BOMA INTERROGATORY 1

Issue 1.0, 5.1

INTERROGATORY

Reference: Issues 1.0, 5.1; Exhibit A, Tab 2, Schedule 2, Appendix 1, p21; Corporate Performance Measures

a) Please provide a copy of the 2016-2020 Strategic Plan.

b) Please provide the input received from the IESO's Stakeholder Advisory Committee as it relates to each of the ten CPMs described on pp21-24.

c) "Ontario's electricity service is reliable". To what extent is the IESO compliant with the NERC's other (medium or low level risk factor) reliability standard requirements? Please provide a quantitative assessment.

d) For each of the forty-four key recommendations from the fifteen regional plans, please provide a brief status report, noting achieved targets and milestones for each project.

e) Please list the five priority and key transmission projects in Northwest Ontario that are referred to here, and provide a brief status report for each, noting milestones, achieved or not, and targets.

f) What are the target dates for sharing operating data and two-way communication with Ontario LDCs? For how many and which LDCs has this link/structure been put in place, and now operating? What is the target date, and milestones for having this data sharing in place for the remaining LDCs? What are the objectives for establishing this coordination? For example, how will such information sharing increase the likelihood of reaching DSM targets (2015-2020 program)? Please discuss fully.

g) What is the operational data being shared and for what purpose(s)? Please provide a detailed answer.

h) Cybersecurity, p22 - Has the advanced malware detection technology been installed by the end of First Quarter, 2017, as promised at p20? If not, what is the target date for completion and milestones?

i) What are the objectives contained in the 2016-2017 cybersecurity work plan? When is each objective going to be achieved?

RESPONSE

a) A copy of the IESO's 2016-2020 strategic plan is provided as Attachment 1.

b) Input was received and responses were provided throughout 2016 as the IESO actively sought to engage and incorporate the feedback of the SAC into developing publically valuable, outcome-oriented measures.

SAC discussions pertaining to CPMs are documented on the IESO's public website and provided below with highlights of the input provided.

- Feb 1, 2017 – The IESO communicated that 2017 CPMs were updated to reflect SAC input regarding the overall structure of the measures and to provide further clarity in distinguishing between the longer term measure, defined as an outcome to achieving the strategic objective, and the target set for the upcoming year.

- Oct.19,2016 - The IESO acknowledged the feedback of the SAC to evolve the CPMs for the next iteration and better decipher between the goals for the long term versus annual targets.

- Aug. 17, 2016 – SAC feedback from the May meeting was incorporated into developing draft CPMs for the 2017-19 Business Plan to be more specific and outcome oriented.

- May 11, 2016 - The IESO sought advice from SAC members on whether the level of detail in the 2016 CPMs was appropriate and if there were any areas the IESO should focus on for the development of the 2017 CPMs

c) Please refer to the response to BOMA Interrogatory 28 at Exhibit I, Tab 5.1, Schedule 2.28.

d) A status report, as of June 30, 2017, of each of the forty-four key recommendations from regional plans and the five priority transmission projects is provided in the table below:

Key recommendations – regional plans

NO.	Key Recommendations	Timeline	Status	Comments
Regional Plans				
Brant				
1	Implement new switching facilities at Brant TS	Q3 2019	On Track	New switching facilities are expected to be in-service by Q2-Q3 2019. This implementation is being carried out by Hydro One Transmission and the local LDCs.
2	Investigate opportunities for a Demand Response (DR) pilot in the Brant Area	Q4 2016	Complete	A contract was not awarded as a result of the RFP. A decision will be made whether to proceed with a second phase of the RFP.
Bronte				
1	Transfer one feeder worth of load from Bronte TS to Tremaine TS	No Longer Required	No Longer Applicable	Transfer is now to be accomplished through a series of smaller transfers over time to stations inside Oakville Hydro service territory. Lower cost, and simpler to apply from a regulatory perspective
Central Toronto				
1	Design SPS for Manby TS and Leaside TS	Q1 2018	On Track	SIA completed; Hydro One leading implementation with Toronto Hydro support.
2	Implement Manby supply area-targeted conservation program to defer transmission needs	Q4 2016	No Longer Applicable	No longer required due to changes in load forecast as a result of changes in rapid transit electrification plans.
3	Develop LAC for Toronto to discuss long-term future	Q2 2016	Complete	Third and fourth LAC meetings have occurred; fifth meeting in September 2017.

Key recommendations – regional plans (cont'd)

NO.	Key Recommendations	Timeline	Status	Comments
Regional Plans				
Kitchener-Waterloo-Cambridge-Guelph (KWCG)				
1	Implement the Guelph Area Transmission Refurblsihment (GATR) Project	Q2-Q3 2016	Complete	
2	Install two 230 kV circuit switchers at Galt Junction and explore opportunities to further improve restoration capability in the Cambridge area	~2017	Complete	
3	Maintain ongoing dialogues with communities about their future electricity supply	On-going	On Track	The IESO has reached out to municipal planners to explore opportunities to coordinate and align community energy planning and regional electricity planning.
Ottawa				
1	Replace two lower rated 230/115 kV transformers at Hawthorne TS, which are approaching their end-of-life, with higher rated transformers.	Q2 2018	On Track	Project is being carried out by Hydro One. Planned In-service date is Q2 2018.
2	Rebuild the section of circuit A5RK between Overbrook TS and the junction with circuit A6R near Riverdale TS into a double-circuit line, and reconfiguration of supply to	Q2 2019	On Track	Project is being carried out by Hydro One. Planned in-service date is Q2 2019.
3	Address the need for additional supply capacity in the South Nepean area	2021	On Track	A hand off letter was provided by the IESO to Hydro Ottawa and Hydro One recommending initiation of development work for a new South Nepean station and supply line. Engagement with community is continuing

Key recommendations – regional plans (cont'd)

NO.	Key Recommendations	Timeline	Status	Comments
Regional Plans				
Northwest Greater Toronto Area				
1	Increase step-down capacity in Milton and Halton Hills. Two new stations required in the near/mid-term	Q4 2018 and 2020 (estimated)	On Track	Development work on Halton Hills station is underway by Halton Hills Hydro: Land purchased and consultant selected, targeted 2018 in-service. Development work for Halton TS in Milton is not yet required - load will continue to be monitored.
2	Secure long term transmission rights for new corridor in Northern Brampton/ Southern Caledon	On-going - need is long term in nature	On Track	
3	Engage LAC to assist with developing long term solutions	To be determined	To be determined	A LAC is under consideration for the GTA West planning region to provide input into electricity planning in this area. Northwest GTA is a sub-region of the GTA West planning region.
Windsor-Essex				
1	Develop new transformer station in Leamington (Supply to Essex County Transmission Reinforcement Project)	Q2 2018	On Track	Project is being carried out by Hydro One. The OEB granted Hydro One LTC approval in July, 2015. Cost allocation is is still being considered by the OEB.

Key recommendations – regional plans (cont'd)

NO.	Key Recommendations	Timeline	Status	Comments
Regional Plans				
York				
1	Develop a new station in Vaughan	~2017	On Track	Construction underway by PowerStream for in-service Q4 2017
2	Add switching facilties at Holland TS	~2017	On Track	Project is being carried out by Hydro One
3	Install two in-line circuit switchers on the Parkway-to-Claireville line	~2018	On Track	Development work for the project is being carried out by Hydro One
4	Develop solution to address electricity needs in the Markham-Richmond Hill area	Q1 2017	Complete	A hand-off letter was sent to Hydro One and PowerStream in April 2017 to initate the development work for a new transformer station in Markham and associated connecton lines
5	Undertake engagement to gather community's input on the longer-term needs and solutions and to inform the next iteration of the York Region IRRP	On-going	On Track	Engagement with community is continuing on solutions for needs in York region
Greenstone - Marathon				
1	Synchronous condenser or STATCOM and new customer-based grid-connected generation at Geraldton mine. New 2x10 MW gas engine generating facility.	Dependent on industrial customer commitment. Industrial customer planned in-service date: 2020	On Track	Dependent on industrial customer need. No Commitments have been made by the Industrial Customer considered in the IRRP. Greenstone Gold has been briefed on this option. Additional analysis has been performed for Greenstone Gold to take their perspective (as opposed to a societal analysis included in the
2	New 230 kV line, 115 kV line, 230/115 kV autotransformer station, switching, and voltage control devices, in-service coincident with pumping station loads associated with a potential pipeline project.		On Track	Dependent on industrial customer need. The IESO has participated in meetings between potential proponents, communities, and potential customers. A Ministry of Energy-led Working Group has been established. No customer commitments have been received at this time.
3	Mine developers in Greenstone to retain the option of upgrading circuit A4L as an economic alternative for longer-term development		On Track	Long-term planning consideration
4	Investigate opportunities for a multi-use corridor to the Ring of Fire which includes a new transmission line.		On Track	Interfacing with appropriate government bodies on potential synergies. Government is leading Ring of Fire-related discussions.
5	The Town of Marathon conduct a detailed study of community energy options related to cogeneration		Not Started	Preliminary discussions with the Town of Marathon Economic Deveopment Corporation (EDC). Town's EDC is investigating the opportunity.

Key recommendations – regional plans (cont'd)

NO.	Key Recommendations	Timeline	Status	Comments
Regional Plans				
Pickering Ajax Whitby 2016 IRRP				
1	Build a new 203/27.6 kV (175/25MVA) step-down station in 2018 and associated circuit upgrade to provide supply by 2019 to the new community of Seaton	TBD	On Track	Veridian Board has approved the project. Site selection is underway
West of Thunder Bay				
1	Coordinate regional and community energy planning activities	On-going	On Track	
2	Monitor electricity demand growth closely to determine if and when a decision on Dryden 115 kV sub-system is required	Q4 2017	Not Started	
Thunder Bay				
1	Monitor electricity demand growth to determine if and when a decision for the Thunder Bay 115 kV system is required	Q4 2017	On Track	Thunder Bay LAC agreed to meet once per year. Next meeting will be Q4 2017
Barrie/Innisfil				
1	Rebuild and upgrade Barrie TS and E3/4B to 230 kV, with 75/125 MVA transformers	Q1 2021	On Track	
2	New feeders from Midhurst to allow for a load transfer from Barrie TS to Midhurst TS	Q1 2020	On Track	
3	A new 2 circuit 44 kV feeder from Barrie TS to the InnPower service territory	Q4 2020	On Track	
4	Continue to explore options to defer need for a future station in south Barrie	On-going	On Track	

Key recommendations – regional plans (cont'd)

NO.	Key Recommendations	Timeline	Status	Comments
Regional Plans				
Parry Sound/Muskoka				
1	Install two 230kV motorized switches at Orillia TS	Q4 2020	On Track	
2	Resupply some customers in the Parry sound and Waubaushene areas from neighbouring transformer stations using distribution facilites	Q4 2020	On Track	
3	Determine the cost and feasibility of using DERs and local CDM options to defer major captial investment in the Parry Sound Muskoka area	Q1 2017	On Track	
4	Examine the cost-benefit and cost responsibilty of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from an alternate transformer station	Q4 2017	Not Started	
5	Determine whether it is cost-effective to advance the end of life replacement and to replace the aging asset with upgrade/upsized facilites at Parry Sound TS and Waubaushene TS	Q4 2017	On Track	
6	Inform communities and LAC members of the 44kV sub-transmission service reliability performance in the Parry Sound-Muskoka area	Q4 2017	Not Started	
London				
1	As part of the planning forecast methodology - monitor the actual peak demand impacts of provincial conservation programs delivered by the local LDCs (Conservation First policy) and contracted DG.	On-going	On Track	Verified peak demand results for 2016 to be provided to LDCs and transmitter September 2017.
2	Install automated switching devices on the existing distribution system where feasible to provide faster load restoration ; and extend existing feeders from Clarke TS and Talbot TS to other stations in the sub-region where feasible to provide additional load transfer capability	Q4 2019	Not Started	
3	Monitor the actual peak demand impacts of provincial conservation programs delivered by the local LDCs (Conservation First policy) and contracted distributed generation (DG). If necessary, adjust the forecast for the sub-region	On-going	Not Started	

Key recommendations – provincial plans

NO.	Key Recommendations	Timeline	Status	Comments
Northwest Ontario Priority Transmission Projects				
East-West Tie				
1	East-West Tie line	2020	On Track	Project is proceeding. Order in Council on need was issued on March 4, 2016. Development work continuing with NextBridge and Hydro One in preparation for LTC application.
Provincial Bulk Transmission Project Northwest Bulk Line				
1	Northwest Bulk line	2024	On Track	The IESO's studies are currently underway in support of Hydro One's Environmental Assessment (EA) application. Studies completed in Q4 2016.
Provincial Bulk Transmission Project - Pickle Lake				
1	Line to Pickle Lake	2021	On Track	• On July 20, 2016 Order in Council (OIC) for the need for the new Line to Pickle Lake and to designate Watay Power as the proponent for the line and remote community connections. Wataay has also received approval for a Transmitter license. Wataay's SIA for the line to Pickle Lake is underway. • Upgrades to E4D by Hydro One to accommodate Rubicon have been put on hold as Rubicon is no longer pursuing additional capacity. Upgrades to E4D and E2R will be completed as load materializes and customers commit to funding the upgrades, consistent with the plan.
Remotes Community Connection				
1	Remote Communities Connection	2021-2024	On Track	On July 29, 2016, the province of Ontario selected Wataynikaneyap Power LP (Wataay) to connect 16 remote First Nation communities that currently rely on diesel power to the province's electricity grid. Wataynikaneyap Power has an active SIA application, is expecting to file LTC in October 2017. LTC will include plans for Phase 2 (Remote Connections). IESO has begun developing draft evidence in anticipation of the LTC proceeding(s).
Ottawa				
1	Hawthorne-Merivale Upgrade	To be determined	To be determined	Evidence has been drafted in anticipation of a future filing, however the project has not been triggered yet.

e) Please refer to the response to part (d) above.

f) One of the IESO's strategic objectives is to enhance reliability and efficiency through coordination of operations of IESO- and LDC-controlled resources. In support of that objective, the IESO has a pilot project underway with Alectra and is receiving real-time telemetry data for distribution-connected generation from a number of points within Alectra's service territory and is in the early stages of receiving geo-magnetically induced current (GIC) readings from Alectra. The IESO is also in discussions with two other LDCs to receive similar data by the end of 2017. The results of this pilot project will help inform future data sharing arrangements with other LDCs.

The IESO also formed a Grid-LDC Interoperability Standing Committee with the following objectives:

- Establishing a partnership to discuss issues and opportunities for a more coordinated operation of Ontario's electricity system;
- Increasing awareness of upcoming changes at both the grid and distribution levels to understand the impact on system operations and identifying practical ways to leverage these opportunities; and
- Identifying existing capabilities that can be better leveraged to support efficient and reliable operation of Ontario's electricity system.

The Standing Committee is not seeking to address DSM targets. Further information about the Standing Committee can be found at the IESO's website[1].

g) The Grid-LDC Standing Committee is considering a number of aspects of operational data sharing with the latest ideas included within the Grid-LDC Interoperability and Data Sharing Framework. Please refer to Attachment 2.

h) The advanced malware detection technology is progressing as per the revised project plan. The revised target completion date is Q4 2017.

i) The strategic goals contained within the cybersecurity work plan are described below. The project is on track and planned to be completed before the end of 2017.

[1] http://www.ieso.ca/en/sector-participants/engagement-initiatives/standing-committees/grid-ldc-interoperability-standing-committee

Strategic Goal #1: To establish cyber security information sharing capabilities within Ontario's electricity sector.

Strategic Goal #2: Augment the resilience of the Ontario power system by promoting best practice in cybersecurity including, incident response, information sharing, governance, security operations and analysis capabilities.

Strategic Goal #3: Maintain ongoing awareness of cyber security threats and risks associated with the Ontario power system and the broader North American interconnected grid.

Strategic Goal #4: Increase industry situational awareness and power system resiliency by hosting an annual senior leadership conference focusing on setting direction for the IESO Cybersecurity Forum, increasing awareness on threats and promoting best practice.

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IESO Strategic Plan
2016–2020

ieso
Connecting Today.
Powering Tomorrow.

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Letter from Bruce Campbell and Tim O'Neill

Ontario's electricity sector continues to undergo transformational change – as the sector evolves, the Independent Electricity System Operator (IESO) too must evolve to maintain the value we deliver to Ontarians. To prepare for these coming changes, we have developed a five-year corporate strategy that defines our goals and strategic objectives during this period of continued change. The strategy will inform the development of our annual business plans and allow us to maintain a clear focus on priorities, success drivers and measures.

Over the last five years, the IESO has contributed to successfully eliminating coal from Ontario's supply mix, reliably introducing a significant amount of renewable generation into the system, and executing procurements that leave Ontario adequately resourced for the foreseeable future. In addition, we have introduced demand response into the market, helped achieve significant energy savings through our conservation programs, and facilitated the transition to a new conservation framework that sees local distribution companies (LDCs) taking a more active role in the achievement of conservation results. We have also implemented a new regional planning process that gives communities a greater say in defining and executing their own energy solutions. Most importantly of all, these have occurred without impacting our ability to maintain a reliable power system for Ontario.

More change awaits Ontario's electricity sector on the policy, technology and structural fronts. Ontario's Climate Change Action Plan, new cap-and-trade regulations, the introduction of new technologies including the further development of smart grids and storage technology, and the expected consolidation of LDCs with larger amounts of resources embedded in their networks will all have significant impacts on the IESO in the coming years.

Guided by our vision of powering a reliable and sustainable energy future for Ontario, we remain focused on maintaining our core responsibilities. These include planning and operating Ontario's power system, enabling conservation and energy efficiency, procuring supply, and administering Ontario's wholesale electricity market.

Our five-year strategy was designed around our three strategic themes of providing public value; respecting and valuing our communities, customers and stakeholders; and building corporate resilience. With a focus on continued system reliability, a more efficient and sustainable marketplace, providing our insights and technical expertise, and the need to invest in our people and processes, this strategy will help define the priorities of the IESO over the next five years.

Engagement remains a priority for the IESO and we look forward to continuing to work with our sector partners, communities, customers and stakeholders to better serve the electricity sector during these changing times.

Bruce B. Campbell
President and Chief Executive Officer
Independent Electricity System Operator

Tim O'Neill
Chairman of the Board
Independent Electricity System Operator

Vision, Mission and Values

The IESO has a unique vantage point in the electricity sector – from operating the grid in real time to planning for the future needs of the province, from interacting with residential customers on conservation and generation programs to securing over 6,300 MW of electricity from the Bruce Nuclear Generating Station.

The IESO's mandate is far reaching.

For the public, we keep the lights on. We operate the electricity grid in a way that keeps it reliable and sustainable while ensuring value for ratepayers.

For our stakeholders, we engage with those who are affected by our initiatives as we work to evolve the electricity system to respond to changing circumstances.

For many, we are the go-to source for accurate information on Ontario's electricity system, providing technical expertise on electricity matters.

Our vision and mission capture this – our vision leads the way and our mission describes how we'll get there. And as we strive to achieve this vision, we will be grounded in our approach. Our values provide the framework for how we conduct business and define the IESO as an organization.

Vision

Powering a reliable and sustainable energy future for Ontario

Mission

We will do this by:

- Operating and shaping the electricity system and market in an effective and transparent manner
- Planning for and competitively procuring the resources that meet Ontario's electricity needs today and tomorrow
- Leading a culture of conservation
- Seeking and acting on input from our communities, customers and stakeholders
- Sharing relevant and valued information, data, analysis and expertise
- Attracting, retaining and developing a highly skilled and professional workforce.

Values

Trusted
We are trusted for the expert advice and service we provide.

Lead Change
We encourage learning, innovation and change.

Collaborate
We work together for a common purpose.

Diversity
We value the richness of each other's differences.

Integrity
We act with honesty and accountability.

Respect
Courtesy and dignity are at the forefront of all of our relationships.

Environmental Scan

The development of the IESO's five-year strategy included a comprehensive scan of the electricity sector to identify key considerations that could impact Ontario in the coming years. These key considerations include:

Supply and Demand Outlook

As we look at the supply and demand outlook for Ontario over the next 20 years, electricity demand growth is expected to remain relatively flat due to the effects of conservation and energy efficiency, the increase in embedded generation, and the change in the economy to less energy-intensive industries. At the same time, Ontario is expected to see a significant resource turnover, including nuclear refurbishment and retirement. Provided that planned resources come into service on schedule, Ontario is expected to remain adequately supplied for the foreseeable future, giving the IESO an opportunity to focus on the integration of new and emerging technologies through competitive market-based mechanisms.

Climate Change

While 90 percent of Ontario's electricity production now comes from non-fossil resources, there is an opportunity for the electricity system to play a significant role in reducing Ontario's overall emissions through the electrification of transportation and fuel switching. While electricity demand growth is expected to remain relatively flat over the next 20 years, climate change policy could considerably change this picture.

Climate Change Action Plan

With specific commitments for meeting the 2020 emission reduction targets and establishing the framework to meet 2030 and 2050 targets, the Climate Change Action Plan could have a significant impact on how the electricity system is planned and operated. Coordination between the IESO and sector partners will be critical in achieving these emission reduction targets while maintaining a reliable, efficient and sustainable electricity system.

Operability

With the evolving supply mix, we face new operating challenges in managing the bulk power system. Increasing variable generation, integration of distributed energy resources, and changing demand and supply patterns are creating operability challenges with respect to regulation, voltage control and flexibility. The IESO, with stakeholder input, will develop cost-effective solutions to address these challenges.

Emerging Technologies

The electricity sector is evolving with the emergence of new technologies such as microgrids, distributed energy resources, storage, demand management technologies and smart systems. These technologies are shaping the way we plan and operate the IESO-controlled grid with a shift to a more distributed system as compared to the centralized model of the past.

Sustainable Energy Future

With the emergence of these new technologies, there are additional resources available to provide necessary reliability services, each bringing its own unique operating characteristics. This provides an opportunity for the IESO to find innovative and cost-effective solutions to meet provincial and regional reliability needs. This can include leveraging and evolving existing market mechanisms to allow for broad participation in addressing these reliability requirements.

Consumer Engagement

Customers are becoming increasingly engaged and involved in managing their energy consumption. With new technologies being integrated into an increasingly connected world, customers will have the tools to manage their energy consumption in a more responsive manner than in the past, integrating data from appliances, thermostats, vehicles and many other devices.

Regional Planning

With the increase in distributed energy resources, demand management solutions and a more engaged customer base, there is a need to put a greater focus on regional planning and how local resources can meet regional reliability needs. Not only are customers becoming more informed, but they also have views as to how energy services are provided to their communities. Integrating and coordinating regional and bulk planning efforts are critical in developing cost-effective energy solutions for the overall reliability of the electricity system.

Cybersecurity

As the electricity system becomes more distributed, cybersecurity threats will become more diverse, posing additional risks to the reliability of the electricity system. As a result, there is a growing need for greater collaboration and information sharing of cybersecurity practices to protect electricity system operations and critical information.

Community, Customer and Stakeholder Engagement

More engaged customers, a greater focus on regional planning, a more interconnected electricity system, and an evolving sector – these factors all emphasize the need for the IESO to inform and engage communities, customers and stakeholders on electricity matters that may affect them. Engagement must remain a key priority for the IESO.

IESO Corporate Resilience

As with the rest of the electricity sector, the IESO sees a significant percentage of its experienced workforce approaching retirement in the coming years. To meet this challenge, we must invest in our people and processes to ensure an engaging work environment, providing development programs and career opportunities. The IESO must also be a focused and flexible organization in order to support the ongoing transformation of the energy industry.

Engagement with the individuals and organizations impacted by our decisions is one of the IESO's priorities.

IESO Strategy at a Glance (2016–2020)

The key considerations identified during the environmental scan helped frame the development of the IESO's strategy for the next five years. Building on the company's three core themes – providing public value; respecting and valuing our communities, customers and stakeholders; and building corporate resilience – the IESO set four overarching corporate goals as well as 11 strategic objectives that broadly define the processes through which these goals will be achieved.

Themes What we do	Providing public value		Respecting and valuing our communities, customers and stakeholders	Building corporate resilience
Goals What we want to achieve in the next five years	Deliver superior reliability performance in a changing environment	Drive to a more efficient and sustainable marketplace	Be recognized as a trusted advisor, informed by engagement	Invest in our people and processes to meet the needs of the sector
Strategic Objectives How we will achieve our goals	▪ Plan and manage the power system so Ontarians have power when and where they need it. ▪ Enhance reliability and efficiency through coordination of IESO- and LDC-controlled resources. ▪ Promote robust cybersecurity practices across the sector.	▪ Evolve the IESO markets to increase market efficiency and value for consumers. ▪ Foster an open and competitive electricity marketplace with broad participation.	▪ Enhance public confidence in the IESO and the sector to facilitate informed customer choice. ▪ Work effectively with government to support policy development and IESO's excellence in implementation. ▪ Seek out and respond to input from communities, customers and stakeholders to inform IESO decisions.	▪ Strengthen the development and engagement of our employees. ▪ Attract and retain the best talent. ▪ Be a focused and flexible organization positioned to support the ongoing transformation of our industry.

"Deliver superior reliability performance in a changing environment"

- Plan and manage the power system so Ontarians have power when and where they need it.
- Enhance reliability and efficiency through coordination of IESO- and LDC-controlled resources.
- Promote robust cybersecurity practices across the sector.

At the core of the IESO's mandate is a requirement to plan, operate and maintain the reliability of Ontario's electricity system, ranging from minute-to-minute operations to long-term system planning. With the new challenges that we face as Ontario's supply mix evolves and new technologies emerge, the IESO must find new and innovative ways to continue to deliver superior reliability performance to Ontarians.

The IESO will achieve this strategic goal by:

- Responding and adapting to changing system conditions, including increases in renewable and distributed energy resources, smart grids, electric vehicles and other new technologies, to maintain power system reliability;
- Supporting the implementation of priority transmission projects, including the connection of remote communities;
- Evolving the regional planning process to better integrate conservation, distributed generation, storage and demand response, and to explore opportunities for local acquisition of these resources;
- Enhancing the organization's situational awareness, particularly with our interconnected neighbours, through increased wide-area monitoring, event analysis capability, and understanding of emerging trends;
- Defining, developing and implementing coordinated operations with LDC partners;
- Maintaining a cybersecurity leadership role through the IESO's cybersecurity forum and related initiatives; and
- Supporting the Ontario Energy Board in its program with respect to cybersecurity practices for regulated entities.

"Drive to a more efficient and sustainable marketplace"

- Evolve the Ontario market to increase market efficiency and value for consumers.
- Foster an open and competitive electricity marketplace with broad participation.

In providing a reliable electricity system for Ontarians, the IESO aims to do so in a cost effective and sustainable manner. While the emergence of new technologies may pose challenges to reliable system operations, it also creates opportunities and alternatives to provide needed reliability services, introducing more competition into a market where resources can participate on a level playing field.

These emerging technologies are already altering the way the power system operates. From the centralized model that features large-scale generators delivering power across high-voltage transmission lines to lower-voltage distribution networks, the electricity system is evolving to a more distributed model with more small-scale generation located close to the load that it serves. This shift is requiring sector participants to re-examine their business models and evolve to meet these changing conditions. With its unique vantage point, the IESO can help shape how this energy future unfolds and is looking to work with sector partners to define this vision.

The IESO will achieve this strategic goal by:

- Designing, developing and implementing a renewed market structure, addressing known market inefficiencies and laying the foundation for a more dynamic marketplace in the future. The IESO will look at both evolving the wholesale energy market and growing capacity as a market-based product. In doing so, the IESO will build on stakeholder input and ensure appropriate funding, rules, processes and governance structures are in place;
- Continuing to enhance the demand response market with a focus on enabling residential demand response;
- Designing, implementing and administering a portfolio of competitive resource acquisition mechanisms for a variety of services (capacity, flexibility and ancillary services) to address needs identified through bulk and regional planning. These mechanisms should allow for broad participation while meeting reliability needs and policy goals, such as sustainability and low carbon, while balancing ratepayer value with fairness to service suppliers;
- Enhancing the value of electricity data by expanding the type of and access to smart meter data received by our systems;
- Working with sector partners to foster an open and competitive electricity marketplace that is equally open to the buy and sell sides, encourages new opportunities for innovation and meeting policy goals, and focuses on acquiring services, agnostic to technologies; and
- Continuing to promote competitive solutions for energy efficiency to inform the future of conservation.

"Be recognized as a trusted advisor, informed by engagement"

- **Enhance public confidence in the IESO and the sector to facilitate informed customer choice.**
- **Work effectively with government to support policy development and IESO's excellence in implementation.**
- **Seek out and respond to input from communities, customers and stakeholders to inform IESO decisions.**

We recognize that, in order to be successful in achieving our public value goals of delivering superior performance in a changing environment and driving to a more efficient and sustainable marketplace, our efforts must be supported. We need our stakeholders, customers and others to have trust in us – to trust that we will not only advise based on our broad technical expertise but that we will also actively and transparently engage with our communities, customers and stakeholders to inform our decisions and advice.

The IESO will achieve this strategic goal by:

- Using communication opportunities, such as those provided through regional planning and speaking engagements, to inform the public on electricity matters;
- Maintaining and building on our positive relationships with First Nations & Métis communities through the use of innovative approaches to engagement;
- Enhancing both transparency of and access to data and information to meet the needs of communities, customers, stakeholders and others;
- Building trust with government by providing unbiased expertise and advice;
- Effectively implementing initiatives that achieve government policy objectives; and
- Applying IESO stakeholder principles in the development of initiatives by ensuring stakeholders and communities have the opportunity to provide input on matters that impact them.

"Invest in our people and processes to meet the needs of the sector"

- **Strengthen the development and engagement of our employees.**
- **Attract and retain the best talent.**
- **Be a focused and flexible organization positioned to support the ongoing transformation of our industry.**

Our employees are critical to our success. As such, we need to focus on the ongoing development of our people and ensuring we have engaged and high performing employees. In addition, as we undertake to implement our strategy and further define our role in the electricity sector, we require effective organizational processes to achieve our desired outcomes. The need to minimize the financial impacts of our operations on electricity customers will require us to be flexible in deploying our resources to manage the ongoing transformation of our sector.

The IESO will achieve this strategic goal by:

- Providing formal opportunities for employees to enhance cross-functional understanding;
- Conducting employee engagement surveys with annual updates to action plans;
- Implementing the Operations Readiness Initiative[1] to meet future operational needs;
- Achieving excellence in project governance and management;
- Evolving the IESO systems and practices to best serve our evolving business priorities;
- Developing an enabling environment that facilitates high performance and builds the appetite and capacity for change;
- Adopting best practices for records and information management;
- Implementing a talent management system that includes enhanced recruitment and selection capabilities, a suite of comprehensive learning and development programs, organizational development services, and reward and recognition plans; and
- Expanding and deepening leadership bench-strength and capabilities.

[1] The Operations Readiness Initiative will provide an operational framework that will allow the IESO to adapt to the evolving environment while maintaining the same level of performance in managing the reliability of the grid.

Looking Ahead

This strategy provides a roadmap for the IESO's activities over the next five years. The strategy will help set the priorities for the organization and will inform the development of our annual business plans. Recognizing the changing environment in which we operate, the IESO will do an annual review of our strategy and the sector overall, including seeking stakeholder input, and update our strategy as necessary.

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Grid-LDC Interoperability and Data Sharing Framework

Purpose:

- To identify current opportunities that local distribution companies (LDCs) have to interact with the IESO to access or submit information and participate in collaboration opportunities; and
- To highlight areas where further collaboration and data sharing opportunities may exist.

Summary:

The IESO currently makes Market and System Information available to market participants through several mechanisms, which are listed below. In addition, some planning and training activities are conducted on a regular basis that could be of value to the LDC community. Future collaboration opportunities are items that may be of greater importance in the future due to the changing nature of the electricity sector in Ontario.

Tables below include the following:

- Current Interaction with the IESO
  - Information Currently Available Online
  - Collaboration Forums
  - Testing and Confirmation of Operational Data

- Future Collaboration Opportunities
  - Data Sharing and Planning

Current Interaction with the IESO

Information Currently Available Online		
Item	Location	Value
Current Ontario Demand	IESO Web Site	Provides an indication of provincial demand relative to LDC demand
IESO Market and System Data	IESO Reports Site	Various Physical and Financial Files and Statements used for real time operations and settlements
Data Submission Tools for: • Reliability Compliance • Meter Trouble Reporting • Notice of Disagreements • Outage Management	IESO Portal	On-line methods to submit data to IESO
Ontario Reliability Compliance Program	Reliability Standards Compliance	Access to compliance deadlines and Online Compliance Self-Certification
Market Place Training	IESO Training	Enhance understanding of various aspects of IESO Market and System Operations
Market Rules and Manuals	Market Rules and Manuals	Understanding of obligations and processes for participating in IESO's administered markets, related to: • Metering; • System Operations; and • Reliability Compliance.

Collaboration Forums		
Subject	Medium	Value
Emergency Preparedness	• Participation in IESO led Emergency Preparedness Task Force (EPTF) • Participation in Emergency Preparedness Working Groups • Information on Emergency Preparedness page of IESO web site • The Ontario Electricity Emergency Plan	The stakeholder-represented Emergency Preparedness Task Force (EPTF), chaired by the IESO's Chief Operating Officer meets three times a year to support market participants' Emergency Preparedness efforts.

Collaboration Forums Cont'd		
Subject	Medium	Value
Ontario Power System Restoration Plan (OPSRP)	Participation in IESO-led training & workshops: • Online OPSRP • Workshops • Exercises (incl. NERC Gridded)	Each workshop features the review of the bulk electricity system, its operation and IESO/restoration participants' roles in maintaining system reliability during normal and abnormal conditions and/or when restoring the power system following large-scale blackouts using specific interactive table-top exercises.
Cyber/Physical Security Information & Awareness	Participation in: IESO Cyber Forum • CEA Security Infrastructure Protection Committee (SIPC) • Canadian Cyber Incident Response Centre (CCIRC) • NERC Electric Information Sharing and Analysis Centre (E-ISAC)	Sharing of Issues, concerns and mitigations to improve security at all levels
Reliability Compliance	Reliability Standards Standing Committee	Provides market participants with updates on new and revised reliability standards and compliance best practices.

Testing and Confirmation of Operational Data	
Test	Details/Required Information
Satellite Phone testing	Monthly tests to ensure proper functioning of satellite equipment.
Voltage Reduction Tests	Conducted every 18 months to verify amount of reduction in Ontario Demand achieved through 3% and 5% voltage reductions
Load Shedding Simulations and Rotational Load Shedding (RLS) Schedules	Verify the readiness of participants to shed load including the identification of Priority Customer Loads within the LDC system (this might include telecom CO's)

Future Collaboration Opportunities

Data Sharing and Planning			
Item	From	To	Value
Embedded Generation (EG) Visibility	LDC	IESO	Providing telemetry and registration data for embedded resources to improve visibility of these resources
Solar variable generation forecast	IESO	LDC	Aggregated EG telemetry forecasted at a station level to assist LDC's in forecasting their variable generation outputs
Geomagnetic ally Induced Current (GIC) values	LDC	IESO	• Share LDC real-time GIC values, where available to improve monitoring and studies • IESO to share GMD operating guidelines with LDC and provide individualized plan
Coordination of Load Transfers	IESO	LDC	Having prior knowledge of what transfers are possible as well as load distribution details could help with restoration plans and coordinating difficult outages
Improved understanding of customer consumption patterns	LDC	IESO	LDCs have more experience with changes in consumption patterns of their customers, either from the impacts of time of use prices, conservation efforts or changes in end use technologies

BOMA INTERROGATORY 2

Issue 1.0, 5.1

INTERROGATORY

Reference: Issues 1.0, 5.1; Conservation First Framework; Industrial Accelerator Program

a) What percentage of the 1.7 Twh of targeted savings to be achieved by the Industrial Accelerator Program by the end of 2020 is currently (i) has been achieved and measured to date; (ii) under construction pursuant to implementation contracts; (iii) under study pursuant to engineering/audit contracts; (iv) not yet the subject of a site specific study? Please provide this information as of June 30, 2017. When was the program established?

b) Please explain the management structure and reporting structure for this program. How many FTEs are dedicated to this program? What are their functions? Are outside contractors used to administer, manage, or promote the program?

c) The program has been very slow to produce results in the form of projects in operation. Please describe the plan to increase contracted investments to 0.78 Twh (half of the six year target) by December 2017 (our emphasis), or explain fully why that acceleration is not possible. When will these projects come into operation? Please provide a rough timetable for project completion and commencement of measured savings.

d) What are the milestones between now and December 31, 2020 to measure progress of the program?

e) Please provide copies of any internal or third party studies that have been done to assess the reasons for the slow start and which suggest solutions. Should this program be transferred to another party, such as Hydro One Transmission? Please discuss.

RESPONSE

a) The Industrial Accelerator Program (IAP) has achieved 0.231 TWh of projects in-service. Further, there is an additional 0.368 TWh of projects contracted, but not yet in service. The IAP also has 0.181 TWh in project applications (but not yet contracted), and a further 0.522 TWh of project under study that have not proceeded to project applications. This version of the IAP Program was established on June 23, 2015, and has a mandate until December 31, 2020.

The uncertainty of the “not yet studied” opportunities, even in aggregate, is too high to extract meaningful projections for potential contracted energy reductions.

b) The Industrial Accelerator Program at the IESO is managed by a team of six FTEs, including a Program Manager (to oversee the program, provide financial approvals, update the processes and procedures), three Business Managers (who manage the intake of applications and relationships with the IAP customers), one Program Lead (who manages customer contracts, program compliance, and reporting), and one Engineering Lead (who provides technical support, technical review, and potential risk management of the program).

The IESO has engaged a Technical Reviewer to provide technical review services that includes application review, Measurement and Verification plan creation, invoice and documentation review, and broad technical assistance, among other tasks. The IESO is also considering engaging support, on a pay-for-performance basis, to assist customers to increase participation and uptake in the program.

c) The IAP has an aggressive target and a limited group of customers, who are energy-efficient by design. The customers eligible in the IAP are some of the largest customers in the province, and make up a significant portion of the province’s employment and GDP. The size and complexity of their operations is unmatched, and there are long lead times needed for project approval and project implementation. There are also many factors that influence their ability to spend capital on energy efficiency projects.

The projects described in the response to part a) typically have two years from contract signing to be brought into service.

The IAP team has been working diligently to engage with customers and to improve our processes. To that end, there have been program enhancements, including the Energy Manager initiative, and a newly released streamlined contract. The IAP team has been working on developing multi-year agreements with a few customers for a portfolio of projects, and bringing forward a pay-for-performance pilot program for industrial facilities. The IAP will continue to be a strong steward of ratepayer funds, enabling cost-effective projects, and work closely and collaboratively with customers to bring their energy efficiency projects forward.

d) There are no milestone targets between now and December 31, 2020. The IAP reports end of year progress in the Annual Report (refer to Exhibit A-3-1). The Environmental Commissioner of Ontario[1] also reports on the IAP progress.

[1] http://docs.assets.eco.on.ca/reports/energy/2016-2017/Every-Joule-Counts.pdf

e) The 2015 third-party evaluation report is provided as Attachment 1. The IAP team seeks to continually improve the processes for program delivery including, but not limited to, the following:

- Direct and indirect feedback from participants
- Stakeholder sessions, particularly those that are part of the mid-term review
- Benchmarking against other industrial programs across North America through our involvement with organisations such as Association of Energy Services Professionals, American Council for an Energy Efficient Economy and Association of Energy Engineers

The IAP has a short and static list of engaged customers, and we work closely with them to realize potential projects. As indicated, the IAP is looking at engaging support for customers, similar to the agreements in place at multiple LDCs.

The role of the IAP within the IESO is very complementary to our work with the Conservation First Framework, and the IESO is also the body that transacts with this group of customers for metering, settlement etc. As a result, there is a broad and deep relationship between the IESO and the transmission-connected customers. Target achievement is an important goal of the IESO, with a focus to build the culture of conservation in the province and providing programs to assist customers in reaching their energy efficiency and sustainability goals.

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2015 EVALUATION OF INDUSTRIAL ENERGY EFFICIENCY PROGRAMS

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

Final Report

October 7, 2016

ECONOLER

ABBREVIATIONS

BMG	Behind-the-meter Generation
EM	Energy Manager
EM&V	Evaluation, Measurement and Verification
EUL	Effective Useful Life
HVAC	Heating, Ventilation and Air-conditioning
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
LC	Levelized Delivery Cost
LDC	Local Distribution Company
M&T	Monitoring and Targeting
M&V	Measurement and Verification
NTGR	Net-to-gross Ratio
PAC	Program Administrator Cost
PSU	Process and Systems Upgrades
TR	Technical Reviewer
TRC	Total Resource Cost
VFD	Variable Frequency Drive

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EXECUTIVE SUMMARY

The evaluation team, comprised of Econoler and Cadmus experts, was commissioned to perform the 2015 impact evaluation of the Industrial Accelerator Program (IAP), the Process and Systems Upgrades (PSU) program, the Energy Managers program, and the Monitoring and Targeting (M&T) program operated by the Independent Electricity System Operator (IESO).

The IAP is offered to all companies connected to the transmission system and provides financial support through various initiatives, such as Process and Systems, Retrofit and Energy Managers.

The PSU, Energy Managers, and M&T programs are offered to companies connected to the distribution systems of local companies.

Evaluation Goals and Objectives

The goals and objectives of this evaluation are summarized as follows:

- **Gross Savings Review:** To determine, with a 90% confidence level and a maximum margin of error of 10%, the annual gross verified electric energy savings, summer peak demand savings[1], and the Realization Rates (RR) of the programs.
- **Savings Attribution Analysis:** To determine the net-to-gross ratio (NTGR) and calculate the annual net verified energy and peak demand savings resulting from the programs.
- **Cost-effectiveness Assessment:** To assess the cost-effectiveness of the programs based on the costs incurred to implement the programs and the benefits they produced.

Impact Evaluation Methodology

The impact evaluation consisted of two main steps. First, the gross reported savings were verified through desk reviews, and on-site visits or phone interviews. The realization rates were established for energy and summer peak demand savings by comparing verified and reported gross values. Adjustment ratios were also calculated for the effective useful life (EUL) and incremental costs. Then, the NTGR was determined to establish the net verified savings. This ratio includes free-ridership for all programs, and spillover for IAP and PSU.

[1] Throughout this report, peak demand savings values apply to the summer peak. The summer peak was identified by the IESO as the critical peak for the evaluation.

Gross Savings Review

The 2015 evaluation was completed by reviewing a total of 120 projects and measures, selected from a total of 454 projects. For the program with the largest number of projects, Energy Managers, a 21% representative sample was selected for review to ensure cost-effectiveness of the evaluation. The evaluation team made on-site visits to conduct the reviews. However, when an on-site visit was not possible, the team scheduled a phone interview to complete the review. Of the 120 projects and measures reviewed, an on-site visit was done for 115 and only five were reviewed with the help of a phone interview.

Table 1: Sample Size for the 2015 Evaluation

Program/Initiative	Total Number of Projects/Measures	Total Number of Projects/Measures Reviewed
IAP - Retrofit	11	11
IAP - Process and Systems	4	4
IAP - Energy Managers	1	1
PSU	12	12
Energy Managers	424	90
M&T	2	2
Total	**454**	**120**

A desk review of the documentation available for a project was completed prior to the on-site visit or the phone interview. The evaluation team developed a standardized data-collection protocol for each program to ensure consistency of the collected information during the reviews. As part of the review, the EUL and incremental cost of each of the projects and measures were also validated.

The evaluation team used the results and information of the desk reviews, on-site visits and phone interviews to establish the gross verified energy and peak demand savings for each program. In cases where a review provided additional information or information different from that contained in the project and measure documentation, or where errors were found in the calculations, modifications were made to the gross savings calculation to account for these new elements.

For all the programs except Energy Managers, the realization rates and adjustment ratios were calculated for each individual project since all the projects were reviewed. For Energy Managers, a sample was selected, and =an extrapolation of the results was applied to the entire program. The overall realization rates and adjustment ratios were calculated based on the individual results obtained for the measures in the sample. For each extrapolated value, the evaluation team made sure that the target confidence level of 90% and maximum margin of error of 10% were met.

Net-to-gross Ratio

The NTGR was established using a self-reporting approach. Two questionnaires were developed: one for IAP Process and Systems, IAP Retrofit and PSU, and the other for non-incentivized measures in IAP Energy Managers, Energy Managers and M&T.

For all the programs, free-ridership was measured by assessing two factors, namely the participant's intention and the program's influence.

Spillover was evaluated for IAP Process and Systems, PSU and IAP Retrofit. The questionnaire was intended to determine whether the participants had implemented other energy-efficiency projects, for which they had not submitted applications to any IESO program and had been influenced by the IESO or their local distribution company in doing so.

The questionnaires were administered during the site visits or the phone interviews for IAP Process and Systems, IAP Retrofit and PSU. The non-incentivized measures' questionnaire was conducted through an online survey[2] targeting facility managers for a sample of Energy Managers measures. This methodology ensured reaching a maximum margin of error of 10% at a confidence level of 90%.

Cost-effectiveness

To assess the cost-effectiveness of each of the programs, the impact evaluation results and the programs' cost information were analyzed and reviewed. This cost-effectiveness assessment involved performing the following cost-effectiveness tests: the Total Resource Cost (TRC), the Program Administrator Cost (PAC) and the Levelized Delivery Costs (LC). The performance indicators generated by these tests included: the benefits, costs, net benefits and benefit-to-cost ratio for each program.

Impact Evaluation Results

Savings Results

The impact evaluation revealed that the programs collectively achieved 209.305 GWh in net verified annual energy savings and 26.960MW in net verified summer peak demand savings.

The program that generated the highest total net energy and peak demand savings was PSU, followed by IAP and Energy Managers. In comparison, the M&T program yielded significantly lower levels of savings. The savings from PSU were mostly attributable to behind-the-meter generation (BMG) projects. Of the total 12 projects, only four were BMG projects, but they accounted for 70% of the net peak demand savings and 71% of the net energy savings. The industrial programs reaffirmed the
trend in increased savings observed in previous years, as their total energy savings increased by 66%

[2] This survey questionnaire can be found in Appendix VII.

over 2014.

The overall program realization rates for summer peak demand savings and energy savings were 99% and 101%, respectively. These close-to-unity rates indicate that overall, the reported savings were similar to the evaluated values. In general, the realization rates for peak demand savings were further from unity than those for energy savings. This is due to the fact that the IESO's definition of peak demand savings (as set out in the Conservation First Framework Evaluation, Measurement and Verification Protocols[3]) is not used to establish gross reported savings. Despite the overall good realization rates, for some programs, a small share of their projects or measures had to be adjusted more significantly. For PSU, the realization rates varied from 18% to 122% for energy and peak demand savings.The lowest realization rates were due to the adjustments made to the baseline energy use, where the Evaluator found that the values were not representative of the energy consumption of the period before the project was implemented. Another issue was that for PSU and IAP Process and Systems, the reported values for energy and peak demand savings were based on direct metering results.The technical reviewer did not make adjustments to ensure that the reported values are representative of savings to be expected in future years. Instead, the evaluation team made these adjustments, causing the realization rates varied slightly from unity.

To estimate the lifetime savings, the evaluation team also reviewed the reported EUL values for each program. Those values were accurate for most programs, and the majority of the adjustments made were for the Energy Managers program. One noticeable issue was that 12% of the sampled Energy Managers measures were actually behavioural measures and had been misidentified as equipment replacement. This led to significant adjustments to EUL, which was adjusted downward to one year.

The interviews conducted with participants showed that little measurable spillover occurred for IAP Process and Systems, PSU and IAP Retrofit. However, some free-ridership was observed in most programs. The programs' NTGRs for peak demand savings and energy savings range from 0.7 to 1.0. For PSU, the free-ridership level specific to BMG projects was compared to that of other projects. It was established at 22% for BMG projects and at 13% for all the other projects.

[3] IESO, *Evaluation, Measurement and Verification (EM&V) Protocols and Requirements*, v. 2.0, pp. 75-79.

Table 2: Program Metrics

Program Metric	IAP Process and Systems	IAP Retrofit	IAP Energy Managers	Process and Systems Upgrades	Energy Managers	M&T	Total
Number of Projects/Measures	4	11	1	12	424	2	**454**
Program Realization Rate for Energy Savings (%)	109%	103%	102%	100%	101%	100%	**101%**
Program Realization Rate for Demand Savings (%)	96%	100%	100%	94%	115%	0%	**101%**
Annual Gross Verified Energy Savings (GWh)	22.209	32.965	0.041	152.701	47.779	1.369	**257.064**
Gross Verified Peak Demand Savings (MW)	2.506	3.882	0.005	17.026	9.370	0.000	**32.789**
Net-to-gross Ratio for Energy Savings	0.93	0.87	0.70	0.80	0.75	1.00	**0.81**
Net-to-gross Ratio for Demand Savings	0.93	0.87	0.70	0.80	0.81	1.00	**0.82**
Net Annual Verified Energy Savings (GWh)	20.669	28.700	0.028	122.704	35.834	1.369	**209.305**
Net Verified Peak Demand Savings (MW)	2.330	3.387	0.003	13.649	7.590	0.000	**26.960**
Average Verified Effective Useful Life (years)	12.0	9.3	6.0	15.87	7.7	1.0	**13.1**
Net Verified Lifetime Energy Savings (GWh)	248.381	267.211	0.171	1,946.749	275.544	1.369	**2,739.424**

Cost-effectiveness Results

The cost-effectiveness results are presented at the program level to provide an overall program perspective. Namely, the cost-effectiveness results of all IAP initiatives have been combined together under IAP to provide information about the entire program portfolio offered to transmission-connected participants.

The results of the PAC test show that M&T is the only program that is not cost-effective from a program administrator's standpoint, because it has a PAC ratio of less than 1 (0.08). The three other programs have a ratio between 1.20 and 1.52.

The results of the TRC test show that from society's standpoint (particularly the IESO and participating customers), none of the four programs are cost-effective. These results are mostly due to the relatively small number of projects in IAP, PSU and M&T, and high program costs in all the programs. Also, a number of PSU projects completed in 2015 did not present a complete measurement and verification report; so, they were not included in the 2015 impact evaluation. Although costs were already incurred for those projects, their savings have not been accounted for in the 2015 evaluation.

The LC test indicates that avoided energy and demand resulting from M&T are much costlier to achieve, up to 10 times more, than for other programs. This is mostly because only two projects were completed under M&T this year. The analysis indicates that the costs of saving one GWh with the IAP, PSU, and Energy Managers programs are between $47,000 and $53,000.

Table 3: Cost-effectiveness Tests Summary

Cost Test		IAP	PSU	Energy Managers	M&T
Program Administrator Cost (PAC)	Benefit (million $)	22.729	81.950	15.796	0.057
	Cost (million $)	18.078	68.487	10.368	0.681
	Net Benefit (million $)	4.651	13.462	5.427	-0.624
	Net Benefit Ratio	1.26	1.20	1.52	0.08
Total Resource Cost (TRC)	Benefit (million $)	26.139	94.242	18.165	0.066
	Cost (million $)	32.704	110.909	25.086	0.812
	Net Benefit (million $)	-6.565	-16.667	-6.921	-0.746
	Net Benefit Ratio	0.80	0.85	0.72	0.08
Levelized Delivery Cost (LC)	$/GWh	47,139	52,508	47,010	482,491
	$/MW-yr	405,810	474,786	218,239	-

Conclusions and Recommendations

Conclusion No. 1:

The TRC indicators show that the programs are not cost-effective; however, these indicators provide a skewed perspective because the calculations include all the program costs, but do not fully account for the benefits that result from the program. For IAP P&S and PSU, this is mostly due to the delay between the initiation of the participation process and the accounting of savings when projects are completed, as well as the significant costs incurred by business development (in the form of engineering studies). For Energy Managers, the issue is mostly that only non-incentivized measures are considered benefits, while the program leads to many more projects being submitted through the Business Retrofit program or PSU.

Recommendation No. 1

Analyze the overall cost-effectiveness from a program-wide perspective, especially for Energy Managers.

Conclusion No. 2:

The reporting procedures could be improved for the M&V reports and the program database. The reported savings are not calculated by following the same rules as those for the verified savings calculations.

Recommendation No. 2a

Define the guidelines for calculating the reported annual energy savings and the peak demand savings. These should be applied by the TR so that energy savings correspond to the annual savings expected during a normal year and peak demand savings correspond to the definition outlined in the EM&V Protocols & Requirements.

Recommendation No. 2b

Include a specific section in the M&V report to identify the unusual events or changes in static variables. This will help ensure that M&V results are adjusted appropriately to represent the savings of a normal year.

Conclusion No. 3:

The benefits of the M&T program are underestimated because the current savings calculation methodology requires the use of an EUL of one year.

Recommendation No. 3

Consider calculating the savings associated with equipment retrofit measures using simple engineering calculations, so that a portion of the savings can be assigned an EUL value of more than one year.

Conclusion No. 4:

The savings calculations are not quite consistent among EMs.

Recommendation No. 4a

Encourage the use of standardized calculation sheets for common energy-efficiency measures. Some have already been developed for IAP Retrofit and could be used for the Energy Managers program.

Recommendation No. 4b

Raise awareness about the guidelines concerning the peak demand definition and peak demand savings calculations. As many EMs have indicated that they did not know or understand the peak demand definition, there seems to be potential for improvement at this level.

Conclusion No. 5:

Some of the guidelines to be followed by the TR in reviewing the projects are not clearly explained, namely how to treat fuel-switching projects or projects that are aimed solely at increasing capacity. The Evaluator also noticed that the TR only applied adjustments to reported savings when the savings were overestimated.

Recommendation No. 5a

Clarify the eligibility criteria applicable to the Energy Managers program non-incentivized measures. This includes providing clear direction on when fuel-switching projects should be accepted and how to calculate savings when a measure involves an increase in production capacity.

Recommendation No. 5b

Require the TR to make both downward and upward adjustments to the savings reported by the EMs. The objective of the technical review is to increase accuracy rather than to make the most conservative estimates of savings.

Recommendation No. 5c

Establish a savings threshold over which an energy manager (EM) must submit a savings substantiation plan to the TR prior to implementing a measure.

INTRODUCTION

The evaluation team, comprised of Econoler and Cadmus experts, was commissioned to perform the 2015 impact evaluation of the Industrial Accelerator Program (IAP), the Process and Systems Upgrades (PSU) program, the Energy Managers program, and the Monitoring and Targeting (M&T) program.

The goals and objectives of the evaluation are summarized as follows:

- **Gross Savings Review:** To determine, with a 90% confidence level and a maximum margin of error of 10%, the annual gross verified electric energy savings, summer peak demand savings and Realization Rates (RR) of the programs.
- **Savings Attribution Analysis:** To determine the net-to-gross ratio (NTGR) and calculate the net annual verified energy and net verified peak demand savings resulting from the programs.
- **Cost-effectiveness Assessment:** To assess the cost-effectiveness of the programs based on the costs incurred to implement the programs and the benefits they produced.

The present report describes the programs and the methodology used for their evaluation. The findings of the impact evaluation are also presented along with recommendations aimed at improving these programs' effectiveness.

1 PROGRAM BACKGROUND AND DESCRIPTION

In Ontario, over 50% of all the industrial-sector electricity consumption is accounted for by approximately 200 companies, which are all considered as large electricity consumers. About a quarter of these companies are connected to the high-voltage transmission system, while the other companies are connected to local distribution companies (LDCs). To help reduce the high electricity consumption of these industrial companies, the Independent Electricity System Operator (IESO) launched several programs and initiatives, including the IAP, the PSU program, the Energy Managers program and the M&T program. The IESO contracted a firm to act as a technical reviewer (TR), which is responsible for: (1) reviewing the savings calculations; (2) developing the measurement and verification (M&V) plans and reports for applicable projects; (3) processing the applications; and (4) providing technical support to the LDCs.

1.1 Overview of the Industrial Accelerator Program

Launched in 2010, the IAP provides transmission-connected companies with incentives for implementing their electric energy-efficiency projects and provides financial support through three initiatives, namely: Process and Systems, Retrofit and Energy Managers. Below is a brief description of these three initiatives:

1. Process and Systems is a five to ten-year contractual commitment to assist customers in making their major processes and equipment more energy-efficient. Incentives include funding for preliminary and detailed engineering studies, and project incentives of up to $10 million per application.[4]
2. Launched in December 2013, Retrofit provides customers with incentives to purchase high-efficiency equipment. Popular retrofits include lighting, heating, ventilation and air-conditioning (HVAC) measures, motors, variable frequency drives (VFDs), and new control systems. The Retrofit initiative includes the following tracks: (1) Prescriptive Lighting; (2) Prescriptive Non-lighting; (3) Engineered Lighting; (4) Engineered Non-lighting; and (5) Custom. The Retofit Initiative is more flexible in terms of contractual duties than Process and Systems as it allows customers to withdraw at any time.
3. The IAP Energy Managers initiative offers funding for hiring the services of an energy manager (EM) who is trained to identify energy-saving opportunities and energy investments. The Energy Managers program does not offer incentives for implementing measures; rather, it offers financial support for the salary of specialized energy efficiency staff, technical support and training to help with the implementation of projects that are non-incentivized or incentivized through other programs.

[4] Financial incentives for capital projects can be higher than $10 million with the board’s approval.

1.2 Overview of the Programs Administrated by the LDCs

PSU, Energy Managers and M&T provide incentives to customers served by LDCs so that all the regional industrial[5] customers have access to an incentive program to encourage them to improve energy efficiency. LDCs deliver these three programs.

What follows is a brief description of these three programs:[6]

1. The PSU program is designed to help organizations with complex systems and processes identify and implement energy-saving projects of various sizes for a minimum of 100 MWh in annualized electricity savings. Financial incentives can cover up to 70% of project costs, and is capped at $10 million for larger projects. Incentives are determined based on criteria related to annual electricity savings, eligible project costs or the payback period.
2. Like the IAP Energy Managers initiative, the Energy Managers program also offers funding for hiring the services of an EM, who provides services to (1) an eligible participant with one or more facilities and is employed by the eligible participant (embedded energy manager) or (2) multiple industrial facilities, when employed by the LDC or a group of LDCs (roving energy manager). Among these opportunities, some projects may use PSU incentives, but a minimum of 30% of the savings must be achieved through non-incentivized projects.
3. The M&T program provides organizations with incentives to implement a metering system which helps companies identify opportunities to reduce their energy consumption through operational changes or process improvements. The Program provides funding for up to 80% of actual eligible costs (less any third-party contributions), or up to $75,000 per site, to purchase and install an M&T system and make it operational. In addition, energy savings and demand savings targets are set for each site. These targets may come from projects incented through other programs, but also non-incented projects. The targets must be met over a full two-year period after the M&T system is installed.

[5] Alhough Energy Managers is part of the industrial program offerings, many participants are from the commercial and institutional sectors.

[6] The program descriptions correspond to the 2015 extension of the 2011-2014 SaveONEnergy Framework, since a vast majority of the projects and measures included in this evaluation were part of this framework.

2 METHODOLOGY

This section describes the evaluation team and the methodology used to evaluate the IAP, PSU, Energy Managers and M&T programs.

Project Management to carry out the 2015 evaluation, Econoler and Cadmus partnered up to form the evaluation team. The tasks were divided as follows:

- Econoler acted as the team leader and was responsible for the overall project management, including coordinating all the evaluation activities, as well as reviewing all the data-collection and in-field instruments, and deliverables. Econoler led the gross and net impact evaluation work and cost-effectiveness assessments, while also conducting a number of the desk reviews and on-site visits required for the impact evaluation.
- Cadmus was responsible for developing the attribution questions and the scoring methodology to measure the free-ridership levels and the NTGR values for all initiatives. They also conducted the online survey with facility managers who hired an EM.

In addition, Posterity was commissioned as a sub-contractor to assist the evaluation team in conducting some project desk reviews and on-site visits under Econoler's supervision.

2.1 Methodological Model

Figure 1 illustrates the research strategy employed and the data-collection activities carried out in the 2015 impact evaluation. The data-collection tools used are shown in the appendices.

