
The Future of Ontario's Electricity Market

A Benefits Case Assessment of the Market Renewal Project

PREPARED FOR



PREPARED BY

Johannes Pfeifenberger
Kathleen Spees
Judy Chang
Mariko Geronimo Aydin
The Brattle Group

Walter Graf
Peter Cahill
James Mashal
John Imon Pedtke

With contributions from
Vikki Harper
Ken Donald
Utilicast

William Schwant

DRAFT REPORT

MARCH 3, 2017

THE **Brattle** GROUP

This report was prepared for Ontario's Independent Electricity System Operator (IESO). All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

Staff of the IESO provided extensive intellectual contributions and analytical support for this study. Members of the Market Renewal Working Group also provided valuable feedback and assistance, including representatives of Brookfield Renewable Power Inc., EnerNOC, Goreway Power Station, Hydro Québec Energy Marketing, Invenergy, Ivaco Rolling Mills, NextEra, Northland Power, NRStor, Ontario Power Generation, PowerStream, Tembec, TransCanada Energy Ltd., Gerdau Long Steel North America, and Glencore. We also thank stakeholders that provided written comments or participated in the stakeholder engagement for providing input to this study. Finally, we are grateful to the many people who we interviewed as part of this project. This includes stakeholder representatives as well as employees of U.S. Regional Transmission Operators including California ISO, ERCOT, ISO New England, Midcontinent ISO, New York ISO, PJM, and SPP, and employees of software vendor companies ABB, GE/Alstom, and Siemens.

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Table of Contents

Executive Summary	iii
I. Introduction	1
A. The Need for Market Renewal	1
B. Scope and Objectives of Market Renewal	6
C. Approach to This Benefits-Case Analysis	7
D. Applying Lessons from Other Markets in Ontario's Unique Context.....	10
II. Stakeholder and Market Observer Input on Market Renewal.....	13
A. Inefficiencies in the Current Market Design.....	13
1. Concerns Identified by the Market Surveillance Panel	13
2. Concerns Identified by the Working Group and Other Stakeholders	16
B. Market Visioning Workshop.....	17
1. Key Drivers Affecting the Future Electricity Sector	17
2. Range of Market Futures that Ontario May Face.....	19
C. Implications for Market Renewal	20
III. Energy Market Enhancements.....	22
A. Description of Current Market Design and Proposed Enhancements	22
B. Prior Analyses of Ontario's Market.....	25
C. Experience from Other Markets.....	26
1. Scope of Design Enhancements in Other Markets	28
2. Range of Marginal Costs in Other Markets	30
3. Magnitude of Intermittent Resource Deployment in Other Markets.....	31
4. Benefits Achieved by Other Markets	32
D. Estimating Potential Benefits to Ontario.....	35
1. Estimates of Potential Benefits to Ontario	35
2. Non-Quantified Benefits.....	38
IV. Operability Reforms.....	40
A. Description of Current Market Design and Proposed Enhancements	41
B. Prior Analysis of Ontario's Market	43
C. Operability and Intertie Reforms in Other Markets	45
1. Intermittent Resource Integration Studies	45
2. Ancillary Service Market Reforms	47
3. Intertie Enhancement in Other Regions.....	49
D. Potential Operability Benefits to Ontario.....	52
1. Estimated Range of Ontario-Internal Operability Benefits	52
2. Estimated Range of Intertie-Related Operability Benefits	55
3. Non-Quantified Operability Benefits.....	58

V. Incremental Capacity Auction	58
A. Description of Historical Approach and Proposed Enhancements	59
B. Prior Analysis and Experience in Ontario	61
C. Experience in Other Markets	62
1. Attracting Low-Cost Non-Traditional and New Generation Supply	63
2. Comparison of Contracted and Market-Based Entry Prices	66
3. Interactions Between Merchant and Out-of-Market Supply Investments	68
D. Potential Benefits to Ontario	71
1. Estimated Range of Potential Benefits in Ontario	71
2. Non-Quantified Benefits	74
VI. Accounting for Existing Contracts	75
A. Overview of Existing Contracts	76
1. Magnitude and Duration of Existing Contracts	76
2. Primary Contractual Structures and Incentives	78
B. Adjustments to Efficiency Benefits to Account for Contracts	81
VII. Implementation Costs and Project Management	83
A. Evaluation of Implementation Costs	84
1. Project Schedule	84
2. Preliminary Estimate of IESO Business Costs	85
B. Experience from Other Markets	86
1. ERCOT and SPP Experiences	87
2. Advice from Other RTOs	88
C. Stakeholder Business Costs	89
D. Managing Implementation Risks	92
1. Identified Risks	93
2. Scoping Initial Design and Deferred Enhancements	94
3. Stakeholder Relations and Support	95
VIII. Benefit-Cost Analysis of Market Renewal	95
A. Primary Benefits of Market Renewal	95
B. Efficiency Benefits to Ontario as a Whole	98
1. Efficiency Benefits Over Time	99
2. Net Present Value of Efficiency Benefits	101
C. Implications for Market Participants	102
1. Impacts on Customers	102
2. Impacts on Other Market Participants	107
D. Alignment with Ontario's Energy Future	110
IX. Findings and Recommendations	112
List of Acronyms	116
Bibliography	118

Executive Summary

This study estimates the net benefit that Ontario could realize by reforming the wholesale electricity markets operated by the Independent Electricity System Operator (IESO). This reformation will include significant changes to Ontario’s energy markets, a number of features designed to improve the system’s operating flexibility, and the introduction of an incremental capacity auction for maintaining resource adequacy. This coordinated set of market reforms has been termed “Market Renewal” and represents the culmination of many years of analysis and observation by the IESO, the Market Surveillance Panel (MSP), and Ontario electricity sector stakeholders. The results of this study will be used as an input to help determine whether to proceed with developing a market design for Market Renewal and to identify options for maximizing benefits and mitigating risks of the effort.

Our key findings are that:

- The estimated province-wide efficiency and customer benefits of Market Renewal significantly outweigh estimated implementation costs, with a ten-year present value of net benefits ranging from \$2,200 million to \$5,200 million. These province-wide benefits are shared by customers and suppliers.
- The benefits from Market Renewal are likely to grow over time as Ontario’s electricity sector continues to decarbonize, as contracts expire, and as the sector becomes more distributed in nature.
- Market Renewal will better prepare Ontario for the future by creating a competitive framework for effectively incorporating new and emerging technologies.
- The IESO and stakeholders have substantial opportunities to enhance the benefit-cost ratio of Market Renewal by learning from the experiences of other jurisdictions and applying them to Ontario’s unique context.

The Need for Market Renewal

The contemplated Market Renewal would be the first significant overhaul to Ontario’s 15-year old “two-schedule” wholesale electricity market, which uses two separate scheduling sequences to first determine market prices and then physical dispatch instructions. The Market Design Committee who originally recommended the two-schedule system recognized that it has significant limitations. The current design was originally intended to persist for only 18 months, as a transitional mechanism toward a single-schedule system with locational marginal pricing (LMP) or “nodal pricing”. However, the two-schedule system has endured much longer than anticipated. Over time many patches and temporary improvements have been layered onto the foundational design, and it has become increasingly clear that the two-schedule system causes significant inefficiencies. These inefficiencies have been extensively documented and analyzed by the IESO, the MSP, and independent observers. The complexities associated with the two-

schedule system have become a barrier to evolving the market to cost-effectively meet shifts in market fundamentals and public-policy goals.

The market was originally designed to coordinate the operations of nuclear, hydro, and fossil-fueled resources, with coal-fired generation providing about 25% of Ontario's total energy needs and providing the bulk of the system flexibility. In 2014, Ontario retired its last coal-fired generating plant as part of a concerted effort by the province to decarbonize the electricity sector.¹ Non-emitting resources (particularly nuclear, biomass, wind, and solar) and additional natural gas generation have replaced most of the coal-fired generation. The changing supply mix and loss of flexibility have amplified the challenges with the existing market design.

This study evaluates the potential benefits of the IESO's proposed Market Renewal efforts; it is not an evaluation of specific market design elements or implementation details. As this study comes at the initial stage of the Market Renewal initiative, we do not analyze the specific details of how the IESO's market rules and operating procedures would change. Instead, we base our analysis of Market Renewal benefits on the concepts and general features of market enhancements that have already been identified by the IESO, MSP, and stakeholders for operating Ontario's electricity system more efficiently in the future. The general features of Market Renewal as currently proposed fall into three workstreams:

1. **Energy:** Move to a single-schedule market, including locational marginal pricing for suppliers, improved generation commitment and dispatch in real time, and a financially-binding day-ahead market.
2. **Operability:** Increase system flexibility and improve utilization of interties with neighboring systems to reduce the cost of surplus-generation conditions, variable renewable generation uncertainty, and the need to curtail resources.
3. **Capacity:** Improve procurement of resources to meet the province's resource adequacy needs through an incremental capacity auction that stimulates competition from all qualified supply resources in a technology-neutral manner.

These reforms would increase the extent to which Ontario relies on transparent, market-based mechanisms to reliably supply electricity to customers. As evidenced in other jurisdictions across North America that already incorporate these design elements to address challenges similar to those in Ontario, markets have a role in providing efficient and low-cost outcomes in the electricity sector.

Our Approach to Estimating Net Benefits

We rely on stakeholder input to develop a framework for estimating the benefits of each of the three Market Renewal workstreams. We leverage studies of the Ontario market as well as

¹ See Ontario Ministry of Energy (2015).

experience from similar market redesign efforts in other North American power markets over the last decade to estimate the benefits of Market Renewal. Our estimates account for the reduction of benefits due to pre-existing long-term power contracts. Finally, we partnered with Utilicast to estimate the IESO's costs for implementing Market Renewal.

Participants in the stakeholder process have emphasized the importance of recognizing Ontario's unique characteristics when evaluating the benefits of Market Renewal. We account for Ontario's distinctive characteristics by first relying on prior Ontario-specific analyses. We also rely on the experience in other regions where relevant aspects of market design enhancements, resource characteristics, and policy drivers are similar to Ontario. Combining Ontario-focused analyses with the real-world experiences from other markets provides a more complete picture of the potential benefits and risks associated with Market Renewal.

Primary Drivers of Benefits from Market Renewal

We find that the primary benefits of Market Renewal will be associated with:

- **Fuel, Emissions, and Operations and Maintenance (O&M) Cost Savings.** The current market does not fully account for all costs and system constraints in price-setting, commitment, and dispatch. This can result in higher-cost resources being used when lower-cost resources are available. Market Renewal will improve the system's ability to identify and utilize the lowest-cost resources to meet demand, including wind, solar, nuclear, hydro, storage, demand response, and interties. This will reduce the fuel costs, emissions, and O&M costs associated with operating the system.
- **Reduced Curtailment/Spilling of Non-Emitting Resources.** The current market does not fully utilize the existing resources or incentivize innovative solutions to meet system flexibility needs. This causes unnecessary loss of non-emitting resources by curtailing wind, solar, and nuclear, and spilling hydro generation.
- **Increased Export Revenues and Reduced Import Costs.** A reformed energy market and better optimized interties will lower the frictions to efficient trading of power with neighboring jurisdictions. This will allow for increased imports of lower-cost generation from neighboring markets and enable Ontario suppliers to export more power when export revenues exceed Ontario's generation costs.
- **Investment Cost Savings.** Transitioning to a more market-based capacity procurement process, combined with enhanced energy and ancillary market incentives, will increase competition to meet system needs at lower investment cost. A technology-neutral approach will level the playing field for existing resources and new technologies that have traditionally been left out of the capacity procurement process.
- **Reduced Gaming Opportunities, Administrative Complexity, and Unwarranted Transfer Payments.** The current two-schedule system does not always align generation dispatch with market prices, introducing the need for uplift payments to address these inconsistencies. These uplifts amplify the inefficiencies and administrative burden of operations for both the IESO and participants and create incentives for all market

participants (suppliers, consumers, and traders) to profit from exploiting the design flaws. A more competitive market design can potentially eliminate these inefficiencies and gaming opportunities.

- **Supporting Competition and Innovation.** Prices that more accurately reflect market conditions will support competition among a broader set of traditional and non-traditional resources to minimize system costs and encourage innovation.
- **Alignment with Provincial Policy Goals.** Market Renewal will create an improved platform for enabling market evolution in support of Ontario's policy objectives and changing market fundamentals.

Quantified and Non-Quantified Benefits

Figure ES-1 summarizes our estimated benefits and costs of Market Renewal. The figure shows the 2021–2030 present value of quantified benefits from the proposed energy market reforms, operability improvements, and capacity auction workstream. These benefits will continue beyond 2030. As shown, we estimate that Market Renewal will produce benefits with a present value of approximately \$510 million from energy market reforms, \$580 million from operability reforms, and \$2,530 million from capacity auction reforms. Realized benefits will likely be greater if the existing contracted resources are more responsive to market prices than assumed in our analysis and considering that the value of many benefits has not been quantified. As shown, the estimated benefits are offset by \$200 million in estimated IESO implementation costs.² Additional costs will likely be incurred by stakeholders. We qualitatively discuss but do not estimate these additional stakeholder costs, which can vary significantly among different classes of market participants as we describe qualitatively in this report.

Together, we estimate a 2021–2030 net present value of approximately \$3,400 million in efficiency benefits to Ontario from Market Renewal net of implementation costs, with a baseline benefit-cost ratio of 18:1. Considering the uncertainties in the nature of reforms and the magnitude of benefits from each workstream, these net benefits could range from \$2,200 million to \$5,200 million, with a benefit-cost ratio ranging from 12:1 to 27:1.³ We conclude that the benefits from Market Renewal will greatly outweigh implementation costs, even considering the significant uncertainty range.

² This \$200 million is the net present value of the costs in 2021 using a 5% discount rate. The simple sum of nominal implementation costs is \$189 million.

³ This range compares our high and low benefits estimate to our baseline estimate of costs.

Figure ES-1
Present Value of Market Renewal Benefits and Costs (2021–2030)



Notes:

Results represent province-wide benefits from efficiency gains net of IESO implementation costs; they exclude any transfers payments among market participants. Does not include benefits that could be realized if all contracted resources become responsive to market prices.

In addition to these quantified benefits, we expect Market Renewal to produce other benefits that we have not been able to quantify. The investment and variable cost savings that we report are limited to only those materializing from the reforms that have been explicitly studied in Ontario or other markets; but the benefits of some market design advancements such as better integration of diverse and emerging resource types were not estimated in the studies on which we relied. We have also not captured the potential benefits from a simplified market design that reduces gaming opportunities and administrative burden for both the IESO and market participants. Finally, the studies we rely on typically do not account for the longer-term savings from enabling innovation through an open, competitive marketplace.

Distribution of Benefits

Ontario's customers are likely to realize a significant share of the market-wide efficiency gains, with baseline estimates of customers' annual net benefits ranging from \$160 million per year in 2021, increasing to a range of \$170 million and \$670 million in subsequent years. We do not explicitly estimate the benefits and costs to other market participants, but discuss how these benefits would likely be distributed across market participants. For example, the most competitive suppliers will share in the estimated benefits through increased opportunities to sell flexibility services, by generating energy where and when it is most valuable, and through improved opportunities to export energy and capacity. New entrants and technologies will

similarly benefit from opportunities created by the reforms across all three workstreams. Suppliers owning resources that are inflexible, that have high going-forward costs, or that are currently benefitting from above-market compensation are likely to see a reduction in total revenues under Market Renewal relative to today as they are exposed to greater competition.

Recommendations

Based on the significant net benefits to the province, we recommend that the IESO and stakeholders proceed into the design stage of Market Renewal. To maximize the benefits and mitigate the risks of Market Renewal, we recommend that the IESO and stakeholders carefully examine the available design choices, taking advantage of experiences of other markets, before selecting those that are most beneficial and consistent with Ontario's unique fundamentals and policy environment. We provide more specific recommendations for each workstream in the Findings and Recommendations section of this report.

I. Introduction

Ontario's electricity market, like all energy markets, has a foundational objective of maintaining reliability at least cost. However, there is a long-understood and growing concern that several aspects of Ontario's wholesale market and supply-contracting approaches are no longer cost-effectively achieving this objective. The Independent Electricity System Operator (IESO) recognizes that a fundamental reform of the market design is needed to address the many challenges faced by the industry today. The IESO has therefore begun to lay the groundwork for a "Market Renewal" initiative that will increase the efficiency of its energy and ancillary service markets and develop an auction-based mechanism to maintain resource adequacy. Market Renewal will help create a more dynamic and competitive marketplace that will more cost-effectively operate in Ontario's changing market and public-policy environment.

A. THE NEED FOR MARKET RENEWAL

Ontario's current electricity market design, which has been in place for 15 years, relies on a "two-schedule" energy market for determining and settling operational decisions, and a system of administrative supply contracting for determining investment decisions. Market Renewal will fundamentally reform both of these approaches to address a number of well-documented problems in order to mitigate and contain system-wide cost increases.

On May 1, 2002 the IESO implemented the current two-schedule system as a transitional mechanism to a single-schedule, locational energy market. The Market Design Committee who originally recommended this two-schedule system recognized its limitations from the outset and recommended it only be used for 18 months.⁴ However, the system has endured much longer than anticipated and remains essentially unchanged today. Over the years, a range of concerns over operational complexity and economic inefficiency have emerged. These problems have been documented and analyzed extensively by the IESO, the Ontario Energy Board (OEB) Market Surveillance Panel (MSP), and independent industry observers.⁵ The IESO has addressed some problems through modifications of specific market rules within the existing market framework, but other more fundamental flaws cannot be addressed without moving away from the existing two-schedule design.

One of the core problems with the two-schedule system is the disconnect between actual system operations and final price signals. The five-minute dispatch of generating resources is determined by a *constrained* optimization algorithm. This algorithm represents system constraints including transmission line limits, transmission losses, ramping constraints, and other generator characteristics in a realistic way. However, generation and load settlements use the

⁴ Market Design Committee (1999), pp 1-9, 3-7, and 3-8.

⁵ For example see Ontario Energy Board (2012), pp 87-88; also Drake (2016).

prices based on an *unconstrained* transmission system. The unconstrained transmission pricing algorithm uses a simplified representation of the Ontario grid, resulting in a uniform system-wide price that does not reflect locational constraints or physical feasibility. The IESO and its stakeholders have recognized that this two-schedule system creates many pricing and operational inconsistencies, which result in inefficient dispatch and unnecessarily high system-wide costs.

To manage the two-schedule system, the IESO pays additional out-of-market “uplift” payments to compensate suppliers for actual or potential costs that are not reflected in the unconstrained schedule. Total system-wide uplift payments have been between \$300 and \$600 million in each of the past nine years.⁶ Some of these uplift payments, such as congestion management settlement credits, compensate suppliers for price and quantity discrepancies between the unconstrained and constrained schedules. Other uplift payments, such as most of those for losses and constrained-on congestion management settlement credits, are critical missing pieces in setting prices that are reflective of actual system costs.

Another class of uplift payments are associated with a need to issue day-ahead unit commitment instructions without a financially-binding day-ahead market and to rely on intra-day unit commitment decisions based on incremental energy offers without considering start-up costs. Market prices should reflect the costs associated with having to dispatch higher-cost resources when facing a binding system constraint, but the Hourly Ontario Energy Price (HOEP) does not send these price signals. Out-of-market payments are a workaround solution, but they are applied in piecemeal fashion and do not address the poor underlying incentives.

The IESO and its stakeholders have studied possible day-ahead market designs since 2003, but have thus far found the explored options to be infeasible despite recognizing the significant efficiency benefits to be obtained. In 2004 they found that the two-schedule system would make day-ahead market settlements excessively complex. Instead the IESO introduced a partial solution through the non-market day-ahead commitment process in 2006 (as updated in 2011).⁷ This process provides a day-ahead schedule and cost guarantee to gas generators and importers, but does not provide similar commitments or settlement opportunities to other resources. Without a financially-binding day-ahead market, the current process does not provide efficient incentives to ensure that all generation resources commit to providing the energy and ancillary services ahead of the operating time frame. Most suppliers are not able to obtain a financially-binding day-ahead schedule, which means some potentially valuable assets such as pumped hydro plants go under-utilized. Exporters similarly face excess risk from participating in day-ahead scheduling and so are not fully accounted for when setting day-ahead unit commitments and schedules. Demand-side resources and other suppliers face more scheduling and price risks than they would under a day-ahead market and therefore are less likely to procure fuel efficiently or provide energy at the lowest costs.

⁶ Ontario Energy Board (2016c).

⁷ See IESO (2008) for a detailed discussion of this partial solution.

In contrast, experience from other wholesale electricity markets shows that the introduction of a day-ahead market can produce significant quantifiable efficiency gains. This is consistent with the Market Design Committee’s recommendation from the outset of the current design that Ontario should adopt a voluntary, financially-binding day-ahead forward market.⁸

The complexity of the current system that relies on uplift charges and administrative workarounds creates incentives for gaming and introduces unwarranted transfer payments from consumers to other market participants. One example of gaming identified by the MSP results in excessive congestion management settlement credit payments during negative pricing periods or when a resource ramps up or down.⁹ Both the MSP and the IESO have found that identifying and addressing the many types of gaming behavior and unwarranted transfer payments is difficult and time-consuming.¹⁰

Market Renewal, through the *energy market workstream*, will provide an opportunity to eliminate this entire set of inefficiencies and incentive challenges. A single-schedule, locational energy market will produce more accurate price signals and settlement incentives that align with operations. A state-of-the-art real-time unit commitment mechanism will minimize the combination of commitment and variable costs. The day-ahead market will achieve more cost-effective unit commitments and natural gas schedules. Together, these energy market reforms will reduce total system costs to serve load, eliminate inefficient incentives and gaming opportunities, and significantly reduce (if not eliminate) many classes of uplift payments.

The existing approach of capacity planning and long-term supply contracts has similarly demonstrated a range of problems and growing costs. Under the current system, the IESO (and formerly the Ontario Power Authority) has signed a large number of long-term supply contracts procured on a technology-specific basis that were often driven by government directives. This approach has met the province’s resource adequacy needs and enabled rapid decarbonization, but has contributed to excess capacity and associated costs. The IESO has recognized the challenges of the current approach and has implemented a demand response auction as a first step toward a more competitive and transparent approach to capacity procurement. The IESO is also making efforts to enable capacity exports that will generate revenue to the province and is planning to enable cost-effective capacity imports in the future. The next step, as outlined by the Minister of Energy, is “moving to [a] technology-agnostic [incremental capacity auction that] will provide new opportunities for innovation and modernization...[and] ensure that ratepayers receive the best prices possible.” By more effectively harnessing competition among different resource types and between new and existing technologies, the *capacity auction workstream* of Market Renewal will reduce the cost of meeting resource adequacy needs.

⁸ Market Design Committee (1999), p. 1-8.

⁹ For example, see Ontario Energy Board (2016c), (2015a), and (2014b).

¹⁰ See Drake (2016).

There is significant strategic value to remedying the current system, given how public policies and market fundamentals have shifted over the past decade. In 2013, the Ontario Ministry of Energy reiterated its commitment to building and maintaining a clean, reliable, and affordable electricity system in its Long-Term Energy Plan.¹¹ Ontario met its goal of reducing province-wide greenhouse gas emissions by 6% below 1990 levels by 2014, partly by achieving 80% electricity sector decarbonization over the past decade.¹² The province has made large investments in transmission, distribution, and clean energy to help achieve that goal, and retired its last coal-fired generating plant in 2014.¹³ The Government of Ontario's five-year Climate Change Action Plan conveys the province's strong commitment to fighting climate change and reducing greenhouse gas emissions across all sectors in the years to come.¹⁴

Going forward, the government's Climate Change Action Plan outlines measures to reduce economy-wide greenhouse gas emissions by 15% by 2020, 37% by 2030, and 80% by 2050 (all compared to 1990 emissions levels). Most of Ontario's greenhouse gas emissions come from the transportation industry and buildings sectors now that the electricity system is largely decarbonized. To continue on this path, the electricity sector may need to support growing electrification of other industries and maintain or replace existing clean energy resources.

The limitations of Ontario's market design are amplified by the fact that the current energy market and resource-contracting system were created based on the then-existing fleet of traditionally controllable generating resources. In 2003, coal-fired generation provided about 25% of Ontario's total energy needs, as shown in Figure 1.¹⁵

Today, a very different mix of intermittent, distributed, and non-emitting resources has emerged with significant further changes on the horizon. Today, without coal-fired generation, about 90% of Ontario's electricity production is from non-emitting resources. As Figure 1 shows, by 2015, non-emitting resources, particularly nuclear, biomass, wind, and solar, had replaced most of the coal-fired generation. However, because the new resource mix is less flexible and contains more intermittent generation, this development has left the existing system less able to meet reliability requirements in a cost-effective manner. Natural gas-fired generation is able to provide the needed flexibility services in many hours, but those flexibility services oftentimes are dispatched and remunerated through inefficient out-of-market mechanisms. In addition, the system increasingly faces surplus baseload generation challenges when non-emitting resources must be spilled or curtailed. While Ontario currently has a significant quantity of flexible resources including interties, hydro generation (including pumped hydro), and distributed resources, the current market design is unable to fully utilize these resources. The *operability*

¹¹ Ontario Ministry of Energy (2013).

¹² IESO (2016d) p. 4.

¹³ See Ontario Ministry of Energy (2015).

¹⁴ Ontario Ministry of the Environment and Climate Change (2016).

¹⁵ IESO (2016c).

workstream will aim to modernize the market design to more fully and more cost-effectively utilize the flexible resource potential of the existing system and improve the incentive to develop more flexibility going forward.

Figure 1
Ontario's Energy Supply in 2003 and 2015



Sources:

2003 and 2015 values from Ontario Ministry of Energy (2010) and (2016).

It has become clear to the IESO and its stakeholders that the current market design established in 2002 is not able to efficiently utilize the unique operating characteristics of the province's current, and mostly emissions-free, generation mix. Oversupply conditions during low-demand and high-baseload-generation hours have forced the IESO to curtail substantial amounts of solar, nuclear, wind, and hydroelectric generation to maintain a reliable system and balance supply and demand. Expensive generation is deployed inefficiently due to the two-schedule system that contributes to uneconomic commitment and dispatch of higher-cost resources. Trade with neighbors over interties, which could lower costs for Ontario customers, is underutilized. And the Ontario's current capacity procurement framework has resulted in excess supply conditions and does not ensure that the lowest cost resources are procured.

Market Renewal is a coordinated series of reforms that aim to more cost-effectively support reliable operations and planning under Ontario's expected policy context and market fundamentals. Market Renewal presents a unique opportunity to learn from the experience in other markets to build a more cost-effective Ontario electricity market. Other North American system operators who engaged in similar market redesign efforts over the last decade have realized the benefits of markets that better accommodate, and in some cases internalize, public-policy goals to reduce emissions and develop clean energy resources. Many U.S. markets are also modifying their energy and ancillary service market designs to more effectively support flexibility needs. California, New York, and New England's markets are currently taking proactive steps to recognize and incentivize low- or non-emitting resources through market mechanisms.

Ontario's Market Renewal effort is an opportunity to incorporate the most cost-effective market design approaches that have a proven track record in other markets, and lay the foundation for a new market design that can leapfrog the challenges recently encountered by other markets. An advanced "made-in-Ontario" market design can create a more robust platform to reliably and cost-effectively meet future system needs and policy objectives.

Are the U.S. Markets "Broken"?

The recent rapid growth of intermittent, zero-marginal-cost resources in Canada, the U.S., and many other international jurisdictions has introduced a number of reliability, economic, and policy challenges that need to be addressed. This shift in resource mix is requiring both regulated and market-based systems to enhance their traditional approaches to maintaining reliability, operating the fleet, incentivizing investment, and planning transmission. The U.S. nodal day-ahead and real-time markets continue to perform relatively well even under these significant changes, but have needed to supplement traditional approaches with more advanced ancillary services, scarcity pricing, surplus baseload pricing, and other flexibility reforms. These energy and ancillary market advancements are generally keeping pace with intermittent resource penetration but continue to require ongoing enhancements. To date, capacity markets have fared well in maintaining resource adequacy standards by attracting new technologies and investment needs at competitive costs, requiring only modest reforms to adequately account for clean energy resources' capacity value.

One area where the U.S. markets are beginning to face more pressing challenges is that some states' significant decarbonization objectives are not yet fully reflected in the market design. California has already modified its market design to account for carbon pricing and carbon emissions (including for both unit-specific and generic imports). However, New England and New York's markets are just beginning to address these concerns by considering market-based approaches to reflecting policy objectives, such as CO₂ pricing and market-based clean energy procurements.

Overall, these markets are far from "broken." The markets are fulfilling their design objectives of maintaining reliability cost effectively, and are now taking the evolutionary steps necessary to address changing technologies, resource mix, and policy objectives. How some markets should be modified to address decarbonization policies as an additional design objective is an important question that is only beginning to emerge.

B. SCOPE AND OBJECTIVES OF MARKET RENEWAL

In many respects, Ontario's market design is a decade behind the more efficient approaches adopted in U.S. markets even though the challenges Ontario faces are much more acute. Ontario has already achieved an 80% decarbonization of the electricity sector, a reduction target that

many U.S. jurisdictions will not achieve until 2050 or later.¹⁶ As a consequence, Ontario faces greater reliability and economic challenges from more ambitious environmental goals and flexibility needs. At the same time, its market design offers less robust energy, operability, and investment incentives for addressing these challenges.

The IESO's Market Renewal has the following objective: "[to] deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meets system and participant needs at lowest cost." To achieve this objective, the IESO has proposed the following three workstreams:

1. **Energy:** Move to a single-schedule market with locational marginal pricing, improve generation commitment and dispatch in real time, and adopt a financially-binding day-ahead market.
2. **Operability:** Increase system flexibility, including better utilization of interties with neighboring systems, and reduce the cost of surplus-generation conditions, variable renewable generation uncertainty, and the need to curtail resources.
3. **Capacity:** Improve procurement of resources to meet the province's resource adequacy needs through an incremental capacity auction that stimulates competition from all resources and that enables capacity trade.

The IESO has long been aware of the need for market reform and has taken the first steps to address the challenges related to the evolving supply mix. Introducing the day-ahead commitment process, implementing operational systems that acknowledge the nodal nature of the market, and introducing a demand response auction have all been important, though only partial, steps in this direction. In addition, on January 1, 2015 the Ontario Power Authority merged with the IESO, combining supply contracting and market operations in one organization. This merger provides an opportunity to integrate the expertise of both prior organizations and address the challenges on a coordinated basis in full recognition of the interactions between the energy market and contracted capacity. Market Renewal presents an opportunity to address changes necessitated by system operability requirements, global-warming-related public policies, increasingly decentralized electricity production, and other industry trends.

C. APPROACH TO THIS BENEFITS-CASE ANALYSIS

The scope of this benefits case analysis is to estimate the quantitative and qualitative benefits of Market Renewal to Ontario and compare these benefits to the expected costs of implementation. Expected benefits include province-wide efficiency savings due to a lower-cost commitment and dispatch of generating resources, improved balancing of the intermittency of wind and solar

¹⁶ For example, California has some of the most aggressive goals and only reduced electricity sector emissions (including imports) by about 20% between 2005 and 2014. See California Air Resource Board (2016).

output with other system resources, attracting or retaining the most cost-effective resources to ensure resource adequacy, and more effectively trading with neighboring systems. These efficiency savings mean that the Ontario power system will serve load and maintain reliability at a lower overall cost. The efficiency savings we measure and present are a metric that provide the most holistic view of the impacts of Market Renewal and represent true efficiency gains to the province as a whole, regardless of which individual entities capture most of the benefits.

Though our primary focus is on province-wide efficiency gains, it is important to understand how Market Renewal will affect customer and other market participants. While it is beyond the scope of our analysis to estimate impacts for individual market participants, we estimate customer impacts and consider impacts on a variety of other market participants.

To estimate the potential efficiency benefits of Market Renewal, we rely on a combination of Ontario-specific analysis, benefit estimates from other markets that have undertaken similar design changes, and bottom up cost analyses as summarized in Figure 2. To evaluate the drivers and estimate efficiency benefits, we first review prior studies of the Ontario market including those from the MSP and those conducted in prior IESO stakeholder engagements. Second, we review and analyze numerous studies of market redesign benefits in other North American power markets, with the primary focus on understanding how these other markets have transformed themselves and the efficiencies they were able to realize. We supplement this effort with interviews with system operators in other regions. Third, we evaluate how the experiences in those other markets can help estimate potentially achievable long-term benefits in the Ontario context, with explicit consideration of the differences between Ontario and these other markets. Finally, we assess how existing contracts and regulatory arrangements affect the ability for Ontario to immediately achieve the magnitude of the estimated potential benefits.

To estimate the incremental cost of Market Renewal, we collaborated with Utilicast to develop a bottom-up estimate of going-forward IESO implementation and system maintenance costs. This estimate is based on a combination of Utilicast's direct experience with other implementation efforts, public data from other jurisdictions, and the IESO's estimates of its own personnel needs and cost parameters. It includes estimated information technology and other business costs that would be incurred by the IESO. Based on our assessment of the IESO's existing information technology systems and experiences of other markets, we provide a discussion of the most important implementation risks that the IESO should proactively manage in order to prevent cost over-runs and project delays. We also provide a qualitative evaluation of stakeholders' potential business costs, and a discussion of how transition costs could vary depend on the class of market participant and based on key design decisions.

Figure 2
Framework for Estimating Benefits and Costs



Our estimate of implementation costs is compared to estimated benefits realized over a ten-year period from 2021 through 2030.¹⁷ This ten-year period represents a typical timeframe over which many of the software and technology systems associated with the energy and operability workstreams are recovered. The benefits of Market Renewal will persist, however, beyond 2030. The costs of Market Renewal will mostly be incurred during the lead up to operationalization of the project, as the planning and implementation of new systems and markets take place. The majority of these costs will be capitalized, however, and will not be recouped from consumers until the project is implemented and its benefits are starting to be realized. Where necessary, we use a reasonable proxy for the timing of Market Renewal activities and design change implementation, and for specific features of design changes. Specifically, to convert the annual benefits to a net present value, we assume that capacity exports are able to begin in 2017 (as they have), an incremental capacity auction is implemented in 2020, and the energy market enhancements (including a financially-binding day-ahead market and expanded ancillary services) start in 2021.

¹⁷ More precisely, we estimate costs that are primarily incurred through 2021 when Market Renewal is assumed to be fully implemented. We compare these costs to the benefits achieved through 2030—with capacity exports starting in 2017, the incremental capacity auction starting in 2020, and energy/operability reforms implemented in 2021. We then compare these annual benefits and costs on a net present value basis in 2021 dollars, using a 5% discount rate.

