the sessions to support their education and understanding on design concepts to have productive interaction with IESO staff on various design concepts and proposals.

In addition to these engagement sessions, the IESO conducted specific education and awareness building workshops in the fall and winter of 2018 that were tailored to particular resource types (i.e., Local Distribution Companies, generators, loads). These sessions were intended to raise the level of knowledge and understanding of the MRP Energy Stream for stakeholders who were not actively involved in the earlier engagement process.

8.2.2 Stakeholder Participation

A diverse set of stakeholders have been engaged in all phases of the engagement on the MRP Energy Stream engagement and represent a very broad and diverse range of constituencies within the electricity sector. The MRP Energy stream has received feedback, both written and verbal during sessions, which has helped advance the design and overall progress of Market Renewal.

The IESO received a significant amount of feedback from stakeholders which will be outlined in the next section. At the time of posting the three HLDs, there were no outstanding design issues with stakeholders on the MRP Energy Stream.

8.2.3 Stakeholder Input

The input that was received from stakeholders, both during the engagement sessions and through written feedback, helped ensure that the IESO produced design documents that were informed by stakeholder feedback.

For reference, each of the three projects within the MRP Energy Stream HLDs include an engagement summary that identifies specific design topics where stakeholder input directly shaped the final design.[56]

At times, feedback from stakeholders challenged the IESO design proposal which required further discussion at the engagement level to understand the merits of the design proposals and rationale for proceeding in any one particular direction.

For example, the approach to load pricing was a design item that received particular attention from stakeholders in the SSM HLD. In this instance, concern was focused on how loads would be priced in the renewed energy market. Further engagement and one-on-one meetings were required to clearly understand the concern which led to the modification of the original design proposal.

In the end, the IESO relied on stakeholder engagement and input from many active participants to produce informed MRP Energy Steam design documents.

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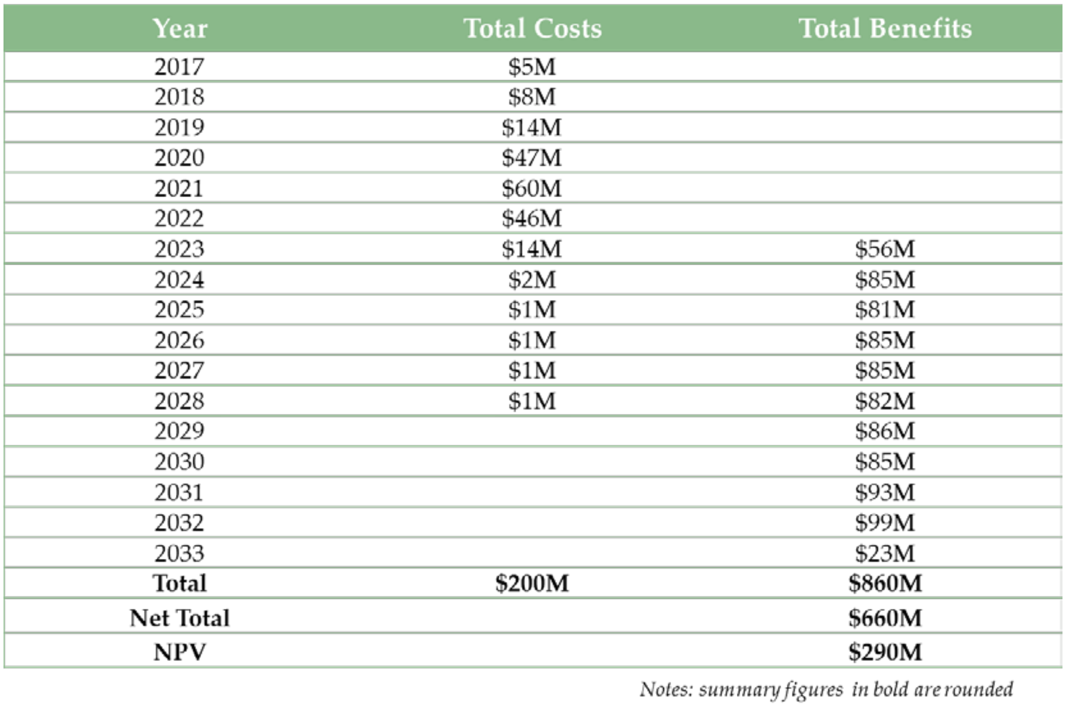
[56] Those summaries are included towards the end of each HLD and can be reviewed here: http://www.ieso.ca/en/Market-Renewal/High-Level-Designs/Energy-Stream-High-Level-Designs.