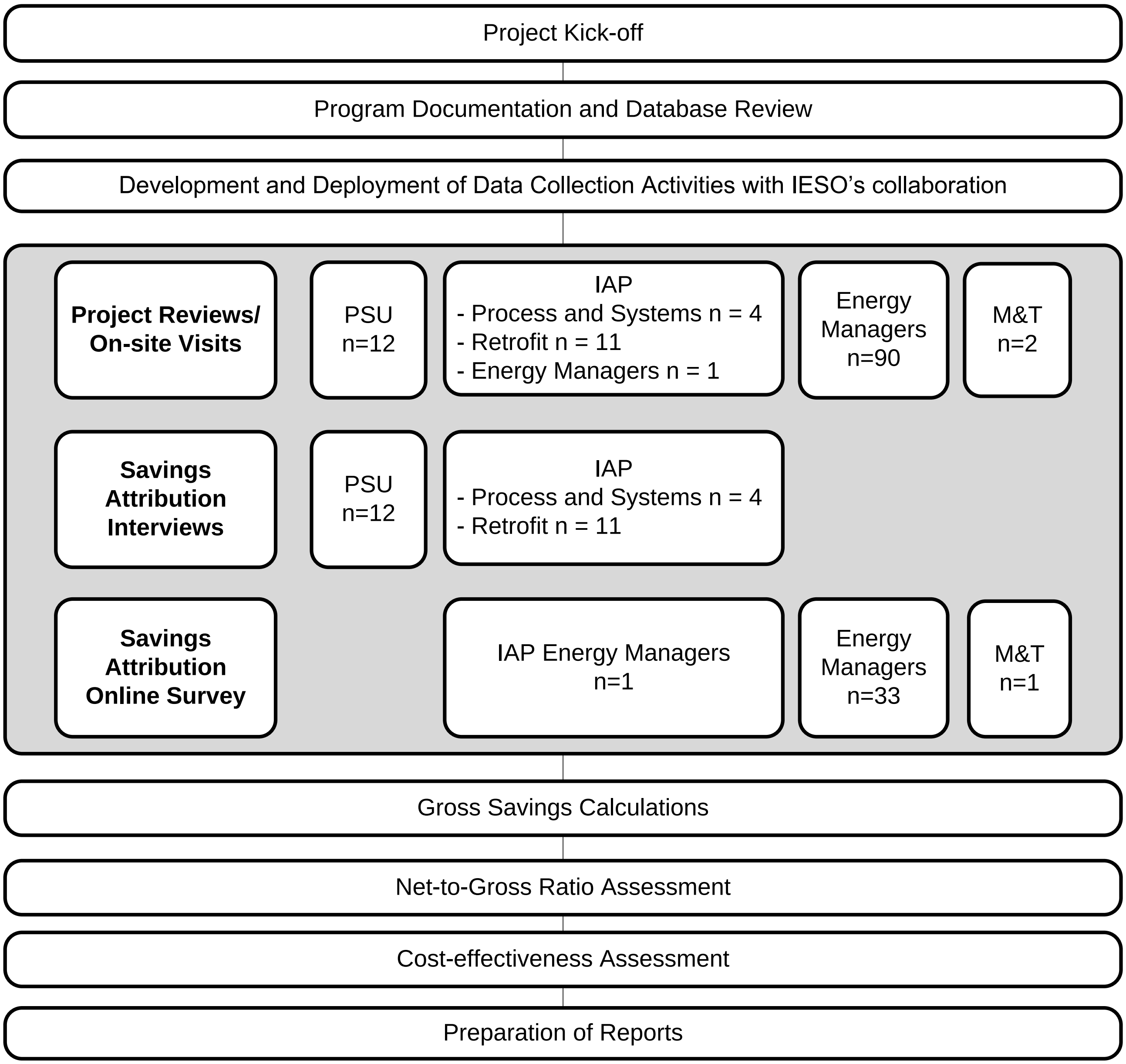

Figure 1: Methodological Model

2.2 Methodology Description

This section describes each of the tasks carried out as part of the 2015 evaluation.

2.2.1 Program Documentation and Database Review

Analyzing the documentation was the first task in the evaluation and involved reviewing all the available program-related information.

The information analyzed was obtained primarily from the following sources:

- Project tracking systems: I-Con and SharePoint.
- Database extracts provided by the IESO or the TR.
- Program websites.
- 2015-2020 Conservation First Framework LDC tool kit.[7]

2.2.2 Project Reviews and On-site Visits

The 2015 evaluation was completed by reviewing a total of 120 projects and measures, selected from a total of 454 projects. For the program with the largest number of projects, Energy Managers, a 21% representative sample was selected for review to ensure cost-effectiveness of the evaluation. The evaluation team made on-site visits to conduct the reviews; when an on-site visit was not possible, the team scheduled a phone call to complete the review. As shown in the table below, a total of 115 on-site visits and five phone reviews were conducted.

Table 4: Sample Size of Reviewed Projects for the 2015 Evaluation

Program	Total Number of Projects/Measures	Total Number of Projects/Measures Reviewed	Number of Projects/Measures Including an On-site Visits	Number of Projects/Measures Including a Phone Review
IAP - Retrofit	11	11	11	-
IAP - Process and Systems	4	4	4	-
IAP - Energy Managers	1	1	1	-
PSU	12	12	12	-
Energy Managers	424	90	86	4
M&T	2	2	1	1
Total	**454**	**120**	**115**	**5**

A desk review of the documentation available for a project was completed prior to the on-site visit. The evaluation team developed a standardized data-collection protocol for each program to ensure consistency of the collected information during the reviews. As part of the review, the effective useful life (EUL) and incremental cost of each of the projects and measures were also validated.

[7] While the new framework rules were not fully implemented in 2015, this collection of documentation provided useful guidance on the eligibility of measures, for instance for fuel-switching, as set out in the following link: http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/Guidelines-Fuel%20Switching-v1-0-20150622.pdf

IAP Process and Systems and PSU

The reviews of projects implemented under the IAP Process and Systems initiative and the PSU program were focused on the verification of the M&V plan and the treatment of the metering data in the M&V report. The project variables and assumptions associated with the baseline and post-implementation measurements were validated and discussed with project staff during the on-site visits. Where appropriate, adjustments were made to take into account the elements that were not captured by the M&V. Then, the gross verified energy savings were calculated using the results from the M&V reports.

All the IAP Process and Systems and PSU projects were reviewed with the help of an on-site visit. The protocol used for these projects can be found in Appendix I.

For some sites whose reporting had been completed on a full year's basis, the results from their first annual M&V reports were used directly. In other cases, if reporting had been completed for only one to three quarters of the year, the energy savings measured during the M&V periods were extrapolated over the full year based on the number of days in a full year divided by the number of days in the reporting period(s). For each project, seasonal variations were analyzed to ensure that the extrapolation remained valid. These gross annual energy savings were considered valid for 2015 and over subsequent years throughout the EUL of the project implemented.

IAP Retrofit

IAP Retrofit projects' savings were generally based on engineering calculations and on limited metering activities. The calculations were mostly compiled in standardized workbooks prepared by the IESO. Therefore, the review was focused on validating two main areas: (1) whether the equations in the workbooks were appropriate and (2) whether the inputs used in the calculations were correct. In some cases (especially projects in the Prescriptive Path), the input values were default values; the evaluation team made efforts to obtain the actual values that were representative of the projects implemented. As for Custom projects where metering data was available, the evaluation team verified whether it was used properly in the savings calculations. The protocol developed for this program is presented in Appendix II.

All the projects submitted under this program were reviewed as part of the 2015 evaluation; nine projects were reviewed with the help of an on-site visit while for two projects, a phone call was conducted.

IAP Energy Managers and Energy Managers

The review was conducted by following the same procedure used for the IAP Energy Managers and Energy Managers programs, since the measures and the substantiation methods are the same for both. The Energy Managers Review Protocol was adapted to take into account the lower level of complexity of the measures implemented and the documentation available. The reviews validated the equations and assumptions used, and established the gross verified savings based on engineering calculations or metering data, where these were available. The protocol is shown in Appendix III.

Because of the large number of measures submitted through Energy Managers, the TR usually only reviews a sample of measures for each EM. The TR presented the results of the 2015 review in an Annual Review Report and provided supporting documentation upon request. For measures not reviewed by the TR, the evaluation team contacted the EMs prior to the on-site visits asking for documentation and engineering calculations supporting the savings.

For IAP Energy Managers, the single project in 2015 was evaluated with the help of an on-site visit. For the Energy Managers program, a sample of 90 measures was selected for review by the evaluation team, which represented 21% of all the measures completed in 2015. The sample was divided into two categories to calculate separate realization rates for reviewed and non-reviewed measures. The Energy Managers program sample included 51 measures that had previously been reviewed by the TR and 39 that had not been. The TR reviewed 45% of the projects completed in 2015, which covered 68% of the savings. Given that a large proportion of the savings were already reviewed by the TR, and that the realization rate for this category has a large impact on the verified savings,the evaluation team included more sampled projects from this category and made efforts to cover the largest projects.The 90 measures were selected according to the following criteria:

› They cover various regions across Ontario;
› They include only measures that the TR had finished treating (defined as closed-out in the database); and
› They maximize the proportion of savings evaluated by excluding measures with less than 5 MWh of energy savings.

M&T

Only two projects were completed under the M&T program. Because of the various types of measures implemented by M&T participants, the evaluation team decided to use the same protocol as for Energy Managers, which is sufficiently flexible to accommodate custom measures. For each project, the savings were established based on the International Performance Measurement and Verification Protocol (IPMVP) Option C, which uses whole-facility metering to establish expected energy consumption and compares it to actual energy consumption after measures have been implemented. The evaluation team verified whether the regression built included appropriate independent variables and whether non-routine adjustments to the baseline had been made where necessary. One of the two projects was reviewed with the help of a phone call with the participant; the other one was reviewed with the help of an on-site visit. The M&T protocol is shown in Appendix IV.

2.2.3 Savings Attribution Interviews and Online Survey

The savings attribution was aimed at quantifying two distortion effects, namely free-ridership and spillover.

Free-ridership

Free-ridership occurs when participants would have implemented an energy-efficiency measure without the program. To evaluate this effect, the evaluation team surveyed program participants using one of two approaches according to the program. Interviews were conducted on site or over the phone (in the rare cases where a site visit was not possible) for IAP Process and Systems, PSU, IAP Retrofit, and they were conducted for every reviewed project. Consequently, the same number of interviews as the number of project reviews (presented in Table 4 above) was conducted for these three initiatives. In every case, it was verified whether the respondent was well aware of the decision-making process within the company to ensure that their answers were accurate.

For IAP Energy Managers, Energy Managers and M&T, the evaluation team assessed the NTGR for non-incentivized[8] projects by conducting an online survey of the facility managers who worked with an EM. The surveyed participants are therefore not the same as those sampled for the project reviews. The following table shows the number of interviews conducted for IAP Energy Managers, Energy Managers and M&T. It should be noted that because the online survey was completed by facility managers, the population and sample sizes are expressed in number of different facility managers rather than in number of projects.

Table 5: Sample Size of Interviews for Non-incentivized Projects

Program/Initiative	Population	Sample Size	Margin of Error at 90% Confidence Interval
IAP – Energy Managers	1	1	None (census)
Energy Managers	62	33	± 9.8%
M&T	2	1	N/A[9]

Two questionnaires were developed: one for IAP Process and Systems, IAP Retrofit and PSU, and the other for non-incentivized measures in IAP Energy Managers, Energy Managers and M&T. The questionnaires were aimed at evaluating two free-ridership components: the participant's intention and the program's influence. Based on the participant's progress in their decision-making process, intention determines the likelihood of the same project being implemented in the absence of program

[8] Although the energy manager's salary is paid through the program, and is considered an incentive, non-incentivized projects are those that did not receive a capital incentive or other rebate through other IESO programs.

[9] Margins of error are not applicable when the sample is very small.

assistance. The program's influence refers to the effect that various program elements could have had on the participant's decision to whether or not implement the project in the way it was implemented.

Spillover

The internal spillover effects are defined as the additional energy and peak demand savings that may have been achieved due to the influence of the program without any direct financial or technical support from the program (technical assistance, incentives, on-bill financing, etc.). This effect was evaluated for IAP Process and Systems, PSU and IAP Retrofit. During on-site visits, a questionnaire was used to determine if the participants had implemented other energy-efficiency projects for which they had not submitted applications to an IESO program.

No spillover questionnaire was administered for IAP Energy Managers, Energy Managers and M&T since the projects and measures implemented were non-incentivized. No distinction was made between the measures reviewed by the TR and those not previously reviewed by the TR.

2.2.4 Gross Verified Savings Calculations

The evaluation team used the results and information gathered from the desk reviews, on-site visits and phone calls in the rare cases where an on-site visit could not have been conducted to establish the gross verified energy and peak demand savings for each program. In cases where a review provided additional information or information different from the contents of the project and measure documentation, or where errors were found in the calculations, modifications were made to the savings calculation to account for these new elements.

The variation between the verified and the reported gross savings is expressed in the form of the realization rate, which was calculated for the energy savings and peak demand savings. The adjustment ratios between the reported and verified values of the EUL and the incremental costs were also calculated. For all the programs except Energy Managers, the realization rates and adjustment ratios were calculated for each individual project.

The calculation of the results was based on the sampling methodology for the Energy Managers program. The overall realization rates and adjustment ratios were calculated with the results obtained from all the individual measures in the sample. The overall realization rates and adjustment ratios were determined using the weighted averages based on the energy savings of the measures. Separate realization rates and adjustment ratios were calculated for the measures that were previously reviewed by the TR and those that were not. For each average value, the evaluation team made sure that the target confidence level of 90% target and maximum margin of error of 10% were met (the calculation of the margin of error is explained in Section 3.3). The overall realization rates and adjustment ratios were then applied to all the measures submitted in 2015 according to their status (reviewed or not reviewed by the TR).

2.2.5 Net-to-gross Ratio Calculation

The NTGR calculation includes the assessment of two key distortion effects: free-ridership and internal spillover. Once each effect is quantified, the NTGR is calculated using the following equation:

NTGR = (1 - % Free-ridership + % Internal Spillover)

Free-ridership

For IAP Process and Systems, IAP Retrofit and PSU, all the surveyed participants' responses to the intention and program-influence questions were compiled and converted into an average value for each project questionnaire. In the questionnaire, the evaluation team included questions to assess the influence of the corporate energy-efficiency policy, as it was done in 2014, with the objective of identifying partial free-riders among those participants who had set clear energy-efficiency targets and would still have implemented the energy-efficiency projects, even with lower or non-existent incentive. Additionally, this year, the evaluation team considered the effect of the incentive on the project payback when the corporate energy-efficiency policies were described as highly influential by the participant. The evaluation team believes that the corporate policy did not result in partial free-ridership when both of the following conditions were met: (1) the payback period was reduced by more than a third by the program incentive; and (2) the initial payback before the incentive granted was more than 2.5 years. The algorithm for this calculation is presented in Appendix V.

For IAP Energy Managers, Energy Managers and M&T, the evaluation team asked a series of questions designed to measure the EM's influence on decision-making and project implementation. The algorithm translating those answers into a free-ridership level is shown in Appendix VIII.

Spillover

When the questionnaire-based survey was conducted to assess the level of spillover, the energy savings of the projects implemented without the assistance of the IESO were estimated. The influence of the participants' previous participation in the IAP or PSU program was also evaluated by an influence factor of 0 (meaning "no influence on their decision to go forward with another project) to 10 (meaning "extremely influential in their decision"). The algorithm for assessing the levels of spillover based on the answers provided by the participants is shown in Appendix VI.

Net-to-gross Ratio

The levels of free-ridership and spillover were used to calculate the NTGR for both energy and peak demand savings for each program, based on the equation presented at the beginning of this section. The NTGR calculated for each program was applied to gross savings to establish the net savings.

2.2.6 Cost-effectiveness Assessment

The impact evaluation results and the programs' cost information provided by the IESO were analyzed to assess the cost-effectiveness of each of the programs. To do so, the evaluation team used the IESO's internal cost-effectiveness calculation tool, which involves using the gross verified energy and peak demand savings, EUL, NTGRs and incremental costs as inputs for each individual project and measure. The tool required specifying the type of electric connection (distribution or transmission) of each participant and the nature of each project (whether or not electricity production is present behind the meter).

An industry and project-specific load profile was also selected for each project implemented. For the Energy Managers program, a custom load profile was created based on the weighted average of the individual load profiles of the 18 most important measures which collectively generated 50% of the program's gross reported energy savings. The custom load profile created was then applied to all the 424 measures.

The cost-effectiveness assessment involved performing several cost-effectiveness tests: the Total Resource Cost (TRC), the Program Administrator Cost (PAC) and the Levelized Delivery Costs (LC). The performance indicators generated by the tests included the benefits, costs, net benefits and benefit-to-cost ratio for each program.

2.2.7 Preparation of Reports

The impact evaluation results, including the high-level findings, realization rates and adjustment ratio applied to each reviewed project, attribution analysis and cost-effectiveness assessment, were provided to the IESO in a pre-determined format prior to the submission of this report.

This report provides a detailed description of the context and the impact evaluation work done by Econoler, the adjustments made to the reported savings, the net verified energy and peak demand savings and the possible improvements the IESO could make to its programs.

3 IMPACT EVALUATION RESULTS

3.1 Documentation Review

This section presents observations on the quality of the documentation for four of the six programs and initiatives. There are no particular comments on M&T and IAP Energy Managers, which had a limited number of projects to review.

3.1.1 IAP Process and Systems and PSU

For each of the projects, the TR provided a Project Review Report, an M&V plan and quarterly or annual M&V reports (depending on what was available at the time of evaluation). This documentation contained sufficient information needed to understand the project and the M&V methodology used to establish the reported savings.

One potential improvement identified is that some of the M&V reports could have provided more details about the calculation steps between the metering data and the reporting-period energy. For instance, for one project, the correlation between the equipment power draw and the flow rate was indicated, but it was not clear which flow rate data was used to calculate the energy consumption.

The evaluation team noticed that for projects where unexpected events occurred during the reporting period (unusual downtime, changes in the usage made of the premises), the M&V report did not always mention the events and their impact on the measured energy savings. A best practice suggests that a section of the M&V report should be devoted to the monitoring of static variables, which ensures that these variables are brought to the attention of the reader, and in doing so, identify the reasons for any variations from the expected savings.

Also noted was that the recommendation formulated in the 2014 evaluation report concerning the inclusion of peak demand savings measurements in the M&V plan had not yet been implemented.

3.1.2 IAP Retrofit

For all the projects submitted through the Prescriptive and Engineered paths, the documentation was standardized in the form of IESO worksheets. These worksheets included clearly defined input cells, and embedded formulas for calculating energy and peak demand savings. These worksheets are also sometimes used for the Custom projects, especially for lighting projects. The only inconvenience is that some of the calculations are not transparent and are not visible to the evaluation team. In general, the information was complete and sufficient to allow for conducting the desk review. However, the evaluation team maintains that the organization of information could be improved by clearly naming each project's folders and documents. A few documents existed in more than one version, with no clear indication which was the final version.

3.1.3 Energy Managers

The quality of the documentation varied depending on if the measures had been previously reviewed by the TR. The measures that underwent a technical review were accompanied by a year-end or quarterly report from the TR. In general, the evaluation team found that these reports clearly described the initial methodology adopted by the EM to calculate the savings, the modifications applied by the TR and the explanations for applying them. However, in a number of cases, their reports referred to calculation sheets, previous engineering studies or other external documents, which were not made available to the evaluation team. In these cases, some of the assumptions and values used to make the engineering calculations could not be validated.

For the non-reviewed measures, the evaluation team was generally able to obtain the necessary supporting documentation through the EMs. In a few cases, these documents were reports from external consultants, which did not provide sufficient details about the methodology for establishing the reported results, preventing the evaluation team to thoroughly validate the savings calculations.

Moreover, 11 of the 90 measures reviewed by the evaluation team (7 of which were previously reviewed by the TR) had incomplete or insufficient information, thus making it difficult to quantify the savings claimed. For the measures reviewed by the TR, reported savings were often accepted by the TR when they could not be validated, because of incomplete documentation or the complexity of the project. During the reviews, the evaluation team did not obtain more information needed to validate the savings because of several reasons, including: staff turnover since the measure's implementation, a lack of responses from EMs, who failed to send the information requested, or because the documents provided to the evaluation team did not mention the origins of the values used in the calculations. When the information required for the gross savings review was not provided, the evaluation team validated whether the measures had been properly installed and whether the order of the magnitude of the reported savings was reasonable. If both conditions were met, the reported savings for those measures were accepted as they were.

In 2015, 20 measures out of the total 424, generated more than 500 MWh each in annual savings and accounted for 55% of the total program savings. Of these measures, 12 were part of the sample of measures reviewed by the evaluation team, of which two presented incomplete information needed to validate the energy savings (1,817 MWh and 668 MWh, respectively). A recommendation from the 2014 evaluation was to establish a threshold over which an EM would need to submit a savings substantiation plan to the TR prior to implementing measures expected to generate more than 500 MWh in gross savings, but this recommendation has not been applied yet.

3.2 Project Reviews

This section summarizes the findings from the desk reviews and on-site visits for each of the programs or initiatives.

3.2.1 IAP Process and Systems

All the four projects included in IAP Process and Systems were reviewed and visited as part of the 2015 evaluation. The four projects involved making improvements to motors, pumps or blowers, with VFDs used in three of the four cases. The reported energy savings ranged from 0.5 to 8.9 GWh. Overall, the realization rates for energy and peak demand savings were close to unity, at respectively 1.09 and 0.96, but all four projects required making small adjustments to their reported savings values. Section 4.3 provides details on the Realization Rate results and methodology.

Energy Savings

The adjustments made to the energy savings were of three types. First, corrections were made because the reported savings did not correspond to annual savings that can be expected throughout the EUL of the project. The annual energy savings are used to calculate the lifetime energy savings of the project (except when there is a step-down in the baseline); so, they should be representative of a typical year. However, the reported energy savings are based on a direct extrapolation of the metering data available at the time of evaluation; this means that they are only representative of the first year (or first few quarters) of metering. For this reason, the evaluation team made adjustments to one project, because an exceptionally long downtime occurred during the M&V reporting period. In fact, the plant had to shut down for many weeks because a piece of major equipment had to be rebuilt, an event that would have occurred only every 10 years. The evaluation team believes that it was inaccurate to annualize the savings based on the hours of operation of this particular metering period. The same issue was also observed in the methodology for calculating the reported energy savings for some Process and Systems Upgrades projects.

The second type of adjustment made to the reported energy savings was to change the hours of operation used for the existing equipment in the baseline energy consumption calculations, which was done for two projects. In one case, the uptime was considered unrealistic because it was based on an “ideal” year, while historical data showed that there was always a higher proportion of downtime. In the other case, the operation hours of the wrong piece of equipment had been used; the value was that of a pump that was not equipped with a VFD and was not a part of the project.

Finally, one project underwent an adjustment of the reporting-period energy consumption due to an error identified by the TR in the metering equipment. The TR adjusted the data in the third quarterly M&V report. The evaluation team had to perform the same adjustment to the two previous M&V reports before calculating the annual energy savings.

Summer Peak Demand Savings

The reported peak demand savings were also adjusted for all the IAP Process and Systems projects. In addition to the changes made to the energy savings calculations previously mentioned (which could have affected the peak demand savings values), the evaluation team identified an issue that was common to all IAP Process and Systems and PSU projects. The reported peak demand savings were calculated by the TR by dividing the reported energy savings by the hours of operation of the equipment. The resulting values correspond to the average demand reduction during hours of operation and not summer peak demand savings.

To calculate the summer peak demand savings, the evaluator considered the seasonal variations and the hours during which there were no savings. The definition of peak demand savings can be found in Appendix IX.

For all the projects under IAP Process and Systems, the equipment was operated 24/7, with no seasonal variations (meaning that there were no significant differences in the production volume throughout the year, no major maintenance specifically planned during the peak season, energy consumption unaffected by outdoor temperature, etc.). As a result, the summer peak demand savings were calculated by dividing the metering data for the entire reporting period by the number of hours in the reporting period.

3.2.2 PSU

A total of 22 PSU projects were implemented in 2015, though 12 were included in this evaluation. The remaining ten projects were not included because the M&V reports, which are used to establish gross reported savings, were not yet available. These projects will be included in subsequent evaluation years. The 12 evaluated projects can be grouped into four types. As highlighted in Figure 2, the gross energy savings reported were not evenly distributed among these types of projects. The four behind-the-meter projects (cogeneration) generated 72% of the total PSU energy savings, but the four projects involving motors, fans and blowers accounted for only 3% of the total energy savings.

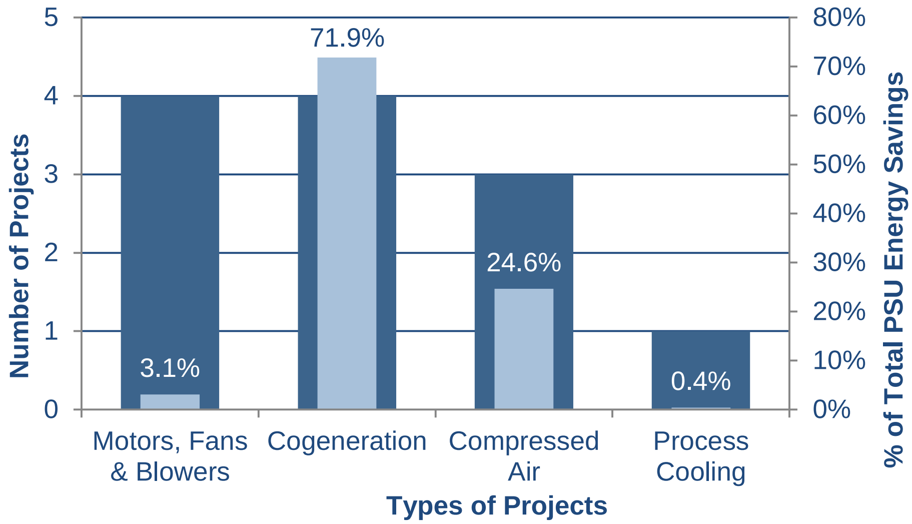

Figure 2: Number of Projects and Gross Energy Savings by PSU Project Type

Similar to the case of IAP Process and Systems projects, the overall realization rates are close to one: 1.00 for energy savings and 0.94 for peak demand savings. Most peak demand savings values had to be adjusted because they were not calculated using the IESO's standard definition, as discussed in the IAP Process and Systems section. However, significant changes to the energy savings were made for only four projects. Those changes were of a different nature for each of the four projects as shown below.

1. The issue regarding the Aeration Blower VFD project was related to the precision of the metering data. The power meter installed by the participant could only provide readings by increments of 100 kW, resulting in all data-points being one of three levels of readings (0, 100 and 200 kW). Each data-point could be quite far from the actual power value. So, the TR considered two scenarios: (1) the data was first used as it was; (2) a value was assumed for each reading, based on the average of the range where that reading would occur.[10] The second scenario was considered to be the most conservative, since it would most likely slightly overestimate the reporting-period energy consumption. The evaluation team chose the first scenario, in line with the IPMVP's requirement that when metering data is uncertain, the most conservative approach should be used.[11] The reported savings were based on the first scenario, which resulted in a realization rate of 0.46 for both energy and peak demand savings.
2. As for the Cooling Tower Upgrade project, an adjustment was made because the baseline regression was not representative of the equipment used during the reporting period. Instead, the baseline energy consumption was based on a constant value, which was established by

[10] It was assumed that when 0 kW was recorded, the power value used was 25kW (halfway between 0 and 50 kW). When 100 kW was recorded, the power value used was 125 kW (halfway between 100 and 150kW). When 200 kW was recorded, the power value used was 186 kW (blower's rated power output).
[11] Efficiency Valuation Organization, *International Performance Measurement and Verification Protocol: Core Concepts*, April 2016, p.4

measuring the hours of operation of each of the three main pieces of equipment during the baseline period. During the reporting period, the main driver of the cooling tower's demand was the paint shop department, which was shut down indefinitely. The hours of operation previously metered were no longer appropriate or valid; the M&V plan did not include the measurement of these variables. The reported values for energy and peak demand savings were based on the difference between the actual energy consumption of the new equipment and the static baseline. Since the new equipment was much less used than expected, the measured savings were significantly increased. The evaluation team believed that the savings documented in the M&V report were inaccurate, since the suitable routine and non-routine adjustments required by the IPMVP were not made.[12] Furthermore, the TR used the realization rate of the first quarter and applied it to the expected annual savings calculated in the feasibility study to establish the reported savings. Since the monthly expected savings varied significantly during the year (there were even negative savings in some months), the evaluation team would argue that this extrapolation is not appropriate. Without the data needed to adjust the baseline energy consumption, the evaluation team used the savings estimated in the M&V plan as the verified savings (without applying the first quarter's realization rate). Those savings are representative of the project only if the paint shop remains open during most of the project's EUL. The participant did not expect the paint shop to be shut down over an extended period of time. This adjustment resulted in a realization rate of 0.46 and 0.18 for energy and peak demand savings respectively.

3. As for the Synthesis Compressor Enhancement project, an adjustment was made to the value of the independent variable used in the baseline energy regression. The baseline energy use was established by multiplying the reporting-period gas-flow rate by a coefficient representative of the efficiency of the old turbine. However, the project review revealed that the improved turbine could process a slightly higher gas flow rate; while this constituted a benefit to the participant who could increase the production capacity, the old turbine did not consume as much energy as the baseline energy regression suggested. The evaluation team concluded that the reported savings were overestimated, because they included savings associated with additional production activity, which would not have been possible if the energy efficiency project had not been completed. Consequently, the baseline-period flow rate was used to calculate the baseline-period energy. Since the turbine runs continuously at its maximum flow rate, this value was considered representative of the maximum output of the old turbine. This approach is more appropriate than the one used to calculate the reported savings, because the latter overestimated the savings. A second adjustment was made to the turbine's hours of operation; during the reporting period, the uptime was 89%, which was considered abnormally low. This was due to early trouble-shooting of the improved turbine after its installation. The hours of operation were adjusted to 99%, which is the expected uptime in a normal year. As a result of the adjustments, this project's realization rates were established at 0.90 for the energy savings and 0.89 for the peak demand savings.

[12] Efficiency Valuation Organization, *International Performance Measurement and Verification Protocol: Core Concepts*, April 2016, p.3

4. As for the fourth project, the cogeneration project, an adjustment was also made to take into account the unusual downtime that occurred in the first year due to installation-related issues. The uptime was increased to 99%, which is how frequently the turbine would have been in use if it had not had a 6-week shutdown during the fall of 2015. Overall, the energy and peak demand savings were adjusted by applying realization rates of 1.22 and 1.15 respectively.

3.2.3 IAP Retrofit

Figure 3 highlights the distribution of the projects implemented in 2015 among IAP Retrofit's five tracks. All these five tracks were used in 2015, with Prescriptive Lighting having the most projects (four).

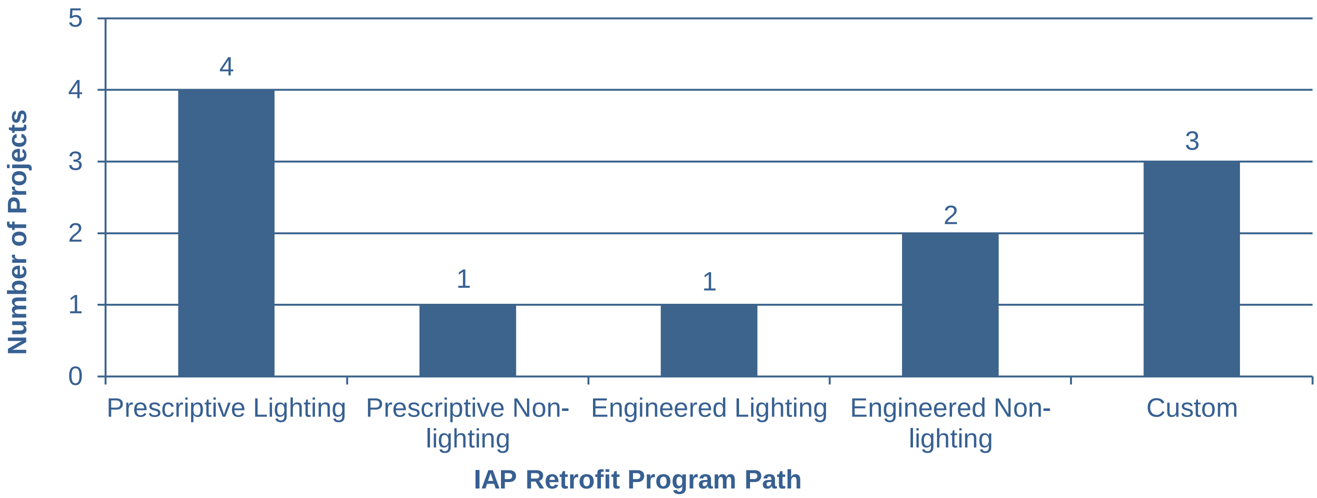

Figure 3: Breakdown of Projects by IAP Retrofit Program Track, 2015

Out of the 11 projects reviewed, six required a significant adjustment to their energy savings and three projects had their peak demand savings changed. The overall realization rates for the energy savings and peak demand savings were 1.00 and 1.03 respectively.

It is worth noting that only the projects using the Prescriptive and Engineered paths required adjustment to their savings.All the Custom path projects had a realization rate of 1.00 for both energy and peak demand savings. The evaluation team also noticed that though the savings of the projects following the Prescriptive path are expected to be deemed (i.e., a fixed value that does not reflect the projects' actual operating conditions), in most cases they were adjusted by the TR to match the actual hours of operation. This can partially explain why the adjustment ratios were so close to unity in 2015.

Four of the six projects whose energy savings were adjusted were lighting projects. In three cases, the hours of operations were adjusted to better represent their actual usage, based on the information gathered during the on-site visits. For two projects, the efficient lighting wattage was slightly adjusted based on technical specifications, and for one project, the baseline wattage was changed to match the value found in the IESO's 2015 Measure and Assumption List. There was one project that included occupancy sensors, but the energy savings associated with the reduction of hours of operation had not been taken into account.

The last two projects for which the evaluation team revised the energy savings required more significant adjustments. The first project involved replacing an HVAC rooftop unit with a more efficient one. Although the existing equipment had been established as the baseline, the on-site visit revealed that this unit was truly at the end of its effective useful life and that the participant had already planned in their budget for its replacement with a standard new unit. Therefore, the baseline was changed to a standard new HVAC rooftop unit representing the common practice, which was significantly more efficient than the existing equipment. The realization rates for the energy and peak demand savings were established at respectively 0.22 and 0.20.

The last project was a complex project involving adding a VFD on a fan on a mining site. Although this project was submitted through the Engineered path, the standard equations for VFDs did not apply to it because the performance curve of the fan's VFD system varied in the course of the year. Indeed, as the mining operations take place at deeper underground levels, the duct length changes, thus impacting the system's performance. To estimate the savings more accurately, the evaluation team obtained metering data for a six-month period from the participant. Arguably, the savings for this project would have been calculated more accurately if it had been treated as part of the Custom path. Using the calculation approach developed by the evaluation team, the reported energy savings increased by 50%, and the peak demand savings reduced by 21%.

3.2.4 IAP Energy Managers

The only project completed was a lighting project, which did not require making any major adjustments. The realization rates for the energy savings and peak demand savings were respectively 1.02 and 1.00. No issues were identified regarding the project details and assumptions, but it was noted that the energy savings reported were rounded downwards, which has led to the slight increase in the verified energy savings.

3.2.5 Energy Managers

For the Energy Managers program, a significant proportion of the measures completed were related to lighting (efficient fixtures and lamps or lighting controls). Indeed, as shown in Figure 4, 44% of the energy savings came from lighting measures in 2015. Moreover, the measures implemented through the Energy Managers program were generally small, with the majority of the reported measures generating energy savings below 25 MWh.

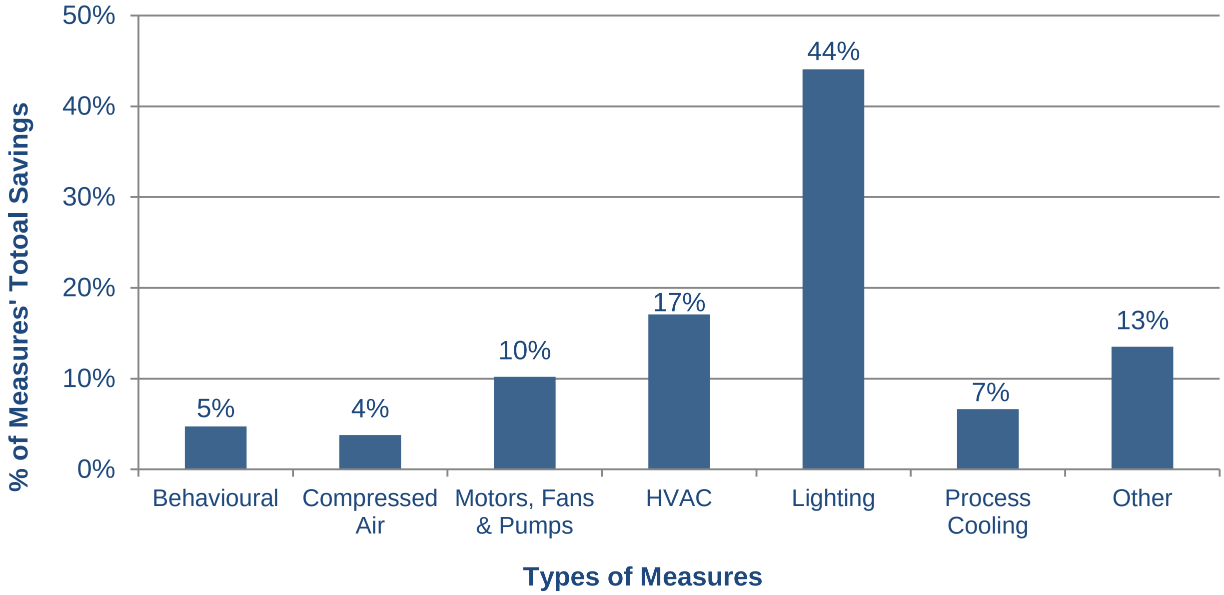

Figure 4: EM Gross Savings Breakdown by Type of Measure Implemented, 2015

Although the Energy Managers program is part of the industrial portfolio, only 17% of the program's measures were implemented in the industrial sector in 2015.

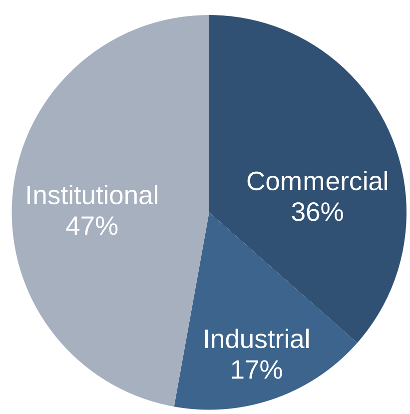

Figure 5: Breakdown of the EM Measures by Sector

Four measures from the sample reviewed by the evaluation team involved fuel-switching, namely replacing electricity with natural gas. According to the new Conservation First 2015-2020 Framework Guidelines,[13] these projects should have been disqualified. However, since the new Framework was not fully implemented in 2015, the evaluation team decided to include the savings generated by these four measures in the impact results of the Energy Managers program. Their energy and peak demand savings represent respectively 9% and 12% of the total gross energy and peak demand savings reported through the Energy Managers program.

The evaluation team also noticed that some measures submitted to the program involved modifications to a process driven by an increase in production capacity. For example, one measure involved combining two production lines to reduce the energy demand following a load-shifting strategy. But, during the site visit, the evaluation team was informed that this new arrangement was done to create space needed to build a new production line. The Energy Managers program current eligibility criteria do not require that submitted projects be implemented primarily for energy efficiency improvement purposes. When the project is intended to increase production capacity, the energy savings calculation methodology used by the TR establishes the old equipment as the baseline, rather than the new standard efficiency equipment that would have been installed to meet capacity needs.

The overall realization rates for Energy Managers measures previously revised by the TR were 0.95 and 1.30 for energy and peak demand savings respectively; those for non-reviewed measures were 1.15 and 0.92 respectively. What follows is a summary of the main adjustments that the evaluation team made to EM's reported energy and peak demand savings.

Energy Savings

For measures that previously underwent a technical review, adjustments were made to about half of the energy savings calculations. Overall, the energy savings realization rate of 0.95 for the measures previously revised by the TR was quite close to unity; 80% of the sampled measures had realization rates between 0.75 and 1.25.

A major adjustment was made to a turbine measure, which accounted for 7% of the gross energy savings of the sample. The energy savings realization rate of this measure is 0.69 due to incorrect annualization of the energy savings of a turbine which is in operation only from May to September. Although this measure was excluded from the calculation of the average realization rate that was then applied to all the non-sampled projects, this one-off adjustment had a significant impact on the overall verified savings value.

When annualizing savings, a common mistake was the failure to take into account plant shutdowns or any specifics related to the equipment's operating schedule.

[13] IESO Conservation First Framework LDC Tool Kit. 2015. Fuel Switching Guideline. http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/Guidelines-Fuel%20Switching-v1-0-20150622.pdf

In general, the evaluation team noticed that the TR was more inclined to make an adjustment when it reduced the reported savings. In many cases, the TR's analysis described the methodology for making a potential upward revision; but such a method was not applied if the TR considered the value conservative and therefore acceptable. A good practice for improving the accuracy of the reported savings would be to make all the justified adjustments, regardless of whether these adjustments revise the savings values upward or downward.

For measures that were not previously reviewed by the TR, the energy savings realization rate is 1.15. The values remained unchanged for only 21% of the measures. As can be expected, the number of adjustments for measures not reviewed by the TR were more numerous than those of reviewed measures. Echoing the 2014 evaluation, the evaluation team noticed again this year that more training or support is needed to better inform the EMs about the expected levels of detail and accuracy for the savings calculations that they submit.

A big proportion of the adjustments were associated with lighting measures. The evaluation team made many modifications to the Energy Managers energy savings calculations, the majority of which omitted the interactive effects, the ballast factors and the ballast's consumption. The interactive effects identified as part of this evaluation usually revised the energy savings upward since they took into account additional savings associated with a reduction of the cooling load in the air-conditioned space (powered by electricity). When the missing ballast factor and the ballast's consumption were applied to the savings calculations, these savings increased or decreased, depending on the efficient technology and the baseline technology involved.

Summer Peak Demand Savings

The overall peak demand savings realization rate is as high as 1.30 for measures reviewed by the TR. The peak demand savings calculations were adjusted for about half of the measures. Here again, 80% of the measures had realization rates between 0.75 and 1.25. However, the overall realization rate is significantly above unity. This can be partly explained by the turbine measure mentioned earlier, which had a realization rate of 4.51 for peak demand savings. Although still conservative, reported peak demand savings were heavily adjusted by the evaluation team to better reflect the operating conditions of the 3.3-MW turbine. This project accounted for 33% of peak demand savings in the sample. How this outlier result was treated in the calculation of the overall realization rate is thoroughly explained in section 3.3.

For measures that were not previously reviewed by the TR, the realization rate was 0.92, and only 28% of the reported peak demand savings remained unchanged.

Similar mistakes were found in the calculation methodology for both reviewed and non-reviewed measures. The definition of the summer peak demand was correctly applied to only a small proportion of the measures. Both the TR and the EMs often submitted the non-peak demand savings values. Consequently, the evaluation team adjusted the peak demand savings in compliance with the IESO's Evaluation, Measurement and Veirifcation (EM&V) Protocols & Requirements.[14] The adjustment was not specific to one type of measure, but was made to several ones including lighting, blowers, motors, etc.

Another common error was the low accuracy of the reported hours of operation and schedule. After asking questions about weekend operations, work schedules, and facility shutdowns, the evaluation team often had to adjust the operating schedule of the entire facility or a piece of equipment involved in an energy-efficiency measure. As for schools and educational institutions, their summer holidays were often omitted, for instance. This had a big impact on the peak demand savings because of the number of weeks taken up by the holidays per year.

3.2.6 M&T

Two projects generated savings as part of the M&T program in 2015. For both, the evaluation team concluded that the baseline energy regression was appropriate: the independent variables were properly chosen and the correlation (e.g., defined by the R^2 value) was acceptable. The savings deductions for projects already claimed under other programs to avoid double-counting were complete and accurate. For these reasons, the realization rates for energy savings were 1.00 for both projects.

The peak demand savings were generated by one of the two M&T projects. For this project, the reported peak demand savings were calculated as the difference between the average demand in the summer of 2012 minus the average demand in the summer of 2015. The evaluation team accepts the assumption that the savings are evenly distributed over time. Hence, the peak demand savings can be established by dividing energy savings by the total number of hours in the months of June to August. However, the savings should consider the baseline regression to ensure that the changes in production and cooling degree-days are taken into account. Furthermore, the savings between 2012 and 2013 cannot be attributed to the M&T system, which was not fully functional during those two years. Consequently, the peak demand savings were established by first dividing the adjusted baseline consumption (as per the regression built with 2013-2014 data) for the summer of 2015 by the number of hours during the period, and then subtracting the actual average peak demand consumption for June to August 2015. The resulting average peak demand reduction was 72 kW, from which 183 kW of savings already associated with other projects were deducted. As a result, the verified peak demand savings for this project were found to be nil.

3.3 Realization Rates

The realization rates were calculated using the following equations:

[14] Ontario Power Authority, *EM&V Protocols & Requirements*, March 2011, p. 142.

$$\textbf{Realization Rate (Energy)} = \frac{\textbf{Verified Annual Gross Energy Savings (GWh)}}{\textbf{Reported Annual Gross Energy Savings (GWh)}} \; \textbf{x 100\%}$$

$$\textbf{Realization Rate (Demand)} = \frac{\textbf{Verified Annual Gross Summer Peak Demand Savings (MW)}}{\textbf{Reported Annual Gross Demand Savings (MW)}} \; \textbf{x 100\%}$$

For all programs with the exception of Energy Managers, the gross verified savings and associated realization rates were calculated for all projects. Therefore, no extrapolation was required and the sampling error is nil.

For the Energy Managers program, an extrapolation of the realization rates of the measures sampled was needed. The margin of error at a confidence level of 90% was calculated, using the following formula:

$$\%\,error = \frac{1.64 \dfrac{\sigma}{\sqrt{\dfrac{(N-1)*n}{N-n}}}}{R}$$

Where:

› σ is the standard deviation of the realization rate for the sampled measures.
› n is the number of measures for which a realization rate was calculated.
› N is the total number of measures from which the sample was selected.
› R is the weighted average realization rate established for the sample.
› 1.64 is the z-score which applies for a confidence level of 90% for a sample bigger than 30 measures.

To ensure that the realization rates could be applied to all the Energy Managers measures claimed in 2015, the evaluation team maintained the margin of errors at a maximum of 10% by excluding outliers from the ratio calculation.

The same procedure was adopted for both gross energy savings and peak demand savings. In both cases, the realization rates were calculated separately for two sets of measures: the measures that were reviewed and those that were not reviewed by the TR. The procedure can be summarized as follows:

1. The realization rate was calculated for all the measures in the sample.
2. The margin of error was calculated using the formula presented above.
3. If the margin of error was above 10%, outlier measures were identified in the sample.
4. The adjusted realization rate (R_{Adj}) was calculated for all the non-outlier measures and its margin of error was verified to be of 10% or less.

5. The final verified savings were calculated by applying the adjusted realization rate to all the non-outlier measures and by making one-off adjustments to the outliers, as shown in the following formula:

$$Total\ ES_{\mathrm{Ver}} = \left(R_{\mathrm{Adj}} * \left(\sum ES \quad - \sum ES_{\mathrm{OR}}\right)\right) + \sum ES_{\mathrm{OV}}$$

Where :

1. Total ES_{Ver} is the sum of the gross verified energy savings for the reviewed or the non-reviewed measures
2. R_{Adj} is the adjusted realization rate, i.e., the realization rate of the non-outlier measures sampled.
3. Σ ES is the sum of the gross reported energy savings of all the measures in the database.
4. Σ ES_{OR} is the sum of the gross reported energy savings for the outlier measures.
5. Σ ES_{OV} is the sum of the gross verified energy savings for the outlier measures.
6. The overall realization rate was calculated using the following equation:

$$RR_{Overall} = \frac{Total\ ES_{\mathrm{Ver}}}{Total\ ES_{Reported}}$$

7. The overall realization rate was applied to the total gross reported energy savings ($ES_{Reported}$) of all the measures, including the outliers.

Table 6 lists the adjusted realization rates for both the non-reviewed and reviewed sets of measures, along with the margins of error of the adjusted ratios.

Table 6: Adjusted Realization Rates for Energy Managers

	Adjusted Realization Rate (R_{Adj})	Margin of Error (% Error)	Overall Realization Rate Ratio ($RR_{Overall}$)
Reviewed Measures			
Energy Savings	0.95	5%	0.95
Peak Demand Savings	1.30	9%	1.30
Non-reviewed Measures			
Energy Savings	1.14	9%	1.15
Peak Demand Savings	0.93	10%	0.92

3.4 Overall Gross Verified Annual Savings

Table 7 shows the gross verified energy savings and the associated overall realization rate for each program. Table 8 shows the results of the peak demand savings.

Table 7: 2015 Annual Gross Verified Energy Savings

Program/Initiative	Annual Gross Reported Energy Savings (GWh)	Annual Gross Verified Energy Savings (GWh)	Overall Realization Rate
IAP	52.547	55.214	105%
IAP Process and Systems	20.377	22.209	109%
IAP Retrofit	32.130	32.965	103%
IAP Energy Managers	0.040	0.041	102%
PSU	153.194	152.701	100%
Energy Managers	47.116	47.779	101%
M&T	1.369	1.369	100%
Total	**254.226**	**257.064**	**101%**

Table 8: 2015 Gross Verified Peak Demand Savings

Program/Initiative	Gross Reported Peak Demand Savings (MW)	Gross Verified Summer Peak Demand Savings (MW)	Overall Realization Rate
IAP	6.495	6.393	98%
IAP Process and Systems	2.606	2.506	96%
IAP Retrofit	3.884	3.882	100%
IAP Energy Managers	0.005	0.005	100%
PSU	18.110	17.026	94%
Energy Managers	8.152	9.370	115%
M&T	0.200	0.000	0%
Total	**32.957**	**32.789**	**99%**

3.5 Net-to-gross Ratio

This sub-section presents the NTGR results for all the programs.

3.5.1 Free-ridership

The overall free-ridership levels were calculated separately for energy savings and peak demand savings for each individual program/initiative. These weighted averages were established based on the energy and peak demand savings values of each project. Using this approach, the following free-ridership levels were determined.

Table 9: Free-ridership Levels by Program/Initiative

Free-ridership	For Energy Savings	For Peak Demand Savings
IAP Process and Systems	7%	7%
PSU	20%	20%
IAP Retrofit	13%	13%
IAP Energy Managers	30%	30%
Energy Managers	25%	19%
M&T	0%	0%

Although the IAP Process and Systems and PSU programs are similar, PSU has a higher free-ridership level. The evaluation team argues that this difference is due to the program's small population size. ; In a small population, a single value can have a significant impact on the average free-ridership level. Another element that can explain this difference between the two programs is the nature of the relationship with transmission-connected customers. TheIESO may have more influence on transmission-connected participants because of their close collaboration. Finally, for PSU, the free-ridership level specific to BMG projects was compared to that of other projects. Free-ridership was established at 22% for BMG projects and at 13% for all the other projects. The difference between the free-ridership levels of the two programs may be partially explained by the fact that no BMG projects were submitted through IAP Process and Systems

IAP Retrofit has a free-ridership level between those of IAP Process and Systems and PSU. A majority of IAP Retrofit participants had a moderate level of free-ridership (12% to 25%), because they had either already planned the project prior to program participation or other motivations to implement the project. The IAP Energy Managers initiative presents a higher level of free-ridership, though this level depends on only one individual participant in 2015.

For the Energy Managers program, the free-ridership level was established at 25% and 19% respectively for energy and peak demand savings. This means that a number of participants would have implemented energy-efficiency measures even without the presence of an EM at their facility. The level of free-ridership varied from 0% to as high as 88% for certain facilities. Higher free-ridership levels could be explained by the fact that EMs may first implement simpler and less costly energy-efficiency measures. However, facility managers ranked EMs as "somewhat influential" to "highly influential" in the implementation of the non-incentivized projects. For the most part, the facilities decided to install the measures after hiring an EM and only 13% of the measures implemented were decided on prior to hiring the EMs. Overall, these findings suggest that EMs are important and serve as a key resource in helping facilities achieve energy savings.

Finally, M&T presents no free-ridership, which can be explained by the nature of the program. Since the M&T system technology was introduced only recently in industries, its free-ridership is expected to be nil. The long-term monitoring also requires quite a level of involvement of the participant, thus discouraging free-ridership. For the one M&T project where the facility manager completed the survey, the facility manager indicated that the M&T project decision had been made after hiring the EM, which indicates that the IESO's programs were highly influential in the implementation of the system.

3.5.2 Spillover

The overall level of spillover was nil across all programs for which it was evaluated (IAP Process and Systems, PSU and IAP Retrofit). Low spillover was identified for three IAP Retrofit participants and one PSU participant, though the resulting overall spillover levels represented 0% of the incentivized savings associated with the IAP and PSU programs as a whole.

3.5.3 Net-to-gross Ratio Calculation

Using the equation shown in Section 2.2.5 and the free-ridership and spillover values just discussed, the NTGR was calculated for both the energy savings and peak demand savings of each program, as shown in the table below.

Table 10: NTGR by Program/Initiative

Program/Initiative	NTGR for Energy Savings	NTGR for Peak Demand Savings
IAP Process and Systems	0.93	0.93
IAP Retrofit	0.87	0.87
IAP Energy Managers	0.70	0.70
PSU	0.80	0.80
Energy Managers	0.75	0.81
M&T	1.00	1.00

For all the programs and initiatives except Energy Managers and M&T, a census approach was used for the survey; so, the sampling error is nil. For Energy Managers, the sample of 33 facility managers resulted in a margin of error of 8% at a confidence level of 90%, which was calculated using the same formula as for realization rates (see Section 3.3). For M&T, the margin of error cannot be calculated because of the very small population size.

3.6 Net Verified Savings Results

This section reports on the net verified annual and lifetime savings.

3.6.1 Overall Net Savings

The verified net annual savings for the program portfolio were estimated by applying the NTGRs calculated in the previous section. The following equation was used to calculate the net savings.

$$\textit{Net Verified Savings} = \textit{Gross Verified Savings} \times \textit{NTGR}$$

This equation was used to calculate both energy savings and peak demand savings. The results for each individual program/initiative are presented in the following two tables.

Table 11: 2015 Verified Annual Net Energy Savings

Program/Initiative	Annual Gross Verified Energy Savings (GWh)	NTGR	Annual Net Verified Energy Savings (GWh)
Total IAP	55.214	0.89	49.398
IAP Process and Systems	22.209	0.93	20.669
IAP Retrofit	32.965	0.87	28.700
IAP Energy Managers	0.041	0.70	0.028
PSU	152.701	0.80	122.704
Energy Managers	47.779	0.75	35.834
M&T	1.369	1.00	1.369
Total	**257.064**	**0.81**	**209.305**

Table 12: 2015 Verified Net Summer Peak Demand Savings

Program/Initiative	Gross Verified Summer Peak Demand Savings (MW)	NTGR	Net Verified Summer Peak Demand Savings (MW)
Total IAP	6.393	0.89	5.721
IAP Process and Systems	2.506	0.93	2.330
IAP Retrofit	3.882	0.87	3.387
IAP Energy Managers	0.005	0.70	0.003
PSU	17.026	0.80	13.649
Energy Managers	9.370	0.81	7.590
M&T	0.000	1.00	0.000
Total	**32.789**	**0.82**	**26.960**

To put the 2015 results in perspective, the net annual energy savings values were compared to the savings claimed each year since 2010, by program/initiative.

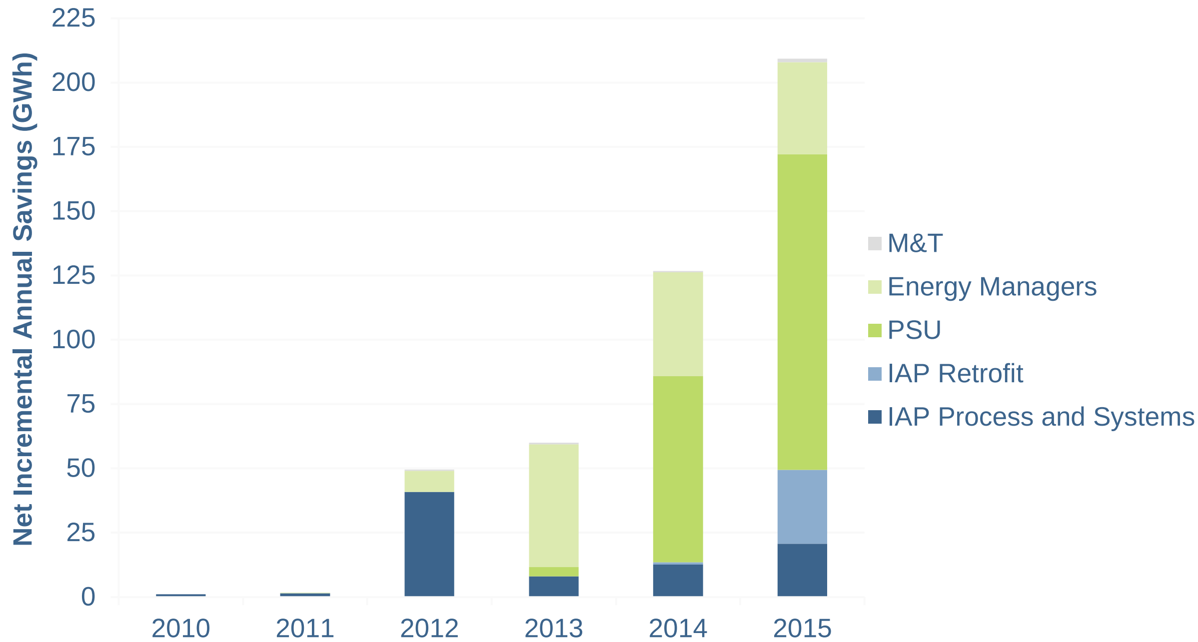

Figure 6: Evolution of Annual Net Energy Savings, 2010-2015

Overall, the industrial program portfolio continued to perform well in 2015. With a similar trend as observed in 2014, significant additional annual net savings were generated in 2015 compared to the previous years. PSU projects were responsible again this year for the biggest portion of the savings achieved. With 122.7 GWh, the PSU program generated almost 60% of all the net energy savings in 2015. The savings of the Energy Managers program were somewhat lower in 2015 with a reduction of 11% compared to 2014, despite an increase in the measures implemented (12%). In contrast, the biggest increase was achieved with the IAP Retrofit initative, which achieved 36 times the amount of savings achieved in 2014. The large increase in savings for IAP Retrofit can be due to not only a higher number of projects completed (11 in 2015, compared to 5 in 2014), but also some projects that generated a very high level of savings.Three projects achieved gross verified savings between 1 GWh and 20 GWh in 2015.

3.6.2 Effective Useful Life of Measures

To establish the lifetime net verified energy savings, the reported EUL was validated for each project reviewed by the evaluation team. The EUL indicates the minimum life expectancy of the equipment involved in a project or measure. The evaluation team verified the reported EUL values by consulting standard references from the IESO Assumptions and Measure Lists[15] and the Wisconsin Measure Life Study.[16] When no EUL was reported, a value was assigned. The EUL values were also reviewed based on the evaluation team's experience.

For all the other programs except Energy Managers, the EUL was revised for each individual projects. For the EM program, the evaluation team reviewed the EUL of the sampled measures and calculated an adjustment ratio.

$$Adjustment\ Ratio\ (EUL) = \frac{Verified\ EUL\ (years)}{Reported\ EUL\ (years)}\ x\ 100\%$$

An overall EUL adjustment ratio was determined based on the weighted average of the gross energy savings and applied to all the Energy Managers measures. This ratio was 0.92 for the reviewed measures and 0.83 for the non-reviewed measures.

The table below summarizes the verified EULs by program/initiative, as obtained through a weighted average based on the gross energy savings.

Table 13: 2015 Verified Effective Useful Life by Program/Initiative

Program/Initiative	EUL
IAP Process and Systems	12.0
IAP Retrofit	9.3
IAP Energy Managers	6.0
PSU	15.9
Energy Managers	7.7
M&T	1.0

Almost no adjustments were needed for the EUL of IAP Process and Systems and PSU projects since the M&V plans of these programs required providing accurate EUL. For IAP Retrofit, most EUL values were assigned by the evaluation team since few EULs were reported.

[15] Ontario Power Authority, "Prescriptive Measures and Assumptions List", January 2014 (Excel format) and Ontario Power Authority, "Quasi-Prescriptive Measures and Assumptions List", Release Version 1, December 2010.
[16] PA Consulting Group, Inc., "Focus on Energy Evaluation, Business Programs: Measure Life Study", report presented to the Public Service Commission of Wisconsin, August 25, 2009.

More adjustments were needed for the EULs of EM measures. A common adjustment was made to the EUL of lighting and lighting control measures. Typically, lighting controls (sensors or timers) were assigned a verified EUL of 8 years, which differs from the standard EUL of 11 years used by the TR. The value used by the TR is in fact valid for lamps, and is based on an average of a variety of CFL, LED, Metal Halide and fluorescent lamps from the Wisconsin Measure Life Study.[17] Because of the wide differences in EUL values among LED technologies, the EUL for lighting measures involving LED was revised according to the rated life value (in hours) of the LED lights divided by the validated annual hours of operation (instead of the standard value of 11 years for all the other types of lighting). Another common adjustment was for behavioural and control measures. The EUL was often assigned by the TR as if the equipment had been replaced, which resulted in higher values. Behavioural measures, which typically have a low persistence, were assigned an EUL of one year by the evaluation team. The verified values for control measures generally ranged from three to eight years, depending on the type of controls implemented and how easily the settings can be changed.

The EUL of the two M&T measures were set to one year because of the methodology used to quantify savings. Indeed, the IPMVP Option C captures all the savings achieved at the plant level, which includes a mix of behavioural measures and equipment replacement measures. Option C is, however, most appropriate for the M&T program because it can capture behavioural-change-related savings, which is the focus of the program. Option C's methodology allows for quantifying these savings while gathering and treating less data than what would be required if the measures were to be quantified individually with engineering calculations or other IPMVP options. The downside to that approach is that an EUL of one year has to be used because the weighted average EUL of all the measures cannot be calculated without the detailed savings of each measure. This drawback is minimal if the majority of the savings come from behavioural-change measures, since their EUL is one year in any case. Nevertheless, this year's evaluation suggests that a fair proportion of the savings achieved were due to equipment retrofit.