At the time of this report, some aspects of Market Renewal are more well-defined than others. For example, the IESO presently has a more complete high-level description of the intended energy and capacity auction reforms than the intended operability reforms. However, even in these more well-defined energy and capacity auction workstreams there are many design decisions and implementation details that have not yet been determined. Some stakeholders recommended that a detailed modeling analysis of Ontario's proposed Market Renewal effort should be used to estimate the benefits of this effort. We agree that Ontario-specific studies can provide significant insights and have therefore relied on existing Ontario-specific analyses of various aspects of Market Renewal that were conducted prior to this Stakeholder Engagement. Undertaking new Ontario-specific analyses would be premature given that the process of developing detailed market design specifications has not yet begun. Later in the process, as specific design elements are developed and finalized, it may well be warranted to conduct targeted analyses of these design options.

Note that only a subset of all benefits from Market Renewal is fully quantified in this study. For the most part, the Ontario-specific and other markets' studies we review focus only on quantifying production cost savings realized by the contemplated design changes. Some studies quantify additional benefits through sensitivity or scenario analysis. Most of these studies also have qualitative descriptions of additional benefits that could be expected beyond those quantified. For example, most studies of energy and operability reforms report only production cost savings without quantifying the potential efficiency gains from investment cost savings or enabling innovation. Reviewing these studies allowed us to gather an understanding of the fundamental drivers of the quantified benefits, as well as any non-quantified benefits that Ontario might expect from Market Renewal. Lessons learned in other markets allow us to develop recommendations for further consideration by the IESO and Ontario policymakers.

D. APPLYING LESSONS FROM OTHER MARKETS IN ONTARIO'S UNIQUE CONTEXT

Ontario's electricity sector reflects a unique combination of policy objectives, resource mix, and market fundamentals that make it different from every other market. These differences will affect the nature of benefits realized from Market Renewal in Ontario, compared to similar design changes in other jurisdictions. As we describe in more detail in Section II, our conversations with stakeholders, market observers, and the IESO provided valuable insights for understanding the challenges with the current market design and opportunities from Market Renewal. These conversations highlighted a number of characteristics that distinguish Ontario's power system and electricity markets from other markets. Nevertheless, while Ontario's situation is unique, there is no one aspect of Ontario's market that does not have a parallel elsewhere. By carefully accounting for the differences and similarities between Ontario and other markets, we are able to draw useful lessons learned.

Stakeholders identified several common themes related to Ontario's uniqueness that need to be considered in the Benefits Case. We provide here a high-level explanation of how we account for these unique elements, and we provide more detail later in this report. One aspect of the regulatory context affecting Market Renewal is the degree to which Ontario relies on long-term

contracts and rate-regulated assets. This limits the extent to which suppliers are exposed to market prices and the extent to which more efficient prices will incentivize more efficient behavior. We account for the mitigated benefits of more efficient energy and ancillary services prices by discounting the potential benefits of Market Renewal as discussed further in Section VI. Existing contracts and rate regulated assets also limit the benefits from implementing a capacity market because only resources that are exposed to market prices will make entry and exit decisions based on market signals. We account for this proportion of merchant resources based on the timeframe over which contracts roll off, as discussion in Section V.

Ontario's greenhouse gas regulations will affect the benefits of Market Renewal and its design elements. The new cap-and-trade market, similar to that implemented in California, will impose additional production costs on fossil generators and this policy may continue to expand the proportion of non-emitting resources in the province. However, Ontario is not alone in facing these changes. Ontario is a member of the Western Climate Initiative, a program with the goal of developing market-based programs to reduce carbon dioxide and other greenhouse gas emissions; British Columbia, Manitoba, Quebec, and California are also members. Of these, both California and Quebec have adopted regulations to implement the Initiative. These policies will affect fossil generators' production costs, but will not alter the fundamental economic principles governing their respective wholesale electricity markets. Similar to Ontario, all of the other markets we examine are significantly expanding their intermittent non-emitting resources and have been implementing operability reforms to better accommodate these resources.

With respect to the energy workstream, we do not explicitly account for the effect of Ontario's cap-and-trade policy, but note that it is likely to increase the steepness of Ontario's current supply curve and so would likely increase the estimated benefits of Market Renewal. We do however explicitly account for the need to integrate higher levels of intermittent renewable resources in both the energy and operability workstreams by examining Ontario's intermittent resource levels in comparison with other markets at the time of their reforms, as discussed further in Sections III and IV.

Ontario's power system operates in an environment of regulatory risk that is arguably higher than in many other jurisdictions. Some stakeholders suggested that most U.S. markets offer more competitive electricity markets with lower regulatory risks and more transparent governance structures, which serves to increase investor confidence. This issue has been raised with respect to many aspects of Market Renewal, but is most important in the context of the capacity auction that the IESO intends to rely on for attracting and retaining resources. We agree with stakeholders that governance and regulatory risks are critical components of the capacity auction workstream, and discuss the similarities and differences between Ontario and other jurisdictions. Based on this comparison, we recommend that the IESO and stakeholders explicitly address these risks through a combination of improved governance structures and market design elements that address Ontario's unique challenges and environmental policies as discussed in Section V.

Stakeholders pointed out that Ontario’s unique market fundamentals similarly present challenges that need to be considered. These fundamentals include fleet characteristics, the characteristics of the transmission system, and the nature of Ontario’s system needs. Ontario’s generation fleet includes a high level of baseload nuclear generation that reduces the power system’s flexibility, a high share of baseload resources, relatively large inerties, and a significant quantity of intermittent resources. The high level of baseload resources introduces significant flexibility needs that may exceed other systems’ needs at similar levels of intermittent resource. However, Ontario’s market fundamentals offer greater untapped flexible resource potential from hydro and inerties. We account for these fleet characteristics and market fundamentals by comparing the “steepness” of supply curves and levels of resource integration in Ontario and other markets, as discussed further in Sections III and IV. The combination of greater flexibility needs and greater untapped flexibility potential could result in operability benefits beyond those observed in other markets.

Using these approaches, we supplement Ontario-specific studies with the experience from other markets after accounting for the most important differences between the regions. We also draw on the experience in these other markets to identify the lessons learned that may be particularly relevant for the IESO and stakeholders to consider in the next phase of Market Renewal.

It is important to note that the similarities between the various markets are greater than the differences. Ontario’s electricity system fundamentally relies on the same types of resources and operates according to the same physical laws and economic principles as all other electricity markets. This means that the fundamental drivers of benefits of market design changes are similar across markets. In fact, our review of studies shows that very different markets—all with their own unique features, fleet composition, and regulatory context—have achieved very similar benefits from similar changes in market design changes.¹⁸ We acknowledge that there is judgement and uncertainty involved in translating the experience from other markets to Ontario. However, the similarity of benefits from similar changes in market designs across several very different markets provides a strong basis for supporting the estimated range of potential benefits.

¹⁸ For example, Midcontinent ISO (MISO) and California ISO (CAISO) have very different fleet characteristics (with CAISO being more like Ontario than like MISO), yet the realized benefits of similar design changes are of similar magnitude after accounting for differences in market size. The relatively modest differences in benefits are explained by slightly different scopes of design changes, the difference between higher-cost and lower-cost units (as represented by the “steepness” of the supply curve), and the level of intermittent resource penetration—all factors that we consider when interpreting and translating results from those other markets to Ontario. For more details on this process, see Section III.C.

II. Stakeholder and Market Observer Input on Market Renewal

Throughout this benefit and cost analysis for Market Renewal, we relied extensively on the insights, feedback, and ideas offered by members of the Market Renewal Working Group (an advisory group of stakeholders that the IESO convened to provide expertise and advice to support Market Renewal initiatives, also referred to as the “Working Group”), as well as other stakeholders and market observers. We used this information to help formulate and refine every aspect of this study, including our high-level approach, the methods we used to interpret results from other studies to best fit Ontario’s context, and the overall findings of both the quantified and non-quantified benefits of Market Renewal.

A. INEFFICIENCIES IN THE CURRENT MARKET DESIGN

A number of stakeholders, market participants, and market observers have voiced their concerns regarding Ontario’s current market structure and the need for reform, some of which existed since the start of the market in 2002. Our discussions with these various groups were invaluable in helping us understand the issues at hand. In this section, we highlight the issues described by the Market Surveillance Panel and those discussed with stakeholders during several in-person meetings.

1. Concerns Identified by the Market Surveillance Panel

The MSP is a three-member panel of market observers tasked with monitoring and investigating activities and behavior in the IESO-administered energy markets. The MSP regularly publishes reports on the efficiency of Ontario’s electricity markets and has expressed concerns with the design going back to the beginning of the wholesale energy market. Though the views of the MSP cannot be fully documented here, we summarize several high-level MSP concerns that would be addressed by Market Renewal.

One of the MSP’s main concerns is that the two-schedule system does not reflect the realities of the physical transmission grid, which introduces significant inefficiencies.¹⁹ The two-schedule system leads to market prices paid to suppliers and by consumers that are systematically out of alignment with marginal system costs. In fact, the MSP has referred to the market schedule setting prices based on “fictional supply” and “fictional resources.”²⁰ As a result, the incentives for market participants are incorrect and cause them to act in ways that lower system efficiency.²¹ As noted by the MSP, many of the two-schedule system inefficiencies, such as

¹⁹ Ontario Energy Board (2016b), pp. 5–6; Ontario Energy Board (2011).

²⁰ Ontario Energy Board (2016c), p. 6.

²¹ Ontario Energy Board (2012), pp. 87–88.

constrained-off payments, increase system costs and customer costs, while providing “little or no commensurate value”.²²

The MSP has identified at least three types of inefficiencies induced by the two-schedule system.²³ *General inefficiency* is caused by the mismatch in price charged for the marginal unit of consumption (the Ontario-wide uniform price) and the actual price or cost of the marginal unit of generation. When there are binding constraints unaccounted for in the system-wide price, wholesale consumers may face an artificially low price of electricity, inducing inefficiently high consumption. This often occurs when transmission constraints limit the amount of low-cost generation from northern Ontario that can reach southern Ontario; the true marginal cost of producing electricity for consumption in the south is higher than that reflected in the uniform price. Conversely, other consumers (in this example, the consumers in northern Ontario) may also face an artificially high price, inducing inefficiently low consumption. *Intertie inefficiency* is similar to general inefficiency and occurs in transactions on Ontario’s interties with neighboring markets. A market participant may buy artificially low-priced power (at the uniform price) in southern Ontario and sell it at a higher price in a neighboring market. However, the true marginal cost of producing that power may have been even higher than the avoided cost in the neighboring market, making the transaction harmful to market efficiency and total cost.²⁴ Finally, *dynamic* or *investment inefficiency* occurs when investment decisions are skewed by artificial prices. Investment in generation and transmission are driven, in part, by the price of electricity over time in different parts of the system. Locations with systematically higher generation costs should normally attract additional generation investments. Similarly, large consumers of electricity would tend to locate in areas with lower prices. To the extent that these price signals are systematically biased by the uniform price, investment decisions will be skewed and sub-optimal.

In an attempt to reconcile market participants’ remuneration with incurred costs and dispatch instructions, the two-schedule system features a number of out-of-market payments, including congestion management settlement credits (CMSC), generator cost guarantees, and intertie offer guarantees.²⁵ Out-of-market or “uplift” payments are common features of organized electricity markets meant to incentivize actions beneficial to system goals that are not properly compensated or incentivized through market mechanisms. However, the MSP finds that they are especially pervasive in the IESO system, reducing the market’s transparency and efficiency. While uplifts address the problem of creating sufficient incentives for generators to follow dispatch instructions from the IESO, they fail to solve the underlying efficiency issues of the two-schedule system, and sometimes are the source of new inefficiencies, including gaming.²⁶

²² Ontario Energy Board (2011), pp 108–110.

²³ Ontario Energy Board (2016c), pp. 7–9.

²⁴ Ontario Energy Board (2016c), pp 8; Ontario Energy Board (2016b).

²⁵ Ontario Energy Board (2016c), p. 7.

²⁶ Ontario Energy Board (2015c), pp 84–86; IEMO (2002)

The MSP has recommended many times that the IESO review CMSC and other uplift payments to ensure they are as efficient and transparent as possible, and reduce unwarranted transfer payments.²⁷ Market Renewal is an opportunity to implement a system that naturally incentivizes market participants to maximize system efficiency and lower system and customer costs.

Another inefficiency identified by the MSP is associated with the existing day-ahead commitment process (DACP). Currently, the process introduces excess risks that exclude otherwise economic day-ahead export schedules, creating results that are systematically out of alignment with predictable outcomes in the real-time market. Furthermore, due to the lack of day-ahead settlement, day-ahead bids are disconnected from cost because they are not financially binding. As a result of these inefficiencies, internal generators and importers often receive large out-of-market payments. The MSP has suggested that a true day-ahead settlement would improve the market by “eliminating the need for most generator and import guarantees.”²⁸ The MSP argues further that day-ahead settlement would encourage exporters to become active participants in a day-ahead market by facilitating firm export sales.²⁹ By incentivizing an increase in imports and exports, the MSP continues, a day-ahead market can reduce “the market’s reliance on non-quick start resources to meet real-time supply and demand mismatches.”³⁰ Additional benefits of implementing a true day-ahead settlement through Market Renewal, including enhanced market power mitigation, improved optimization of day-ahead dispatch, and reduced reliance on the more volatile real-time market for making intra-day unit commitments.

Finally, the MSP has identified challenges resulting from centralized procurement and long-term contracts to secure resource adequacy.³¹ Under the current system, the costs and risk of inaccurate demand and supply forecasts are borne by consumers. A more competitive market design could shift the risk of over-procurement to capacity suppliers and lead to a more efficient mix of new and existing resources.³² In addition to these investment-related shortcomings of the current system, the incentives resulting from long term contracts can result in sub-optimal bidding strategies that lead to negative prices and increase system costs.³³ Market Renewal would implement a competitive capacity auction that eliminates these uneconomic incentives for

²⁷ For more discussion of these unwarranted transfers see Ontario Energy Board (2016c); Ontario Energy Board (2015a); Ontario Energy Board (2014c); Ontario Energy Board (2014a); Ontario Energy Board (2013); Ontario Energy Board (2012); Ontario Energy Board (2011).

²⁸ Ontario Energy Board (2015c), p 86.

²⁹ Ontario Energy Board (2015c), p 86.

³⁰ Ontario Energy Board (2015c), p 86.

³¹ Ontario Energy Board (2015b), p 162.

³² Ontario Energy Board (2015b), p 162.

³³ Ontario Energy Board (2015c), p 65.

new resources and existing resources that roll off existing contracts, increasing system efficiency and lowering costs.

Overall, the MSP has identified a number of shortcomings and inefficiencies of the current system. While Market Renewal would not be a panacea for every concern that the MSP has identified with the current design, it will make significant progress toward addressing several of the most problematic inefficiencies.

2. Concerns Identified by the Working Group and Other Stakeholders

Beyond the inefficiencies documented by the MSP, we also asked stakeholders to share their individual perspectives on the current market design. The Working Group members and stakeholders discussed their views about how the current wholesale market affects their companies and supply resources. They shared their concerns about specific elements of the current market design that are not working well today:

- Several stakeholders identified weak and inefficient pricing signals as a shortcoming of the current market. Consistent with MSP findings, stakeholders saw market prices that were disconnected from actual costs as problematic. Some identified the Global Adjustment as a barrier to pricing transparency and market efficiency.
- A number of stakeholders highlighted the DACP as an element of the current market that contributed to inefficiency. They identified the lack of a financially-binding day-ahead market, the fact that exports and hydro are not adequately accounted for in the DACP, and the resulting misalignment of the DACP and balancing markets as problematic.
- Several stakeholders noted that the current market does not adequately support emerging technologies. They mentioned that there is little incentive for technology research and development and that the current market does not fully incorporate or enable certain emerging technologies to fully participate in the market.
- Many stakeholders identified concerns with current methods for capacity procurement. These included high costs associated with long-term contracts and low competition, a lack of opportunities for new technologies such as storage and distributed energy resources, a lack of locational prices to inform capacity decisions, and significant regulatory risk associated with government influence on capacity procurement.

Stakeholders and Working Group participants also identified many opportunities that Market Renewal could unlock. Among these were:

- Opportunities for cost reduction and better utilization of existing resources;
- Better integration with neighboring power markets, with enhanced potential for trading and improved intertie utilization;
- Greater ability for new technologies to participate in the market;
- Improvements in price formation, including single-schedule pricing, fewer uplifts and other cost programs, and greater transparency in price formation; and

- Opportunities resulting from implementing a capacity auction, including increased competition and more efficient prices, broader participation by new technologies and increased innovation, more transparency in capacity procurement, and reduced regulatory risk from government influence.

We used this input to better understand deficiencies with the current market design and inform our benefits case analysis. This was instrumental in helping to identify the most significant benefits of similar reforms in other markets, and how those benefits were likely to manifest in Ontario.

B. MARKET VISIONING WORKSHOP

Working Group members engaged in a workshop to explore how future market trends and uncertainties should be considered in Market Renewal. The participants articulated that Ontario has set a clear policy direction of continuing to reduce greenhouse gas emissions, economy-wide and in the power sector. Others emphasized uncertainties around the pace and magnitude of renewable resource development in Ontario, stating that if aggressive greenhouse gas reduction is a goal, Ontario may need to electrify other sectors of the economy and move them onto an electricity system powered by mostly non-emitting resources. Through Market Renewal, Ontario has the opportunity to develop a market design that is robust to these key drivers and to the range of market futures that the sector may need to support.

1. Key Drivers Affecting the Future Electricity Sector

The Working Group members organized market trends and uncertainties into a number of drivers that will shape the character and function of the electricity sector. We focused on the 10–20 year timeframe that is most relevant to Market Renewal. The Working Group identified the following as the primary drivers of Ontario’s energy future:

- **Future electricity usage and load growth.** Working Group members identified the pace and magnitude of load growth as a key driver, arising from the increased use of electronics and other new technologies, the continued development of data centers, and potential electrification of transportation and heating sectors to support decarbonization. The Working Group discussed how these changes might affect Ontario’s electricity consumption in magnitude, pace, and consumption patterns. Some felt that future customers will be more “data and technology-savvy” and may want more price and cost transparency so that they can be informed about the choices they make about controlling their consumption patterns and what resources they are using.
- **Demand-side and distributed resources.** Working Group members discussed the importance of demand-side and distributed resources. We heard a consensus that distributed resources have a significant role to play in Ontario’s future, but there are large uncertainties regarding the pace and magnitude of distributed technology deployment. There are also many alternative paths regarding how it might affect grid operations and the sector’s regulatory structure. The future of the market will need to include adequate

processes and mechanisms for these emerging technologies to be well-integrated with the market through adequate pricing, dispatch, qualification standards, and two-way flow capabilities.

- **Public Policies.** Working Group members discussed uncertainties in the province's public policies and how the market framework and design will need to be flexible enough to accommodate changing government policies. The current direction is clearly toward reducing economy-wide greenhouse gas emissions, but exactly how much more the electricity sector will decarbonize and how much electrification will be needed to support decarbonization in other sectors' remains uncertain. In addition, government policies that surround the future incentives for clean energy will have a significant impact on wholesale energy prices and potentially capacity auction prices. Stakeholders have repeatedly stressed the significant regulatory risks that currently face and may continue to face investors in the Ontario market, and the need to account for Ontario's unique historical context in this regard when developing appropriate governance structures under Market Renewal.
- **The interaction of power contracts and power markets.** One the most prominent themes of all our stakeholder discussions has centered on existing supply contracts and their interaction with Market Renewal. Working Group participants explained some of the mechanics of how the existing market design interacts with contract provisions, challenges faced in prior market reforms when contracts had to be amended, and concern that Market Renewal could significantly change the value of existing contracts. For some Working Group members, these value implications are more important to their business decisions than the longer-term, post-contractual benefits that they might share in under Market Renewal.
- **Future fuel and resource mix.** Ontario's fleet makeup has changed significantly over the past decade, and uncertainties remain around future policies around the use of natural gas and the scope of clean energy procurements. Some Working Group members expressed concern that a substantial decrease in the use of natural gas in power generation may reduce the availability of natural gas supplies and associated pipeline infrastructure over time, which in turn may affect the reliability of the electricity system. Others voiced their concerns about the efficient scheduling between the gas and electricity markets and how those interactions need to be well-managed through market design features so that suppliers will not be caught with significant downside risks associated with locking into power prices prior to the ability to secure the fuel at the corresponding prices. Some discussed the uncertainties around the cost and deployment of solar and wind resources, which in turn would affect the need for gas generation and gas fuel supplies and associated infrastructure. A final uncertainty relates to future technology breakthroughs and costs, given the possibility that significant cost reduction in storage, smart grid, or control technologies could change the future investment trends in supply and demand resources, as well as how the system will be operated. The timing and outage risks associated with nuclear refurbishments create additional uncertainty in the cost and reliability of power supplies.

- **Other key risks and uncertainties.** Some Working Group members discussed other uncertainties that pose risks to some classes of market participants. Shifting market fundamentals and a changed market design could strand certain resources and associated costs for some investors. Ontario will be affected by major market redesign efforts and market changes in neighboring markets, and may be more greatly affected as Ontario increasingly integrates and coordinates with other North American power markets.

Understanding these key drivers of Ontario's energy future allowed the project team to better understand the potential benefits of Market Renewal in the future, and how Market Renewal could better prepare Ontario to face significant uncertainties in those important drivers.

2. Range of Market Futures that Ontario May Face

Using information on the key drivers affecting Ontario's electricity sector, Working Group members developed four distinct visions of futures that reflect a reasonable range of how policies and market conditions could evolve over the next 10 to 20 years:

- **Current Trends:** Under Current Trends, the Working Group developed a vision of a future consistent with current expectations about the evolution of resources and policies. Environmental policies, such as those that drive the development of renewable energy resources will continue to be pursued in the province, but not too aggressively, with a trajectory of some additional renewable generation built. Electricity usage will grow slowly, with some electrification of other sectors in the long term but not sufficient enough to significantly alter the system's needs. Policies will continue to increase the province's reliance on market-based mechanisms to create incentives for operations and investment.
- **Deep Decarbonization:** The Deep Decarbonization future incorporates an ambitious reduction of fossil fuel use across all sectors, including electricity, heating, transportation, and industry. There will be more emissions-free generation and almost no gas-fired generation. For the grid and wholesale market to function without relying on gas plants to provide peaking power and flexibility services, the electricity sector must incorporate new types of clean energy and flexible resources. This will create a greater role and reliance on interties, demand response, distributed resources, storage, and customer participation.
- **Distributed Grid:** In the Distributed Grid future, local distribution companies will play a larger role in serving loads and in enabling distributed technologies. Customers become "prosumers," both consuming and producing electricity, with more opportunities to buy and sell power with other customers. New roles emerge for distributed service platforms to manage distributed resources, and for energy managers in smart homes and communities. Customers value the ability to control their own consumption, particularly if they can help decarbonize the system and are willing to accept new technologies and paradigms to do so. Storage becomes more economical and it becomes a part of customers' distributed resources portfolio.

- **Regional Integration:** In the Regional Integration future, a large and well-coordinated market region evolves around Ontario, including other Canadian Provinces and U.S. Regional Transmission Organization (RTO) footprints. New inter-regional transmission development may be beneficial or needed to expand interconnections with neighboring systems. The regions adopt more aggregated system controls and more tightly integrated market structures. The more robust transmission systems and market structures enable cross-border support for achieving clean energy policies and traditional energy/capacity needs more cost-effectively, but there are also greater risks introduced by cross-border impacts of conflicting policy goals or market designs between regions.

These futures represent a distinct set of plausible market evolution paths. The evolution of Ontario's electricity system is likely to incorporate some elements from all of these futures. A robust market design developed under Market Renewal should be positioned to address the distinct requirements of each possible future.

C. IMPLICATIONS FOR MARKET RENEWAL

Based on the identified drivers and possible futures, Working Group members discussed how Market Renewal can better position Ontario to support market evolution. Working Group members discussed key requirements of Ontario's power markets under each potential future, and how these requirements overlapped with market design elements under consideration in Market Renewal. Stakeholders recommended that Market Renewal should be pursued with these identified futures in mind in order to reduce the risk of expensive "retrofits" of the new market design to an unexpected industry outcome at a later date. This approach may take additional planning at the outset, but could yield a more robust market design and significant benefits for the province in the longer-term. Table 1 summarizes the market design requirements identified by the Working Group that may be needed to support each market future.

Working Group members also identified several requirements that exist in several or all futures. The majority of these design requirements identified by the Working Group are aligned with the scope of Market Renewal. For example, several elements, including creating a financially-binding day-ahead energy market, developing location-based energy pricing, developing new ancillary services products to properly incentivize system flexibility, and improving coordination between Ontario and neighboring markets through improved use of interties, are specifically under consideration in Market Renewal. Other design requirements could potentially be added or considered in the scope of Market Renewal within the detailed design phase, while others we recommend at a minimum should be considered as potential future requirements that Market Renewal must contemplate and retain the option for pursuing in the future.

While there is overall alignment between Market Renewal and these future design requirements identified by stakeholders, there are some differences. First, the Working Group placed a greater focus on enabling innovation and integrating emerging technologies than has been placed in discussions of Market Renewal. We view this design requirement as consistent with the

principle that Market Renewal should help level the playing field among different technologies, both in the energy market and capacity auction. Based on feedback from stakeholders, we recommend that the ability and optionality to fully incorporate a range of emerging technology types be included throughout the Market Renewal design process.

Table 1
Market Design Requirements Under Potential Market Futures

Futures Developed	Potential Market Design Requirements
Current Trends	• Financially-binding day-ahead market • Capacity auction for incremental resources to meet resource adequacy requirements • New or revised ancillary services products (ramping, fast-responding reserves, regulation) for increased system flexibility • Closer coordination with external markets
Deep Decarbonization	• Financially-binding day-ahead market • New ancillary services products for increased system flexibility • Pricing of emissions in the electricity market and better coordination with government policies on clean energy procurements • Enhanced capability to manage interactions with distributors or other distribution system managers • Enhanced intertie utilization and flexibility to import and export power to match short-term changes in intermittent generation
Distributed Grid	• Managed coordination with distributors • Locational prices to inform the value of resources • Managed participation from decentralized resources • Access to wholesale market prices for customers • Visibility of all resources to market operator for efficient dispatch, pricing, participation, and enabling of non-traditional distributed resources • Simple settlements, even in a more complex system • Increased market visibility and ability to monitor changes in customers' preferences and investments over time, including transparent and efficient pricing to help customers make efficient investment decisions
Regional Integration	• Explicit coordination with neighboring regions for more than just reliability • Market-based incentives for resource adequacy, with less regulatory uncertainty • Clear roles for markets while managing existing contracts • Enhanced cross-border coordination on interactions that affect the ability and cost-effectiveness of achieving policy goals

Second, the Working Group and stakeholders have voiced consistent, strong concerns about governance and interactions with environmental policy objectives, neither of which will be directly addressed by Market Renewal. Though Market Renewal would prepare the Ontario market to more efficiently accommodate and operate under changing policy objectives, Market Renewal does not currently include all elements necessary to achieve the new policy objectives. Partly in response to this feedback, the IESO has begun a parallel stakeholder effort to address the question of governance and determine how best to support a more dynamic marketplace and mitigate regulatory risks. We also recommend that a component of Market Renewal,

particularly in the capacity auction workstream, should involve an evaluation of how government policies will interact with or be achieved through the market design.

Some of the requirements of the individual market futures may not be addressed immediately through Market Renewal. However, we expect that Market Renewal will create a platform to more efficiently support the design enhancements that may be required in certain market futures. Market Renewal can and will put Ontario in a better position to flexibly and efficiently meet the needs of an uncertain future.

III. Energy Market Enhancements

The first workstream under consideration in Market Renewal involves enhancing the current energy market through a number of reforms aimed at improving price formation and the commitment and dispatch of Ontario's supply resources. Improved pricing, commitment, and dispatch create efficiency benefits by ensuring electricity demand is served by the lowest-cost supply possible while meeting system reliability needs. We estimate the potential magnitude of efficiency benefits that the IESO might achieve through energy market improvements by starting with prior studies of Ontario. We supplement these Ontario-specific analyses with experience from similar market reform efforts in other markets, after considering the applicability of these experiences in Ontario's unique context.

A. DESCRIPTION OF CURRENT MARKET DESIGN AND PROPOSED ENHANCEMENTS

The IESO's current energy market relies on a two-schedule system: one for pricing and one for resource dispatch. To calculate energy prices, the market clears using "unconstrained" resource schedules which ignore many physical system constraints such as transmission limitations and resource ramp rates. The resulting unconstrained price is used for settlement; it is paid by wholesale consumers and paid to generators injecting energy. For resource dispatch, "constrained" resource schedules are calculated that do consider all physical system constraints.

This bifurcation creates market inefficiencies and leads to large CMSC and other uplift payments.³⁴ Further, market participants can sometimes magnify available uplift payments by offering their resources above or below their true costs.³⁵ The IESO has already limited several such "gaming" opportunities, but further improvements will be difficult to achieve while still maintaining the two-schedule system. Intra-day unit commitment is relatively inefficient because the heuristic approach does not attempt to minimize start-up and shut-down costs, but instead considers only variable costs and expected online time.

³⁴ See Drake (2016).

³⁵ See Drake (2016).

Why are Transparent and Accurate Prices Important?

Transparent prices that accurately reflect the marginal costs of the power system are critical to competitive outcomes and market efficiency in both the short and long terms. In the short-term, efficient prices ensure the system will deliver power to customers at the lowest production cost while maintaining reliability standards. Efficient market participation is incentivized both for controllable resources that are incorporated within the system operator's market dispatch, and for non-controllable resources that may not be fully accounted for (such as demand response and distributed resources). Accurate and transparent prices also provide efficient long-term incentives for entry and exit by signaling to participants where and what type of existing and additional investments are most valuable.

Prices that do not accurately reflect true system costs mislead market participants, incentivize uneconomic behaviors that disproportionately increase costs elsewhere on the system, and inflate the need for out-of-market uplift payments. Non-controllable resources that are ineligible to receive such uplift payments will not have proper incentives to operate efficiently. Inaccurate prices may also create opportunities to game the market, create unwarranted transfer payments and simply not properly incentivize participants to act in the most efficient way possible.

The lack of a financially-binding day-ahead market contributes to the existing inefficiencies. The non-market day-ahead commitment process does not incorporate appropriate incentives for exports to be scheduled on a day-ahead basis.³⁶ The lack of financially-binding schedules reduces the opportunities to utilize pumped hydro and efficiently schedule other hydro resources.

As discussed in Section II.A, the problems with the current design have been documented and analyzed extensively by the IESO, the MSP, and independent observers. The inefficiencies of the current market design have also been confirmed through discussion with Working Group members and other IESO stakeholders. The energy market reforms that would be implemented through Market Renewal are intended to correct these issues at their source. The key design elements of Market Renewal that are proposed to correct these inefficiencies are:

- A single-schedule commitment and dispatch with locational marginal prices (LMPs) for all suppliers (although customers may maintain uniform or zonal prices),
- A financially-binding day-ahead market, and
- Improved intra-day unit commitment.

Moving from the current two-schedule commitment and dispatch system to a single-schedule system would allow wholesale energy prices to be determined consistently with actual system

³⁶ Imports and exports technically are considered in the day-ahead commitment, but there are no financial guarantees for exports (while there are penalties), which means there is little incentive for exports to participate.

conditions and resources actual dispatch. This would eliminate the inconsistencies between resource scheduling and wholesale energy market prices and significantly reduce or eliminate existing uplift payments. The Ontario Minister of Energy emphasized the importance of these reforms stating that “the power to remove inefficiency from the existing market; offer increased transparency to generators; enhance the opportunity for innovative new-entrants and—most importantly for our Government—help drive the competitive tension necessary to reduce system electricity costs.”³⁷

As is the case in other markets, nodal prices would likely reflect three components: the marginal cost of energy, the marginal cost of congestion on the transmission system, and the marginal cost of transmission losses at any given location.³⁸ By accounting for locational differences in marginal costs, nodal prices more accurately incentivize production (or load reductions) where it is most valuable to the system. This provides improved incentives for both short-term dispatch and long-term investment purposes.

In other jurisdictions, loads are usually charged based on zonal prices even if suppliers are settled based on nodal prices. Load zone prices vary from the system-wide average based on transmission constraints and losses, but experience less variability than nodal prices. Locational energy markets generally provide financial mechanisms to limit the extent to which customers are exposed to congestion costs by returning “congestion rent” to the customers that are most exposed to high congestion pricing. This can be done directly through credits or indirectly through financial transmission rights (FTRs).³⁹ The pricing regime for customers and the approach to managing congestion costs will need to be determined in the design phase of Market Renewal through collaboration between the IESO and stakeholders.

Establishing a financially-binding day-ahead market will reduce price uncertainties for suppliers and customers. Suppliers will have the ability to offer to produce energy for the following day and receive a financially-binding schedule for a majority of their production. This lets market participants better manage their risks by allowing them to lock in prices on a day-ahead basis, thereby avoiding the often much larger price fluctuations in the real-time market. In other wholesale electricity markets, market participants commit and schedule the vast majority of energy on a day-ahead basis, leaving only a minor portion of all transactions exposed to real-time

³⁷ Thibeault (2016), p. 6.

³⁸ We use the terms “nodal pricing” and LMP interchangeably in this report. We also sometimes refer to locational or location-based prices in other cases where we may be referring either to nodal or zonal prices.

³⁹ “Congestion rent” is the excess revenue that an RTO collects from customers (who tend to be located in higher-price locations) compared to what is paid out to generators (who tend to be located in lower-price locations). Financial transmission rights (also referred to as congestion revenue rights) give the owner the right to collect congestion revenue along a given transmission path.

price volatility.⁴⁰ The day-ahead settlement also allows natural-gas generators to procure much of their fuel on a day-ahead basis, which reduces fuel-related intra-day balancing costs.

While the IESO has determined the primary elements of the energy market workstream of Market Renewal, the IESO staff and stakeholders will need to develop the specific design elements in a manner most suitable to Ontario. While this Benefits Case study does not assume any particular detailed design, the general direction of energy market reforms is expected to be consistent with the features described above, reflecting best industry-wide practices and lessons learned from other regions.

B. PRIOR ANALYSES OF ONTARIO'S MARKET

The Benefits Case for the energy market workstream of Market Renewal is supported by a significant body of work from prior IESO stakeholder engagements, Market Surveillance Panel studies, and other studies that provide both quantitative and qualitative analyses of the economic benefits offered by certain elements of Market Renewal in Ontario.