9. Appendix

9.1 Additional Details on the NPV Analysis

In order to provide more detail on the NPV analysis, a breakdown of the costs and benefits by year has been included for the three NPV Cases as shown in Table 9-1, Table 9-2, and Table 9-3 below. Using the NPV assumptions outlined in Table 5-1, the NPV results in Table 5-2 and cited elsewhere in this document should be reproducible with these details.

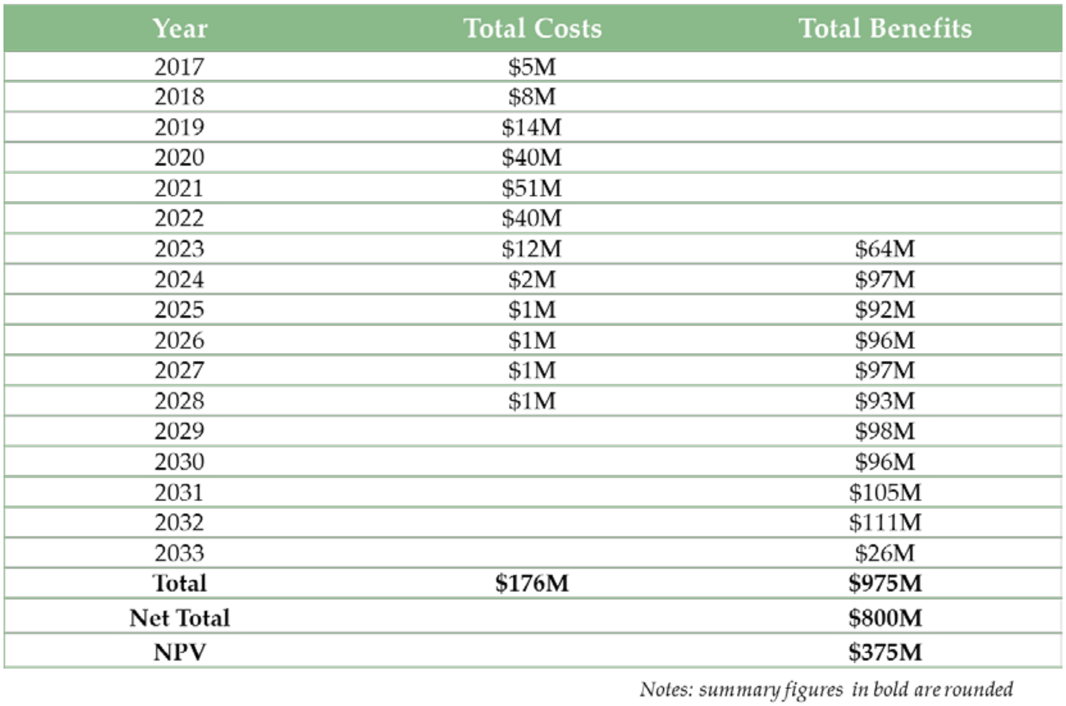
Table 9-1: Low NPV Case Cost and Benefits Summary



Year	Total Costs	Total Benefits
2017	$5M	
2018	$8M	
2019	$14M	
2020	$47M	
2021	$60M	
2022	$46M	
2023	$14M	$56M
2024	$2M	$85M
2025	$1M	$81M
2026	$1M	$85M
2027	$1M	$85M
2028	$1M	$82M
2029		$86M
2030		$85M
2031		$93M
2032		$99M
2033		$23M
Total	**$200M**	**$860M**
Net Total		**$660M**
NPV		**$290M**