To evaluate the possibility of a dual baseline (step-down) in annual energy savings, questions were asked about the age of the existing equipment and its planned replacement. A step-down may occur if the old equipment is planned to be replaced at some point during the EUL by the new efficient equipment and if the standard efficiency of new equipment at that time is higher than the current baseline. However, no occurrences of dual baseline were found this year. This was partially due to the difficulty in clearly identifying a replacement schedule for large industrial equipment. Additionally, many of the projects involved installing VFDs, for which the baseline (the absence of VFD) does not change over time.

[17] PA Consulting Group, Inc., "Focus on Energy Evaluation, Business Programs: Measure Life Study", report presented to the Public Service Commission of Wisconsin, August 25, 2009.

3.6.3 Verified Lifetime Energy Savings

To establish the lifetime net verified energy savings, the annual net verified energy savings in every year throughout the EUL were added up for every project/measure. Because no step-down in savings was identified for any project or measure in 2015, the net lifetime verified energy savings were established by multiplying the net annual savings by the verified EUL. The peak demand savings are also expected to remain constant over the entire EUL.

Table 14: 2015 Lifetime Net Verified Energy Savings

Program/Initiative	Annual Net Verified Energy Savings (GWh)	Average Verified EUL (Years)	Lifetime Net Verified Energy Savings (GWh)
Total IAP	49.398	10.4	515.762
IAP Process and Systems	20.669	12.0	248.381
IAP Retrofit	28.700	9.3	267.211
IAP Energy Managers	0.028	6.0	0.171
PSU	122.704	15.9	1,946.749
Energy Managers	35.834	7.7	275.544
M&T	1.369	1.0	1.369
Total	**209.305**	**13.1**	**2,739.424**

3.7 Cost-effectiveness Analysis

The evaluation team used the impact results from this evaluation (including net energy and peak demand savings, EUL and incremental costs) in the cost-effectiveness calculations.

Following recommendations from the 2014 program evaluation, a particular effort was made by the evaluation team to distinguish the total project costs from the incremental costs for Energy Managers measures during the on-site visits and phone reviews. This allowed the evaluation team to determine the adjustment ratios for the incremental costs which were applied to all the measures completed in the Energy Managers program. These ratios were 1.16 for the reviewed measures and 0.94 for the non-reviewed measures. For all the other programs, minimal adjustments were made to the incremental costs, on an individual project basis.

The assessment of the program’s cost-effectiveness covered only one energy source, namely electricity. The savings and expenditures related to all the programs are included in the cost-effectiveness calculations. All program cost information was provided by the IESO.

The evaluation team assessed the program's cost-effectiveness of each program by calculating several tests of benefit/cost metrics. These tests include benefits and costs that persist over the EUL of the measures implemented through the program. These benefits and costs are adjusted based on the inflation and discount rates (respectively 2% and 4%) provided by the IESO to determine their present values.

The calculations were made using the IESO's CDM Energy Efficiency Cost Effectiveness Tool. The cost-effectiveness results are presented at the program level to provide an overall program perspective. Namely, the cost-effectiveness results of all the IAP initiatives have been combined together under IAP to provide information on the entire program portfolio offered to transmission-connected participants.

Total Resource Cost Test

From the perspective of both the utility and participating customers, the TRC metric reveals the total net benefits of an energy efficiency program. The TRC test compares the program design and delivery costs incurred and customers' costs with the avoided costs of electricity and other supply-side resources (generation, transmission and distribution).

The TRC ratio is calculated using the following formula:

$$TRC = \frac{PV\ (Marginal\ Benefits) + PV\ (Tax\ Credits)}{PV\ (Net\ Participant\ Costs + Total\ Program\ Admin\ Costs)}$$

The TRC net benefit (NB) is calculated based on the following formula:

$$TRC\ net\ benefit = PV\ (Marginal\ Benefits) + PV\ (Tax\ Credits) - PV(Net\ Participant\ Costs + Total\ Program\ Admin\ Costs)$$

The marginal benefits represent the present value of the electricity-system-related costs that are no longer required (the energy consumed by participating customers and the avoided cost of new infrastructure). No tax credit is quantified or included in the calculations for this program.

The net participant costs is the incremental product cost (e.g., the difference in cost between the energy-efficient technology and the standard technology that would have been installed in the absence of the energy-efficient technology) paid by the participant.

The total program administration costs include the administrative costs involved in program planning, design, marketing, implementation and evaluation.

The results are presented in the following table.

Table 15: TRC Ratio and Net Benefit Results

Program	Ratio	Benefits ($)	Costs ($)	NB ($)
IAP	0.80	26,138,662	32,703,664	-6,565,002
PSU	0.85	94,241,932	110,909,382	-16,667,449
Energy Managers	0.72	18,164,833	25,085,802	-6,920,968
M&T	0.08	65,503	811,960	-746,457

From society's standpoint (particularly IESO and participating customers), none of the programs were cost-effective in 2015. These results are mostly due to high program costs for all the programs and the small number of projects in IAP, M&T and PSU. In 2015 particularly, higher administrative costs may have been associated with the change of program framework. A number of projects were also completed in 2015 though their savings were not included in the present evaluation report; these projects did not have their M&V reports completed in time for the savings to be covered by this year's evaluation activities.

Program Administrator Cost Test

The PAC metric reveals the benefits of the program from the perspective of the program administrator. The PAC test compares the program design and delivery costs incurred by the program administrator with the avoided electricity supply-side resource costs.

The PAC ratio is calculated using the following formula:

$$PAC = \frac{PV\ (Marginal\ Benefits)}{PV\ (Utility\ Program\ Admin\ Costs+Incentives)}$$

The PAC's NB is calculated using the following formula:

$$PAC\ NB = PV\ (Marginal\ Benefits) - PV(Utility\ Program\ Admin\ Costs + Incentives)$$

The marginal benefits represent the present value of the electricity-system-related costs that are no longer required (the energy consumed by participating customers and the avoided cost of new infrastructure).

The present value of the total administration costs and incentives is equal to the sum of (1) the total program administration costs, which include the administrative costs incurred in program planning, design, marketing, implementation and evaluation, and (2) the incentives that the program administrator offered to participating customers.

The results are summarized in the following table.

Table 16: PAC Ratio and Net Benefit Results

Program	Ratio	Benefits ($)	Costs ($)	NB ($)
IAP	1.26	22,729,272	18,078,043	4,651,229
PSU	1.20	81,949,506	68,487,348	13,462,158
Energy Managers	1.52	15,795,507	10,368,117	5,427,391
M&T	0.08	56,960	680,734	-623,774

From a program administrator's standpoint, all the programs except M&T were cost-effective in 2015. The low PAC ratio for M&T can be explained by the fact that there were only two M&T participants in 2015.

Levelized Delivery Cost

The LC indicates an economic cost value for the energy or peak demand saved by an energy-efficiency program. The LC indicates the total cost of the conserved energy or peak demand based on the utility's investment made on behalf of the ratepayer on a per-unit basis levelized over a fixed time period. The cost value allows for a high-level comparison with other supply options and other DSM programs occurring over different timeframes.

The LC ratio is calculated using the following formula:

$$LC = \frac{PV\ (Utility\ Program\ Admin\ Costs{+}Incentives)}{PV\ (Energy\ or\ Peak\ Demand\ Saved)}$$

The present value of the total administration costs and incentives of the utility-run program is the same value as that for the PAC test.

The present value of the energy or peak demand saved is the amount of energy in GWh or peak demand in MW saved through the program.

The results for LC energy savings and peak demand savings are summarized in the table below.

Table 17: LC Ratio Results for Energy Savings

Program	Ratio ($/GWh)	Costs ($)	Benefits (GWh)
IAP	47,139	18,078,043	383.504
PSU	52,508	68,487,348	1,304.317
Energy Managers	47,010	10,368,117	220.552
M&T	482,491	680,734	1.411

The results for LC peak demand savings are summarized below.

Table 18: LC Ratio Results for Peak Demand Savings

Program	Ratio ($/MW)	Costs ($)	Benefits (MW)
IAP	405,810	18,078,043	44.548
PSU	474,786	68,487,348	144.249
Energy Managers	218,239	10,368,117	47.508
M&T	-	680,734	0.000

4 CONCLUSIONS AND RECOMMENDATIONS

4.1 Cross-cutting Conclusions

Conclusion No. 1:

The TRC indicators show that the programs are not cost-effective; however, these indicators provide a skewed perspective because the calculations include all the program costs, but do not fully account for the benefits that result from the program.

M&T has the lowest TRC ratio, at 0.08, while IAP, PSU and Energy Managers have TRC ratios between 0.72 and 0.85, meaning that the costs are higher than the benefits for all the programs. For IAP Process and Systems and PSU, this is in part because:

› There is a relatively long interval between the occurrence of expenses and the accounting of benefits. Savings are often realized many years after the initiation of the project because of the long process that starts with an IESO-funded engineering study (which does not always lead to incentivized projects). This means that cost-effectiveness indicators would be lower if the volume of projects in progress increases.

› Additionally, some projects completed in 2015 did not have a complete M&V report by the time of the 2015 evaluation. Their savings will only be accounted for in the 2016 evaluation as part of the true-up reporting process.

› In the case of Energy Managers and M&T, the issue is that all the program costs are considered, while only the benefits related to non-incentivized measures are included in the cost-effectiveness calculations.

Recommendation No. 1

Analyze the overall cost-effectiveness from a program-wide perspective. Programs should be evaluated by including all the costs and benefits of all their components. For instance, perhaps Energy Managers is not cost-effective as a stand-alone initiative, but it nevertheless draws many projects to the PSU program and even more to the Business Retrofit program. Positive distortion effects, such as spillover, should also be accounted for as part of the assessment of the overall program cost-effectiveness, rather than being attributed to a separate initiative, as it is currently the case with Enabled Savings.

4.2 Conclusions and Recommendations Specific to IAP Process and Systems and PSU

Conclusion No. 2:

The reporting procedures could be improved for the M&V reports and the program database.

- The reported savings are not calculated by following the same rules as those for the verified savings calculations. The energy savings values documented by the IESO in its program database are strictly based on the metered data available at the time of evaluation. Indeed, the TR reports observed savings for the reporting period and no further calculations were performed to ensure that these values were representative of the performance to be expected from the projects in the long run. This problem is even more serious if the reporting period only includes a few months after the project has been commissioned, when troubleshooting and fine-tuning is still needed.
- The M&V reports did not always clearly mention these unusual events; so, it was not explicitly indicated whether any adjustment should be made to the annual energy savings.
- Also, the reported value of peak demand savings is actually the annual demand savings, which are equivalent to the average demand reduction during the equipment's hours of operation.

Recommendation No. 2a

Define the guidelines for calculating the reported annual energy savings and the peak demand savings. It is recommended that the IESO clearly define a methodology for calculating the annualized energy savings and peak demand savings based on the metering results. This will allow the Evaluator to make an "apple-to-apple" comparison between the reported energy savings and the verified values calculated.

Recommendation No. 2b

Include a specific section in the M&V report to identify the unusual events or changes in static variables. The evaluation team noticed that for projects where unexpected events occurred during the reporting period (unusual downtime, changes in the usage made of the premises), the M&V report did not mention the events and their impacts on the measured energy savings. The evaluation team urges that a section of the M&V report should be devoted to monitoring the static variables to ensure that they are always validated before the M&V report is prepared and submitted.

4.3 M&T-Specific Conclusions and Recommendations

Conclusion No. 3:

The benefits of the M&T program are underestimated because the current savings calculation methodology requires the use of an EUL of one year.

The IPMVP Option C currently used to estimate savings has some major advantages: it allows for capturing all the savings (both those associated with the equipment and those associated with behavioural changes), while requiring little time for making data collection and engineering calculations. On the other hand, this methodology requires calculating the savings every year by inputting new independent variable values.

Recommendation No. 3

Consider calculating the savings associated with equipment retrofit measures using simple engineering calculations. Many non-incentivized measures implemented by M&T participants generate savings that can be easily quantified with engineering calculations. This is the case for electrical equipment shutdown (when the hours of operation can be accurately estimated) or for lighting retrofit, for instance. The savings of those measures could be deducted from the savings established by following Option C methodology. Similarly, their EUL values could be estimated in the same manner as for Energy Managers non-incentivized measures. Consequently, the remaining savings would be mostly behavioural-change-related savings, for which an EUL of one year is valid. This would result in higher and more accurate lifetime energy savings for this initiative, which will increase the values of cost-effectiveness indicators.

4.4 Energy Managers-Specific Conclusions and Recommendations

Conclusion No. 4:

The savings calculations are not quite consistent among EMs.

The impact evaluation revealed that EMs have varying levels of knowledge about energy and demand savings estimations. Some elements that are often omitted include the interactive effects and the ballast factors for lighting applications.

Recommendation No. 4a

Encourage the use of standardized calculation sheets for common energy-efficiency measures. Many common measures contribute a large portion of the savings in Energy Managers, such as motor replacement and lighting retrofits. The IESO already has standardized calculation sheets (developed for the Retrofit program), which could be adapted and used for Energy Managers as well. They would help EMs limit the omission of certain variables in calculations.

Recommendation No. 4b

Raise awareness about the guidelines concerning the peak demand definition and peak demand savings calculations. While the evaluation team considers that the peak demand savings are very well explained in the EM&V protocol, it seemed that many EMs did not know about this document or have never used it. It is recommended that the IESO distribute the protocol to all the EMs and clearly explain how to use the document.

Conclusion No. 5:

Some of the guidelines to be followed by the TR in reviewing the projects are not clearly explained.

- The evaluation team discovered some non-incentivized projects that did not meet the new eligibility criteria for the new framework (namely, fuel-switching projects). It was found that the TR had continued applying the old framework's rules without being given a clear directive to do otherwise.
- Some of the projects reviewed in this evaluation did not include specific energy-efficiency measures; the savings they generated were actually a side effect of the modifications made primarily to increase production capacity. This seemed to fall within an eligibility "grey zone".
- Also, the TR generally applied a conservative review approach: when the TR's savings value was higher than the value proposed by the energy manager, it was assumed that the initial value was correct. On the other hand, when the information substantiating the savings was insufficient, the savings value was left unchanged.

Recommendation No. 5a

Clarify the eligibility criteria applicable to the Energy Managers program's non-incentivized measures. While the new framework's rules were not being implemented quickly enough during the framework transition period, it would have been better to issue an official directive to the TR and the EMs. The IESO should prevent proposed EM measures aimed only at increasing production capacity from being claimed as measures. For instance, one option could be to require using new standard efficiency equipment that meets the new production needs as the baseline, instead of the old production equipment. In this manner, if a project replaces old equipment with new standard equipment of a larger capacity, the savings are to be nil.

Recommendation No. 5b

Require the TR to make both downward and upward adjustments to the savings reported by the EMs. The objective of the technical review is to increase accuracy rather than to make the most conservative estimates of savings.

Recommendation No. 5c

Establish a threshold over which an EM must submit a savings substantiation plan to the TR prior to implementing a measure. The Evaluator observed that some of the measures with big savings did not have an appropriate methodology for assessing their savings. If the engineering calculation parameters cannot be estimated with a sufficient level of certainty, it is necessary to make some measurements. Such a requirement should be set and met as early as possible at a project's design stage in order to determine pre-implementation measurements. The evaluation team reiterates last year's recommendation that a 500 MWh threshold be established, above which a savings-substantiation plan must be submitted to the IESO for its approval prior to the project implementation.

Appendix I
PROJECT REVIEW PROTOCOL FOR IAP PROCESS AND SYSTEMS AND PSU

ECONOLER

Capital Incentive Project Evaluation
Independent Electricity System Operator (IESO)
On-Site Visit Protocol

1. General Information

Site Visit Date:		Eval Team:		Contact Name:	
Project ID:				Contact Title:	
Project Type:				Contact Phone:	
Company Name:				Email:	
Address:					

List of people met during the visit:

Type of building:	Commercial/institutional		Industrial/manufacturing			
	Municipal		Other (specify)		*Specify:*	

Preparation Prior to Site Visit

2. Key Project Variables

Variable Descriptions: *List project variables and key performance indicators from the M&V Plan on which the saving measurementsare are based*

NOTE: PC Users "Alt+Enter" for new line in cell. MAC Users "CMD+Option+Enter".

3. M&V Post Implementation Results

Seasonal Load Profile? ____ *(Y/N)* *Summer Load* ____ *(Y/N)*

Predicted Results (MWh)	M&V Results	Percent of Expected (%)	M&V Start Date	M&V Finish Date	Days in Period	Notes

Notes: *Insert Comments from M&V Reports*

4. Pre-Visit Assessment of the Project

Indicate the key information/elements to validate during the site visit from the project review report and M&V report analysis.
List notes and main questions that will serve to guide the visit. ***IMPORTANT: EUL TO BE VALIDATED.***

Is the EUL used for this project reasonable? (Y/N)	
Revised EUL (see Wisconsin Measure Life Study) If acceptable, enter tracked value.	
Explanation	

On-Site Visit

5. Facility Description and Schedule

Facility Description: *Outline a quick description of the facility and its primary operation/purpose.*

NOTE: PC Users "Alt+Enter" for new line in cell. MAC Users "CMD+Option+Enter".

Facility Operation:

Provide a description of the daily and annual operating schedule.
If necessary, fill in the Facility Schedule to report detailed schedule (see separate tab)

Any annual shut downs?		(Y/N)
Any shutdown and/or variations during the baseline measurement?		(Y/N)
Any expected variations in future usage/production of the facility?		(Y/N)

NOTE: PC Users "Alt+Enter" for new line in cell. MAC Users "CMD+Option+Enter".

6. Interactive Effects

Interactive Effects? *YES* ☐ *NO* ☐

If YES, describe the interactive effects for the project and fill the table below for each heating/cooling systems applica

Heating Systems *Fill the table below for each heating system at the site.*

Description	Heating System 1	Heating System 2
Energy Source *(electricity, natural gas, oil, etc.)*		
Heating System Type *(electric resistance, furnace, heat pump...)*		
Nominal Capacity *(indicate the unit – kW, Mbtu/h...)*		
Heating system **Efficiency or COP**		
Percent of Load (Declaration)		
If any, changes in building **set points** (occ./ unocc. temp., % hum)		

Cooling Systems *Fill the table below for each cooling system at the site.*

Description	Cooling System 1	Cooling System 2
Energy Source *(electricity, natural gas, oil, etc.)*		
Cooling System Type *(compressor, absorption...)*		
Nominal Capacity *(indicate the unit – kW, tons, etc.)*		
Cooling system **SEER or COP**		
Percent of Load (Declaration)		
If any, changes in building **set points** (occ./ unocc. temp., % hum)		

7. On-Site Observations and Findings

Report the on-site visit and indicate the key observations and findings made on site.

8. Spillover and Free-Ridership Assessment

Spillover Questionnaire Completed?		(Y/N)
Free-Ridership Questionnaire Completed?		(Y/N)
Incremental Cost Questionnaire Completed?		(Y/N)

9. Notes on Savings Calculations

If adjustments were made to the energy savings, demand savings or PCF, describe the rationale and provide calcul

Adjustments made to energy savings?		(Y/N)
Adjustments made to demand savings?		(Y/N)
Adjustments made to PCF?		(Y/N)

10. Energy and Demand Savings Adjustments

Tracked Savings

Tracked Energy Savings:		kWh/yr
Tracked Non-Peak Demand Savings:		kW
Peak Coincidence Factor Used by IESO:		
Tracked Peak Demand Savings		kW

Project Estimated Finish Month:	
Notes on Project Status:	

Revised Savings by the Evaluator

Revised Energy Savings:		kWh/yr
Revised Non-Peak Demand Savings:		kW
ak Coincidence Factor Used by Evaluator:		
Revised Peak Demand Savings		kW

Conclusion

11. Conclusion

Briefly justify the adjustments applied to the savings:

Free-ridership

#	Statement	FR Scores	Answers
***This series of questions must always be asked to end-users that were involved in the decision process.**			
Now I'm going to ask you a few questions about what you might have done differently in the absence of the program.			
INTENTION QUESTIONS			
FR1	A1. When you first learned about the [PROGRAM NAME], was the entire cost of purchase and installation of the [MEASURE CODE] included in your company's approved capital budget? 1. Yes 2. No 99. DK/Refused	A1 is not scored. It is used to confirm A5. Consider response if A2 = 3. Ask A5 and score A5.	
FR2	Had your company ALREADY ordered or purchased all of the equipments to be installed through the project BEFORE your company heard about the program? 1. Yes 2. No 99. DK/Refused	-	
FR3	Which of the following is most likely what would have happened if if your company had never learned about the [PROGRAM NAME]? 1. Canceled or postponed the project at least one year 2. Reduced the size, scope, or efficiency of the project 3. Done the exact same project (no change) 99. DK/Refused	IF FR3 = 1. --> 0 2. --> Ask and score A3 (FR4) 3. --> Ask and scoreA4 (FR5) 99. --> 25	
FR3 SCORE			

FR4a	**ASK IF FR3= 2** By how much would you have reduced the size, scope, or efficiency? Would you say a…[READ LIST] 1. Small amount (10 - 20%) 2. Moderate amount (20 - 50%) 3. Large amount (over 50%) 99. DK/Refused	**SCORE IF FR3= 2** **IF FR4a =** 1. --> 37.5 2. --> 25 3. --> 12.5 99. --> 25	
FR4b	**ASK IF FR4 = 1, 2 OR 3** Please describe what your company would have changed about the size, scope, or efficiency of the project. [RECORD ANSWER] 99. DK/Refused	Used to validate FR4a	
FR4 SCORE (validate with FR4b)			
FR5	ASK IF FR3= 3 Now I want to focus on what it would have cost your company to implement the project without the incentive from the IESO. How likely is it that your company would have paid the full cost to complete the same project at the same time? Would you say… [READ LIST] 1. Very likely 2. Somewhat likely 3. Not too likely 4. Not at all likely 99. DK/Refused	**SCORE IF FR3= 3** **1. --> 50** **2. --> 37.5** **3. --> 25** **4. --> 0** **99. --> 25**	
FR5 SCORE			**FAUX**
	FR3 Score		**0**
	FR4 Score		**0**
	FR5 Score		**0**
	Max Score Intention (50)		**0**

Influence Score (50)			
FR6	I'm going to read a list of items about the program. Please rate each item on how much influence it had on the decision to complete the project the way it was done. Please use a scale from 1, meaning no influence, to 5, meaning the item was extremely influential in your decisions. PSUI participants: Ask items in green IAP participants: Ask items in blue Ask items in black to all participants	**FR6 =** MAX COMPONENT SCORE	
FR6a	Assistance provided by your IESO/[LDC] Key Account Manager or CLEAResult	[RECORD SCORE] 99. DK/Refused	
FR6b	The [PROGRAM NAME] funded engineering study	[RECORD SCORE] 99. DK/Refused	
FR6c	[PROGRAM NAME] financial incentives for energy projects	[RECORD SCORE] 99. DK/Refused	
FR6d	A program sponsored energy manager	[RECORD SCORE] 99. DK/Refused	
FR6e	A program funded energy monitoring system	[RECORD SCORE] 99. DK/Refused	
FR7	Was there anything else that was highly influential in your decision to complete the project in the way that you did? [RECORD ANSWER] 99. DK/Refused	**Consider this score if the influencial factor is related to the programme/IESO.*	
FR7b	If yes, RECORD DESCRIPTION AND ENTER SCORE OF 4 OR 5, BASED ON DESCRIPTION OF TOPIC 99. DK/Refused		-
FR8	Was your company considering any other energy efficiency projects that could have been implemented instead of the project that received funding from IESO? 1. Yes 2. No 99. DK/Refused	No scoring attached to this question. If FR8 = No, skip to FR11	

FR9	ASK IF FR8=1, YES How did the assistance from IESO influence which project was implemented? [RECORD ANSWER] 99. DK/Refused	**Consider this score if the influencial factor is related to the programme/IESO.* *Score:* *0 to 10*	
FR10	Using the same scale of 1 to 5, please rate how much influence the assistance from IESO had on WHICH project was implemented.		
FR11	Does your company have corporate policies about energy efficiency that are considered when purchasing new equipment or making improvements? [RECORD ANSWER] 1. Yes 2. No 99. DK/Refused		
FR12	Which of the following best describes this policy? [RECORD ANSWER] 1. Your company purchases energy efficient equipment regardless of cost 2. Your company purchases energy efficient equipment if it meets payback or return on investment criteria 3. Something else [SPECIFY] 98. (Don't know) 99. (Refused)		
FR13	How would you rate the influence of your company's corporate policies on decisions to make energy efficiency upgrades? Please use a scale of 1 to 5, where 1 means no influence and 5 means the policies were extremely influential. [RECORD ANSWER] 99. DK/Refused	[RECORD SCORE] 99. DK/Refused	
MAX RATING A6a - A6e, A7, A10			**0**
INTERIM INFLUENCE SCORE (MAX 50)			**FAUX**
ADJUST SCORE IF A13 CORPORATE POLICIES ARE HIGLY INFLUENTIAL (SCORE 4 OR 5)			**0**
ALMOST FINAL INFLUENCE SCORE (WITH ADJUSTMENT FOR POLICY)			**0**
FINAL INFLUENCE SCORE (MAX 50, WITH ADJUSTMENT FOR POLICY)			**0**
FINAL FR (INTENTION + INFLUENCE)			**0%**

Spillover

#	Statement	Participant's Answers
SO1	After participating in the Industrial program, have you implemented other energy efficiency measures than those you implemented through the project either elsewhere in your facility or in another of your facilities without participating in any IESO's energy efficiency program? 1. (Yes) 2. (No) 98. (Don't know) 99. (Refused)	
SO2	Validation - For each of the additionnal EE measures identified in SO1: Did you obtain any incentive from IESO or your energy distributor, or do you intend to submit a funding request in the future?	
SO3	**SO Savings Quantification - For each of the additionnal EE measures identified in SO1:** What type of measure were they? Can you give an approximate percentage of the energy savings achieved with respect to those of this facility (or quantity of measures implemented, or area covered)? Do you have a feasibility study or other measurements that had evaluated those savings?	
SO4	**For each of the additionnal EE measures identified in SO1:** Did your experience with the energy efficiency measures implemented through the [PROGRAM NAME] influence your decision to implement these additional energy efficiency measures on your own? Please, give your answer on a scale of 0 to 10, where 0 indicates that the program "had no influence at all on your decision to implement the energy efficiency measures" and 10 indicates that the program was "extremely influential to your decision to implement energy efficiency measures."	

Facility Schedule

Facility Annual Schedule:

Fill the table below for each occupancy schedule reported by the site contact as occupancy could vary for each section of the facility. Use additional sheets if necessary.

Description	1 - Normal Schedule		2 - Specify:		3 - Specify:	
	Weekdays	Weekends	Weekdays	Weekends	Weekdays	Weekends
Number of day with regular schedule per year						
Number of days with regular holidays schedule per year						
Number of days with no occupancy per year (For example: seasonal closure)						
Total number of days per year	0	0	0	0	0	0

Facility Daily Schedule:

Fill the table below for each occupancy schedule reported by the site contact as occupancy could vary for each section of the facility. Use additional sheets if necessary.

Schedules		Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday	Holidays
Schedule 1: Normal	Time of use (e.g. 8:00 am to 5:00 pm)								
	Hours per day								
Schedule 2 (specified above)	Time of use								
	Hours per day								
Schedule 3 (specified above)	Time of use								
	Hours per day								

Incremental Cost

Value of incremental cost given in the project review report		
Explanation of this value		
#	**Statement**	**Participant's Answers**
Section 1: Remaining Effective Useful Life (EUL)		
Q1.	Is the efficient equipment installed as part of this project…?	
	a) a replacement for an equipment at the end of its effective useful life (EUL)	
	b) a replacement for an equipment that had not yet reached its EUL	
	c) an additional equipment that reduces energy consumption	
	[ASK IF Q1=b, OTHERWISE SKIP TO Q4]	
Q2.	For how many years could this equipment have kept running?	
	[ASK IF Q2>PROJECT EUL]	
Q3.	What would have been the efficiency of the standard equipment (i.e. not high efficiency equipment) that would have replaced the old equipment at the end of its EUL? If unsure, probe to obtain a description of the technology or type of equipment that could have replaced the old equipment.	
Section 2: Incremental Cost		
If Q1=a, incremental cost = efficient (incented) equipment cost - standard equipment cost		
If Q1=b or c, incremental cost = total project cost		
[ASK IF Q1=a]		
Q4.	What is the approximate cost of the standard equipment that would have replaced the old equipment if this energy-efficiency project had not gone forward? *If unsure, probe to obtain an estimation of the premium associated with the efficient equipment, either in $ or %.*	
Reviewed incremental cost value		
Justification		

Appendix II
PROJECT REVIEW PROTOCOL FOR IAP RETROFIT

ECONOLER

Retrofit
Independent Electricity System Operator (IESO)
Project Review

Review date:		Reviewer name:	
Project ID:		Contact name:	
		Contact phone:	
		Contact email:	

Retrofit Category:	Prescriptive	
(Check applicable option)	Engineered	
	Custom	

Company name:	
Facility address:	
Building type	
List of people contacted for the review and contact information:	

Was M&V conducted as part of this project? (Y/N)	
Is a site visit planned for this project? (Y/N)	

Prepration Prior to Review

1. Project Review Summary

savings)

2. Questions for Review

B) List of questions for the project review

Enter below the list of questions and key variables to be validated during the site visit or phone interview.
For Custom measures, include information from the M&V plan if applicable.
Items that may need to be verified: operating schedule, number of hours per year, interactive effects, etc.

Incremental Cost questionnaire filled out?	
Is the EUL used for this project reasonable? (Y/N)	
Revised EUL (see Wisconsin Measure Life Study)	
Explanation	

Review

3. On-Site Observations and Findings

Report the on-site visit and the key observations and findings following the review.

For Prescriptive and Engineered projects:

Eligibility of the equipment in the program validated? (Y/N)

3. Savings Calculations

Provide the source for the Tracked Savings

For Prescriptive projects :	Category of equipment and prescriptive value
For Engineered projects :	Formula for tracked savings, with default and project-specific variables
For Custom projects	Custom calculation

Reviewer's Calculation and Notes

Include notes to document the approach

Please note: while tracked savings for prescriptive and engineered measures might not be representative of the real usage of the equipment due to the nature of the program, the verified savings should be calculated to be as accurate as possible.

	Summer Peak Demand (kW)	Energy (kWh)	Comments
1. Savings from Tracking Sheets (IESO's reported values)			
2. Verified Savings (by the Evalutor)			
Savings to Anticipated Savings Ratio (Line 2./1.)	#DIV/0!	#DIV/0!	

4. Conclusion

E) Summarize, if any, the adjustments of the project review

Incremental Cost

Value of tracked incremental cost		
Explanation of this value		
#	**Statement**	**Participant's Answers**
Section 1: Remaining Effective Useful Life (EUL)		
Q1.	Is the efficient equipment installed as part of this project…?	
	a) a replacement for an equipment at the end of its effective useful life (EUL)	
	b) a replacement for an equipment that had not yet reached its EUL	
	c) an additional equipment that reduces energy consumption	
	[ASK IF Q1=b, OTHERWISE SKIP TO Q4]	
Q2.	For how many years could this equipment have kept running?	
	[ASK IF Q2>PROJECT EUL]	
Q3.	What would have been the efficiency of the standard equipment (i.e. not high efficiency equipment) that would have replaced the old equipment at the end of its EUL? If unsure, probe to obtain a description of the technology or type of equipment that could have replaced the old equipment.	
Section 2: Incremental Cost		
If Q1=a, incremental cost = efficient (incented) equipment cost - standard equipment cost		
If Q1=b or c, incremental cost = total project cost		
[ASK IF Q1=a]		
Q4.	What is the approximate cost of the standard equipment that would have replaced the old equipment if this energy-efficiency project had not gone forward? *If unsure, probe to obtain an estimation of the premium associated with the efficient equipment, either in $ or %.*	
Reviewed incremental cost value		
Justification		

Free-ridership

#	Statement	FR Scores	Answers
This series of questions must always be asked to end-users that were involved in the decision process.			
Now I'm going to ask you a few questions about what you might have done differently in the absence of the program.			
INTENTION QUESTIONS			
FR1	A1. When you first learned about the [PROGRAM NAME], was the entire cost of purchase and installation of the [MEASURE CODE] included in your company's approved capital budget? 1. Yes 2. No 99. DK/Refused	A1 is not scored. It is used to confirm A5. Consider response if A2 = 3. Ask A5 and score A5.	
FR2	Had your company ALREADY ordered or purchased all of the equipments to be installed through the project BEFORE your company heard about the program? 1. Yes 2. No 99. DK/Refused	-	
FR3	Which of the following is most likely what would have happened if if your company had never learned about the [PROGRAM NAME]? 1. Canceled or postponed the project at least one year 2. Reduced the size, scope, or efficiency of the project 3. Done the exact same project (no change) 99. DK/Refused	IF FR3 = 1. --> 0 2. --> Ask and score A3 (FR4) 3. --> Ask and scoreA4 (FR5) 99. --> 25	
FR3 SCORE			

FR4a	**ASK IF FR3= 2** By how much would you have reduced the size, scope, or efficiency? Would you say a…[READ LIST] 1. Small amount (10 - 20%) 2. Moderate amount (20 - 50%) 3. Large amount (over 50%) 99. DK/Refused	**<u>SCORE IF FR3= 2</u>** **IF FR4a =** 1. --> 37.5 2. --> 25 3. --> 12.5 99. --> 25	
FR4b	**ASK IF FR4 = 1, 2 OR 3** Please describe what your company would have changed about the size, scope, or efficiency of the project. [RECORD ANSWER] 99. DK/Refused	Used to validate FR4a	
FR4 SCORE (validate with FR4b)			
FR5	ASK IF FR3= 3 Now I want to focus on what it would have cost your company to implement the project without the incentive from the IESO. How likely is it that your company would have paid the full cost to complete the same project at the same time? Would you say… [READ LIST] 1. Very likely 2. Somewhat likely 3. Not too likely 4. Not at all likely 99. DK/Refused	**<u>SCORE IF FR3= 3</u>** **1. --> 50** **2. --> 37.5** **3. --> 25** **4. --> 0** **99. --> 25**	
FR5 SCORE			**FAUX**
	FR3 Score		**0**
	FR4 Score		**0**
	FR5 Score		**0**
	Max Score Intention (50)		**0**

Influence Score (50)			
FR6	I'm going to read a list of items about the program. Please rate each item on how much influence it had on the decision to complete the project the way it was done. Please use a scale from 1, meaning no influence, to 5, meaning the item was extremely influential in your decisions. PSUI participants: Ask items in green IAP participants: Ask items in blue Ask items in black to all participants	**FR6 =** MAX COMPONENT SCORE	
FR6a	Assistance provided by your IESO/[LDC] Key Account Manager or CLEAResult	[RECORD SCORE] 99. DK/Refused	
FR6c	[PROGRAM NAME] financial incentives for energy projects	[RECORD SCORE] 99. DK/Refused	
FR6d	A program sponsored energy manager	[RECORD SCORE] 99. DK/Refused	
FR7	Was there anything else that was highly influential in your decision to complete the project in the way that you did? [RECORD ANSWER] 99. DK/Refused	**Consider this score if the influencial factor is related to the programme/IESO.*	
FR7b	If yes, RECORD DESCRIPTION AND ENTER SCORE OF 4 OR 5, BASED ON DESCRIPTION OF TOPIC 99. DK/Refused		-
FR8	Was your company considering any other energy efficiency projects that could have been implemented instead of the project that received funding from IESO? 1. Yes 2. No 99. DK/Refused	No scoring attached to this question. If FR8 = No, skip to FR11	

FR9	ASK IF FR8=1, YES How did the assistance from IESO influence which project was implemented? [RECORD ANSWER] 99. DK/Refused	**Consider this score if the influencial factor is related to the programme/IESO.* *Score:* *0 to 10*	
FR10	Using the same scale of 1 to 5, please rate how much influence the assistance from IESO had on WHICH project was implemented.		
FR11	Does your company have corporate policies about energy efficiency that are considered when purchasing new equipment or making improvements? [RECORD ANSWER] 1. Yes 2. No 99. DK/Refused		
FR12	Which of the following best describes this policy? [RECORD ANSWER] 1. Your company purchases energy efficient equipment regardless of cost 2. Your company purchases energy efficient equipment if it meets payback or return on investment criteria 3. Something else [SPECIFY] 98. (Don't know) 99. (Refused)		
FR13	How would you rate the influence of your company's corporate policies on decisions to make energy efficiency upgrades? Please use a scale of 1 to 5, where 1 means no influence and 5 means the policies were extremely influential. [RECORD ANSWER] 99. DK/Refused	[RECORD SCORE] 99. DK/Refused	
MAX RATING A6a - A6e, A7, A10			**0**
INTERIM INFLUENCE SCORE (MAX 50)			**FAUX**
ADJUST SCORE IF A13 CORPORATE POLICIES ARE HIGLY INFLUENTIAL (SCORE 4 OR 5)			**0**
ALMOST FINAL INFLUENCE SCORE (WITH ADJUSTMENT FOR POLICY)			**0**
FINAL INFLUENCE SCORE (MAX 50, WITH ADJUSTMENT FOR POLICY)			**0**
FINAL FR (INTENTION + INFLUENCE)			**0%**

Spillover

#	Statement	Participant's Answers
SO1	After participating in the Industrial program, have you implemented other energy efficiency measures than those you implemented through the project either elsewhere in your facility or in another of your facilities <u>without participating in any IESO's energy efficiency programs</u>? 1. (Yes) 2. (No) 98. (Don't know) 99. (Refused)	
SO2	**Validation - For each of the additionnal EE measures identified in SO1:** Did you obtain any incentive from IESO or your energy distributor, or do you intend to submit a funding request in the future?	
SO3	**SO Savings Quantification - For each of the additionnal EE measures identified in SO1:** What type of measure were they? Can you give an approximate percentage of the energy savings achieved with respect to those of this facility (or quantity of measures implemented, or area covered)? Do you have a feasibility study or other measurements that had evaluated those savings?	
SO4	**For each of the additionnal EE measures identified in SO1:** Did your experience with the energy efficiency measures implemented through the [PROGRAM NAME] influence your decision to implement these additional energy efficiency measures on your own? Please, give your answer on a scale of 0 to 10, where 0 indicates that the program "had no influence at all on your decision to implement the energy efficiency measures" and 10 indicates that the program was "extremely influential to your decision to implement energy efficiency measures."	

Appendix III
PROJECT REVIEW PROTOCOL FOR IAP ENERGY MANAGERS AND ENERGY MANAGERS

ECONOLER

EEM and REM
Independent Electricity System Operator (IESO)
Project Review

Review date:		Reviewer name:	
Project ID:		Contact name:	
Project category:		Contact phone:	
Project type:		Contact email:	

Company name:	
Facility address:	
Building type	

Was M&V conducted as part of this project? (Y/N)	
Is a site visit planned for this project? (Y/N)	

Notes to the reviewer: *For Energy Managers with multiple projects reviewed, repeat the questionnaire (both for project review and incremental cost) for each different project (with one tab per project, one Excel file per EM).The level of effort to be spend on each project in the sample has to be balanced according to the quantity of expected savings and to the project complexity.*

Prepration Prior to Review

1. Project Review Summary

A) Provide a brief description of the project (baseline and EE measures, source for tracked savings estimate)

2. Questions for Review

B) List of questions for the project review

Enter below the list of questions to be validated during the site visit.
Items that may need to be verified: operating schedule and runtime hourse, control strategy, interactive effects, etc.

Review

3. On-Site/Phone Review Observations and Findings

Report the on-site visit or phone review and the key observations and findings.

Incremental cost questionnaire filled out?		
Is the EUL used for this project reasonable? (Y/N)		
Revised EUL (see Wisconsin Measure Life Study) **If acceptable, enter tracked value.**		

Explanation

3. Verified Savings Calculations

Include notes to document the approach used to establish verified savings.

Reviewer's Calculation and Notes

	Summer Peak Demand (kW)	Energy (kWh)	Comments
1. Savings from Tracking Sheets (IESO's reported values)			
2. Verified Savings (by the Evaluator)			
Savings to Anticipated Savings Ratio (Line 2./1.)	#DIV/0!	#DIV/0!	

4. Conclusion

Summarize, if any, the adjustments of the project review

Incremental Cost

Value of tracked incremental cost		
Explanation of this value		
#	**Statement**	**Participant's Answers**
Section 1: Remaining Effective Useful Life (EUL)		
Q1.	Is the efficient equipment installed as part of this project...?	
	a) a replacement for an equipment at the end of its effective useful life (EUL)	
	b) a replacement for an equipment that had not yet reached its EUL	
	c) an additional equipment that reduces energy consumption	
	[ASK IF Q1=b, OTHERWISE SKIP TO Q4]	
Q2.	For how many years could this equipment have kept running?	
	[ASK IF Q2>PROJECT EUL]	
Q3.	What would have been the efficiency of the standard equipment (i.e. not high efficiency equipment) that would have replaced the old equipment at the end of its EUL? If unsure, probe to obtain a description of the technology or type of equipment that could have replaced the old equipment.	
Section 2: Incremental Cost		
If Q1=a, incremental cost = efficient (incented) equipment cost - standard equipment cost		
If Q1=b or c, incremental cost = total project cost		
[ASK IF Q1=a]		
Q4.	What is the approximate cost of the standard equipment that would have replaced the old equipment if this energy-efficiency project had not gone forward? *If unsure, probe to obtain an estimation of the premium associated with the efficient equipment, either in $ or %.*	
Reviewed incremental cost value		
Justification		

Appendix IV
PROJECT REVIEW PROTOCOL FOR M&T

M&T
Independent Electricity System Operator (IESO)
Project Review

Review date:		Reviewer name:	
Project ID:		Contact name:	
Project category:		Contact phone:	
Project type:		Contact email:	

Company name:	
Facility address:	
Building type	

Is a site visit planned for this project? (Y/N)

Notes to the reviewer: *For Energy Managers with multiple projects reviewed, repeat the questionnaire (both for project review and incremental cost) for each different project (with one tab per project, one Excel file per EM).The level of effort to be spend on each project in the sample has to be balanced according to the quantity of expected savings and to the project complexity.*

Prepration Prior to Review

1. Project Review Summary

A) Provide a brief description of the project (baseline and EE measures, source for tracked savings estimate)

2. Questions for Review

B) List of questions for the project review

Enter below the list of questions to be validated during the site visit.
Items that may need to be verified: operating schedule and runtime hourse, control strategy, interactive effects, etc.

Review

3. On-Site/Phone Review Observations and Findings

Report the on-site visit or phone review and the key observations and findings.

Incremental cost questionnaire filled out?	
Is the EUL used for this project reasonable? (Y/N)	
Revised EUL (see Wisconsin Measure Life Study) If acceptable, enter tracked value.	
Explanation	

3. Verified Savings Calculations

Include notes to document the approach used to establish verified savings.

Reviewer's Calculation and Notes

	Summer Peak Demand (kW)	Energy (kWh)	Comments
1. Savings from Tracking Sheets (IESO's reported values)			
2. Verified Savings (by the Evaluator)			
Savings to Anticipated Savings Ratio (Line 2./1.)	#DIV/0!	#DIV/0!	

4. Conclusion

Summarize, if any, the adjustments of the project review

Appendix V
IAP PROCESS AND SYSTEMS, PSU AND IAP RETROFIT FREE-RIDERSHIP ALGORITHM

The free-ridership level was measured through in-depth interviews with participants. Free-ridership was assessed using a series of questions divided in two sections, intention and influence.

Intention is used to determine how the project likely would have differed if the respondent had not received the program assistance. The maximum number of points in the Intention section is 50.

Influence is assessed by asking about how much influence – from 1 (no influence) to 5 (extreme influence) – various program elements had on the decision to do the project the way it was done. The items selected for rating are specific components of the program being evaluated. The maximum number of points in the Influence section is 50.

The total free-ridership score is the sum of the intention and influence components, resulting in a score ranging from 0 to 100. This score is multiplied by .01 to convert it into a proportion for application to gross savings values.

The figure below presents the algorithm for calculating the free-ridership level.

FR1. Prior to participating in the program, was the purchase and installation costs of the project included in your company's capital budget? 1. Yes 2. No 99. Don't know/Refused	No score for FR1. Used only for FR5 scoring
FR2. Which of the following is most likely what would have happened if you had not received the rebate from the IESO? 1. Canceled or postponed the project at least one year 2. Reduced the size, scope, or efficiency of the project 3. Done the exact same project (no change) 99. Don't know/Refused	**SCORE FR2** IF FR2 = 1 → 0% IF FR2 = 2 → ASK FR3 IF FR2 = 3 → ASK FR5 IF FR2 = 99 → 25%
FR3. By how much would you have reduced the size, scope, or efficiency? Would you say a… 1. Small amount 2. Moderate amount 3. Large amount 99. Don't know/Refused	**SCORE FR3 IF FR2 = 2** IF FR3 = 1 → 37.5% AND ASK FR4 IF FR3 = 2 → 25% AND ASK FR4 IF FR3 = 3 → 12.5% AND ASK FR4 IF FR3 = 99 → 25% AND SKIP TO FR5
FR4. Please describe what your company would have changed about the size, scope, or efficiency of the project	Used for consistency check with FR3
FR5. Now I want to focus on what it would have cost your company to implement the project without the rebate from the IESO. How likely is it that your company would have paid the full cost to complete the same project at the same time? Would you say… 1. Very likely 2. Somewhat likely 3. Not too likely 4. Not at all likely 99. Don't know/Refused	**SCORE FR5 IF FR2 = 3** IF FR1 = 1 AND IF FR5 = 4 → 25% OTHERWISE: IF FR5 = 1 → 50% IF FR5 = 2 → 37.5% IF FR5 = 3 → 25% IF FR5 = 4 → 0% IF FR5 = 99 → 37.5%
Intention Score (MAX 50%)	**FR2 OR FR3 OR FR5**
FR6. I'm going to read a list of items about the program. Please rate each item on how much influence it had on the decision to complete the project the way it was done. Please use a scale from 1, meaning no influence, to 5, meaning the item was extremely influential in your decisions. **FR6a.** The IESO staff such as your Key Account Manager or CleaResult **FR6b.** The program funded engineering study and recommendations **FR6c.** The financial incentives for the project **FR6d.** The program sponsored energy manager (if applicable) **FR6e.** The program funded energy monitoring system (if applicable)	No score for FR6. Used only for FR7 scoring

FR7. Was there anything else that was highly influential in your decision to complete the project in the way that you did? If so, record answer and enter SCORE of 4 or 5, based on description of topic.	IF FR7=4 OR 5 → 50% - [MAX(FR6a : FR6e ; FR7) x 10%] OTHERWISE → 50% - [MAX(FR6a : FR6e) x 10%]
FR8. Was your company considering any other energy efficiency projects that could have been implemented instead of the project that received funding from IESO?	IF FR8 = 1→ ASK FR9 OTHERWISE skip to FR11.
FR9. How did the assistance from IESO influence which project was implemented?	Record answer and ask FR10 if it is relevant.
FR10. Using the same scale of 1 to 5, please rate how much influence the assistance from OPA had on WHICH project was implemented.	Used for process evaluation and consistency validation.
FR11. Does your company have corporate policies about energy efficiency that are considered when purchasing new equipment or making improvements? 1. Yes 2. No 99. Don't know/Refused	IF FR11 = 1 → ASK FR12 AND FR13 OTHERWISE END QUESTIONNAIRE.
FR12. Which of the following best describes this policy? 1. Your company purchases energy efficient equipment regardless of cost 2. Your company purchases energy efficient equipment if it meets payback or return on investment criteria 3. Something else [RECORD] 99. Don't know/Refused	Used for process evaluation and consistency validation.
FR13. How would you rate the influence of your company's corporate policies on decisions to make energy efficiency upgrades? Please use a scale of 1 to 5, where 1 means no influence and 5 means the policies were extremely influential.	IF FR13 = 5 → 25% IF FR13 = 4 → 12.5% OTHERWISE → 0%
Influence Score (MAX 50%)	**IF (FR7+FR13) > 50% → 50%** **IF (FR7+FR13) ≤ 50%→ FR7+FR13**
Final Free-Ridership Level	**Intention Score + Influence Score**

Appendix VI
SPILLOVER ALGORITHM

Spillover was measured through interviews conducted during on-site visits. Participants were asked whether, they implemented any additional energy efficiency measures following their participation in the program, without benefitting from any incentives offered by the IESO or their energy distributor. If a participant declared having implemented additional measures, they were asked a set of questions designed to identify the additional energy efficiency measures implemented and to quantify their associated savings (type of measure, quantity, efficiency level, etc.). Subsequently, another question was asked to quantify the level of influence the program had on the participant's decision to whether implement these additional measures. The value established regarding this level of influence was used to determine the portion of the additional savings attributable to the program.

Then, the level of spillover was established by dividing the total quantity of the additional savings attributable to the program by the total quantity of savings achieved by the program for all the survey respondents.

The figure below illustrates the methodology used to calculate the spillover level.

SO1. After participating in the Industrial program, have you implemented other energy efficiency measures than those you implemented through the project either elsewhere in your facility or in another of your facilities without participating in any IESO's energy efficiency program?	IF 1. Yes: CONTINUE IF 2. No OR 99 : END
SO2. Ask for each of the additionnal EE measures identified in SO1: Did you obtain any incentive from IESO or your energy distributor, or do you intend to submit a funding request in the future?	IF 2. No: CONTINUE IF 1. Yes OR 99 : END
SO3. Which measures have you implemented on your own after participating in IESO's Industrial Program?	SO2 = SUM of kWh associated with each upgrade
Additional Upgrade Savings:	**SO2**
SO4. How influential was your experience with IESO's Industrial Program on your decision to implement the measures that you installed on your own after participating in the program? (Scale 0 to 10)	SO4 = Answer x 10%
Attribution Level:	**SO4**
Spillover Savings:	**SO2 x SO4**

$$\textbf{Final Spillover Level} = \frac{\text{SUM of (SO2 x SO4) for All Respondents}}{\text{SUM of Program Savings for All Respondents}}$$

Appendix VII
ENERGY MANAGERS AND M&T SURVEY QUESTIONNAIRE

The Independent Electricity System Operator (IESO) has hired Econoler and their sub-contractor Cadmus to conduct research on the effectiveness of the energy manager (EM) program. Your company's Energy Manager (EM) **[EM Name]** implemented a number of projects or changes to save energy. As part of this research, we would like to ask some questions regarding projects that were implemented at your facility without a saveONenergy incentive in 2015.

According to our records, the top two non-incentivized projects, in terms of energy savings, that your EM reported in 2015 are: **[MEASURE 1] [MEASURE 2].** Are you familiar with these projects?

1. Yes **[Continue with survey]**
2. No **[Ask for the name of appropriate person and contact number, thank and terminate]**

[IF NEEDED] "I'm not selling anything. We are only interested in your opinions to help improve this program, and better understand how to assist customers in saving money on their utility bills. Your responses will remain confidential. The survey will take about 10 to 15 minutes."

[IF NEEDED] saveONenergy is a suite of energy conservation programs funded by the IESO and offered to businesses and residents of Ontario through your local electric utility.

[ONLY IF INTERVIEWEE ASKS FOR A PERSON AT IESO TO CONFIRM LEGITIMACY OF PROGRAM, DO NOT OFFER] "If you would like to talk with someone from IESO about this study, you can reach out to Liliana Urmuzache, Sr. Specialist – Evaluation, Measurement and Verification, at (416) 969-6238."

What month and year was **[EM Name]** hired?

1. ([RECORD:________________________])
98. (Don't know / don't recall)
99. (Refused)

A. INTENT

A1. When did your company decide to install **[MEASURE 1/2]**? Was it (read options)

1. BEFORE hiring the EM, or
2. AFTER hiring the EM **[SKIP TO B1]**
98. (Don't know) **[SKIP TO B1]**
99. (Refused) **[SKIP TO B1]**

A2. Before hiring the EM, was the entire cost of purchase and installation of the **[MEASURE 1/2]** included in your company's approved 2015 capital budget (last year's capital budget)?

1. (Yes)
2. (No)
98. (Don't know)
99. (Refused)

B. INFLUENCE:

B1. Please think about the influence of the EM on specific aspects of the **[MEASURE 1/2]** project. For each aspect listed, please rank on a 0 to 10 scale, where 0 is no influence at all, and 10 represents significant influence where the EM contributed significantly (or even completely) to the project.

Variable	Influenced a lot		No influence	Don't know /Refused
Rank	10	8 to 1	0	98/99
Identification of energy-saving opportunity				
Creation of business case for project				
Management approval for the energy-saving project				
Implementation of project overall				

B2. Please explain why you gave the overall rating of **[RESPONSE FROM 0]**? Were there any other ways the energy manager had influence on the **[MEASURE 1/2]**'s implementation beyond what we have discussed?

1. ([RECORD:________________________])
98. (Don't know)
99. (Refused)

B3. What else, if anything, was highly influential in your company's decision to complete the project?

1. ([RECORD:________________________])
2. Nothing
98. (Don't know)
99. (Refused)

[REPEAT A and B for Measure 2. If there are more than 2 non-incented projects, ask next question]

C. *All Other Measures*

C1. For all other non-incentivized savings projects, which included **[EXAMPLE OF OTHER MEASURES],** overall would these other projects have been implemented had your company not participated in the EM program?

1. (Yes all of them)
2. (yes, some of them) Please estimate what %:
3. (No, none of them)
98. (Don't know)
99. (Refused)

Thank you very much for your time – your participation is greatly appreciated!

Appendix VIII
ENERGY MANAGERS AND M&T FREE-RIDERSHIP ALGORITHM

The evaluation team assessed the NTGR ratio for M&T and energy managers' non-incented projects by surveying facility managers who worked with an energy manager (EM). Through an online survey, the evaluation team asked a series of questions designed to measure the EMs' influence on the decision-making and project implementation. In order to determine a weighted NTGR for each program, the evaluation team selected the top two non-incentivized projects (in terms of MWh savings) for every EM to review in detail, asking a series of questions at the project level to quantify the influence of the EM on overall project implementation, from concept through completion. For those EMs who implemented more than two projects in 2015, the team asked a question to quantify the influence of the EM on all other projects on record for the 2015 period. The evaluation team weighted the three NTGRs by each project's gross savings to determine an EM-level NTGR value, then weighted each EM NTGR by the EM's overall savings to obtain the program-level ratio.

The figure below illustrates the methodology used to assess the free-ridership level of M&T, IAP Energy Managers and Energy Managers.

A. INTENT	Answer Choice	FR Score
A1. When did your company decide to install [MEASURE 1/2]? Was it (read options) 1. BEFORE hiring the EM, or 2. AFTER hiring the EM [SKIP TO B1] 98. (Don't know) [SKIP TO B1] 99. (Refused) [SKIP TO B1]	This does not directly affect the scoring.	
A2. Before hiring the EM, was the entire cost of purchase and installation of the [MEASURE 1/2] included in your company's approved 2015 capital budget (last year's capital budget)? 1. (Yes) 2. (No) 98. (Don't know) 99. (Refused)	If A2 = yes, this would represent 100% freeridership as long as it is confirmed with a score of 0 in B1. If answer is "no" it provides context to the scoring in B1 although it does not affect the scoring.	

B. INFLUENCE	Answer Choice	FR Score
B1. Please think about the influence of the EM on specific aspects of the [MEASURE 1/2] project. For each aspect listed, please rank on a 0 to 10 scale, where 0 is no influence at all, and 10 represents significant influence where the EM contributed significantly (or even completely) to the project. a. Identification of energy saving opportunity b. Creation of business case for project c. Management approval for the energy saving project d. Implementation of project overall For a-c, these are to set up the response to d, which are where freeridership is evaluated. These questions ensure that the manager has the chance to reflect on the various aspects of EM influence before submitting their response to question d. It also validates the response in d and identifies trends of influence in freeridership with the program.	Score 0 to 10	**Only For d** 0 = 100% FR 10 = 0% FR 1 to 9 = 10% FR for each increment 98/99 – N/A
B2. Please explain why you gave the overall rating of [RESPONSE FROM B1.d]? Were there any other ways the energy manager had influence on the [MEASURE 1/2]'s implementation beyond what we have discussed? 1. ([RECORD:________________________]) 98. (Don't know) 99. (Refused)	Here we are providing context and validation for the score in B1. This does not affect the scoring.	
B3. What else, if anything, was highly influential in your company's decision to complete the project? 1. ([RECORD:________________________]) 2. Nothing 98. (Don't know) 99. (Refused)	The interviewer should probe to get the influence of any other factors that affected decision-making and affected the score in B1. This does not affect the scoring.	

C. All Other Measures	Answer Choice	FR Score
C1. For all other non-incentivized savings projects, which included [EXAMPLE OF OTHER MEASURES], overall would these other projects have been implemented had your company not participated in the program? 1. (Yes all of them) 2. (yes, some of them) Please estimate what %: 3. (No, none of them) 98. (Don't know) 99. (Refused)	1 2 3 98/99	1= 100% FR 2= % provided as the FR score for this bundle of measures. 3= 0% FR 98/99 – N/A

Appendix IX
DEFINITION OF PEAK DEMAND SAVINGS

The verified gross summer peak savings were calculated by following the "EM&V Protocols and Requirements"[18], which includes a standard definition of peak for calculating demand savings, as summarized in the table below. For the 2015 evaluation, the IESO required that summer peak be applied.

Table 19: Standard Definition of Peak Demand Savings

Average Load Reduction over Entire Block of Hours		
	Time	**Month**
Summer (Weekdays)	1 p.m. – 7 p.m. (Daylight Saving Time-Adjusted)	June
		July
		August
Winter (Weekdays)	6 p.m. – 8 p.m.	January
		February
		December

Peak savings estimates are to be based on the average demand reduction across the total number of hours. For instance, if a plant installed efficient lighting and shut off all of its lights at 5 p.m. (both before and after the implementation of the measure), demand savings would occur for only a part of the peak time (between 1 p.m. and 5 p.m.; therefore, for 4 hours of the 6-hour peak time block). In that case, the peak demand savings should be calculated using the following weighted average:

$$Peak\ demand\ savings = \Delta W\ \times \frac{4hrs}{6hrs} + 0\ W\ \times \frac{2hrs}{6hrs} = 0.667\Delta W$$

Similarly, if an energy efficiency measure was applied on an industrial process that is shut down for 4 weeks in July and August every year, the power reduction should be multiplied by a ratio of 9 weeks/13 weeks, to account for that 4-week period during which no savings occur.

For weather-sensitive measures or facilities with variable load characteristics, an alternative method to calculate peak demand savings can be employed and is summarized in the following table.

[18] Ontario Power Authority, "EM&V Protocols and Requirements v.2.0 (2015-2020)," 2015, pp. 75–80.

Table 20: Alternate Definition of Peak Demand Savings

Weighted Average of the Monthly Maximum Load Reduction			
	Time	**Month**	**Weight**
Summer (Weekdays)	1 p.m. – 7 p.m. (Daylight Saving Time-Adjusted)	June	30%
		July	39%
		August	31%
Winter (Weekdays)	6 p.m. – 8 p.m.	January	65%
		February	16%
		December	19%

Capacity savings are calculated on the basis of a weighted average of the maximum demand reduction in each of the three months that occurs within the blocks. Maximum demand reductions usually occur at design conditions. For summer peak savings, the weight of June, July and August are respectively 30%, 39% and 31%.

Weather-sensitive measures are very likely to produce their maximum impacts at the same hour as the actual top system peak hour. One example is the replacement of a chiller for air-conditioning with a more efficient chiller. The savings could vary according to the weather conditions; maximum savings would occur when it is the hottest outside, which will most likely coincide with the system peak hours. Therefore, weather-sensitive measures can be properly credited for their good performance during the periods of electricity system stress by using a much narrower definition of peak, which is 3 individual hours in this case.

For every project and measure verified as part of this evaluation, the most appropriate definition of peak was selected according to the nature of the measures implemented and was applied to its peak demand savings calculation.

The EM&V Protocols and Requirements also define the acceptable methods for collecting data to be used in peak demand savings calculations. Direct methods should be favoured; this means that hourly power data is to be collected before and after the measures' installation, either at the participating site or at other sites where similar measures have been implemented. However, this was not possible since there was not enough M&V data or equipment data to support the direct methods of calculation. In all cases, the indirect method had to be used, which involved (1) assigning the energy savings to a certain period of time (usually the annual or summer hours of operation) and (2) obtaining the demand savings by dividing the energy use savings assigned to that period by the number of hours over that period.

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BOMA INTERROGATORY 3

Issue 1.0, 5.1

INTERROGATORY

Reference: Issues 1.0, 5.1; #7, Business Plan, p23; Conservation First Framework

(a) Please provide more detail on the mid-term renewal of the Conservation First Framework. Who is directing the review within the IESO? What groups in the IESO are on the team? What resources are dedicated to the team?

(b) Who are the members of the external working group? Have any outside contractors been utilized? On what topics? Please provide a copy of the Technical Potential Study, and of the Terms of Reference of the midterm review.

(c) What is the timetable for the completion of the midterm review of the Conservation First Framework? Has the midterm review of the Conservation First Framework been commenced, and has the midterm review of the Industrial Accelerator Program been commenced? Please provide a status report on each review, along with the terms of reference of each review. When will these reviews be filed with intervenors?

(d) How does the IESO propose to collaborate with the gas utilities' midterm reviews which are being done over the same timeframe? How is it collaborating at this time?

(e) Please provide a status report on residential demand response initiative. Please provide an update on the Demand Response program in general, the cost of MW saved since the program commenced, number and type of participants (aggregators, industrial, commercial, institutional, etc.), and average cost per MW.