Quantitative estimates of Ontario's proposed energy market workstream of Market Renewal were presented in the following two studies:

- **Energy Market Pricing System Review** (SE-114, Market Reform 2015):⁴¹ This study examined the impact of moving from the current two-schedule system to a single-schedule system based on LMPs in the real-time market. The study projected that such a change would create \$165 million a year in customer benefits before accounting for contracts (\$40 million per year after contracts) largely through a reduction in CMSCs. In a sensitivity case, the study also estimated a potential efficiency benefits by assuming that twenty gas generators (those receiving the highest CMSC payments) would reduce their offers by 5% in a single-schedule market. The study projected that such a reduction in generation offers would yield \$10 million per year in additional annual efficiency benefits.⁴² However, the limited change in bidding behavior assumed in this sensitivity analysis likely underestimates the behavioral change associated with market reforms. Furthermore, the study does not attempt to quantify the benefits created by improved intra-day commitment. Thus, the efficiency benefits estimated by this study understate the overall benefits that the contemplated energy market reforms would create.
- **Day-Ahead Market Evolution** (SE-21, IESO 2008): The IESO conducted this or study to estimate the potential benefits associated with implementing an improved Day-Ahead Commitment Process or alternatively a day-ahead market. This study estimated that

⁴⁰ For example, in the first year after implementing their day-ahead market CAISO observed that on average 98% of forecasted load was scheduled in the day-ahead market. See CAISO (2010), p 35.

⁴¹ Market Reform (2015). Study values annualized and converted to 2021 CAD.

⁴² Market Reform (2015). Study values annualized and converted to 2021 CAD.

implementing improvements to the then-existing Day-Ahead Commitment Process (including an Energy Forward Market for risk mitigation) would create annual efficiency savings of approximately \$24 million per year.⁴³ These benefits come from a reduction in over-commitment, improved demand response dispatch, and more efficient fuel procurement by the gas generators.⁴⁴ A portion of the benefits estimated in that 2008 study have since been achieved through the Enhanced Day-Ahead Commitment Process implemented in 2011.⁴⁵ The reforms proposed under Market Renewal, however, would create additional benefits that were not analyzed in the SE-21 study and have not yet been realized through improvements made to the Day-Ahead Commitment Process. For example, the Enhanced Day-Ahead Commitment Process does not include a financially-binding day-ahead market. While the SE-21 study did analyze a pseudo-financially-binding day-ahead market, it was conducted when intermittent generation comprised a significantly lower portion of Ontario's generation than the current levels of intermittent generation. As discussed below, intermittent resource penetration is a significant driver of Market Renewal benefits. In addition, the SE-21 study did not consider the impacts of improved intertie scheduling on energy market efficiency (and the associated improvement to in-province day-ahead dispatch) when calculating benefits. Thus, while providing an indication of the types of benefits that can be achieved through further day-ahead market enhancements, the quantitative benefits considered within the scope of the SE-21 study are limited compared to those expected to be realized under Market Renewal.

These previous studies conducted for Ontario provide an important starting point for estimating the type and level of benefits that the energy market enhancements considered in Market Renewal would provide. At the same time, the somewhat limited scope of these studies suggest the quantified benefits likely present only a low-end estimate of the energy market benefits Ontario would likely realize through Market Renewal.

C. EXPERIENCE FROM OTHER MARKETS

Even though Ontario's market is unique compared to other wholesale markets in North America, there are many lessons that can be drawn from the reforms that the other markets have implemented over the past decade. We thus examine and analyze the studies conducted on other wholesale markets' reforms and the benefits realized from those initiatives. The findings from

⁴³ IESO (2008). Study values converted to 2021 CAD.

⁴⁴ IESO (2008).

⁴⁵ The Enhanced Day-Ahead Commitment Process (EDACP) included the following improvements: optimization over 24 hours, three-part bids, day-ahead cost guarantees, and pseudo-units that allow for more effective scheduling of certain combined cycle natural gas facilities.

those studies provide information on the nature and scale of potential benefits from Market Renewal.

The Impact of Ontario's Unique Market

As we undertook our work we heard a lot about Ontario's unique electricity market structure and how it might be a barrier to realizing potential benefits we have identified. It is true that Ontario's electricity sector reflects a unique combination of policy objectives, fleet makeup, and market fundamentals that make it different from every other market. At the same time, there is no one aspect of Ontario's market that is unique by itself, and in many ways the similarities are greater than the differences. Ontario's electricity system operates the same types of resources and equipment and according to the same physical laws and economic principles as other electricity markets around the world. At their core, all electricity markets aim to incentivize the investment and operations of electricity resources in the most efficient way possible, subject to physical constraints. The same core set of market design principles and structures can be applied to many different types of electricity systems to produce the most economic outcomes. Thus, the need for market reforms does not stem from Ontario's uniqueness. Instead, it comes from the need to more efficiently incentivize investments and operational decisions governing those resources – which are broadly consistent across all electricity systems. We also find that the reforms implemented in other energy markets yielded similar levels of benefits (once adjusted for market size) despite the fact that these other markets also differ substantially from each other.

As we consider how the contemplated energy market enhancements affect the benefits of Market Renewal in Ontario, and how to translate the benefits observed in other regions to the Ontario context, we focus on the primary dimensions affecting benefits of market reform. First, benefits will depend crucially on the scope of design enhancement. Secondly, each jurisdiction's unique characteristics will interact with design changes to affect the scale of benefits. The exact same market reform could have different effects in different markets as a result of varying system fundamentals, such as the characteristics of the generation fleet and the transmission system.

To maximize the relevance of other market studies to the Ontario context, we focus on market reforms that, similar to the contemplated Ontario energy market improvements, included the introduction of nodal pricing and financially-binding day-ahead markets. To the extent possible, we gather insights from studies of other markets' reforms from a retrospective approach because these analyses more accurately estimate realized benefits than estimates conducted through prospective studies. Finally, in order to more accurately compare the experiences in other markets to Market Renewal, we consider the similarities and differences of market characteristics between Ontario and the relevant systems analyzed. Every market has its unique fleet mix, regulatory structure, market fundamentals, and policy drivers. Despite these differences, we see quite similar benefit levels across markets that have implemented the same design changes. Ultimately, we see this as confirmation that similarities across markets outweigh differences. Ontario is not a world apart from the other markets. For example, as will be shown below, California has more similarities to Ontario (such as fleet mix and policy context) than it does to the Midcontinent ISO (MISO), yet California and MISO still show similar benefit levels from similar design changes. At the same time, it is clear that important differences between the

markets will drive variations in realized benefits, which is why we attempt to consider these differences when evaluating how similar design changes translate into the Ontario context.

1. Scope of Design Enhancements in Other Markets

Several other energy markets have conducted reforms in the past decade that are similar to those being considered under Market Renewal. The exact scope of these reforms varies across different jurisdictions, with some markets implementing reforms in stages and others implementing them all at once. Table 2 summarizes the scope and the timing of market reform efforts implemented in MISO, California ISO (CAISO), Southwest Power Pool (SPP), and Electric Reliability Council of Texas (ERCOT), which are the regions with the greatest similarity of market reform to the energy workstream under Market Renewal:

- **MISO** has been improving its energy market design over the past 15 years, starting in 2002, with a move from a purely bilateral market design to a market with uniform (“depancaked”) transmission charges and a single transmission operator, but without centralized dispatch of generation resources. Subsequently, in 2005, MISO simultaneously implemented a centralized five-minute dispatch process, locational marginal pricing for generation, and a financially-binding day-ahead market. In 2009, MISO consolidated the multiple balancing authorities within its footprint and implemented co-optimized energy and ancillary services markets.
- **CAISO** initially reformed its energy market in the late 1990s by creating a zonal market with bilateral day-ahead scheduling, a real-time imbalance market, and an intrazonal congestion management system. In 2009, CAISO overhauled its market to implement locational marginal pricing, a financially-binding day-ahead market, and the co-optimization of energy and ancillary services markets.
- **ERCOT** implemented a market redesign in late 2010. The existing zonal market relied on bilateral day-ahead scheduling, a real-time imbalance market, and an intrazonal congestion management system. ERCOT’s 2010 reforms included implementing locational marginal pricing, a financially-binding day-ahead market, and the co-optimization of energy and ancillary services markets (in the day-ahead market only).
- **SPP** first implemented a real-time imbalance market with nodal pricing in 2007. In 2014, SPP updated its market design and, by consolidating its multiple balancing authorities, adding a financially-binding day-ahead market and co-optimized energy and ancillary services markets.

The left-most column of Table 2 describes the primary market reform elements considered in these markets and the darkest green boxes indicate the scope of design changes considered in the respective benefits study that we identified as most comparable to Market Renewal. There are two elements of Market Renewal that have been widely studied across several other markets: locational marginal pricing and a financially-binding day-ahead market. However, some of the studies we considered included other reforms that go beyond the scope of Market Renewal, such as MISO’s real-time market implementation, and SPP’s consolidation of balancing areas. Other

design enhancements have uncertain or only partial similarity with Market Renewal. For example the IESO at present procures and co-optimizes most ancillary services but does not do so for regulation nor does it have a financially-binding day ahead market. Similarly, the IESO also conducts centralized unit commitment, but the resulting day-ahead commitment schedules might not be any more efficient than the day-ahead commitments conducted by individual utilities in these other U.S. markets prior to their implementation of day-ahead markets.

Table 2
Components and Timing of Market Reforms in Other Markets

Design Element	MISO	CAISO	ERCOT	SPP
De-Pancaked Transmission	2002 (Bilateral)	Existing	Existing	2007
Real-Time Market	2005	Existing	Existing	2007
Centralized Unit Commitment	2005	2009	2010	2014
Locational Marginal Pricing	2005	2009	2010	2007
Binding Day-Ahead Market	2005	2009	2010	2014
Consolidated Balancing Authorities	2009	Existing	Existing	2014
Market-Based Ancillary Services	2009	Existing	Existing	2014
Co-Optimization of Ancillary Services	2009	2009	2010 (Day-Ahead Only)	2014

Notes:

-  In place prior to market redesign.
-  Element of other RTO redesign studied (initial stage of implementation)
-  Element of other RTO redesign studied (subsequent stage of implementation).
-  No ex-post study available.

Finally, there are some enhancements under Market Renewal that have not been specifically studied in these other markets, and so the associated benefits will not be accounted for when examining these other markets' reforms. For example, we expect the change from a two-schedule to a single-schedule market to achieve significant efficiency benefits beyond those realized in other markets. We also expect the enhanced intra-day unit commitment process to be an enhancement beyond those studied in other markets, particularly those implemented longer ago.⁴⁶ Overall, we find that the design changes implemented by MISO, CAISO, ERCOT,

⁴⁶ The exact reforms considered within the enhanced real-time unit commitments are not yet specified and we are not able to determine whether the design changes in other markets included the type of enhancements that will be implemented under Market Renewal. However, given that all of the major

Continued on next page

and SPP in 2005, 2009, 2010, and 2014 are the most comparable to the expected scope of Market Renewal in Ontario, but the differences in scope need to be accounted for when interpreting applicability.

2. Range of Marginal Costs in Other Markets

In addition to the scope of reforms, the supply resource mix and resulting marginal cost differences between the high-cost and low-cost units in each market are parameters that influence the magnitude of benefits as a market undergoes energy market reforms. For example, a market with a steeper supply curve can expect larger efficiency gains than a market with a flatter supply curve. A system with a relatively flat supply curve will have similar production costs regardless of which resources are dispatched, and so more efficient prices and dispatch will not achieve significant efficiency benefits. However, when the divergence between high-cost and low-cost resources is greater, the efficiency benefit of improved prices and associated shifts in dispatch from high- to low-cost resources increases. Thus, the range of marginal cost at least partially determines the extent to which energy market reforms can create system cost savings.

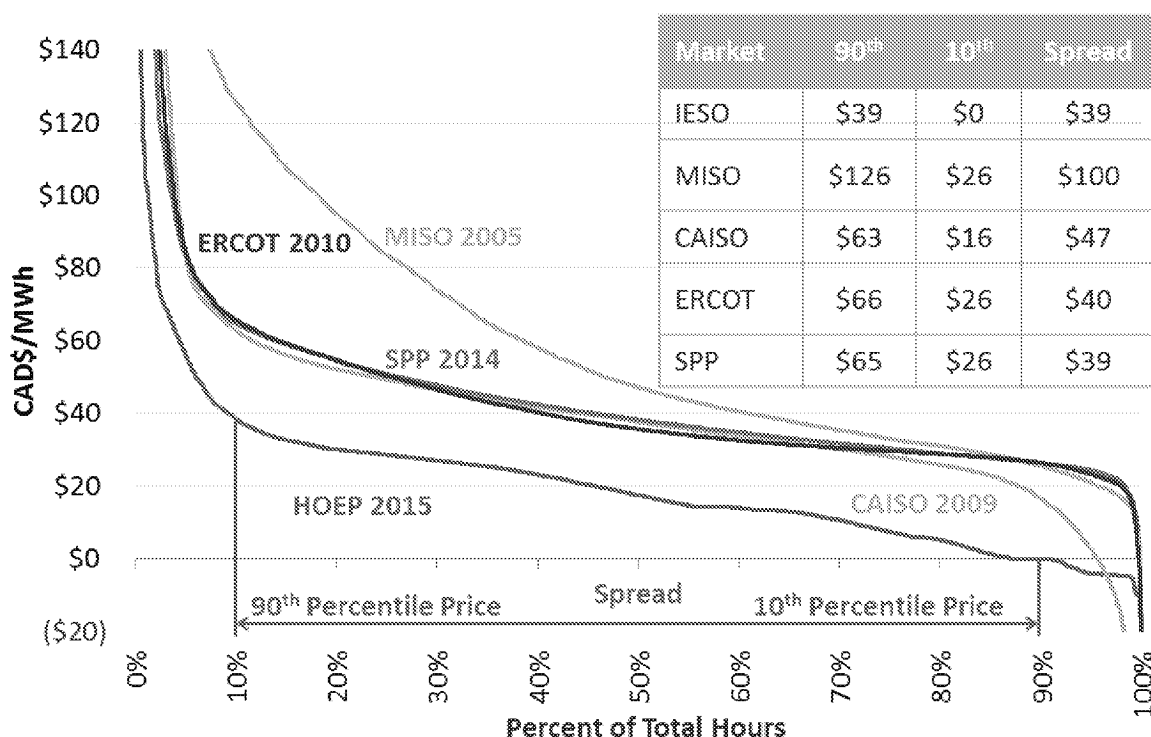
Figure 3 compares the historical price-duration curves of each market that we studied, as relevant at the time of the design change.⁴⁷ As the figure shows, while average prices in Ontario are lower than in the other markets examined, the spread and shape of the price duration curve is very similar to those of SPP in 2014 and ERCOT in 2010, whereas the spread in CAISO was somewhat greater and the spread in MISO was significantly greater. Based on this factor alone, the similarities and differences across these curves suggest Market Renewal would likely create Ontario efficiency gains similar to those observed in SPP and ERCOT, but lower than those observed in CAISO and MISO.

Continued from previous page

software vendors have made continuous and significant advancements in this area over time, we expect that the solutions available to IESO under Market Renewal will exceed those that were available to other RTOs at earlier dates.

⁴⁷ The 90th and 10th percentile prices were chosen as representative high and low prices respectively. The delta between these prices acts as a reasonable measure of the relative steepness of each markets supply curve. Thus a larger delta suggests larger potential for benefits from market reforms.

Figure 3
Historical Price Duration Curves and Price Spreads



Sources:
 ABB, Inc., (2016).

3. Magnitude of Intermittent Resource Deployment in Other Markets

The level of intermittent resources deployed on a system is another driver of benefits. As the level of intermittent resources increases, so do the complexity of system operations and the benefit of a more efficient market design. A market design that yields a more efficient commitment and dispatch of resources reduces the cost of integrating intermittent resources. It also limits periods of surplus generation and incentivizing market participants to compensate for greater system uncertainties. Thus, the benefits of efficient market design increase as the penetration of intermittent resources grows. This relationship has been studied empirically as we discuss later in Section IV.C.1.

Table 3 compares the level of intermittent renewable resources deployed in each market at the time of their respective enhancements. Based on this comparison, the intermittent resource deployment levels that existed during the ERCOT and SPP reforms seem most similar to what is expected in Ontario, while the deployment levels in MISO and in CAISO were much lower. Without considering other factors, this comparison suggests Market Renewal has the potential to create Ontario benefits most similar to those observed in ERCOT and SPP, and higher benefits than those observed in MISO and CAISO.

Table 3
The Degree of Intermittent Resource Deployment by Market

Market	Year	Intermittent Penetration
IESO	2015 (2020s)	8% in 2015 (~12% by early 2020s)
MISO	2005	<2%
CAISO	2009	2%
ERCOT	2010	8%
SPP	2014	12%

Sources and Notes:

"Intermittent penetration" refers to the percent of all energy produced.

Compiled from data provided by IESO staff and from Ontario Planning Outlook data from IESO (2016c).

ISO Annual Reports: SPP (2014), CAISO (2010), Potomac Economics Ltd (2013), Patton (2006).

4. Benefits Achieved by Other Markets

Each of the market reforms that we identified as comparable to Market Renewal created significant benefits in those regions as documented in the *ex post* studies summarized in Figure 4. To account for differences in market size, we normalize the magnitudes of the benefits estimated by the annual load (TWh of annual energy consumption) in each market and show the resulting estimated system-wide and customer savings from those studies on a \$/TWh basis, expressed in 2021 Canadian dollars.

The left-most stacked bar in Figure 4 shows the system-wide savings estimated in the prior analyses of Ontario's market. To the right of it, we show the estimated benefits associated with MISO's market reforms in 2005 in dark blue (with the estimated benefits associated with reforms conducted in 2002 in the lighter blue part of the stacked bar chart). As shown in the summary of reform scope in Table 2 above, the 2005 MISO energy market changes closely align with the expected changes under Ontario's Market Renewal and therefore provide a relatively comparable estimate of potential benefits for Ontario. The study of the MISO reforms, which included nodal real-time and financially-binding day-ahead markets, estimated annual benefits of a USD \$172 million reduction in production costs.⁴⁸ Beyond that, as reported in the 2005 MISO State of the Market Report, these reforms created additional benefits such as a reduced need to rely on transmission line loading relief (TLR) curtailments of wholesale transactions, which decreased by 75% from 2004 to 2005.⁴⁹

⁴⁸ Reitzes (2009), p. 2. Value taken directly from study without adjustment.

⁴⁹ Potomac Economics (2006), p vii.

Figure 4
Estimated Benefits in Ontario and Other Markets
 (Per TWh of Market-internal Annual Load)



Sources and Notes:

All benefits translated to 2021 CAD\$ assuming a 2% inflation rate and standardized by relative system load. The Global Adjustment is abbreviated as GA.

IESO: IESO (2008), Market Reform (2015); MISO: Reitzes (2009); CAISO: Wolak (2011); SPP: Rew (2015); ERCOT: Zarnikau (2014).

The third bar shows the benefits observed in California from its 2009 market reform. The CAISO study describes how the previous zonal market resulted in significant inefficiencies with intra-zonal congestion management. Specifically, prior to reform, generation resources in CAISO system were self-committed on a day-ahead basis, but often needed to be ramped down at high costs (with concerns about incentives for inefficient ramp down bids). Similarly, at times, other units needed to be ramped up at high costs due to inefficient commitment. Both of these concerns are similar to the types of inefficiencies that Ontario observes in the current system: that out-of-market payments and dispatch instructions are used to address internal transmission constraints that are not accounted for in market prices. The CAISO energy market enhancements in 2009 included implementing a nodal real-time and a financially-binding day-ahead market. Those enhancements helped manage intra-zonal congestion much more effectively than the prior system due to more efficient day-ahead unit commitment, dispatch, and settlement. The study of the 2009 CAISO enhancements identified a USD \$105 million annual reduction in production costs.⁵⁰ According to CAISO's 2009 Annual Report on Market

⁵⁰ Wolak (2011), p. 251. Value taken from study without adjustment.

Issues and Performance, other additional benefits included a decrease in customer costs from ancillary service procurement from 1.4% of wholesale energy costs (USD \$0.74/MWh) in 2008 (under the prior design) down to 1.0% (USD \$0.39/MWh) in 2009.⁵¹ Further, the CAISO report shows uplift payments decreasing by more than USD \$400 million per year in 2009.⁵² Part of the documented reduction in uplift costs was a result of the energy market reforms, while another portion of the savings arose from a change to CAISO's local capacity procurement process (which may be relevant to the IESO as it considers various approaches to procure capacity resources).

The fourth bar in Figure 4 summarizes the benefits realized from SPP's 2007 and 2014 market design changes. The most relevant changes, from the 2014 reforms (as reflected in Table 2 earlier), are depicted by the dark blue portion of the stacked bar. SPP's 2014 reforms included adding a financially-binding day-ahead market, co-optimized energy and ancillary services markets, and consolidated balancing areas. The enhancements to ancillary services are only partly similar to Market Reform enhancement, and the consolidation of balancing areas is not relevant for Ontario. Together, these 2014 reforms generated benefits of USD \$260 million per year.⁵³ SPP's 2014 State of the Market report notes that most of the benefits were associated with a 10% reduction in the over-commitment of generating capacity. This means that, prior to the reforms, approximately 5,000 MW of generation were being inefficiently committed prior to the introduction of a day-ahead market.⁵⁴

The bar on the very right summarizes the outcome of ERCOT's market reform. Much like in CAISO, ERCOT recognized the inefficiencies associated with its intra-zonal transmission congestion management under its zonal energy market prior to improving its market design in 2010. Before 2010, ERCOT managed intra-zonal congestion by instructing generating units to ramp up or down from their scheduled output levels in response to system needs. Units that followed these instructions were compensated with out-of-merit energy payments. This meant that generators in ERCOT had very little incentive to consider the state of the transmission congestion when self-scheduling because they were paid to decrease their generation output in real time. ERCOT's approach was similar to the IESO's current system relying on constrained-on and constrained-off CMSC payments. The market reforms implemented in 2010 (moving from zonal to LMP-based real-time and day-ahead markets) rectified these issues and created large savings for customers in Texas. An *ex post* study of market prices estimated approximately a 2% reduction in customer costs across the system after accounting for reductions in wholesale power prices, uplift costs, and congestion payments.⁵⁵ These savings at least partially reflect the customer savings associated with higher congestion rent being returned to customers under the nodal market compared to the prior zonal market. Similar customer cost savings could occur in

⁵¹ CAISO (2010), p 13.

⁵² CAISO (2010), p. A.10.

⁵³ Rew (2015), p. 15. Value taken directly from study without adjustment.

⁵⁴ See SPP (2015), p 47.

⁵⁵ See Zarnikau (2014), p. 207. Value taken from study without adjustment.

Ontario by shifting from the current congestion management approach under CMSC payments to a nodal market. Unlike the other studies, the analysis of ERCOT's reforms did not include an estimate of system-wide efficiency gains. Rather, it only estimated impact on ERCOT customer costs, which are shown by the right-most graph in Figure 4. These benefits translate to annual savings of \$1.2 million per TWh of Ontario load (in 2021 Canadian dollars).

As the first bar in Figure 4 shows, the load-normalized efficiency benefits estimated in prior studies of Ontario's market are relatively small compared to the benefits realized in other markets' comparable market reforms. This is primarily because the scope of these Ontario-specific analyses included only a portion of the design changes and associated benefits expected under Market Renewal, as discussed in Section III.B. For customer benefits, however, the Ontario customer bill impact estimated in the 2015 Market Reform study (before accounting for the Global Adjustment) is similar to the magnitude of customer benefits realized from ERCOT's reform.

D. ESTIMATING POTENTIAL BENEFITS TO ONTARIO

The Ontario market has several unique features that distinguish it from other North American wholesale electricity markets. As a result, we consider the impacts from other markets' reforms only after comparing the similarities and differences with Ontario. We describe here how we account for these similarities and differences and making necessary adjustments in order to estimate the likely benefits that could be achieved in Ontario.

1. Estimates of Potential Benefits to Ontario

Table 4 below summarizes the analysis in Section III.C on comparability of other market structures and conditions relative to the IESO market, in terms of: (1) scope of design changes; (2) range of marginal costs; and (3) level of intermittent resources. Using these comparisons in the first three rows of the table, we summarize in row 4 whether we expect the estimated benefits from those other market reforms to be greater, similar, or lower than the benefits of Market Renewal. Finally, in row 5, we summarize the adjustments that are necessary to make the findings in the analyses of other market reforms applicable to Ontario.

For example, we find that the potential enhancements envisioned for Market Renewal are largely similar in scope to the changes made in MISO (2005), CAISO (2009), and ERCOT (2010), although there are some differences as discussed above. However, SPP's reforms were more extensive than those contemplated in Market Renewal, including the consolidation of balancing authority areas. As a result, the estimated benefits from SPP's 2014 market changes are likely greater than those that would materialize through Market Renewal. These benefits in SPP are not offset by a lower marginal cost spread or a higher intermittent deployment. Thus, SPP's observed benefits must be adjusted downward in order to be accurately applied to Ontario.

Table 4
Comparison of Factors Driving Energy Market Enhancement Benefits

Comparison Factor	Market Renewal	MISO 2005	CAISO 2009	ERCOT 2010	SPP 2014
1. Scope of Enhancements Studied	Nodal Pricing, Day-Ahead, Intra-Day Unit Commitment	Nodal Pricing, Day-Ahead, Real-Time	Nodal Pricing, Day-Ahead, Co-Optimization	Nodal Pricing, Day-Ahead, Co-Optimization	Nodal Pricing, Consolidated Balancing Areas, Day-Ahead, Ancillary Services, Co-Optimization
2. Range of Marginal Costs	\$39/MWh	\$100/MWh	\$47/MWh	\$40/MWh	\$39/MWh
3. Intermittent Resource Deployment	8% 12% by 2020s	<2%	2%	8%	12%
4. Relation to Market Renewal	n/a	Similar	Similar	Similar	Higher
5. Adjustments Needed to Apply Benefits to Ontario	n/a	Slight Upward Adjustment Needed	Slight Upward Adjustment Needed	None Needed	Downward Adjustment Needed

Notes:

-  Lower than Market Renewal
-  Similar to Market Renewal
-  Higher than Market Renewal

Based on the same considerations, we expect that the benefits found in MISO and CAISO are lower than those that can be expected from Market Renewal, primarily due to Ontario having a greater share of intermittent resources at the time of reform. ERCOT provides a good comparison for Ontario without adjustment. Thus, to derive a baseline estimate of potential efficiency benefits in Ontario, we take the average of efficiency benefits (in CAD\$/TWh) from the MISO and CAISO studies and 50% of the production cost savings from the SPP analysis, resulting in approximately \$0.59 million/TWh consumed, as summarized in the center column of Figure 5 below.⁵⁶ Multiplying these savings by the projected annual consumption in Ontario in 2021, we estimate that the overall efficiency benefits would be approximately \$84 million per year before considering the effects of contracts (and growing with inflation and load growth over time). This approach assumes that annual benefits will increase with energy consumption, which is what we expect given that the benefits are associated with the fuel, variable cost, and net import costs that will grow with consumption.⁵⁷ We find this approach to be reasonable

⁵⁶ This estimate does not reflect adjustments to account for existing contracts, which we discuss further in Section VI below.

⁵⁷ We considered other potential scaling and translation approaches as well, but ultimately selected consumption-based scaling as likely to be the most accurate compared to others that we considered. For example, we considered standardizing and scaling benefits based on \$/TWh of generation but

Continued on next page

given the similarity of observed benefits on a \$/TWh basis shown in Figure 4, despite large differences in market size and significant variations in other characteristics.

We also recognize that there is an uncertainty range around the estimated efficiency benefits that should be considered in the Benefits Case. This range is driven by uncertainties in the scope of Market Renewal and uncertainties in translating benefits into the Ontario context. As a low-end estimate of benefits (shown in the left column of Figure 5 below), we use the sum of benefits estimated in prior Ontario analyses to arrive at approximately \$33 million of overall efficiency savings per year. On the higher end of the range (summarized in the right column of Figure 5 below), we believe that the benefits of Market Renewal could reach approximately 75% of the benefits realized from SPP's 2015 market reforms. These benefit estimates are not yet adjusted to account for the implications of existing contracts, which we discuss further in Section VI below.

Market Renewal also has the potential to create significant benefits that accrue only to customers. As shown in Figure 4 above, estimates of customer savings from energy market reforms have been conducted for both Ontario and ERCOT. While providing useful data points for comparison and informational purposes, we note that these customer benefits are not the same as the overall province-wide efficiency benefits that are the focus of our study. Customer benefits at least partly reflect transfer payments from other market participants.

Continued from previous page

determined this approach was less desirable because it could be heavily distorted by the level of imports and exports (*i.e.*, an import-dependent region like California would show an unrealistically high level of benefits per unit of TWh internal generation). Similarly, we considered standardizing and scaling benefits as a fraction of production costs. We would expect this approach to be less accurate because it fails to capture the role that the slope of the supply curve plays determining benefits (*i.e.*, a system with high production costs), but all costs across a similar fleet will not achieve more benefits than a system with low production cost, but more diversity in marginal costs; the second system will achieve greater benefits because small displacements to improve operational efficiency have a greater dollar value.

Figure 5
Range of Potential Efficiency Benefits from Energy Markets to Ontario
(Prior to Downward Adjustments Accounting for the Implications of Existing Contracts)

Low	Base	High
\$33 million / year - Sum of benefits estimated in previous Ontario studies - Scaled to 2021 demand from Outlook A of the Ontario Planning Outlook	\$0.59 million / TWh - Average of total production cost benefits realized in MISO, CAISO, and half of production cost benefits realized in SPP - Benefits normalized per unit of delivered energy and translated to 2021 CAD\$ 143 TWh - Average of projected total energy demand in Ontario by 2021 across Outlooks A, B, C, & D included in the Ontario Planning Outlook \$84 million / year - Projected efficiency benefits in a system of Ontario's size by 2021, if the scope and scale are assumed to be similar to those achieved in other markets	\$174 million / year 75% of production cost benefits realized in SPP - Scaled to 2021 demand from Outlook D of the Ontario Planning Outlook

2. Non-Quantified Benefits

Almost all of the benefits estimated in other studies are related to savings from lower production costs associated with more efficient energy market dispatch. Those estimated efficiency gains are useful in understanding how the cost of power can be reduced by reductions in fuel consumption, variable operations and maintenance (O&M) costs, and improved intertie scheduling. However, several other benefits associated with operating a more efficient market are likely to materialize as well, providing significant benefits to market participants and, ultimately, electricity end users. Thus, focusing only on these quantified benefits would yield an incomplete representation of Market Renewal benefits.

For example, energy market prices that more accurately and transparently reflect marginal production costs (including all costs associated with system constraints) will reduce the need for uplift payments, the potential for inefficient bidding, and opportunities for gaming. While some studies have tried to estimate the potential savings associated with more efficient bidding (such as the Market Reform study), most of the impact associated with changes in suppliers' bidding behavior has not been considered in these studies. As referenced in the analysis of the CAISO market reforms, CAISO was able to avoid uplift and out-of-market payments of more than

\$400 million per year associated with better management of transmission congestion after implementing nodal pricing and locational capacity requirements.⁵⁸

Implementing locational and more efficient market prices will improve investment signals for traditional supply resources and transmission. Recent experience in PJM provides an example of this process, where higher energy and capacity prices combined to bring forth investment in natural gas fired generators in the locations where the added supply was most needed.⁵⁹ In many regions where incremental transmission investments are determined based on the benefits associated with reducing system congestion costs, having locational energy pricing can also help provide the economic rationale for cost-effective future transmission investments.

More efficient, locational energy pricing will also increase the efficiency of investment and dispatch signals for non-traditional resource types such as storage and demand response. Many Working Group members and other stakeholders have indicated that it is important to the future of Ontario to ensure that the market can support and encourage the efficient deployment and use of new technology, storage, and demand response. Having prices that more accurately reflect marginal costs on the system, including location-specific costs, can support stakeholders' desire to use market signals to inform future investment and usage decisions for innovative new technologies and business models.

Many stakeholders have indicated the importance of ensuring that any market design changes consider the uncertainty in future market fundamentals and policy environment. Market Renewal's significant overhaul of the energy market will better prepare Ontario for these uncertainties and enable the sector to more effectively adapt to change. For example, a renewed and efficient wholesale market will enable Ontario to more cost-effectively integrate increasing amounts of demand response and other types of distributed energy resources. A more efficient energy market will also be better able to cost-effectively adapt to climate policies by minimizing costs under the cap-and-trade mechanism and better integrating increasing quantities of intermittent resources.

In addition, some markets have implemented advanced scarcity pricing and/or surplus baseload generation (SBG) pricing. Some of those features would yield further efficiencies that are not yet captured in the analyses we relied upon. Enhancing the scarcity pricing in the energy market can help efficiently and effectively signal shortages in the market, which in turn creates incentives for low-cost solutions, such as demand response, to participate more fully in the market. The co-optimization of regulation service offers another potential reform that could further lower the cost of procuring ancillary services beyond the current co-optimization of other operating reserves. As the levels of intermittent resources on the system continue to grow, these cost savings would increase in magnitude.

⁵⁸ CAISO (2010), p. A. 10.

⁵⁹ Gelbaugh and Gilbert (2015).

There are other benefits that may not be fully captured in our estimate because the associated design enhancements were either only partially included or not included within the scope of the studies we examined. For example, two Market Renewal initiatives, the change from a two-schedule to single-schedule market and implementing advanced intra-day unit commitments, were not part of the design enhancements in any other markets. It is possible that Market Renewal could incorporate modern software enhancements that are uniquely valuable in Ontario's context or that were not yet available to other market operators at the time of their reforms, such as advanced modeling of cascading hydro systems, pumped storage, or optimized gas combined cycle modeling. Finally, the proposed Market Renewal effort would align the design of the Ontario wholesale power markets more closely with that of market-based neighboring regions, which could increase the number of market participants in Ontario, the efficiency and competitiveness of trading across interties with these markets, and the overall liquidity and transparency of the Ontario market.

Experience from other jurisdictions consistently shows that the energy market reforms that the IESO is proposing with Market Renewal can significantly improve the efficiency of resource use. Those analyses show that some benefits are not easily quantified, even though they will positively affect customers and other stakeholders, and contribute to a more dynamic, flexible, and competitive marketplace.

