# Electricity planning outlooks as context for 2017 LTEP development

*Prepared for Discussion with the Minister of Energy*

June 15, 2017

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# Purpose

- To provide an overview of the IESO’s updated electricity planning outlook developed to inform the preparation of the 2017 Long-Term Energy Plan

# The Ontario Planning Outlook is the starting point for the IESO's updated planning outlook which will be used to inform the development of the 2017 LTEP

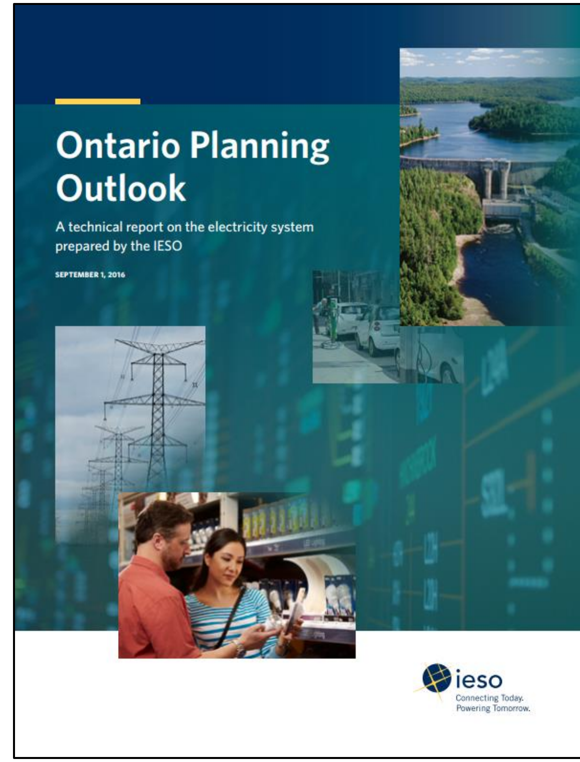
Bill 135, the *Energy Statute Law Amendment Act*, 2016

Received Royal Assent on June 9, 2016

IESO Technical Report, "Ontario Planning Outlook"

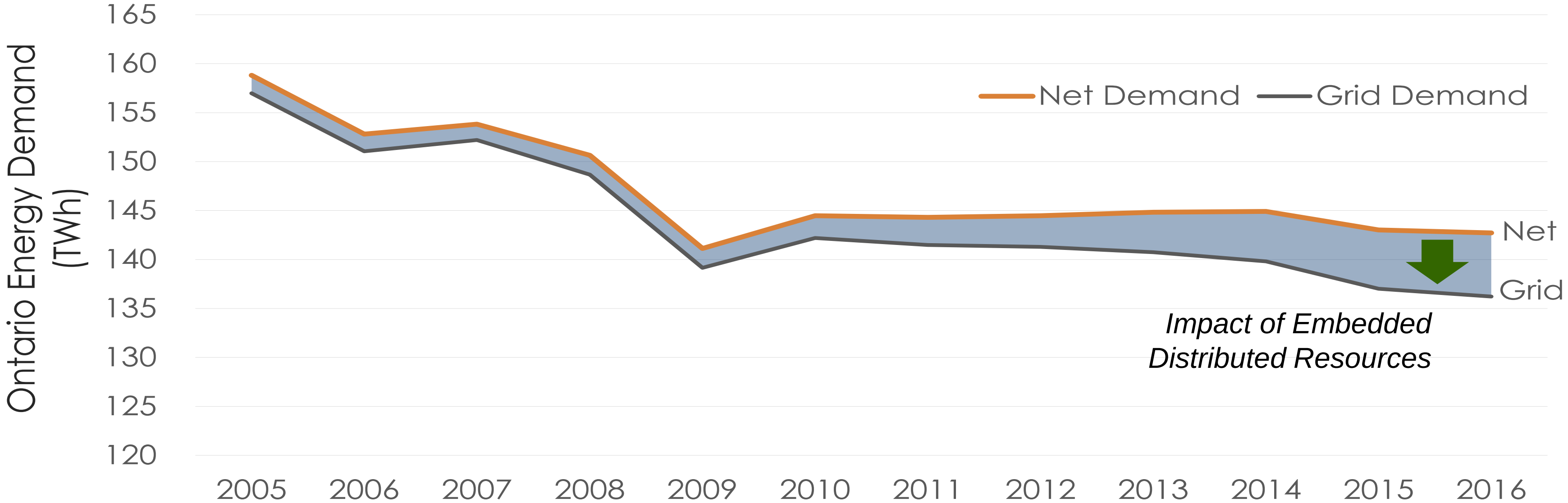
Ontario Government's Long-Term Energy Plan (LTEP)