(f) Please provide the target dates and nature of the utility innovation programs that will make up the $50 million share of the Conservation First Framework. What grants have been given to date; to whom; for what projects?

(g) Please provide the membership of the demand response working group. What is the target date for an auction for residential demand response in 2017?

(h) What access do consumers currently have to SME data received by IESO systems? When will they have such access?

(i) What level of access will consumers have to the data?

(j) What are the milestones for achieving this access, and when will the access be put in place for all Ontario smart-meter customers? How exactly will such access help customers conserve energy, do demand response, or install distributed generation? Please discuss.

RESPONSE

(a) The Mid-term Review is being directed by the Director of Conservation Performance and Innovation who also chairs the Mid-term Advisory Group. A Mid-term Review internal working group has been established at the IESO comprising of ten members representing different functions within the Conservation and Corporate Relations business unit and the Transmission Planning department. One IESO staff is dedicated full-time as project manager for the Mid-term Review Study with a number of IESO subject matter experts supporting various topics identified under the Mid-term Review project plan as needed.

(b) The full list of external members who are participating in the mid-term advisory group can be found on the IESO's stakeholder engagement website for the Conservation First Mid-Term Review, as well as provided below:

Consumers (5)

Housing Services Corp.

LaFarge

Loblaw

University Health Network

CBRE Limited

Local Distribution Companies (5)

Customer First Inc.

Entegrus Powerlines Inc.

Hydro One

PowerStream Inc.

Toronto Hydro-Electric System

Electricity Service Providers/Consultants (2)

CLEAResult Canada Inc.

Nest Labs

Navigant Consulting is conducting the Mid-term Review Study on behalf of the IESO. Ipsos will be supporting the review by conducting the market research work planned as part of the Mid-term Review.

The following topics are being explored through current state summaries of the Mid-term Review: customer and market engagement and satisfaction, definition of conservation and demand management (CDM), collaboration, governance and operations, planning integration, climate change, budgets, targets and cost-effectiveness as well as non-energy impacts.

Achievable potential study results from the 2016 study are included in Attachment 1. (Note this is a separate study that serves as an input into the Mid-term Review Study.)

The Terms of Reference for the Mid-term Review Advisory Group are included in Attachment 2.

(c) Navigant Consulting is targeting completion of the Mid-term Review Study by the first quarter of 2018. The study commenced in February of 2017 with the first meeting of the Advisory Group. The Conservation Framework Mid-term Review will focus on both the Industrial Accelerator Program (IAP) and the Conservation First Framework (CFF). Current progress of the Conservation Framework Mid-term Review can be accessed on the Mid-term Review Engagement Website[1] by reviewing more recent Advisory Group materials.

The Mid-term Review Study final report will be posted publically on the IESO's website when it is complete.

(d) The OEB and both Union Gas and Enbridge are observers on the Mid-term Review Advisory Group. The OEB has provided a progress update of the DSM Framework Mid-term Review to the Mid-term Review Advisory Group. The OEB is encouraged to continue to provide updates to the Mid-term Review Advisory Group as progress is made in the DSM Framework Mid-term Review.

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[1] http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/conservation-framework-mid-term-review

(e) In response to the Direction from the Minister of Energy issued to the Ontario Power Authority on March 31, 2014 “Re: Conservation First Framework”, the peaksaverPLUS program continued to be supported through Conservation funding until a plan was developed to evolve existing demand response programs, potentially including the peaksaverPLUS program, to the IESO-administered market.

After conducting a stakeholder engagement to consider the future role and treatment of the peaksaverPLUS program, the IESO confirmed it would not fund the installation of new load control devices or information displays after December 31, 2015. The program has continued to be administered with funding available for Local Distribution Companies to maintain existing devices; however, the IESO intends to discontinue administration of the program at the end of 2017.

The IESO has worked with Local Distribution Companies and other stakeholders through the Demand Response Working Group to facilitate participation of residential demand response (DR) through the IESO-administered market, as it best reflects the market value for the resource. The 2016 demand response auction revealed that residential customers are successfully participating through demand response providers.

The results of the DR auctions to date can be found in the Post-Auction Summary Reports on the IESO website, and included as Attachments 3 and 4 for the two auctions that have occurred. The summary reports provide the quantity cleared, the clearing price and the participant details. For example, for the 2016 auction, the clearing price for the Summer 2017 commitment period in Toronto was $331.33/MW-day and for the Winter 2017-2018 commitment period was $299.48/MW-day. Comparing these clearing prices against the auction reference price of $413/MW-day (which is based on the historical contracting cost) results in an approximate cost savings of 23% on a per MW basis

There are currently 25 organizations registered to participate in the DR Auction. Most are aggregators or industrial participants. Commercial, institutional and residential groups mostly participate through aggregators.

(f) The Local Distribution Companies (LDC) Innovation Fund provides support to LDC (utility) led testing of innovative program design or delivery strategies. The funding is provided directly to the utility with the intent of testing new ideas that could lead to a full-scale launch of a new program. Table 1 below lists all LDC Innovation Fund approved projects committed by IESO to date under the Conservation First Framework. All LDC Innovation Fund pilots have in market dates within the 2015-2020 timeframe of the Conservation First Framework.

Table 1 – LDC Innovation Fund Projects

Pilot Name	**LDC(s)**	**Description**
Residential Direct Mail Pilot Program	Canadian Niagara Power Inc., Algoma Power Inc.	Customizable Energy Savings Kits (ESKs) mailed out to customers including lighting, plug load, weatherization and domestic hot water measures.
Home Energy Assessment & Retrofit Pilot Program	Customer First	Home assessment, energy report, and direct install of programmable Wi-Fi thermostat, three LEDs, and a block heater timer and/or pool pump timer, as applicable for customers with electrically heated homes.
Small & Medium Business Energy Management System Innovation Pilot	Kitchener-Wilmot Hydro Inc.; Energy+ Inc., Waterloo North Hydro Inc.	Ecobee Energy Management Systems (EMS) thermostats to drive non-lighting savings in the Small and Medium Business (SMB) sector
Benchmarking for ICI	Enersource Hydro Mississauga Inc.	Energy reports and benchmarking for the ICI sector, via a web portal, for behaviour and operational savings and to increase uptake in other SaveONenergy programs.
Truckload Events	Enersource Hydro Mississauga Inc.; Toronto Hydro-Electric System Limited; Hydro One Brampton Networks Inc.; Oakville Hydro Electricity Distribution Inc.	Instant discount for LEDs during event days at Home Depot.
Intelligent Air Technology	EnWin Utilities Ltd.	Air nozzles and curtains for compressor systems in industrial facilities. These measures could eventually be included as a prescriptive measure in a broader scale program offering.
Residential Ductless Heat Pump/Financing	EnWin Utilities Ltd.	Incentives and financing options for the supply and installation of air source ductless heat pumps (DHP) for customers with electric heat.
ECM Furnace Fan Residential Upstream Pilot	Horizon Utilities Corporation, Toronto Hydro-Electric System Limited, Kitchener-Wilmot Hydro Inc.	Upstream sales points and incentive levels to encourage Electrically Commutated Motor (ECM) fan retrofits existing home furnaces.

Pilot Name	**LDC(s)**	**Description**
Solar Powered Attic Ventilation Research Oriented Pilot	Hydro One Brampton	Testing cooling load electricity savings of solar powered attic fans (SPAFs) in centrally cooled residential homes with unconditioned attic spaces.
Integration of Smart Thermostat with Dynamic Electricity Pricing and Customer Feedback	Hydro One Networks Inc.	Tests the savings impact of Energate thermostats with various dynamic rate structures using instantaneous kWh savings feedback to reduce energy consumption and costs.
Air Source Heat Pump – For Residential Water Heating	Hydro One Networks Inc.	Promotion of Air-Source Heat Pump (ASHP) water heaters in residential homes in order to provide savings on electricity consumption
Air Source Heat Pump – For Residential Space Heating	Hydro One Networks Inc.	Incentives for customers to install air source heat pumps to remove need for residential electric space heating.
Hotel/Motel in suite A/C upgrades	Niagara Peninsula Energy Inc.	Utility bill and capital review, site assessments and audits, energy management plan, and prescriptive incentives for two measures; Packaged Terminal Air Conditioners (PTAC), for hotel and motel customers.
Advanced Roof Top Unit (RTU) Control Pilot	Toronto Hydro-Electric System Limited	Tests the energy savings of retrofitting Roof-Top-Units with Variable Frequency Drives, sensors, unitary controller and communication equipment.
Toronto Hydro – Enbridge Joint Low-Income Program Pilot	Toronto Hydro-Electric System Limited, Enbridge Gas Distribution	Tests savings and cost feasibility of jointly delivered Home Assistance Program and Winterization Program for low-income Toronto Hydro and Enbridge Gas customers.
Electronics Take Back Pilot	Toronto Hydro-Electric System Limited	Tests the savings and costs of decommissioning eligible working condition electronics in exchange for Advanced Power Strip (APS) for residential customers.
Data centre pilot	Toronto Hydro-Electric System Limited	Tests savings and costs of specific energy optimization measures (EOM) for data centers.
P4P for Class B Office (Op saver)	Toronto Hydro-Electric System Limited	Tests Pay for Performance funding mechanism through the promotion and implementation of operational savings in the commercial office sector.

Pilot Name	LDC(s)	Description
Hydronic Balancing (Pumpsaver)	Toronto Hydro-Electric System Limited	Tests the delivery model and energy savings associated with direct Install of Variable Frequency Drives on pump motors of hydronic systems (in place of balancing valves).
Residential Direct Install	Westario Power Inc.	Simple audit followed by direct install of measures including lighting, plug load, weatherization and domestic hot water.
Low-Income Air Source Heat Pump Pilot	Hydro One Networks Inc.	Direct install Air Source Heat Pump (ASHP) pilot for low-income sector.
Advanced Power Strip Pilot	Waterloo North Hydro Inc.	Direct install of Advanced Power Strips (APS) for computer terminals. Pilot is designed to test the savings, Cost Effectiveness, and IT barriers to implementation. For business and institutional customers.

(g) The Demand Response Working Group is an open membership forum that serves as an advisory role to the IESO. More information about this working group along with the meeting notes that contain information on who attends each session can be found on the IESO's website[2] .

The demand response (DR) auction, which includes residential DR, occurs annually starting on the first Wednesday of December.

(h) The Smart Metering Entity (SME) does not have control over a consumer's access to their smart meter data; this is the responsibility of the LDCs. The SME processes billing information and provides data to those LDCs with smart meters that are registered with the SME to enable billing of customers with smart meters.

(i) Please see the response to part (h) above.

(j) Please see the response to part (h) above.

[2] http://www.ieso.ca/en/sector-participants/engagement-initiatives/working-groups/demand-response-working-group

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Conservation Behind the Meter Generation Potential Study

Potential Analysis Report

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June 30th, 2016

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COMPREHENSIVE EXECUTIVE SUMMARY

The IESO engaged Navigant Consulting, Ltd. (Navigant) to evaluate the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario. Key study objectives include:

- Understanding the potential to displace electric loads for Combined Heat and Power (CHP)[1] and Waste Energy Recovery (WER) installed in facilities connected:
    - To each of the local distribution systems
    - Directly to the transmission system
- Gaining insights, evidence, and documentation to make critical policy decisions about how, when, where, and to what extent to promote the installation and operation of BMG across Ontario.

Navigant documented each task under this assignment in separate task reports to the IESO. This Task 5 report includes a comprehensive executive summary.

The scope of this study is limited to:

- BMG nominal capacities of 100 kW to 10 MW (to 20 MW if the facility is connected directly to the electric transmission system)
- Facilities that have access to pipeline natural gas.

The key outputs of this study include:

- Technical Potential: Potential savings based on instantaneous installation of BMG in all technically suitable applications, regardless of economics
- Economic Potential: Portion of the technical potential that passes the Program Administrator Cost (PAC) test
- Market Potential:
    - Financial Market Potential: Portion of the economic potential that customers would eventually implement based on financial factors alone
    - Non-Financial Market Potential: Portion of the economic potential that customers would eventually implement accounting for both financial and non-financial factors
- Cap & Trade Potential: Financial and non-financial market potentials adjusted for the impacts of the Climate Mitigation and Low-Carbon Economy Act
- Constrained Potential: Portion of the market potential achievable after accounting for electricity system constraints that may limit BMG installations

Each potential analysis includes:

- Results for CHP and WER
- Results by LDC (including transmission-connected facilities) and facility type

[1] CHP systems that qualify for incentives under either the IESO's Conservation First Framework LDC Tool Kit, or the IESO's Industrial Accelerator Program, are referred to as Conservation Combined Heat and Power (CCHP). We use the more general acronym "CHP" in this report.

- Results for the years 2015, 2017, 2020, and 2025
- Nominal installed capacities (MW), annual electricity savings (GWh), and electric demand reductions (MW).

Results also include impacts on greenhouse gas emissions (metric tonnes CO_2 equivalent) for market potentials.

The results of the BMG potential analysis show that:

- The 2025 province-wide market potential for multi-family, commercial, and institutional facilities is very low—only about 23 GWh out of the almost 10,000 GWh of technical potential for these facility types
- The 2025 province-wide market potential for industrial facilities is about 1,100 GWh, or about 7 percent, of the almost 16,000 GWh of technical potential for these facility types
- Scenarios 1 and 2 (40 percent versus 70 percent first-cost incentive) generally result in little or no difference in market potential. This occurs because other scenario constraints limit the incentive paid. For example, for both scenarios, the incentive cannot be higher than the annual electricity savings multiplied by $200 to $230/MWh.
- The Climate Mitigation and Low-Carbon Economy Act is projected to have almost no impact on WER and will decrease CHP potential by approximately 20%
- The constrained potential analysis shows modest reductions in market potential (about 6 percent reduction in CHP potential for scenario 1). However, available electricity network connection capacity, which must be determined on a project-by-project basis and which was not accounted for in this analysis, will reduce constrained potential further.

Table 1 summarizes the province-wide market potentials for CHP and WER for scenario 1 (current program incentives) based on modelled results.

Table 1: Summary of BMG Market Potentials Based on Modelled Results (for Scenario 1) [a]

Year	BMG Type	Installed Capacity (GW)	Electricity Savings (GWh)	Demand Savings (MW)
2015	CHP	13	95	11
	WER	~0	2	~0
2017	CHP	43	307	34
	WER	1	8	1
2020	CHP	89	639	71
	WER	2	16	2
2025	CHP	147	1040	116
	WER	4	26	3

a) Market potentials listed here are not adjusted to account for actual projects and project applications, connection constraints, or cap and trade legislation.

Analysis Scenarios

Table 2 summarizes the three analysis scenarios used in this study.

Table 2: Summary of Analysis Scenarios

Scenario	Description	Rationale
Scenario 1: Current Program Rules	• First-Cost Incentive is lowest of: ○ 40% of eligible costs for CHP; 70% of eligible project costs for WER ○ Annual (single year) electricity savings multiplied by \$200/MWh or \$230/MWh [a] ○ Amount that would provide a Project Payback of one year for a Project.	• Current program rules
Scenario 2: Increase First-Cost Incentive Level	• Increase CHP incentive to 70% of first cost • Other requirements remain the same as in Scenario 1	• Straight-forward program change • Straight-forward comparisons to Scenario 1 for TRC and PAC • 70% provides a significant change relative to current programs, but still leaves the customer with first costs high enough to eliminate those who are not serious about operating BMG
Scenario 3: No First-Cost Incentive Level combined with Production Incentive	• Eliminate first-cost incentive • Include production incentive of \$0.02/kWh for the first 10 years of operation • Other requirements remain the same as in Scenario 1	• Precedents for use • Provides insights into the cost-effectiveness of production-based incentives compared to first-cost-based incentives • Will incent customers to operate BMG units effectively after installation

a) $200/MWh for the Conservation First Framework; $230/MWh for the Industrial Accelerator Program (for transmission-connected facilities)

BMG Technologies

Table 3 and Table 4 summarize cost and performance characteristics for the BMG technologies used in this study.

Table 3: Summary of CHP Cost and Performance Characteristics

Attribute	Internal-Combustion Engine [a]	Simple-Cycle Gas Turbine [a]	Steam Turbine (Rankine Cycle) [a]
Installed Cost (2015 $CAD/kW) [b]	$2200 - $4200	$2500 - $5800	$3300 - $5300
Variable O&M Cost (2015 $CAD/MWh) [b]	$14 - $36	$14 - $20	$6
Fixed O&M Cost (2015 $CAD/kW) [b]	$2 - $22	$14 - $43	Included under Variable O&M
Heat Rate (HHV) (Btu/kWh)	8000 – 12,000	11,000 – 17,000	37,000 – 55,000
Overall Efficiency (HHV) [c]	0.79	0.71	0.8

a) Ranges for CHP capacities of 100 kW to 5 MW for engines, 1 MW to 20 MW for gas turbines, and 500 kW to 20 MW for steam turbines. The analysis used performance and cost correlations that are a function of nominal CHP capacity.
b) Converted from USD to CAD (1.2767 CAD = 1 USD), and labour component adjusted from U.S. labour rates to Ontario labour rates.
c) Based on the unweighted sum of the electricity and recoverable thermal output of the CHP system while operating at full-load conditions.

Table 4: Summary of WER Cost and Performance Characteristics

Attribute	Steam Rankine Cycle a	Organic Rankine Cycle a
Installed Cost (2015 $CAD/kW) [b]	$1700 - $3800	$2900 - $5800
Fixed and Variable O&M Cost (2015 $CAD/MWh) [b]	$7 - $16	$13 - $23
Electrical Generation Efficiency (HHV) (% of Carnot) [c]	40%	40%

b) Ranges for WER capacities of 100 kW to 20 MW. The analysis used performance and cost correlations that are a function of nominal WER capacity.
c) Converted from USD to CAD (1.2767 CAD = 1 USD), and labour component adjusted from U.S. labour rates to Ontario labour rates.
d) Carnot efficiency is the theoretical maximum efficiency of a heat engine. It is a function of the absolute temperatures of the hot source and cold sink.

Applicable Facilities

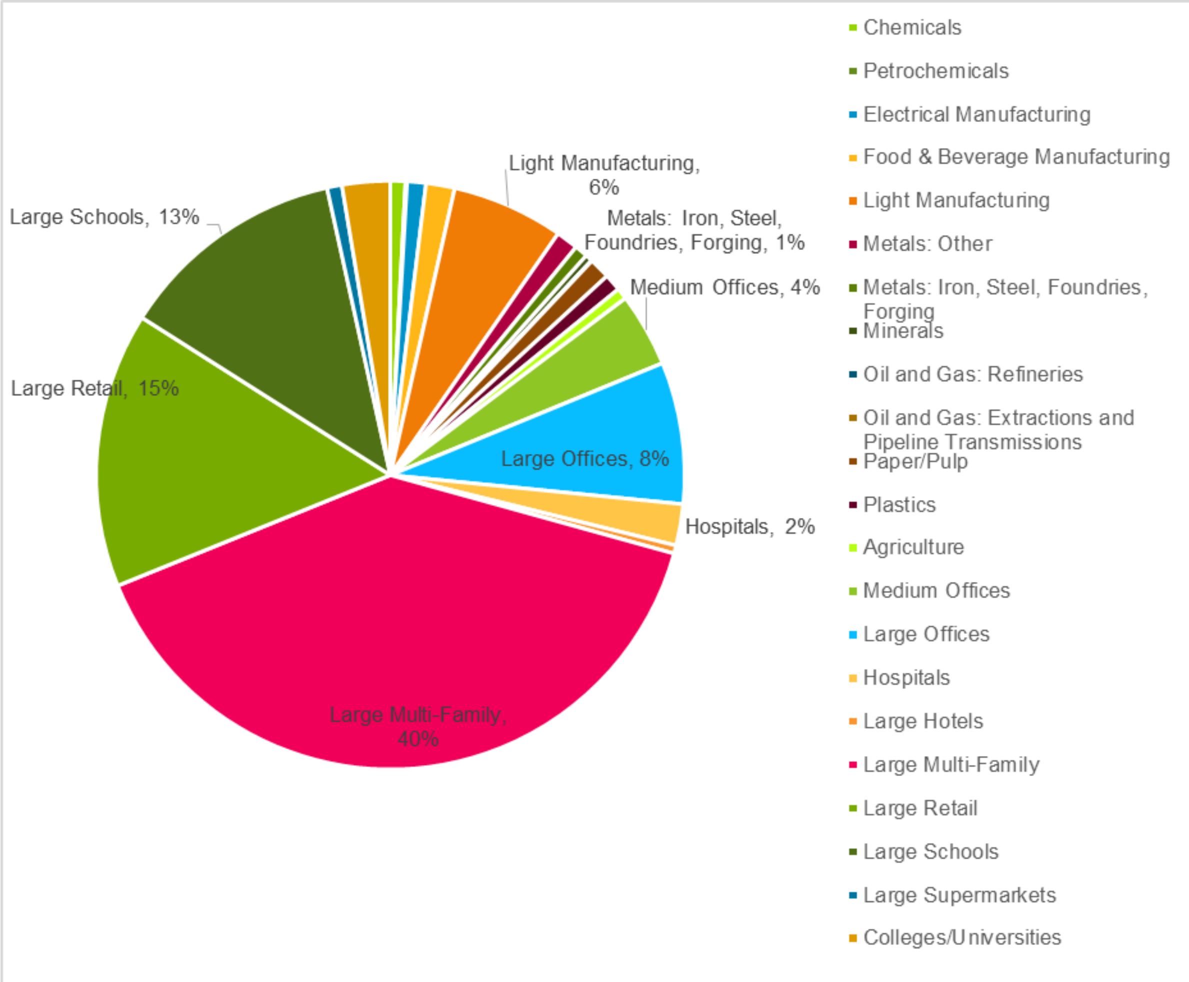
Table 5 lists the types of applicable facilities considered for this study. We selected facility types based on their potential to use BMG systems of 100 KW or larger, including multi-family, commercial/institutional, and industrial facilities that have significant thermal loads. At the request of the IESO, we also included greenhouses, which fall under the agricultural sector.

Table 5: Applicable Facilities Types

Commercial and Multi-Family Facility Types	Industrial Facility Types
Hospitals	Agriculture/Greenhouses
Large Hotels	Chemicals
Large Multi-Family	Electrical Manufacturing
Medium Offices	Food & Beverage Manufacturing
Large Offices	Light Manufacturing
Large Retail	Metals: Iron, Steel, Foundries, Forging
Large Schools	Metals: Other
Large Supermarkets	Minerals
Colleges/Universities	Oil & Gas: Refineries
	Oil and Gas: Extractions and Pipeline Transmissions
	Paper/Pulp
	Petrochemicals
	Plastics

Figure 1 shows the percent of floor space for each facility type considered in this study.

Figure 1: Applicable Facilities by Facility Type (Percent of Floor Space)

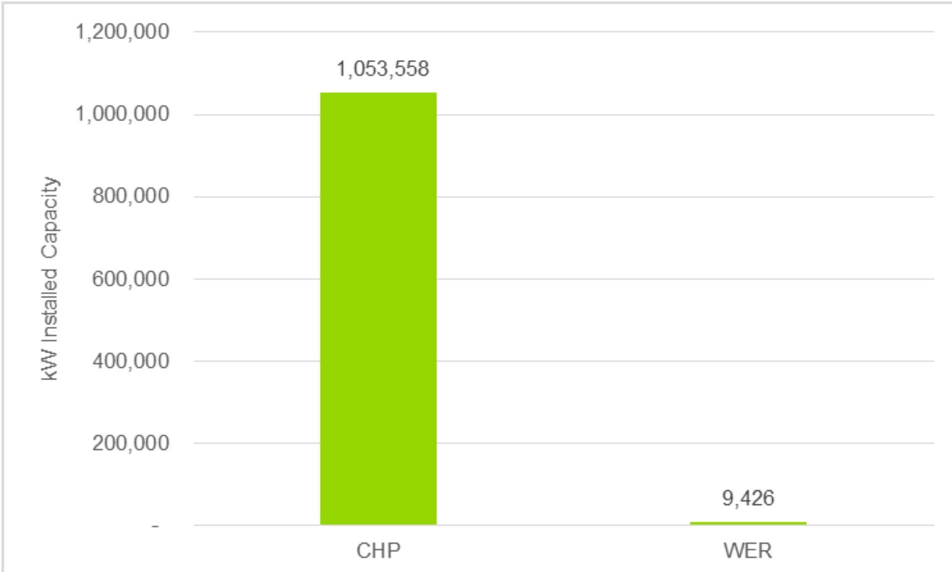


Source: IESO-supplied data, including MPAC commercial and multi-family data and D&B industrial data

Existing Projects

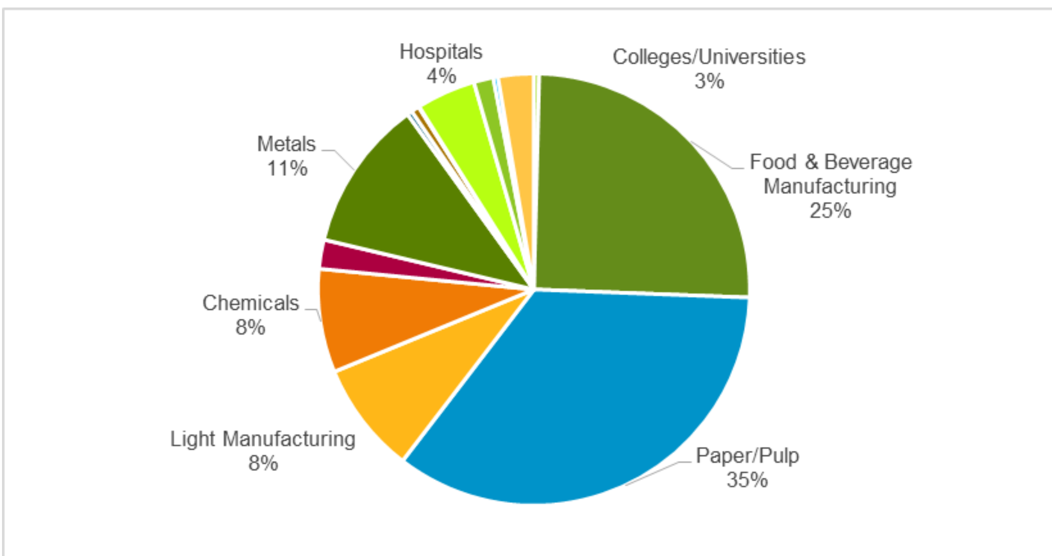
We identified 107 CHP projects and 3 WER projects already in operation in Ontario facilities, representing about 1.1 GW of existing BMG projects (see Figure 2 and Figure 3).

Figure 2: Existing BMG Projects in Ontario



Sources: CIEEDAC CHP database; IESO-supplied data on previous BMG projects; inputs from Ontario LDCs.

Figure 3: Existing BMG Projects in Ontario by Facility Type (Percent of Installed Capacity)



Sources: CIEEDAC CHP database; IESO-supplied data on previous BMG projects; inputs from Ontario LDCs.

Energy Profiles

We modelled each facility type using annual hourly energy profiles (both thermal and electric). For commercial/institutional and multi-family facilities, we generated energy profiles using the U.S.

Department of Energy's (DOE's) EnergyPlus building energy model, using inputs consistent with the DOE's Commercial Reference Buildings.[2] We used Typical Meteorological Year weather data for the largest city in each of Ontario's three climate zones (Windsor, Toronto, and Thunder Bay for ASHRAE climate zones 5, 6, and 7, respectively) to generate the profiles.

Table 6: DOE Reference Buildings used to Generate Commercial/Institutional and Multi-Family Energy Profiles

IESO Study Profile	DOE Profile	Reference Building Size (sq. ft.)
Colleges/Universities	Mix [a]	230,199
Hospitals	Hospital	241,351
Large Hotels	Large Hotel	122,120
Large Offices	Large Office	498,588
Medium Offices	Medium Office	53,628
Large Retail	Stand Alone Retail	24,962
Large Schools	Secondary School	210,887
Large Supermarkets	Supermarket	45,000
Large Multi-Family	Mid-Rise Apartment	33,740

a) Approximated using the following mix of available reference buildings: 52% large schools, 22% large offices, 25% large multi-family, and 1% hospitals

We obtained most industrial facility energy-use intensities (EUIs) from the Energy Information Administration, *Manufacturing Energy Consumption Survey (MECS).*[3] We calibrated these data using consumption data from Natural Resource Canada's (NRCan) *Comprehensive Energy Use Database: Industrial Sector – Ontario.*[4]

For oil and gas extraction facilities, we determined EUIs by Ontario-specific facility floor spaces, Ontario-specific production, and industry-standard Energy Return on Investment (EROI) values both for conventional extraction and for oil sands extraction. We obtained greenhouse EUIs from a Cornell University study of greenhouse energy use.[5]

We used profiles representing Ontario-based industries to distribute consumption data over the 8760 hours in a year. We developed energy profiles by normalizing and combining metered and modelled energy profiles using energy profiles of industries in Ontario (provided by the IESO). Where we did not have adequate Ontario-specific data for a given industry, we supplemented IESO-provided energy profiles with profiles from CHP studies in areas outside of Ontario.

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[2] Source: US Department of Energy. http://energy.gov/eere/buildings/commercial-reference-buildings
[3] Manufacturing Energy Consumption Survey, Energy Information Administration, 2010, https://www.eia.gov/consumption/manufacturing/
[4] Comprehensive Energy Use Database: Industrial Sector – Ontario, Natural Resource Canada, http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_agg_on.cfm
[5] CUAES Greenhouses – Energy Consumption and Equivalents, Cornell University Agricultural Experiment Station, March 2014. https://cuaes.cals.cornell.edu/sites/cuaes.cals.cornell.edu/files/shared/documents/Greenhouse-energy-consumption-2014-03-21.pdf

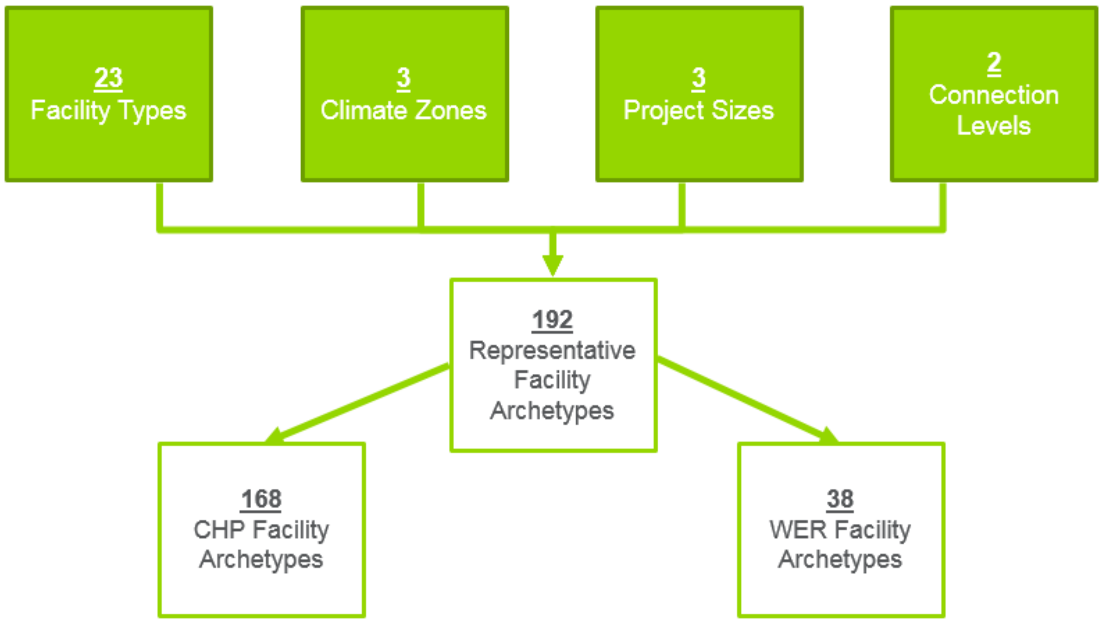
BMG Simulation Tool

The rigor and complexity required to conduct this analysis led Navigant to develop a new BMG analysis tool. The key features of the new BMG tool are:

- Simulates BMG operation at the hourly level, accounting for:
    - Hourly variations in facility thermal and electric loads
    - Both volumetric-based and demand-based components of electric and gas rates
- Provides three options for CHP operational strategy:
    - "Smart" strategy (CHP operation responds to price signals)
    - Thermal-and-electric-load-following strategy (facility loads dictate operation, with no dumping of excess thermal energy)
    - Modified thermal-and-electric-load-following strategy (allows dumping of excess thermal energy during peak electric periods, subject to program constraints)
- Ensures compliance with IESO program constraints
- Provides high levels of granularity to show results by facility type, LDC, connection level (transmission or distribution), and analysis scenario.
- Accommodates multiple BMG capacity choices available to customers
- Developed in the Analytica platform to permit sophisticated operational algorithms, reduce coding errors, and reduce execution time compared to traditional spreadsheet-based models.

For CHP, Navigant identified approximately 27,000 customers that met the minimum peak-demand requirements for BMG eligibility as per the IESO program rules for the Process and Systems and Industrial Accelerator programs in 2015. Navigant grouped these customers in 192 representative customer archetypes based on facility type, climate zone, facility size, and connection level (see Figure 4).

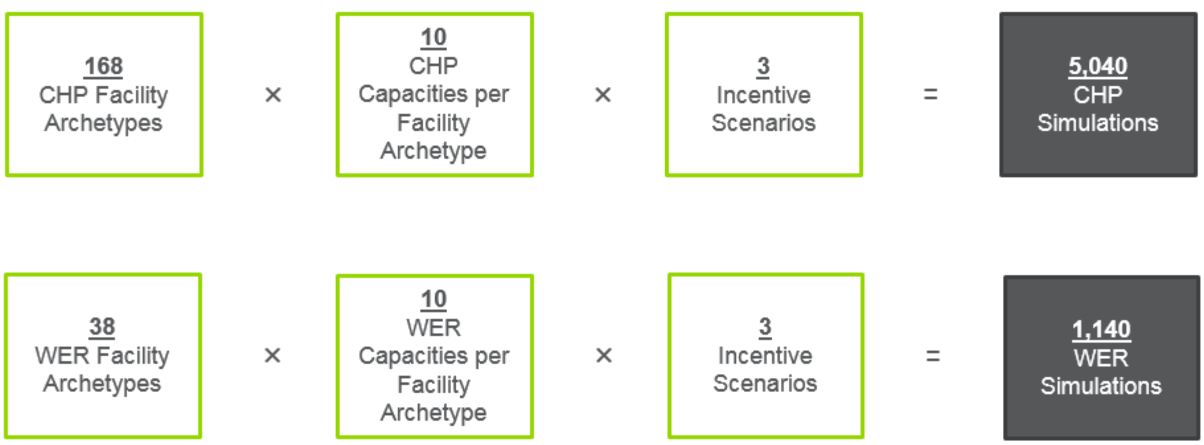
Figure 4: Representative Facility Archetypes [a]



a) The total representative facility archetypes add up to a number higher than 192 because the paper/pulp facility type (14 archetypes) is considered eligible for both CHP and for waste fuel-based WER.

As Figure 5 shows, we simulated 5040 CHP installations and 1140 WER installations to conduct this analysis.

Figure 5: CHP and WER Simulations



For technical and economic potentials, we assumed that BMG potentials increase in proportion to population growth. We used population growth projections for the major city in each climate zone (London, Toronto, and Thunder Bay for climate zones 5, 6, and 7, respectively).

While the BMG tool can simulate multiple CHP operational strategies, working with the IESO, we ultimately based the analysis on a modified load-following strategy:

- No electricity export to the grid

- No dumping of recoverable thermal energy, except during the 180 hours/year that, in our judgment, could impact Global Adjustment (GA). Thermal dumping is limited to ensure that the total system efficiency does not fall below 65% (HHV) for the year (per IESO program requirements).
- If either electric or thermal energy use falls below the minimum turn-down ratio of the CHP system, the CHP system does not run for that hour

WER can be driven by two different sources: waste heat (generally steam or hot air from industrial processes), or waste fuel (such as biomass from paper/pulp production). Navigant's BMG tool uses a straight-forward operational strategy for WER: if the hourly operational cost of running a WER unit is lower than the base-case hourly cost, the WER unit will operate at full capacity or up to the facility electric load, whichever is lower. Operation is also constrained by how much waste heat or waste fuel is available on an hourly basis.

Potential Analyses

We used three parameters to quantify potentials:

- **Electricity Savings:** The annual electricity generated by BMG at the customer site-level, which is equivalent to the amount of grid electricity saved (gigawatt-hours).
- **Demand Savings:** The average reduction in electric demand during summer peak hours achieved by BMG at the customer site (megawatts) (see Figure 6).

Figure 6: Summer Peak Demand Savings Periods

Season	Time	Months
Summer (Weekdays)	1 PM – 7 PM	June
		July
		August

Source: Ontario Power Authority[6]

- **Capacity:** The total nominal electric generation capacity of BMG units (gigawatts).

This summary reports only energy savings at the province-wide level—see the main body of the report for additional results.

Technical Potential

We based technical potential on the largest technically feasible BMG system beyond which there are no appreciable electricity savings.

[6] http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and-Requirements-2015-2020-Apr29-2015.pdf

CHP technical potential does not depend on incentive scenario because no price signals are taken into account during operation. WER results show differences by incentive scenarios due to the hourly cost minimization operational strategy.

Figure 7 summarizes the CHP technical potential for Ontario by year based on electricity savings. The province-wide CHP technical potential is about 22 TWh in 2015, increasing to about 24 TWh by 2025. This compares to about 53 TWh of baseline electricity consumption in 2015 for CHP applicable facilities, or about 42 percent reduction in electricity consumption. It also corresponds to about 16 percent of Ontario's total 2015 electricity consumption (about 137 TWh).[7]

Figure 7: CHP Technical Potential in Electricity Savings for System

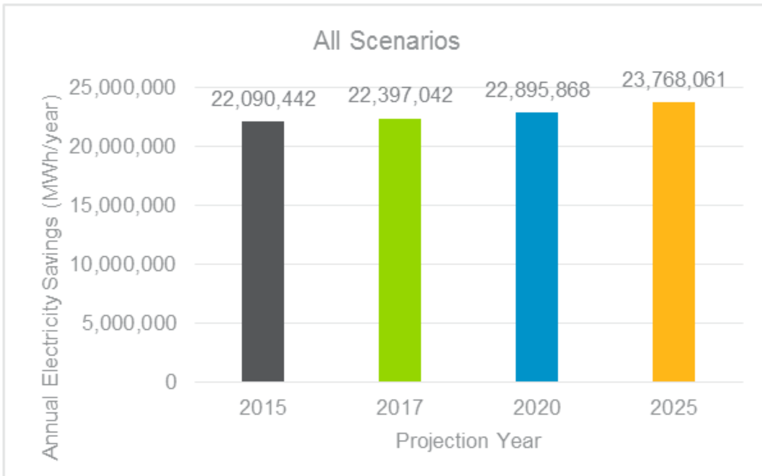
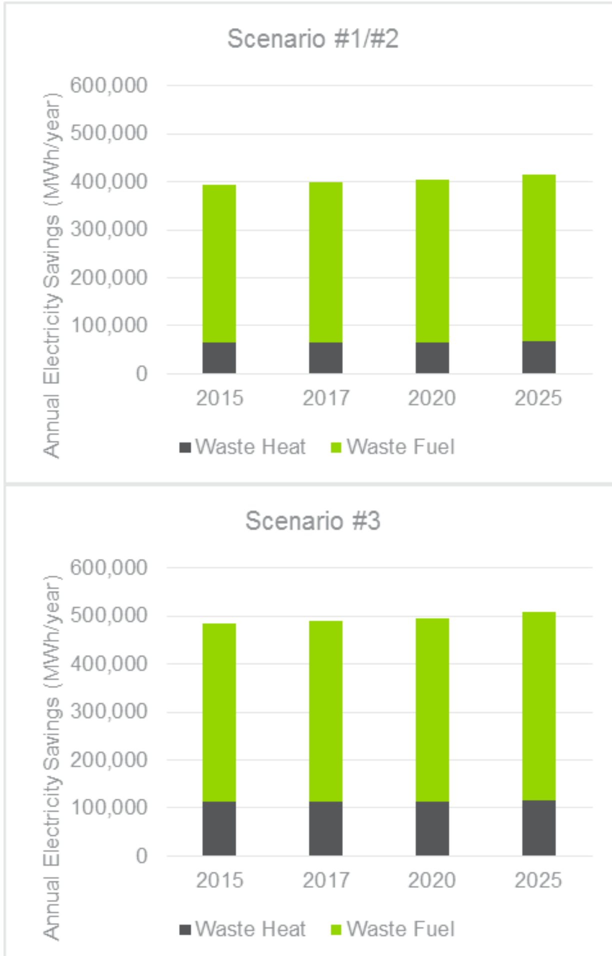


Figure 8 shows the province-wide WER technical potential based on electricity savings for the three analysis scenarios. WER technical potentials are substantially lower compared to CHP technical potentials. WER technical potentials in 2015 range from about 0.4 to 0.5 TWh of baseline electricity consumption (depending on scenario), or about 2 percent of the 2015 CHP technical potential. It also corresponds to about 0.3 percent of Ontario's total 2015 electricity consumption (about 137 TWh). Waste fuel-based WER represents the bulk of WER technical potential (77 to 84 percent in 2015, depending on scenario).

[7] Ontario Energy Reports—Demand for 2015 Q1, Q2, Q3, and Q4.

Figure 8: WER Technical Potential in Electricity Savings for System



Economic Potential

Economic potential is the portion of technically feasible BMG that produces a net benefit from a program administrator perspective. Economic potential is determined by completing one cost-effectiveness screen on each BMG size and facility archetype that is at or below the capacity selected for calculating technical potential. The Program Administrator Cost (PAC) test evaluates the benefits to the program administrator (i.e., the IESO). Cost-effectiveness tests calculate the relevant benefit and cost components and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the PAC test if it results in a positive net benefit or if the benefit-cost ratio is greater than 1.0.

All facility types analyzed pass the PAC test and, therefore, BMG economic potentials are the same as the technical potentials summarized above.

Market Potential

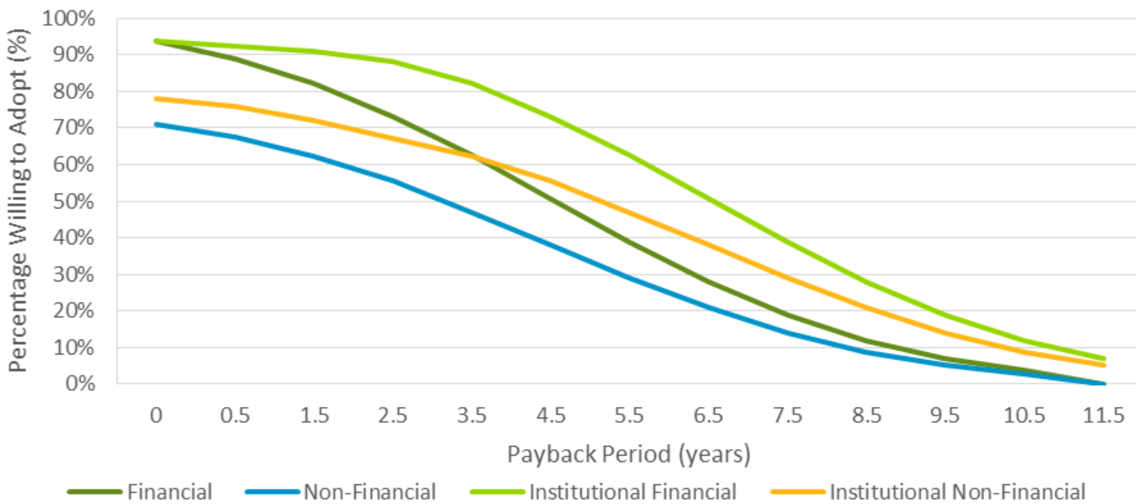
Market potential represents the portion of economic potential that is likely to be achieved over time. In contrast to technical and economic potentials, market potential considers the time required to raise awareness, generate market interest, conduct engineering analyses, and design, develop, and install BMG systems. Market potential is determined using three key steps and concepts:

1. Participant cost screen and optimal sizing
2. Financial and non-financial potential
3. Market diffusion.

The first step of the market potential considers all BMG sizes for a given facility that pass the PAC. These projects are run through a cost-effectiveness test that captures the customer perspective. The participant cost screen uses the Participant Cost (PC) test to evaluate the project from the customer's perspective. The PC test calculates the benefit and cost components, and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the participant cost test if a positive net benefit results or if the ratio is greater than 1.0.

Payback acceptance curves define the relationship between the simple payback of a project and the percentage of the market that will proceed with a project. Both financial and non-financial factors impact a customer's decision whether or not to move forward with a project, and different sectors generally have different payback thresholds. Navigant segmented the analysis of payback acceptance into four types: financial and non-financial (institutional facilities), and financial and non-financial (non-institutional). The financial payback acceptance curves were developed leveraging an in-depth analysis conducted by Navigant for an energy-efficiency potential study. The non-financial payback acceptance curves were developed using both quantitative and qualitative analyses to account for both financial and non-financial factors. Non-financial factors can include environmental permitting, technical constraints, site-specific concerns, customer security/reliability, and other factors. Figure 9 shows the resulting payback acceptance curves.

Figure 9: Payback Acceptance Curves



Market Diffusion characterizes the pace of project implementation taking into account factors such as marketing and outreach efficacy, project lead times, and equipment cost reductions over time. Navigant used a Bass Diffusion model to represent the implementation of market potential over time. The model considers the influence from early adopters (innovators) and late adopters (imitators), which explains how uptake occurs at the onset of a new product, idea, or process. Figure 10 shows the market diffusion curve developed for this analysis.

Figure 10: BMG Bass Diffusion Curve

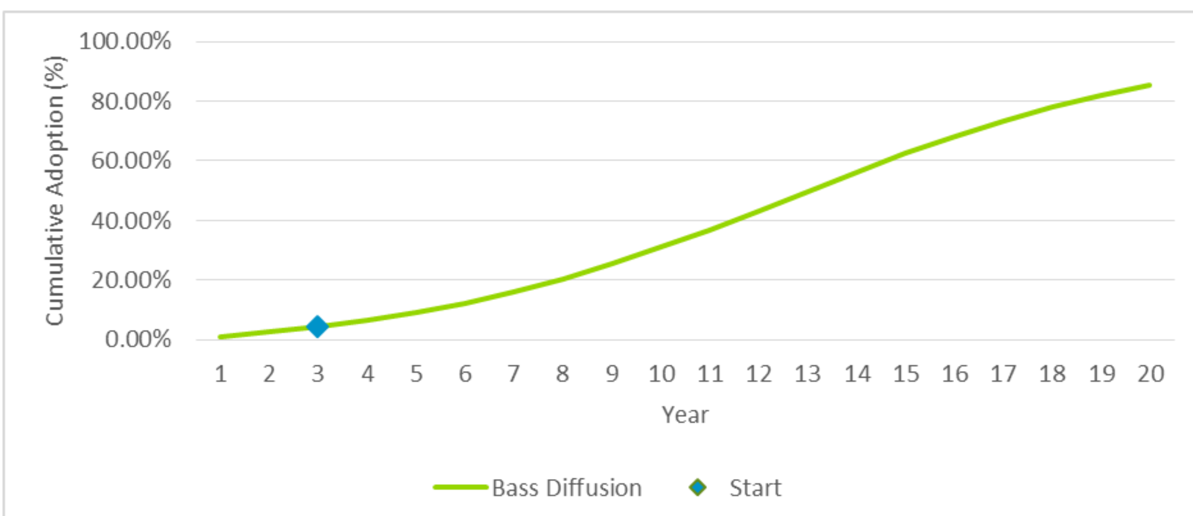
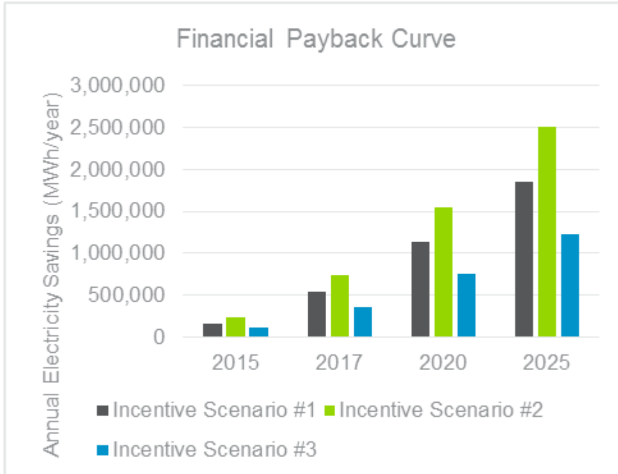


Figure 11 shows the province-wide CHP market potential based on electricity savings. The two charts in the figure, labeled "Non-Financial Payback Curve" and "Financial Payback Curve", represent the overall market potential and the market potential considering only financial factors, respectively. The province-wide CHP market potential increases from about 60 to 130 GWh in 2015 (depending on scenario) to about 700 to 1400 GWh in 2025. The 2025 projections represent about 3 to 6 percent of the 2025 CHP technical potential (depending on scenario).

Figure 11: CHP Market Potential in Electricity Savings for System



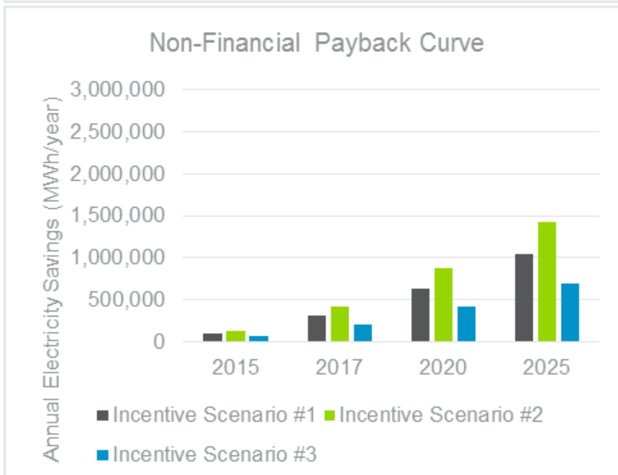
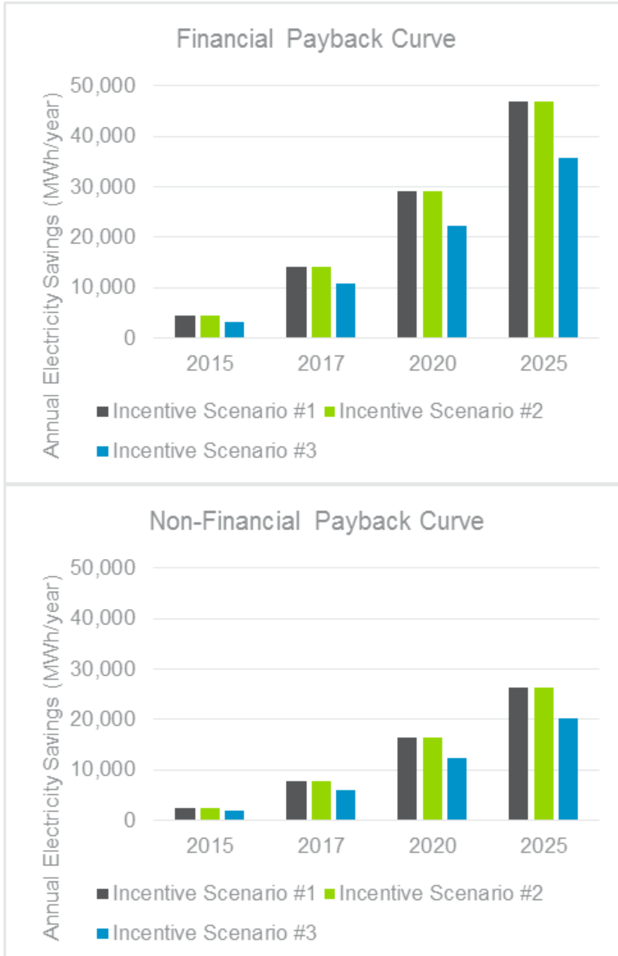


Figure 12 shows province-wide WER market potential based on electricity savings (both overall and financial-only market potentials). The province-wide WER market potential increases from about 1.9 to 2.4 GWh in 2015 (depending on scenario) to about 20 to 26 GWh in 2025 using non-financial payback curves. The 2025 market potential represents about 4 to 5 percent (depending on scenario) of the 2025 WER technical potential based on electricity savings.

Figure 12: WER Market Potential in Electricity Savings for System



Cap & Trade Potential

We evaluated the impact of recent cap and trade regulations to the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario.

The regulation creates a price for carbon which will directly affect natural gas prices and indirectly affect electricity prices. The changes in these prices may impact the potential for CHP across Ontario as costs and benefits are directly tied to both natural gas and electricity costs.

Navigant developed a Cap and Trade scenario to evaluate the impact of the new regulation relative to the base case (i.e., current program rules). Under the Cap and Trade scenario, Navigant leveraged electricity and gas forecasts provided by the IESO which account for the expected carbon prices.[8] We applied these forecasts at the Market Potential stage of the analysis to determine the impact of the proposed legislation on BMG potential.

[8] Because the forecasts are not public, we do not describe them herein.

The impact of the carbon cap-and-trade market shows a relatively minor increase in WER potential and a decrease of about 20% for CHP potential. The cap-and-trade pricing has a much larger impact on projected gas prices than electricity prices which results in a much larger impact for CHP than WER.

Figure 13 shows CHP market potential under carbon cap-and-trade based on electricity savings. Under scenario 1, in 2025, this market potential is about 81 percent of market potential without cap-and-trade (0.84 TWh vs. 1.04 TWh).

Figure 13: CHP Market Potential with Carbon Market in Electricity Savings for System

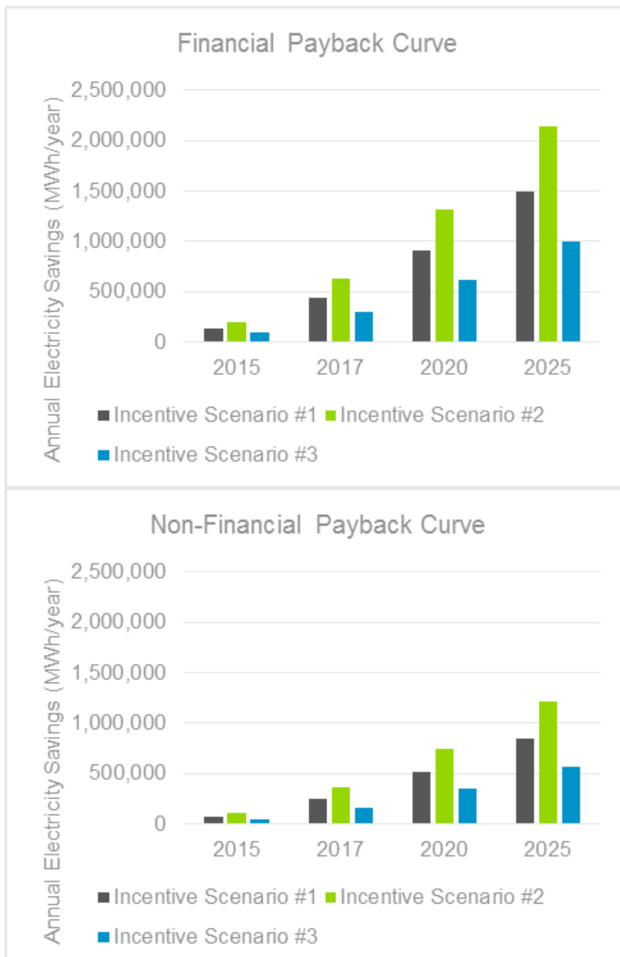
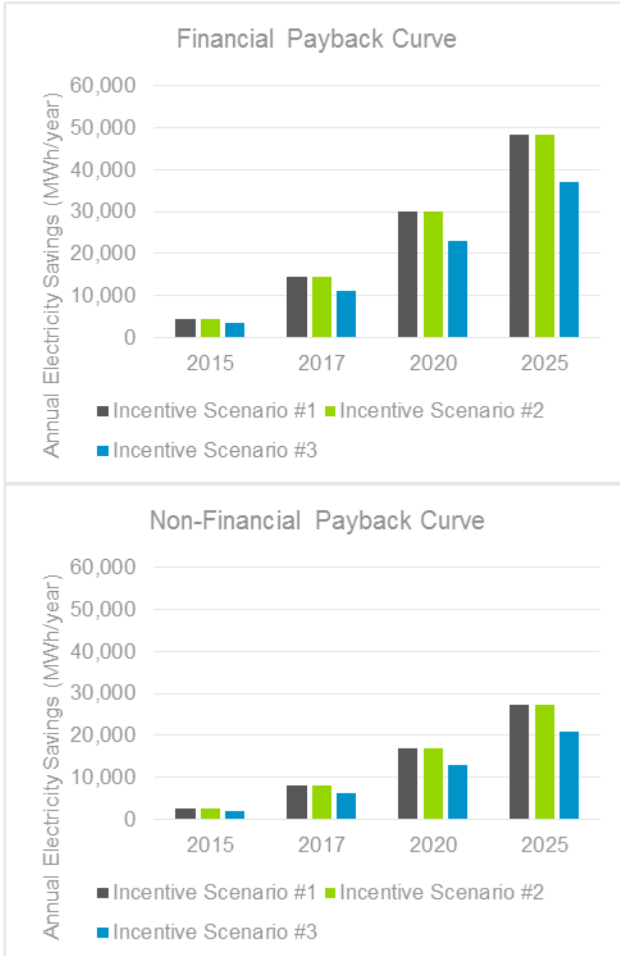


Figure 14 shows WER market potential under cap-and-trade based on electricity savings. For scenario 1, that potential is approximately 103% of potential without a carbon cap-and-trade market (27.2 GWh/year vs. 26.4 GWh/year).

Figure 14: WER Market Potential with Carbon Market in Electricity Savings for System



Constrained Potential

Constrained potential is the portion of the market potential achievable after accounting for electricity system constraints that may limit BMG installations. The IESO's planning department has determined that electricity network constraints must be determined at the transformer station, rather than LDC level, and that electricity network connection capacity will need to be assessed on a project-by-project basis when applications are received. Because this study estimates potential at the LDC level (not at the transformer-station level), it is not possible to apply constraints to quantify impacts on market potentials for all LDCs.

In cases where an LDC lies within an area that is fully area constrained, there is no potential for BMG projects larger than 500 kW. We excluded these LDCs from the constrained potential analysis.

Figure 15 shows that CHP constrained potential represents about 94 to 95 percent of 2025 market potential under incentive scenario #1 based on electricity savings.

Figure 15: CHP Constrained Potential in Electricity Savings for System

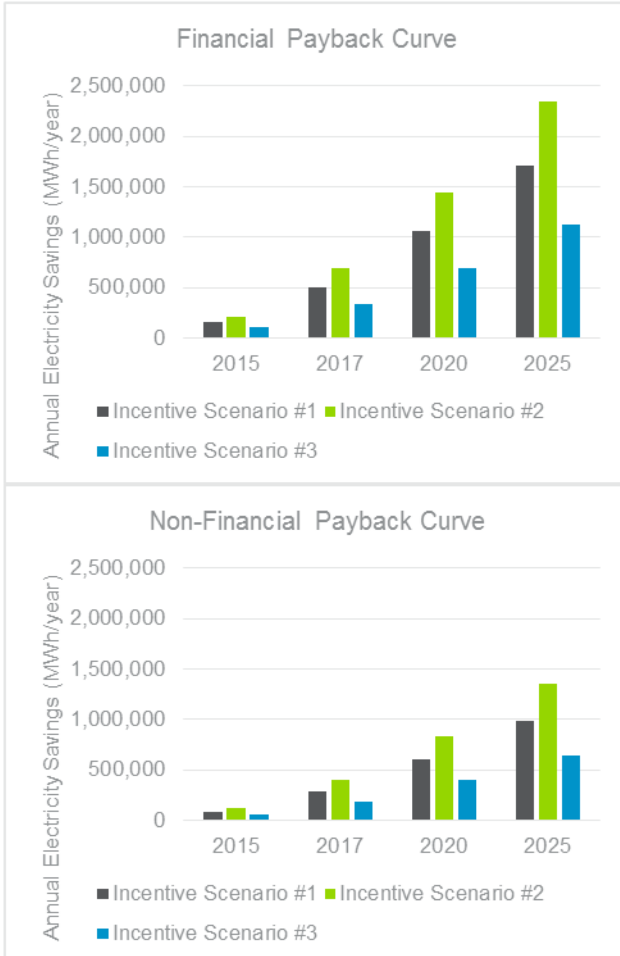
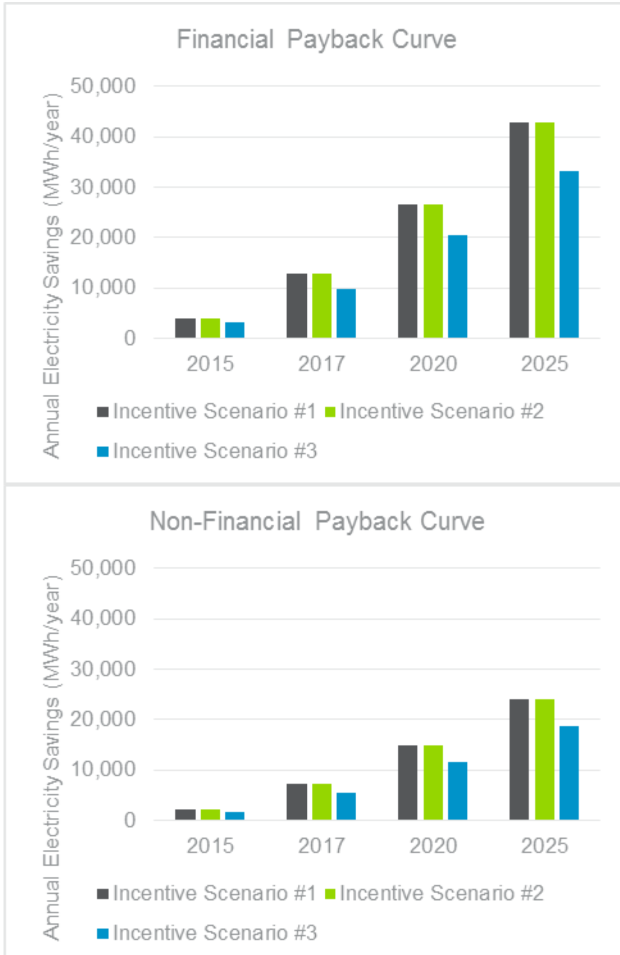


Figure 16 shows that 2025 WER constrained potential under scenario 1 represents about 91 percent of market potential by electricity savings.