IV. Operability Reforms

Relative to 2002 when the current electricity market began, Ontario's electricity sector faces a growing need for flexibility due to increases in intermittent generation, growing reliance on relatively inflexible nuclear generation, and policy-driven decommissioning of coal resources. Design restrictions in the current market limit the degree to which Ontario can rely on existing internal resources and interties to meet growing flexibility needs. Through the operability workstream of Market Renewal, the IESO and stakeholders are considering a number of improvements that would better align incentives to provide flexibility with system needs and improve other market features to make it easier for participants to do so. Specific design changes under this workstream are not yet fully defined. In this section, we give an overview of the issues, summarize prior analyses of operability in Ontario's market, and provide a survey of how other markets are approaching these challenges. Based on studies of intertie and other flexibility enhancements in Ontario's market and studies of other markets, we estimate the potential benefits of operability enhancements after translating estimates into Ontario's unique context.

A. DESCRIPTION OF CURRENT MARKET DESIGN AND PROPOSED ENHANCEMENTS

Since 2005, Ontario's electricity sector has reduced its greenhouse gas emissions by 80%.⁶⁰ This significant decarbonization has been driven by conservation efforts and by substantial increases in generation from non-emitting resources, including baseload nuclear and intermittent resources such as wind and solar generation. The uncertainty and variability of this intermittent generation in combination with low loads during off peak periods and relatively inflexible nuclear resources have adverse effects on the operation of Ontario's power system.

The short-term uncertainty of intermittent resources by itself is challenging to manage. When variable generation is over-forecasted, the system operator may not commit sufficient resources ahead of time, resulting in a potential generation shortage. Conversely, when output from intermittent resources is under-forecasted, conventional resources are overcommitted. If these conventional resources cannot be quickly and efficiently ramped down, the system operator must curtail the near-zero-marginal-cost output from hydro, wind, or solar resources. In Ontario, heavy reliance on nuclear resources, which are relatively inflexible, make operability more challenging than in other jurisdictions with similar levels of intermittent resource penetration.

As more variable generation resources come online, forecast errors will become larger in relation to system size. They will become increasingly detrimental to the efficient operation of Ontario's power system if the fleet as a whole is not sufficiently flexible. Figure 6 shows the distribution of uncertainty of variable generation from several forecast periods, as evaluated in a recent IESO study. The forecasts do not significantly improve between day-ahead, five-hour-ahead, and one-hour-ahead pre-dispatch intervals. There remains significant uncertainty in generation when spare generation on-line commitments are made (in five-hour-ahead pre-dispatch) and when intertie transactions are scheduled (in one-hour-ahead pre-dispatch). In addition to the uncertainty in forecasting renewable generation output, the variability of intermittent generation can create further challenges (such as frequency regulation and grid voltage control problems), requiring additional system flexibility on an even shorter time scale.

Ontario's current approach to managing operability needs can at times rely on manual interventions, which may produce sub-optimal outcomes and inefficient use of the province's resources. To balance supply and demand, operators sometimes need to manually curtail (or the market uses zero or negative pricing to curtail) wind, solar, and hydro at times of unanticipated generation surplus. In the opposite case of unanticipated shortfall, the IESO relies on real-time commitment and dispatch through an inefficient real-time unit commitment process as discussed in the prior section. If these actions occur outside the wholesale market, they are not transparent and do not provide incentives to market participants who could meet the system needs at lower cost.

⁶⁰ See IESO (2016a).

Figure 6
Uncertainty of Variable Generation in Ontario across Various Forecast Intervals



Source and Notes:
 IESO) (2016a), p. 2.

Due to design limitations, Ontario's current market does not effectively utilize existing resources to address these flexibility needs. Existing hydro resources have the capability to provide additional flexibility to the system, but are not incentivized or dispatched in such a manner to maximize these benefits. Pumped storage resources are likewise underutilized due to incomplete optimization. Ontario also has the opportunity to use more demand response resources and provide better incentives for investment in flexible resources of the future including distributed energy resources and storage. Finally, a lack of accurate day-ahead export schedules, due to insufficient incentives to participate in the Day Ahead Commitment Process, unnecessarily increases the market's real-time need for flexibility and intra-day commitments.

Ontario's existing interties with neighboring power markets, with the New York ISO (NYISO), the MidContinent ISO (MISO) and Québec, offer valuable opportunities to increase system flexibility and reduce balancing requirements by diversifying variable generation uncertainties across a larger geographic area. However, in Ontario's current market design, intertie flows are scheduled in hour-long blocks one hour before the start of the dispatch hour.⁶¹ Because forecast uncertainty in Ontario does not significantly decrease until within the hour the current market design prevents meeting flexibility needs through interties with neighboring regions.

Through the operability workstream of the Market Renewal effort, the IESO seeks to address these flexibility limitations of Ontario's power system. Similar to other jurisdictions, Ontario is

⁶¹ See IESO (2013), pp 9–10.

considering a number of potential design improvements, and various options are still under development. The only design element specified at this point is increasing the frequency of intertie scheduling. Additionally, the 2016 IESO Operability Assessment Summary suggests that “methods to increase the flexibility of Ontario resources could include: increased utilization of existing resources, enabling simple cycle operation at combined cycle plants, or adding new peaking generation, grid energy storage, or demand response resources.”⁶² Market Renewal would include changes to market rules designed to incentivize the aforementioned flexibility resource options. The IESO’s Enabling System Flexibility Stakeholder Engagement seeks to identify and discuss potential solutions that are cost-effective, transparent, scalable, technology neutral, and send efficient price signals.⁶³ Stakeholders are discussing solutions including improving existing market mechanisms, introducing new market products, and developing or improving other incentives to increase system flexibility.⁶⁴

We anticipate that future design elements would likely include changes seen in other North American markets, including reformed ancillary service products, increased quantity requirements for particular ancillary services, changes to increase resource-specific flexibility, enabling new resource types to provide flexibility services, and harnessing the flexibility value of the interties. We have analyzed the potential benefits to Ontario in light of these options.

B. PRIOR ANALYSIS OF ONTARIO’S MARKET

Preexisting analyses for specific operability improvements in Ontario are still limited. Several types of operability enhancements have not yet been studied for the IESO system, as the focus on operability has been driven by reliability needs. However, two studies are available which quantify the benefits of enhanced intertie scheduling in Ontario:

- **An Examination of More Frequent Intertie Scheduling** (SE-115, IESO 2013): This IESO study quantified the benefits of reducing uneconomic intertie transactions by allowing intertie schedules to change every 15 minutes instead of hourly. The study estimates efficiency benefits to Ontario of \$1.5–\$3.2 million per year (2013 CAD) by reducing inefficient transactions, by terminating uneconomic transactions before the end of the scheduling hour or introducing additional transactions that become economic within the scheduling hour.⁶⁵ Furthermore, the study estimated \$3.3–\$6.0 million per year in

⁶² See IESO (2016d), p 4.

⁶³ See Matsugu (2016), p 50.

⁶⁴ See Matsugu (2016), pp 52–55.

⁶⁵ The study presents results for 2012 and the first six months of 2013. The low end of the range represents estimated benefits in 2012. The high end is calculated by assuming benefits in the latter half of 2013 would have continued accruing at the same rate as in the first half, so first-half benefits are multiplied by two. See IESO (2013).

additional potential benefits to Ontario from being able to schedule interties at or closer to real time, reducing inefficiencies related to forecast error.

The study, performed for 2012 and 2013 historical intertie schedules, understates benefits due to its scope. The study was conducted during a time when flexibility needs were expected to be lower, based on then-current understandings of the electricity system. It does not quantify the benefits of updating scheduling-algorithm data inputs more frequently or of increasing flows of economic intertie transactions over the historically-observed levels. The study uses the reference bus price to estimate benefits instead of the nodal price that will apply under Market Renewal, which may understate the realized benefits of the two enhancements in combination. In addition, it does not quantify avoided gaming and efficiency effects from uplifts (including CMSC and the Intertie Offer Guarantee (IOG)), and does not consider other types of scheduling enhancements such as coordinated transaction scheduling or tie optimization. Furthermore, it does not consider the benefits of reducing transmission charges and other fees (depancaking), or the benefits of enhanced scheduling with Québec or Manitoba. The study accurately captures part of the benefit of more frequent intertie scheduling, but tells only one part of the story and was not designed to fully assess today's issues. Due to the study's scope, we believe that it captures a single portion of the potential benefits that improving intertie scheduling can offer in Ontario, and that significant further benefits could be realized under Market Renewal.

- **Analysis of the Broader Regional Markets Initiatives** (Patton, 2010): This study undertaken by the market monitor for ISO New England (ISO-NE), MISO, and NYISO examines the potential efficiency benefits of fully optimizing the interties between PJM, ISO-NE, MISO, NYISO, and IESO.⁶⁶ The study assumes “ideal” operation of interties between these markets and estimates the production cost savings from the ability to use lower-cost resources in one market to displace higher-cost resources in an adjacent market. The study estimates total efficiency benefits of USD \$66 million per year optimizing the interface between Ontario and New York, and additional benefits of USD \$61 million per year from optimizing the interface between Ontario and MISO.⁶⁷ These benefits to Ontario and its neighboring markets represent an upper limit that would be achievable only with perfectly-optimized interties.⁶⁸ The author states that “real-time coordination of net scheduled interchange (or intra-hour scheduling) would likely capture most of the savings” but that “simply shortening the scheduling timeframes for participants would capture a much smaller share of the potential benefits.” The scope of

⁶⁶ The purpose of this study was to quantify total potential efficiency gains. As a result, it does not quantify the share of efficiency gains accruing to each individual market. Furthermore, specific analysis of which market participants would benefit, and to what extent, was outside the study scope.

⁶⁷ Patton (2010). Values in 2010 USD\$ taken directly from study without adjustment.

⁶⁸ The reported efficiency benefits are not

this study did not include Ontario's interties with Québec and Manitoba, two neighboring regions without an organized wholesale power market.

C. OPERABILITY AND INTERTIE REFORMS IN OTHER MARKETS

Ontario is not the only market currently facing operability and system flexibility challenges. Markets across the U.S. have been considering and implementing reforms intended to improve system performance under increasingly challenging operational conditions. These enhancements include a wide range of market-design enhancements including:

- **Ancillary services reforms:** different products, different quantities, enabling more resource types, and co-optimization;
- **Energy market enhancements:** improved scarcity pricing, improved surplus-generation event management and pricing, improved hydro scheduling, improved real-time commitment and dispatch (including look ahead), enabling new resource types;
- **Flexible resource requirements:** flexible resource capability requirements and incentivized operational enhancements to existing resources; and
- **Intertie enhancements:** more frequent intertie scheduling, shorter forward periods between scheduling and delivery periods, and cross-border coordinated transaction scheduling.

Studies conducted on some of these reforms (discussed below) suggest the potential benefits of these enhancements will be considerable and grow as challenges related to surplus generation and intermittent resources increase over time. The operability reforms previously implemented or considered by U.S. markets provide potentially highly-beneficial options for Ontario to pursue under Market Renewal.

1. Intermittent Resource Integration Studies

Intermittent resource integration studies provide a useful starting point for understanding the effects of high intermittent penetration and potential solutions. Typically these studies attempt to simulate the specific impacts, both positive and negative, that different levels of intermittent penetration would cause for a given market design. After identifying the challenges associated with high levels of intermittent resources, these studies often test different market enhancements that could be used to address these challenges. We have identified two such studies that help to illustrate how higher levels of intermittent resources magnify the potential benefits of operability enhancements. These studies can only provide indicative information for Market Renewal however, given that the specific design enhancements have not yet been determined.

Published in the summer of 2016, the *Pan-Canadian Wind Study* looked into how varying wind penetration levels will impact Canada's power system in the future. The study modeled the Canadian electricity system in 2025 under wind generation levels varying from a business-as-usual case of 5% to a high-integration-case of 35%. As a sensitivity to their main cases, the study

authors developed a case examining the impacts of allowing hydro resources to be scheduled more efficiently against real-time net load rather than forecast day-ahead net-load. This increase in hydro flexibility created \$16 million in annual efficiency benefits per year for Canada in the 5% wind penetration case.⁶⁹ In the 20% wind penetration case, the increase in hydro flexibility created \$144 million in annual efficiency benefits, primarily due to a reduction in wind curtailments. In addition to providing an indicative estimate of value from one type of operability enhancements, this study sheds light on the relationship between the benefits of greater flexibility and levels of intermittent resource penetration. Flexibility improvements offer exponentially higher benefits with greater levels of renewable penetration because they can more often avoid curtailments and inefficient dispatch based on those curtailments. This study supports this conceptual reasoning with empirical evidence.

Another study, the US Department of Energy National Renewable Energy Laboratory (NREL) *Low Carbon Grid Study*, examined the impacts of California’s continued pursuit of electric sector decarbonization. The study examined the impacts of operating California’s system at two intermittent resource levels in 2030: 36% and 56%.⁷⁰ For each level, the study simulated system conditions under “conventional” and “enhanced flexibility” conditions. The “enhanced flexibility” case allowed for greater regional exchange of power, removed local minimum generation requirements, added additional flexible resources, and enabled hydro and pumped storage to provide higher levels of ancillary services. The study estimated that these improvements could create USD \$65 million in annual efficiency benefits in the 36% renewable generation case and USD \$544 million in annual efficiency benefits in the 56% renewable generation case.⁷¹ It is important to note that the benefits projected by this study rely on the concurrent implementation of several flexibility improvements. Not all of these flexibility options are relevant to Ontario and others would not necessarily be implemented in the same way through Market Renewal. While the specific reforms and subsequent benefits may not be directly applicable to Ontario, the exponential relationship between renewable generation levels and efficiency benefits of increased flexibility is consistent with the findings of the Pan-Canadian Wind Integration Study. Figure 7 illustrates this exponential relationship for both studies.

⁶⁹ General Electric Energy Consulting (2016c), p 39. Value taken directly from study without adjustment.

⁷⁰ Brinkman, *et al.* (2016), p v.

⁷¹ Brinkman, *et al.* (2016), p v. Value taken directly from study without adjustment.



Sources and Notes:

All benefits translated to 2021 CAD\$ assuming a 2% inflation rate and standardized by relative system load.

Data from General Electric Energy Consulting (2016c) and Brinkman, *et al.* (2016).

2. Ancillary Service Market Reforms

Improved ancillary service markets offer system operators another opportunity to deal with operational challenges. Several other markets have started to consider or implement initiatives that attempt to better meet increased flexibility needs using existing resources and enable new resource types to do the same. These ancillary services market enhancements include innovations in products, pricing, and resource qualification:

- Product Innovations:** Enhancements aimed at modifying existing ancillary services products or adding new products to more efficiently procure the resource flexibility needed to operate the system reliably. For example, ERCOT's Future of Ancillary Service (FAS) proposal attempted to redefine ancillary service products to facilitate more efficient procurement based on resource capabilities. In terms of new products, both MISO and CAISO have added a dedicated ramping product that incentivizes some resources to hold back output based on the forecast ramping needs for future dispatch intervals.
- Pricing Innovations:** Market changes that attempt to reduce procurement costs by sending more accurate energy and ancillary price signals to resources providing flexibility services. For example, most U.S. power markets have implemented co-optimized energy and ancillary services with administrative "penalty factors" that incentivize stronger and faster market responses in five-minute dispatch intervals when the system is running

short of operating reserves. These mechanisms produce energy and ancillary service market dispatch instructions that minimize the system-wide costs of procuring both. ERCOT's Operating Reserve Demand Curve offers another pricing innovation example. This pricing mechanism increases the price of energy and ancillary services as the system approaches shortage conditions and must operate with lower reserve quantities. Doing so more strongly incentivizes resources to provide reserves when they are needed most and reduces the likelihood of an outage due to lack of supply.

- **Resource Qualification:** Efforts allow new technologies with different characteristics to participate in ancillary services markets by removing resource qualification barriers. For example, one driver of the ERCOT FAS program was to reduce barriers for storage to participate in ancillary services markets. Other markets, such as MISO, have facilitated the participation of demand response resources in ancillary services markets, including regulation.

Despite the fact that significant enhancements in ancillary service markets are taking place across many markets, few benefit studies exist in support of these changes. The generally modest costs associated with implementing individual improvements often have not warranted full benefit-cost analyses. We have reviewed two benefit-cost studies that do attempt to quantify the benefits associated with two ancillary market enhancement efforts: the ERCOT Future of Ancillary Service proposal and the MISO ramp product. These studies offer insights into what Ontario could expect from improving its ancillary service markets under Market Renewal.

The study conducted on ERCOT's Future of Ancillary Service proposal projected the efficiency benefits created by redesigning ancillary services to better match fast-ramping needs and enabling new technology types. The study projected annual benefits of USD \$19.4 million in the form of lower start-up costs, lower-cost procurement in the energy market, and opportunity cost savings in the real-time market.⁷²

The MISO ramp product study analyzed the benefits of creating a dedicated ramp product within the MISO ancillary service market. This ramp product provides enhanced operational flexibility during times of high volatility in net load due to intermittent resources. The study estimated the annual efficiency benefits of such a product to be USD \$5.4 million per year.⁷³ The study noted that these benefits would be created by an improved real-time dispatch, avoided commitments of combustion turbines, and avoided scarcity events.⁷⁴

Even though Market Renewal has not yet outlined specific ancillary market reforms, the benefits quantified for ERCOT and MISO provide an illustration of the potential benefits Ontario could achieve with similar enhancements. In addition, Ontario would likely experience benefits not

⁷² Newell, *et al.* (2015). Values taken directly from study without adjustment.

⁷³ Navid, *et al.* (2013). Values taken directly from study without adjustment.

⁷⁴ Navid, *et al.* (2013). Values taken directly from study without adjustment.

quantified in these studies, including better management of surplus generation conditions and avoided investment costs due to a reduction in resources needed to provide reserves and the integration of non-traditional resources.

3. Intertie Enhancement in Other Regions

Interties between markets provide a significant opportunity to effectively extend the geographic scope for the procurement of lower-cost resources, thereby diversifying uncertainty and increasing competition. For example, because the output of renewable resources is less correlated at greater distances, the use of interties across wider geographic areas helps diversify the uncertainty and variability of renewable resources. Additionally, interties can increase effective system flexibility by allowing variable generation to be balanced by the most efficient, most competitive resources available for that purpose in the larger geographic footprint.

Current methods for scheduling intertie flows between market regions often limit the extent to which these advantages can be realized. There are several root causes of economic inefficiencies in how interties are used today:

- **Transaction Costs:** Fixed transmission charges and other fees that do not reflect true incremental costs reduce or eliminate market participants' incentives to flow power when it would be optimal from a system-wide perspective. Where these transaction costs exist, interties can be systematically underutilized, especially when price spreads between markets are relatively small.
- **Latency Delay:** In most markets, there is a delay between when intertie transactions are scheduled and when the power is delivered. During the intervening time, system conditions may change significantly. For example, the actual load or actual output of generation resources may be higher or lower than forecasted. This can change prices in the neighboring markets relative to the anticipated levels and result in transactions that, anticipated to be economic when scheduled, turn out to be uneconomic by the time power flow actually occurs. However, due to bidding or scheduling deadlines, it is too late to change the now-locked-in intertie schedules.
- **Scheduling Frequency:** Relative prices and other market conditions may vary within the minimum intertie delivery period, which currently is one hour in Ontario but has been reduced to 15 minutes in U.S. markets. Further, in Ontario, like most other markets, real-time market prices are adjusted every 5 minutes. However, intertie schedules are determined based on the average of system conditions over the entire delivery hour, even though greater or lesser intertie flow would be more optimal at certain points within that hour.
- **Non-Economic Schedules Caused by Lack of Coordination:** Clearing intertie flows requires coordination between markets. Limited coordination between markets can cause uneconomic schedules to proceed (or prevent economic schedules from proceeding), because of sometimes complex logistics, different mechanisms, and different timeframes for separately approving or rejecting schedules on either side of the market

seam. Whereas latency delay causes intertie schedules that are optimal at scheduling time to become sub-optimal by the time dispatch occurs, non-economic clearing refers to schedules that are sub-optimal even at scheduling time.

Depending on the specific market design on either side of the intertie, the magnitude of these inefficiencies can vary significantly. Figure 8 shows the potential benefits from full intertie optimization across several markets, normalized by the intertie capacity between each pair of markets. As shown, there is significant variation in the current level of inefficiency of intertie scheduling between these markets.



Sources and Notes:

Chart shows combined efficiency benefits in markets on both sides of an intertie, normalized by the intertie capacity between the markets. Benefits from Patton (2010) and translated to 2021 CAD\$ assuming a 2% inflation rate. Patton (2010).

To capture the potential efficiency benefits identified above, several markets have taken steps to improve intertie scheduling. We summarize the spectrum of different intertie enhancement in Figure 9. These range from relatively small changes such as shortening the length of intertie scheduling blocks and finalizing schedules closer to dispatch time, to better coordination of intertie schedules between markets through coordinated transaction scheduling (CTS), to more complete optimization of intertie schedules across markets, including tie optimization (TO) and the 5-minute intertie scheduling associated with the energy imbalance market (EIM) between CAISO and other areas in the Western Electricity Coordinating Council (WECC).

Figure 9
Spectrum of Intertie Scheduling Design Enhancements



CTS improves scheduling of interties by allowing system operators to incorporate forecasted prices from neighboring system operators into their dispatch, enabling intertie transactions to be scheduled based on the forecast price differences between the regions. Prior to CTS, market participants needed to separately bid for imports and exports in both markets using their own projection of each markets' real-time price. This type of transaction requires that the imports and exports be cleared independently in both of the neighboring areas.⁷⁵ CTS was activated between NYISO and PJM in November 2014 and between NYISO and ISO-NE in December 2015. The latest estimates indicate annualized benefits of CTS of USD \$1.5 million per year for the NYISO/PJM interties and USD \$2.0 million per year for the NYISO/ISO-NE interties.⁷⁶ These realized benefits of CTS have been quite modest due to price forecast errors by the system operators on either side of the intertie, the occasional curtailment of scheduled transactions, and

⁷⁵ The NYISO 2014 State of the Market Report identifies at least three advantages CTS has over the previous intertie scheduling system. First, because CTS bids are evaluated relative to the forecasted spread in prices between two markets, market participants do not need to accurately forecast market prices in order to place efficient import and export bids, reducing the risk of non-economic clearing or not clearing both legs of the transaction. Second, CTS reduces technical frictions and allows market operators to schedule intertie transactions much closer to operating time, reducing latency delay. Finally, CTS is built on intertie flows and can be adjusted every 15 minutes instead of only every 60 minutes, reducing frequency-related inefficiencies discussed previously. See Patton, LeeVanSchaick, and Chen (2015), p 51.

⁷⁶ First value from Patton, LeeVanSchaick, and Chen (2016a), p A-129; the value in USD is taken directly from the study without adjustment. Second value from Patton, LeeVanSchaick, and Chen (2016b), p 48 and Patton, LeeVanSchaick, and Chen (2016c), p 42; annualized benefits in USD are estimated from quarterly results but are otherwise unadjusted.

interface ramping constraints. Participation from traders has also been limited due to remaining market-seams-related frictions, including transmission fees and other charges that were not fully eliminated, for example, between NYISO and PJM. Because CTS still relies on market participants to arbitrage price differences between markets, it does not guarantee price convergence (at which point no trading profits would be earned). As the result of these factors, CTS still leads to less than fully-efficient intertie schedules.

Several markets have taken steps toward more complete optimization of interties. In these markets, the system operators set intertie schedules automatically to optimize resource dispatch across neighboring areas. In Europe, for example, national markets have begun to implement “market coupling,” where transactions (including sharing balancing services) are scheduled automatically across market borders based on intertie capacity that remains available after bilateral markets close. At present, most day-ahead markets are coupled across Europe, with intraday coupling expanding across many more European power markets as of the third quarter of 2017.⁷⁷ Similarly, some US markets, including ISO-NE, have considered full tie optimization (TO).⁷⁸ Tie optimization coordinates real-time energy dispatch across ISOs to minimize production costs across both markets. Another example is the EIM among CAISO, PacifiCorp, and NV Energy in the western U.S. The EIM enables five-minute real-time economic re-dispatch of available resources across multiple systems, automatically adjusting intertie schedules based on market conditions and the intertie capacity that remains available after bilateral trading closes. The EIM has been operational since 2014, and more systems are expected to join in 2017, 2018, and 2019. The latest estimates indicate that the EIM yields annual benefits of USD \$97 million across the currently-participating entities.⁷⁹

D. POTENTIAL OPERABILITY BENEFITS TO ONTARIO

While many elements of Ontario’s wholesale market are unique, Ontario is not alone in experiencing an increased need for flexibility. The experiences of other markets and the results of a variety of initiatives aimed at improving system operability provide insights to the options available to Ontario and the potential benefits of those options. We estimate benefits of similar market reforms in Ontario and account for elements that may drive differences in benefits across markets.

1. Estimated Range of Ontario-Internal Operability Benefits

Consistent with the approach taken with estimated benefits related to energy-market improvements, we use a combination of benefits estimated specifically for the Ontario system

⁷⁷ See XBID (2016), p 6.

⁷⁸ See White and Pike (2011).

⁷⁹ See CAISO (2016a); annualized benefits in US dollars calculated from 2016 quarterly estimates but otherwise unadjusted.

with benefits studies from other markets. Due to the lack of certainty in terms of the specific operability reforms that will be pursued under Market Renewal, the scope of the enhancements is less of a driver of benefits than it was for the energy market analysis. For example, it is uncertain whether or not Market Renewal will include the ancillary market reforms studied under the ERCOT Future of Ancillary Service study or the MISO ramp product study. Accordingly, we treat the benefits observed in these studies (summarized on the left of Figure 10) as representative of the type and level of benefits that could be realized in Ontario. To estimate the potential efficiency benefits from ancillary service improvements in Ontario, we assume both types of improvements can be pursued in Ontario and, accordingly, add the estimated efficiency benefits from these two studies.

The additional benefits due to increasing flexibility of the existing system, such as the measures studied in the Pan-Canadian Wind study and the California Low Carbon Grid (shown on the right in Figure 10) require more adjustment in order to translate to Ontario. The California Low Carbon Grid study includes a number of flexibility enhancements that would likely go beyond the scope of measures implemented under Market Renewal (specifically a large increase in existing intertie capability), so we choose to not include its projected benefits in our baseline estimate of Ontario-internal operability benefits from Market Renewal. The benefits projected in the Pan-Canadian Wind study, on the other hand, come from enhancing hydro flexibility by improving the utilization of hydro for providing flexibility, which we believe could be achieved under Market Renewal. This study considers only one type of flexibility enhancement for better utilizing hydro, though several other non-quantified potential enhancements may exist.



Sources and Notes:

All benefits translated to 2021 CAD\$ assuming a 2% inflation rate and standardized by relative system load.
See Newell, *et al.* (2015); Navid, *et al.* (2013); General Electric Energy Consulting (2016c); Brinkman, *et al.* (2016).

In terms of translating the other flexibility enhancement benefits summarized in Figure 10 to Ontario, Ontario is projected to have approximately 14% renewable penetration by 2020, or in between the two penetration levels reflected in the Pan-Canadian Wind Integration Study. We believe that the large quantity of relatively inflexible baseload generation in Ontario magnifies the impact of Ontario's levels of intermittent resources compared to other markets. Therefore, we use the benefits observed in the 20% wind integration case as our baseline estimate for efficiency benefits due to flexibility enhancements. Thus, the \$0.34 million/TWh value shown in Figure 11 is the sum of the first three bars in Figure 10.⁸⁰

Figure 11
Range of Efficiency Benefits from Operability to Ontario
(Prior to Downward Adjustments Accounting for the Implications of Existing Contracts)

Low		Base		High
\$29 million / year - Sum of total benefits estimated in AS reform studies and hydro flexibility study (half the benefits from the 20% wind integration case) - Scaled to 2021 demand from Outlook A of the Ontario Planning Outlook		\$0.34 million / TWh Sum of total production cost benefits estimated in AS reform studies and hydro flexibility study (20% wind integration case)		\$89 million / year - Sum of total benefits estimated in AS reform studies and hydro flexibility study (twice the benefits from the 20% wind integration case) - Scaled to 2021 demand from Outlook D of the Ontario Planning Outlook
	×	143 TWh Average of projected total energy demand in Ontario by 2021 across Outlooks A, B, C, & D included in the Ontario Planning Outlook		
	=	\$49 million / year Projected efficiency benefits in a system of Ontario's size by 2021, if the scope and scale are assumed to be similar to those projected in other markets		

Given the uncertainties associated with operability reform in Ontario and the differences between Ontario and other markets, we estimate high and low benefit numbers that reflect a plausible range. The low end of the plausible benefit range based on the sum of the first two benefit categories, but only half of the third. This low-end estimate adopts the hydro flexibility benefit at 5% wind penetration levels, reflecting a more pessimistic assumption that the flexibility reforms pursued in Ontario are less comprehensive or less valuable than those considered in the Pan Canadian Wind Integration Study. In our high-end estimate of the plausible range, we double the hydro-flexibility benefit identified in the Pan-Canadian Wind Integration study, implicitly assuming that Ontario will pursue a wider range of flexibility

⁸⁰ This estimate does not reflect adjustments to account for existing contracts, which we discuss further in Section VI below.

enhancements. We view this higher-end estimate as plausible given that additional options for hydro flexibility enhancements beyond the one considered in this study have already been identified by market participants, and given that many other flexibility enhancements such as advanced gas plant modeling or demand response incorporation are not considered in this study. We summarize the assumptions and calculation of the base, high, and low benefits estimates in Figure 11. These benefit estimates are not yet adjusted to account for the implications of existing contracts, which we discuss further in Section VI below.

2. Estimated Range of Intertie-Related Operability Benefits

Similar to Ontario-internal operability enhancements, the scope of intertie-specific enhancements in this workstream remains uncertain at this point. Although moving to 15-minute scheduling has been identified as a likely design component, significant additional enhancements of Ontario's interties are possible. The benefits we quantify are estimates for potential enhancements that could be considered within Market Renewal.

Figure 12 compares the benefits of various intertie enhancements, normalized by the rated intertie capacity between the neighboring markets. The magnitude of efficiency benefits generally increases when moving from simpler intertie enhancements to more complete intertie optimization. When translating this range of benefits to Ontario we assume that, unlike other benefits streams, intertie-related benefits are not affected by existing contracts.

At the low end we estimate potential intertie-operability benefits of \$11 million per year in 2021 (increasing with inflation) based on the IESO Examination of More Frequent Intertie Scheduling, which accounts for the benefits of reducing all latency delay (forecasting errors) by scheduling intertie flows close to real time.⁸¹ This estimate may somewhat overstate benefits from 15-minute scheduling because forecast error cannot be eliminated entirely. At the same time, this study misses other benefits that were outside its scope but that are likely to be realized even with this modest design enhancement, including amplified benefits from combining nodal pricing with 15-minute scheduling, higher wind penetration levels, more frequent scheduling with non-market neighboring regions, avoided gaming, or efficiency benefits from reduced uplifts. The study scope also did not include potential benefits from more advanced market design changes. Thus, we see this as a very conservative estimate of the benefits of going only to 15-minute scheduling and finalizing intertie schedules closer to dispatch time, without further intertie optimization efforts.

⁸¹ This estimate does not reflect adjustments to account for existing contracts, which we discuss further in Section VI below.

Figure 12
Cross-Study Comparison of Benefits from Intertie Enhancements



Sources and Notes:

All benefits translated to 2021 CAD\$ assuming a 2% inflation rate and standardized by relative intertie rating.

CTS benefits “projected at scheduling” are those benefits estimated prospectively at the time intertie schedules were determined. Realized benefits are estimated retroactively and are lower than those projected at scheduling due primarily to latency delay and price forecast error.

Data from IESO (2014a), p. 7; Patton, *et al.* (2016a); Patton, *et al.* (2016b, 2016c); CAISO (2016b, 2016c); Patton (2010).

If Ontario were to follow its neighboring U.S. markets and implement coordinated transactions scheduling with NYISO and MISO, we estimate that the province would realize approximately 25% of the total potential benefits of fully-optimized interties, consistent with the fraction of total benefits realized by NYISO and ISO-NE in their implementation of CTS.⁸² Because the estimated efficiency benefits accrue to both markets on either side of the intertie, we assume that half of this benefit from CTS would accrue to Ontario. The assumption that Ontario would capture half of the total intertie-related benefits between the interconnected markets is conservative because the size of some of the neighboring markets (in particular MISO) substantially exceeds the market size in Ontario. Because Ontario is the smaller market, its supply curve will tend to be steeper than that of the neighboring markets, so moving closer to the optimal intertie flow will have a larger effect on market prices and supply costs in Ontario. This results in higher cost savings per MWh of intertie transaction for the smaller market. Our baseline estimate of improved intertie-operability benefits assumes that Ontario achieves the benefits associated with 15-minute scheduling as well as those associated with implementing CTS

⁸² We do not use the benefits of CTS between NYISO and PJM, as these are depressed by not fully eliminating transmission fees and other charges.

between with NYISO and MISO. This yields an estimated annual benefit of \$32 million per year in 2021.⁸³

Our high-end estimate of potential intertie-operability benefits is \$51 million per year in 2021, based on the possibility that Ontario and its neighbors would move beyond CTS to implement more optimized coordination, such as that used by EIM.⁸⁴ For this high estimate, we take the total annualized benefits of EIM and scale to the Ontario system using total intertie capacity. As the EIM benefit estimate is for both markets on either side of the interties, we again assume that 50% of the total benefits would accrue to Ontario.

Figure 17 summarizes the baseline calculations to translate benefits of intertie scheduling enhancements to Ontario, along with the approach used to specify the plausible uncertainty range of these benefits. These benefit estimates are not affected by existing contracts given that intertie transactions are driven only by market incentives and are not governed by any contract terms, unlike the other benefit categories that we examine in this study.

Figure 13
Range of Efficiency Benefits from Intertie Enhancements to Ontario
(No Adjustments Are Needed to Account for Existing Contracts)

Low		Base		High
\$11 million / year IESO estimated benefits of more frequent intertie scheduling and reduced forecast error from closer to real-time scheduling, in 2021 CAD\$		\$85 million / year - Ontario's share of potential benefits of fully optimized interties with MISO and ISO-NE - Benefits translated to 2021 CAD\$		\$0.011/ MW-year Each market's share of normalized benefits of EIM, translated to 2021 CAD\$
	×	25% Fraction of potential benefits of fully optimized interties achieved by CTS between NYISO and ISO-NE	×	3,530 MW Total interchange capacity between Ontario-NYISO and Ontario-MISO
	+	\$11 million / year Additional benefits of more frequent intertie scheduling	+	\$11 million / year Additional benefits of more frequent intertie scheduling
	=	\$32 million / year Projected benefits in a system of Ontario's size in 2021, if CTS is implemented similar to in NYISO and ISO-NE	=	\$51 million / year Potential benefit of ideal (Integrated Regional Markets) intertie scheduling in Ontario in 2021

⁸³ This estimate does not reflect adjustments to account for existing contracts, which we discuss further in Section VI below.