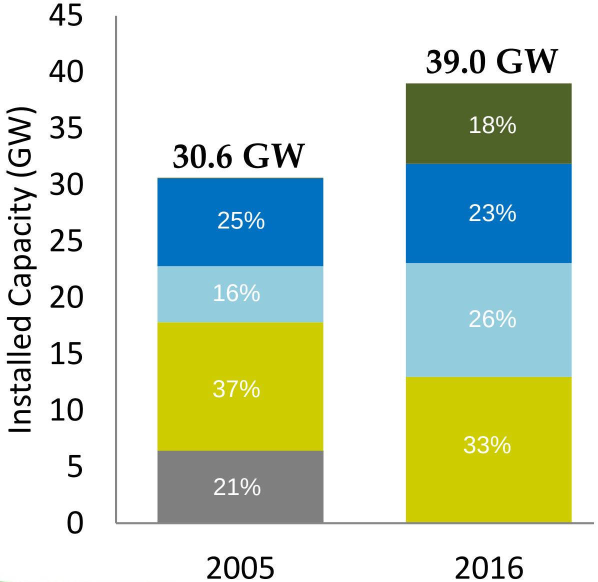
IESO Implementation Plan

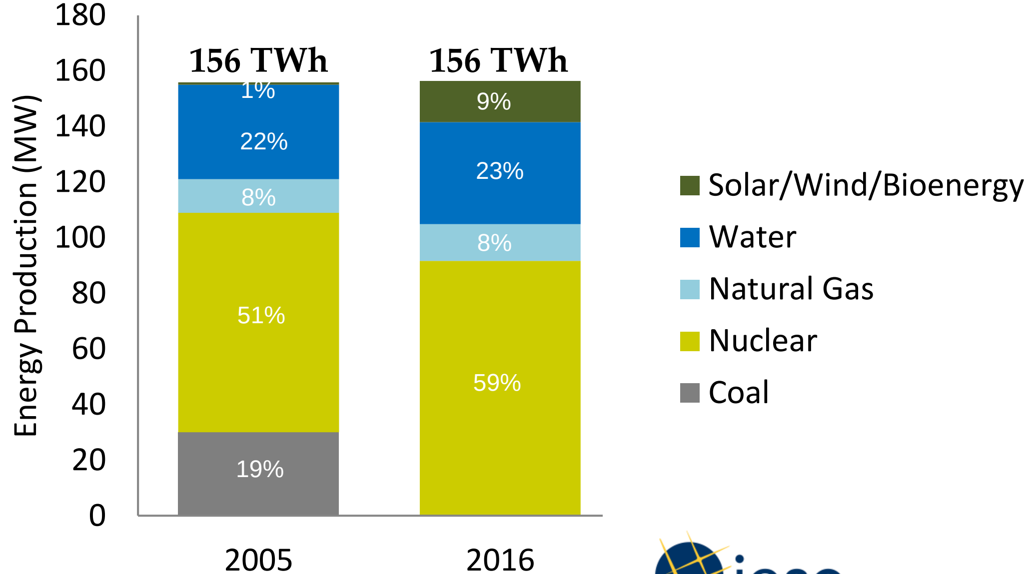



The report , supporting modules, and data tables can be found on the IESO's website: www.ieso.ca

# Over the past decade, electricity demand has been on a declining trend. At the same time Ontario saw additions in non-emitting resources.