Figure 16: WER Constrained Potential in Electricity Savings for System



Merged Results

The IESO has some existing BMG projects which went in-service through the program in 2015 and some applications which have already been received for BMG projects. These projects will contribute to the potential for the BMG program from 2015 to 2025. As a result, Navigant has also created merged results which present the combination of actual in-service projects and applications with the modelled potential. These merged results were created only for incentive scenario #1 (existing program rules) after applying constraints to the modelled results. Before merging results, Navigant assumed that some attrition will occur for projects for which applications were received but which are not yet in service. For these projects, Navigant assumed 75% of the application potential would result in achieved potential. Feedback from LDCs and previous BMG project contacts indicate that the average length from application to in-service is approximately 2 years. Navigant assumed that this application project potential will be realized by 2017. Navigant merged results at the facility type and LDC level. If the actual or application potential was greater than the modelled potential, than the modelled potential was overridden with actual and applications.

Merging the in-service and application projects with the modelled potential increases CHP electricity savings by 1.5 times and WER electricity savings by almost 5 times (see Figure 17 and Figure 18).

Figure 17: CHP Merged Model and Actual Constrained Potential in Electricity Savings for System

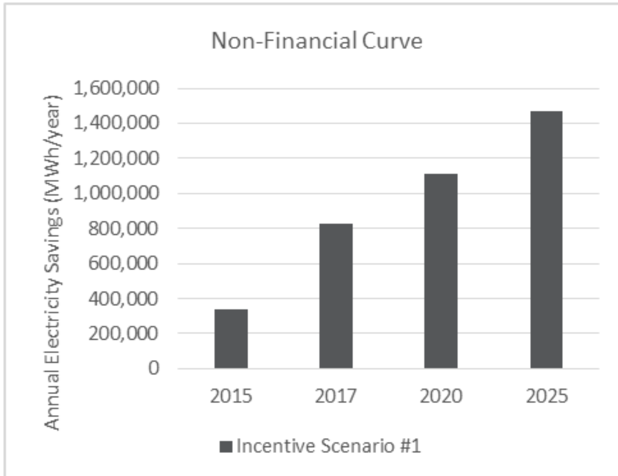
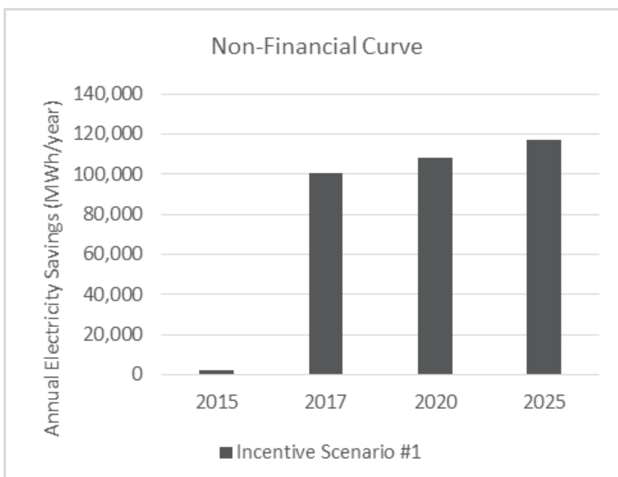


Figure 18: WER Merged Model and Actual Constrained Potential in Electricity Savings for System



1. INTRODUCTION

The IESO engaged Navigant Consulting, Ltd. (Navigant) to evaluate the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario. Key study objectives include:

- Understanding the potential to displace electric loads for Combined Heat and Power (CHP)[9] and Waste Energy Recovery (WER) installed in facilities connected:
    - To each of the local distribution systems
    - Directly to the transmission system
- Gaining insights, evidence, and documentation to make critical policy decisions about how, when, where, and to what extent to promote the installation and operation of BMG across Ontario.

Navigant produced a report for each key task. This report focuses on Task 5 (Potential Analysis). Under Task 5 of this study, Navigant, completed four subtasks (see Table 7) that are documented herein. Under a separate assignment, Navigant also evaluated the impacts of the Climate Mitigation and Low-Carbon Economy Act (Cap & Trade) on BMG potential, which is also documented in this report.

[9] CHP systems that qualify for incentives under either the IESO's Conservation First Framework LDC Tool Kit, or the IESO's Industrial Accelerator Program, are referred to as Conservation Combined Heat and Power (CCHP). We use the more general acronym "CHP" in this report.

Table 7: Study Activities Documented in this Report

Subtask	Title	Description
5.1	"Technical" Potential	For each LDC (and for transmission-connected BMG—Tx level), select the largest technically feasible BMG system for each facility type, total the potential installed BMG capacity, annual electricity savings, and demand impacts by LDC (and Tx level) and facility type, and project potential for 2017, 2020, and 2025
5.2	"Economic" Potential	Assess BMG cost effectiveness from a Program Administrator Cost (PAC) perspective for a range of plausible BMG plant sizes. Identify all plant sizes and facility types that pass the PAC test. Determine economic potential based on the largest plant size for each facility type that passes the PAC test. [a]
5.3	"Market" Potential	Determine both "Financial" and "Non-Financial" Potentials: • Financial Potential: Portion of the economic potential that customers would eventually implement based on financial factors alone • Non-Financial Potential: Portion of the economic potential that customers would eventually implement accounting for both financial and non-financial factors. In principle, non-financial potential could be either higher or lower than financial potential.
5.4	"Constrained" Potential	–Based on the limited information available about electricity network capacity and constraints, estimate the associated impacts on market potential
-	Cap & Trade Potential [b]	Develop modified financial and non-financial market potentials that reflect the impacts of the Climate Mitigation and Low-Carbon Economy Act

a) Description as modified by the IESO in a May 18, 2016 conference call. The IESO requested that we not include a Total Resource Cost constraint.

b) Add-on assignment to the original study authorized by the IESO on April 8, 2016.

2. BMG SIMULATION TOOL

The rigor and complexity required to conduct this analysis led Navigant to develop a new BMG analysis tool. This section discusses the tool development.

2.1 Approach to BMG Tool Development

The key features of the new BMG tool are:

- Simulates BMG operation at the hourly level, accounting for:
    - Hourly variations in facility thermal and electric loads
    - Both volumetric-based and demand-based components of electric and gas rates
- Provides three options for CHP operational strategy:
    - “Smart” strategy (CHP operation responds to price signals)
    - Thermal-and-electric-load-following strategy (facility loads dictate operation, with no dumping of excess thermal energy)
    - Modified thermal-and-electric-load-following strategy (allows dumping of excess thermal energy during peak electric periods, subject to program constraints)
- Ensures compliance with IESO program requirements
- Provides high levels of granularity to show results by facility type, LDC, connection level (transmission or distribution), and analysis scenario.
- Accommodates multiple BMG capacity choices available to customers
- Developed in the Analytica platform to permit sophisticated operational algorithms, reduce coding errors, and reduce execution time compared to traditional spreadsheet-based models.

The BMG tool uses:

- BMG cost and performance characteristics that are documented in Navigant’s Task 3 report (April 12, 2016)
- Hourly facility energy profiles that are documented in Navigant’s Task 4 report (May 11, 2016).

2.2 Electric Rate Archetypes

Navigant developed detailed electric rate archetypes that closely capture the nuances of the relevant electric rates used in each of Ontario’s LDCs. Table 8 summarizes the electric rate archetypes. The electric rate archetypes consist of three separate charges: demand charges, standby charges and fixed charges.

Table 8: Representative Electric Rate Archetypes

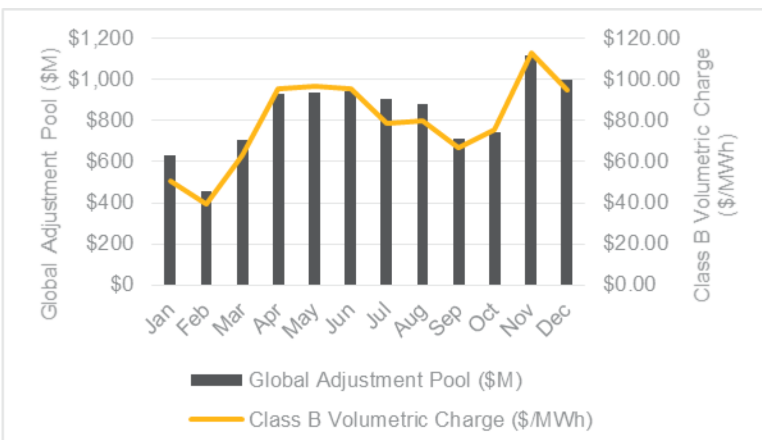
Charge Type	Units	General Service > 50 kW	Large Users > 5 MW	Tx-Connected Users
Demand Charge[10]	*$/kW-month*	$9.74	$7.67	$6.15[11]
Standby Charge[12]	*$/kW-month*	$2.73	$2.73	-
Fixed Charge	*$/month*	$628	$7,131	-

All electric rates are subject to IESO's Global Adjustment (GA) charge, which recovers out-of-market costs for generation capacity and conversation programs in Ontario. GA charges are split into two classes, whose eligibility and charges are calculated as follows:

- **Class A:** defined as customers with a maximum hourly demand in a month that exceeds an average of 5 MW during a specified base period. Customers between 3 MW and 5 MW with an eligible North American Industry Classification System (NAICS) code may also qualify. [13] Each customer's contribution to the system peak load during the five system peak hours of the year is calculated in a "Peak Demand Factor" (PDF). The PDF is then multiplied against a monthly cost pool to determine each customer's monthly GA charge.
- **Class B:** defined as customers that are not eligible to be Class A customers or are eligible to be Class A customers, but have opted out or have not opted in. Class B GA charges are calculated monthly on a volumetric basis.

Actual Class A and Class B GA charges for 2015 are shown in Figure 19.

Figure 19: 2015 IESO Global Adjustment Charges

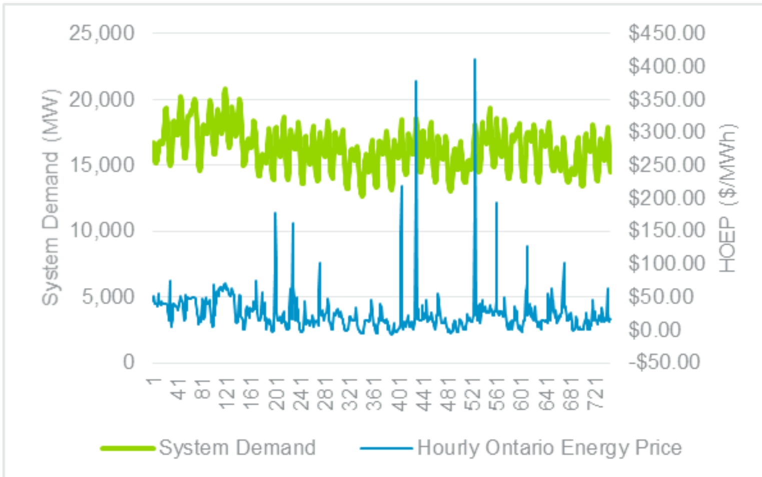


Source: IESO[14]

[10] Demand charge denominator is based on the customer's maximum peak power drawn from the grid for that month
[11] There are three components of the demand charge for transmission customers: Network Service, Line Connection and Transformer Connection. The latter two are based on gross load, while the Network Service is based on net load.
[12] Standby charges are calculated based on the difference between contracted maximum power drawn from the grid by the customer (which is contracted annually) and the monthly peak demand
[13] Ontario Regulation 429.04
[14] http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx

In addition, large customers are subject to the Hourly Ontario Electricity Price (HOEP). The HOEP is directly tied to the wholesale cost of electricity generation for each hour of the year. HOEP cost data relative to system demand for March 2015 are plotted in Figure 20.

Figure 20: IESO Hourly Ontario Electricity Price – March 2015



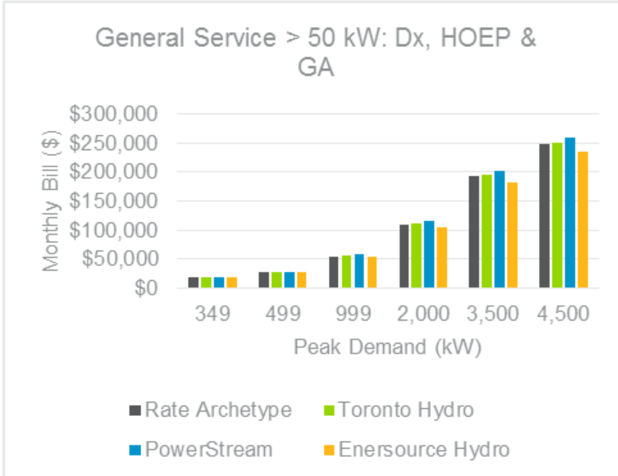
Source: IESO[15]

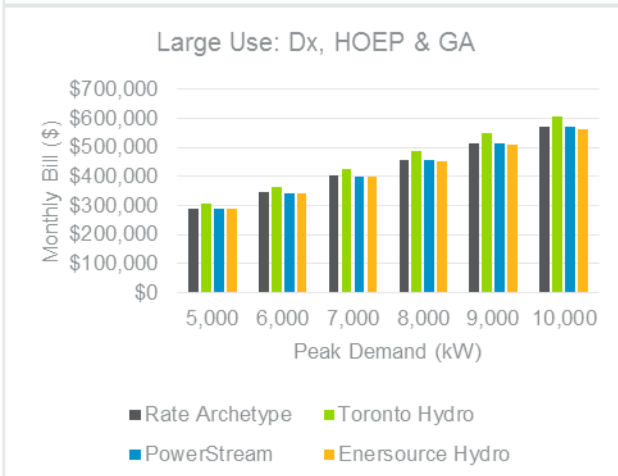
Navigant compared customer bills under these representative electric rate archetypes to what customer bills would look like for Toronto Hydro Electric System Limited (Toronto Hydro), PowerStream Inc. (PowerStream) and Enersource Hydro Mississauga Inc. (Enersource) in Figure 21. The close alignment of the rate archetypes with actual rates show that the rate archetypes accurately represent rate structures across Ontario.

http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-B.aspx

[15] http://www.ieso.ca/Pages/Power-Data/Price.aspx

Figure 21: Navigant Rate Archetype Comparisons to LDC Rate Structures





Source: Navigant analysis and Toronto Hydro, PowerStream and Enersource Hydro rate structures:

http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates

2.3 Natural Gas Rate Archetypes

For natural gas, Navigant developed six rate archetypes that were largely based on the rate structures for Union Gas Distribution and Enbridge Gas Distribution, the two largest natural gas utilities in Ontario. Customers in each of the three climate zones have two possible rate structures, which are determined based on a combination of volumetric gas use and monthly contracted demand. The breakdown of each rate can be seen in Table 9, and their geographic mappings are color-coded to the regions in Figure 22. These rate archetypes estimate customer bills that are virtually identical to those calculated using actual rate structures.

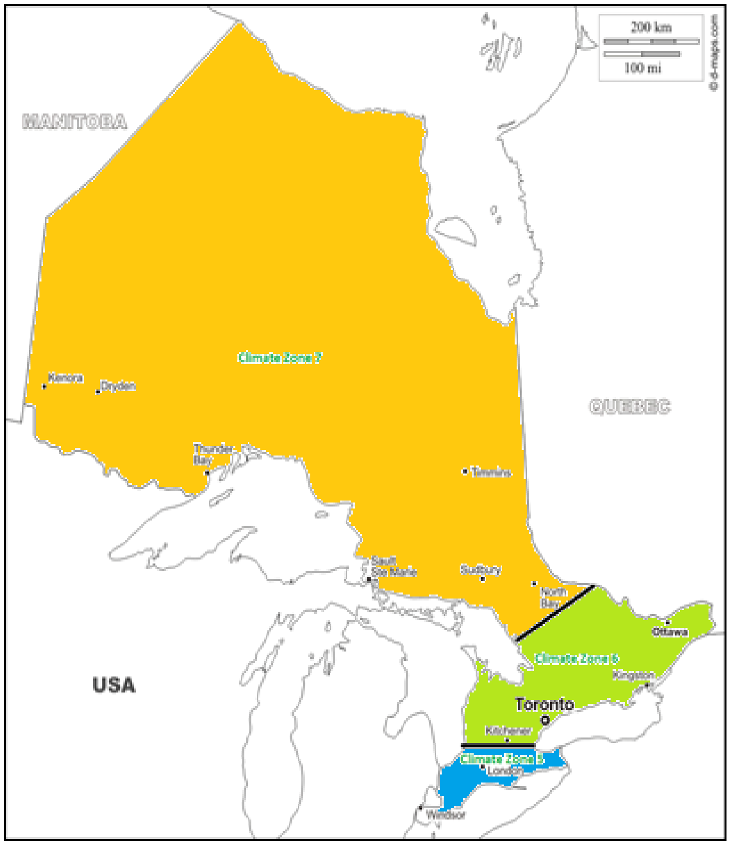
Table 9: Representative Natural Gas Rate Archetypes

Rate	Climate Zone	Blended Volumetric ($/m3)	Contracted Demand ($/m3-day)	Fixed Charge ($/month)
Union Northern/Eastern 10	7	$0.1869	-	$69
Union Northern/Eastern 20	7	$0.1401	$0.27 / $0.16 (tiered based on usage)	$915
Enbridge 100	6	$0.2182	$0.35	$120
Enbridge 110	6	$0.2099	$0.22	$576
Union M2	5	$0.1792	-	$69
Union M4	5	$0.1493	$0.48 / $0.21 / $0.18 (tiered based on usage)	$685

Source: Union Gas & Enbridge Gas rate structures[16]

[16] https://www.uniongas.com/business/account-services/unionline/contracts-rates
https://www.enbridgegas.com/businesses/accounts-billing/understanding-your-bill/rate-calculator.aspx

Figure 22: Mapping of Rate Structures to Ontario Climate Zones



Source: Navigant analysis

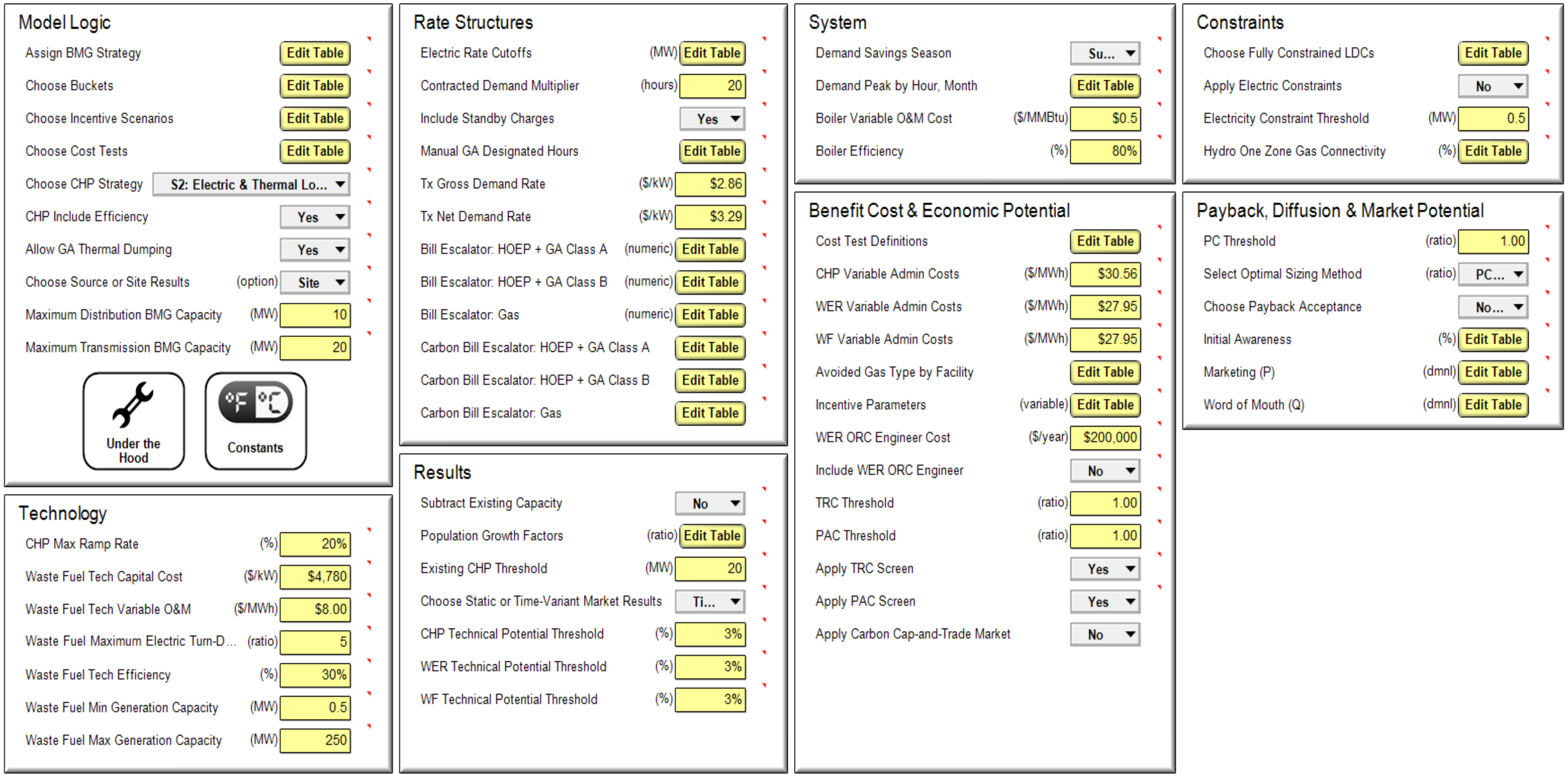
2.4 Tool Functionality and Inputs

The BMG tool has the flexibility and robustness to handle numerous scenario analyses. Figure 23 shows a list of the various switches and functionalities available in the BMG tool.

NAVIGANT

Conservation BMG Potential Study

Figure 23: Model Inputs & Functionality



Source: Navigant analysis

In addition, the tool imports an additional 20 sets of data (as seen in Figure 24) that include facility energy profiles, energy-use intensities, facility floor space, utility rates, BMG technology performance and cost characteristics, avoided costs, and more.

Figure 24: Imported Datasets for BMG Potential Study Model

3. TECHNICAL POTENTIAL

Technical potential captures the theoretical electric energy savings and demand reductions associated with instantaneous installation of an energy-saving technology in all technically suitable applications, without consideration of economic and market factors. Unlike most energy-efficiency measures, any given facility can select from a broad range of BMG capacities. Therefore, the traditional definition of technical potential was further refined. Navigant defines technical potential as the BMG capacity beyond which there are no appreciable energy savings.[17]

3.1 Analysis Matrix and Methodology

3.1.1 Summary of Analysis Scenarios

Table 10 summarizes the three incentive scenarios that Navigant modelled for BMG potential (as agreed to with the IESO).

Table 10: BMG Incentive Scenario Parameters

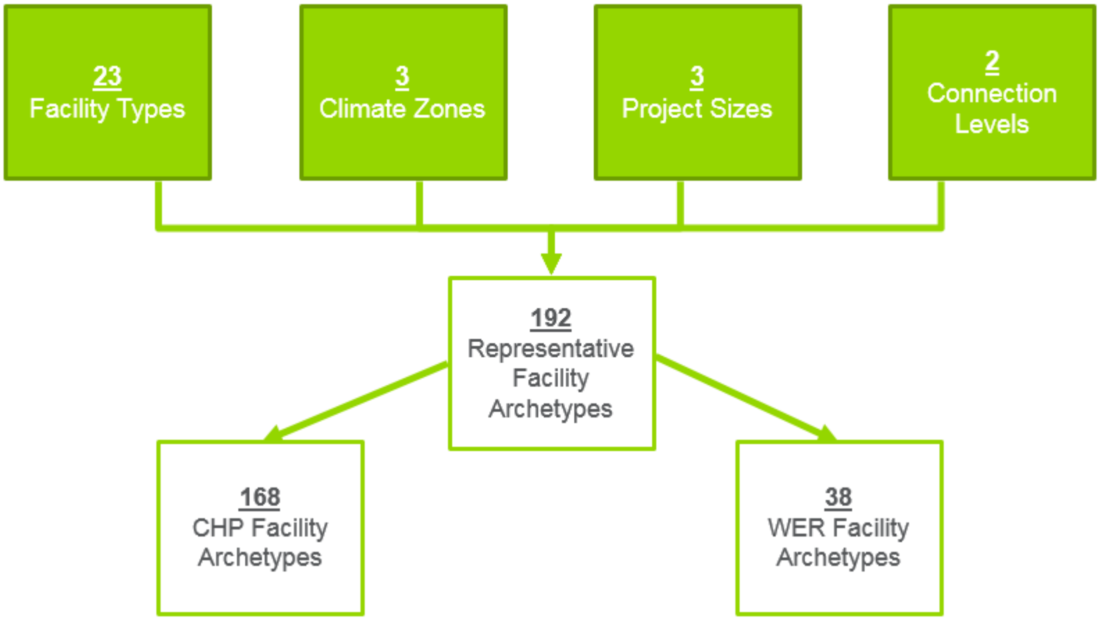
Scenario	Definition	
#1	First cost incentive is the lowest of:	40% of initial capital cost
		$200/MWh (distribution) or $230/MWh (transmission) of annual electricity savings
		Incentive to create 1-year payback
#2	First cost incentive is the lowest of:	70% of initial capital cost
		$200/MWh (distribution) or $230/MWh (transmission) of annual electricity savings
		Incentive to create 1-year payback
#3	$0.02/kWh production incentive for the first 10 years of operation	
	No first-cost incentive	

3.1.2 Analysis Matrix

For CHP, Navigant identified approximately 27,000 customers that met the minimum peak demand requirements for BMG eligibility as per the IESO program rules for the Process and Systems and Industrial Accelerator programs in 2015. Navigant grouped these customers in 192 representative customer archetypes based on facility type, climate zone, facility size, and connection level--see Figure 25.

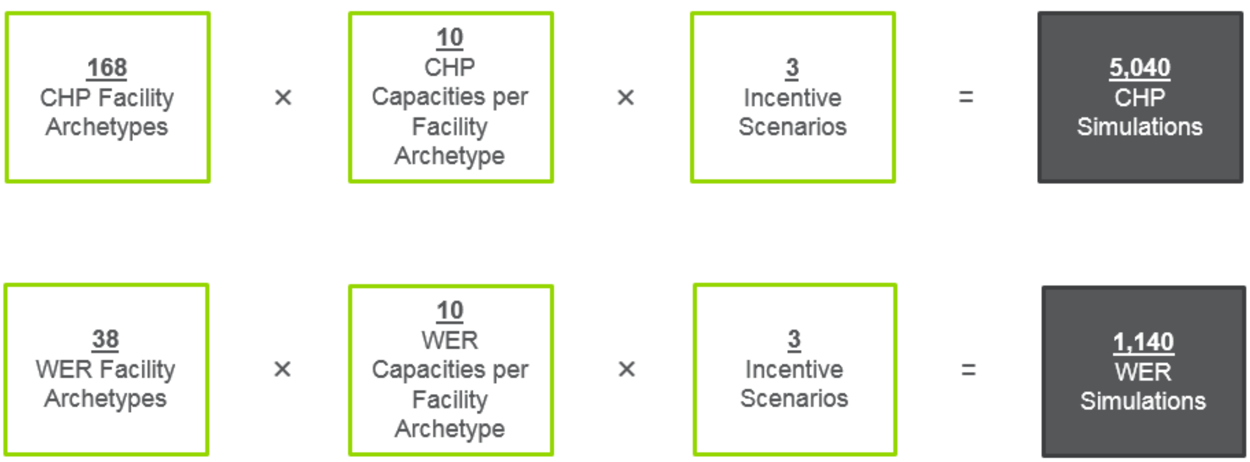
[17] Navigant analyzed 10 capacity increments ranging from 10 percent to 100 percent of the facility's annual peak electric demand, and based technical potential on the BMG capacity beyond which electricity savings increase by less than 3 percent of the facility annual electricity consumption.

Figure 25: Representative Facility Archetypes[18]



The result is a powerful, hourly simulation tool capable of multiple scenario analyses and thousands of 8,760-hour simulations--see Figure 26.

Figure 26: CHP and WER Simulations



3.1.3 Adjustments to Applicable Facilities for Access to Natural Gas

Navigant identified a pool of approximately 27,000 applicable facilities that would be eligible for BMG using the data and approaches identified in the Task 4 report. Some of these 27,000 facilities do not have access to natural gas.

[18] The total representative facility archetypes add up to a number higher than 192 because the paper/pulp facility type (14 archetypes) is considered eligible for both CHP and for waste fuel-based WER.

The scope of this potential study is limited to facilities having access to natural gas. 108 facilities (0.4% of the original 27,000 applicable facilities) were removed as their associated LDC territories do not have access to natural gas. These LDCs are: Chapleau Public Utilities Corporation, Dubreuil Lumber, Sioux Lookout Hydro and Westario Power. In addition, we removed a portion of Hydro One facilities using the following approach:

- 24% of Hydro One customers are urban (UDd) versus rural (GSd)[19]
- Navigant estimates that about one-third of rural customers (defined as those between urban areas) have access to pipeline natural gas
- Based on the above, 52% of Hydro One customers (those over 50kW) have access to natural gas, and 48% do not.

3.1.4 Adjustments for Existing Projects

As documented in the Task 4 report, through the Canadian Industrial Energy End-Use Data and Analysis Center (CIEEDAC), existing project lists from the IESO and feedback from the LDCs, Navigant developed lists of existing CHP and WER projects by capacity and their associated climate zones, facility types and LDCs. These lists include facilities served by existing, utility-scale CHP. Before completing the potential analyses, Navigant adjusted these lists of existing projects further:

- Include in existing projects only the utility-scale CHP systems under 20 MW (which is a small fraction of utility-scale CHP) because it was assumed that larger utility-scale CHP systems generally provide thermal energy to a small number of very large facilities that are not candidates for this study (i.e., these facilities are large enough that they would be unlikely to use CHP systems under 20 MW even if they did not already have an external source for thermal energy).
- At the request of the IESO, Navigant excluded from existing projects all 2015 projects (planned and actual) receiving incentives under IESO programs because these will be documented as part of the 2015 potential.

3.1.5 Population Growth Factors

Navigant developed escalation factors for technical and economic potential based on population growth data from the Ontario Ministry of Finance (see

[19] Based on Hydro One's customers and consumption by rate class, http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2013-0416%20Dx%20Rates/Exhibit%20G/G2-01-02.pdf

Table **11**). These factors are used to project future technical and economic potentials (for 2017, 2020 and 2025) from 2015 estimates. We did not apply growth factors to multi-family facilities because (due to new requirements) new multi-family facilities will all be tenant-metered. Tenant-metered multi-family facilities are not conducive to CHP.

Table 11: Population Growth Factors for Technical and Economic Potential

Climate Zone	2015	2017	2020	2025
CZ5 (London)	1.0000	1.0055	1.0154	1.0333
CZ6 (Toronto)	1.0000	1.0213	1.0555	1.1152
CZ7 (Thunder Bay)	1.0000	0.9982	0.9973	0.9956

Source: Ontario Ministry of Finance (adjusted by Navigant for climate zones)[20]

3.2 Operational Strategies

3.2.1 CHP

Based on IESO feedback, Navigant ultimately used CHP operational strategy #3 described in

[20] http://www.fin.gov.on.ca/en/economy/demographics/projections/

Table 12. This strategy operates the CHP system in response to electrical and thermal loads, but permits some dumping of thermal energy during hours of peak electric demand, to the extent permitted by the 65% minimum total system efficiency requirement imposed by the IESO's BMG programs.

Table 12: CHP Operational Strategy Iterations

	Strategy	Description
1	Cost Minimization + Electric Load Following	1. CHP units operate at full capacity during designated GA operational hours.[21] 2. For non-GA operational hours, CHP is operated at full capacity if baseline hourly cost is higher than the hourly cost while running a CHP unit. 3. For the remaining hours, CHP is not operated if the volumetric rate of electricity is below $0/MWh. 4. For remaining hours after that, CHP is operated to reduce facility demand by 20%, 40%, 60%, 80% or 100%. The optimal "demand reduction" strategy is chosen based on the lowest resulting monthly cost.
2	Electric + Thermal Load Following (Strict)	CHP units operate at a level where no electricity is exported and no thermal energy is dumped for each hour of the year. If this level falls below the minimum turn-down ratio allowed by the assigned CHP technology, the CHP unit does not run for that hour.
3	Electric + Thermal Load Following (Partial Thermal Dumping Allowed)	Similar to strategy #2, but CHP units are allowed dump thermal energy during the 180 designated GA operational hours until the 65% overall system efficiency floor is met.

Table 13 compares key characteristics of the three CHP operational strategies.

Table 13: CHP Operational Strategy Comparison

Strategy	Cost Optimization & Electric Load Following	Electric & Thermal Load Following	Electric & Thermal Load Following w/ Partial Thermal Dumping
Exports Electricity	X	X	X
Dumps Thermal Energy	✓	X	✓
Responds to Price Signals	✓	X	X
Responds to Possible GA Hours	✓	X	✓

[21] GA "operational" hours are determined based on 20 peak hours of the year (not occurring on the same day) that customers suspect will be subject to Global Adjustment Class A charge calculations. CHP customers would operate their generator to meet as much of their demand as possible for those 20 hours along with the four hours before and after those suspected peak hours for a total of 180 hours of the year.

3.2.2 WER

Waste energy recovery can be driven by two different sources: waste heat (generally steam or hot air from industrial processes) or waste fuel (such as biomass from paper/pulp production). Navigant's BMG tool uses a straight-forward operational strategy for WER: if the hourly operational cost of running a WER unit is lower than the base-case hourly cost, the WER unit will operate at full capacity or up to the facility electric load, whichever is lower. Operation is also constrained by how much waste heat or waste fuel is available on an hourly basis.

Hourly costs are ultimately determined by volumetric electricity costs, generator O&M costs and production incentives (for incentive scenario #3). This strategy is strongly influenced by the Hourly Ontario Energy Price (HOEP). In 2015, HOEP was zero or negative in 1,142 hours of the year.[22] During those hours, the WER is not operated.

3.3 Results—Technical Potential

As noted above, Navigant based technical potential on the largest technically feasible BMG system beyond which there are no appreciable electricity savings.

CHP technical potential does not depend on incentive scenario because no price signals are taken into account during operation. WER results show differences by incentive scenarios due to the hourly cost minimization operational strategy.

We use three parameters to quantify potential:

- **Electricity Savings:** The annual electricity generated by BMG at the customer site-level, which is equivalent to the amount of grid electricity saved (gigawatt-hours).
- **Demand Savings:** The average reduction in electric demand during summer peak hours achieved by BMG at the customer site (megawatts) (see Figure 27).

Figure 27: Summer Peak Demand Savings Periods: Summer Peak Demand Savings Periods

Season	Time	Months
Summer (Weekdays)	1 PM – 7 PM	June
		July
		August

Source: Ontario Power Authority[23]

- **Capacity:** The total nominal electric generation capacity of BMG units (gigawatts).

[22] http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx
[23] http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and-Requirements-2015-2020-Apr29-2015.pdf

3.3.1 CHP

The sections below show CHP technical potential for Ontario. As noted above, CHP technical potential does not vary by scenario, so these results apply to all three analysis scenarios. Appendix A includes detailed technical potential results by LDC.

3.3.1.1 Energy Savings

Figure 28 summarizes the CHP technical potential for Ontario by year based on electricity savings. The province-wide CHP technical potential is about 22 TWh in 2015, increasing to about 24 TWh by 2025. This compares to about 53 TWh of baseline electricity consumption in 2015 for CHP applicable facilities, or about 42 percent reduction in electricity consumption. It also corresponds to about 16 percent of Ontario's total 2015 electricity consumption (about 137 TWh).[24]

Figure 28: CHP Technical Potential in Electricity Savings for System

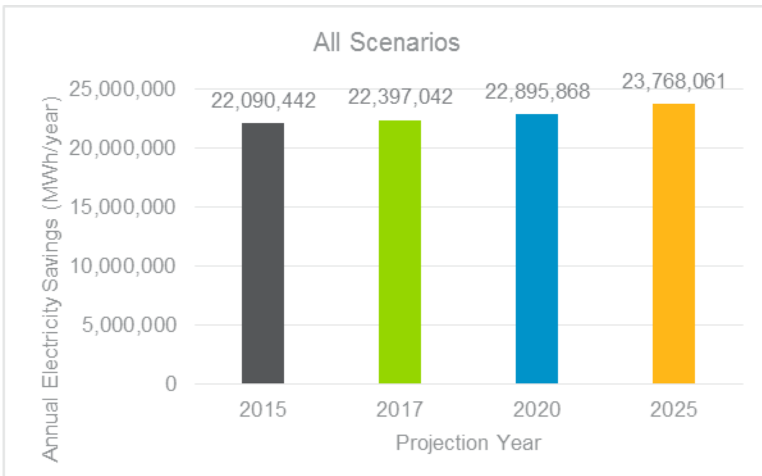
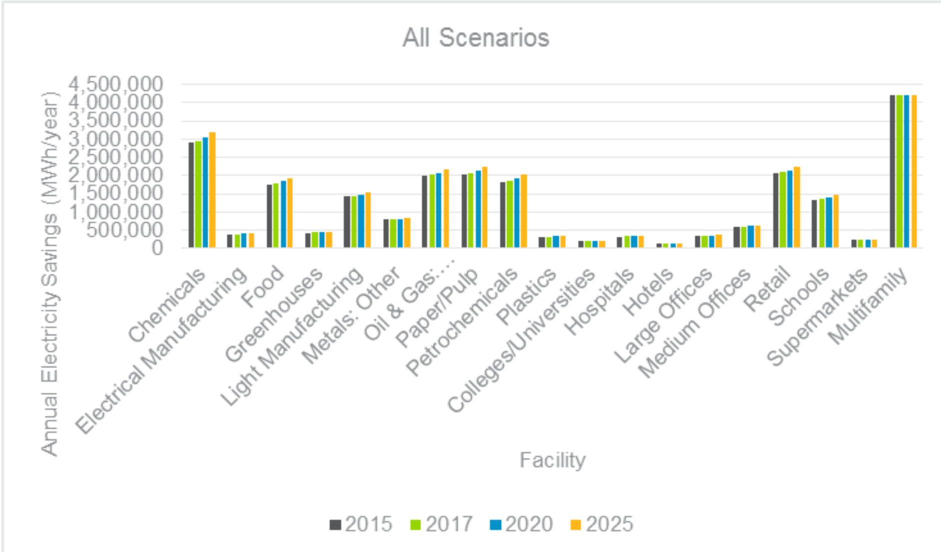


Figure 29 shows the distribution by major facility type of province-wide CHP technical potential based on electricity savings. Not surprisingly, industrial facilities generally present the largest technical potential, but retail and multi-family facilities also present substantial technical potential. Industrial facilities represent 61 percent of the CHP technical potential.

[24] Ontario Energy Reports—Demand for 2015 Q1, Q2, Q3, and Q4.

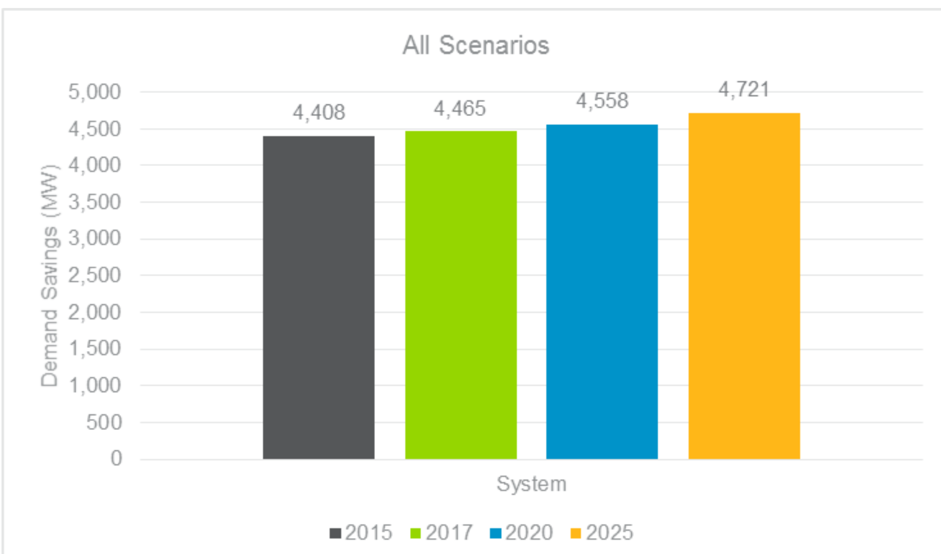
Figure 29: CHP Technical Potential in Electricity Savings by Facility Type



3.3.1.2 Demand Savings

Figure 30 shows the province-wide CHP technical potential based on summer electric demand reduction (see demand definition in section 3.3 above). 2015 CHP technical potential for demand reduction (about 4.4 GW) is about 20 percent of Ontario's total summer peak demand (about 22.5 GW).[25]

Figure 30: CHP Technical Potential in Demand Savings for System

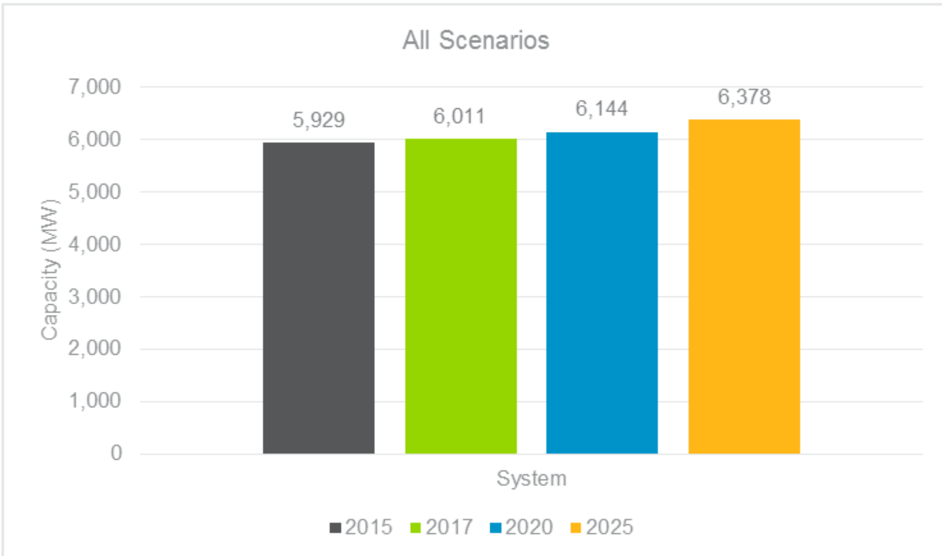


[25] http://www.ontarioenergyreport.ca/

3.3.1.3 Installed Capacity

Figure 31 shows the province-wide CHP technical potential based on nominal installed capacity, indicating that the CHP technical potential increases from about 5.9 GW in 2015 to about 6.4 GW in 2025.

Figure 31: CHP Technical Potential in Capacity for System



3.3.2 WER

The sections below show WER technical potential for Ontario. See also 8.Appendix B for additional technical potential results.

3.3.2.1 Energy Savings

Figure 32 shows the province-wide WER technical potential based on electricity savings for the three analysis scenarios. WER technical potentials are substantially lower compared to CHP technical potentials. WER technical potentials in 2015 range from about 0.4 to 0.5 TWh of annual electricity savings (depending on scenario), or about 2 percent of the 2015 CHP technical potential. It also corresponds to about 0.3 percent of Ontario's total 2015 electricity consumption (about 137 TWh). Waste fuel-based WER represents the bulk of WER technical potential (77 to 84 percent in 2015, depending on scenario).

Figure 32: WER Technical Potential in Electricity Savings for System

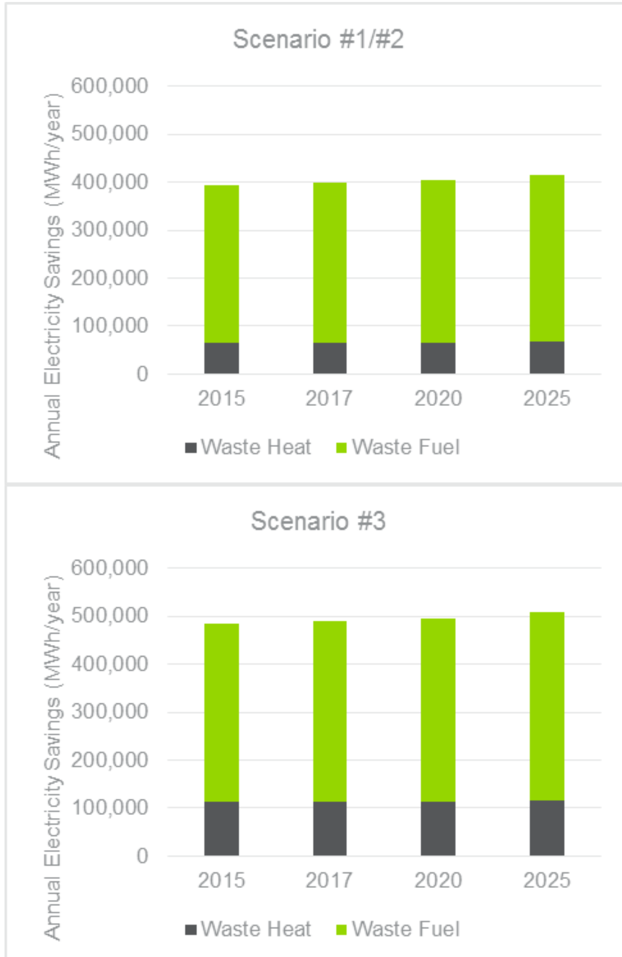
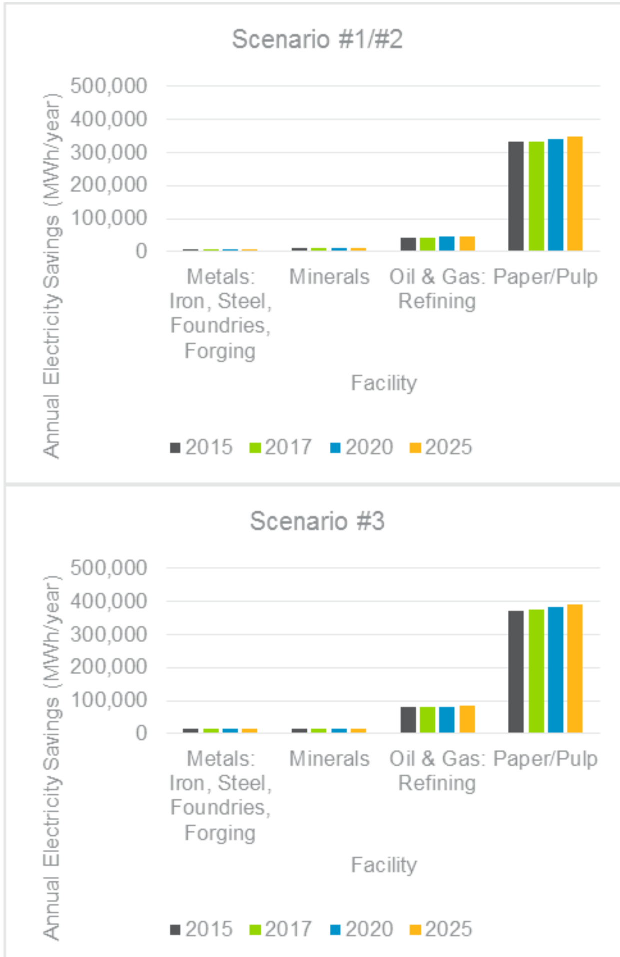


Figure 33 shows the distribution by major facility type of province-wide WER technical potential based on electricity savings. Paper/pulp facilities provide the bulk of the WER potential (77 to 84 percent, depending on scenario).

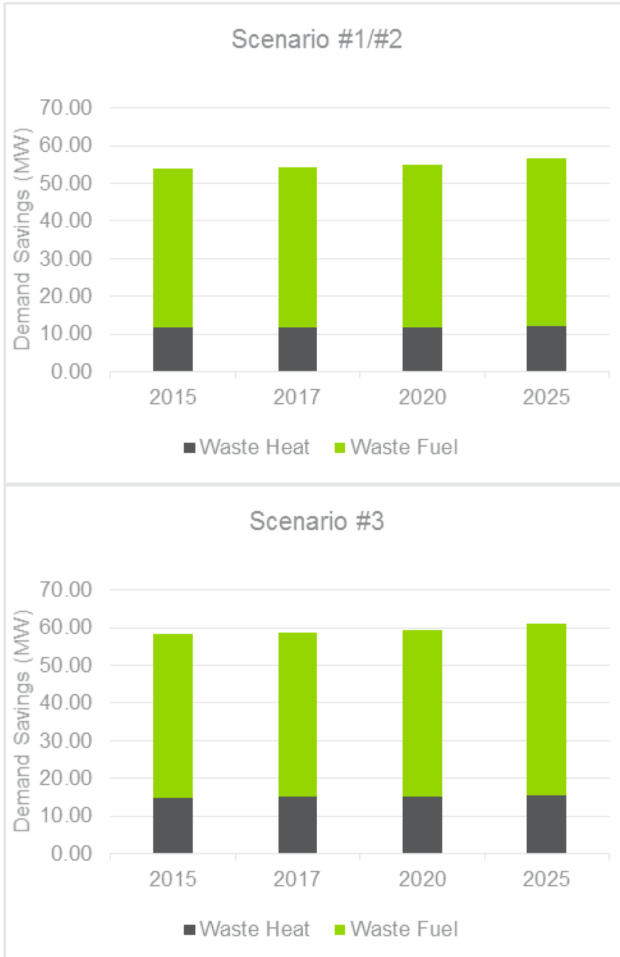
Figure 33: WER Technical Potential in Electricity Savings by Facility Type



3.3.2.2 Demand Savings

Figure 34 shows province-wide WER technical potential based on summer electric demand reductions (as defined in section 3.3 above). In 2015, WER technical-potential demand reduction (about 0.05 to 0.06 GW, depending on scenario) represent about 0.2 to 0.3 percent of the province’s demand (22.5 GW). Scenario 3, which includes a production incentive, does not significantly change technical-potential demand reductions because the production incentive primarily increases WER hours of operation, rather than increasing generation capacity during any given hour.

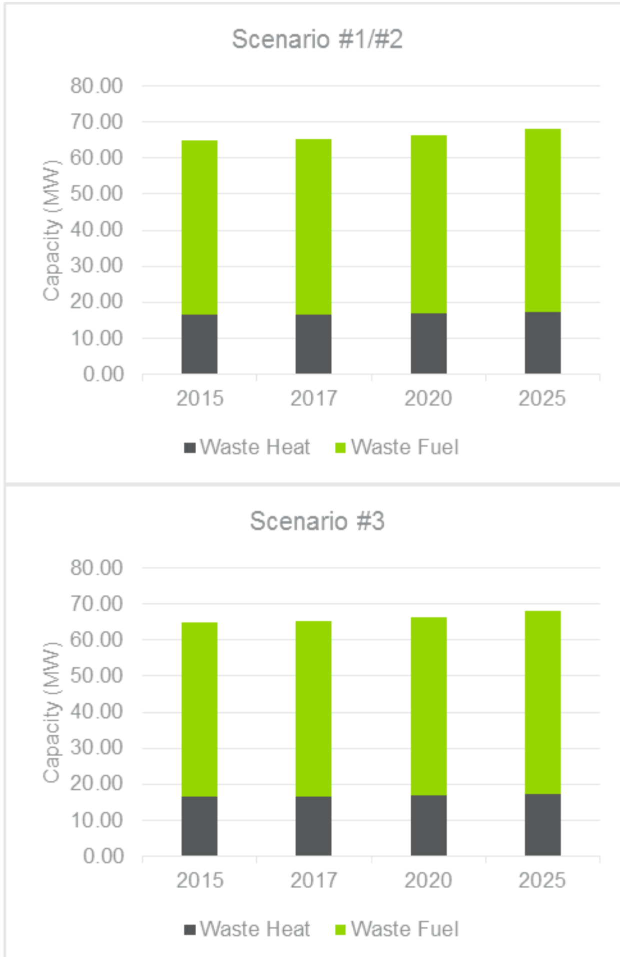
Figure 34: WER Technical Potential in Demand Savings for System



3.3.2.3 Installed Capacity

Figure 35 shows province-wide WER technical potential based on nominal installed capacity, indicating that WER technical potential increases from about 0.065 GW in 2015 to about 0.068 GW in 2025. Similar to the observations noted in section 3.3.2.2 above, the production incentive under Scenario 3 has almost no impact on the WER nominal capacity selected for a particular facility.

Figure 35: WER Technical Potential in Capacity for System



4. ECONOMIC POTENTIAL

Economic potential is the portion of technically feasible BMG that produces a net benefit from a program administrator perspective. Economic potential will be expressed in terms of capacity (MW), peak demand savings (MW), and annual energy savings (GWh).

4.1 Methodology & Approach

Economic potential is determined by completing one cost-effectiveness screen on each BMG size and facility archetype that is at or below the capacity selected for calculating technical potential. The Program Administrator Cost (PAC) test evaluates the benefits to the program administrator (i.e., the IESO). Cost-effectiveness tests calculate the relevant benefit and cost components and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the PAC test if it results in a positive net benefit or if the benefit-cost ratio is greater than 1.0.

Economic potential assessments typically include the Total Resource Cost (TRC) test which considers a societal perspective. The IESO opted not to include the TRC assessment in the economic potential stage to reflect that both LDCs and customers are not driven to install BMG projects solely from a societal perspective. Under the Energy Conservation Agreement between LDCs and the IESO, LDCs are assessed from a PAC perspective. The TRC test components are outlined below. The TRC test is calculated for informational purposes, but the metric is not used as part of the economic screen.

Table 14 outlines the relevant cost-effectiveness components (i.e., benefits and costs) used in the TRC and PAC tests. A description of each component is described below.

Table 14: TRC and PAC Cost-Effectiveness Test Components

Cost Test Component		TRC	PAC
Benefits	Avoided Electricity Cost	✓	✓
	Avoided Capacity Cost	✓	✓
	Non-Energy Benefits Adder	✓	
Costs	Incremental Equipment Costs (or participant costs)	✓	
	Incremental O&M Costs	✓	
	Program Administration Costs	✓	✓
	Incentive Costs		✓

Source: IESO

Avoided Electricity Cost
The avoided electricity cost captures the value of grid electricity offset by the implementation of the BMG project. To determine the avoided electricity cost, the annual energy savings (GWh) are determined for each size and archetype and broken down into the eight season-and-time-of-use (STOU) buckets based

on the facility load profile and hours of use. The savings by STOU are multiplied by the corresponding value of electricity in each STOU bucket according to the IESO's avoided cost table[26]. This calculation is performed for the effective useful life of the BMG project (assumed to be 20 years) and the stream of avoided electricity costs are converted to net-present-value using the IESO's assumed discount rate[27].

Avoided Capacity Cost

The avoided capacity cost captures the value of electricity system capacity (generation, distribution, and transmission) no longer required as a result of the implementation of the BMG project. To determine the avoided capacity cost, the peak demand savings (MW) are determined for each size and archetype in accordance with the IESO EM&V Protocols and Requirements[28] supported by the facility load profile and hours of use. The peak demand savings are multiplied by the corresponding annual value according to the IESO's avoided cost table. This calculation is performed for the effective useful life of the BMG project (assumed to be 20 years) and the stream of avoided capacity costs are converted to net-present-value using the IESO's assumed discount rate[29].

Non-Energy Benefits Adder

The non-energy benefits adder is required as per the October 23rd, 2014 Direction to the (former) Ontario Power Authority.[30] As per the Direction, the adder increases the TRC benefits (i.e., avoided electricity costs and avoided capacity costs) by 15 percent. It is important to note that, as per the Direction, the 15 percent adder is intended to account for the non-energy benefits such as environmental, economic, and social benefits. It is possible that some environmental benefits would be offset by an increase in emissions due to increased natural gas use, however, such an analysis was not within the scope of this study.

Incremental Equipment Costs (or Participant Costs)

The incremental equipment costs or participant costs capture the capital cost to the customer to implement the BMG project. Dissimilar to many energy efficiency projects, the participant costs capture the full capital cost of the BMG project. The participant costs also capture the cost of the Preliminary Engineering Study (PES) and Detailed Engineering Study (DES) required to move forward with a capital incentive project in the Process & Systems or Industrial Accelerator programs.

Incremental O&M Costs

Incremental operations and maintenance (O&M) costs are intended to capture the net increase or decrease in facility O&M costs as a result of implementing a BMG project. When considering a BMG project there are two main components to Incremental O&M costs: facility O&M costs and increased natural gas costs. The facility O&M costs are determined based on the methodology specified within the task 3 report. Increased natural gas costs are determined using the rate archetypes described in section 2.3. Incremental O&M costs must be considered over the effective useful life of the BMG project (assumed to be 20 years). Facility O&M costs were assumed to escalate with inflation (2 percent) and natural gas prices were assumed to escalate as per the Sproule natural gas price forecast for the Dawn

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[26] http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/CDM-EE-Cost-Effectiveness-Test-Guide-v2-20150326.pdf
[27] Ibid, 4 percent
[28] http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and-Requirements-2015-2020-Apr29-2015.pdf
[29] Ibid, 4 percent
[30] Amending March 31, 2014 Direction Regarding 2015-2020 Conservation First Framework. October 23, 2014. http://www.powerauthority.on.ca/sites/default/files/news/MC-2014-2415.pdf

hub (i.e., the same source as the 2013 LTEP, but a newer forecast vintage). The stream increased or decreased O&M costs are converted to net-present-value using the IESO's assumed discount rate[31].

Program Administration Costs
Program administration costs capture the additional costs required to support the program from an administrative perspective. These costs could include, for example, marketing materials, contract review, customer outreach, or IT support. Program administration costs for BMG projects were determined using a $/MWh rate developed by CLEAResult for application review purposes using the IESO's original budget and savings forecasts for the Process and Systems Upgrades Incentive and Industrial Accelerator programs. This value was developed on the basis of the original program forecast (energy savings and budget) and is intended to capture both fixed and variable (or per project) program costs. The value was confirmed by IESO as a reasonable and accurate value.

Incentive Costs
Incentive costs capture the monetary or in-kind compensation provided directly to customers to encourage the installation of a BMG project. Incentives include the costs of the PES and DES which are covered by the IESO for the Process and Systems Upgrades Program up to $10,000 and $50,000, respectively, and for the Industrial Accelerator program $20,000 and up, and the capital incentive provided to customers. As per direction from the IESO, three incentive scenarios were calculated for the purposes of this study: (1) 40 percent of capital costs; (2) 70 percent of capital costs; and, (3) $0.02/kWh production incentive.

Other Assumptions
There are several other assumptions required to calculate the components of the cost-effectiveness tests in alignment with the IESO Cost Effectiveness Guide[32]. For example, all electricity and peak demand savings are increased by a provincial average distribution and/or transmission system losses according to the connection point of the BMG project.

4.2 Benefit-Cost Results

Figure 36 and Table 15 show the benefit-cost results for selected representative customers.