⁸⁴ This estimate does not reflect adjustments to account for existing contracts, which we discuss further in Section VI below.

3. Non-Quantified Operability Benefits

As with the energy workstream, we anticipate that the operability workstream of Market Renewal would lead to benefits that go beyond what we have quantified here. These additional non-quantified benefits include further cost reductions and improvements to system operation. For example, many new ancillary services products will likely be explored for which benefits have not yet been quantified in other market studies. We also have not quantified the value of improvements to existing ancillary services or the value of increasing the quantities of existing ancillary services that may be needed at higher levels of generation from intermittent resources and inflexible baseload generation.

Improving the utilization of existing flexible resources may reduce the need for new investment, creating capital savings benefits not quantified here. This may be especially relevant in Ontario due to the underutilization of existing pump storage capacity. If this capacity were to be used more efficiently due to operability reforms under Market Renewal, the need for new fast ramping capacity would be diminished, which would reduce capital costs that might otherwise be needed. At the same time, due to the likelihood of that new capacity being gas-fired, the increased flexibility of existing pump storage resources would further lower costs by eliminating the fuel costs and emissions that would have been generated by operating that new capacity. Beyond pumped storage, increasing the flexibility of other existing hydro resources, demand response, and other resources may also offer significant benefits in Ontario (*e.g.*, avoiding spill of hydro generation) that has not been analyzed in the studies reviewed. These benefits would potentially include both a reduction in costs and an increase in taxpayer revenues associated with hydro rental charges. Better intertie scheduling would avoid CMSC and intertie offer guarantee payments that have created inefficient incentives, gaming opportunities, and sometimes unwarranted wealth transfers.

Finally, the potential for increased ability to harness the flexible resource potential of nuclear, storage, demand response, and distributed resources offer significant benefits we do not quantify. In addition to providing further cost reductions, this increased flexibility could potentially offer non-quantified reliability benefits. As increasing levels of intermittent resources continue to create uncertainty within system operations, this increased flexibility will prove increasingly valuable.

V. Incremental Capacity Auction

The third and final workstream contemplated under Market Renewal is to implement an incremental capacity auction. The incremental capacity auction will use a market-based approach to procure sufficient resources to meet Ontario's resource adequacy needs. Capacity auctions can achieve efficiency benefits by creating a competitive market for suppliers, increasing the system's ability to adjust to changing supply and demand dynamics, and attracting low-cost, non-traditional capacity resources that may not be identified under Ontario's existing procurement framework. We estimate the potential magnitude of efficiency benefits that the IESO might achieve through an incremental capacity auction based on experience in other

markets, after considering the applicability of these experiences in Ontario's unique context. Our benefit estimates explicitly consider Ontario's projected supply-demand conditions over time, the status and term of existing contracts, and realized contract costs under the status quo contracting approach.

A. DESCRIPTION OF HISTORICAL APPROACH AND PROPOSED ENHANCEMENTS

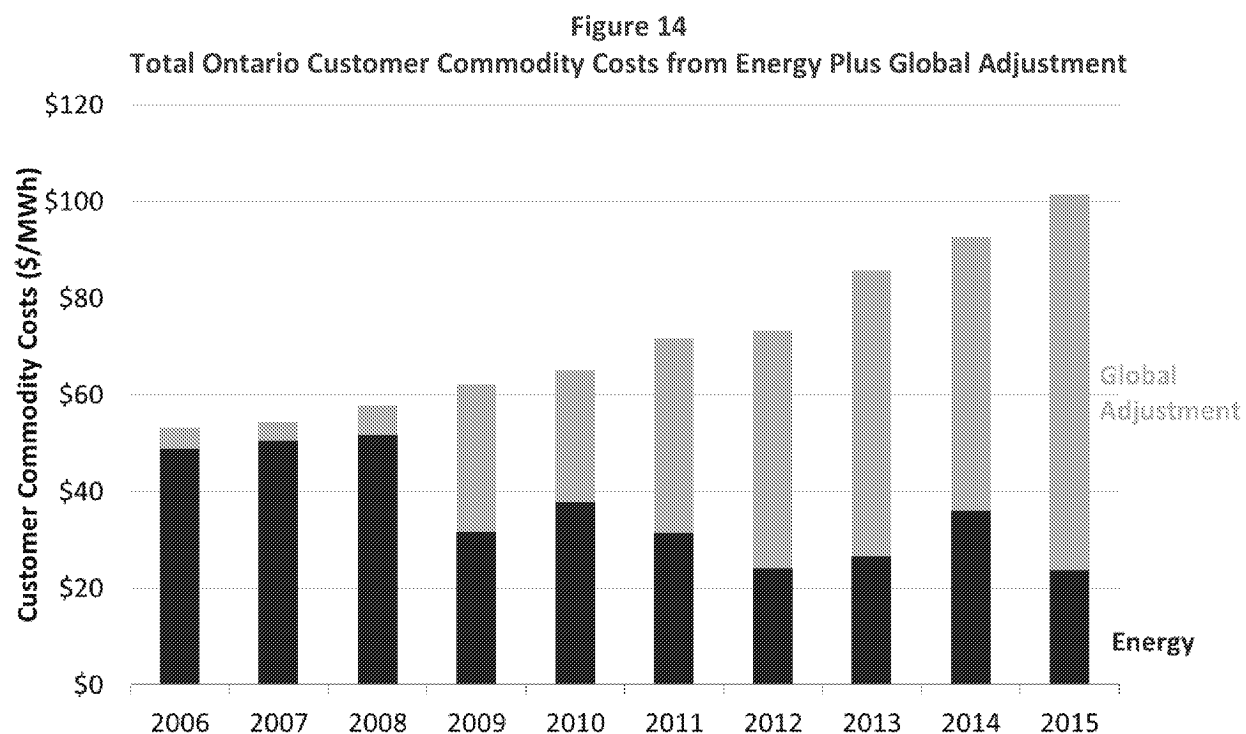
For more than a decade, Ontario has relied on a system of administrative resource planning and supply contracting to determine when and what type of resources should be developed. New resources have been developed under 10–20 year contracts with the IESO (and formerly, the Ontario Power Authority), under Ministry of Energy oversight and direction. Other existing contracts are administered by the Ontario Electricity Financial Corporation (OEFC) as a consequence of the restructuring of the former Ontario Hydro. Another subset of existing resources owned by Ontario Power Generation (OPG) is paid for through regulated cost recovery at rates approved by the OEB. Through these contracting and regulatory mechanisms, the majority of the sector's investment costs are recovered through the Global Adjustment.

The size of the Global Adjustment has increased significantly over the past decade, both in absolute terms and as a fraction of total customer commodity costs. The Global Adjustment made up 8% of total customer commodity costs in 2006, increasing to 77% of customer commodity costs by 2016, as shown in Figure 14. The net increases in energy plus Global Adjustment costs have introduced substantial concerns about the impact on customer bills.

Much of this increase is associated with Ontario's transition to a non-emitting fleet of resources, for two reasons. First, Ontario has paid a premium for non-emitting resources above fossil-emitting resources, based on environmental policy objectives. And second, low gas prices and high proportions of non-emitting resources have driven down energy prices. Low energy prices require a higher Global Adjustment in order to keep contracted resources whole. The IESO, MSP, and others have identified the non-market-based approach to resource planning, selection, and contracting as a key driver of Global Adjustment costs.⁸⁵ Ontario's Government has identified containing the increases in customer bills and the Global Adjustment as a priority that will be pursued through an incremental capacity auction and related reforms. For example, the Minister of Energy has endorsed an incremental capacity auction and explained that "adopting a technology neutral stance will allow the IESO to take advantage of cutting edge innovations and engineering solutions...[and] allow Ontario to fully optimize existing resources."⁸⁶

⁸⁵ See IESO's discussion: IESO (2016a). See MSP's reviews: Ontario Energy Board (2014c) (Ch. 3 and Appendix 3-A). Ontario Energy Board (2014b) (Ch. 3 sec 2.5). Others: Goulding (2013).

⁸⁶ Thibeault (2016), p. 4.



Source:

Global Adjustment compiled from IESO (2016f).

Annual energy prices taken from IESO (2016g).

In response to the increasing Global Adjustment and associated concerns about customer bill impacts, the IESO in 2014 initiated a stakeholder engagement to develop an incremental capacity auction.⁸⁷ The IESO and stakeholders worked together to develop a high-level design proposal for all major features of an incremental capacity auction including:⁸⁸

- Developing capacity requirements consistent with Ontario's reliability standards;
- Resource qualification principles that will enable non-discriminatory participation of traditional resources, demand response, and imports (but excluding the portion of any existing capacity that is already remunerated under contract or regulation); and
- An incremental auction designed to procure the capacity needs from the resources offered into the auction at lowest cost.

The incremental capacity auction stakeholder effort has been on hold since 2015, but the IESO has implemented steps toward an incremental capacity auction in the interim. IESO introduced a demand response auction that is consistent with the high-level incremental capacity auction

⁸⁷ IESO (2016h).

⁸⁸ IESO (2014b).

design. The IESO also made progress in enabling exports for a portion of Ontario's current capacity excess, with the first 88 MW of capacity exported to NYISO as of 2016.⁸⁹

B. PRIOR ANALYSIS AND EXPERIENCE IN ONTARIO

The IESO has identified an incremental capacity auction as a market reform that could generate significant efficiency benefits to Ontario. As indicators of the nature and magnitude of potential benefits from implementing an incremental capacity auction, we review a 2014 IESO study of potential benefits to Ontario and the results of the first two demand response auctions:

- **Capacity Auction Benefits:** In 2014 the IESO conducted a study analyzing the customer benefits of implementing a capacity auction in Ontario.⁹⁰ In this study, the IESO calculated the savings achievable if a capacity auction were used to procure capacity, instead of relying on long-term contracts. To do this, the IESO compared the prices at which capacity had been procured in NYISO and PJM's capacity auctions to the payments the IESO would need to make under a continuation of existing contracting approaches. The IESO accounted for the quantity of expected resource needs, the type of contracts with contract expirations, and the size of payments recently made under re-contract arrangements with similar resource types. Applying the expected reduction in payments, the IESO estimated \$60 million/year in customer benefits starting in 2019, rising to \$700 million/year in customer benefits by 2030.⁹¹ The IESO estimated how benefits grow over time as existing contracts expire and a greater proportion of resource needs will be competitively procured under the capacity auction. The IESO did not explicitly estimate efficiency benefits from a capacity auction.
- **Demand Response Auction Results:** The IESO held its first two demand response auctions in December 2015 and 2016 respectively, providing an indication of the potential performance from the eventual incremental capacity auction. The auctions demonstrated significant improvements compared to the most recent standard offer program available to demand response. Each successive auction cleared a greater quantity of capacity at a lower price, and attracted more participation.⁹² Specifically:
 - *Lower Prices:* The last standard offer rate available to demand response was \$104,000/MW-year. The first and second demand response auctions cleared at

⁸⁹ Butler (2016).

⁹⁰ IESO (2014a).

⁹¹ Benefits from IESO (2014a) are translated from real to nominal dollars at a 2% inflation rate.

⁹² Second Demand Response Auction results: IESO (2017). First Demand Response Auction results: IESO (2015).

\$93,000/MW-year and \$77,000/MW-year, or 11% and 26% lower than under the prior non-market mechanism.⁹³

- *Increased Participation:* Six demand response providers were registered market participants under the prior standard offer program. Each successive demand response auction has attracted more participation, with 21 registered and 9 cleared as of the last auction.

This analysis and historical experience indicate that Ontario is likely to achieve significant customer and efficiency benefits from an incremental capacity auction.

Who Pays for a Capacity Auction?

Typically the costs of a capacity auction are recovered by charging wholesale market customers based on their contributions to the system peak load, with higher rates paid by customers in import-constrained regions. In Ontario, these charges could be passed on to customers through mechanisms similar to current Global Adjustment charges, via peak demand charges for large commercial and industrial customers and volumetric charges for residential and small commercial customers. Customers will have an opportunity to avoid capacity charges either by reducing their peak consumption, or by participating on the supply side as demand response resources.

Unlike the Global Adjustment, capacity auction prices will be driven by market conditions. Suppliers will respond to high prices by investing in new resources where and when they are most needed. A broad set of technologies will compete to provide this incremental supply at least cost. Experience in other markets suggests that a capacity auction can procure capacity at 60%-90% of long-term contracting prices, leading to lower prices for end-use customers. Capacity auctions also transfer the risk of uneconomic investments from customers to suppliers. Under current contracting approaches, customers must pay for unneeded excess capacity; under a capacity market, customers would face low prices during periods of capacity excess.

C. EXPERIENCE IN OTHER MARKETS

There is a substantial body of evidence that the IESO can, and already has, drawn upon when evaluating and designing its incremental capacity auction. The U.S. markets of PJM, ISO-NE, and NYISO have successfully relied on capacity markets to meet their reliability needs for more than a decade. Experience in these markets demonstrates that capacity markets can attract substantial quantities of low-cost capacity resources, although each has faced challenges from which Ontario can learn. Both MISO and California have integrated short-term capacity market elements within primarily regulated markets, a mixed construct that has introduced greater challenges than in the all-merchant markets. Looking to the future, each of these markets is re-evaluating interactions between policy-driven investments and the capacity markets, particularly

⁹³ These prices are reported in UCAP \$/MW-year. Auction clearing prices are reported in \$/MW-day for each summer and winter season, and must be multiplied by the number of peak days that the resources are required to be available.

in response to regional decarbonization initiatives. In this section, we briefly summarize this experience and evaluate the relevance in Ontario's context.

1. Attracting Low-Cost Non-Traditional and New Generation Supply

Over more than a decade of experience, the U.S. capacity markets in PJM, ISO-NE, and NYISO have met or exceeded their resource adequacy requirements cost-effectively.⁹⁴ They have done so by clearly defining their capacity needs in reliability terms, and then procuring the needed supplies through non-discriminatory auctions that are open to all types of resources. This auction-based format has proven effective at leveraging competitive forces to attract the lowest-cost combination of available resources. Capacity markets have created a level playing field that enables competition among new and existing generators, incumbents and new entrants, internal supply and imports, traditional and new types of technology, generation and demand-side resources, and centralized and distributed resources. In the early years after market implementation, the capacity markets attracted primarily non-traditional resource types to meet incremental capacity needs, including from increased imports, demand response, and generation uprates. These non-traditional resources were attracted at low, and sometimes very low, prices. More recently, each of the markets has been facing the need for new generation supply. Capacity prices have risen consistent with the costs of attracting new generation resources, but are still below the system operators' estimates of the long-run costs of new generating plants.

There have also been challenges in each capacity market that have required regular design enhancements.⁹⁵ System operators have identified unanticipated new reliability concerns that required changes to their designs.⁹⁶ Market rules sometimes created unintended economic advantages or disadvantages to particular resource types that required adjustments to participation rules.⁹⁷ Auction parameters representing the load forecast, transmission limits, and demand curve are subject to administrative judgement and substantial stakeholder scrutiny. Market participants also express concerns about market prices: suppliers are concerned that prices are too low, customers are concerned that prices are too high, and many sectors are concerned that prices are too uncertain. Overall, one of the primary disadvantages of capacity

⁹⁴ For a review of the experience with the first decade of capacity market operations, see Spees, Newell, and Pfeifenberger (2013).

⁹⁵ For examples of recommendations to improve the existing capacity market designs, see Pfeifenberger, *et al.* (2014); Spees, Newell, and Lueken (2015); and Pfeifenberger, Spees, and Newell (2012).

⁹⁶ For example, in response to growing concerns about gas pipeline constraints and potential reliability concerns, all three markets have implemented reforms, such as enhanced non-availability penalties or back-up fuel. ISO-NE (2015), PJM (2015) 151 FERC ¶ 61,208, Bouchez (2015).

⁹⁷ For example, PJM's market originally failed to fully integrate demand response within the auction, instead providing a standard-offer price on an out-of-market basis. This led to a large influx of resources in one year (and very low resulting prices) when demand response was finally integrated. See Pfeifenberger, *et al.* (2011).

markets is that design and parameter changes have significant financial implications, and so tend to be the focus of contentious stakeholder debates. There are also significant concerns about interactions between environmental and other policy-driven supply resources and market-based resources, as discussed further in Section V.C.1.

These observations apply across all three markets, but the PJM experience provides a good example of capacity market performance in achieving reliability objectives cost-effectively, despite facing challenges along the way. PJM's capacity market was implemented in 2007 at a time when PJM anticipated impending shortfalls in capacity, especially in import-constrained areas.⁹⁸ The new capacity market was able to procure enough supply to meet and exceed the requirement by attracting a substantial influx of new, low-cost resources as shown in Figure 15. These low-cost resources included increases in net imports, uprates to existing generation, and demand response resources, amounting to approximately 15% of PJM's total capacity requirement.⁹⁹ No one anticipated so many low-cost resources; they likely would never have been identified as supply options under administrative or utility planning efforts. This significant quantity of low-cost, non-traditional entry is an example of the innovation that can take place in non-discriminatory, competitive markets. Securing a large quantity of low-cost resources postponed the need for new merchant generation investments for almost a decade in PJM.

More recently, new generating capacity has been needed due to load growth and retirements. Capacity prices have risen sufficiently to attract those investments, but still remain substantially below the system operator's estimates of the long-run cost for new generating plants as shown in Figure 15 (the estimated net cost of new entry or "Net CONE"). Over the past five auctions, PJM has added 46,150 ICAP MW of generation, mostly gas-fired combined cycles developed on a fully merchant basis.¹⁰⁰ This merchant supply has entered at capacity prices that are only 30–75% of PJM's estimated Net CONE.¹⁰¹

We expect that much, but not all, of the experience from other markets will apply to Ontario. We expect that market participants in Ontario will similarly identify low-cost opportunities for incremental capacity when the need arises. There will be low-cost opportunities for generation uprates and capacity imports. Ontario will be able to import capacity from Manitoba, Québec, MISO, New York, and possibly from PJM when those regions have a greater supply excess; similarly, Ontario will benefit from exporting capacity at other times. Ontario seems to have more room to continue developing demand response, although more of the latent potential has already been developed compared to other capacity markets at their start. We expect that such

⁹⁸ See a more detailed discussion of this history in Pfeifenberger, *et al.* (2011) and PJM (2016d).

⁹⁹ PJM (2016d).

¹⁰⁰ See PJM (2016d), p. 7 and Table 8, and the same auction report data from prior years.

¹⁰¹ This range of prices is based on years new entry cleared the market in RTO, MAAC, and EMAAC zones. PJM (2016c)

low-cost opportunities could be developed at prices similar to those realized in other capacity markets.



Sources and Notes:

Data compiled from PJM (2016b) and PJM (2016d).

For new generation, we expect that an incremental capacity auction in Ontario will be able to attract merchant supply as long as the design and associated governance structures are sufficiently tailored to address Ontario's specific challenges and policy context. We expect these resources could be attracted at competitive prices, though not as low as the recent prices available in PJM. Ontario's market fundamentals are very different from those in PJM, and so we cannot expect that the same marginal technology type or price point will prevail.¹⁰² The types of new supply that are economic in the incremental capacity auction will also depend on how the IESO addresses the interactions with clean energy policy, as discussed further in Section V.C.3.

¹⁰² PJM has a unique circumstance with relatively high coal prices, very low gas prices, and modest environmental policies that make it a profitable time and place for building gas combined cycle plants.

Can Capacity Auctions Attract New “Steel in the Ground”?

Capacity markets in other jurisdictions have demonstrated that they are able to attract new entry even at low capacity prices. At the initiation of many capacity markets, most of the incremental resource needs were met by low-cost, non-traditional resources such as demand response, uprates, and imports that had lower going-forward costs than new generation resources. Over time as these low-cost supply opportunities are exhausted, the capacity markets have attracted incremental new generation resources, and at prices significantly below the administratively-estimated costs. As noted in the text, over the past five auctions, PJM has added over 45,000 MW of generation developed on a fully merchant basis. The competitive capacity auction format contributes to these cost-effective outcomes by incentivizing innovative approaches to financing investments and attracting competition from new entrants.

2. Comparison of Contracted and Market-Based Entry Prices

Experiences from the U.S. capacity markets offer a few examples that enable a direct comparison between the costs of long-term contracts to the results of capacity auctions. As one example, in 2011 New Jersey policymakers directed state utilities to sign long-term contracts with generators, rather than relying on the capacity market to procure the needed supply. At the time, state regulators were concerned that the capacity market might be unable to attract new generation supply, or only at prices that would exceed those that they might achieve through long-term contracts procured through competitive solicitation.¹⁰³ The utility commission conducted a competitive solicitation and selected contracts at the prices illustrated in Figure 16. These contracts were later invalidated through a Supreme Court decision, but at the time they were understood to be financially-binding commitments. Over the same timeframe as these contracts, a large number of new gas combined cycles entered PJM’s market under much lower prices and with no multi-year guarantees (see Section V.C.1 above). As shown in Figure 16 capacity prices have been only 60%, 75%, and 87% of the contracted prices for the CPV Woodbridge, NRG Old Bridge, and Hess Newark facilities respectively.¹⁰⁴

As another example, in 2007 the Connecticut Department of Public Utility Control approved a long-term contract with Kleen Energy Systems based on a similar belief that a long-term contract

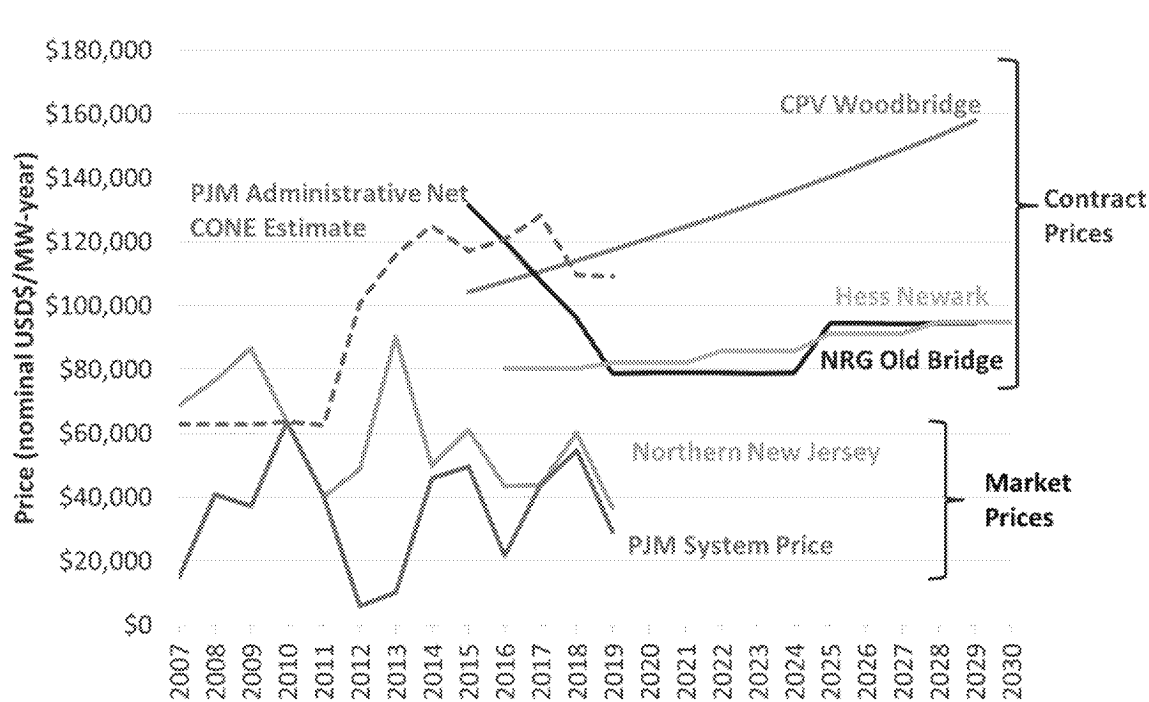
¹⁰³ Boshart (2011).

¹⁰⁴ The costs of these contracts and realized capacity prices need to be levelized across the entire contract life in order to make a complete comparison of costs, a comparison that will not be possible until capacity prices through 2029 are available. As a proxy for that comparison, we use a simplified present value analysis that assumes capacity prices will increase with inflation. To calculate the present value, we use a 7.5% discount rate consistent with a merchant developer’s after-tax weighted-average cost of capital (ATWACC). For capacity prices, we take the simple average of actual capacity prices in PSEG North Zone over the past five years since the contracts began, and assume future capacity prices will increase 2% per year with inflation.

would be more cost-effective than relying on the capacity market.¹⁰⁵ The price at which the contract was signed is not public, but is likely far above realized capacity market prices. Over the 2011 through 2017/18 timeframe applicable to the contract, capacity prices in ISO-NE have been USD \$58,800/MW-year on average, or only 75% of the administratively-estimated Cost of New Entry.¹⁰⁶ Market prices were substantially below the likely contract price because ISO-NE was able to retain existing resources and attract incremental new resources for many years, and market-based new entry was not needed for system needs until 2017/2018.¹⁰⁷

Figure 16

Comparison of Market Prices to Competitively-Procured Long-Term Contract Prices in New Jersey



Sources and Notes:

SNL Financial (2016).

PJM capacity auction parameters and results, PJM (2016b)

These examples illustrate the advantages of a broad-based competitive auction. This competition can achieve lower prices even if the same underlying technology type is selected, as it was in

¹⁰⁵ McCarthy (2010).

¹⁰⁶ Kleen Energy contract duration taken from: SNL Financial (2016). ISO-NE prices and Net CONE taken from Forward Capacity Auction result page: ISO-NE (2017). The average capacity price as a percent of CONE is calculated by finding the capacity price as a percent of CONE for each year between 2011 and 2018, then averaging the annual percentages.

¹⁰⁷ This was the first year that capacity was needed in the Rest of System region that includes the state of Connecticut. New entry was needed one year earlier in the Northeastern Massachusetts/Boston subregion. Date taken from Forward Capacity Auction result page: ISO-NE (2017).

PJM. One-year commitment periods reduce the risk that customers will be locked into high price contracts for many years and shift the risk of uneconomic investments onto suppliers. Enabling competition among all resource types (including between new and existing resources) reduces the risk that contract prices could be high because the wrong resource type was selected, or because new generation is built under contract before it is needed as in the ISO-NE example. We expect that Ontario will be able to achieve the same types of advantages under an incremental capacity auction.

Ontario's recent experience highlights the lack of year-to-year flexibility within long-term contracts to respond to changing supply and demand dynamics. Supply and demand are inherently uncertain on a forward basis, the costs associated with managing these risks are borne by customers under all types of integrated planning and contracting approaches. This will naturally lead to periods where high load forecasts or incorrect retirement assumptions lead to excess supply, the costs of which must still be paid by customers. This is the present situation in Ontario, which has nearly 1,900 MW of excess capacity as of 2017.¹⁰⁸ In capacity auctions, the same type of supply and demand uncertainties exist but the responsibility for managing those risks falls on suppliers rather than customers. Rather than relying on long-term contracts, capacity auctions allow ISOs to procure only the amount of capacity they expect to need in a single year. Even if load growth slows, fewer units than expected retire, or lower cost resources enter the auction, customers do not need to pay for more capacity than they need. Suppliers will experience excess supply conditions through lower capacity prices that encourage them to mothball, export, or retire unneeded and higher-cost resources. Capacity auctions thus provide a more nimble platform for supporting year-to-year adjustments to capacity needs, and more effectively incorporate resources such as imports and demand response that can enter and exit the market quickly compared to traditional resources.

3. Interactions Between Merchant and Out-of-Market Supply Investments

Managing tensions between market-based and out-of-market supply is possibly the biggest challenge facing most capacity markets. These markets are designed to attract merchant supply investments when prices raise high enough to signal the need. If policy-driven or regulated supply is introduced, it displaces the need for merchant entry and suppresses prices compared to an all-merchant market. Large quantities of non-market supply can leave merchant suppliers in a severely degraded financial position. New investors evaluate the risk of regulatory interventions when assessing the attractiveness of entering a market; prices will need to be higher or locked in for a longer period to attract investments into a market with substantial regulatory risks.

To date these tensions have been challenging but manageable in PJM, ISO-NE, and NYISO. These regions rely on merchant generation for the large majority of their capacity supply, and

¹⁰⁸ Excess capacity is the average across outlooks A, B, C, and D from IESO (2016i).

the markets are designed to accommodate the merchant business model. The markets incorporate a number of traditionally-regulated utilities and public power entities that own regulated assets and use them for self-supply. Vertically-integrated entities buy or sell a small proportion of supply to balance their portfolios, but the imbalances are small enough that they do not introduce significant regulatory uncertainties into the broader capacity market. A more significant regulatory risk is that state policymakers might introduce policies to build new resources on an out-of-market basis and therefore intentionally or unintentionally suppress capacity prices.¹⁰⁹ The RTOs have acknowledged these risks and introduced design elements that mitigate the collateral impacts of regulatory risks. Most notably, all three markets incorporate minimum offer price rules that prevent resources under state-driven contracts from entering uneconomically low prices.¹¹⁰ ISO-NE also incorporates a seven-year price lock-in for new entrants to offset perceptions of excess regulatory risk.¹¹¹ These design elements have enabled the RTOs to manage, but not eliminate, the tensions between merchant and policy-driven supply. Despite the ongoing challenge, all of these markets have demonstrated success in attracting non-traditional capacity supply and new generation investments at low cost.

MISO and CAISO experiences with capacity markets form a strong contrast. These regions rely primarily on regulated assets developed under utility self-supply or long-term PPAs, but also incorporate a minority of merchant supply. CAISO's bilateral capacity market and MISO's centralized capacity auction are mechanisms for enforcing resource adequacy requirements. These non-forward markets create platform for supply-demand accounting, price formation, and enabling market participants to exchange capacity obligations.¹¹² However, they have not provided the same benefits as the other U.S. capacity markets in attracting large quantities of low-cost capacity supply and new merchant generation. This is because all supply and investment decisions continue to be made through regulated planning processes, utility programs, and state-directed procurements for preferred resource types several years in advance. New generation is not required to compete with demand response, imports, existing resources, or uprates on a level playing field. By the time the short-term capacity market arrives, all investment decisions are already made and little or no residual decision-making is left to market forces. The result is a bifurcated system between regulated new entry that can be developed at relatively high cost, and all other types of merchant resources earning a very low price in the short-term markets. The merchant price then leaves little incentive to attract low-cost demand response or uprates, and can lead to the early retirement of relatively new existing plants with

¹⁰⁹ The scenario is exemplified by the state-mandated PPAs for new generation in New Jersey and Maryland in 2011, and in Connecticut in 2013. Speigel (2014) and Thomas (2012).

¹¹⁰ The details of which resources are covered by the rule, the price level, and duration of applicability are different in every market. See PJM (2016e) Section 5.4.5; FERC (2012); and ISO-NE (2016) Section III.A.21.

¹¹¹ See FERC (2014).

¹¹² For more comprehensive discussions of the issues in California and MISO, see Pfeifenberger, Spees, and Newell (2012) and Spees, Newell, and Lueken (2015).

expired contracts.¹¹³ To acknowledge and address the challenge of its bifurcated market, MISO recently proposed a new market design tailored to its unique circumstances. MISO proposed to conduct a voluntary three-year forward auction to procure supply on behalf of the approximately 10% of retail choice loads served by merchant supply, with the remaining 90% of utility load continuing to be served by integrated planning and a short-term auction.¹¹⁴ However, the design change was rejected by the Federal Energy Regulatory Commission (FERC) and so the issue remains as yet unresolved.

Another growing concern relates to interactions between capacity markets and new generation developed to meet environmental policy goals. Modest levels of clean energy developments typically do not introduce significant regulatory risks into capacity markets. Intermittent renewables have relatively low capacity value that displaces only a portion of the merchant capacity need and are typically developed under a predictable outlook driven by state renewable portfolio standards. However, if large quantities of clean energy procurements are supported through out-of-market mechanisms, this can undermine in-market incentives and even cause the market to work at cross-purposes with policy objectives. For example, in ISO-NE substantial quantities of clean energy procurements have the potential to suppress both energy and capacity prices in coming years. These suppressed prices disadvantage existing non-emitting resources including hydro and nuclear that are not under contract, introducing greater retirement risks for non-emitting resources that have modest going-forward costs. Thus, out-of-market non-emitting resource procurements have the potential to undermine policy objectives by displacing existing non-emitting resources rather than displacing greenhouse gas-emitting resources as intended.

The underlying problem is that these markets have traditionally been designed to maintain reliability at lowest cost; they were not designed to achieve the separate and distinct policy objective of reducing CO₂ emissions. As a consequence the markets do not help in, and can sometimes work against, achieving that policy objective. ISO-NE and NYISO are working with state regulators and market participants in their respective jurisdictions to examine how the markets can be better aligned with policy goals. New England stakeholders are considering a range of proposals such as higher CO₂ pricing and market-based non-emitting resource procurements.¹¹⁵

The policy and regulatory environment plays a substantial role in determining how well a capacity auction will function and what design elements can help it to perform better. This

¹¹³ As a prominent example, the 15-year-old Sutter gas CT plant in California was mothballed in 2016 despite other contemporaneous procurements for higher-cost capacity and preferred resources. SNL Financial (2016).

¹¹⁴ MISO (2016) and Newell, Spees, and Oates (2016).

¹¹⁵ For example, one proposal includes CO₂ pricing as well as a proposed approach to integrated clean energy procurements into the centralized capacity market. See Stoddard, Elmer, and Spees (2016).

starts with defining the right design objectives consistent with the reliability requirement and over-arching sector policies. Then a well-designed auction can enable competition and innovation to achieve those objectives at least cost. The benefits of a capacity auction and any market-based clean energy mechanism will be greater if more of the system-wide investment costs are recovered through these competitive mechanisms. If some policy objectives such as clean energy procurements are pursued through out-of-market mechanisms, a capacity auction can cost-effectively support the remaining capacity needs (with the benefits being limited if only a fraction of the system investment costs are recovered on a merchant basis). Large, persistent, and unpredictable out-of-market regulatory interventions can impose inefficient risks and costs on merchant suppliers. To maximize the benefits to Ontario and minimize regulatory risks, the province can inform its design based on lessons from other markets. However, Ontario will need to carefully evaluate its own policy environment, governance structure, and interactions with clean energy policy in order to develop a well-designed incremental capacity auction tailored to achieve the needs of the province cost-effectively.

D. POTENTIAL BENEFITS TO ONTARIO

To estimate the potential benefits of an incremental capacity auction, we have updated the IESO's 2014 capacity auction benefits study of customer benefits and assessed the benefits of exporting excess capacity. We then adopt this customer benefit estimate as a reasonable proxy for overall efficiency benefits to the province, although we explain the reasons that efficiency benefits could be higher or lower. We also identify several additional benefits that are not accounted for in our quantitative estimate.