Notes: summary figures in bold are rounded

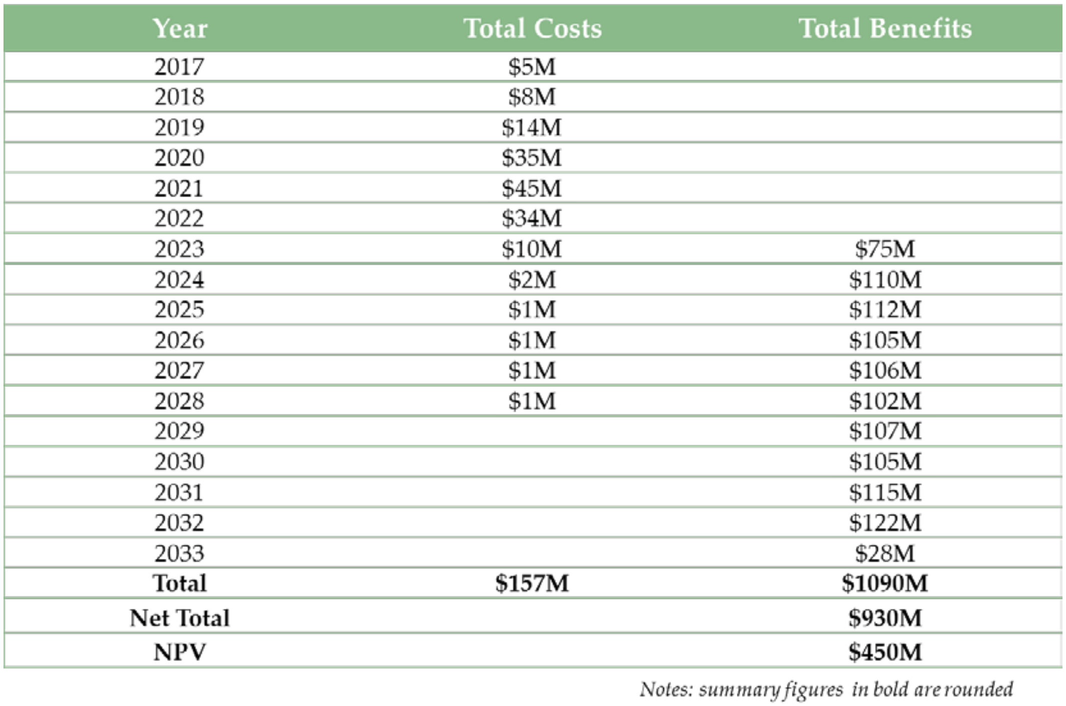
Table 9-2: Expected NPV Case Cost and Benefits Summary



Year	Total Costs	Total Benefits
2017	$5M	
2018	$8M	
2019	$14M	
2020	$40M	
2021	$51M	
2022	$40M	
2023	$12M	$64M
2024	$2M	$97M
2025	$1M	$92M
2026	$1M	$96M
2027	$1M	$97M
2028	$1M	$93M
2029		$98M
2030		$96M
2031		$105M
2032		$111M
2033		$26M
Total	**$176M**	**$975M**
Net Total		**$800M**
NPV		**$375M**

Notes: summary figures in bold are rounded

Table 9-3: High NPV Case Cost and Benefits Summary



Year	Total Costs	Total Benefits
2017	$5M	
2018	$8M	
2019	$14M	
2020	$35M	
2021	$45M	
2022	$34M	
2023	$10M	$75M
2024	$2M	$110M
2025	$1M	$112M
2026	$1M	$105M
2027	$1M	$106M
2028	$1M	$102M
2029		$107M
2030		$105M
2031		$115M
2032		$122M
2033		$28M
Total	**$157M**	**$1090M**
Net Total		**$930M**
NPV		**$450M**

Notes: summary figures in bold are rounded

Independent Electricity
System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca
@IESO_Tweets
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