[31] Ibid, 4 percent
[32] Independent Electricity System Operator; *Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide*; March 2015; http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/CDM-EE-Cost-Effectiveness-Test-Guide-v2-20150326.pdf

Figure 36: Benefit-Cost Streams for Selected Customer Archetypes

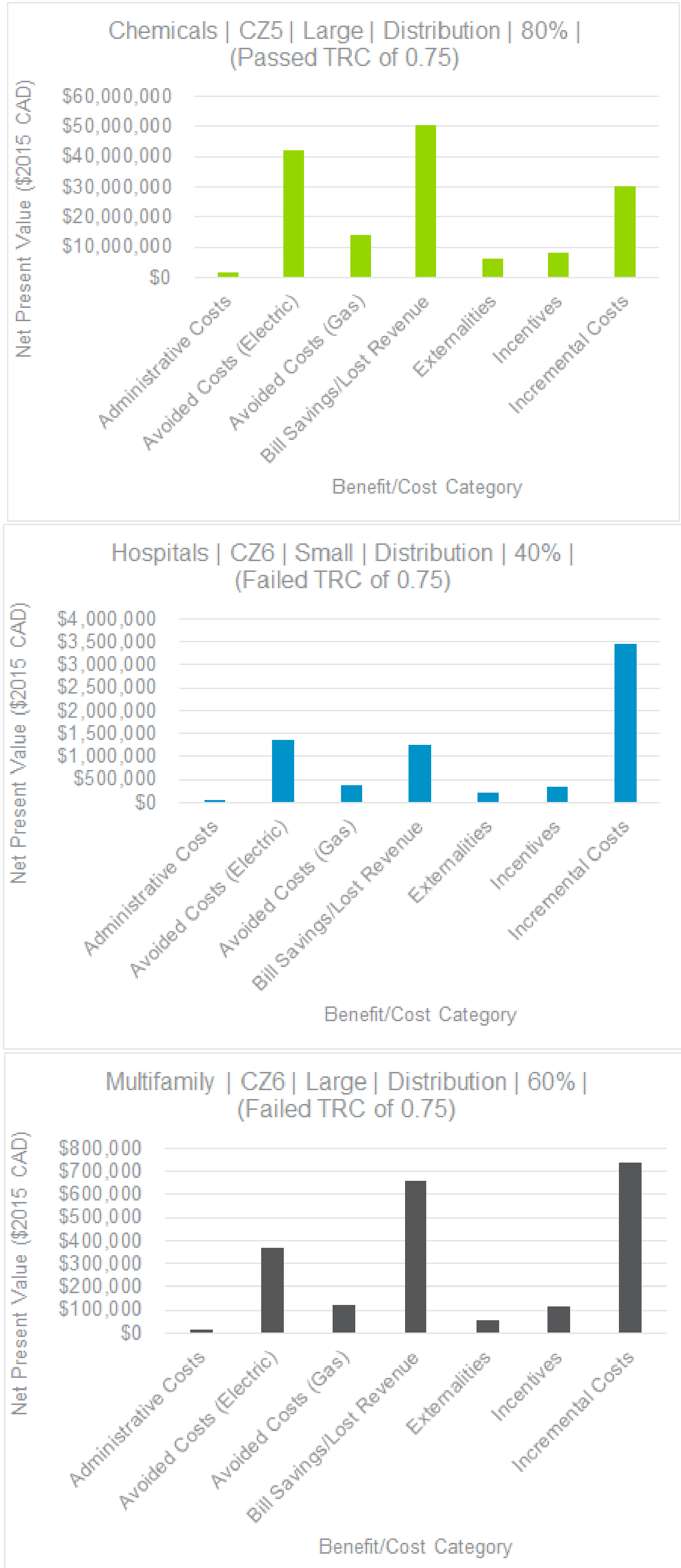


Table 15: Benefit-Cost Test Results for Selected Customer Archetypes

Representative Customer	Chemicals	Hospital	Multifamily
Capacity (MW)	7.1	0.52	0.17
TRC	1.06	0.51	0.44
PAC	4.34	3.18	2.86
PC	1.92	0.80	0.89

4.3 Results—Economic Potential

This section communicates the results of the economic potential analysis. As discussed in section 3 above, different facility sizes are considered for each archetype. Economic potential results are selected based on the largest BMG capacity (in megawatts) that passes the PAC screen. Due to the modified load-following operational strategy for CHP, which does not depend on price signals, results do not differ among the three scenarios. Incentives impact the PAC cost-effectiveness test, but PAC ratios are highly in favour of CHP (as utilities do not incur the high capital cost of CHP). As a result***, all facility types modelled pass the PAC test***.

Because the economic potential screens only based on PAC, and all facility types modelled pass the PAC test, CHP economic potentials match technical potentials.

Appendix A includes detailed results by LDC.

4.3.1 CHP

In addition to reporting economic potential results based on a PAC screen only, for informational purposes, we report CHP economic potential results using minimum TRC of 0.75.

4.3.1.1 Energy Savings

Figure 37 shows the province-wide CHP economic potential based on electricity savings. Removing the 0.75 TRC screen approximately doubles economic potentials.

Figure 37: CHP Economic Potential in Electricity Savings for System

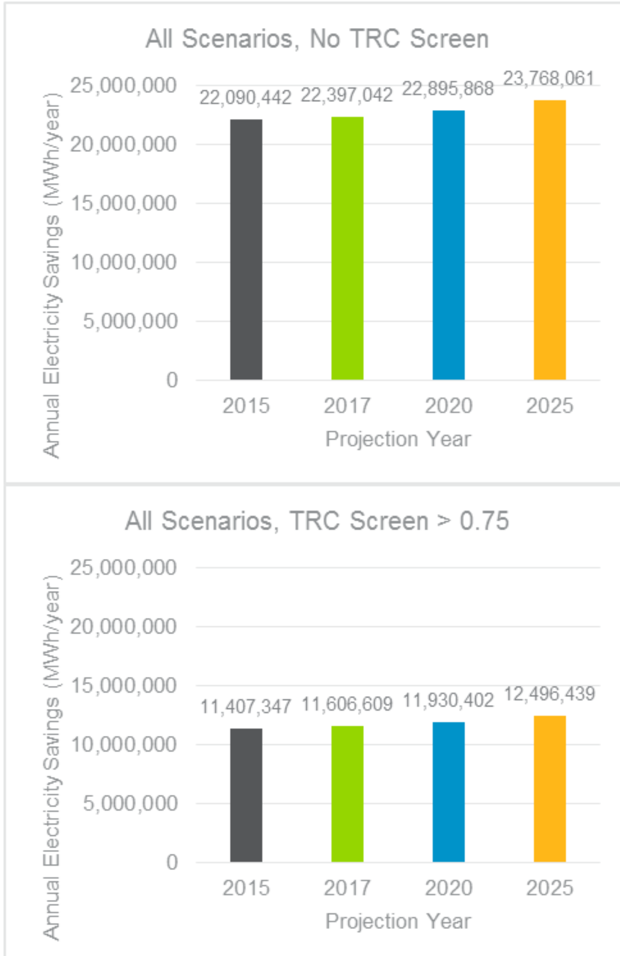


Figure 38 and Figure 39 show the distribution by major facility type for province-wide CHP economic potential. The figures show that removing the 0.75 TRC screen has a modest impact on economic potential for most industrial facilities, but substantially increases economic potential for multi-family and commercial//institutional facilities.

Figure 38: CHP Economic Potential in Electricity Savings by Facility, No TRC Screen

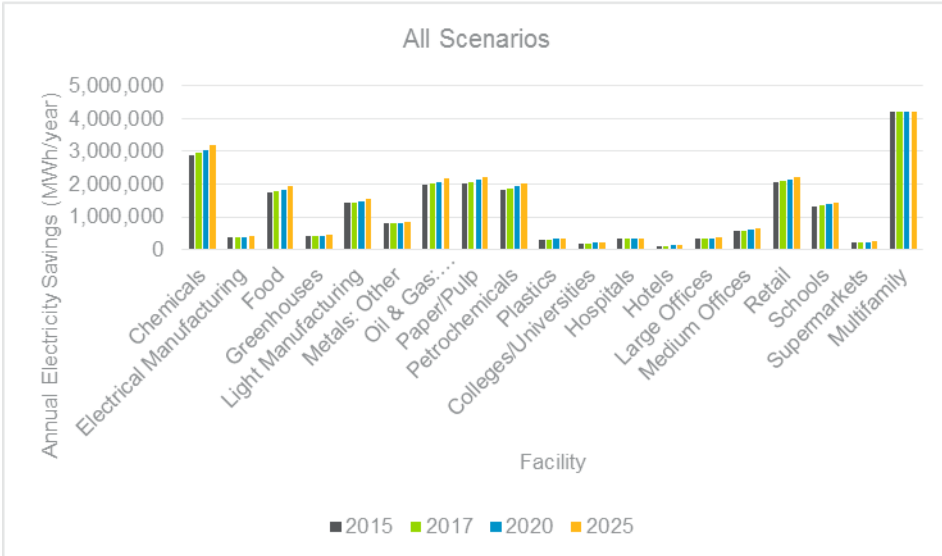


Figure 39: CHP Economic Potential in Electricity Savings by Facility, > 0.75 TRC Screen

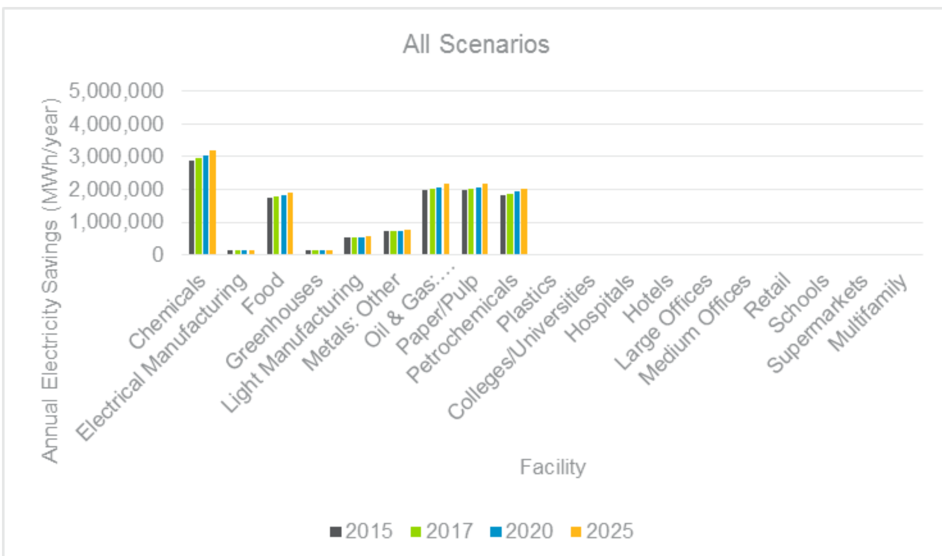
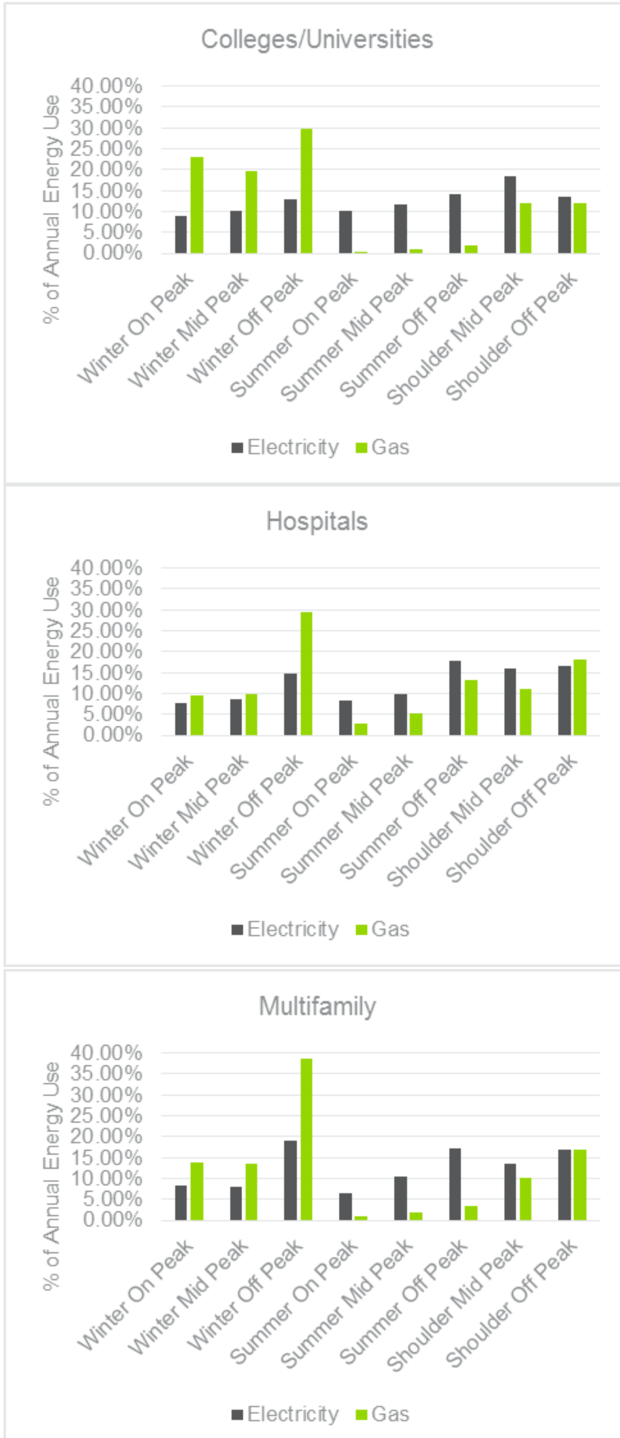


Figure 40 shows selected comparisons of the relative seasonal distributions of facility electric and thermal loads for several multi-family/commercial/institutional facility types. For these facility types, thermal loads tend to drop off in summer months, which can limit the hours that the CHP system can operate, despite the allowance in the operational strategy for limited thermal dumping. Figure 41 shows selected comparisons of the relative seasonal distributions of facility electric and thermal loads for two industrial facility types. In these industrial examples, while thermal loads vary somewhat throughout the year, they remain well aligned with the distribution of electrical loads, allowing the CHP system to operate more consistently throughout the year compared to the multi-family/commercial/industrial facility types.

Figure 40: Selected Commercial Load Profiles by Peak Status



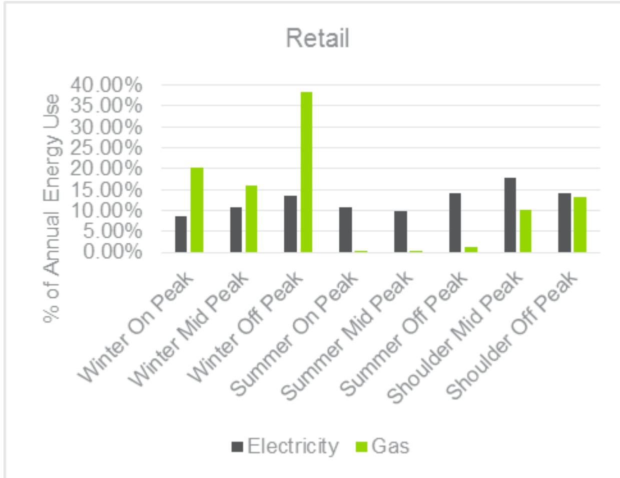
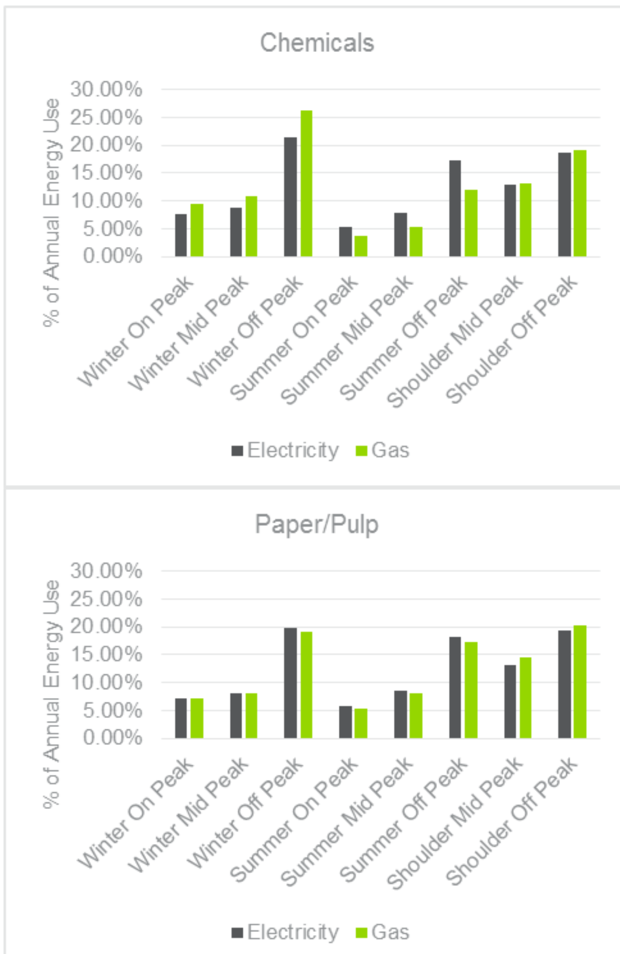


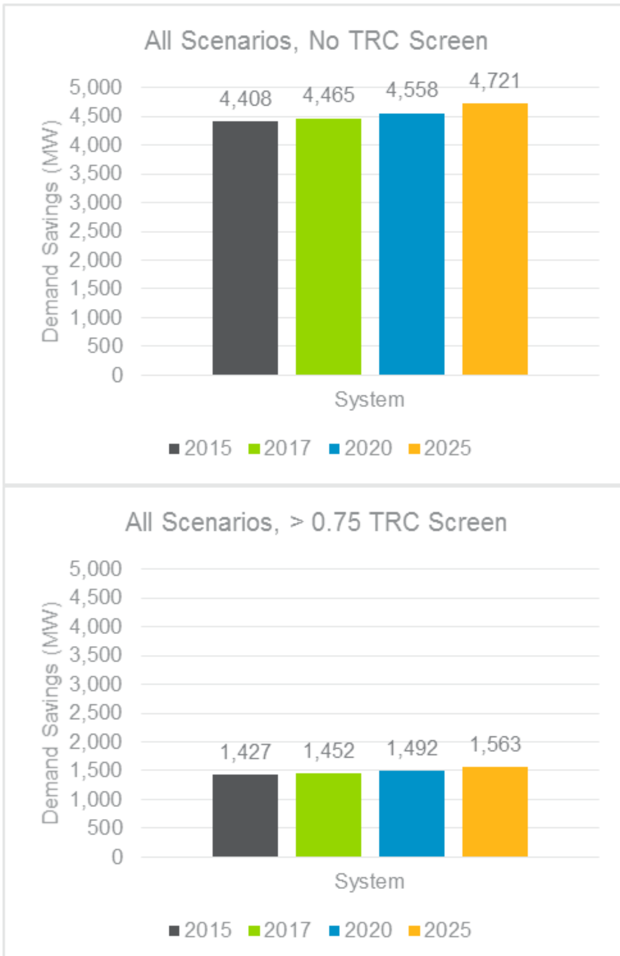
Figure 41: Select Industrial Load Profiles by Peak Status



4.3.1.2 Demand Savings

Figure 42 shows the province-wide CHP economic potential based on summer electric demand reduction. Removing the 0.75 TRC screen increased economic potential demand savings by about a factor of three.

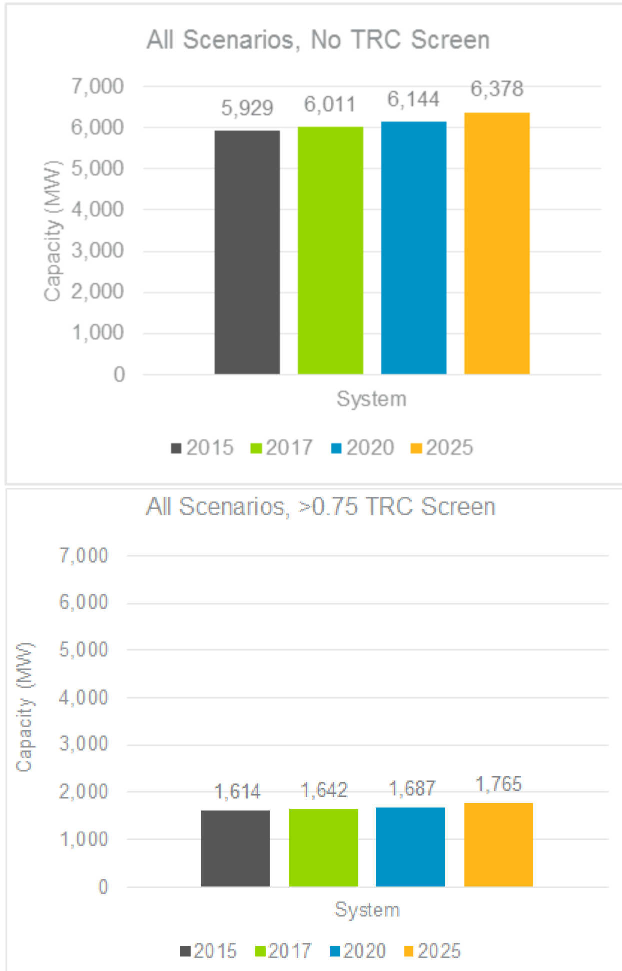
Figure 42: CHP Economic Potential in Demand Savings for System



4.3.1.3 Capacity

Figure 43 shows the province-wide CHP economic potential based on nominal installed capacity. Removing the 0.75 TRC screen increases CHP economic potential capacity by almost a factor of four.

Figure 43: CHP Economic Potential in Capacity for System



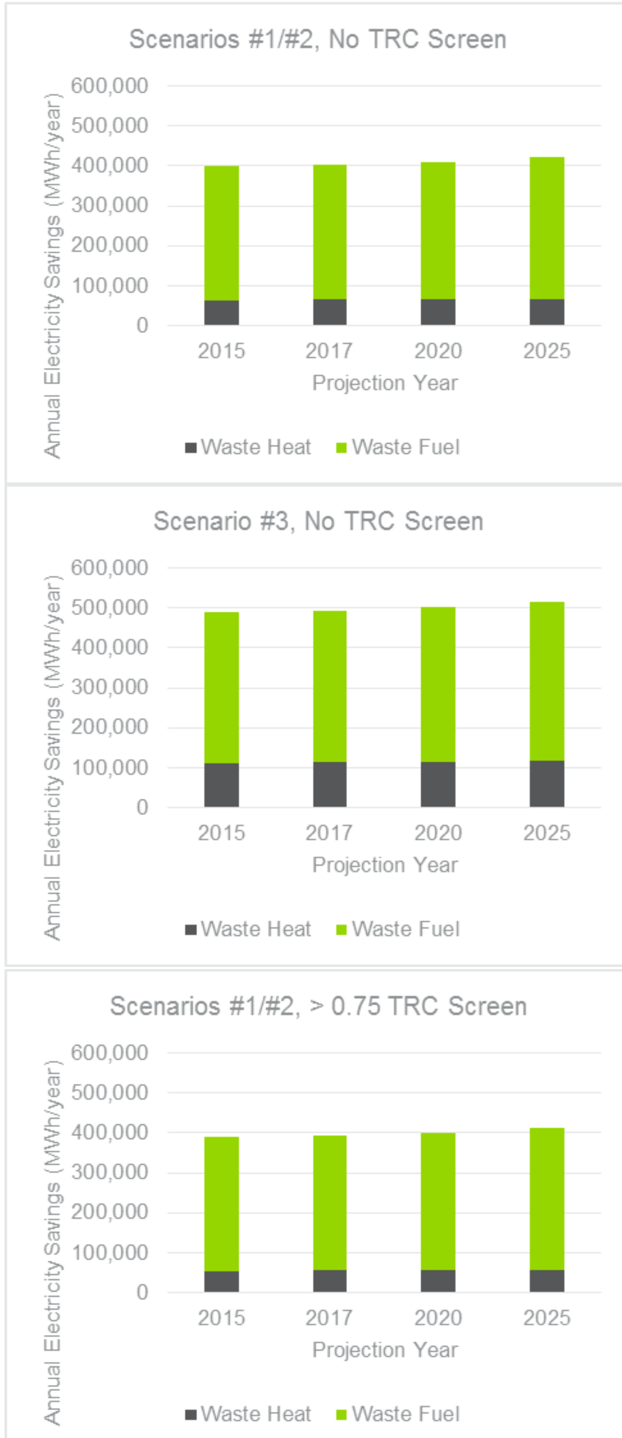
4.3.2 WER

For WER economic potential, results for incentive scenarios #1 and #2 differ from those for scenario #3 due to the hourly cost minimization employed in the WER operational strategy.

4.3.2.1 Energy Savings

Figure 44 shows the province-wide WER economic potential based on electricity savings. As discussed above, the economic potential matches the technical potential when no TRC screen is used.

Figure 44: WER Economic Potential in Electricity Savings for System



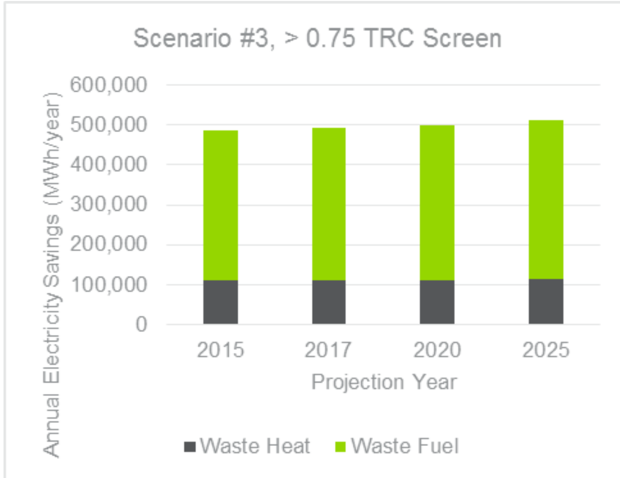
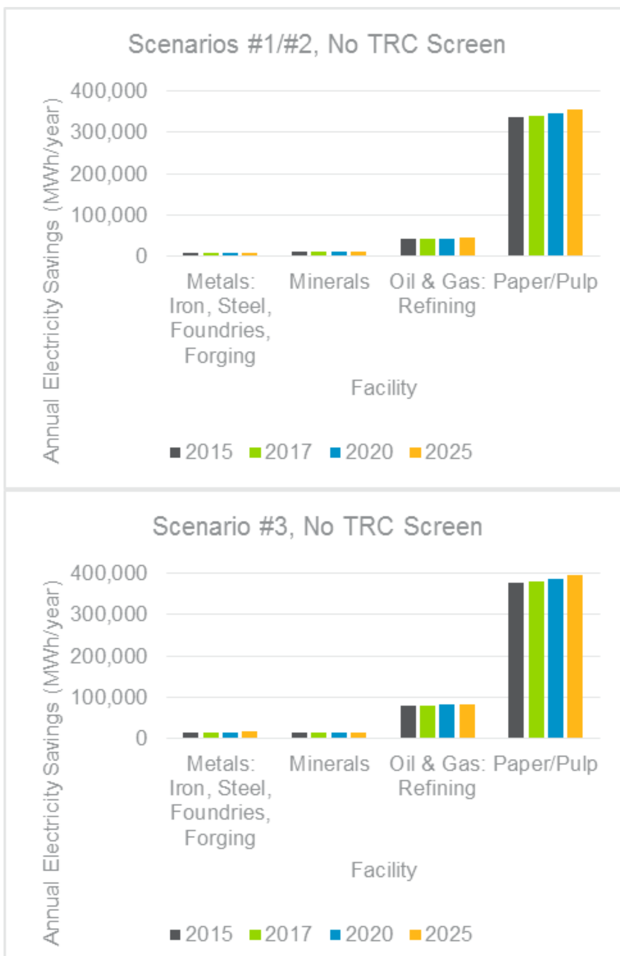


Figure 45 shows the distribution by facility type of WER economic potential based on electricity savings.

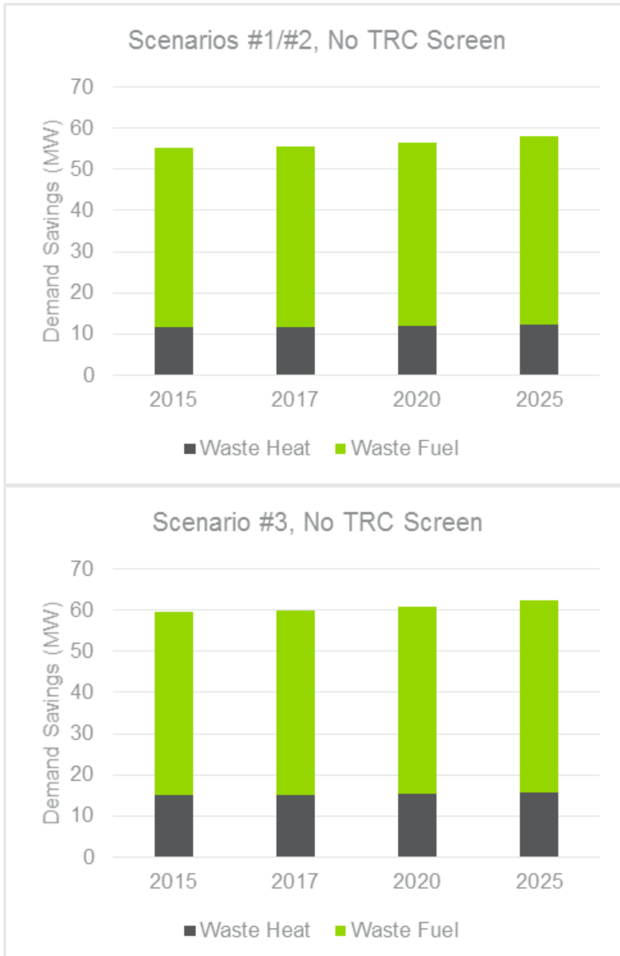
Figure 45: WER Economic Potential in Electricity Savings by Facility Type



4.3.2.2 Demand Savings

Figure 46 shows the province-wide WER economic potential based on summer electric demand reductions.

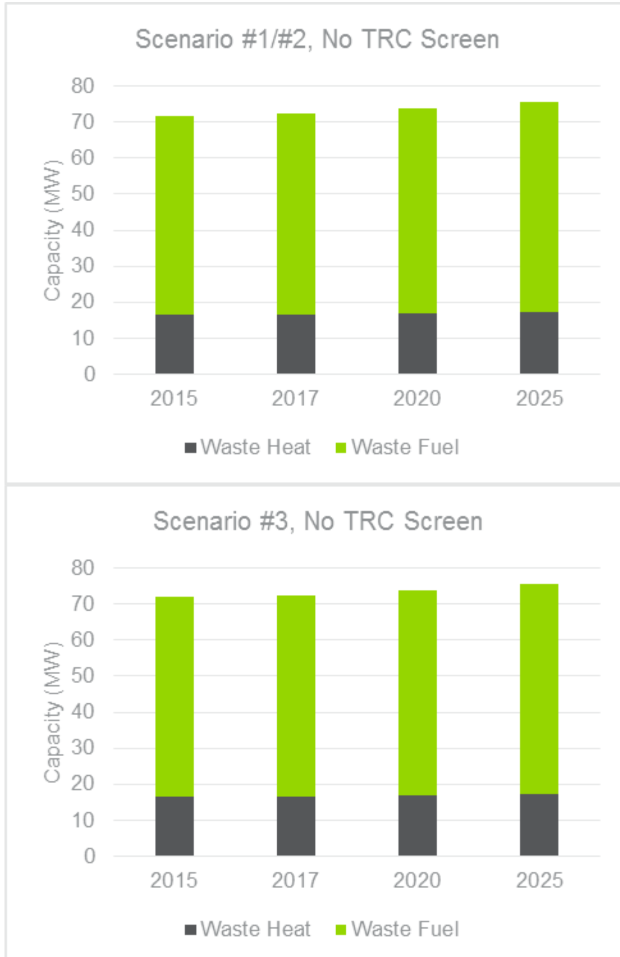
Figure 46: WER Economic Potential in Demand Savings for System



4.3.2.3 Capacity

Figure 47 shows province-wide WER economic potential based on nominal installed capacity.

Figure 47: WER Economic Potential in Capacity for System



5. MARKET POTENTIAL

Market potential represents the portion of economic potential that is likely to be achieved over time. Market potential is expressed in terms of capacity (MW), peak demand savings (MW), and annual energy savings (GWh). Both the technical and economic potential do not include a time component beyond adjustment for population changes (i.e., potential is calculated as if it is realized immediately). In contrast, market potential considers the time required to raise awareness, generate market interest, conduct engineering analyses, and design, develop, and install BMG systems.

5.1 Methodology and Approach

Market potential is determined using three key steps and concepts that are described in more detail below:

1. Participant cost screen and optimal sizing
2. Financial and non-financial potential
3. Market diffusion.

5.1.1 Participant Cost Test Screen and Optimal Sizing

As discussed above, the BMG tool was used to analyze several BMG sizing options for each facility type, and the economic potential stage screened all projects from a PAC perspective and the largest BMG that passed was selected. The first step of the market potential considers all BMG sizes for a given facility that pass the PAC. These projects are run through a cost-effectiveness test that captures the customer perspective. The participant cost screen uses the Participant Cost (PC) test to evaluate the project from the customer's perspective (see Table 16). The PC test calculates the benefit and cost components, and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the participant cost test if a positive net benefit results or if the ratio is greater than 1.0. A description of the component not already described in section 4.1 follows.

Table 16: PC Cost-Effectiveness Test Components

Cost Test Component		PC
Benefits	Bill Savings	✓
	Incentive Costs	✓
Costs	Incremental Equipment Costs (or participant costs)	✓
	Incremental O&M Costs	✓

Bill Savings

The bill savings component is intended to capture how much the customer saves on their electricity bill as a result of implementing a BMG project. To determine the value of this component, all components of the electricity bill are simulated for the customer prior to implementing the BMG project and after implementing the BMG project. The difference determines the value for this component. Bill savings must be considered over the effective useful life of the BMG project (assumed to be 20 years). To determine the bill savings over time, an index was developed to capture the increase rates over the life of the project. IESO's 2013 Long Term Energy Plan (LTEP) Hourly Ontario Energy Price (HOEP) and Global Adjustment (GA) forecasts for class A and class B customers were used. The stream of bill savings are converted to net-present-value using the IESO's assumed discount rate[33].

The optimal sizing option for each facility type that passed the PC test continued to the next step in the market potential analysis.

5.1.2 Payback Acceptance

Payback acceptance curves define the relationship between the simple payback of a project and the percentage of the market that will proceed with a project. Both financial and non-financial factors impact a customer's decision whether or not to move forward with a project, and different sectors generally have different payback thresholds. Navigant segmented the analysis of payback acceptance into two types: financial and non-financial.

Financial Potential

The financial payback acceptance curves were developed leveraging an in-depth analysis conducted by Navigant for an energy-efficiency potential study. The study assessed telephone interviews with 400 commercial customers and 150 industrial customers. The survey inquired about the company's payback requirements or guidelines for the purchase of energy-efficient technologies. If a direct response was not provided, a series of questions were asked to deduce the payback range. The resulting data was used to develop a parametric estimation of payback functions. Navigant specified and estimated a functional form for the payback period that includes both payback time and other variables expected to affect payback times, and tested whether these other variables had statistically significant effects on payback. After a review of histograms of the payback times reported in the survey data, a normal-distributed specification was developed for the commercial and industrial versions of the curves.

Non-Financial Potential

The non-financial payback acceptance curves were developed using both quantitative and qualitative analyses, described in more detail below. In addition to accounting for financial factors, the non-financial payback acceptance curves account for factors such as environmental permitting, technical constraints, site-specific concerns, and customer security/reliability.

The quantitative analysis leveraged the United States Department of Energy (US DOE) Industrial Assessment Centers (IAC) database. IAC provides no-cost energy assessments to small- and medium-sized US manufacturers with recommended actions to reduce electricity use, fuel consumption, and waste. The IAC program has conducted over 17,282 assessments using a consistent, documented methodology resulting in more than 131,031 associated recommendations. The database includes publicly available information on assessments including facility details (e.g., North American Industry Classification System or NAICS code, size, energy use, etc.) and recommendation details (e.g., type of recommendation, payback, energy and dollars saved, implemented or not, etc.). Cogeneration recommendations and electricity only energy efficiency (EE) projects were pulled from the database, including the payback period and whether or not the recommendation was enacted. Two regression

[33] Ibid, 4 percent

analyses were conducted on the data. The first regression analysis resulted in a simplified payback acceptance curve for cogeneration projects and the second regression analysis resulted in a simplified payback acceptance curve for energy efficiency (electricity only) projects. The goal of this analysis was to determine to what extent non-financial factors influence the decision whether or not to proceed with a BMG project. Purely financial factors influence any project whether it is an EE project, a BMG project, or any other project. BMG project decisions, however, are also influenced by several non-financial factors that tend to have less impact on EE projects. Therefore, we deduced that the difference between the EE curve and the BMG curve represents reasonably well the non-financial factors attributable to BMG projects.

The qualitative analysis leveraged interviews conducted with eight LDC staff working directly with customers and five customers that initiated BMG applications, but abandoned their applications. Based on the interviews, customers are driven by the key benefits outlined in Table 17. During the interviews, customers highlighted that they rarely implement a BMG project for purely financial reasons. There is typically another reason that drives initial interest and in turn leads to the investigation of BMG.

Table 17: Benefits of BMG Implementation

Benefit	Description
Cost reduction	A key benefit of BMG is reducing electricity costs by generating onsite. There is also an opportunity for larger customers (>3MW) to reduce their global adjustment cost by reducing their demand.
Reliability/resilience	Customers cited the loss of electricity to be a significant cost to their business and the need for back-up power to be particularly important to them.
Predictability	Electricity bills can vary substantially on a month to month basis. By using more natural gas rather than electricity, there are additional opportunities to hedge the cost, and the bills are more consistent.
Expansion Costs	When businesses expand, in some cases an additional connection is required or the utility requires the customer to incur additional costs to serve the increase in load. Installing BMG can reduce these costs.
GHG reductions	Organizational policies to lower climate impacts can motivate customers to install BMG.[34]

Based on the interviews, customers are influenced by the key barriers outlined in Table 18. These barriers do not necessarily prevent project implementation, however, they can slow the implementation process. The customers interviewed that did not continue with their BMG application primarily noted technical constraints and financial constraints as the key reason(s) not to move forward.

[34] Some interviewees also cited this as a barrier because BMG can sometimes increase GHG emissions.

Table 18: Barriers to BMG Implementation

Barrier	Description
Policy uncertainty	LDCs noticed a slow-down in application progress and program interest following the announcement of the Ontario cap and trade program.[35] In addition, LDCs expressed uncertainty related to standby rates and the treatment of GA charges.
Technical constraints	Some customers interviewed either did not have the thermal load to support a BMG project or encountered system constraints such as fault current, short circuit, and other equipment issues.
Internal constraints	Customers that are part of a company with multiple facilities face internal competition for capital and are often subject to capital spending cycles.
Gas connection	Some BMG technologies require a minimum natural-gas pressure. Natural-gas supplies in some locations are below this pressure requirement, which would necessitate an auxiliary gas compressor.
Environmental permitting	Customers must undergo an environmental permitting process prior to their in-service date. The timelines for environmental permitting are highly variable and one project experienced a 12 month process.
Paperwork/process	Though not a major barrier to implementation given the size of incentive, customers expressed frustration with the paperwork required. In some cases the contract required legal review and some customers expressed concern with allowing auditors in their facility at any time (for M&V and EM&V purposes).
Exchange rate	The recently unfavourable Canadian-dollar exchange rate has made some equipment more expensive and some customers are intending to wait until conditions improve.
Community impact	Some facilities are in more residential areas, and customers considered both the potential community impacts and community reaction to the BMG project.

The key findings from the interviews are:

- Financial payback is a critical metric impacting a customer's decision
- Reliability of supply and predictability of costs are secondary factors, but also important in the decision whether or not to implement
- Uncertainty in rates and policy are major barriers (cap and trade in particular).

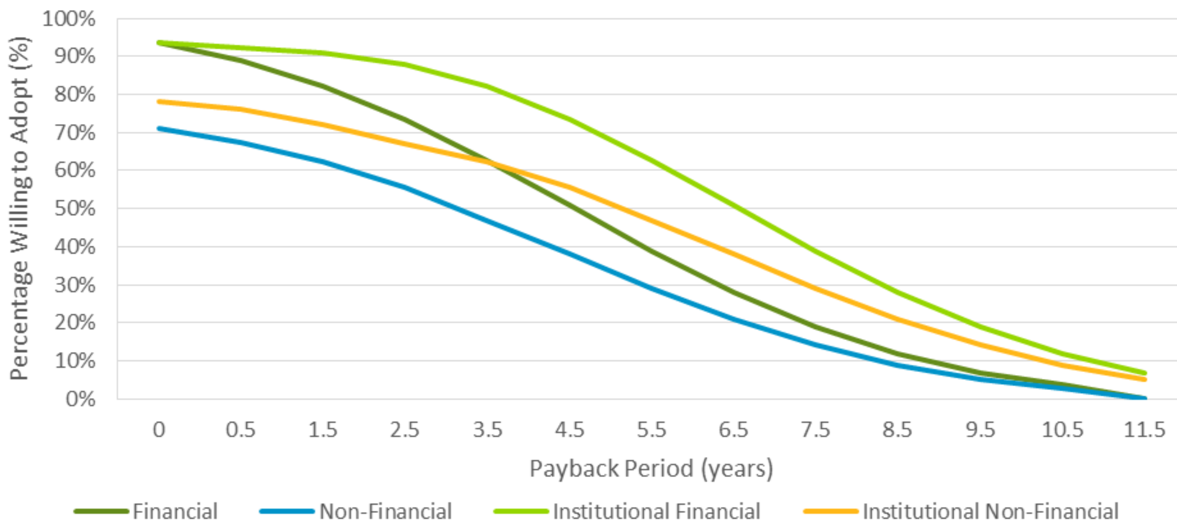
The interviews also identified special circumstances impacting the Multi Unit Residential Building (MURB) sector. Recently, additional environmental regulations and code changes were enacted preventing MURBs from storing diesel onsite for back-up generation purposes. MURBs are investigating BMG as an

[35] Interviews were conducted when the Climate Mitigation and Low-Carbon Economy Act was pending.

alternative to comply with regulations while realizing additional benefits. The non-financial payback curves were adjusted to reflect the qualitative findings noted above.

The resulting financial and non-financial payback acceptance curves are illustrated in Figure 48. Some types of industrial facilities will accept longer payback periods than some types of commercial facilities, and vice versa, making it difficult to differentiate payback acceptance based on sector. For example, within the industrial sector a lower payback is required for a pulp and paper facility which may have less confidence in its longevity, but a chemical facility would be willing to accept a slightly longer payback to realize the benefits. Therefore, we use a common payback acceptance curve for both the commercial and industrial sectors. However, decision-making considerations vary for institutional facilities which include hospitals, universities and schools as compared to other facility types. The curves reflect the fact that institutional facilities generally accept longer payback periods compared to most other facilities. A primary contributing factor is that institutional facilities generally have higher certainty that operations will continue for the foreseeable future.

Figure 48: Payback Acceptance Curves



Navigant used the payback period for the optimal sizing by facility type that passed the initial PC screen to determine the percentage of projects that would be willing to adopt from a financial and then non-financial perspective.

5.1.3 Market Diffusion

Market Diffusion characterizes the pace of project implementation taking into account factors such as marketing and outreach efficacy, project lead times, and equipment cost reductions over time. Navigant used a Bass Diffusion model to represent the implementation of market potential over time. The model considers the influence from early adopters (innovators) and late adopters (imitators), which explains how uptake occurs at the onset of a new product, idea, or process. Coefficients were developed to reflect the level of innovation (impacted by marketing, sales, and outreach) and imitation (impacted by word-of-mouth, social connections, and associations) based on the interviews discussion in the prior section.

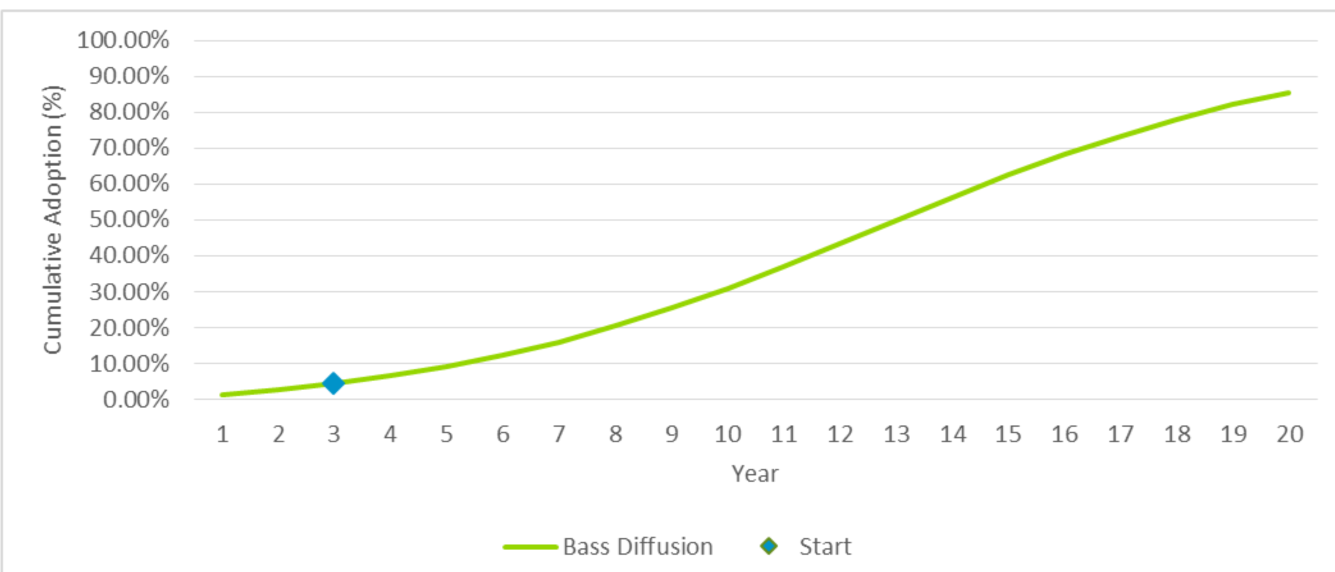
The interviews conducted provided insight into the pace of adoption, barriers that impact one sector over another, and enablers that can speed up the pace of adoption. Key influencers are:

- Industrial customers tend to have more knowledge of BMG and what the business case is, some industrial customers are actively seeking BMG incentives and opportunities. One customer revisits the financial payback of a BMG facility every 2 years.
- The market (consultants and LDCs) are actively contacting MURB customers with incentive options (PSUI) and offering build/own/operate services.
- The sales cycle (from first contact to project in-service) is highly variable and dependent on the sector:
    - Average ranges from 12 to 18 months for small and from 1 to 2.5 years for larger facilities
    - One environmental assessment was reported to take 1 year, with an average of around 6 months
    - Consultants targeting MURBs state 6 months to in-service (to be tested)
- Environmental permitting can be a time consuming step, taking up to 12 months
- All sectors can be influenced by capital spending cycles.

The Bass Diffusion model also requires an initial saturation assumption and a final market saturation assumption. The IESO programs offering BMG incentives have been in-market since 2012. To capture this market timing, year 3 of the Bass Diffusion Curve represents 2015. The final market saturation is assumed to be approximately 85 percent over 20 years. This indicates that 15 percent of the market potential will not be realized within 20 years.

The final curve (see Figure 49) was developed based on the information and methodologies discussed above. Navigant assumed that year three of this diffusion curve was representative of adoption in 2015.

Figure 49: BMG Bass Diffusion Curve



The total financial and non-financial potential determined from the payback acceptance step was modelled using the BMG Bass Diffusion curve to determine the demand savings (MW) and electricity savings (GWh) from 2015 to 2025.

5.1.4 Emissions

Navigant assessed the avoided CO_2 emissions associated with the BMG potential. The IESO provided a representative hourly profile of the CO_2 emissions associated with grid-supplied electricity use.[36] The CO_2 emissions associated with natural gas use is 53.18 kg CO_2/MMBtu.[37] For each facility, the electricity and natural gas use were modelled prior to the installation of BMG and after the installation of BMG.

5.2 Results—Market Potential

The sections below summarize the results of the BMG market potential analysis. Appendix A includes detailed results by LDC. Appendix B provides simple payback periods associated with the market potential analysis.

5.2.1 CHP

5.2.1.1 Energy Savings

Figure 50 shows the province-wide CHP market potential based on electricity savings. The two charts in the figure, labeled “Financial Payback Curve” and “Non-Financial Payback Curve”, represent the market potential considering only financial factors and the overall market potential, respectively. The province-wide CHP market potential increases from about 60 to 130 GWh in 2015 (depending on scenario) to about 700 to 1,400 GWh in 2025. The 2025 projections represent about 3 to 6 percent of the 2025 CHP technical potential (depending on scenario).

[36] The emissions profile was based on the assumed 2017 generation mix.
[37] From EIA: https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

Figure 50: CHP Market Potential in Electricity Savings for System

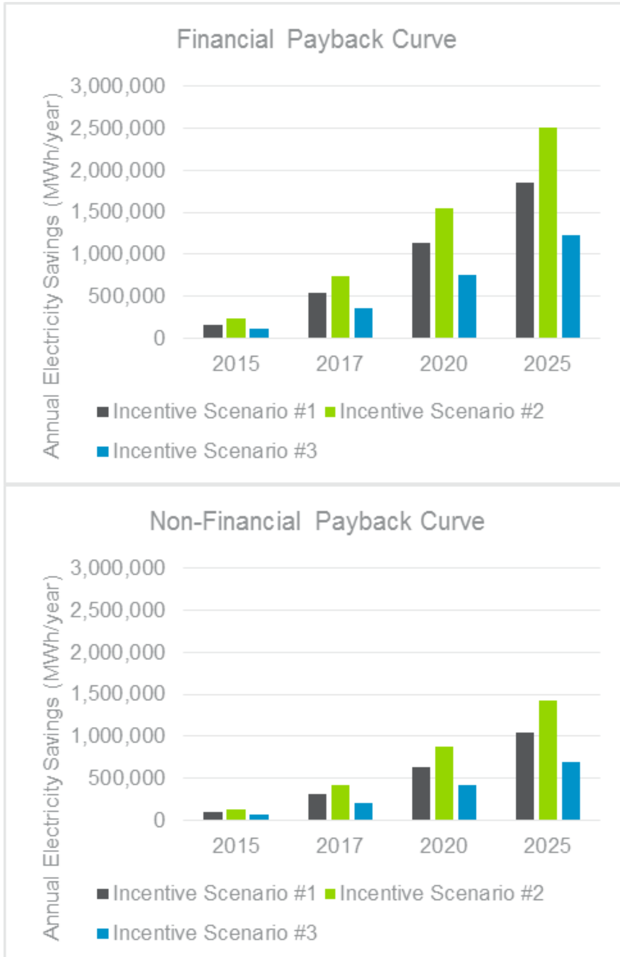
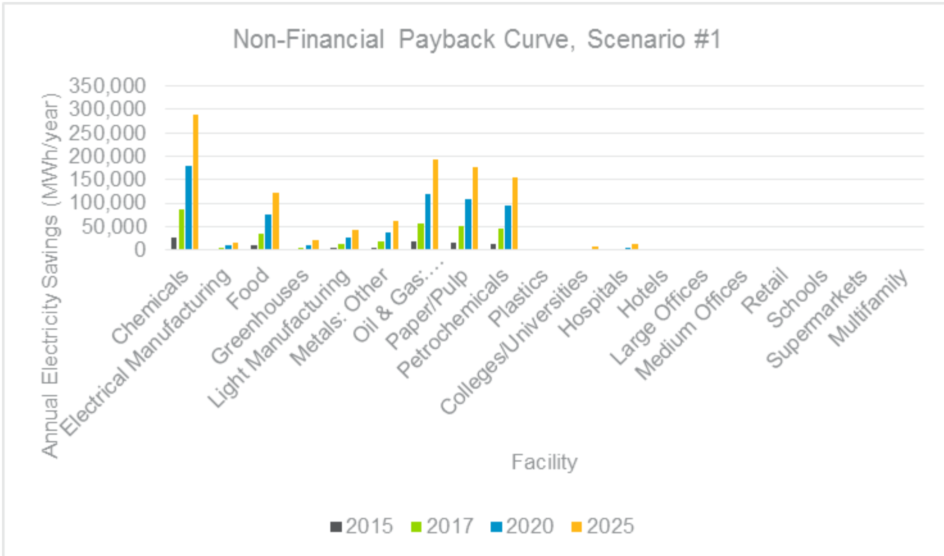


Figure 51 shows the distribution by major facility type of province-wide CHP market potential based on electricity savings. Large industrial facilities dominate the CHP market potential.

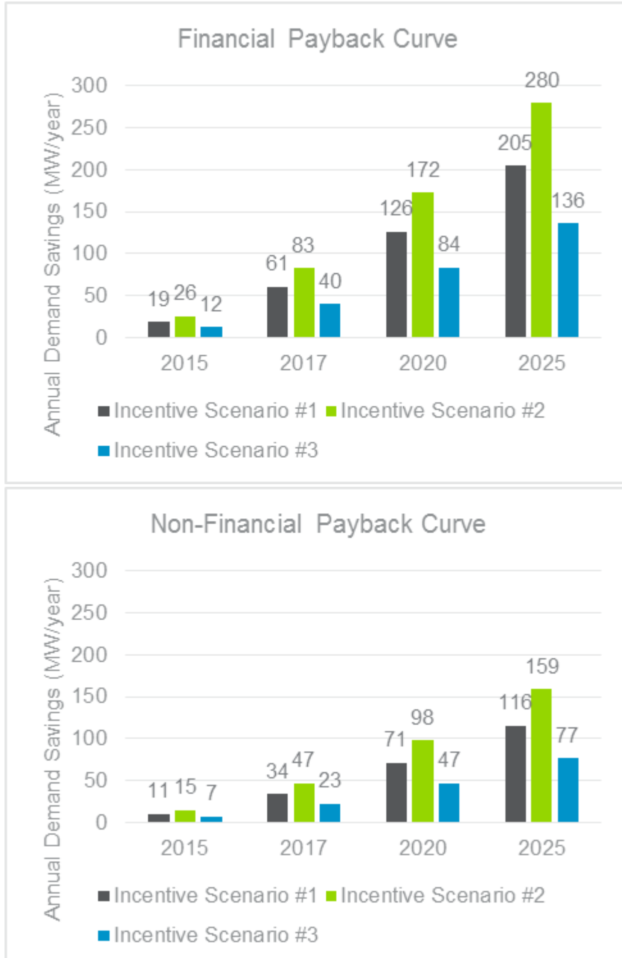
Figure 51: CHP Market Potential in Electricity Savings by Facility Type



5.2.1.2 Demand Savings

Figure 52 shows the province-wide CHP market potential based on summer electric demand reduction Again, the figure shows separate charts for market potential based only on financial factors (Financial Payback Curve). And the overall market potential (Non-Financial Payback Curve). The province-wide CHP market potential increases from about 7 to 15 MW in 2015 (depending on scenario) to about 77 to 159 MW in 2025 using a non-financial payback curve. The 2025 market potential represents about 2 to 3 percent of the 2025 CHP technical potential based on demand reductions.

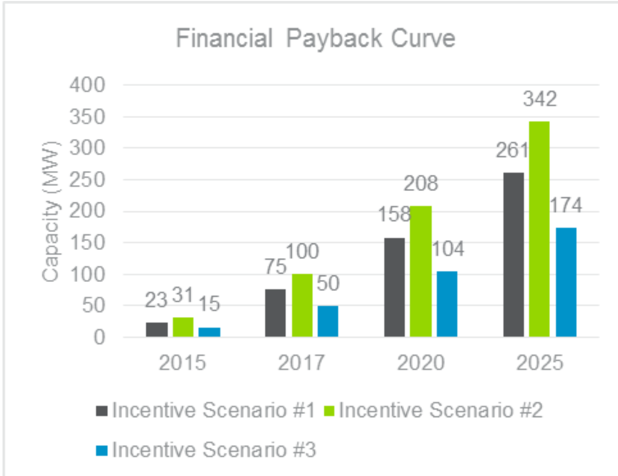
Figure 52: CHP Market Potential in Demand Savings for System

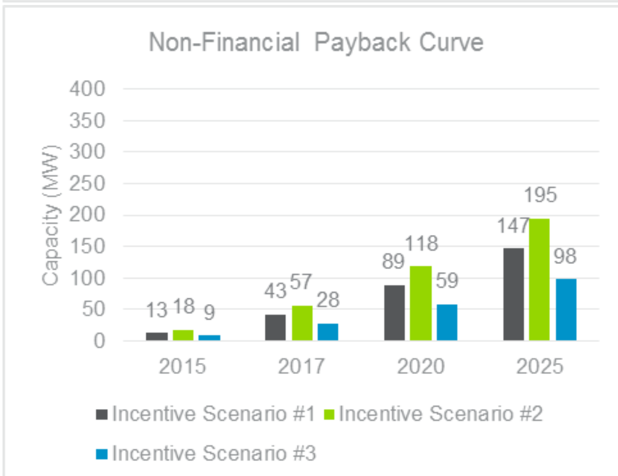


5.2.1.3 Capacity

Figure 53 shows the province-wide CHP market potential based on nominal installed capacity (both financial-only and overall market potentials). The province-wide CHP market potential increases from about 9 to 13 MW in 2015 (depending on scenario) to about 98 to 195 MW in 2025 using a non-financial payback curve. The 2025 market potential represents about 2 to 3 percent of the 2025 CHP technical potential based on installed capacity.

Figure 53: CHP Market Potential in Capacity for System





Based on information that the IESO provided, 83.9 MW of CHP capacity is expected to come online during or after 2015 through the PSUI and IAP programs. This is substantially higher than our 2015 market potential estimate (9 MW, under current program rules).

5.2.2 WER

5.2.2.1 Energy Savings

Figure 54 shows province-wide WER market potential based on electricity savings (both financial-only and overall market potentials). The province-wide WER market potential increases from about 1.9 to 2.4 GWh in 2015 (depending on scenario) to about 20 to 26 GWh in 2025 using non-financial payback curves. The 2025 market potential represents about 4 to 5 percent (depending on scenario) of the 2025 WER technical potential based on electricity savings.

Figure 54: WER Market Potential in Electricity Savings for System

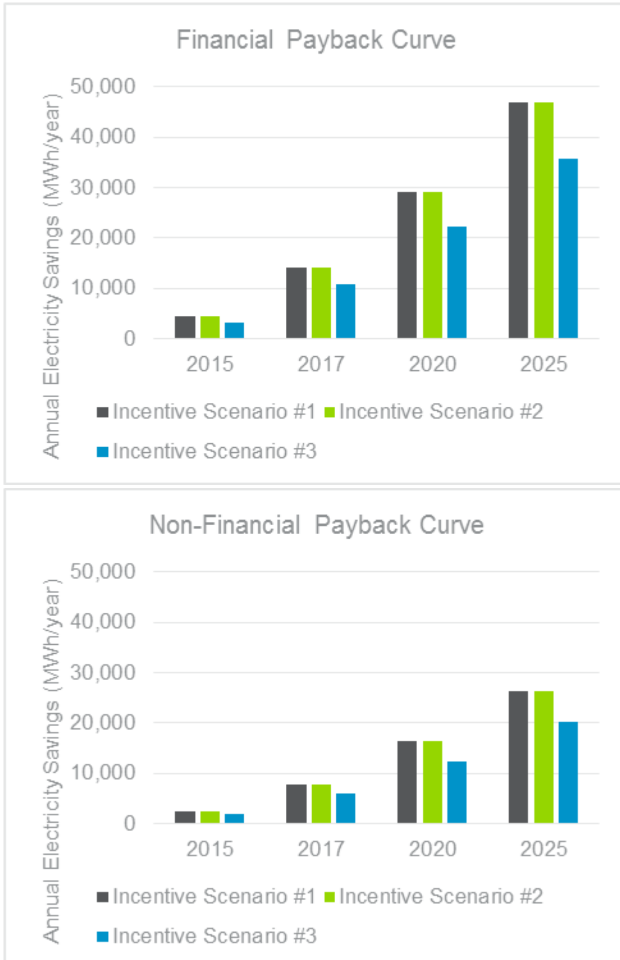
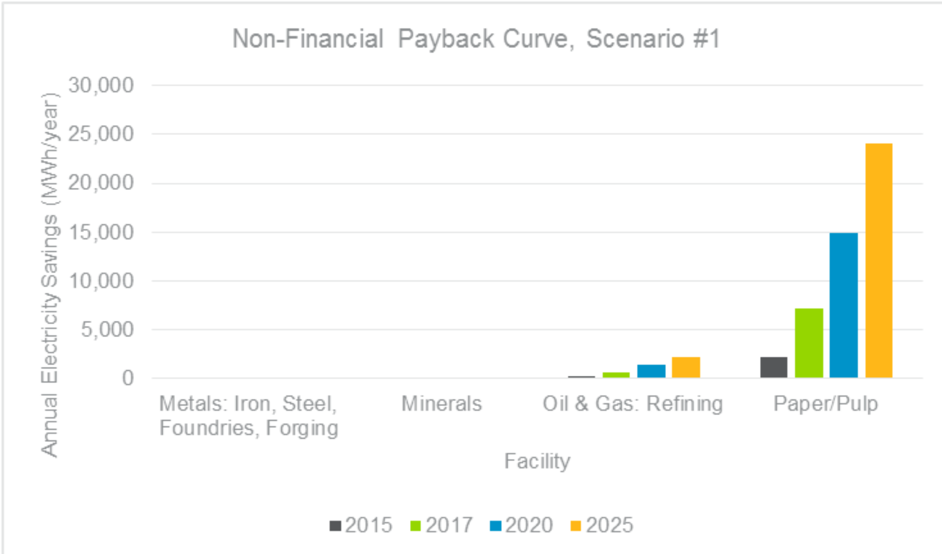


Figure 55 shows the distribution by major facility type of the province-wide WER market potential based on electricity savings (scenario 1 only). Paper/pulp dominates the WER market potential (over 90 percent of the market potential).