1. Estimated Range of Potential Benefits in Ontario

The 2014 IESO study compared two alternative scenarios in which: (1) the IESO was assumed to continue to sign long-term contracts for capacity at the same prices that the IESO has historically paid for the same resource types; and (2) the IESO was assumed to procure resource needs through an incremental capacity auction at the same prices historically observed in U.S. capacity markets.¹¹⁶ We have not changed the overall approach to estimating customer benefits, but we have updated the assumptions based on recent market conditions and data as follows:

- **Supply and Demand Outlook:** The IESO's 2014 study relied on the supply and demand outlooks from the 2013 Ontario Planning Outlook.¹¹⁷ We updated this analysis based on the most recent 2016 Ontario Planning Outlook, developing separate estimates for the quantity of capacity that would be procured in Outlooks A, B, C, and D as shown in Table 5. The updated supply-demand outlook reflects a deferred need for new capacity,

¹¹⁶ We do not report the complete details of the estimate here, but instead reference the original study, see ISEO (2014a).

¹¹⁷ ISEO (2014a) p. 6.

reducing the estimated benefits from the incremental capacity auction. In the contracting scenario, we assume that all existing supply is recontracted even if the quantity exceeds the reliability requirement, and that in the long run a contracting approach will procure 2% excess supply on average. We chose this assumed level of over-procurement in a supply contracting scenario as a modest level compared to the expected 9% over-procurement in Ontario by 2018, and modest compared to the over-procurement that would be realized if the IESO contracted enough supply to meet Outlook C or D but realized load growth consistent with Outlook A or B.¹¹⁸ In the incremental capacity auction scenario we assume the exact quantity of needed resources will be procured, given that risks associated with net supply demand conditions will be shifted to suppliers under an incremental capacity auction.

- * **Prices:** We updated expected capacity auction prices from CAD \$51,300/MW-year to CAD \$58,300/MW-year in UCAP 2021\$.¹¹⁹ These updates reflect realized capacity market prices from NYISO, PJM, and ISO-NE from additional years, using a weighted average of 75% based on prices from the unconstrained systems, and 25% from the import-constrained metropolitan areas where prices are higher. We used prices only from years before new merchant generation entry was needed in each market, based on our expectation that Ontario is not likely to need new generation within the timeframe of this benefits study.¹²⁰ We expect that Ontario will be able to attract similar quantities of low-cost incremental supply compared to the 15% attracted into PJM, which will be sufficient to meet all capacity needs through 2030 even under the highest load growth contemplated in Outlook D.¹²¹ In the contracting scenario, we maintained the same assumed contract prices used in the IESO's 2014 report, net of an offset for expected energy and ancillary service margins. These contract prices have not been made public, but reflect the contract prices that the IESO has historically paid to the same or similar recontracted plants.

¹¹⁸ Avoiding 2% excess capacity procurement amounts to savings of \$88 million annually by 2030 (in 2030\$). See IESO (2016i).

¹¹⁹ The 2014 study reports a gross capacity market cost of CAD \$50,900/MW-year in 2012\$, including capacity price plus expected energy and ancillary service margins. The CAD \$51,300/MW-year 2021\$ capacity price reported here reflects only the capacity price and after adjusting to 2021\$. We compare these capacity prices to resource contracting costs for each resource after making a downward adjustment for energy and ancillary service revenues. See IESO (2014a); PJM Interconnection (2016d); ABB Inc. (2016); and ISO-NE (2017).

¹²⁰ We use the years 2003/04–2015/16 for NYISO, 2007/08–2015/16 for PJM, and 2010/11–2016/17 for ISO-NE to reflect the years prior to the need for new generation entry using data from PJM Interconnection (2016d); ABB Inc. (2016); and ISO-NE (2017).

¹²¹ We expect that a similar quantity of low-cost uprates may be possible in Ontario, likely a smaller quantity of incremental DR (given the quantities of DR that are already developed), and likely a larger quantity of incremental imports (given Ontario's significant interties that represent larger proportion of the total market).

- **Capacity Exports:** The IESO's 2014 study did not consider the benefits of capacity exports; we have now included the benefits of capacity exports. We assume that only contracted capacity in excess of the reliability requirement will be exported, so there are no capacity exports once incremental capacity is needed in Ontario.¹²² We assume the sales price in external markets will be equal to the \$58,300/MW-year price developed above, and that half of the revenue from capacity exports will be awarded to customers.¹²³ We conservatively assume that transmission system limitations and external market demand will impose a maximum of 90 MW, 450 MW, and 900 MW of capacity exports that could be pursued in years 2017, 2018, and 2019+ respectively, even if Ontario's quantity of capacity excess is larger.

Table 5
Capacity Contribution of Incremental Capacity Shortfall

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Outlook A (UCAP MW)	0	0	2,386	1,025	3,104	3,171	3,125	2,993	6,058	7,206
Outlook B (UCAP MW)	0	0	3,688	2,475	4,656	4,815	4,902	4,885	8,057	9,303
Outlook C (UCAP MW)	243	350	4,166	3,043	5,799	6,073	6,273	6,375	9,729	11,503
Outlook D (UCAP MW)	525	707	4,598	3,552	6,386	7,122	7,724	7,920	11,322	12,809

Sources and Notes:

Shortfall includes new capacity needs and expired contracts. Based on data from IESO (2016i).

We take the average customer benefits from across all four planning outlooks as our base estimate, and adopt Outlook D and Outlook B as our high and low estimates as shown in Figure 17. We find initial customer benefits of \$120–\$200 million/year in the early years from surplus capacity exports and avoided contracting, with benefits increasing to approximately \$290–\$610 million/year in the later years. These benefits have a similar magnitude to those estimated by the IESO in its 2014 study, but are achieved later primarily because lower load growth and the deferred Pickering retirement postpone the need for capacity. A future consistent with Outlook B produces the lowest benefits from an incremental capacity auction because there is the least need for incremental capacity and the least amount of excess recontracting and therefore the least opportunity to benefit from low-cost supply. Outlook D is the highest-demand scenario and has commensurately high customer benefits.

¹²² As a consequence of this simplified methodology, we incorporate no value from enabling capacity exports beyond the timeframe of Ontario's projected capacity excess. However, in reality there will be continuing and ongoing value to enabling capacity exports by allowing Ontario customers and capacity suppliers to share the benefits of selling capacity during periods of excess that will inevitably arise as a consequence of year-to-year variations in supply and demand.

¹²³ The Ontario capacity supplier whose resource is exported will need to retain a portion of the benefits from export in order to have an incentive to sell that capacity. Customers can share in the benefits from exporting any contracted resource, and may share in benefits for non-contracted resources depending on how export rights are allocated or sold.

Figure 17
Estimated Customer Benefits from Adopting a Capacity Auction



Sources and Notes:

2014 IESO Estimate of Benefits calculated using data from IESO (2014a).

Reported in nominal dollars, 2014 Study results are adjusted so they are also nominal using 2% inflation rate.

Efficiency benefits could be higher or lower than customer benefits. We expect efficiency benefits to be higher, because a portion of the total benefits will be realized as enhanced profitability to sellers with low-cost resources that have new opportunities to sell into the incremental capacity auction at the uniform price. A subset of suppliers with high-cost resources will be worse off however, as their assets are proven to be economically uncompetitive. It is possible that a portion of the customer benefits may be in the form of a transfer payment from generators to customers, rather than as a true efficiency gain. This would happen if one assumed that contract prices would substantially exceed the underlying resources' true costs, representing significant generator profits that would be eliminated on an aggregate basis under a capacity auction. Considering these offsetting possibilities, we adopt the customer benefits estimate as a reasonable proxy for efficiency benefits.

2. Non-Quantified Benefits

As with the other two work streams, we expect that the incremental capacity auction could deliver a number of additional benefits beyond those we quantify in our benefits case estimate. These benefits will likely accrue to Ontario in the form of reductions in the fixed and investment costs of achieving resource adequacy needs, enhancement of benefits created by the energy and operability workstreams, and avoided or deferred investment needs.

In terms of further capacity procurement cost reductions, Ontario could experience lower system costs associated with seasonal capacity products for imports and exports if the IESO has different seasonal profiles compared with its neighbors, particularly if Ontario becomes winter-peaking. For example, NYISO is summer-peaking but has a seasonal capacity construct, allowing cost-sharing with winter-peaking systems that can only deliver supply in the summer. We do not quantify the benefits of such cost-sharing as it would require a more detailed analysis of Ontario's seasonal capacity needs, as well as those in surrounding markets.

Additional reductions in cost could be created through the attraction of new technology types other than those that have entered in existing capacity markets. Innovative technologies may be able to supply capacity at a lower net capacity price, particularly when combined with the enhanced incentives available based on energy and operability reforms. Similarly, benefits will be created from locational capacity and energy constructs that attract supply into the locations within the province where it is most needed, rather than in locations where it is less valuable. Optimizing resource location will likely lower congestion costs across the system, creating additional benefits under the energy market reforms. Quantifying these benefits would require a locational analysis, which lies outside the scope of our study.

Cost-effective flexible resource requirements or clean energy procurements, to the extent that such requirements are expressed through the incremental capacity auction or associated market mechanisms under Market Renewal, could create additional benefits for Ontario. For example, California requires that a subset of total capacity meet flexibility requirements sufficient for balancing intermittent resources. So far, California's existing fleet has come forward with sufficient flexibility capability to avoid investments in new plants to provide those flexibility services. Similar measures could be used in Ontario as a way to facilitate continued renewable penetration at a lower cost to the system and potentially defer the need to invest in new flexible generating plants. In order to quantify these benefits we would need to explicitly quantify the timing and magnitude of potential flexibility needs.

Finally, the total efficiency benefits created by an incremental capacity auction could exceed the customer benefits estimated here because we do not account for the portion of efficiency benefits that will be captured by low-cost, inframarginal suppliers. These incremental and low-cost suppliers will benefit from the capacity auction based on the difference between their costs and the market-clearing price.

VI. Accounting for Existing Contracts

Ontario's current fleet of resources is comprised almost entirely of resources developed under long-term contracts and those developed based on regulated cost recovery. The large number and volume of existing contracts introduce substantial complexity in both the design and implementation phases of Market Renewal.

These complexities affect this benefits case study. Total potential benefits from Market Renewal may not be achievable if existing contracts limit market participants' exposure to improved

incentives. To account for these implications in the benefits case, we have worked with IESO staff and stakeholders to: (1) understand the two-way interactions between contracts and Market Renewal for different categories of contracted and regulated assets; and (2) adjust our efficiency benefits estimates to reflect what is likely to be achieved in Ontario in light of these interactions.

A. OVERVIEW OF EXISTING CONTRACTS

We provide here an overview of the magnitude, duration, and incentive structure for each major category of contracts. This characterization provides the starting point for evaluating implications for the benefits case.

1. Magnitude and Duration of Existing Contracts

Figure 18 summarizes Ontario's current supply outlook by resource type compared to the total resource requirement, consistent with the 2016 Ontario Planning Outlook. Nearly all capacity in Ontario is presently contracted or regulated. The ownership and contractual counterparties for these resources include:

- **IESO Contracts:** 27,216 MW (27,646 contracts) cover a wide range of resource types including natural gas generating plants (reflecting the largest proportion of MW, but a relatively small number of contracts), hydroelectric plants, and other renewables (reflecting a relatively small proportion of unforced MW but the vast majority of the contracts).¹²⁴ The largest contracts in MW terms are the 6,300 MW of contracts with the Bruce nuclear plant. The resources under contract with the IESO (or formerly with the Ontario Power Authority) are predominantly owned by independent power producers.
- **OEFC Contracts:** 360 MW (5 contracts) cover a relatively small number of mostly gas-fired resources owned by independent power producers that had contracts with the former Ontario Hydro before the sector was restructured in 1998.¹²⁵ Most of the original OEFC contracts have expired, but some of these contracts will not expire until 2031.
- **OPG Regulated Assets:** 10,300 MW (56 resources) of hydroelectric and nuclear generation is owned by OPG, with cost recovery earned under regulated tariff structures approved by the OEB.¹²⁶

In aggregate, the province has a contracted/regulated capacity surplus of 1,900 MW as of 2017 (averaged across the four outlooks in the Ontario Planning Outlook).¹²⁷ Over the coming decade

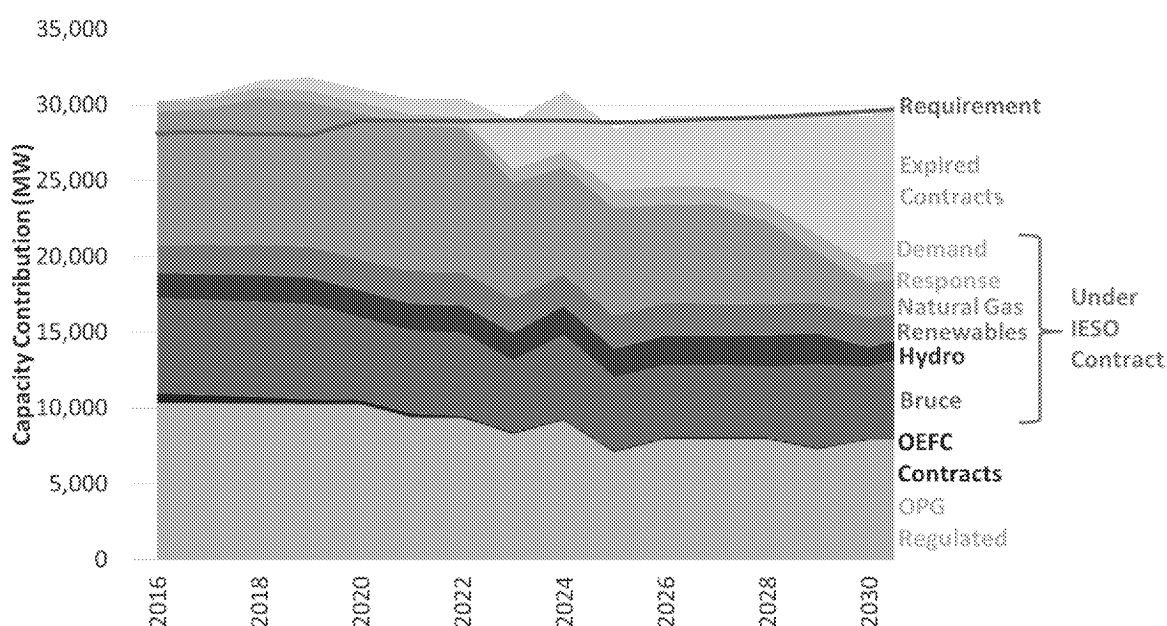
¹²⁴ The "unforced" MW reported in the figure reflects the derated capacity value of intermittent resources, which is substantially lower than the nameplate capacity. More detail on these contracts is available within IESO (2016e).

¹²⁵ From Ontario Electricity Financial Corporation (2016) and data from IESO staff.

¹²⁶ Ontario Power Generation (2016).

the province will face a decline in capacity associated with nuclear refurbishments and some retirements, resulting by 2030 in a modest capacity deficit under most load growth scenarios.¹²⁸ By sometime in the early 2020s, the IESO will no longer have enough contracted capacity to meet its reliability requirement, as load grows and existing contracts expire.¹²⁹ Over the same timeframe many existing contracts will expire, predominantly those with natural gas plants that were under 10- to 20-year contracts that started in 2006–2014.¹³⁰ By 2030, approximately 10,000 MW of supply will be operating on a merchant basis.¹³¹

Figure 18
Outlook for Ontario Supply that is Regulated, Under Contract, or Merchant



Sources and Notes:

Compiled from data provided by IESO staff and from Ontario Planning Outlook data from IESO (2016i).

Expired contract supply includes renewable and thermal plants with expired contracts.

Demand Response (DR) capacity contributions include some capacity procured through the DR auction (not strictly contracted DR).

Reliability requirement is based on an average of Outlooks A, B, C, and D.

Continued from previous page

¹²⁷ These numbers represent the capacity contribution, rather than installed capacity, of these resources. We report supply relative to the reliability requirement across the simple average of the four planning outlooks. See IESO (2016i).

¹²⁸ IESO (2016i) slide 45.

¹²⁹ Reliability requirement is based on an average of Outlooks A, B, C, and D. Capacity based on existing, refurbished nuclear, committed, and directed supply as shown on Slide 41 of IESO (2016i).

¹³⁰ IESO (2016e).

¹³¹ Including both existing resources coming off of contract and new resources developed sufficient to meet the reliability requirement under Outlook C. See IESO (2016i).

2. Primary Contractual Structures and Incentives

The combination of market prices and contractual terms will determine what incentives generating resources have to operate more efficiently under Market Renewal. A purely merchant generator will attempt to operate in ways that maximize the market value of the associated supply resources. For these suppliers, more efficient market prices will induce more efficient behavior. In the opposite and extreme case of contracts that entirely insulate the supplier from market conditions, more efficient market prices will have no impact on the operational behaviors of the generators. Other contracts are structured such that the generating resource is partly, but not fully, exposed to market incentives.

To assess the extent to which contracted generators will have the incentive to improve operational efficiency under Market Renewal, we worked with the IESO staff to understand the primary contractual terms governing all major categories of contracts as summarized in Table 6.¹³² Each contract has a number of unique provisions and clauses, but most resources are governed by one of four primary incentive structures:

- **Merchant** (Non-Contracted Resources): Resources that are not under contract have an incentive to maximize their value in the energy and ancillary services markets. More efficient prices under Market Renewal will incentivize more efficient operations.
- **Capacity-Only** (Lennox, Demand Response): These resources earn a capacity payment sufficient to recover fixed costs and ensure the resource is available during emergency events, but do not earn any contract payments for energy produced. However, these resources can earn (and keep) revenues gained from participating in the energy and ancillary services markets through adjusting generation supply (or in the case of demand response, by adjusting consumption levels) based on energy and ancillary market prices. Like merchant plants, these capacity-only resources have the incentive to maximize energy and ancillary service market value and improve operational efficiency under Market Renewal.
- **Deeming** (Gas Plants): Gas plants are remunerated under the terms of “deeming” contracts designed to pass energy and ancillary service market incentives through to the generator. These hedging arrangements have three primary components as summarized in Equation 1: (a) a contracted *capacity payment* reflecting the total revenue requirement needed to cover investment and fixed cost; minus (b) the *deemed net revenue* calculated based on contractual terms and realized market prices (but that does not depend on how the plant operates); and (c) plus *actual net revenues* earned from wholesale energy and ancillary service markets. If actual and deemed net revenue are identical, then total *net revenue* is identical to the *capacity payment* and the generator has a perfect hedge.

¹³² See also the discussion of contractual arrangements developed by the MSP. Ontario Energy Board (2007b) chapters 3 and 4.

The structure passes energy and ancillary market incentives through to the generator because **actual net revenues** may be higher or lower than **deemed net revenues**. **Deemed net revenue** does not depend on how the generator operates, and so does not introduce marginal operating incentives. **Actual net revenues** from the market do depend on how the plant operates, with the plant becoming most profitable if it maximizes its value relative to market prices, just like a merchant supplier.¹³³

$$\text{Equation 1} \quad \text{Net Revenue} = \underbrace{\text{Capacity Payment} - \text{Deemed Net Revenue}}_{\text{Contractual Payments}} + \underbrace{\text{Actual Net Revenue}}_{\text{Market Revenues}}$$

Where:

Net Revenue is annual revenue net of operating costs from contract and market operations.

Capacity Payment is a fixed annual payment established under the contract.

Deemed Net Revenue is a formulaic estimate of the net revenue the generator might have earned from the market based on the plant parameters and operating characteristics assumed in the contract. This deduction does not depend on how the plant operates.

Actual Net Revenue is revenue minus operating costs as earned from selling into energy and ancillary service markets similar to a merchant generator. The magnitude of this revenue will be increased if the resource improves operational efficiency.

- **Fixed Energy Price** (Renewables, Hydroelectric, Bruce, OPG Regulated): The remaining contracted resources including renewables, hydroelectric, and nuclear plants are remunerated through a fixed \$/MWh price for as many MWh of production as the plant can produce. The contract-for-difference structure awards an incremental payment in low-price hours (or subtracts a deduction in high-price hours), such that the total energy market plus contract payment always equals the fixed contractual price.¹³⁴ In high-price hours, the generator must return a portion of energy market revenue to the IESO. The rate-regulated nuclear and hydroelectric assets owned by OPG are awarded cost recovery under a similar financial structure.¹³⁵ These resources operating under fixed energy price contracts or regulation always have an incentive to output generation as long as their variable costs are below the fixed price. Thus, their operational behavior is largely independent from market price signals, and is not likely to become more efficient under Market Renewal until the associated contracts or regulated rates expire or are amended.

¹³³ There are qualifications to our general finding that the deeming contracts incentivize merchant-like behavior. As one example, most gas contracts have a “revenue sharing” clause allowing the seller to keep only a portion of the revenues from new products (such as new ancillary service products). Revenue sharing will reduce the incentives for those products to fall below the market price.

¹³⁴ Some exceptions and nuances to this payment formula exist. For example, some hydroelectric resources have a modest incentive to produce energy during on-peak hours. As a bigger exception, most resources have special provisions governing hours with negative prices, such that IESO can implement involuntary curtailments or incentivize economic curtailments as market prices become more negative.

¹³⁵ Ontario Energy Board (2014d).

The size of the efficiency benefits Ontario will be able to realize under Market Renewal will be proportional to the degree to which resources are incentivized to operate more efficiently. Table 6 reports our assessment of which resource and contract categories will pass the more efficient market incentives through to suppliers under Market Renewal. We note that intermediate and peaking resources that are most able to change operational behavior (including gas plants, and demand response) are largely exposed to market incentives, indicating that Market Renewal is likely to achieve significant efficiency gains associated with these resources. Baseload nuclear and intermittent renewables are largely insulated from market incentives and so will not likely contribute to efficiency gains absent contract amendments, but the efficiency gains would likely be smaller in any case given the baseload and less-controllable nature of these operations.

Table 6
Primary Contractual and Regulatory Structures

Category		Number of Contracts	Volume of Contracts	Contract or Regulatory Structure	Exposed to Energy & Ancillary Market Incentives?
Merchant	• Existing non-contracted	n/a	n/a	Market Prices	Yes
	• New resources and uprates				
IESO/OPA	Demand Response		634 MW	Capacity Payment	Yes
	Gas	47	8,800 MW	Deeming Contracts (Most Plants) or Capacity Payment (Lennox)	Mostly Yes
	• Lennox				
	• CES				
	• CHP				
IESO/OPA	Renewables	27,479	1,870 MW	Fixed Price Contract	Mostly No
	• FIT				
	• RES				
	• RESOP				
IESO/OPA	Hydro	119	1,660 MW	Fixed Price Contract	Mostly No
	• HCI				
	• HESA				
IESO/OPA	Bruce	1	6,280 MW	Fixed Price Contract	Mostly No
OEFC		5	360 MW	Fixed Price Contract	Mostly No
OPG Rate Regulated	Hydro		10,300 MW	Rate Regulated	Mostly No
	Nuclear				Mostly No

Sources and Notes:

Capacity values reported in UCAP terms. Compiled from data provided by IESO staff and IESO (2016i).

Number and quantity of contracts as of 2016, compiled from IESO (2016e) p. 19.

CES = Clean Energy Supply, CHP = Combined Heat and Power, NUG = Non-Utility Generator, FIT = Feed-in Tariff, RES = Renewable Energy Supply, RESOP = Renewable Energy Supply Offer Program, HCI = Hydroelectric Contract Initiatives, and HESA = Hydroelectric Energy Supply Agreements.

We highlight hydro resources as a key concern given that there could be substantial potential to operate these resources more efficiently for providing energy and operability services, but some of these operational efficiency gains may not be realized to the extent that fixed price arrangements partly insulate the asset owners from market incentives.¹³⁶

B. ADJUSTMENTS TO EFFICIENCY BENEFITS TO ACCOUNT FOR CONTRACTS

In estimating the total potential efficiency benefits to Ontario from energy and operability reforms in prior sections, we have not yet taken into account the implications of existing contracts. For intertie-related operability benefits, we do not expect contracts to affect realized benefits. Intertie schedules are determined by market participants in response to the incentives available through Ontario's and its neighbors' markets (not through contracts). In estimating capacity-related benefits, we have accounted for the impacts of existing contracts when updating the IESO's capacity benefits study. The capacity benefits estimate already accounts for the fact that the market incentives will only apply to the proportion of Ontario's capacity needs that are procured through the market.

In evaluating what proportion of the total potential energy and internal operability benefits are likely to be realized, we consider two factors: (1) which resources would be most likely to enhance the efficiency of operations in the absence of contracts, as assumed in our total potential benefits estimates; and (2) what fraction of these resources are exposed to market incentives. These energy and operability benefits comprise approximately one-third of the total estimated potential efficiency benefits from Market Renewal.

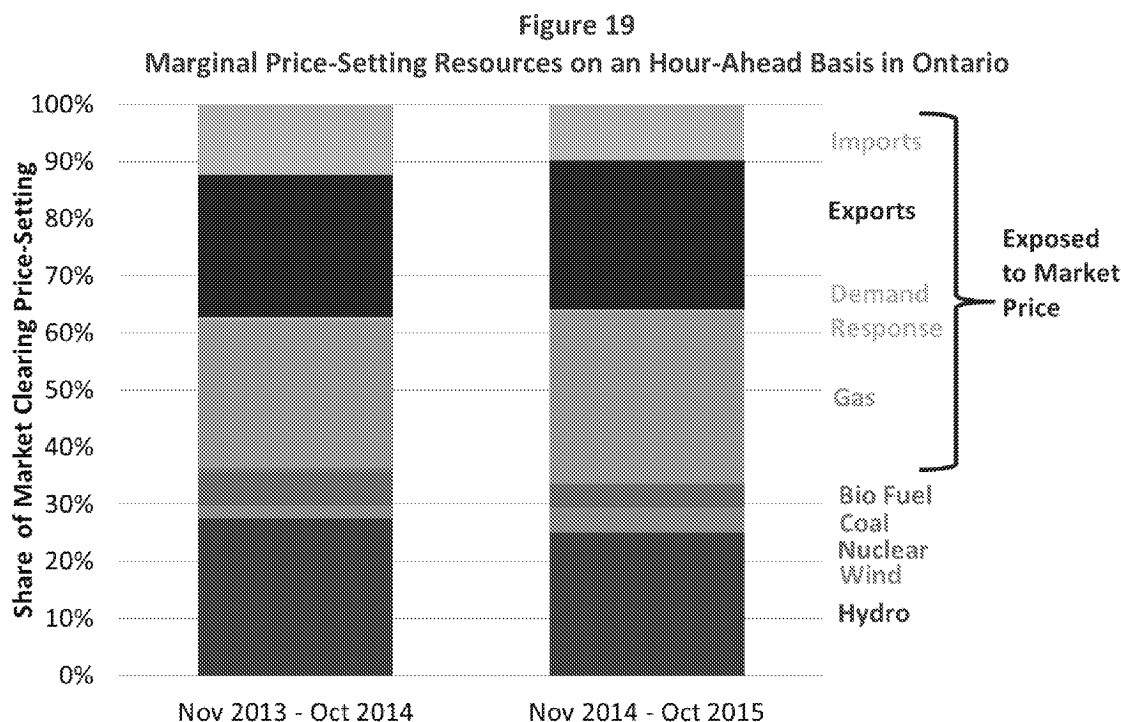
In terms of enhancing efficiency of operations, we expect that most operational improvements would likely come from intermediate and peaking resources whose output profiles are shaped by daily, seasonal, hourly, and sub-hourly changes in market conditions and prices. The marginal price-setting resources in each hour are the most likely to change behavior, since a small change in price would incentivize them to increase or decrease production. As shown in Figure 19, gas plants, hydro plants, and interties are most commonly price-setting resources on an hour-ahead, and so would be the most likely to enhance efficiency (absent contracts).¹³⁷ Wind and nuclear

¹³⁶ Our characterization of hydro resource incentives is simplified. Some resources do have contractual or regulatory rate terms that pass a portion of market incentives through to the asset owners, for example through on-peak incentive payments or the ability to retain a portion of market revenues.

¹³⁷ When evaluating alternative options for how to determine the fraction of benefits to assume are being collected, we considered a series of alternative options but determined that each of these alternatives would introduce limitations compared to our chosen approach. These alternative scaling options include: (a) *fraction of system capacity exposed to market prices*—would not adequately capture the significant differences in operating hours among resource types; (b) *fraction of energy generated by resources exposed to market prices*—would not adequately account for the relatively greater importance of exposing marginal or near-marginal cost resources to market prices as compared to highly infra-marginal resources that should output their maximum capability nearly all the time

Continued on next page

plants have become the price-setting resources in a larger but still relatively small number of hours. This is consistent with our expectation that these resources have limited ability to make substantial changes to generation profiles regardless of how market prices change under Market Renewal (with or without contracts).



Sources and Notes:

Hour-ahead marginal resources, adapted from Ontario Energy Board (2016b), Figure 1-7.

Of these price-setting resources, only a portion is exposed to market incentives. Based on these data and our analysis of the existing contracts from VI.A.2, we find that resources exposed to market incentives were marginal in 66% of all hours over 2013–2015. Considering the timeframe of load growth and expirations for each type of contract, we expect that resources exposed to market incentives will be on the margin in 66% of all hours by 2021 and in 72% of all hours by 2030. To estimate these numbers we assume that the fuel types of the marginal resources will remain constant over time, but the proportion of each resource type that remains under contract will decline as contracts roll off and new merchant supply is added.¹³⁸ Based on this analysis, we assume that only 66–72% of the potential benefits from energy and internal

Continued from previous page

regardless of market price; and (c) *fraction of real-time (as opposed to hour-ahead) resources exposed to market price*—would not incorporate imports or exports into the measure since those resources currently can only set prices on an hour-ahead basis, while Market Renewal has the potential to significantly enhance the efficiency and granularity of intertie schedules.

¹³⁸ These estimates are consistent with Outlook C from the Ontario Planning Outlook, and assume contracts roll off consistent with the timeframes as summarized in Section VI.A.1.

operability enhancements estimated in Sections III and IV will be achieved under Market Renewal, absent amendments to existing contracts and regulated rate structures. Figure 20 illustrates how we adjust efficiency benefits to account for contracts for the base estimate in the year 2021.

Figure 20
Adjusted Energy and Operability Benefits (Example for Year 2021)

Base Energy Benefits		Base Internal Operability Benefits	
\$84 million / year		\$49 million / year	
• Base estimate for energy-market related benefits from Market Renewal • Reflects total potential benefits if there were no contracts		• Base estimate for internal operability related benefits from Market Renewal	
66%		66%	
• Proportion of the time that resources exposed to market price are marginal • Proportion increases from 65% as of 2014/15, to 72% by 2030 as contracts roll off		• Proportion of the time that resources exposed to market price are marginal	
\$56 million / year		\$32 million / year	
• Base estimate of projected efficiency benefits in Ontario system, <i>after</i> accounting for a discount associated with contracts		• Base estimate of projected efficiency benefits in Ontario system, <i>after</i> accounting for discount	
Range of \$22–116 million / year		Range of \$19–59 million / year	

Notes:

Ranges reflect the same contract adjustment, as applied to the high and low total potential benefit numbers. Capacity and intertie operability benefits are not affected by contracts.

66% illustrates the proportion of the time that resources exposed to market price are marginal in 2021. As the contracts expire resources previously unresponsive to prices will become price responsive.

VII. Implementation Costs and Project Management

Market Renewal, as proposed, is a wide-reaching effort that will require the IESO to enhance the processes and software systems for every one of its wholesale markets. This will incur significant costs over a multi-year period both for the IESO itself and for market participants. We have partnered with Utilicast to assess the magnitude and uncertainty range of these implementation costs, and to assess the associated implementation risks. We describe here the primary assumptions and approach used to develop our estimates, findings from our review of experience in other markets, a qualitative assessment of stakeholders' business costs, and recommendations based on experiences from other ISOs. These cost estimates should be interpreted as early-stage and indicative estimates. For example, the cost estimates are not reflective of actual vendor quotes for software enhancements, which are not possible to develop until the scope of design requirements is better defined.

A. EVALUATION OF IMPLEMENTATION COSTS

We estimate the costs of implementing Market Renewal based on a combination of Utilicast's direct experience with other implementation efforts, public data from other jurisdictions, and the IESO's estimates of its own personnel needs and cost parameters. This estimate encompasses the total costs to the IESO of developing and installing the new technology systems and other business costs incurred during implementation. The technology costs include development of the core systems including the combined hardware and external resourcing costs of licensing, customization, and implementation. Other business costs will be associated with designing the market and supporting the new systems' implementation, such as outside experts assisting in the market design and temporary IESO staff supporting the development and management of the new IT systems.

Given the early stage of planning and scoping for Market Renewal, this costs estimate should be interpreted as a preliminary indication, but one that is reasonable given present uncertainties. The IESO will be able to update these estimates with more accurate information as the scope, timeframe, and vendor costs associated with Market Renewal are more fully established.

1. Project Schedule

For each of the capacity, operability, and energy workstreams we estimate costs according to three phases: (1) design, (2) building and testing, and (3) operations and production support. We assume that the design phase for the each of the workstreams will start in 2017 and will run in parallel. The energy market will begin building new systems in 2018 and enter operation in 2021. Operability enhancements will begin building and testing in 2019, with the systems beginning operations in mid-2021.¹³⁹ Despite requiring upgrades to many of the same systems, we assume that the energy and operability reforms begin operations at different times consistent with an assumption that some reforms will be rolled out through a second-stage release. The second-stage release would include any refinements required based on initial experience with the new systems. The capacity auction is the least resource-intensive workstream, with exports beginning in 2017 and the incremental capacity auction implemented with an initial delivery year starting 2020.

The assumed timeline and project schedule that we adopted for our cost estimate is rudimentary and will need to be adjusted and made more detailed by the IESO. However, it reflects our understanding of the level of resourcing needs and context based on our interviews with IESO staff. We recommend considering the following issues when staging implementation:

- **Capacity Auction:** The capacity auction workstream is largely independent of the other two workstreams; it has large expected benefits with modest implementation costs. Even

¹³⁹ The upper-end estimate has a longer implementation timeline for energy market and operability enhancements; they come online in second quarter of 2022 and third quarter of 2023, respectively.

though the implications for IT systems are relatively modest, the capacity auction reflects a much more significant and fundamental effort for stakeholders, the IESO organization, and policymakers. Implementing the capacity auction in advance of the energy and operability changes by as much as possible will help to mitigate the scope and magnitude of change that stakeholders are required to absorb simultaneously.