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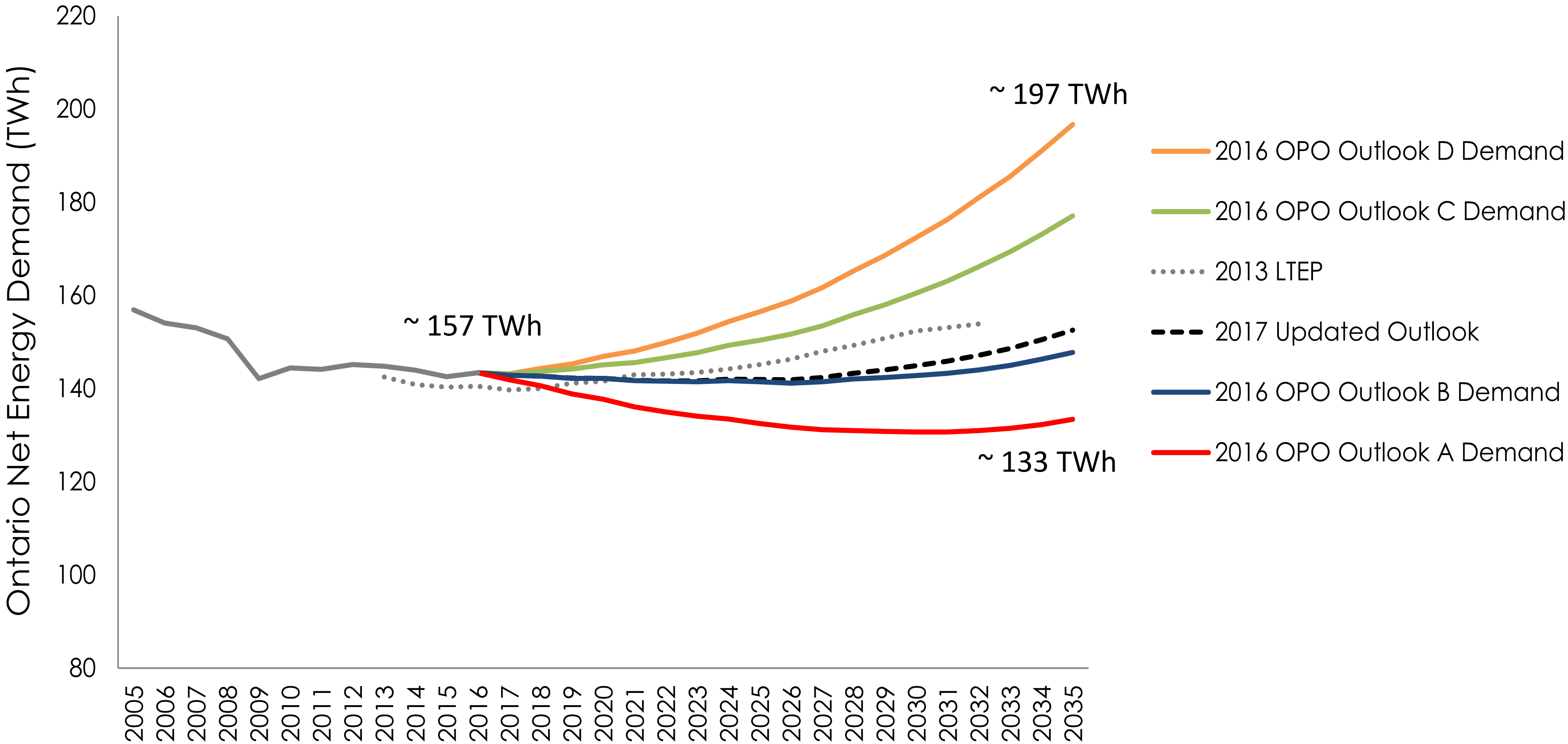
The bar charts include embedded distributed resources.