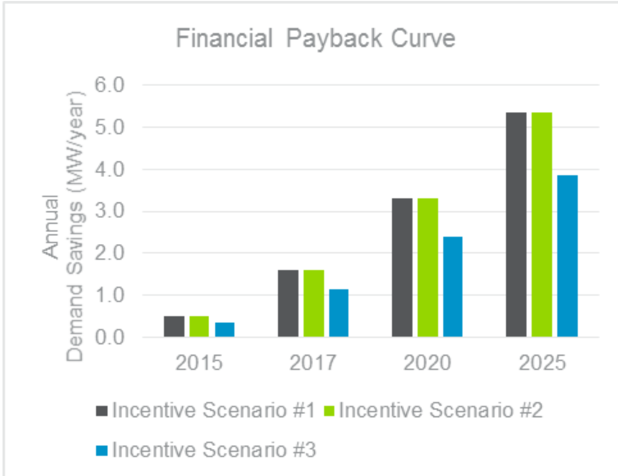
Figure 55: WER Market Potential in Electricity Savings by Facility Type

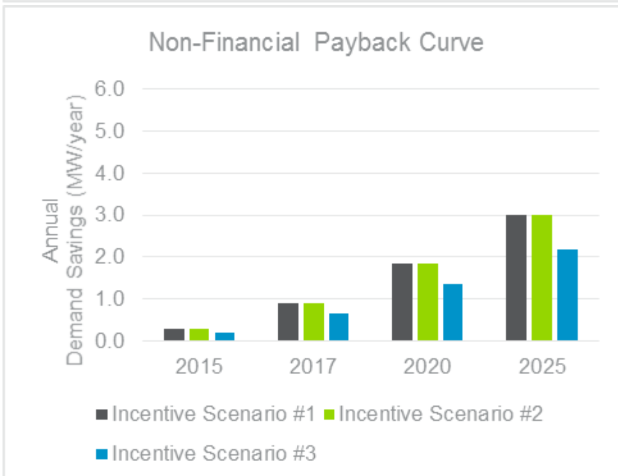


5.2.2.2 Demand Savings

Figure 56 shows province-wide WER market potential based on summer electric demand reductions (both financial-only and overall market potentials). The province-wide WER market potential increases from about 0.2 to 0.3 MW in 2015 (depending on scenario) to about 2.2 to 3.0 MW in 2025. The 2025 market potential represents about 4 to 5 percent (depending on scenario) of the 2025 WER technical potential based on demand reduction.

Figure 56: WER Market Potential in Demand Savings for System

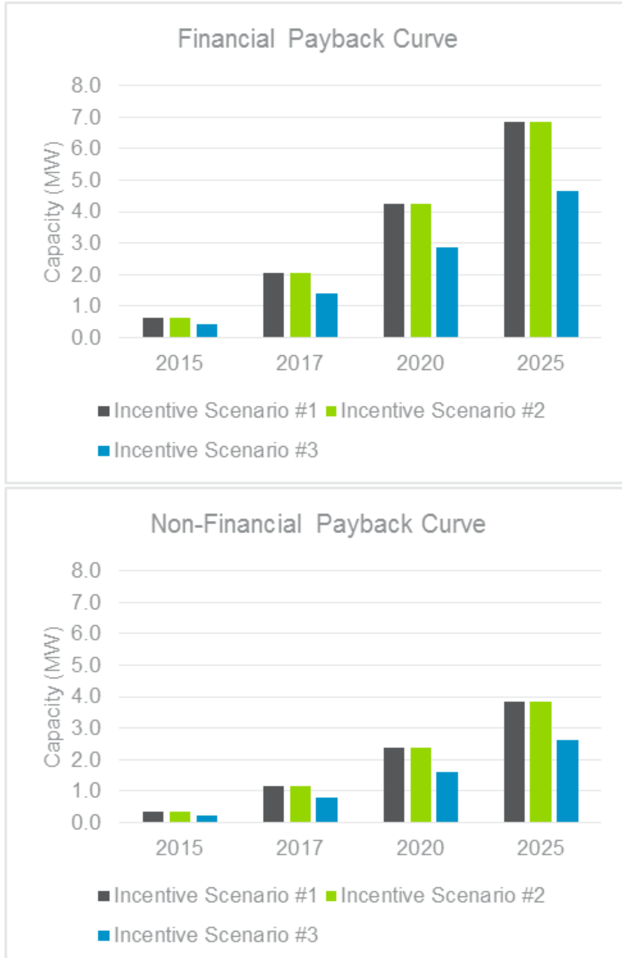




5.2.2.3 Installed Capacity

Figure 57 shows province-wide WER market potential based on nominal installed capacity (both financial-only and overall market potentials). The province-wide WER market potential increases from about 0.2 to 0.4 MW in 2015 (depending on scenario) to about 2.6 to 3.9 MW in 2025. The 2025 market potential represents about 4 to 6 percent (depending on scenario) of the 2025 WER technical potential based on installed capacity.

Figure 57: WER Market Potential in Capacity for System



5.2.3 Payback Periods

Table 19 and Table 20 summarize the ranges of CHP and WER payback periods by major facility type, respectively. Payback periods vary within a major facility type depending on climate zone, size (small, medium, or large), whether the facility is transmission-level or distribution-level, and scenario. As can be seen in Appendix B, ***payback periods do not vary significantly between scenario 1 and scenario 2 despite the substantial difference in first-cost incentive (40 percent versus 70 percent of first cost).*** This occurs because other incentive constraints limit the incentive paid. For example, for both scenarios, the incentive cannot be higher than the annual electricity savings multiplied by $200 to $230/MWh.[38] First-cost incentives also may not exceed the amount necessary to reduce the simple payback period of a project to one year. The combination of these other constraints means that the 70% first cost incentive is rarely in effect for a BMG project.

[38] $200/MWh if connected at the distribution level; $230/MWh if connected at the transmission level

Table 19: Summary of CHP Payback Periods [a]

Industrial Facility Type	Simple Payback Periods (Years)	Commercial Facility Type	Simple Payback Periods (Years)
Chemical	2 – 9	College/University	6 – 11
Electrical Manufacturing	3 – 7	Hospital	6 – 14
Food	2 – 9	Hotel	5 – 9
Greenhouse	3 – 11	Large Office	No Potential
Light Manufacturing	2 – 11	Medium Office	No Potential
Metals: Other	3 – 9	Multi-Family Residential	10 – 11
Oil & Gas Extraction	1.5 – 5	Retail	No Potential
Paper/Pulp	2 – 9	School	12 – 13
Petrochemicals	1 – 6	Supermarket	10 – 11
Plastics	4 – 9		

a) Excludes facilities that show no market potential because they do not pass the Participant Cost Test. See Appendix B for further breakdown of payback periods by facility type

Table 20: Summary of WER Payback Periods [a]

Industrial Facility Type	Simple Payback Periods (Years)
Metals, Iron, Steel, Foundries, Forging	7 – 10
Minerals	7 – 12
Oil- & Gas: Refining	5 – 6
Paper/Pulp	4 – 7

a) Excludes facilities that show no market potential because they do not pass the Participant Cost Test. See Appendix B for further breakdown of payback periods by facility type

5.2.4 Emissions

Figure 58 shows market potential in annual CO_2 savings at the system level for CHP (both financial and non-financial potentials). In the case of CHP, CO_2 emissions increase due to switching from a relatively low-carbon electric grid to higher-carbon natural gas. For non-financial potential, increases in province-wide CO_2 emissions range from about 7,500 to 16,100 metric tons/year in 2015 and increase to 82,400 to 175,700 metric tons/year in 2025.

Figure 58: CHP Market Potential in CO_2 Savings for System

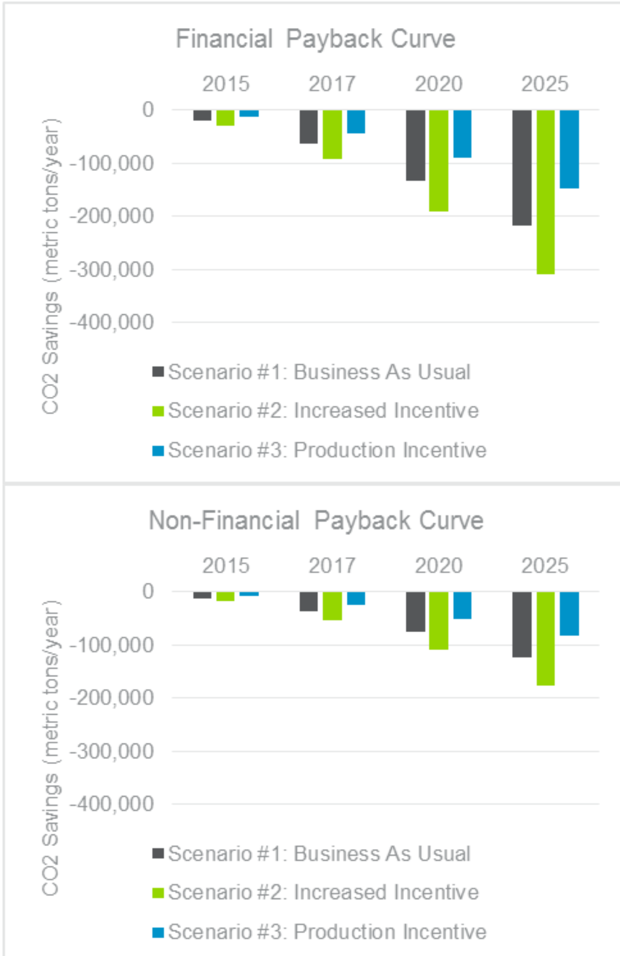
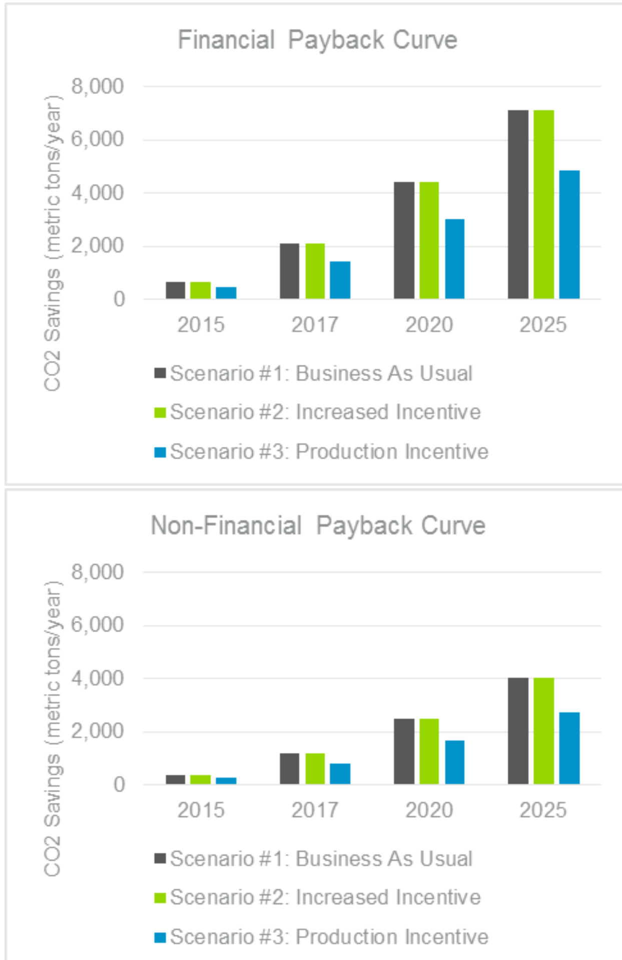


Figure 59 shows market potential in annual CO_2 savings at the system level for waste energy recovery (both non-financial and financial potentials). In the case of WER, CO_2 emissions decrease because little or no additional natural gas is used to generate electricity.[39] For non-financial potential, province-wide CO_2 savings range from about 250 to 370 metric tons/year in 2015 and increase to 2,740 to 4,010 metric tons/year in 2025.

[39] For WER, the program rules permit up to 10% co-firing with natural gas. Therefore, some natural gas is used, but we neglect the impacts.

Figure 59: WER Market Potential in CO_2 Savings for System



6. CAP & TRADE POTENTIAL

6.1 Methodology and Approach

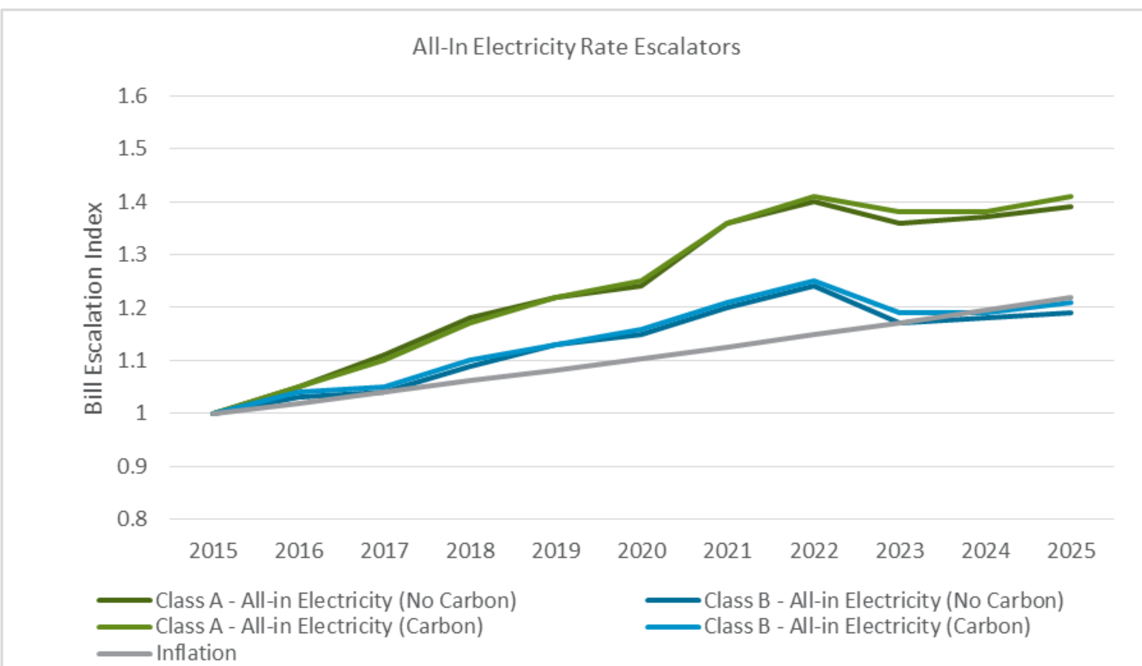
The IESO requested an evaluation of the impact of recent cap and trade regulations on the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario.

The regulation creates a price for carbon which will directly affect natural gas prices and indirectly affect electricity prices. The changes in these prices may impact the potential for CHP across Ontario as costs and benefits are directly tied to both natural gas and electricity costs.

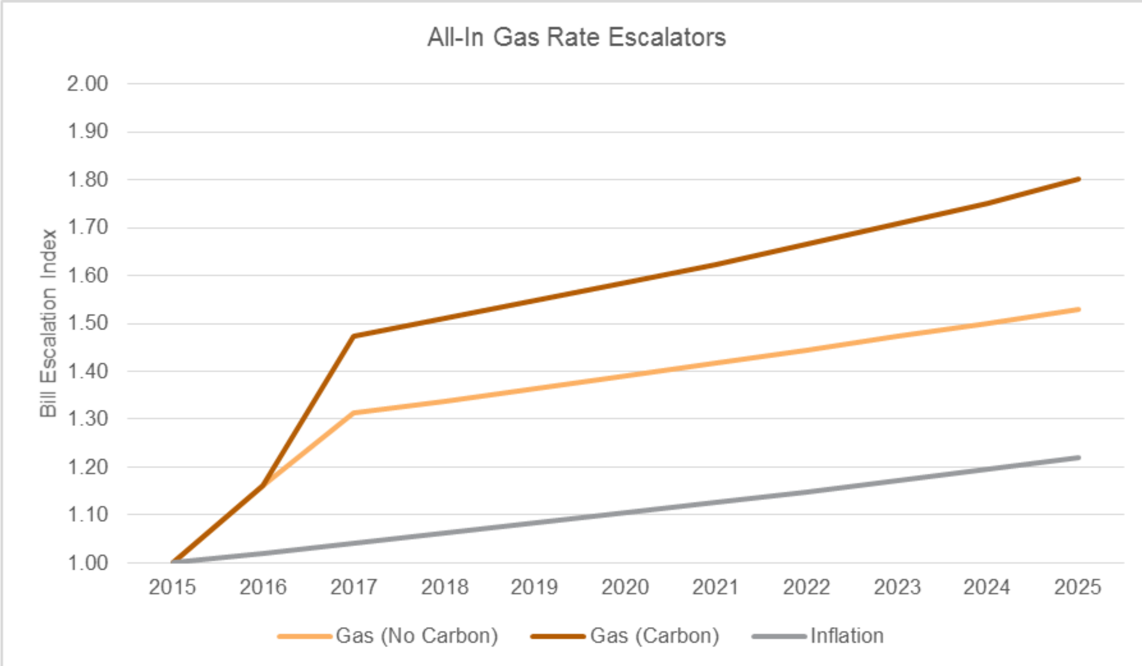
Navigant developed a Cap and Trade scenario to evaluate the impact of the new regulation relative to the base case (i.e., current program rules). Under the Cap and Trade scenario, Navigant leveraged electricity and gas forecasts provided by the IESO which account for the expected carbon prices.[40] We applied these forecasts at the Market Potential stage of the analysis to determine the impact of the proposed legislation on BMG potential.

The rate of change for these indices can be seen in Figure 60. Note that the "Change Index" represents the ratio of change from the component's starting point in 2015. Natural gas prices increase faster than electricity prices both without and with a carbon market but gas prices are also far lower than electricity prices to start with on an equivalent-energy unit comparison.

Figure 60: Customer Bill Escalation Indices



[40] Because the forecasts are not public, we do not describe them herein.



6.2 Results

The impact of the carbon cap-and-trade market is a relatively minor increase (approximately 3%) in WER potential and a decrease of about 20% in CHP potential. The cap-and-trade pricing has a much larger impact on projected gas prices than electricity prices which results in a much larger impact for CHP than for WER.

Potential for some facilities drops more significantly under cap and trade than for others. This is the result of a number of factors which are used to determine the payback period for each project. As noted earlier, BMG projects at some facility types have longer payback periods than others. Under the cap and trade scenario these facility types have more projects which move to a payback period above what is generally acceptable based on the payback curves, meaning that a larger portion of the projects will not move forward.

Appendix A includes detailed results by LDC and facility type.

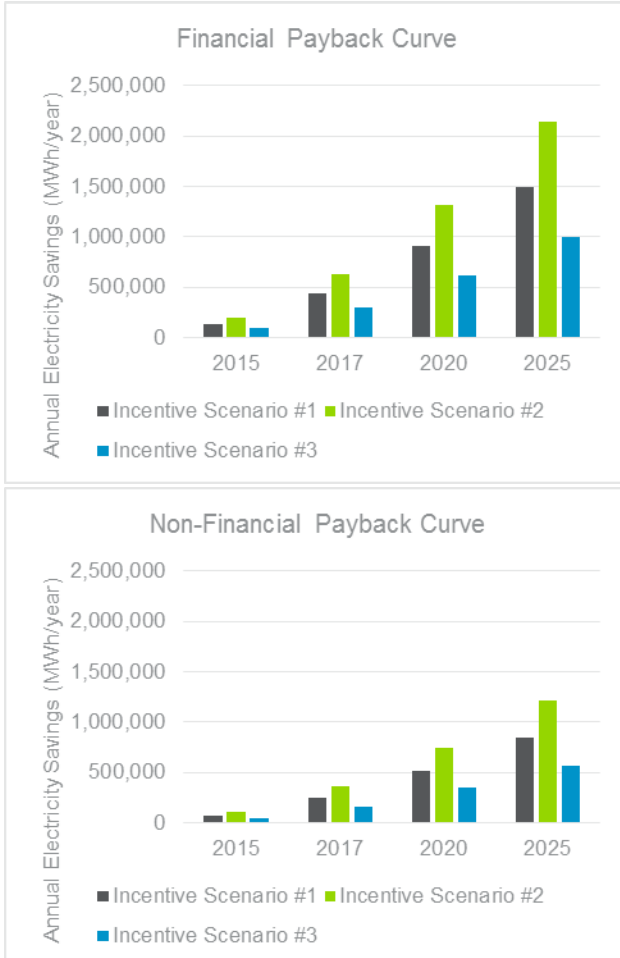
6.2.1 CHP

The following sections compare CHP market potential results under a cap-and-trade market to the market potential results reported in section 5.2.1 above.

6.2.1.1 Energy Savings

Figure **61** shows CHP market potential under carbon cap-and-trade based on electricity savings. Under scenario 1, in 2025, this market potential is about 81 percent of market potential without cap-and-trade (0.84 TWh vs. 1.04 TWh).

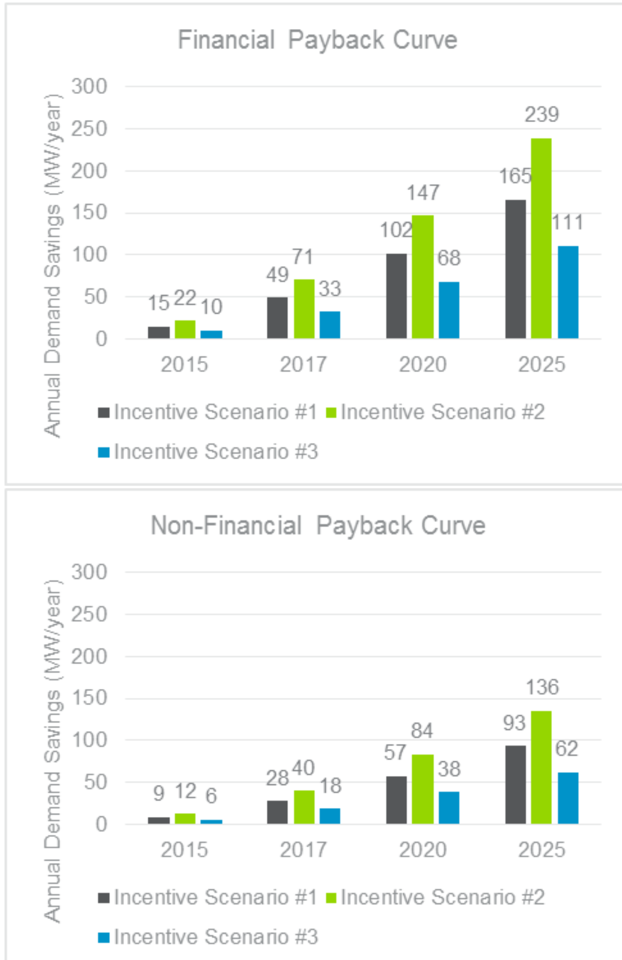
Figure 61: CHP Market Potential with Carbon Market in Electricity Savings for System



6.2.1.2 Demand Savings

Figure 62 shows CHP market potential under carbon cap-and-trade based on summer electric demand reduction. Under scenario 1, in 2025, this is about 80% of market potential without cap-and-trade (93 vs. 116 MW).

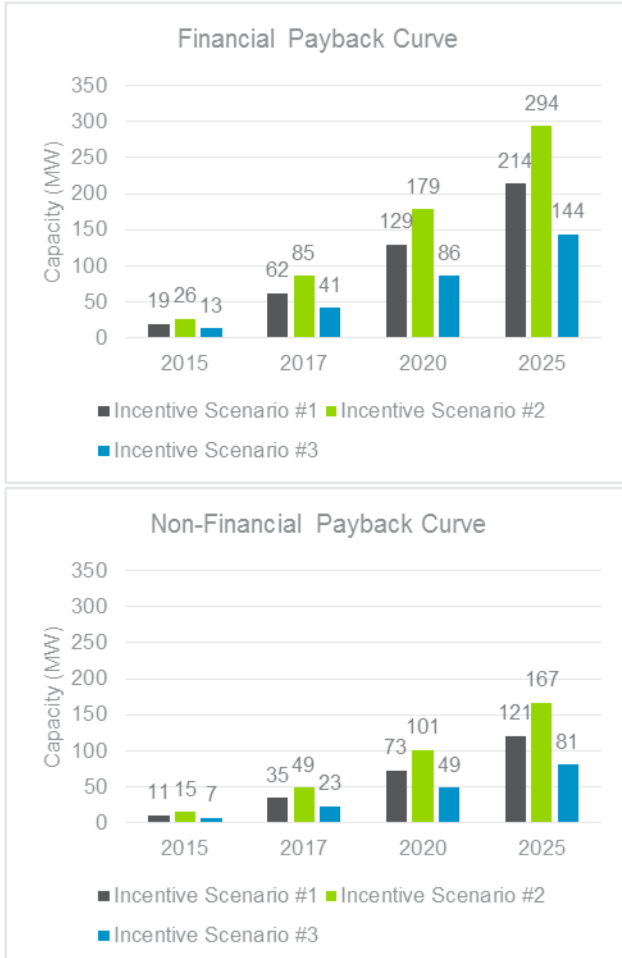
Figure 62: CHP Market Potential with Carbon Market in Demand Savings for System



6.2.1.3 Installed Capacity

Figure 63 shows CHP market potential under cap-and-trade based on installed capacity. Installed capacity shows a similar trend compared to demand savings. In 2025, under scenario 1, capacity-based market potential under carbon cap-and-trade is about 82% of capacity-based potential without cap-and-trade (121 MW vs. 147 MW).

Figure 63: CHP Market Potential with Carbon Market in Capacity for System



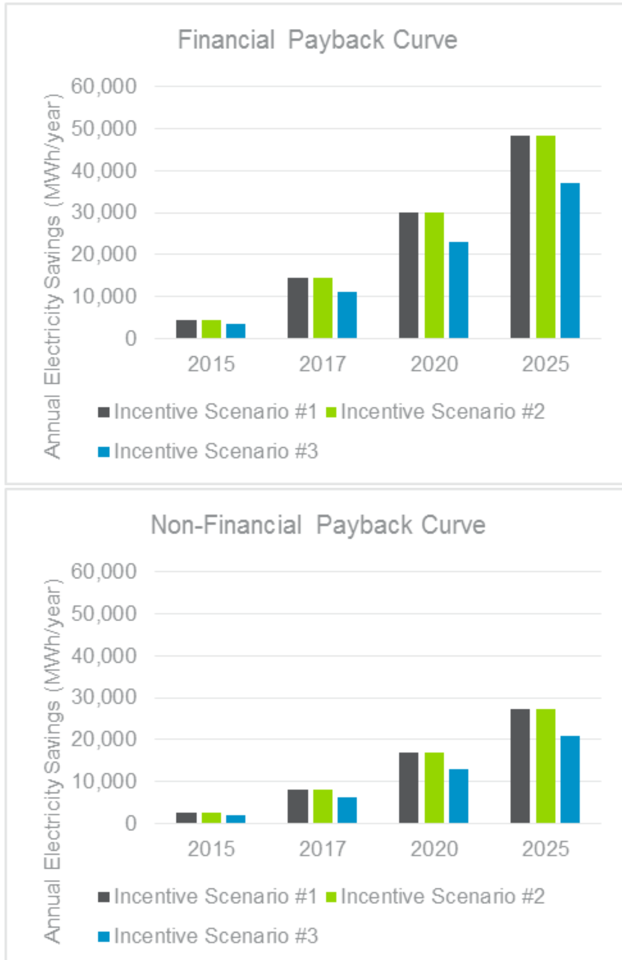
6.2.2 WER

Our analysis found that WER potential increases slightly under cap-and-trade. This results from the slight impact that cap-and-trade has on electricity prices.

6.2.2.1 Energy Savings

Figure 64 shows WER market potential under cap-and-trade based on electricity savings. For scenario 1, the market potential is approximately 103% of the potential without a carbon cap-and-trade market (27.2 GWh/year vs. 26.4 GWh/year).

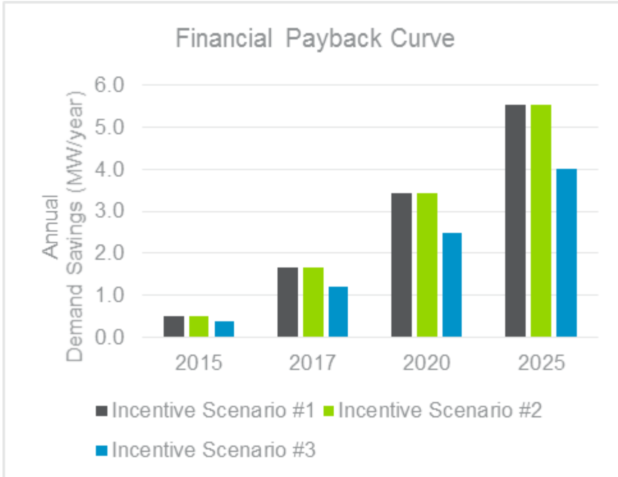
Figure 64: WER Market Potential with Carbon Market in Electricity Savings for System

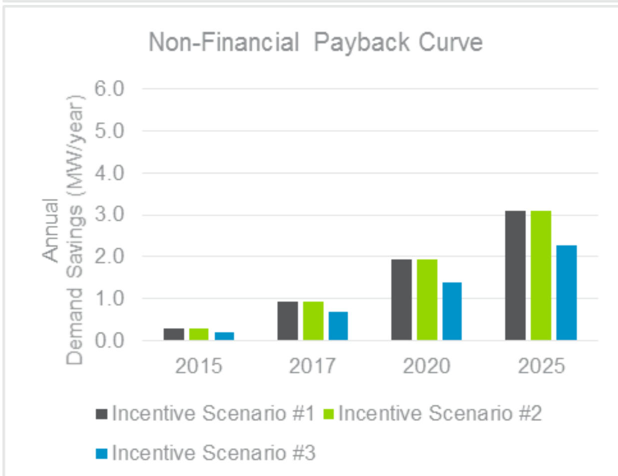


6.2.2.2 Demand Savings

Figure 65 shows WER market potential under cap-and-trade based on summer electric demand reduction. For scenario 1, the market potential is approximately 103% of the potential without a carbon cap-and-trade market (3.1 MW vs. 3 MW).

Figure 65: WER Market Potential with Carbon Market in Demand Savings for System

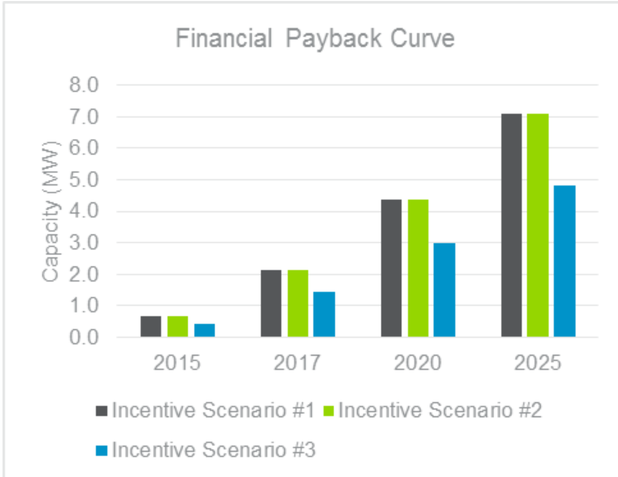


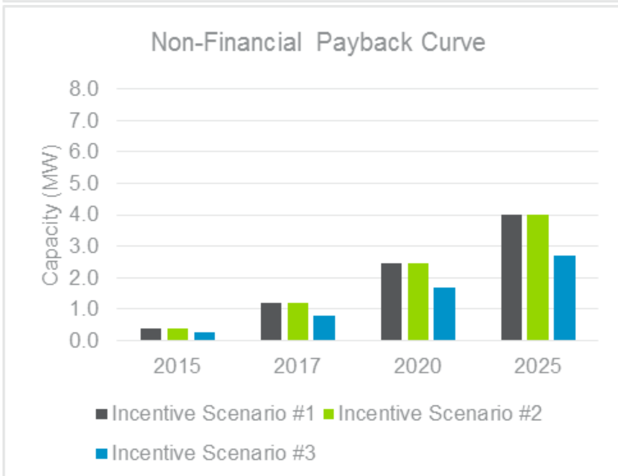


6.2.2.3 Installed Capacity

Figure 66 shows WER market potential under cap-and-trade based on installed capacity. For scenario 1, the market potential is approximately 103% of the potential without a carbon cap-and-trade market (4.0 MW vs. 3.9 MW).

Figure 66: WER Market Potential with Carbon Market in Capacity for System





6.2.3 Emissions

Figure 67 shows market potential in annual CO_2 savings at the system level for CHP (both non-financial and financial potentials) for the cap-and-trade scenario. Province-wide increases in CO_2 range from about 6,000 to 13,500 metric tons/year in 2015 and increase to 66,000 to 148,000 metric tons/year in 2025 for a non-financial potential.

Figure 67: CHP Market Potential with Carbon Market in CO_2 Savings for System

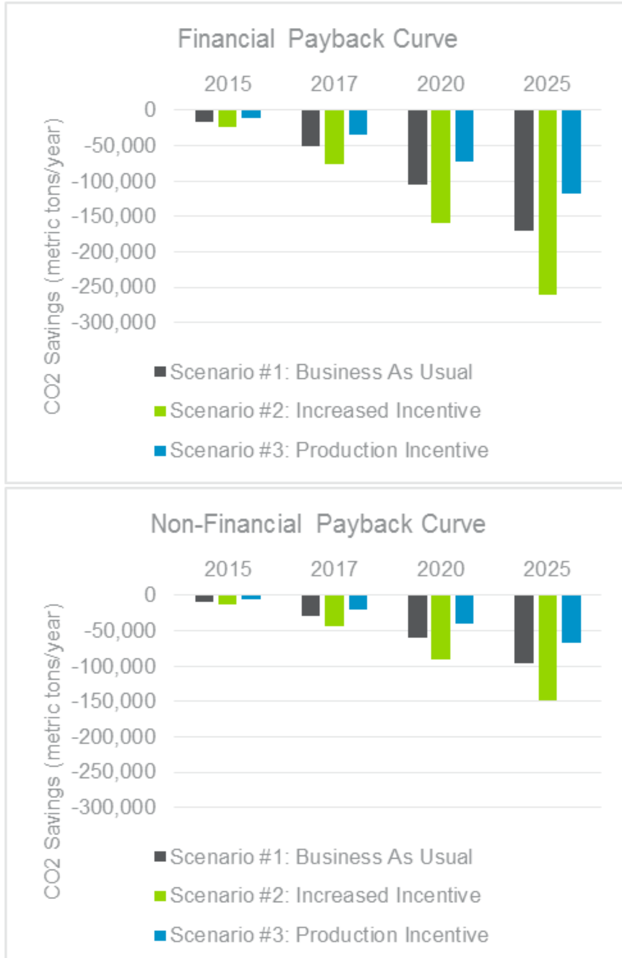
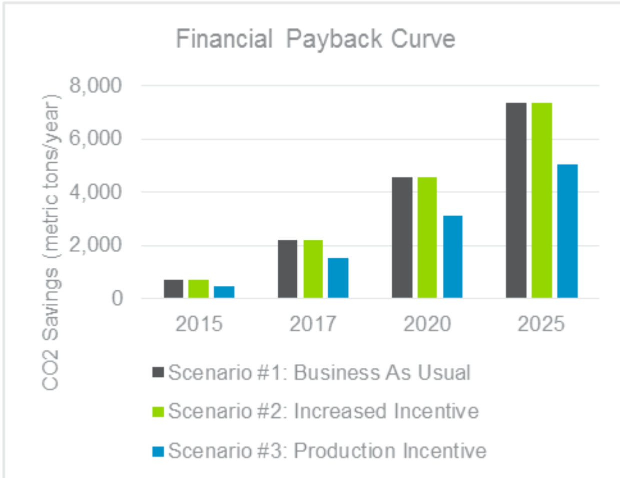
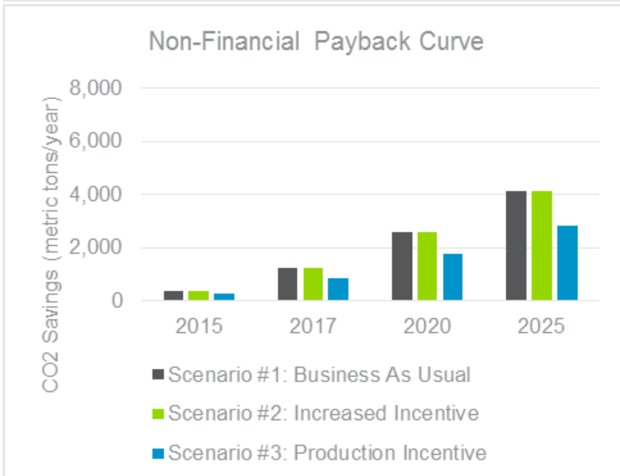


Figure 68 shows market potential in annual CO_2 savings at the system level for waste energy recovery (both non-financial and financial potentials). In the case of WER, CO_2 emissions decrease because little or no additional natural gas is used to generate electricity. Province-wide CO_2 savings range from about 260 to 380 metric tons/year in 2015 and increase to 2,840 to 4,150 metric tons/year in 2025 for non-financial potential.

Figure 68: WER Market Potential with Carbon Market in CO_2 Savings for System





7. CONSTRAINED POTENTIAL

7.1 Methodology and Approach

Navigant was tasked with determining the constrained potential given the electricity network connection capacity by LDC. The IESO's planning department determined that electricity network constraints must be determined at the transformer station, rather than LDC level, and that electricity network connection capacity will need to be assessed on a project-by-project basis when applications are received. Because this study estimates potential at the LDC level (not at the transformer-station level), it is not possible to apply constraints to quantify impacts on market potentials for all LDCs.

The IESO provided some information about area constraints. In cases where and LDC lies within an area that is fully area constrained, there is no potential for BMG projects larger than 500 kW.

Figure 69 lists the LDCs that are within a fully constrained area and potential for projects over 500 kW, and that have been removed at the constrained potential step.

Figure 69: LDCs Within Fully Constrained Area

LDC
Niagara-on-the-Lake Hydro Inc.
Welland Hydro-Electric System Corp
Canadian Niagara Power
EnWin Utilities Ltd.
E.L.K. Energy Inc.
Essex Powerlines Corp.
PUC Distribution Inc.
Thunder Bay Hydro Electricity Distribution Inc.
Algoma Power Inc.
Kenora Hydro Electric Corporation Ltd.
Greater Sudbury Hydro Inc.
Sioux Lookout Hydro Inc.
Fort Frances Power Corporation
North Bay Hydro Distribution Limited
Midland Power Utility Corporation
Fort Albany Power Corporation
Chapleau Public Utilities Corporation
Northern Ontario Wires Inc.
Hearst Power Distribution Company Limited
Atikokan Hydro Inc.

Espanola Regional Hydro Distribution Corporation
Dubreuil Lumber Inc.
Attawapiskat Power Corporation
Kashechewan Power Corporation

7.2 Results

Because only area constraints have been applied where LDCs are within fully constrained areas, the constrained potentials presented below are expected to be higher than what can be achieved. Available electricity network connection capacity, which must be determined on a project-by-project basis, will reduce constrained potentials relative to the projections below. Appendix A includes detailed results by LDC.

Constrained potential results below are compared to the market potential results in sections 5.2.1 and 5.2.2.

7.2.1 CHP

Figure 70, Figure 71, and Figure 72 show that CHP constrained potential represents about 94-95 percent of 2025 market potential under incentive scenario #1 based on electricity savings, demand savings and installed capacity.

Figure 70: CHP Constrained Potential in Electricity Savings for System

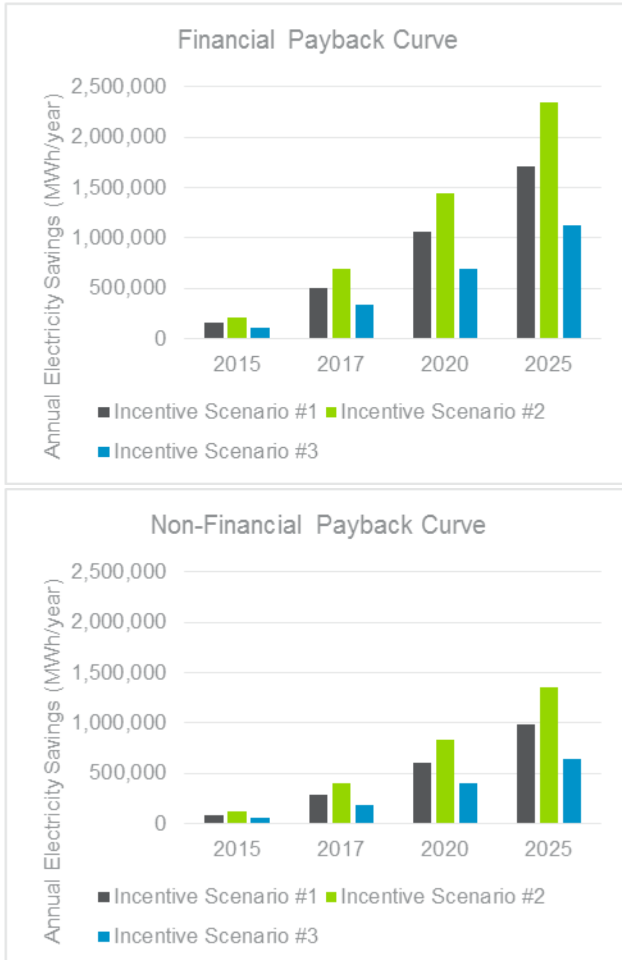


Figure 71: CHP Constrained Potential in Demand Savings for System

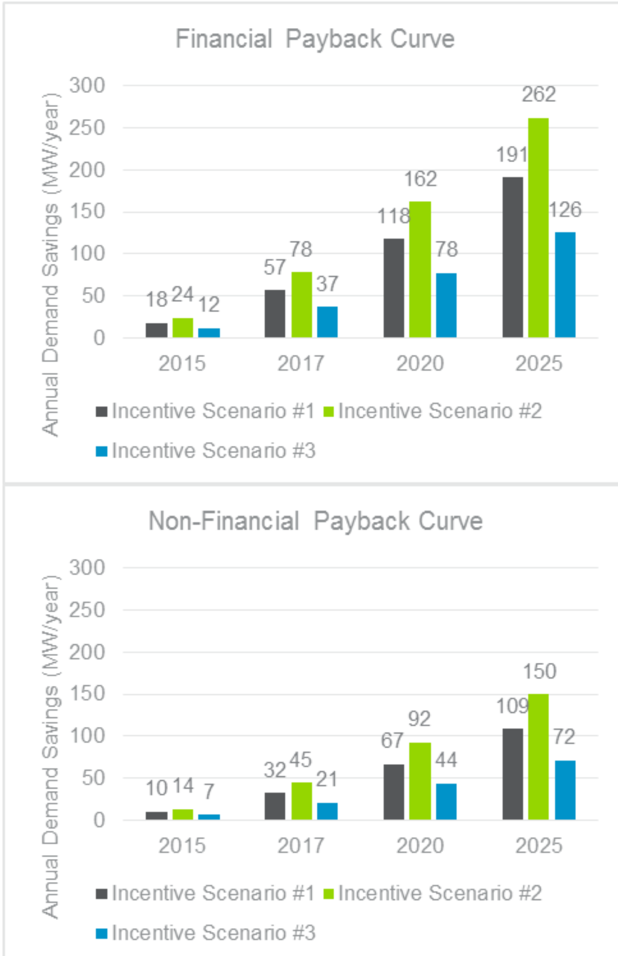
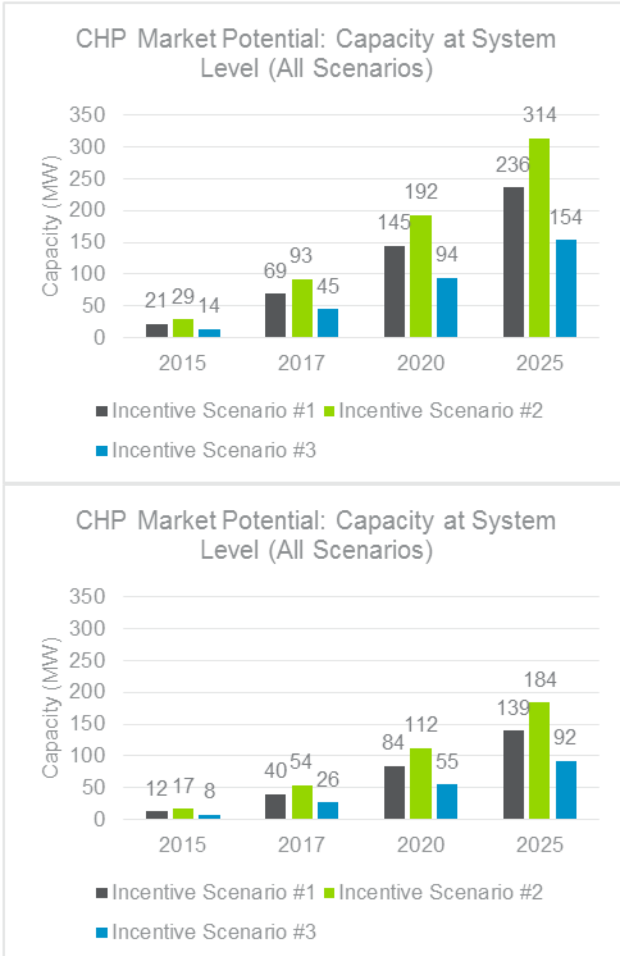


Figure 72: CHP Constrained Potential in Capacity for System



7.2.2 WER

Figure 73,

Figure 74, and Figure 75 show that 2025 WER constrained potential under scenario 1 represents about 91 percent, 93 percent, and 90 percent of market potential by electricity savings, demand savings and capacity, respectively.

Figure 73: WER Constrained Potential in Electricity Savings for System

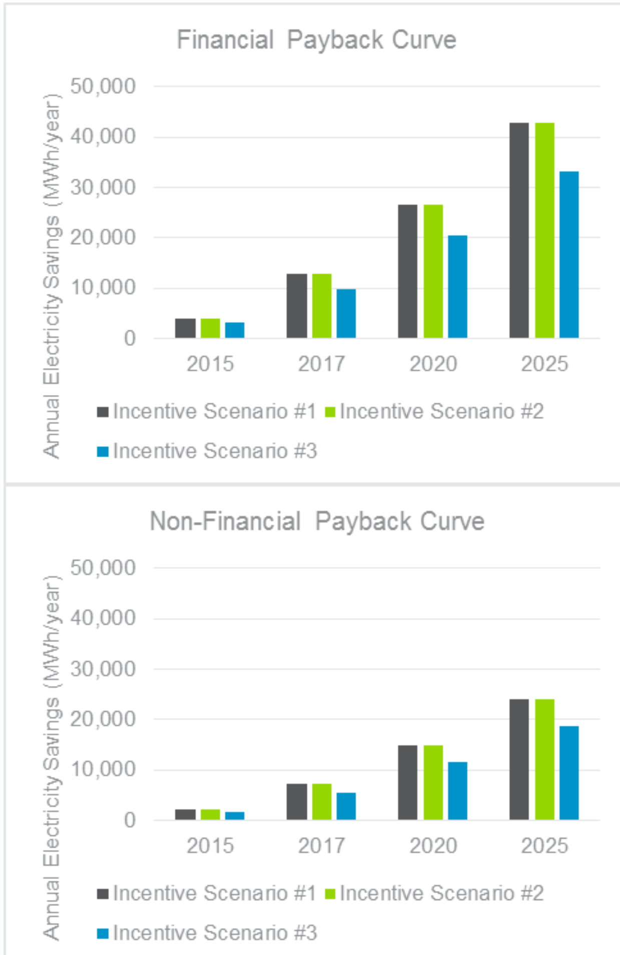
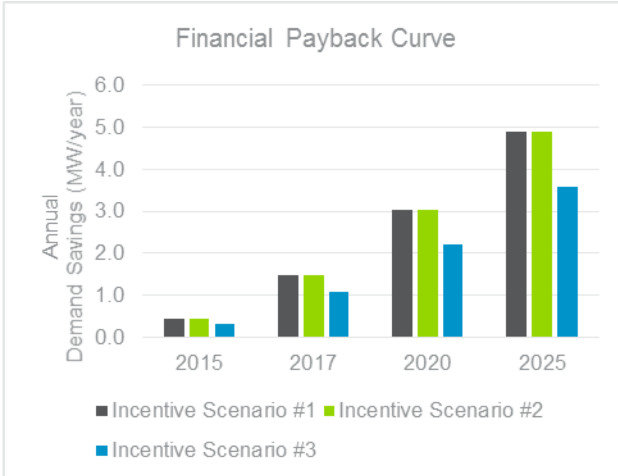


Figure 74: WER Constrained Potential in Demand Savings for System



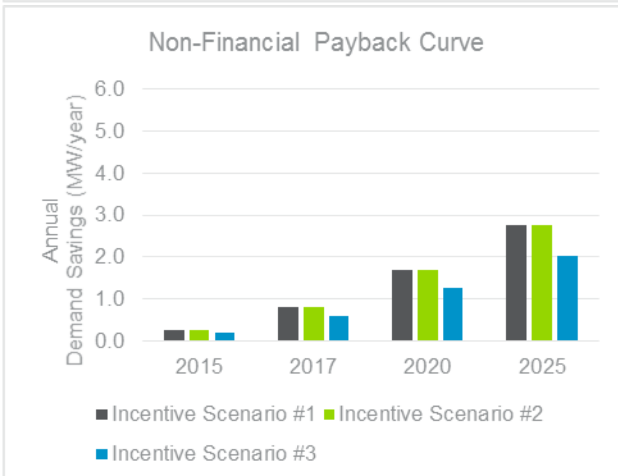
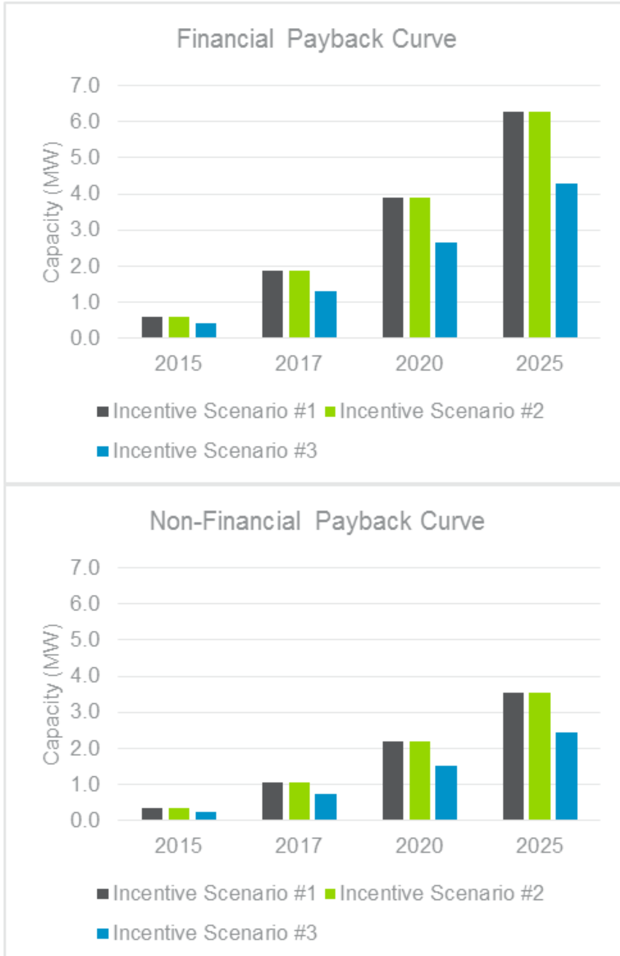


Figure 75: WER Constrained Potential in Capacity for System



7.2.3 Emissions

Figure 76 shows the constrained potential in annual CO_2 savings at the system level for CHP (both non-financial and financial potentials). Province-wide increases in CO_2 emissions range from about 7,100 to 15,300 metric tons/year in 2015 and increase to 77,600 to 167,000 metric tons/year in 2025 for non-financial potential.

Figure 76: CHP Constrained Potential with Carbon Market in CO_2 Savings for System

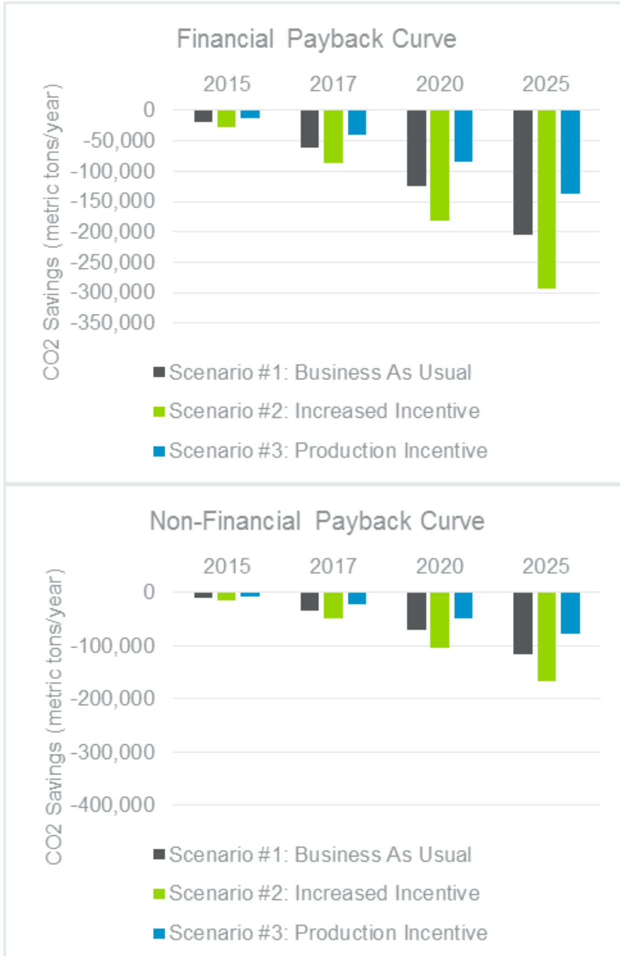
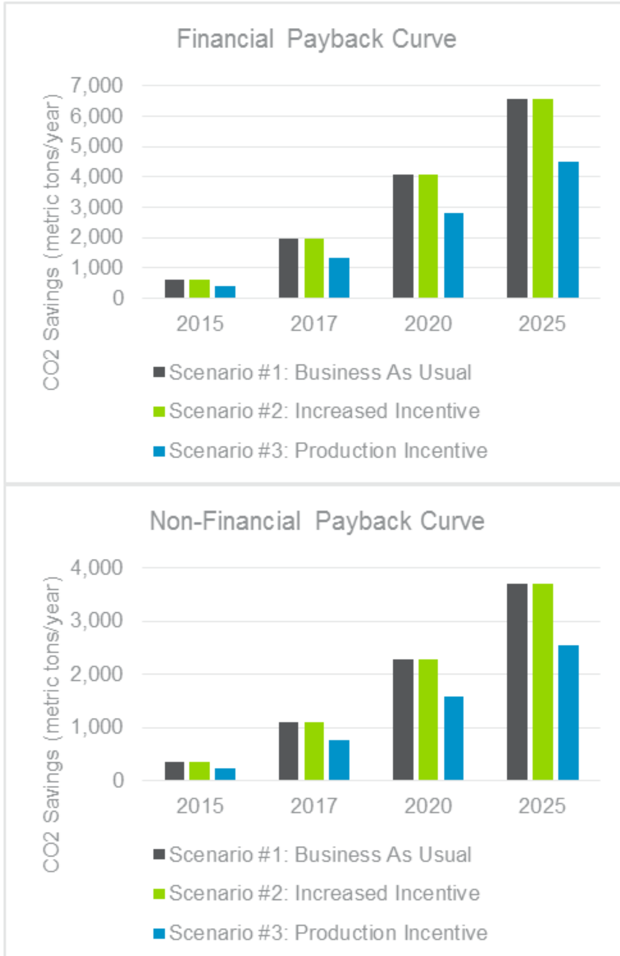


Figure 77 shows constrained potential in annual CO_2 savings at the system level for WER (both non-financial and financial potentials). Province-wide CO_2 savings range from about 230 to 340 metric tons/year in 2015 and increase to 2,500 to 3,700 metric tons/year in 2025 for non-financial potential.

Figure 77: WER Market Potential with Carbon Market in CO_2 Savings for System



7.2.4 Merged Results

The IESO has some existing BMG projects which went in-service through the program in 2015 and some applications which have already been received for BMG projects. These projects will contribute to the potential for the BMG program from 2015 to 2025. Navigant created merged results which combine actual in-service projects and applications with the modelled potential. These merged results were created only for incentive scenario #1 (existing program rules) after applying constraints to the modelled results. Before merging results, Navigant assumed that some attrition will occur in projects for which applications were received but which are not yet in service. For these projects, Navigant assumed 75% of the application potential would result in achieved potential. Feedback from LDCs and previous BMG project contacts indicate that the average length from application to in-service is approximately 2 years. Navigant has assumed that this application project potential will be realized by 2017. Navigant merged results at the facility type and LDC levels. If the actual or application potential was greater than the modelled potential, then the modelled potential was overridden with actuals.

Merging the in-service and application projects with the modelled potential increases CHP electricity savings by 1.5 times and WER electricity savings by almost 5 times (see Figure 78 and Figure 79) by

2025. Figure 80 illustrates the merged potential results for all BMG (CHP and WER) split between distribution and transmission connected customers.

Figure 78: CHP Merged Model and Actual Constrained Potential in Electricity Savings for System

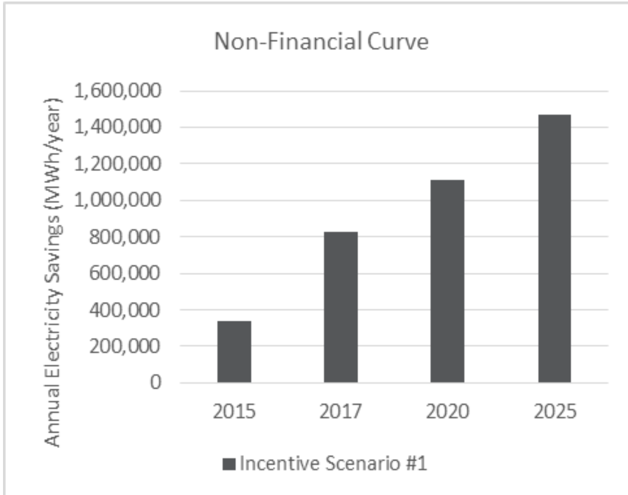


Figure 79: WER Merged Model and Actual Constrained Potential in Electricity Savings for System

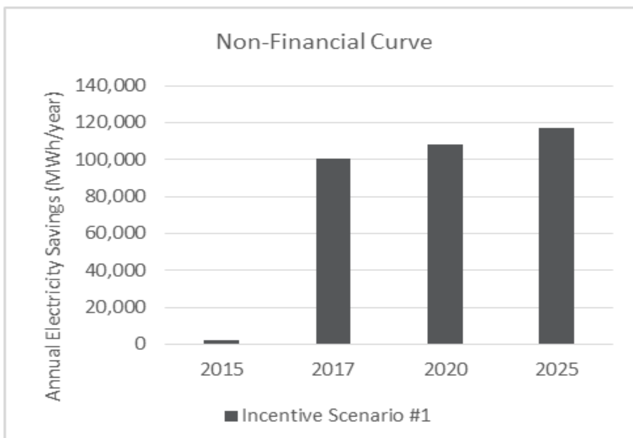
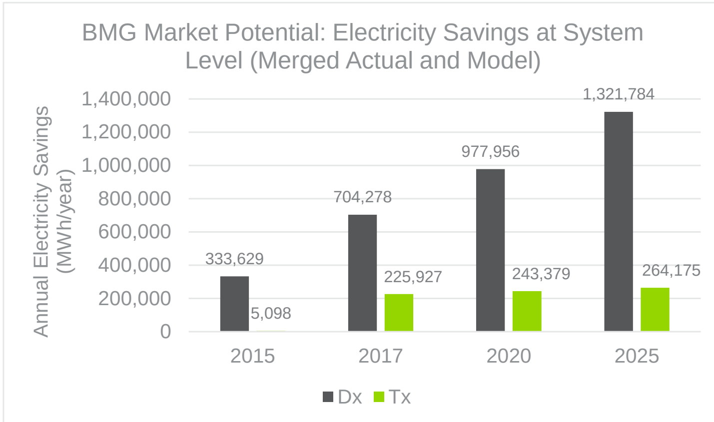


Figure 80: BMG Merged Model and Actual Constrained Potential in Electricity Savings for System



8. OBSERVATIONS

The results of the BMG potential analysis show that:

- The 2025 province-wide market potential for multi-family, commercial, and institutional facilities is very low—only about 23 GWh of the almost 10,000 GWh technical potential for these facility types
- The 2025 province-wide market potential for industrial facilities is about 1,100 GWh, or about 7 percent, of the almost 16,000 GWh technical potential for these facility types
- Scenarios 1 and 2 (40 percent versus 70 percent first-cost incentive) generally result in little or no difference in market potential. This occurs because other scenario constraints limit the incentive paid. For example, for both scenarios, the incentive cannot be higher than the annual electricity savings multiplied by $200 to $230/MWh.
- The Climate Mitigation and Low-Carbon Economy Act is projected to have almost no impact on WER and will decrease CHP potential by approximately 20% in the long term
- The constrained potential analysis shows modest reductions in market potential (about 6 percent reduction for scenario 1). However, available electricity network connection capacity, which must be determined on a project-by-project basis and which were not accounted for in this analysis, will reduce constrained potentials further.
- Merged results reveal an achievable potential of 978 GWh of annual distribution-level electricity savings by 2020.

Table 21 summarizes the province-wide market potentials for CHP and WER for scenario 1 (current program incentives).