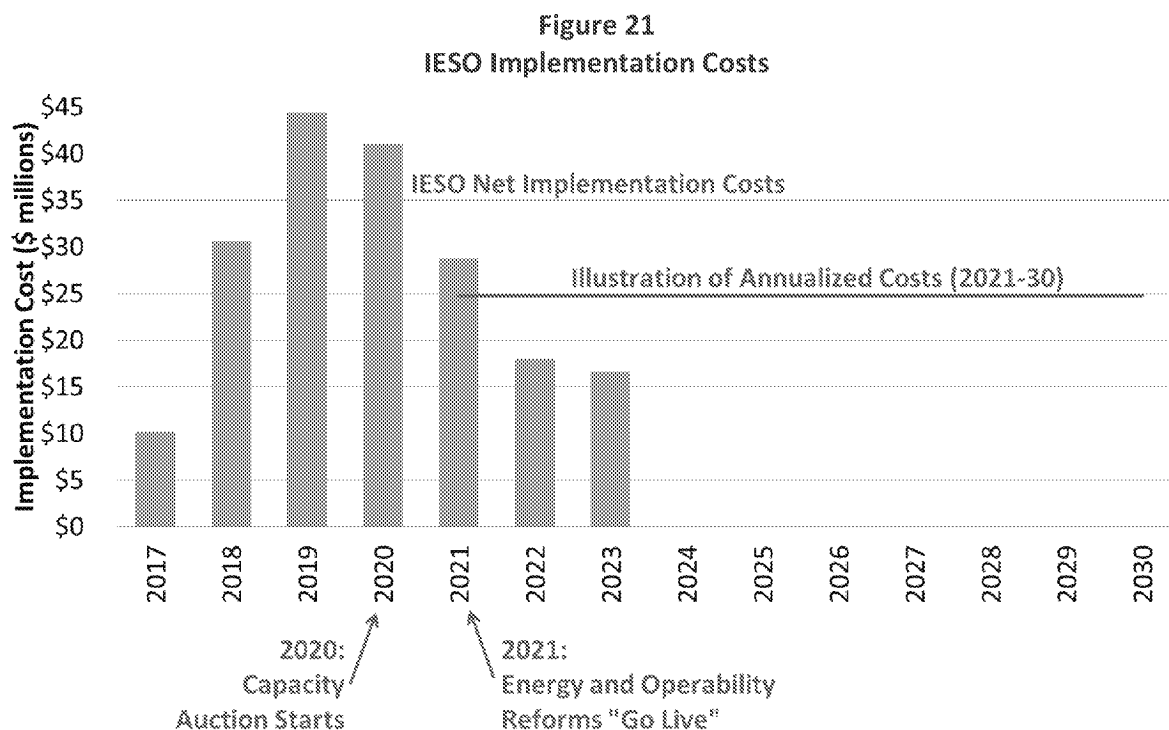
- **Energy and Operability:** Reforms to the day-ahead, real-time, and ancillary service markets are tightly interlinked in implementation because they require interacting upgrades to the same IT systems. We recommend that the primary design upgrades to these markets should be designed at the same time (although potentially released separately but in a pre-planned fashion) to manage implementation costs and timeline. Most of the core design changes being considered have been adequately tested through implementation in other markets and have stable vendor solutions that can be rolled out without facing the same risks that can be introduced by untested solutions. After initial implementation, a subset of the energy and operability reforms can be implemented as enhancements particularly any that require significant vendor customization.
- **Internal Financial Transmission Rights:** Internal financial transmission rights are a final market that can be examined as having an independent implementation timeline, because of the separate and distinct software systems, vendors, and market design decisions involved. The IESO and stakeholders have not yet determined whether an internal transmission rights market will be incorporated into Market Renewal. If the IESO and stakeholders do decide to incorporate internal transmission rights into the market design, we advise that there is some flexibility to adopt this market in a later phase of implementation (although some approach will need to be implemented immediately along with the nodal energy market for allocating congestion rent to customers).

2. Preliminary Estimate of IESO Business Costs

We estimate implementation costs of \$190 million under baseline assumptions including 20% contingency.¹⁴⁰ As shown in Figure 21, over 80% of the costs will occur during the startup phase during which the technology systems will be designed, implemented, and tested. The remainder of costs after the startup will be incurred as the legacy systems continue to operate for an additional 2-3 years in order to ensure a smooth transition. The 20% contingency factor represents the expected value of realistic scope and timeline changes that could be encountered. The figure also shows an indicative cost recovery schedule in red, which assumes that implementation costs would be recovered from customers over ten years starting at the same time that the energy market is implemented and most customer benefits would begin to be realized.

¹⁴⁰ These are a simple sum of the net implementation costs reported in nominal dollars. The present value of the cost in 2021 using a 5% discount rate is \$200 million.

There is substantial uncertainty in this estimate given the early indicative stage of the initiative, with a bigger uncertainty on the high end than on the low end. We therefore provide an upper-end estimate of \$300 million.¹⁴¹ This upper-end estimate incorporates higher-end assumptions regarding technology costs and project schedule.



Notes:

The baseline estimate is based on the best current information on expected costs and parameters. We use a 5% discount rate to annualize the costs.

B. EXPERIENCE FROM OTHER MARKETS

We interviewed staff at other ISOs and reviewed public documentation to identify lessons learned, implementation risks, and successful strategies that the IESO might adopt in Market Renewal. Each of these markets faced different challenges and drew different lessons from their experience. We first provide a discussion of the experiences in ERCOT and SPP, which are the markets we believe offer the IESO the most relevant and actionable information based on the detailed documentation on the challenges they faced during implementation. We then report the primary pieces of advice from staff at other ISOs offered to the IESO while pursuing Market Renewal.

¹⁴¹ These are a simple sum of the net implementation costs reported in nominal dollars. The present value of the cost in 2021 using a 5% discount rate is \$310 million.

1. ERCOT and SPP Experiences

In September 2003, the Public Utility Commission of Texas (PUCT) ordered ERCOT to develop a new set of rules for a nodal wholesale market in order to address deficiencies in the zonal market. After an extensive stakeholder process, the Commission approved the protocols in April 2006, with operation scheduled to begin in January 1, 2009. However, the implementation faced a number of significant problems. The project was originally budgeted at a cost of USD \$263 million but nearly doubled to USD \$509 million by its conclusion. Further, it was not completed until December 1, 2010, nearly two years after its originally-targeted completion date.¹⁴² These costs are higher than those that we project for Ontario's Market Renewal partly because of the larger scope of enhancements needed in ERCOT and partly because of challenges encountered during implementation.¹⁴³

Due to the substantial delays in implementation and cost overruns, the PUCT commissioned a report by Navigant Consulting to diagnose the problems.¹⁴⁴ Navigant identified several contributing challenges, including: (a) underestimating the complexity of system integration and project management; (b) creating their own nodal protocols instead of “forklifting” rules from another market; (c) using a “best in breed” approach to selecting vendors rather than relying on one vendor to deliver all of the major software systems; and (d) difficulty in standardizing modeling data across multiple vendors.¹⁴⁵ Despite the challenges and higher-than-anticipated costs, the reformed ERCOT market design is an advanced system that has delivered significant net benefits to the region (See Section III.C.4 above).

Prior to and during the implementation of their day-ahead market, SPP made a concerted effort to adopt lessons learned from other market operators including ERCOT, PJM, and MISO. They made several choices that helped the success of their implementation, including: (a) forklifting market design and protocols; (b) selecting an external system integrator rather than relying exclusively on their own staff; and (c) implementing strong project management practices to effectively manage stakeholder relations, timeline, workstream dependencies, and IT system integration.

SPP also made the choice to defer the implementation dates of some key design enhancements to a later stage due to the level of customization required. For example, because of the large number of gas combined cycle plants in its footprint, SPP and its stakeholders identified

¹⁴² Lester, *et al.* (2012), pp. 11–15.

¹⁴³ In terms of the scope of changes, IESO's network model, market management system, and energy management system currently have more of the capabilities needed to support nodal markets compared to ERCOT's original systems. The ERCOT system upgrades also included additional scope related to load metering data.

¹⁴⁴ See Lester, *et al.* (2012).

¹⁴⁵ Lester, *et al.* (2012), p. 17. In this context “forklifting” means using market protocols and software systems designed for other markets, and applying limited customization to that core design.

advanced gas combined cycle modeling as an important design requirement. However, this was not a previously-tested solution available off-the-shelf from their chosen vendor. SPP therefore decided to gather the necessary data from market participants when updating the network model, creating the optionality to implement this design at a later stage. SPP first went live with the core market software systems and then implemented an updated design six months later that included the advanced combined cycle modeling capability. SPP's focus on lessons learned from other RTOs' experience, incorporating strong project management practices, and bringing stakeholders along every step of the way, were critical to their successful transition to an enhanced market design.

2. Advice from Other RTOs

As part of our interviews with staff from other ISOs, we asked whether they had any advice for the IESO and its stakeholders in implementing Market Renewal. The responses of ISO staff from each marketplace reflect their unique historical experiences, and each provides a useful vantage point on the potential challenges:

- **ERCOT:** From the very beginning, focus on data and engage in close collaboration across the organization. By proactively identifying the exact data requirements, units of measure, and exchange requirements among IT systems and with stakeholders, many later-stage risks to implementation costs and timeline can be avoided. Have an effective project manager with a realistic schedule who ensures everyone understands the functional requirements of the system. Avoid “scope creep” both internally and from stakeholders, for example by making sure there is a formally-understood process for making decisions in a timely manner. Establish vendor agreements or internal personnel for maintenance after the new systems are operational.
- **CAISO:** “Do it right the first time” to avoid spending the same money twice. For example, CAISO increased costs and delayed benefits by taking interim steps with hourly and then 15-minute intertie schedules, rather than immediately adopting the more efficient five-minute intertie scheduling process that has been implemented more recently. In hindsight, it would have been more beneficial to implement five-minute intertie scheduling right away. As another example, CAISO implemented the Market Redesign and Technology Upgrade with real-time dispatch on a five-minute basis and unit commitment processes on staggered 15-minute schedules; now CAISO is facing a patch or re-build of those systems to make them consistent.
- **SPP:** Focus on people, process, and technology both in the RTO and stakeholder organizations every step of the way. The *people* need to have the training and readiness to understand design decisions, manage risks, and maximize business value; the *process* needs to effectively coordinate stakeholder relations and significant investments to change the RTO's internal business practices; the *technology* needs to meet well-defined design rules, technical specifications, performance requirements, and integration standards. Be selective with unproven or time-consuming features. Instead, work with vendors to build infrastructure that makes it easy to add on enhancements in the future.

Finalize market designs as early as possible to prevent the systems from needing to adapt during their development. Operations and maintenance of the systems is as important as implementation; establishing effective processes to operate the systems once they are in use should be done at the same time as the design. Ensure stakeholders are developing their own systems and monitor their implementation closely.

- **PJM Interconnection:** Work closely with stakeholders to ensure they understand the new market rules. This includes making it easy for them to understand the changes, provide input, and test their systems. Be transparent about real-time system conditions, and what is driving real-time market results; this allows participants to understand results and gain confidence in results and settlement. Build in flexibility up front to add on new features in the future.
- **NYISO:** Make all of the design changes at once. After one market design is in place it becomes hard to change later on, partly because stakeholders will have developed their own business decisions and approaches based on the initial design. Entrenched interests and processes can create a significant barrier to future advancements, even those that create significant net benefits.
- **ISO-NE:** Use the best available already-built solutions from the chosen vendors, even if those cutting-edge solutions do not seem the most urgent needs at the time. Save any customized enhancements until the core systems are fully functional. Manage energy-limited resources and demand response effectively, and make sure every resource type is dispatchable and able to set prices.

Many of the same recommendations were repeated by several ISOs, particularly the recommendations to engage stakeholders throughout the process and build systems that can readily add on new functionality in the future. However, some of the ISOs offered conflicting advice on whether to implement all the desired enhancements at once or to only implement the proven systems with minimal customization. We view both sets of advice as valuable, and discuss our recommendations for how the IESO and stakeholders could balance the competing considerations in Section VII.D below.

C. STAKEHOLDER BUSINESS COSTS

Stakeholder readiness will be vital to the successful launch of Market Renewal. Just as the IESO must enhance its business and technology, stakeholders need to assess the scope and properly time their enhancements for a smooth transition. This may require the IESO to solicit input from stakeholders in crafting market manuals, make available reference material and training guides, or provide opportunities to cooperate during market trials testing. The major categories of stakeholder implementation costs include investment in information technology systems and expansion of staff (both temporary augmentation with outside services and potentially permanent positions to fulfill new business functions). We qualitatively assess these expected implementation costs for three different types of entities: generation owners, wholesale market customers, and financial participants.

Other studies often do not estimate stakeholder costs because the cost implications are so varied among individual companies. Even for similar types of entities, stakeholders' costs will vary based on the flexibility of their existing systems and the business choices they make to adjust to the new market design. However, as one reference point, a 2008 study of ERCOT's transition from a zonal to its proposed nodal market estimated stakeholder implementation costs based on interviews with the 20 largest market participants. The study found that costs ranged widely for different market participants, with generators without previous experience in nodal markets bearing the greatest costs. It estimated market participant costs of approximately USD \$175 million in aggregate.¹⁴⁶ These costs were for a market reform that was more substantial than what Market Renewal is proposing and applied to a system that is more than twice the size of Ontario, and so likely reflect significantly higher costs than IESO market participants should expect.

Our qualitative assessment of stakeholder costs considers the scope of technology and process changes that the IESO will undertake with Market Renewal, which types of market participants will be affected by these changes, and the consequential impact on market participants' mirroring processes. We primarily focus on the gross implementation cost impacts on stakeholders, but in some cases consider the avoided costs that may be achieved through more efficient, streamlined interactions with the IESO or avoided costs from initiating, renegotiating, and managing contracts. Similarly, the net cost implications may be less significant if these costs are simply redirected from personnel training or technology upgrades that would need to be pursued regardless. With these qualifications in mind we see the primary cost drivers for stakeholders as follows:

- **Incumbent Supply Companies:** One of the most significant business costs for generation owners will be enhancements associated with sales of energy and ancillary services. The systems and personnel responsible for submitting offers, receiving offer awards, and following IESO dispatch instructions will require upgrades under Market Renewal. The cost of upgrading these systems will depend on how much experience the market participant has with other nodal markets. A study of ERCOT's transition to a nodal market estimated that market participants without experience in other nodal markets could incur implementation costs of up to \$2,800/MW, while suppliers with experience in other nodal markets incurred approximately \$225/MW in implementation costs.¹⁴⁷

There will be additional costs associated with capacity auction participation. Minimum technology and process requirements for capacity auction participation may be relatively moderate and largely supported by adapting existing business and technology processes

¹⁴⁶ These numbers are as reported in the study (2008 USD\$). Their estimate focused predominantly on generators, cooperatives, and municipalities and was for a system much larger than IESO. See CRA International and Resero Consulting (2008) pp. 49–52.

¹⁴⁷ These numbers are as reported in the study (2008 USD\$). See CRA International and Resero Consulting (2008) Table 20.

that support seeking and managing contracts. Regardless of whether an internal financial transmission rights market is implemented, incumbent suppliers will not need to incur any associated costs. Suppliers would only participate in the new market if they expected a positive net business value.

Another optional, but potentially significant, stakeholder cost could be associated with pursuing new business opportunities created by Market Renewal. These opportunities may require a different or enhanced capability to examine economic fundamentals, maximize business value, and manage market risks. Some incumbents may choose to expand expertise or change approaches for managing assets, implementing hedging strategies, and making informed entry and exit decisions. Depending on the individual company's situation, these expanded functions may be possible to support through existing capabilities, vendor relationships, staff reassignments, or new positions.

The IESO is aware of the impact of Market Renewal on existing contracts and has communicated that it will work together with contract counterparties on amendments where needed. This process may result in incremental costs for contracted suppliers.

- **New Entrants to the Ontario Market:** New entrants to the Ontario market will have no incremental costs under Market Renewal compared to being a new entrant without Market Renewal. However, new entrants will likely find Ontario to be more accessible and open to competition with fewer barriers to entry, given the focus on enabling all resource and supply types under Market Renewal.
- **Wholesale Market Customers:** Wholesale market customers will need to update their settlements systems consistent with Market Renewal, specifically to account for the day-ahead market and capacity auction line items. Wholesale market customers that participate in energy markets in adjacent regions have both the benefit of market experience as well as likely lower IT system costs by leveraging existing commercially-purchased or in-house settlement systems.

The size of implementation costs from interacting with the energy market will depend on certain design requirements. For example, if the day-ahead market requires customers to submit bids (whether virtual or physical) rather than relying on an IESO load forecast, then wholesale customers will incur costs that enable them to participate day ahead.¹⁴⁸ Costs associated with the real-time market and capacity auction reforms are likely to be modest because those markets typically do not require significant customer-side participation (although we recommend enabling voluntary customer participation as much as possible). If an internal financial transmission rights market similar to those in the U.S. is included as part of Market Renewal, customer representatives would need to be actively engaged in evaluating desired transmission paths, determining their hedging

¹⁴⁸ Wholesale market customers already submitting bids into the real-time market may need to enhance their approach to support day-ahead participation. Customers that do not directly participate through market bids may not face any incremental costs.

needs, and taking positions in the associated internal financial transmission rights auctions. If an alternative, more formulaic approach to allocating congestion rents to customers were adopted, then customers would incur minimal associated business costs.

Market Renewal may provide more opportunities for customers to actively buy and sell wholesale energy, ancillary, and capacity products. This participation could incur some incremental costs and require expanded staff or vendor capabilities, but we assume that customers will engage in these activities only if they project net positive business value compared to their traditional approach.

- **Financial Participants:** Many financial trading houses engage in transactions in Ontario and other electricity markets and have sufficient continuous investment in training, software systems, and personnel to adapt quickly to market changes. These entities can participate on an optional basis and have no role in maintaining system reliability, so trading firms pose the least concern in terms of stakeholder readiness. New and existing financial participants may voluntarily incur costs in order to begin trading any new financial products that may be introduced, such as virtual trades and internal transmission rights.¹⁴⁹ The costs may be modest if the reforms result in a market design similar to those in other markets, or if processes around intertie transactions are simplified in ways that reduce transactions costs. Given the voluntary nature of any incurred costs, we expect financial participants will only incur costs from which they expect to earn a positive business value.

D. MANAGING IMPLEMENTATION RISKS

Based on the large size of potential benefits that substantially exceed implementation costs, we recommend approaching the implementation effort as an exercise in maximizing the net benefits to the province rather than minimizing implementation costs. Maximizing benefits may often require incurring greater implementation costs (for example, through software customization) in order to implement a superior market design. Implementation can then be pursued at the most beneficial funding level, while minimizing and mitigating implementation risks. We offer a number of recommendations for how to balance the scope of the initial design in light of potential benefits, costs, and risks in the short and long term based on the advice and experience from other markets.

¹⁴⁹ Internal financial transmission rights (also referred to as congestion revenue rights (CRRs) or FTRs) are derivatives used in locational energy markets to hedge price differentials between different locations. In many markets, internal transmission rights serve a second purpose as an indirect mechanism for returning congestion rents back to customers. See PJM (2016a) for a detailed overview of their FTR market. Virtual trades are a derivative used to hedge price differentials between the day-ahead and real-time energy markets. See RTO Insider (2014).

1. Identified Risks

The complexity and scale of Market Renewal should not be underestimated. Based on our review of experience in other markets and discussions with system operators, we have identified several implementation risk factors of which the IESO should be aware and attempt to mitigate to the extent possible:

- **Information Technology System Integration:** The complexity of integrating the systems needed for Market Renewal should be understood as a significant challenge with some associated risk. Interactions among the core technology systems underpinning the network model, market management system, and energy management systems pose the greatest integration challenges and risks. The task becomes greater if the integration crosses software platforms provided by multiple vendors. Partly mitigating these risks, the IESO has already undertaken several enhancements to its data management and exchange systems to make the software systems less inter-dependent and more modular.
- **Addressing Contracts:** The IESO holds numerous long-term contracts that will be affected by Market Renewal. Stakeholders and IESO staff across contracting and market design departments will need to proactively evaluate the interactions with Market Renewal to ensure that issues can be addressed in a timely fashion and without delaying the project.
- **Mid-Implementation Scope Changes:** Based on our assessment of other markets, we find that budget over-runs and timeline delays can be introduced by late-stage reworks of the market design and protocols. These late-stage changes can significantly increase implementation costs, interrupt implementation progress on the critical path, affect dependent workstreams, and leave internal and external resources idle for periods while continuing to incur costs. Risks of such late-stage scoping changes can be mitigated through: (a) fully engaging operations, information technology, vendors, and stakeholders sufficiently in the market design and technical specification stages to identify potential problems early on; and (b) creating clear decision-making authority and processes for quickly resolving issues once identified.
- **Stakeholder Readiness and Buy-in:** It is crucial that stakeholders be deeply involved in the development of protocols and market design, including ensuring that market participants have sufficient information, access, and assistance for upgrading their internal systems. Stakeholders and the IESO will need opportunities to ensure that newly-developed systems are thoroughly tested and verified prior to becoming operational. This includes defining and gathering necessary data from market participants as early as possible, providing adequate technical specifications for software systems, and a graduated plan for staging market trials and cutover.

Adopting best practices for managing a major systems overhaul can help to proactively identify, monitor, and mitigate these risks, and the potential implications for project schedule and budget.

2. Scoping Initial Design and Deferred Enhancements

The IESO and stakeholders will need to make decisions about the scope of the market design changes and which elements should be added immediately versus elements that should be included in a later market reform. This will be an issue for all three workstream reforms, but is the biggest challenge in energy and operability. The scope of initial reforms will need to balance the advice from CAISO and NYISO to “do it right the first time” against the caution from ERCOT and SPP that a bigger and more customized scope of reforms will introduce greater risks and costs.

We recommend prioritizing these design elements by balancing the tradeoffs between having the perfect market design on one hand, and having a smooth and fast implementation on the other. We recommend categorizing desired design elements into:

- **Immediately-Implemented Enhancements:** These elements would be those that are either: (a) core design requirements that are considered critical to the immediate and long-term success of the project and good functioning of the market; or (b) desirable design elements that have a pre-existing stable vendor solution.
- **Planned Enhancements:** These are the desirable design elements that would require sufficient customization and/or are relatively less well-tested in other markets. These elements can be incorporated into the planning and execution of Market Renewal, but may have a staged go-live date, similar to the approach that SPP took in its staged implementation of advanced combined cycle modeling.
- **Deferred Enhancements:** These are desirable design elements that are expected to create net benefits, but that could introduce significant delays or risks to the project, and so would not be incorporated as part of Market Renewal. We recommend that the IESO and stakeholders continue to enhance the market design over time, including pursuing these deferred enhancements in the future.

When prioritizing among potential design elements, we recommend that the IESO and stakeholders consider the: (a) level of potential benefits associated with the enhancement; (b) level of customization and integration costs incurred; (c) problems that could be created by excluding or adding design features; (d) barriers and downstream problems that might be introduced by deferring some desirable enhancements; and (e) ability to leverage and even “forklift” other markets’ approaches and existing vendor solutions.

We recommend that decisions be informed by a clear vision of what changes might be desired and needed in the future. This will ensure the system can be built with the option to add additional functions. For example, even if the initial Market Renewal design does not include all of the desired elements for advanced hydro facility modeling and optimization, we recommend that the IESO and its vendors build components of each system (such as the network model) in ways that will enable adding advanced hydro modeling in the future.

3. Stakeholder Relations and Support

Stakeholders will play a central role in the market redesign and implementation processes. Stakeholders need to be involved in every stage of the process, from the initial design stage through the full implementation of the new system. In our interviews, other RTOs' staff stressed the importance of making it easy for stakeholders to learn about the changes and giving them ample opportunity to test their systems against the new systems, and a clear approach for ensuring the settlement results are accurate and delivered in a timely manner. Our interviews highlighted the importance of effective two-way communication that will enable market participants to make the necessary investments in their people, process, and technology alongside the IESO. This active engagement can enable a collaborative and successful process through market trials and implementation.

VIII. Benefit-Cost Analysis of Market Renewal

Based on the analysis discussed in previous sections, we find that quantifiable impacts of Market Renewal's energy, operability, and capacity reforms would yield expected gross efficiency benefits of hundreds of millions of dollars per year. Furthermore, the benefits of Market Renewal would pay back its implementation cost in just over a year. Benefits would continue to increase and accrue in subsequent years. We find that Market Renewal will yield significant quantifiable net benefits to Ontario even under the most conservative assumptions. It is reasonable to expect that Market Renewal will yield significant benefits that have not been quantified in this report.

The allocation of the benefits from Market Renewal is understandably of great interest to stakeholders and market participants. In this section we first summarize the overall net efficiency benefits expected from Market Renewal, and then discuss how different market participants can expect to be impacted. While stakeholder-specific analysis is outside the scope of this report, we attempt to qualitatively describe how benefits and costs may accrue to customers, generators, and other market participants.

A. PRIMARY BENEFITS OF MARKET RENEWAL

We identify the main drivers of benefits from Market Renewal as summarized in Table 7. These include benefits that we have quantified in our analysis, such as cost savings from reduced fuel usage, reduced operation and maintenance expenses, reduced emissions, and savings from improved price signals that lead to reduced investment needs or lower-cost investments over time. The main drivers also include benefits that we have only partially quantified, such as reduced curtailment and spilling of hydro, nuclear, and intermittent renewable resources. Finally, there are several significant benefits of Market Renewal that our analysis has not quantified at all: increased export revenues, reduced import costs, reduced gaming opportunities, reduced unwarranted wealth transfers between market participants, facilitation of more

competition and innovation, and improved alignment with provincial policy goals. Table 7 summarizes each of these benefits categories.

Table 7
Primary Benefits of Market Renewal

Benefit Category	Description
Fuel, Emissions, and O&M Cost Savings	The current market does not fully account for all costs and system constraints in commitment and dispatch. This can result in higher-cost resources being used when lower-cost resources are available. Market Renewal will improve the system's ability to identify and utilize the lowest-cost resources to meet demand, including hydro, storage, demand response, and interties. This will reduce the total fuel, CO ₂ e emissions, and O&M costs associated with operating the system.
Reduced Curtailment/Spilling of Clean Energy	The current market does not fully utilize the existing resources base or incentivize emerging resources to meet system flexibility needs. This causes unnecessary loss of non-emitting generation by spilling hydro and curtailing wind and nuclear generation.
Increased Export Revenues and Reduced Import Costs	A reformed energy market and better optimized interties would lower the barriers to efficient trading of power with neighboring jurisdictions. This would result in increased imports of cheaper generation from neighboring markets, further reducing Ontario-internal generation costs. It would better enable Ontario suppliers to sell power outside the province when it is profitable to do so.
Investment Cost Savings	Transitioning to market-based capacity procurement, combined with improved energy and ancillary market incentives, will enhance competition to meet system needs at lower investment costs. A technology-neutral approach will further increase competition by leveling the playing field for new technologies that traditionally have been left out of the capacity procurement process.
Reduced Gaming Opportunities, Administrative Complexity, and Unwarranted Wealth Transfers	In the current two-schedule system, dispatch instructions do not align with market prices. Suppliers are paid through several different uplift mechanisms to compensate them for operating at market prices below their costs (or for reducing output that would have been profitable). These uplift payments create uneconomic incentives and gaming opportunities, and amplify the administrative burden of market operations for both the IESO and participants. Gaming opportunities in the energy market and lack of competition in capacity procurements both create incentives and opportunities to profit from exploiting the design flaws (typically at the expense of customers), which leads to unwarranted wealth transfer.
Supporting Competition and Innovation	Prices that better reflect market conditions will support competition; allowing for competition between a broad set of existing and new resources and technologies will reduce system costs and encourage innovation.
Alignment with Provincial Policy Goals	Market Renewal will create an improved platform for enabling market evolution to support Ontario's future policy objectives and changing market fundamentals.

Fuel, emissions, and O&M cost savings. The first main driver of benefits is the reduction in fuel, emissions, and variable O&M costs. These savings are achieved by energy and operability enhancements that can more efficiently commit and dispatch resources compared to today's system. This results in replacing the dispatch of some higher-cost resources with lower-cost ones that were available but not used. The enhancements will produce market prices that better

reflect generator costs, and by relying more on lower-cost resources it will also put downward pressure on market prices. Even after paying a higher Global Adjustment cost to compensate generators for lower market revenues, customers benefit from avoiding the fuel costs associated with inefficient commitment and dispatch.

Reduced curtailment and spilling of non-emitting resources. Certain frictions in the current market design, including intertie scheduling, preclude the IESO from fully utilizing all resources with flexibility on the system. Moreover, incentives for flexible resources are insufficient and not market-driven. This results in the unnecessary curtailment and spilling of non-emitting low-marginal-cost resources such as hydro, wind, and nuclear generation. The curtailed output from these resources cannot be utilized to meet energy needs. Compared to an alternative design that absorbs this energy for productive use, the current design increases production costs and carbon emissions, or results in forgone export market revenues. Market Renewal will increase the extent to which Ontario can utilize its non-emitting resources without curtailments by better enabling system flexibility.

Increased export revenues and reduced import costs. Ontario's current market design does not efficiently use the interties with neighboring markets. At times, high-cost generators in Ontario are operating when lower-cost supply would be available for import across an unconstrained intertie. At other times, low-cost Ontario generators are curtailed (and profitable export opportunities foregone) while neighboring regions are depending on higher-cost generation. Market Renewal would help Ontario take advantage of these opportunities to reduce generating costs and increase export revenues by reducing frictions to more efficient scheduling of power on the interties, by reducing the opportunities market participants have to profit from uneconomic use of interties, and by improving the incentives for participants to take advantage of interties in a manner that enhances system efficiency and lowers costs.

Investment cost savings. Investment cost savings are facilitated by the incremental capacity auction, which is expected to attract low-cost resources and allow the IESO to procure those resources in a more competitive and cost-effective manner. Other market enhancements will further help to improve investment incentives. For example, settlement based on nodal prices increases the compensation to resources in areas that are import-constrained. This incentivizes investments in the locations where the new resources can help reduce system constraints. Further, capacity resources may have enhanced opportunities to export capacity (when not needed in Ontario) and generate incremental revenues to offset the investment costs that need to be recovered from Ontario customers.

Reduced gaming opportunities, administrative complexity, and unwarranted wealth transfers. The current energy market depends heavily on uplift payments due to the structure of the two-schedule system. This complex set of payments is needed to address discrepancies between dispatch instructions and market incentives, but does not align incentives of market participants with reducing system-wide costs. As a result, generators and other market participants are incentivized to engage in actions that are profitable but do not increase system efficiency. At times, these actions cause unwarranted wealth transfers between market participants; in other

cases, they simply increase costs.¹⁵⁰ Market Renewal would significantly reduce reliance on uplift payments, better align incentives with system efficiency, and reduce opportunities for participants to profit while increasing system-wide costs.

The Market Renewal's energy and operability enhancements will significantly reduce or eliminate transfer payments associated with market prices in excess of marginal value and uplift payments that do not reflect actual costs. Market participants benefitting from these above-market payments will realize lower profits. Contracted resources will be kept whole through the Global Adjustment until their contracts expire; merchant generators and intertie traders currently profiting from uneconomic, above-market payments will be worse off under Market Renewal. Market participants will no longer be able to profit from disconnects in the market and settlement structure of the current two-schedule system. Customers will benefit from these reduced out-of-market payments, although a portion of the reduced uplift payments may be offset through Global Adjustment payments until the contracts expire.

Supporting competition and innovation. Increased innovation will help the IESO to meet system needs more cost-effectively. However, this longer-term benefit is not fully captured in our analysis of efficiency benefits, nor is it fully captured in the other market studies we reviewed. Market Renewal effort's to combine enhancements will result in improved price signals that reward higher-value resources for providing their services focused on the best locations, time periods, and energy, ancillary service, and capacity market products. Faced with improved price signals and a more competitive market, existing resources may find low-cost solutions to better capture market revenues and even to provide additional market products. For example, an existing generator may make investments to enhance their capability to provide additional ancillary services that the system needs to more flexibly balance variable output from renewable resources. New suppliers will be attracted by the market's price signals and they will look for innovative and lower-cost options to capture market revenues. Customers will benefit from this innovation through increased competition and their ability to more actively participate in the market.

Alignment with provincial policy goals. The current market design is not well-suited to enable Ontario's current and future policy goals. For example, further additions of intermittent renewable resources will become increasingly expensive unless lower-cost options to provide system flexibility are identified and incentivized through market mechanisms. Market Renewal will enable Ontario's power system to evolve more efficiently and respond to changing market fundamentals and policy directions.

B. EFFICIENCY BENEFITS TO ONTARIO AS A WHOLE

Overall efficiency benefits, sometimes called system-wide or societal benefits, represent welfare gains to Ontario as a whole, regardless of which portion of the overall efficiency benefits accrue

¹⁵⁰ Ontario Energy Board (2016b).

to customers (as cost reductions) or to generators and other market participants (as increased profits). This is the most commonly used metric on which policy makers rely. Customer benefits are the subset of overall efficiency benefits that accrue directly to electricity customers, primarily in the form of lower electricity bills. The existence of large overall efficiency benefits makes it possible for both customers and generators to share a portion of the overall benefits from Market Renewal.

1. Efficiency Benefits Over Time

Figure 22 shows the annual stream of estimated benefits and costs from Market Renewal in nominal dollars from 2017 through 2030, assuming full implementation of Market Renewal by 2021. As the figure shows, a large portion of the potential energy and operability benefits would be realized immediately after implementation of Market Renewal, with the capacity exports assumed to start in 2017, incremental capacity auctions assumed to start in 2020, and energy and operability enhancements assumed to be fully implemented by 2021.



Notes:

Assumes capacity exports start in 2017 and the incremental capacity auction begins in 2020. Energy and operability reforms are fully implemented in 2021. Once the Market Renewal Projects come into service, the IESO recovers costs annually based on expected 10-year life of the investment. Annual cost recovery is small compared to large sector benefits.

The baseline estimate of expected energy market benefits, shown in dark blue in the figure, is \$56 million per year starting in 2021. Expected operability-related benefits, shown in teal, are \$65 million per year starting in 2021 (half of which is related to intertie reforms and the other half to operability improvements). In addition, based on our analysis of Ontario's supply and demand outlook, an incremental capacity auction is estimated to yield significant benefits that grow gradually over time, from about \$120 million per year by 2021 to about \$610 million per

year by 2030, as existing contracts expire and Ontario needs additional commitments to assure resource adequacy. The discrete jumps in these benefits are driven by supply and demand fundamentals. For example, total benefits increase above \$300 million per year around 2023 when a significant portion of the existing contracts expires and the planned retirement of two units at the Pickering nuclear plant is projected to necessitate additional supply to meet Ontario's requirements. In total we expect that Market Renewal will yield approximately \$240 million per year in quantified annual efficiency benefits by 2021. As shown, these annual benefits are estimated to grow to \$775 million per year by 2030.

The light blue (and hatched) area at the top of the graph represents approximately \$45 million per year in potential additional energy and operability benefits that could be realized if contracted resources were more fully exposed to market incentives. As discussed in Section VI, existing contract terms limit the benefits that are realized in the energy and operability components of Market Renewal because many existing resources will not be exposed to the improved market-based price signals. Even considering that a significant portion of resources will not be exposed to improved market incentives under the current contract terms, we estimate that Ontario would immediately realize more than \$120 million per year in annual efficiency benefits from implementation of the energy and operability elements of Market Renewal.

Figure 22 also shows small gray bars representing the approximately \$25 million per year in customer charges that would be needed to recover the IESO's implementation costs over ten years. These costs include only costs incurred by the IESO and do not include any implementation costs that may be incurred by market participants. As shown, the estimated overall efficiency benefits from each one of the three Market Renewal components (energy, operability, and capacity) exceed the total annual costs of the entire Market Renewal effort, yielding substantial net benefits to Ontario. These benefits will continue beyond our 2030 study horizon.

The efficiency benefits we estimate represent only a subset of the total benefits Ontario can expect from Market Renewal. In addition to the quantified benefits shown in Figure 22, there are many unquantified benefits that we have not estimated in this study. The market studies we reviewed identify a wide range of benefits that can be expected but that are not easily quantified. Notably, we expect additional benefits associated with increased export revenues, reduced import costs, avoided gaming, avoided inefficient transfer payments, innovation, and better alignment with policy objectives—none of which have been quantified in the above estimates.

In summary, the total quantified energy, operability, and incremental capacity auction benefits represent only a portion of the overall benefits that would likely accrue to Ontario customers, generators, and other market participants. Comparing the quantified efficiency benefits to estimated implementation costs yields a conservative estimate of the expected *net benefits* of the Market Renewal initiative.

2. Net Present Value of Efficiency Benefits

To compare total benefits to total costs in a more direct manner, we calculate the net present value of these costs and benefits by discounting the annual benefits and costs as shown in Figure 23. We use a 5% discount rate to calculate the net present value of benefits (starting in 2017 but realized primarily over the years 2021–2030) and IESO implementation costs (incurred largely between 2017 and 2021). In comparing the discounted net present values of baseline benefits to projected implementation cost (including a 20% contingency), we estimate a net present value of the overall benefits of Market Renewal at approximately \$3,400 million (in 2021 dollars). The quantified present value of baseline efficiency benefits significantly exceeds the present value of estimated implementation cost, yielding a benefit-to-cost ratio of 18:1. Almost two-thirds of the estimated benefits are derived from the implementation of an incremental capacity auction, driven by access to lower-cost resources, including capacity imports.



As our low- and high-ends of estimated benefits show, there is uncertainty around our baseline estimates. This uncertainty relates to both the actual market design that will be implemented as well as the benefits that will be realized as a result. We estimate a plausible uncertainty range from a low of \$2,200 million to a high of \$5,200 million in 2021–2030 present value terms. The \$5,200 million “high” end of that range is over 50% higher than our baseline estimate and even the low estimate of \$2,200 million substantially exceeds estimated implementation costs with a benefit-to-cost ratio of 12:1.

C. IMPLICATIONS FOR MARKET PARTICIPANTS

Market Renewal will have a significant impact on how market participants buy and sell electricity. For any given market participant the impact of Market Renewal will not be just a proportional share of the societal efficiency gains, but a combined effect of efficiency gains, positive revenue impacts that favor more economically competitive resources, negative net revenue impacts that disfavor less valuable resources, and changes in wealth transfers. It is outside the scope of this study to estimate the net effects of these changes on individual classes of market participants, but we are able to comment on likely high-level impacts for customers and other market participants.

How Can Market Renewal Benefit Both Customers and Suppliers?

Market Renewal is not a zero-sum effort. Suppliers as a whole do not need to be harmed in order for customers to benefit, and vice versa. Instead, Market Renewal has the potential to reduce system-wide investment and production costs to create win-win scenarios that benefit both suppliers and customers. For example, through the energy market workstream, Market Renewal will create a more efficient dispatch of resources, lowering the fuel and variable costs to gas generators, while keeping them whole to the net profits (capacity plus energy margins, minus fuel costs) contemplated in their contracts. Thus, gas generators' profitability can be maintained even while passing fuel cost savings on to customers. As another example, operability reforms may create opportunities for existing resources to profit from selling new flexibility products, while helping customers to avoid the costs of contracting for new flexible resources. As a final example, exporting existing excess capacity will create additional revenue (and no additional costs) to Ontario, with the benefits shared between customers and the exporting seller.

Benefits that reflect true efficiency gains can thus benefit both customers and suppliers at the same time. However, this does not mean that efficiency gains will always be shared equally; instead the distribution of benefits will vary among differently-situated market participants.

1. Impacts on Customers

Customers stand to realize significant benefits from Market Renewal. As summarized in Table 8, customers will directly benefit from every one of the discussed benefit drivers of Market Renewal, although in many cases the benefits will be shared with suppliers and other market participants. All customer classes will share in system-wide production and investment costs savings through a reduction in total energy, uplift, and Global Adjustment charges. Customers will also be the primary beneficiaries from avoided transfer payments and avoided costs of gaming opportunities. Customers that opt to more actively participate in the wholesale marketplace through demand response or distributed resources may capture additional benefits through opportunities to market their services.

Table 8
How Market Renewal Benefits Translate to Customer Benefits

Benefit Category	Impacts on Customers
Fuel, Emissions, and O&M Cost Savings	Reduced system variable costs will translate to lower energy plus uplift costs to customers
Reduced Curtailment/Spilling of Clean Energy	- Improved utilization of non-emitting resources will enable displacing costlier gas-fired generation (reducing system and customer costs) or increased exports (reducing Global Adjustment costs to customers) - Environmental benefits materialized through either avoided CO₂e emissions, or lower clean energy investment costs to maintain the same level of CO₂e emissions
Increased Export Revenues and Reduced Import Costs	- Reduced costs as some expensive Ontario resources are replaced with lower cost imports - Potentially realize additional contributions to capacity costs through share of export revenues
Investment Cost Savings	- Customers will pay lower capacity prices under a competitive auction than current contract prices, materialized as lower Global Adjustment costs - Customers may share a portion of the revenues from capacity exports to offset Global Adjustment costs - Benefits will grow over time as contracts expire
Reduced Gaming Opportunities, Administrative Complexity, and Unwarranted Wealth Transfers	- Avoided excess payments from market gaming will reduce customer costs - Few direct impacts on customers from reduced complexity - Customers will materialize benefits through lower capacity payments (through Global Adjustment) and reduced uplift charges. Payments associated with intertie offer guarantees, CMSC payments, and day-ahead/real-time cost guarantees will be significantly reduced or eliminated
Supporting Competition and Innovation	- Competition and innovation will reduce system costs, translating to lower prices and customer costs - Customers wishing to participate as demand response, distributed resources, or prosumers will have enhanced opportunities
Alignment with Provincial Policy Goals	A more dynamic and cost-effective market platform will enable lower-cost solutions for achieving or adapting to future policy goals, avoiding costlier solutions that customers would have to pay for

We do not quantify the full magnitude of customer benefits from Market Renewal. For example we do not attempt to quantify the magnitude of customer benefits from avoided gaming and wealth transfers. We do however estimate how customers may benefit from a share of efficiency gains, as summarized in Figure 24.

Why Not Focus on Maximizing Customer Benefits Alone?

Customer benefits are an important piece of the Market Renewal effort, but they are not the primary focus. Instead, Market Renewal intends to maximize total Ontario-wide efficiency benefits, which combines benefits to customers, suppliers, and other market participants. For customers, this may seem like an inferior policy to one that seeks only to maximize customer benefits in the short run, but focusing on total Ontario-wide efficiency benefits, and providing appropriate market opportunities to suppliers actually ensures customers will continue to benefit from lowest cost supply in the long-term (rather than just temporarily).

If Market Renewal were instead to focus solely on lowering customer costs, some cost-effective suppliers might be worse off and be forced to leave the market due to a lack of adequate cost recovery or return on investment. In the absence of efficient market incentives, customers would face higher costs of procuring power due to a lack of competitive supply. In a more pessimistic future, customers could face service disruptions due to a lack of adequate supply. Under this scenario, the benefits customers experience in the short-term are more than offset by higher costs later on. In contrast, a policy like Market Renewal that focuses on maximizing overall efficiency benefits ensures that both customers and suppliers can benefit from a market design that minimizes total system costs in both the short and long term.

As shown in Figure 24, the largest customer efficiency benefits from Market Renewal are associated with the incremental capacity auction. These capacity-related benefits range from \$3–27 million per year for 2017–2019 based on the customers’ share of benefits from capacity exports and increase to \$140 million per year in 2020, when the incremental capacity auction is first implemented, and grow over time to approximately \$610 million per year by 2030. The significant growth of incremental capacity auction benefits is driven primarily by contract expirations and transitioning of the associated supply resources to participate in a more competitive market construct. This reflects our expectation that the incremental capacity auction will allow Ontario to defer building new generating plants largely by unlocking unconventional low-cost capacity resources such as imports, demand response, and uprates. These customer benefits are exactly as estimated in Section V above, without any adjustments because that estimate includes only the customer (but not supplier) share of efficiency benefits. Customers will realize these benefits as reductions in capacity charges based on capacity auction procurement costs that are below the costs of expiring supply contracts.

The sharing of overall benefits and cost savings occurs differently for the energy and operability workstreams. The quantified efficiency benefits from the energy and operability reforms are predominately driven by the more efficient commitment and dispatch of resources. Some of these benefits will go to customers in the form of lower energy and ancillary service prices plus uplift payments and some will accrue to suppliers in the form of reduced costs or additional sales opportunities. For example, a financially-binding day-ahead market will provide proper incentives for day-ahead export scheduling and lower-cost unit commitments (compared to supporting exports through the current real-time unit commitment process, which is more costly and less efficient). Customers will benefit from this change by paying lower real-time unit commitment-related uplift costs and purchasing more of their energy at lower day-ahead prices.

However, some other market participants will also share a portion of these efficiency benefits, such as the owners of pumped hydro assets that are currently underutilized but that can be more fully utilized in the presence of a financially-binding day-ahead market. We assume that customers will share approximately half of the efficiency benefits from the energy and operability workstreams, which yields savings of \$60 million to \$80 million per year over the 2021–2030 period. This customer share of efficiency benefits does not account for any benefits from avoided gaming or transfer payments (of which customers will be the primary beneficiaries), such as cost reductions associated with CMSC and other uplift payments. Customers will realize these efficiency and other non-quantified benefits as a reduction in their combined energy and uplift costs.

Taken together, we estimate the three workstreams of Market Renewal to yield customer benefits of approximately \$180 million per year in 2021, growing to nearly \$700 million per year by 2030. These benefits are offset by annualized IESO implementation costs, currently estimated at \$25 million per year, which will be recovered from customers.



Notes:

Capacity exports start in 2017 and the capacity auction begins in 2020. Energy and operability reforms begin in 2021.

Once Projects come into service, the IESO recovers costs based on expected life of the investment. Cost recovery is small compared to large sector benefits.

All classes of customers will share in these benefits, although greater capacity auction benefits will be achieved by customers that pay a larger share of Global Adjustment charges. The distribution of customer benefits from the energy and operability workstreams will depend on how customers are charged. Suppliers will be paid according to their nodal price, which will be higher in the import-constrained regions in southeastern Ontario and lower in the export-

constrained regions in northwestern Ontario. If customers are similarly charged nodal prices, those in low-price regions will capture more benefits from Market Renewal than customers in high-price regions.

However, as a design choice, many nodal markets at least partly insulate customers from the divergence of nodal prices. Rather than being charged at a node-specific LMP, customers could be charged at an average zonal price (as is the case in most nodal markets) or continue to be charged at a system-wide price. In addition, internal financial transmission rights (also referred to as congestion revenue rights) may be introduced to allow customers to hedge their exposure to congestion-related LMP differences. These averaging and congestion-right options would greatly mitigate the LMP divergence among customer groups, ensuring that prices do not automatically go up for some customers under an LMP design. The downside of zonal or system-wide averaging of load LMPs is that it would mute the incentives for future load growth in low-cost regions and the incentives for demand-side participation to avoid peaks in higher-price regions.

Under the nodal energy market design of Market Renewal, customers will benefit from a refund of congestion charges. This congestion rent benefit is associated with switching suppliers to nodal pricing and will be realized regardless of whether customers are subjected to nodal pricing or some average zonal or system-wide prices. Because the majority of generators are located in somewhat lower-price LMP regions while the majority of customers are located in somewhat higher-price LMP regions, this means that the IESO will collect more money from customers than it will pay out to generators in the energy market, with the difference (the “congestion rent”) refunded to customers. The IESO is collecting such congestion revenues today in two ways: (1) associated with congestion charges on the interties, with the excess revenues of \$33–136 million per year contributing to a the Transmission Rights clearing account; and (2) associated with internal constraints that are not priced into the HOEP but that are instead managed with CMSC payments.¹⁵¹ For internal constraints, constrained-on CMSC payments of \$30–80 million per year are an approximate indicator of the magnitude of increased costs that will be incorporated into the locational energy price in import-constrained regions; constrained-off CMSC payments of \$40–150 million per year are an approximate indicator of congestion rents that are currently being paid out to suppliers but would be returned to customers under a nodal market design.¹⁵² Congestion rents can be returned to customers either through direct allocation of funds or through internal financial transmission rights, with a greater share of congestion rents typically being allocated to customers in higher-price regions. Note, however, that this

¹⁵¹ For documentation of the magnitudes of intertie rent over 2011/2012 through 2014/2015, see Ontario Energy Board (2014a); Ontario Energy Board (2015b); Ontario Energy Board (2015c); and Ontario Energy Board (2016a).

¹⁵² The magnitudes reported are the range of CMSC on and off payments over 2005–2015. The IESO has discontinued some types of CMSC payments over time and so has accomplished a portion of the transfer payments described here, particularly those that were introducing significant gaming opportunities and unwarranted intertie incentives. See Ontario Energy Board (2016c).

transfer of congestion charges to customers from other market participants will not occur as an immediate shift upon implementation of nodal pricing because many suppliers will be made whole to their contract price. In other words, suppliers facing a reduction in market revenues from switching from HOEP to a lower LMP and the loss of associated CMSC payments will be made whole by an increase in Global Adjustment payments until the associated contracts expire.

Will Nodal Pricing Increase Costs for Some Customers?

Market Renewal will implement nodal pricing for suppliers, with higher prices in import-constrained regions and lower prices in export-constrained regions. However, the pricing regime for customers will be considered in the design phase and will be determined through collaboration between the IESO and stakeholders. Several pricing options exist that would address the concerns of customers in locations that would have relatively higher nodal prices. For example, rather than being charged at node-specific prices, customers could be charged at an average zonal price (as is the case in many other nodal markets) or continue to be charged at a system-wide price. In addition, locational prices will cause IESO to collect “congestion rent”, or excess revenue from customers (that tend to be in higher-price regions) compared to the somewhat lower payments to generators (that tend to be located in lower-price regions). This congestion rent can be returned to customers directly or indirectly via allocation of internal financial transmission rights (also referred to as congestion revenue rights). These averaging and congestion-right allocation options can greatly mitigate or eliminate the locational price divergence among customer groups.

While some customers will find average prices more attractive, we caution that averaging too broadly would mute the incentives for future load growth in low-cost regions and the incentives for demand-side participation to avoid peaks in higher-price regions. These tradeoffs will need to be considered fully when the IESO and stakeholders design the pricing regime for customers under Market Renewal.

Customers that choose to actively engage in the wholesale energy market, ancillary markets, and capacity auctions may earn additional benefits beyond what we estimate here. One aim of Market Renewal is to foster more competition and opportunities for innovative emerging technologies and new types of resources. A subset of customers may achieve additional cost reductions or earn incremental revenues from the wholesale markets by participating as demand response or with distributed resources.

2. Impacts on Other Market Participants

Unlike customers who will generally benefit from Market Renewal (though potentially to greater or lesser extents), each supplier and financial participant will be affected differently based on the nature of their existing contracts, asset base, and market activities. Fully quantifying the impact for each resource type is outside the scope of our analysis, but we qualitatively discuss the impacts on other market participants as summarized in Table 9.

On an aggregate basis, generators and other market participants will be net beneficiaries by capturing some of the efficiency gains from Market Renewal as quantified in this study. These overall efficiency gains are achieved through true system cost savings, not transfers between customers and suppliers or other market participants. Avoided production and investment costs

will tend to exceed reductions in market prices and uplift payments, allowing generators to share in a portion of the overall benefits on average. Generators with lower costs and greater flexibility will be especially better off as the true value of their assets is better recognized by the market. Most suppliers and other market participants will benefit directly from the reduced administrative complexity of a market design that avoids the complexity of the two-schedule system. Finally, new entrants and emerging technologies will benefit as Market Renewal levels the playing field across technologies, allowing them to compete more directly in the energy, ancillary services, and capacity markets.

However, some suppliers may be made worse-off as a result of certain reforms. Higher-cost and less-flexible off-contract generators may have a harder time competing in a more efficient market. As merchant generators, they may face degraded financial performance or need to retire. Merchant suppliers in lower-price regions may also be negatively impacted by Market Renewal. Suppliers and other market participants that are the recipients of high uplift payments may become less profitable as the need for uplift payments is reduced in a more efficient market design, irrespective of whether these payments were related to gaming activities or were a natural consequence of the inefficiencies of the existing market.

Table 9
How Market Renewal Benefits Impact Other Market Participants

Benefit Category	Impacts on Other Market Participants
Fuel, Emissions, and O&M Cost Savings	• Contracted Suppliers: Kept whole to contract terms for the most part (until contracts expire). Updating contract terms with Market Renewal will introduce costs from contract amendments, and the details of any contractual change will introduce some favorable or unfavorable adjustments. Some may share benefits from incremental opportunities to provide operability services. • Merchant Suppliers: Suppliers will share in Market Renewal efficiency benefits on an aggregate basis (with avoided production costs exceeding the reductions in energy price/uplift payments), but individual suppliers may be better or worse off. Sellers that have assets with lower costs, greater flexibility, and in more favorable locations will benefit most; less economically competitive sellers are likely to be worse off. • Fuel Sellers: Likely reduction in gas sales.
Reduced Curtailment/Spilling of Clean Energy	• Clean Energy Suppliers: Either equally well off (if not subject to curtailment risks or made whole through contracts) or better off (if losing revenue from curtailments). • New Clean Energy Developers: Either equally well off (if the same quantity of non-emitting resources is developed), or worse off (if avoided curtailments reduce the need for non-emitting resource investment).
Increased Export Revenues and Reduced Import Costs	• Suppliers: Realize additional contributions to capacity costs through share of export revenues; high-cost suppliers may be worse off as their power is more easily replaced by cheaper power from neighboring markets. • Traders: Better off from more cost effective intertie trading opportunities.
Investment Cost Savings	• Contracted Suppliers: Kept whole to contract terms until contract expiration. Some may share benefits from capacity exports. • Merchant Suppliers: Low-cost suppliers will benefit from selling capacity at a market price that exceeds their net going-forward costs; this may include new entrants and non-traditional supply types. Higher-cost suppliers will become less profitable and may retire. Sellers that have previously enjoyed contract payments exceeding costs and market value will be worse off.
Reduced Gaming Opportunities, Administrative Complexity and Unwarranted Wealth Transfers	• Market participants currently exploiting existing design flaws through gaming will be made worse off. Other non-customer market participants unlikely to be affected. • Most market participants will benefit from the reduced administrative complexity of a single-schedule system.
Supporting Competition and Innovation	• New Entrants and Emerging Technologies: Benefit from enhanced opportunities to compete and enter the market • Less Competitive Existing Technologies: Worse off if unable to compete with new entrants, potentially leading to lost profitability or retirements
Alignment with Provincial Policy Goals	• Alignment between policy goals and market design will reduce the regulatory risks associated with market intervention (which can be invited by lack of such alignment). All market participants will benefit from mitigating risks.

D. ALIGNMENT WITH ONTARIO'S ENERGY FUTURE

Market Renewal presents the opportunity to better align Ontario's market design with its energy policy future, which is likely to require a greater reliance on low-carbon, intermittent, and distributed resources. While Ontario's public policies have transformed the electricity sector, the current market design predates these changes. In addition, market participants have identified the potential for more significant changes on the horizon. We find that one of the significant benefits of Market Renewal is that it can better position Ontario to meet the existing and future challenges presented by these energy policy-induced transformations. Although the magnitude of this benefit remains unquantified, as the specific public policies and energy landscape over the next few decades remain uncertain, we believe that improved alignment of market design and public policy is a large potential benefit and should not be overlooked when evaluating Market Renewal.

The modernized and more efficient energy, ancillary, and incremental capacity auction designs contemplated through Market Reform can create a more efficient and flexible platform for supporting cost-effective electricity supply irrespective of what the future may hold. A key advantage of a competitive market is that it enables and incentivizes the collective effort of market participants to predict and anticipate how the sector will evolve, and rewards those that identify creative and innovative solutions to emerging challenges. These benefits of a more efficient market are most pronounced at times of significant change, regardless of whether those changes are driven by market fundamentals or public-policy objectives.

Market Renewal is an opportunity to ensure that the market design adequately accommodates, and possibly even facilitates achieving public-policy goals more cost-effectively. Failing to align market design and public-policy goals can sometimes leave these two areas in conflict and create incentives for policymakers to intervene to address that misalignment through out-of-market mechanisms, leading to unanticipated outcomes such as excess supply or high Global Adjustment charges. Such interventions can impose adverse impacts on market participants and increase regulatory risks, thereby undermining market-based investments. To reduce the risks of such outcomes going forward, we recommend making a concerted effort to align market design with public-policy objectives throughout the Market Renewal effort. This is particularly important for the governance discussion and capacity auction workstream in order to mitigate and minimize regulatory risks.

What Is the Role of Electricity Markets in Curbing Carbon Emissions?

Wholesale electricity markets and capacity auctions offer a powerful tool for policymakers intent on reducing carbon emissions from the electric sector. Market-based carbon policies, including carbon taxes and cap-and-trade regimes, attempt to accurately reflect the societal costs of carbon in the price of any commodity whose production creates carbon emissions.

Electricity is one such commodity. Wholesale electricity markets can be harnessed to reduce carbon emissions from power plants. Electricity markets naturally complement cap-and-trade policies by integrating carbon allowance costs into the energy offer prices that fossil plants submit to the system operator. These offers therefore accurately reflect production costs, including the cost of carbon emissions. The system operator then dispatches the plants that minimize total cost to meet load and maintain reliability. Plants with high emission rates run less as their costs increase relative to plants with lower emission rates. Thus, the energy market efficiently reduces carbon emissions in the lowest-cost manner. Capacity markets offer an opportunity to enhance carbon policy effectiveness through long-term investment and retirement decisions. Suppliers offering into a capacity auction take into account their expected carbon costs and energy market net revenues. This makes lower-emitting resources more competitive compared to higher-emitting resources. Over time this incentivizes high-emitting resources to retire and be replaced by lower-emitting resources.

However, electricity markets on their own will not necessarily achieve emissions reductions in the absence of a market-based carbon policy. If no carbon pricing exists or carbon prices are too low to achieve the desired level of emissions reductions, then the wholesale electricity market will simply minimize other costs without fully considering the public policy value of avoiding carbon emissions.

To guarantee that these alignment-related benefits are realized, the IESO and stakeholders must keep in mind Ontario's possible futures market and policy outcomes (*e.g.*, as identified by the Working Group) and design Market Renewal such that it can address the varying challenges across the potential future outcomes. Market design alternatives considered during Market Renewal can be subjected to robustness testing to determine whether they would fully support, provide optionality for, or somehow create barriers to efficiently adapting to the identified set of plausible futures.

The IESO and stakeholders have already identified design elements that are crucial for supporting a future electricity sector that is clean, reliable, and affordable. The improved new market design will need to properly incentivize new technologies like energy storage, distributed generation, and demand response to participate in providing energy, flexibility and ancillary services, and capacity. These resources, along with all other resources on the system, will need efficient price signals to ensure the system can meet energy and reliability needs at the lowest cost.

IX. Findings and Recommendations

We find that there will be significant gross and net benefits from Market Renewal. We estimate overall efficiency benefits of \$3,600 million over a ten-year period in 2021 present value terms, compared to only approximately \$200 million in implementation costs. This yields a baseline net benefit of \$3,400 million over a ten-year period in present value terms. Considering the uncertainty in these estimates, we estimate the present value of net benefits to range from \$2,200–\$5,200 million, with both customers and other market participants sharing in the gains. Market Renewal will address many of the large inefficiencies associated with the current two-schedule market design, as identified over the last 15 years by the MSP and others. Beyond adopting best practices from other regions where applicable in Ontario, Market Renewal will be an opportunity to design a market more suitable for enabling Ontario’s transition to a clean energy future. Considering the significant policy and economic advantages of the proposed Market Renewal, we recommend that the IESO continues to pursue the effort.

Based on our review of existing analyses of the Ontario market, stakeholder input and interviews, and lessons learned in other jurisdictions, we offer a number of specific recommendations for consideration by the IESO, stakeholders, and policymakers in order to maximize the benefits and mitigate the risks of Market Renewal. These recommendations are as follows:

- **Policy Alignment and Future-Readiness:** As part of the benefits case analysis, stakeholders and IESO staff have identified the policy and market drivers that will shape the Ontario electricity sector between now and 2030. They used these drivers to describe several different “Futures” that may emerge over the next decade. We recommend that the IESO and stakeholders continue to use these drivers and Futures throughout the design process to help identify design requirements, prioritize enhancements, and test the robustness of proposed design elements across possible future developments.
- **Energy Market Reforms:** We recommend that the IESO pursue the implementation of a fully-integrated marketplace that includes: (a) adopting a single-schedule constrained system with nodal pricing and settlements for suppliers (we recommend working with stakeholders to determine whether market-wide, zonal, or nodal pricing should be adopted for customers); (b) enhanced real-time unit commitment and pricing; and (c) a financially-binding day-ahead market. This design package has a proven track record in a wide range of power markets, showing that improved unit commitment, day-ahead markets, and providing more efficient price signals to supply resources yields significant production cost savings. To maximize the benefits of energy market reform in Ontario’s context, we recommend:
 - Develop a market design that would minimize uplift payments, for example, by incorporating day-ahead and real-time unit commitment costs into the price-setting process. Remuneration through a single market price (rather than out-of-market

- uplift payments) will create more transparent pricing with incentives that are better aligned with customers' interest and minimizing system-wide costs.
- Focus on improving price formation during previously-unusual scarcity events and during surplus baseload generation events that are now common occurrences in Ontario. To address surplus generation conditions, it will likely be necessary to work with policymakers and stakeholders to better align interactions between energy market participation and incentives created by contract provisions, regulated payment rates, and hydro rental charges.
 - Co-optimize all energy and ancillary service products, including regulation, for dispatch and price-setting purposes in both day-ahead and real-time markets; integrate operating reserve shortage pricing into a comprehensive Ontario scarcity pricing framework within the nodal pricing construct.
 - Fully integrate all resources into dispatch and price-setting. We recommend first focusing on more efficiently integrating resources that already represent a substantial proportion of Ontario's supply fleet, including: (a) multiple types of demand response resources, (b) dispatchable intermittent resources, and (c) Ontario's hydro resources, considering pumped storage, cascading system effects, and the energy-limited nature of these resources. For resources that are not yet a substantial proportion of the fleet but may become so in the future (such as battery storage and distributed generation resources), we recommend that the IESO create the optionality (*e.g.*, when updating its network model and selecting market software packages) to fully integrate these resources in the future.
 - Examine alternative approaches for allocating congestion rents to customers, rather than simply adopting the financial transmission rights approach currently used in U.S. markets. This will allow Ontario to analyze the performance of the U.S. congestion rights markets and, if necessary, adopt alternatives that may be more aligned with Ontario's unique circumstances and objectives.
 - **Operability Reforms:** We recommend that the IESO continue to evaluate the nature of its system flexibility needs and pursue market-based mechanisms for meeting those needs. We anticipate this will include reforms to enhance the energy market, ancillary service market, and intertie scheduling processes. In the context of these operability reforms we specifically recommend:
 - Continue to examine the nature of Ontario's unique flexibility needs. This will enable the IESO to determine the quantity and type of ancillary service products that will maximize benefits to the province. We recommend addressing flexibility needs through advanced energy and ancillary service market designs before considering whether a flexible resource requirement should also be added to the design of the incremental capacity auction.
 - Work with stakeholders to identify and address barriers to more fully utilize the flexibility of existing and potential future resources. This may result in revised

- ancillary service products and qualification requirements to enable competition from non-traditional resources such as demand response, storage, and distributed generation resources.
- Adopt an integrated energy and ancillary service design package that: (a) considers the advanced flexibility solutions that have been tested successfully in other markets, and (b) creates optionality to adopt new (or revised) ancillary service products when doing so becomes necessary.
 - Improve intertie scheduling and pricing as a core design component of Market Renewal, with a clear vision for how to improve coordination with neighboring markets across the various interties. For example, we recommend considering advanced options such as 5-minute intertie scheduling, coordinated transactions scheduling, and full intertie optimization with neighboring markets. We recommend working with software vendors and neighboring system operators to create optionality for these enhancements if they are not all implemented with the initial set of market reforms.
 - **Capacity Auction:** We recommend that the IESO pursue the implementation of a more market-based mechanism for meeting resource adequacy needs, including: (a) enabling capacity trading over interties, and (b) implementing an incremental capacity auction. To develop an incremental capacity auction design that will maximize benefits given Ontario’s unique circumstances, we recommend:
 - Work with stakeholders and policymakers to identify governance and market design structures that reduce regulatory risks to investors.
 - Work with policymakers to more clearly define the reliability and potential policy objectives that should be achieved through the incremental capacity auction. Beyond existing resource adequacy objectives, this may include policy objectives such as clean energy requirements that may not otherwise be achievable through market mechanisms. We recommend creating a capacity market that is not only integrated with energy and ancillary service markets but can also accommodate these additional policy objectives—rather than meeting these policy objectives through out-of-market procurements that are now a significant and growing share of total system costs.
 - **Long-term Contracts:** We recommend that, going forward, the province implement an incremental capacity auction to meet its resource adequacy requirements. Furthermore, we recommend that the IESO and contracted suppliers explore opportunities to better align contract incentives with market mechanisms. This could provide outcomes that are mutually beneficial to consumers and suppliers.
 - **Implementation Process and Costs:** We recommend that the IESO implement Market Renewal using an approach designed to mitigate the risks while maximizing the net benefits of the project—as opposed an approach that focuses solely on minimizing project costs. Based on the lessons learned from the market reform implementation experience in other regions and our assessment of the IESO’s existing systems, we recommend:

- Proactively manage Market Renewal risks by engaging with stakeholders up front and throughout the initiatives, including ensuring that the market design elements are well-established before implementation. Based on our preliminary assessment, the most significant implementation-cost-related risks are: (a) cross-system and cross-vendor system integration, (b) interactions with existing contracts, (c) mid-stream or late-stage scope and design changes, and (d) stakeholder readiness and buy-in.
- Adopt a systematic approach to scoping Market Renewal initiatives into separate categories that include immediately-implemented enhancements and planned (or deferred) enhancements. We recommend that this prioritization effort consider potential benefits and costs, status of available vendor solutions, and associated risks to the timeline and budget.
- Engage with market participants throughout the Market Renewal effort, including on education, design, technical specifications, system enhancements, market trials, and final implementation. We recommend that the IESO offer support and information to assist market participants in making the needed investments to their personnel, processes, and technology.

Ontario will need to develop and select market design choices that reflect its unique market fundamentals and policy environment, considering both the province's immediate and anticipated long-term needs. To do so, we recommend that the IESO and stakeholders examine the design choices and experiences of other markets for all of the Market Renewal workstreams. While we recognize Ontario's unique challenges and market structure, many challenges faced in Ontario have been encountered in other markets. Building on the experience elsewhere, where applicable, can help identify the range of options available for Ontario and provide lessons learned about the advantages and limitations of each approach.

We further emphasize the importance of treating the individual components of Market Renewal as part of a package in which the different elements need to work together in an integrated and complementary manner. Although this benefits case reports distinct estimates for benefits associated with the energy, operability, and capacity workstreams, they should be interpreted as components of a cohesive overall market design. Implementing one component without addressing the others would likely require more costly fixes later.

List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
CAD	Canadian Dollar
CAISO	California Independent System Operator
CES	Clean Energy Supply
CHP	Combined Heat & Power
CMSC	Congestion Management Settlement Credit
CO ₂	Carbon Dioxide
CO _{2e}	Carbon Dioxide Equivalent
CONE	Cost of New Entry
CRR	Congestion Revenue Right
CTS	Coordinated Transaction Scheduling
DACP	Day-Ahead Commitment Process
DR	Demand Response
EDACP	Enhanced Day-Ahead Commitment Process
EIM	Energy Imbalance Market
EMAAC	Eastern Mid-Atlantic Area Council
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
FTR	Financial Transmission Right
GA	Global Adjustment
HCI	Hydroelectric Contract Initiative
HESA	Hydroelectric Energy Supply Agreement
HOEP	Hourly Ontario Energy Price
ICAP	Installed Capacity
IESO	Independent Electricity System Operator
IOG	Intertie Offer Guarantee
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
IT	Information Technology
LMP	Locational Marginal Pricing
MAAC	Mid-Atlantic Area Council
MISO	Midcontinent Independent System Operator

MSP	Market Surveillance Panel
MW	Megawatt
MWh	Megawatt Hour
NREL	National Renewable Energy Laboratory
NUG	Non-Utility Generator
NYISO	New York Independent System Operator
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
OPG	Ontario Power Generation
PJM	PJM Interconnection
PPA	Power Purchase Agreement
PSEG	Public Service Enterprise Group
PUCT	Public Utility Commission of Texas
RES	Renewable Energy Supply
RESOP	Renewable Energy Supply Offer Program
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TLR	Transmission Loading Relief
TO	Tie Optimization
TWh	Terrawatt Hour
UCAP	Unforced Capacity
USD	United States Dollar
WECC	Western Electricity Coordinating Council

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