Table 21: Summary of Ontario BMG Market Potentials (for Scenario 1)

Year	BMG Type	Installed Capacity (GW)	Electricity Savings (GWh)	Demand Savings (MW)
2015	CHP	13	95	11
	WER	~0	2	~0
2017	CHP	43	307	34
	WER	1	8	1
2020	CHP	89	639	71
	WER	2	16	2
2025	CHP	147	1040	116
	WER	4	26	3

APPENDIX A. DETAILED RESULTS

While conducting this analysis, Navigant developed numerous sets of results based on varying combinations of model parameters. These parameters include:

- Without or with a TRC screen of 0.75 (section 4.1 – economic potential only)
- Financial vs. non-financial payback acceptance curves (section 5.1.2, market potential only)
- Without or with a carbon cap-and-trade market (section 6.1, market potential only)
- Without or with electric system constraints (section 7.1, constrained potential only)

Each of these results are presented where applicable by:

- Technical, economic and market potential
- LDC, facility type, connection level and system
- Electricity savings, demand savings and capacity

These detailed results can be found in the zip file attachment "**Appendix A – IESO BMG Potential Study Model Detailed Results 6 21 2016.zip**".

APPENDIX B. PAYBACK PERIODS

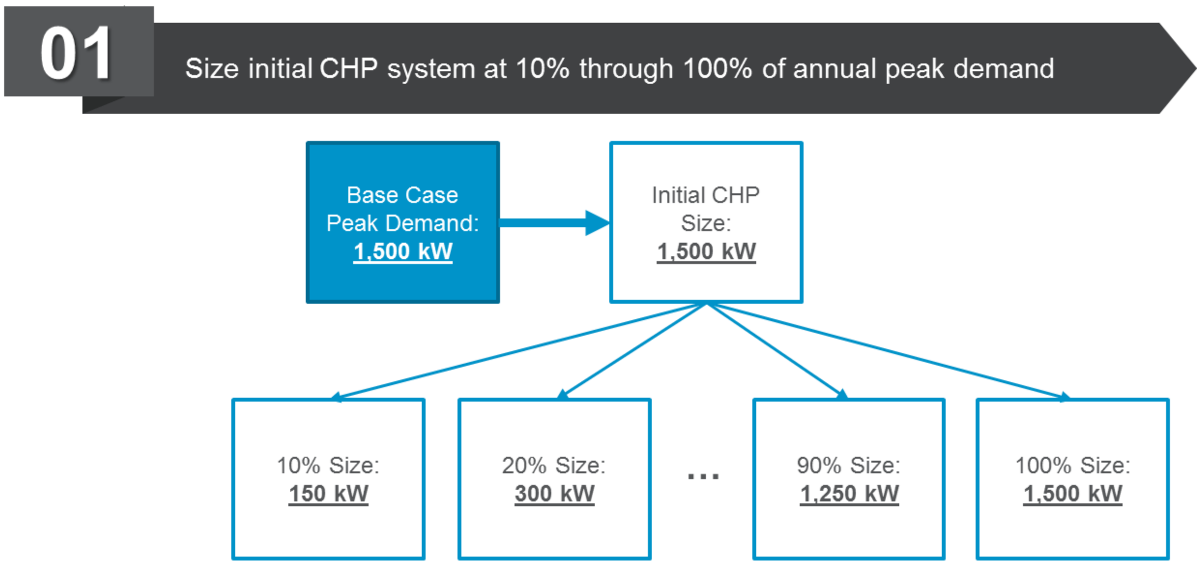
The IESO requested results regarding simple payback periods calculated through Navigant's BMG model. Appendix B is contained within a separate attachment with simple payback periods for all representative customer archetypes (both CHP and WER) under a no-carbon market scenario.

The file title is "**Appendix B – IESO BMG Potential Study Model Simple Payback Periods.xlsx**".

APPENDIX C. DESCRIPTION OF A "SMART" OPERATIONAL STRATEGY

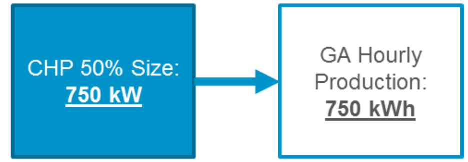
The infographic presented in Figure 81 shows the "smart" CHP operational strategy.

Figure 81: Smart Operational Strategy Infographic



02 For Global Adjustment hours, operate CHP system at full capacity

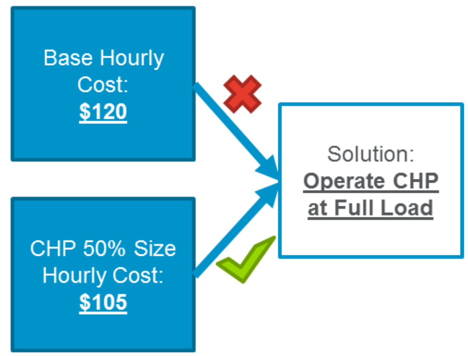
- There are 20 peak hours identified for the year, with the 4 hours preceding and following also considered as GA "operational" hours



03 For non-GA hours, operate CHP at full capacity if baseline hourly cost > full-load hourly cost[1]

CHP hourly costs include:

- Remaining electricity costs
- Variable O&M of generating electricity
- Natural gas fuel costs
- Incentives (Scenario #3)
- Boiler O&M costs for remaining thermal



[1]CHP operation is capped at facility electric load for each hour (no exporting to the grid is allowed).

04 For remaining hours, do not operate CHP if the effective electric volumetric rate is below $0/MWh.

- The Hourly Ontario Energy Price has zero or negative prices for 1,142 instances in 2015.
- These instances usually occur due to high baseload grid production (nuclear, hydro) during low demand hours.

05 For all remaining hours, operate CHP unit to reduce facility demand by 20%, 40%, 60%, 80% and 100%.[1]

CHP 50% Size: **750 kW**

Baseline Demand for Hour: **500 kW**

Demand Reduction	20%	40%	60%	80%	100%
Demand Target	400 kW	300 kW	200 kW	100 kW	0 kW
CHP Production	-	-	300 kW	400 kW	500 kW

Turndown ratio too high (load factor drops too far)

[1]In the case where facility demand for the hour is larger than the CHP unit, CHP operation is reduced by 20%, 40%, 60%, 80% and 100%.

06 Calculate hourly and monthly costs under each demand reduction scenario

	Hourly	Monthly
Electric	• HOEP Charge • GA Charge (Class B) • CHP O&M Cost • Production Incentive (Scenario #3)	• LDC Demand Charge • GA Charge (Class A) • Standby Charge • LDC Fixed Charge
Gas	• CHP Gas Costs • Remaining Thermal Gas Costs • Remaining Boiler O&M Costs	• Contracted Demand Charge

07 Choose demand reduction scenario that results in the lowest total monthly cost for each month of the simulation.

- Checks are then applied to ensure CHP unit meets minimum efficiency and savings targets

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Conservation Framework: Mid-term Review Advisory Group

Terms of Reference

Overview and Context

The IESO's Conservation Framework: Mid-Term Review engagement initiative will work with stakeholders and communities to conduct a combined mid-term review of the 2015 to 2020 Conservation First Framework (CFF) and Industrial Accelerator Program (IAP) – referred to here as the conservation framework. A third party consultant, through a competitive procurement process, will support the IESO with completion of the mid-term review. The review will focus on targets, budgets, progress, lessons learned (on cost recovery, performance incentive mechanisms and CDM contribution to regional planning), and alignment with Ontario's Climate Change Action Plan (CCAP), for CFF and IAP. The results of the review will inform potential approaches to achieving objectives of the conservation framework for the remainder of the term to 2020 and beyond.

This Conservation Framework: Mid-Term Review Advisory Group will provide advice to the IESO for the completion of the mid-term review. The Mid-term Review Advisory Group will complement input provided through a public engagement process by providing a dedicated, consistent group of interested parties to provide input to the review.

Objectives and Scope

The Conservation Framework: Mid-Term Review Advisory Group (the "Advisory Group") will provide comments and advice to inform the IESO in the completion of the mid-term review. Comments and advice will be collected at Advisory Group meetings and in writing on specific items and topics.

Specifically, the Advisory Group will review and provide comment on the study plan, study topics, and draft report(s) for the mid-term review study.

Written feedback provided by Advisory Group members will be compiled on the IESO Conservation Framework: Mid-Term Review engagement webpage. The IESO will respond to this feedback to advise how the views of stakeholders and other interested parties have been considered and incorporated. The final content of the mid-term review report will be determined by the IESO.

In the context of the engagement, the Advisory Group's activities will be integrated with the broader engagement; as the study plan and key topics for the final report are discussed and advanced in the Advisory Group setting, they will then be brought forward for discussion with all stakeholders through the broader engagement initiative.

Composition of the Advisory Group

Members are expected to be able to commit time and resources to support the group, in order to provide feedback, attend scheduled meetings, and review information/materials (some of which may be communicated between meetings). Delegates are not encouraged. A tentative meeting schedule for 2017 is provided in Appendix A.

The IESO will seek a balance of different types of stakeholders on the Advisory Group to ensure feedback from different points of view.

Direct meeting participation will be limited to members. Membership in the Advisory Group will be limited to 12 to14 participants, selected based upon their experience and background. Membership will be balanced to provide representation from different regions of Ontario and different interested groups.

The meeting will be open to registered observers who have been invited and/or selected by the IESO and limited to one individual per organization. Delegates are not encouraged. Observers will be invited to provide comment or ask questions at the discretion of the Advisory Group's Chair.

The Advisory Group will consist of the following representation within the group:

- five consumers (representing a mix of sectors, and distribution/transmission connected customers)
- five LDCs(where possible representing different size utilities and different regions and progress towards CFF targets)
- two consultants, service providers/delivery agents and/or manufacturers that are engaged in CDM
- IESO (Chair plus staff support)

The Advisory Group may also include observers from:

- natural gas utilities
- industry/customer associations
- Environmental Commissioner's Office
- Ontario Energy Board
- Ministry of Energy

Organization and Administration of Meetings

a) IESO staff will chair the meetings. The Chair may act as the facilitator for the meeting, or a separate independent facilitator may be used. The Chair or facilitator will be responsible for the role of a time keeper.

b) The Chair will provide all meeting agendas and support material at least two business days in advance of the meeting dates to the Mid-term Review Advisory Group members.

c) All meeting materials including meeting notes will be recorded and posted on the IESO Conservation Framework Mid-Term Review engagement webpage.

d) Attendance may be in person, via teleconference or webcast. In person attendance is strongly preferred and encouraged.

e) Monthly meetings are planned for the period of Q1 2017-Q1 2018 (a mix of in-person at the IESO offices, 120 Adelaide St. W and teleconference meetings are anticipated depending on the number of agenda items). Additional, ad-hoc teleconference discussions may be added on an as needed basis as the Mid-term review study is executed.

f) The IESO will coordinate attendance through on-line meeting invitations. These invitations are intended for members and registered observers only and are not to be forwarded to any other parties without the consent of the Advisory Group Chair.

Appendix A
Conservation Framework: Mid-Term Review Advisory Group
Draft Meeting Schedule

- Meetings to take place in downtown Toronto
- In-person meetings may be substituted with teleconferences or web meetings when the agenda allows
- Meeting times below are subject to change and intended to provide an idea of the frequency of meetings

January 31, 2017
February 23, 2017
March 23, 2017
April 27, 2017
May 25, 2017
June 22, 2017
July 20, 2017
August 24, 2017
September 21, 2017
October 19, 2017
November 23, 2017
January 9, 2018
February 15, 2018
March 20, 2018

Filed: September 7, 2017, EB-2017-0150, Tab 1.0, Schedule 2.03, Attachment 3, Page 1 of 1

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Demand Response Auction: Post-Auction Summary Report

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DR Auction Results

Zone	Summer Commitment Period (May 01, 2016 - Oct 31, 2016)		Winter Commitment Period (Nov 01, 2016 - Apr 30, 2017)	
	Quantity Cleared (MW)	Auction Clearing Price ($/MW-day)	Quantity Cleared (MW)	Auction Clearing Price ($/MW-day)
EAST	24.7	378.21	25.4	359.87
ESSA	13.7	378.21	13.8	359.87
NIAGARA	15.9	348.45	15.9	332.71
NORTHEAST	56.3	378.21	56.3	359.87
NORTHWEST	51	378.21	50	359.87
OTTAWA	10.8	378.21	11.2	359.87
SOUTHWEST	40	378.21	55.3	359.87
TORONTO	159.4	378.21	159.2	359.87
WEST	19.7	378.21	16.6	359.87
Ontario Total	**391.5**		**403.7**	

DR Auction Results - Participant Details

ZONE	Demand Response Auction Participant	Summer Commitment Period (May 01, 2016 - Oct 31, 2016)	Winter Commitment Period (Nov 01, 2016 - Apr 30, 2017)
		Cleared DR (MW)	Cleared DR (MW)
EAST	ENERGY CURTAILMENT SPECIALISTS, INC.	1	1
	ENERNOC LTD.	13.4	18
	ENERSHIFT CORPORATION	10.3	6.4
ESSA	ENERNOC LTD.	12.3	12.4
	ENERSHIFT CORPORATION	1.4	1.4
NIAGARA	ENERGY CURTAILMENT SPECIALISTS, INC.	1	1
	ENERNOC LTD.	13.9	13.9
	ENERSHIFT CORPORATION	1	1
NORTHEAST	ENERNOC LTD.	1.3	1.3
	ENERSHIFT CORPORATION	15	15
	TEMBEC ENTERPRISES INC.	40	40
NORTHWEST	RESOLUTE FP CANADA INC.	51	50
OTTAWA	ENERNOC LTD.	1	1.4
	ENERSHIFT CORPORATION	9.8	9.8
SOUTHWEST	ENERGY CURTAILMENT SPECIALISTS, INC.	5.6	7.2
	ENERNOC LTD.	17.3	28.1
	ENERSHIFT CORPORATION	14.8	17.7
	GERDAU AMERISTEEL CORPORATION - CAMBRIDGE	2.3	2.3
TORONTO	ENERGY CURTAILMENT SPECIALISTS, INC.	14.8	16.3
	ENERNOC LTD.	29.5	46.1
	ENERSHIFT CORPORATION	43.1	24.8
	GERDAU AMERISTEEL CORPORATION	72	72
WEST	ENERGY CURTAILMENT SPECIALISTS, INC.	2.5	2.5
	ENERNOC LTD.	13.3	10.2
	ENERSHIFT CORPORATION	3.9	3.9

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Demand Response Auction: Post-Auction Summary Report

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DR Auction Results

Zone	Summer Commitment Period (May 01, 2017 - Oct 31, 2017)			Winter Commitment Period (Nov 01, 2017 - Apr 30, 2018)		
	Physical DR Cleared (MW)	Virtual DR Cleared (MW)	Auction Clearing Price ($/MW-day)	Physical DR Cleared (MW)	Virtual DR Cleared (MW)	Auction Clearing Price ($/MW-day)
EAST	-	38.7	331.33	-	31.9	299.48
ESSA	-	6	331.33	-	12.8	299.48
NIAGARA	-	15.9	328.51	-	14.6	299.48
NORTHEAST	40	22.2	275	40	22.2	275
NORTHWEST	48	2.1	331.33	46	-	299.48
OTTAWA	-	24.1	331.33	-	23.1	299.48
SOUTHWEST	2.4	55.2	331.33	2.4	73.5	299.48
TORONTO	72	104.2	331.33	72	113.7	299.48
WEST	-	24.4	331.33	-	25.3	299.48
Ontario Total	162.4	292.8		160.4	317.1	

DR Auction Results - Participant Details

ZONE	Demand Response Auction Participant	Summer Commitment Period (May 01, 2017 - Oct 31, 2017)	Winter Commitment Period (Nov 01, 2017 - Apr 30, 2018)
		Cleared DR (MW)	Cleared DR (MW)
EAST	ENERNOC LTD.	20.7	19.9
	ENERSHIFT CORPORATION	13	7
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	5	5
ESSA	ENERNOC LTD.	5	10.5
	ENERSHIFT CORPORATION	-	1.3
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1	1
NIAGARA	ENERNOC LTD.	13.3	12
	ENERSHIFT CORPORATION	1	1
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1.6	1.6
NORTHEAST	ENERNOC LTD.	1.2	1
	ENERSHIFT CORPORATION	21	21.2
	TEMBEC ENTERPRISES INC.	40	40
NORTHWEST	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.1	-
	RESOLUTE FP CANADA INC.	48	46
OTTAWA	ENERNOC LTD.	6.1	6.1
	ENERSHIFT CORPORATION	12	11
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	6	6
	OHMCONNECT, INC	0	-
SOUTHWEST	ENERNOC LTD.	33.1	32.3
	ENERSHIFT CORPORATION	11.1	29.8
	GC PROJECT LP	1.2	3.1
	GERDAU AMERISTEEL CORPORATION - CAMBRIDGE	2.4	2.4
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	9.8	8.3
	OHMCONNECT, INC	0	-
TORONTO	ENERNOC LTD.	39.4	39.7
	ENERSHIFT CORPORATION	41.1	49.2
	GC PROJECT LP	2.5	5.2
	GERDAU AMERISTEEL CORPORATION	72	72
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	20.2	19.6
	OHMCONNECT, INC	1	-
WEST	ENERNOC LTD.	16.9	17.4
	ENERSHIFT CORPORATION	3.5	3.9
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	4	4

DR Qualified Capacity - Participant Details

ZONE	Demand Response Auction Participant	Summer Commitment Period (May 01, 2017 - Oct 31, 2017)			Winter Commitment Period (Nov 01, 2017 - Apr 30, 2018)		
		Total DR Qualified (MW)	Surplus Total DR Qualified (MW)	Surplus Virtual DR Qualified (MW)	Total DR Qualified (MW)	Surplus Total DR Qualified (MW)	Surplus Virtual DR Qualified (MW)
BRUCE	ENERNOC LTD.	5	5	5	5	5	5
EAST	ENERNOC LTD.	55	34.3	34.3	55	35.1	35.1
	ENERSHIFT CORPORATION	15.5	2.5	2.5	11.6	4.6	4.6
	GC PROJECT LP	0	0	0	1.7	1.7	1.7
	HYDRO ONE NETWORKS INC.	2	2	0	0	0	0
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	7	2	2	7	2	2
	OHMCONNECT, INC	3	3	3	3	3	3

ESSA	ENERNOC LTD.	13	8	8	13	2.5	2.5
	ENERSHIFT CORPORATION	3.5	3.5	3.5	3.5	2.2	2.2
	GC PROJECT LP	1.6	1.6	1.6	1.8	1.8	1.8
	HYDRO ONE NETWORKS INC.	2	2	0	0	0	0
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	5.5	4.5	4.5	5.5	4.5	4.5
	OHMCONNECT, INC	3	3	3	3	3	3
NIAGARA	ENERNOC LTD.	15.9	2.6	2.6	15.9	3.9	3.9
	ENERSHIFT CORPORATION	3.4	2.4	2.4	3.4	2.4	2.4
	GC PROJECT LP	1	1	1	1.7	1.7	1.7
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.8	1.2	1.2	2.8	1.2	1.2
NORTHEAST	ENERNOC LTD.	10	8.8	8.8	10	9	9
	ENERSHIFT CORPORATION	36.3	15.3	15.3	36.3	15.1	15.1
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	4	4	4	4	4	4
	TEMBEC ENTERPRISES INC.	40	0	0	40	0	0
NORTHWEST	ENERSHIFT CORPORATION	10	10	0	10	10	0
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.1	0	0	2.1	2.1	2.1
	RESOLUTE FP CANADA INC.	54	6	0	54	8	0
OTTAWA	ENERNOC LTD.	10	3.9	3.9	10	3.9	3.9
	ENERSHIFT CORPORATION	20.2	8.2	8.2	20.2	9.2	9.2
	GC PROJECT LP	3.4	3.4	3.4	3	3	3
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	10	4	4	10	4	4
	OHMCONNECT, INC	5	5	5	5	5	5
SOUTHWEST	ENERNOC LTD.	45	11.9	11.9	45	12.7	12.7
	ENERSHIFT CORPORATION	31.5	20.4	20.4	40.4	10.6	10.6
	GC PROJECT LP	5.5	4.3	4.3	5.7	2.6	2.6
	GERDAU AMERISTEEL CORPORATION - CAMBRIDGE	3	0.6	0	3	0.6	0
	HYDRO ONE NETWORKS INC.	2	2	0	0	0	0
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	35.3	25.5	25.5	35	26.7	26.7
	OHMCONNECT, INC	10	10	10	10	10	10
TORONTO	ALECTRA UTILITIES CORPORATION - POWERSTREAM INC.	1	1	1	0	0	0
	ENERNOC LTD.	75	35.6	35.6	75	35.3	35.3
	ENERSHIFT CORPORATION	59.2	18.1	18.1	59.2	10	10
	GC PROJECT LP	8.6	6.1	6.1	8.5	3.3	3.3
	GERDAU AMERISTEEL CORPORATION	72	0	0	72	0	0
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	31	10.8	10.8	29.2	9.6	9.6
	OHMCONNECT, INC	15	14	14	15	15	15
WEST	ENERNOC LTD.	40	23.1	23.1	40	22.6	22.6
	ENERSHIFT CORPORATION	8.9	5.4	5.4	8.8	4.9	4.9
	GC PROJECT LP	4.6	4.6	4.6	4.1	4.1	4.1
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	12.5	8.5	8.5	12	8	8
	OHMCONNECT, INC	5	5	5	5	5	5

BOMA INTERROGATORY 19

Issue 1.0

INTERROGATORY

Reference: Issue 1.0; Exhibit A, Tab 2, Schedule 2, p22; Preamble; EB-2010-0279

In Procedural Order in EB-2010-0279, the Board, in determining the issues list, stated:

> *The Board finds that its mandate in this case is limited to approval of the OPA's administrative fees, which comprise approximately 3% of the OPA's total annual spending. However, the Board is of the view that an assessment of the OPA's administrative fees must require an examination and evaluation of the management, implementation, and performance of the OPA's charge-funded activities. This is necessary because the OPA's administrative and non-administrative activities that are funded by fees and charges, respectively, are unavoidably linked. It is the Board-approved fees that give the OPA the means to acquire and allocate the resources (e.g., staff) that are required to undertake its various responsibilities, resulting in charge-funded activities. The Board finds that an assessment of the performance of the OPA's charge-funded activities is a necessary, legitimate and reasonable tool for determining the effectiveness of the OPA's utilization of its Board approved fees.* (our emphasis)

Further, in its findings in that case, it stated:

> *For the purposes of considering the fiscal 2011 proposed expenditure and revenue requirement and fees application by the OPA, the Board expanded the scope of the issues that had traditionally been considered, the purpose of which was to recognize, as set out above, that the OPA's administrative and non-administrative activities that are funded by fees and charges, respectively, are unavoidably linked. While the Board's mandate in this case is limited to approval of the OPA's administrative fees, which comprise approximately 3% of the OPA's total annual spending, an assessment of the performance of the OPA's charge-funded activities is a necessary, legitimate and reasonable tool for determining the effectiveness of the OPA's utilization of its Board approved fees.* (p10) (our emphasis)

Given the importance of IESO's collaboration between IESO and the LDCs to achieve CDM objectives, distributed generation, broader (residential) demand response implementation, why would it not be important to track the achievement and activation of the necessary two-way communication protocols with the LDCs, and to ensure that the protocols, and links, were in place across the province with all LDCs as soon as possible? Please discuss.

<u>RESPONSE</u>

Please refer to the response to BOMA Interrogatory 1 part (f) at Exhibit I, Tab 1.0, Schedule 2.01.

CME INTERROGATORY 8

Issue 1.0

INTERROGATORY

Reference: Exhibit B, Tab 2, Schedule 1 page 6 of 6

The IESO states:

> *After a review of its accounting practices, the IESO decided to include year-end market account balances on its financial statements in an effort to increase transparency.*

(a) Please indicate what sort of detail this information would provide. For example, would it be a single line item, with an aggregated account balance, or would it be multiple line items outlining separate debits and credits in multiple accounts, and on whose behalf the money was being held?

(b) The IESO has stated that the financial transactions do not impact the IESO's deficit, or revenues and expenses. Please confirm that the proposed reporting of those transactions on its financial statement would also not impact the IESO's deficit, or revenue and expenses.

RESPONSE

(a) The market account balances are found on the face of the Statement of Financial Position and the details of the account balances are found in Note 3 of the audited financial statements (please refer to page 29 of Exhibit A-3-1 and pages 39 to 40 of Exhibit A-3-1, respectively). The market accounts are amounts due to and from market participants held on behalf of the IESO-administered markets (please refer to page 37 of Exhibit A-3-1).

(b) Confirmed. The reporting of the market transactions on the financial statements does not impact the IESO's deficit, or revenue and expenses.

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ENERGY PROBE INTERROGATORY 1

1.0 Revenue Requirement, Operating Costs and Capital Spending

INTERROGATORY

Reference: Exhibit A, Tab 1, Schedule 1, Page 3

a) Please provide a table with approved historic revenue requirement and actual revenues from 2010-2016.

b) Please add a column with the forecast for 2017

c) Show the opening and closing balances in the FDVA for each year.

d) Show the amounts collected/rebated from ratepayers each year.

RESPONSE

a) Please find below a table illustrating historic revenue requirements, actual revenues and the amounts collected from ratepayers from 2010-2016 including a column with the forecast for 2017.

	Board Approved 2010	Board Approved 2011	No Application 2012	No Application 2013	Board Approved 2014	No application 2015	Board Approved 2016	RRS Submission 2017
Net Revenue Requirement (Million)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
IESO	122.8	126.1	No OEB approved Revenue Requirement		126.6	No OEB approved Revenue Requirement	182.1	191.4
OPA	76.0	80.9			60.3			
Actual Revenues (Million)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017 (Forecasted)**
IESO	116.9	112.9	116.3	115.7	129.6	193.0	190.2	191.4
OPA	81.5	77.3	75.6	78.4	60.2			
Fees collected from ratepayers (Million)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017 (Forecasted)**
IESO	116.9	112.9	116.3	115.7	129.5	186.2	185.5	190.8
OPA	76.8	76.4	76.3	75.9	60.2			

b) Please refer to the response to part (a) above

c) The IESO's FVDA has existed since the IESO and OPA merged on January 1, 2015. Opening and closing balance in the FVDA post-merger is as follows:

FVDA (Post Merger)		
(in thousands)	2015	2016
Accumulated Surplus - beginning of year	7,604	10,000
Revenues (before rebates due to marlet participants)	192,994	190,219
Rebates due to market participants	(9,595)	-
Core operation expenses	(181,003)	(177,668)
Accumulated Surplus - end of year	10,000	22,551

d) Please refer to the responses to parts (a) and (c) above.

VECC INTERROGATORY 6

Issue 1.0

INTERROGATORY

Exhibit A-2-2, Page 7 of 31

a) At the above reference it states "*Recent directives aimed at improving the effectiveness of the CFF will result in increased responsibility for the IESO.*" Please provide these directives

RESPONSE

a) Copies of the direction(s) from the Ministry of Energy are included as Attachments 1, 2 and 3.

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Ontario

June 10, 2016

Mr. Bruce Campbell
President and Chief Executive Officer
Independent Electricity System Operator
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Campbell:

RE: Upgrades to Existing Renewable Projects, Conservation First Framework and Support Programs

I write in my capacity as the Minister of Energy in order to exercise the statutory power of ministerial direction I have in respect of the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998,* as amended (the "Act").

Background

Upgrades to Existing Renewable Projects

Renewable energy continues to make a significant contribution to Ontario's diverse electricity supply mix. Ontario is working to achieve its target of bringing 10,700 MW of wind, solar, and bioenergy online by 2021 and 9,300 MW of hydroelectric online by 2025. The government recognizes that maximizing existing utility scale assets may provide an opportunity to increase the value these assets provide to Ontario ratepayers while helping the government achieve its renewable energy targets in the most efficient and cost-effective manner.

Conservation First Framework

On March 31, 2014, the Ontario Power Authority (OPA) was directed to encourage licensed electricity distributors ("Distributors") to maximize administrative and delivery efficiencies for Conservation and Demand Management (CDM) programs by utilizing appropriate delivery models (the "Conservation First Framework Direction").

Specifically, the OPA and/or Distributors were to provide enhanced coordination efforts for program delivery, including by procuring and delivering CDM measures where they would afford significant administrative cost and/or delivery efficiencies, and by targeting consumers with multiple locations across several licensed service areas ("Multi-Distributor Consumers"). I now wish to provide further clarification to that direction.

…/cont'd

Support Programs

In a direction dated November 21, 2014, the OPA was directed to consolidate the Community Energy Partnerships Program (CEPP), the Municipal and Public Sector Energy Partnerships Program (MPSEPP) and the Aboriginal Renewable Energy Fund (AREF) and Aboriginal Transmission Fund (ATF) components of the Aboriginal Energy Partnerships Program (AEPP) into one new program, the Energy Partnerships Program (EPP), which consists of two funding streams: the Partnership Stream and the Project Development Stream.

In the same direction, the IESO was directed to allocate funds totalling not more than $10 million annually to the Partnership Stream, the Project Development Stream, the Aboriginal Community Energy Plans (ACEP), the Aboriginal Renewable Energy Network (AREN) and the Education and Capacity Building (ECB) Program (collectively the “Support Programs”).

It is expected that there will be considerable Support Program funding needs in 2016 with the anticipated launch of both the second Large Renewable Procurement (LRP) process and Feed-in Tariff (FIT) 5. It is also expected that there will be continued interest and uptake by Indigenous communities in the ACEP program as well as considerable funding needs to support the participation of First Nations in remote transmission connection, the implementation of diesel-reduction solutions in remote First Nations that are uneconomic to connect to transmission, and education and capacity building initiatives.

Given that the Partnership Stream and Project Development Stream were not launched in 2015, and given the anticipated funding needs for 2016, I now wish to provide further direction to the IESO with respect to the $10 million annual budget.

Direction

Therefore, pursuant to my authority under sections 25.32 and 25.35 of the Act, I hereby direct the IESO as follows:

1. Upgrades to Existing Renewable Projects

1.1 The IESO shall increase the LRP II overall procurement target to 980 MW by re-allocating 50 MW of capacity from prior procurement targets that have not been met.

1.2 As the IESO continues its engagement process for the development of LRP II, the IESO shall explore opportunities to procure, and if feasible the IESO will procure, additional generation resulting from technological upgrades to and optimization of existing renewable generation facilities.

…/cont’d

2. Conservation First Framework

2.1 The IESO shall, in consultation with Distributors, centrally design, fund and deliver two CDM programs (“Centrally-Delivered Programs”):

a. A province-wide pay-for-performance CDM program for Multi-Distributor Consumers (“Multi-Distributor Program”); and

b. A province-wide whole home CDM pilot program for residential consumers (“Whole Home Pilot Program”).

2.2 Reductions in electricity consumption achieved through the Centrally-Delivered Programs will count towards the Distributor CDM Targets, and towards the Distributors meeting their CDM Requirement (as those terms are defined in the Conservation First Framework Direction).

2.3 The IESO shall, where appropriate, deliver Centrally-Delivered Programs in coordination with natural gas distributors. The IESO may manage its relationship with the natural gas distributors on a non-competitive basis.

2.4 Implementation of the Multi-Distributor Program and Whole Home Pilot Program shall commence by the end of the Fall of 2016.

3. Support Programs

3.1 The IESO shall allocate the $4 million in unspent Support Programs funds from the 2015 budget to the $10 million annual Support Programs budget for 2016, increasing the 2016 budget from $10 million to $14 million.

4. General

4.1 This direction supplements and amends previous directions to the extent that a previous direction is inconsistent with the provisions of this direction. All other terms of any previous direction remain in full force and effect.

This direction takes effect on the date it is issued.

Sincerely,

Bob Chiarelli
Minister

c. Tim O’Neill, Chair, Independent Electricity System Operator
Serge Imbrogno, Deputy Minister, Ministry of Energy
Carolyn Calwell, Director, Legal Services Branch, Ministries of Energy, Economic Development, Employment and Infrastructure, and Research and Innovation

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Ontario

December 16, 2016

Mr. Bruce Campbell
President and Chief Executive Officer
Independent Electricity System Operator
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Campbell:

RE: Non-Utility Generators (NUGs) under Contract with the Ontario Electricity Financial Corporation (OEFC), Feed-in Tariff (FIT) Procurements, 2015-2020 Conservation First Framework, and Delivery of Programs under the Conservation First Framework and the Industrial Accelerator Program

I write in my capacity as the Minister of Energy in order to exercise the statutory power I have to amend or revoke continued directions issued to the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998,* as amended (the "Act").

BACKGROUND

NUGs under Contract with OEFC

On December 14, 2015, the IESO was directed to discontinue negotiations for New Contracts (as defined in that direction) for NUGs, while continuing to engage stakeholders, including NUG representatives as relevant, in the IESO's development of an Ontario capacity auction, rules and protocol for Ontario-based capacity exports and to continue to consider NUGs as options to maintain regional reliability.

A number of the thermal NUGs (OEFC NUGs) have contracts (OEFC Contracts) with the Ontario Electricity Financial Corporation (OEFC) that have not yet ended. The terms of those OEFC Contracts, which were originally signed nearly 20 years ago, provide incentives for most of the OEFC NUGs to operate as baseload electricity resources.

Ontario has put in place legislation for its new cap and trade program to limit greenhouse gas pollution while moving to a low-carbon economy. Given the evolution of Ontario's electricity system, there are opportunities to increase system value, reduce costs for Ontario electricity consumers and lower carbon emissions in the province, if the IESO is able to negotiate replacement contracts (IESO Contracts) with OEFC NUGs that incentivize them to operate in a manner that is better aligned with the integrated power system's needs.

.../cont'd

FIT Procurements

In the 2013 Long-Term Energy Plan, the Ministry of Energy committed to exploring the evolution of the microFIT program to net metering. To support this process, the ministry established an Advisory Working Group and undertook stakeholder engagement, including a posting of proposed updates to Ontario's 2005 Net Metering regulation on the Environmental and Regulatory registries in August 2016. Proposed updates include, for example, removal of the existing 500 kW limit on net metered facilities and enabling storage. The ministry is proposing to bring forward amendments to the regulation in the near future and has identified other potential changes for further consultation in winter 2017.

The ministry has also commenced work on the development of the next Long-Term Energy Plan, with stakeholder and Indigenous engagement to be concluded this month. The development of the next LTEP provides an opportunity to examine the future role of distributed renewable energy generation under an updated net metering regulation and in a manner that recognizes the province's robust electricity supply. It is anticipated that the next LTEP will be published in spring 2017.

2015-2020 Conservation First Framework

On March 31, 2014, the IESO was directed to continue to provide, through its Conservation Fund, support and funding for new and innovative electricity conservation initiatives as a means to assist licensed electricity distributors (Distributors) and others in their conservation efforts.

On November 16, 2015, the Ontario Energy Board (the "Board") issued its five-point multi-year *Regulated Price Plan Roadmap* (Roadmap) to redesign the Regulated Price Plan (RPP) to better respond to policy objectives, improve system efficiency, and to give consumers greater control.

One of the major elements of the Roadmap is the implementation of pilot projects for new pricing models and non-price tools (Pilot Projects). The Pilot Projects would, among other things, test alternative pricing options that are aimed at achieving objectives of the RPP. The results of the Pilot Projects would provide an objective basis to inform future decisions about RPP pricing and the design of new tools for customers to manage their electricity usage and provide for increased system efficiency.

On July 18, 2016, the Board issued its *Regulated Price Plan Roadmap: Guideline for Pilot Projects on RPP Pricing,* inviting Distributors to participate in developing and implementing Pilot Projects. A number of Distributors have filed applications with the Board for that purpose.

These Pilot Projects will be funded through the Conservation Fund so the IESO may use the Pilot Project results to help identify potential complementary Conservation and Demand Management programs or initiatives that could assist RPP customers in responding to different pricing mechanisms.

.../cont'd

Delivery of Programs under the Conservation First Framework and the Industrial Accelerator Program

With the Conservation First Framework and renewed Industrial Accelerator Program now underway for close to two years, opportunities have been identified to improve the availability of programs province-wide for customers. A list of all approved Province-Wide Distributor CDM Programs, Local Distributor CDM Programs and associated program rules are located on the IESO website.

DIRECTION

Therefore, pursuant to my authority under section 25.32 of the Act, I hereby make the following amendments to the directions listed below:

1. NUGs under Contract with OEFC

The direction dated December 14, 2015, titled "Non-Utility Generator Projects, Combined Heat and Power Standard Offer Program 2.0, Chaudière Falls Hydroelectric Generation and Whitesand First Nation Biomass Cogeneration" is amended as follows:

1.1 Paragraph 1.1 is amended to read as follows:
"Subject to paragraphs 1.4 and 1.5 below, discontinue negotiations for New Contracts for NUGs."

1.2 The following new paragraphs 1.4 and 1.5 are added:

1.4 Enter into negotiations with the OEFC NUGs regarding a new IESO Contract to change the incentive structure for supplying electricity or capacity so that the facilities operate in a manner that better aligns with the integrated power system's needs and that would satisfy all of the following requirements:
(i) Expected cost and operability benefits for the Ontario electricity system are greater than the cost and operability benefits afforded under the current OEFC Contract;
(ii) All IESO obligations under the IESO Contract end no later than the date on which the current term of the existing OEFC Contract expires

1.5 The IESO is not required by this direction to enter into an IESO Contract with an OEFC NUG where the IESO is unable to reach agreement with the OEFC NUG on terms that satisfy the requirements set out in paragraph 1.4 of this direction.

2. FIT Procurements

FIT 5 Procurement Target

The direction dated June 24, 2015, titled "Feed-in Tariff (FIT) Program" is amended as follows:

.../cont'd

2.1 The paragraph that reads: "For greater clarity, the IESO shall include any unallocated capacity from each future annual microFIT target to the subsequent FIT procurement target" is revoked.

2.2 The paragraph that reads: "Similarly, the IESO shall add any remaining unallocated capacity from FIT procurements to the subsequent FIT procurement target." is revoked.

The direction dated April 5, 2016, titled "Future Renewable Energy Procurements" is amended as follows:

2.3 Paragraphs 2.2 and 2.3 are revoked.

2.4 A new paragraph 2.2 is added that reads: "The FIT 5 procurement target shall be up to 150 MW."

FIT 6 Procurement

The direction dated June 12, 2013, titled "Renewable Energy Program" is amended as follows:

2.5 By revoking the paragraph that reads: "Furthermore, in each of the next four years, starting in 2014, the OPA will award up to 150 MW of contracts for Small FIT Projects. If the full annual Small FIT MW procurement target is not allocated in a given year, the remaining capacity will be added to the Small FIT MW procurement target in the following year." and replacing that paragraph with a new paragraph that reads: "Furthermore, in each of the next three years, starting in 2014, the IESO will award up to 150 MW of contracts for Small FIT Projects. If the full annual Small FIT MW procurement target is not allocated in a given year, the remaining capacity will be added to the Small FIT MW procurement target in the following year. The final FIT application period will be held in 2016. The IESO shall cease accepting applications under the FIT program by December 31, 2016 and any unallocated procurement target at the end of that procurement process will remain unallocated."

3. 2015-2020 Conservation First Framework

Support and Funding for Research and Innovation

3.1. The direction issued on March 31, 2014, entitled "2015-2020 Conservation First Framework" is amended by adding the following new paragraphs to the section titled "Support and Funding for Research and Innovation":

8.3 The IESO shall provide, through its Conservation Fund, support and funding for pilot projects for new pricing models and non-price tools (Pilot Projects) specified by the Board.

.../cont'd

8.4 Since the Pilot Projects are adhering to the Board's guidelines and processes related to such Pilot Projects, the IESO shall provide such Conservation Fund funding without adherence to the Conservation Fund's application process or other requirements. The IESO will create a simplified process for enabling Distributors delivering Pilot Projects to access Conservation Fund funding.

8.5 The IESO shall make Conservation Fund funding available for the Pilot Projects in such amounts as determined by the Board.

8.6 The IESO shall fund only Distributor costs for delivering the Pilot Projects in accordance with the Board specified Pilot Project expenditures. The IESO will pay the Distributor for Pilot Project costs on the terms set out in the procurement contract with the Distributor delivering the Pilot Project.

8.7 The IESO shall enter into one or more procurement contracts with Distributors selected by the Board to fund the Pilot Projects specified by the Board. The IESO shall use a simplified and expedited procurement process for that purpose.

4. Delivery of Programs under the Conservation First Framework and the Industrial Accelerator Program

4.1. The direction issued on March 31, 2014 entitled "2015-2020 Conservation First Framework" is amended by adding a new sub-section 3.6 to Section 3: CDM Plans and Programs, as follows:

3.6 i. Further to the Distributor CDM Requirement that includes making available a core set of province-wide CDM programs in their licensed service areas, and despite Section 1.3 of the Conservation First Framework Direction, the IESO shall request that Distributors that are not making available one or more approved Province-Wide Distributor CDM Programs, considering the eligible program participants in their licensed service area per the program rules, resubmit revised CDM Plans by May 1, 2017 outlining how they will make all approved Province-Wide Distributor CDM Programs available in their licensed service areas beginning in 2017 using their allocated CDM budget. As new approved Province-Wide Distributor CDM Programs and associated program rules become available, the IESO shall request Distributors with eligible program participants to resubmit revised CDM Plans within four months, outlining how they will make the new approved Province-Wide Distributor CDM Program available in their licensed service area.

.../cont'd

ii. Where a Distributor with eligible program participants is not making an approved Province-Wide Distributor CDM Program(s) available to eligible program participants in its licensed service area, the IESO shall deliver the Province-Wide Distributor CDM Program(s) in that Distributor's licensed service area if a Distributor has not submitted a revised CDM Plan indicating an intention to do so per the timelines in Section 3.6(i).

iii. The IESO shall establish a budget to fund the approved Province-Wide Distributor CDM Programs that are to be delivered by the IESO that is within the budget established under Section 1.4 of the Conservation First Framework Direction.

iv. Where the IESO delivers an approved Province-Wide Distributor CDM Program in a Distributor's licensed service area, the associated electricity savings shall not count toward that Distributor's CDM Target.

4.2. The direction issued on July 25, 2014, entitled "Industrial Accelerator Program" is amended by adding the following new sub-sections to section 3.1, as follows:

vi. The IESO shall undertake a pay-for-performance pilot program for customers that are eligible for the Industrial Accelerator Program that is consistent with the Centrally-Delivered Pay-for-Performance Multi-Distributor CDM Program.

vii. The IESO shall allow transmission-connected customers with distribution-connected sites to elect to have their transmission-connected and distribution-connected sites administered through the Industrial Accelerator Program. Any associated electricity savings that result from distribution-connected sites participating in the Industrial Accelerator Program shall count toward Distributor CDM Targets under the Conservation First Framework Direction.

General

5.1. This direction supplements and amends previous directions to the extent that a previous direction is inconsistent with the provisions of this direction. All other terms of any previous directions remain in full force and effect.

.../cont'd

This direction takes effect on the date it is issued.

Sincerely,

Glenn Thibeault
Minister

c. Tim O'Neill, Chair, Independent Electricity System Operator
Rosemarie Leclair, Chair and CEO, Ontario Energy Board
Serge Imbrogno, Deputy Minister, Ministry of Energy
Carolyn Calwell, Director, Legal Services Branch, Ministries of Energy; Economic Development and Growth; Infrastructure; Research, Innovation and Science; and Accessibility

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Ministry of Energy

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Ontario

MC-2017-1301

August 4, 2017

Mr. Peter Gregg
President and Chief Executive Officer
Independent Electricity System Operator
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Gregg:

RE: 2015-2020 Conservation First Framework and Partnering with Green Ontario Fund; Delivery of Conservation and Demand Management Programs Targeted to the Low-Income Customer Segment

I write in my capacity as Minister of Energy to exercise the statutory power of ministerial direction I have in respect of the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998* in regard to conducting activities in relation to the Conservation First Framework (CFF), and in particular, in support of programs to be implemented by the Ontario Climate Change Solutions Deployment Corporation (Green Ontario Fund).

Partnering with Green Ontario Fund

Since 2005, the IESO has developed considerable expertise and resources in the design and delivery of conservation and energy efficiency programs.

On March 31, 2014, my predecessor directed the Ontario Power Authority (now the IESO) to establish a new six-year CFF that would enable the achievement of cost-effective conservation across the province, and help Ontario remain on track to achieve the Province's long-term electricity savings target of 30 terawatt-hours in 2032 (the "CFF Direction"). Among other items, the CFF Direction requires the IESO to provide enhanced co-ordination efforts where these will afford significant administrative cost and/or delivery efficiencies for Conservation and Demand Management (CDM) programs.

…/cont'd

On June 10, 2016, the CFF Direction was amended to direct the IESO to design, fund and deliver two Centrally-Delivered Programs: a provincewide, pay-for-performance program for Multi-Distributor Consumers ("Multi-Distributor Program") and a provincewide whole home CDM pilot program ("Whole Home Pilot Program"). The intention was that the IESO delivery of these programs would result in cost efficiencies and a streamlined customer experience.

Further to my correspondence to the President and CEO of the IESO, dated February 13, 2017, the Ministry of Energy and the IESO have continued to work with the Ministry of the Environment and Climate Change (MOECC) to support the establishment of the Green Ontario Fund, and to ensure that this new entity complements and builds on the success of the Province's existing suite of CDM programs. Through the collaborative work undertaken to date by the IESO, the MOECC and the Ministry of Energy, it has become clear that continued collaboration and co-ordination will enhance and serve the goals of both the CFF and the Green Ontario Fund, achieving even greater efficiencies and ensuring a customer-focused approach.

The Green Ontario Fund will, as part of its mandate, fund programs to stimulate the development of industry, trades and business undertakings in Ontario that further deployment of technology that reduces greenhouse gas emissions from buildings and the production of goods. Continued collaboration and co-ordination will enhance exposure of consumers to electricity CDM programs and improve consumer access to measures related to conservation and management of electricity demand by having the IESO partner with the Green Ontario Fund in the design and delivery of certain Green Ontario Fund programs. In this regard, the IESO will, as a complement to the CFF, enter into one or more agreements with the MOECC or the Green Ontario Fund to support, directly or through contracted third parties, the design and/or delivery of certain Green Ontario Fund programs, as further detailed in this direction.

Delivery of Programs Targeted to the Low-Income Customer Segment under the CFF

A guiding principle of the 2015-2020 CFF is that CDM programs for low-income residential customers will be improved.

In order to improve the availability of CDM programs to customers, including programs targeted to the low-income customer segment, on December 16, 2016, the CFF Direction was amended by adding a new sub-section 3.6 to, among other things, require the IESO to request distributors to resubmit their CDM plans indicating how they would make available each Provincewide Distributor CDM program in their licensed service area, beginning in 2017.

While all LDCs elected to offer Provincewide Distributor CDM programs targeted to the low-income customer segment, there remains an opportunity to further improve the availability of and access to CDM programs targeted to the low-income customer segment through IESO delivery.

…/cont'd

Direction

Therefore, pursuant to my authority under section 25.32 of the *Electricity Act, 1998*, I hereby make the following amendments to the direction dated March 31, 2014, entitled "2015-2020 Conservation First Framework," as amended by adding:

3.7 i. The IESO shall enter into one or more agreements with the MOECC (on behalf of the Green Ontario Fund) or the Green Ontario Fund, whereby the IESO will collaborate with the MOECC or the Green Ontario Fund to support, directly or through contracted third parties, the design and delivery of Green Ontario Fund Programs with a focus on reducing greenhouse gas emissions associated with energy usage and energy sources from Ontario residences and businesses, such as:

a. Residential Direct Install and Energy Review
b. Provincewide Smart Thermostat Rebate Program
c. Low Carbon Technology Incentives Program for Homes and Multi-Unit Residential Buildings
d. Low Carbon Technology Incentives Program for Small and Medium-Sized Commercial Businesses
e. Direct Install and Energy Review for Manufacturing Small and Medium-Sized Enterprises
f. Programs targeted to on-reserve Indigenous customers
g. Programs targeted to low-income customers

ii. To support the delivery of the Green Ontario Fund Programs and maximize efficiencies, the IESO shall as necessary procure and contract with service vendors and leverage existing service vendors, and may enter into other arrangements with other third parties as appropriate.

iii. The IESO shall, in collaboration with the Green Ontario Fund, the MOECC and the Ministry of Energy, and in consultation with electricity and natural gas distributors as appropriate, make reasonable efforts to avoid marketplace confusion in relation to its work in designing, delivering, administering or in assisting with the design, delivery and administration of the Green Ontario Fund Programs, and to ensure the prudent use of funds by avoiding duplication with Provincewide Distributor CDM Programs.

iv. The IESO shall include in any agreement(s) that may be entered into pursuant to subparagraph i provisions regarding required cost-effectiveness thresholds or other required criteria for Green Ontario Fund Programs, and required Evaluation, Measurement and Verification of the energy savings associated with Green Ontario Fund Programs.

…/cont'd

v. Subject to approvals processes required by Government related to funding from the Green Ontario Fund, the IESO shall include in any agreement(s) that may be entered into pursuant to Paragraph i, provisions that require the recovery of all costs related to the design, delivery and administration of Green Ontario Fund Programs from the Green Ontario Fund, with the exception of the Provincewide Smart Thermostat Rebate Program, where funding of the costs related to electricity reductions will be funded from the CFF budget.

vi. The IESO shall maintain a detailed accounting of costs, results and greenhouse gas emissions reductions related to the design, delivery and administration of Green Ontario Fund Programs, including staff resourcing costs.

vii. The IESO shall keep the Ministry of Energy informed of overall progress and key developments related to the design, delivery and administration of Green Ontario Fund Programs, including by submitting reports and information quarterly, or as may be otherwise required from time to time.

3.8 i. Despite Section 1.3 of the CFF Direction, the IESO shall centrally design, fund and deliver across all Distributors' licensed service areas a Provincewide CDM Program(s) targeted to the low-income customer segment ("Provincewide Low-Income CDM Program(s)"), beginning January 1, 2018, within the budget established under Section 1.4 of the CFF Direction.

ii. Reductions in electricity consumption achieved through the IESO-delivered Provincewide Low-Income CDM Program(s) shall not count towards a Distributor's CDM Target.

3.9 Despite Section 3.8, the IESO may continue to allow a Distributor to deliver, funded through their allocated CDM budget, a CDM program(s) targeted to the low-income customer segment in its service area if the Distributor demonstrates, in the determination of the IESO, a commitment to serving this sector.

Consequential Amendments

The Direction is further amended by amending sections 3.1 and 3.5 as follows:

- Amending section 3.1 by deleting "ii. Low-income"
- Deleting 3.5 xii. and replacing it with:
    - *3.5 xii: The IESO shall, or shall require Distributors, where applicable, to co-ordinate and integrate CDM programs targeted to the low-income customer segment under the CFF with Gas Distributor low-income conservation programs.*

…/cont'd

General

This direction supplements and amends previous directions to the extent that a previous direction is inconsistent with the provisions of this direction. All other terms of any previous direction remain in full force and effect.

This direction takes effect on the date it is issued.

Sincerely,

Original signed by

Glenn Thibeault
Minister

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VECC INTERROGATORY 10

Issue 1.0

INTERROGATORY

Exhibit A-2-2, Page 12 of 31

a) Please explain the negative interest rate expense beginning in 2017

RESPONSE

a) Please refer to the response to Society Interrogatory 1 at Exhibit I, Tab 1.3, Schedule 8.01.

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VECC INTERROGATORY 13

Issue 1.0/3.0/5.0 (2.2, 5.4)

INTERROGATORY

Exhibit A-2-2, Page 16 of 31

> *As of December 31, 2016, the IESO was managing more than 27,350 contracts that account for more than 27,350 MW of generation. These include contracts for approximately 24,500 microFIT projects (representing 216 MW) and 3,950 Feed-in Tariff or FIT projects (representing 4,750 MW). The majority of those contracts are in operation with 1,050 projects (or 3,281 MW) under development.*

a) Please confirm that IESO manages the same number of contracts as MW of generation (i.e. on average each contract is for 1 MW).

b) Please reconcile the number of contracts (27,350) with the number of microfit projects and FIT projects (24,500+3,950=28,450).

RESPONSE

a) The numbers quoted included estimates at the time. The actual number as of December 31, 2016 was a total of 28,341 contracts managed, accounting for a total capacity of 27,242 MW, resulting in each contract being an average of 1 MW in size.

b) As of December 31, 2016, there were a total of 24,622 MicroFIT projects and 3,428 FIT projects, totalling 28,050 contracts. The remaining 291 contracts were neither MicroFIT nor FIT projects.

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VECC INTERROGATORY 14

Issue 1.0 (1.3)

INTERROGATORY

Exhibit A-2-2, Page 17 of 31

a) Please provide the referenced reports of the Conservation group review.

b) Please outline the expected savings in conservation delivery.

c) How will expected savings in the Conservation Group impact the proposed revenue requirement?

RESPONSE:

a) VECC confirmed to the IESO that links to the requested information would suffice.

Conservation Targets and Results by LDC can be found in the following location on the IESO website:

http://www.ieso.ca/en/sector-participants/conservation-delivery-and-tools/conservation-targets-and-results

Third-party Evaluation reports can be found in the following location on the IESO website:

http://www.ieso.ca/en/sector-participants/conservation-delivery-and-tools/evaluation-measurement-and-verification

b) There is no impact on the IESO's proposed revenue requirement nor are there specific savings the IESO is able to identify.

c) There is no impact on the IESO's proposed revenue requirement.

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VECC INTERROGATORY 15

Issue 1.0 (1.3)

INTERROGATORY

Exhibit A-2-2, Page 19 of 31

a) Please provide the status of the new corporate website.

b) What is the forecast cost of this project?

RESPONSE

a) The new corporate website was launched in March 2017.

b) The project has been completed and is in service. Costs in 2017 for the corporate website including consolidation and enhancement to Save-On-Energy were $0.5 million. Please refer to the response to VECC interrogatory 12 Exhibit I, Tab 1.5, Schedule 9.12.

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VECC INTERROGATORY 18

Issue 1.0 (1.3)

INTERROGATORY

Exhibit A-3-1, Page 50 of 56

a) Please provide the 2016 actual lease costs

RESPONSE

a) Actual lease costs related to IESO office space for 2016 are $4.5 million.

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VECC INTERROGATORY 21

Issue 1.0 (1.3)

INTERROGATORY

Exhibit B, Tab 1, Schedule 1, Page 8 of 11

a) Please update Table 5 to show 2017 actual spending to August 1 and the remaining forecast budget.

RESPONSE

a) The IESO expects to be on budget for 2017 as shown in Table 5 in Ex B-1-1 page 8. For actual spending to date please refer to the response to PWU Interrogatory 2 part (c) at Exhibit I, Tab 1.6, Schedule 6.02.

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VECC INTERROGATORY 22

Issue 1.0/5.0 (1.3, 5.3)

INTERROGATORY

Exhibit B, Tab 1, Schedule 1, Page 10 of 11

a) Please provide the external direction for IESO providing support to the Ontario Climate Change Solutions Deployment Corporation. If no such direction was given please explain why IESO is providing the described supports.

RESPONSE

a) Please refer to the February 13, 2017 letter from the Minister of Energy in Attachment 1.

Ministry of Energy

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Ontario

FEB 13 2017

MC-2017-273

Mr. Bruce Campbell
President and Chief Executive Officer
Independent Electricity System Operator
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Office of the President & CEO
RECEIVED
FEB 15 2017
Independent Electricity System Operator

Dear ~~Mr. Campbell~~: Bruce,

The Ministry of Energy is pleased to be working with the Ministry of Environment and Climate Change (MOECC) to support the creation and development of the proposed "Ontario Climate Change Solutions Deployment Corporation" (OCCSDC). The IESO will have an important role to play in ensuring that this new entity builds on the success of the province's existing suite of conservation and energy efficiency programs. Toward this end, I am writing to ask your assistance in supporting establishment of the new entity.

Since 2005, the IESO has developed considerable expertise and resources in the design and delivery of conservation and energy efficiency programs. The government sees an opportunity to leverage and enhance existing program resources, where appropriate. I understand that preliminary discussions are underway between the Ministry of Energy, MOECC, IESO and other stakeholders on the proposed role for existing program delivery agents, such as the IESO, and how these delivery agents can provide online and other customer services. I support further discussions to determine how the IESO can support implementation and early adoption of the OCCSDC's services, and request that the IESO work with my ministry and MOECC to determine what mechanisms might be necessary in order for the IESO to provide its services to OCCSDC.

Furthermore, I request the IESO maintain a detailed accounting of costs related to the implementation of the OCCSDC including, but not limited to, technical service costs as well as staff resourcing costs. The IESO may wish to consult with Infrastructure Ontario to understand how it bills for services provided to ministries. I expect that all costs incurred by the IESO related to the implementation of the OCCSDC would be recovered from the Greenhouse Gas Reduction Account, not from electricity ratepayers.

.../cont'd

I commend the IESO for its leadership in conservation, and appreciate your continued support to help Ontario homes and businesses make low-carbon energy choices.

Sincerely,

Glenn Thibeault
Minister

c: Hon. Glen Murray, Minister, MOECC
Mandy Maghera, Chief of Staff, MOECC
Paul Evans, Deputy Minister, MOECC
Hon. Liz Sandals, President, Treasury Board Secretariat
Mike Jancik, Chief of Staff, Treasury Board Secretariat
Helen Angus, Deputy Minister, Treasury Board Secretariat
Serge Imbrogno, Deputy Minister, Ministry of Energy
Tim O'Neill, Chair, IESO
Gillian McEachern, Executive Director of Policy, Office of the Premier
Jacob Mksyartinian, Director of Fiscal Planning and Policy Delivery, Office of the Premier

VECC INTERROGATORY 24

Issue 1.0 (1.4)

INTERROGATORY

Exhibit B, Tab 3, Schedule 1, Page 3 of 3

a) What is the current regular staff vacancy?

b) What is the current temporary staff vacancy rate?

RESPONSE

a) Average headcount for YTD June 2017 is 692 FTEs, which is 5 higher than budgeted. This consists of 27 regular position vacancies, offset by 32 temporary positions over budget, on an average YTD basis.

2017 YTD June Average FTEs	**Actual**	**Budget**	**Variance**
Regular	647	674	(27)
Temp	45	13	32
Total	**692**	**687**	**5**

b) Please refer to the response to (a) above.

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VECC INTERROGATORY 25

Issue 1.0 (1.4)

INTERROGATORY

Exhibit C, Tab 2, Schedule 1, Attachment 4

a) Please amend Appendix 2-K to show executive compensation separately.

RESPONSE

a) Please refer to the response to AMPCO Interrogatory 27 at Exhibit I, Tab 5.2, Schedule 10.27.

VECC INTERROGATORY 26

Issue 1.0/5.0 (1.3/5.4)

INTERROGATORY

Exhibit C, Tab 2, Schedule 1

a) Please provide a detailed breakdown of Appendix 2-JC in the form of the table file in Appendix A – Allocation Detail Worksheet found in EB-2015-0275, Exhibit B-1-1, Attachment 3, Page 39 of 41 which shows the 2015 through 2018 actual and forecast costs

RESPONSE

a) The table, as prepared, aims to provide for comparability among annual data sets. As the IESO integrated its systems and infrastructure post-merger in 2015, comparable actual data is not available for 2015 due to the impact of the transition. The requested table below is populated with data for 2016 and beyond.

Business unit/Department	2016 Actual ($K)	2017 Budget ($K)	2018 Budget ($K)
CEO	**7,304**	**7,258**	**7,283**
CEO Office	5,861	5,679	5,678
Internal Audit	1,443	1,579	1,605
Market & System Operations	**31,969**	**33,016**	**32,807**
VP Office	1,630	1,656	1,684
System Performance	5,530		
Reliability Assessments	3,003		
Connections & Registration	2,991		
Operational Effectiveness	3,875		
System Operations	11,417		
Market Forecasts & Integration	2,434		
Operations Change Initiatives	1,090		
Market Operations		15,921	15,050
Power System Assessments		8,584	8,968
Operations Integration		6,855	7,104
Market & Resource Development	**18,239**	**20,022**	**20,575**
VP Office	13,112	13,974	14,544
Contract Management	2,222	3,382	3,365
Resource Development & Strategy	1,204	2,050	2,050
Markets	1,701	615	615
Conservation & Corporate Relations	**16,554**	**17,591**	**18,562**
VP Office	12,878	13,633	14,603
Conservation Performance	885	1,044	1,044
Alliance & Marketing	375	449	619
Program & Partner Services	396	222	312
Stakeholder & Public Affairs	2,018	2,243	1,983
Information & Technology Services	**46,341**	**45,783**	**46,131**
VP Office	1,346	958	999
Organizational & Governance Support	13,042	12,870	12,982
Business Solutions	14,785	14,682	14,779
Technology Services	17,167	17,273	17,371
Planning, Legal, Indigenous Relations & Regulatory Affairs	**14,506**	**16,187**	**16,320**
VP Office	10,198	11,011	11,145
Corporate Counsel	1,491	2,073	2,073
Board	687	715	715
Regulatory Affairs	1,569	1,446	1,446
First Nations & Metis Relations	410	490	490
Resource Integration	92	249	249
Transmission Integration	60	202	202
Corporate Services	**16,773**	**16,399**	**16,774**
VP Office & Corporate Controller	3,952	3,648	3,957
Financial Planning & Analysis	1,260	1,538	1,571
Treasury Operations	1,655	1,816	1,829
Human Resources	4,702	3,926	3,905
Settlements	5,204	5,471	5,513
Market Assessments & Compliance Division	**2,980**	**3,835**	**3,917**
Market Renewal		**12,000**	**14,000**
Corporate Adjustment	**26,916**	**19,274**	**19,733**
Total	**181,581**	**191,364**	**196,103**