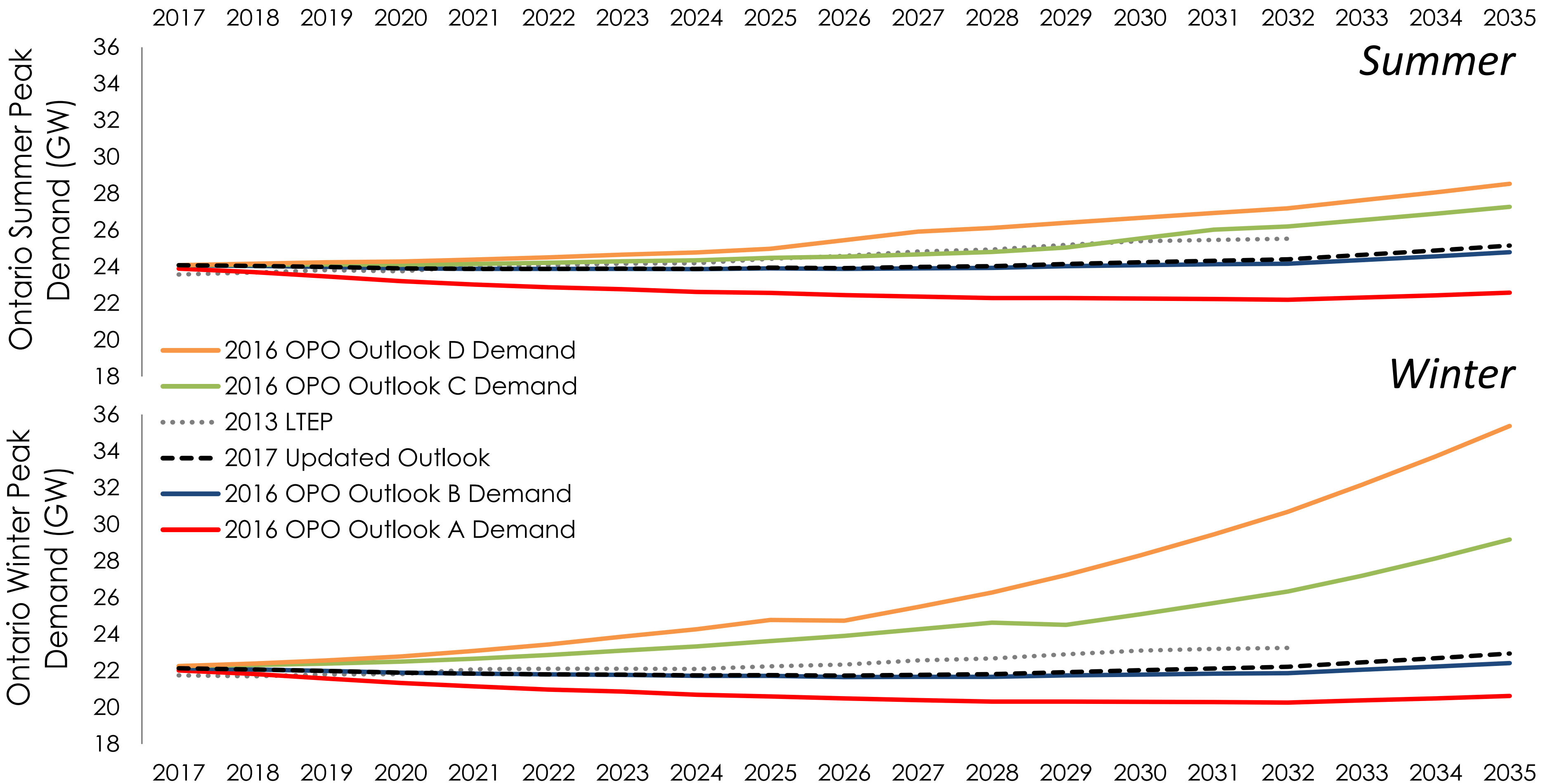
# Electricity demand is the starting point for the planning outlook. The updated energy demand outlook is about 5 TWh higher than the OPO Outlook B by 2035. The updated outlook reflects an accelerated increase in electric vehicles.




- 2.4 million EVs in the updated outlook vs 1 million in OPO Outlook B, by 2035. This higher level of EV uptake is consistent with Outlook C and D in the OPO.

Outlooks A through D per 2016 Ontario Planning Outlook report.

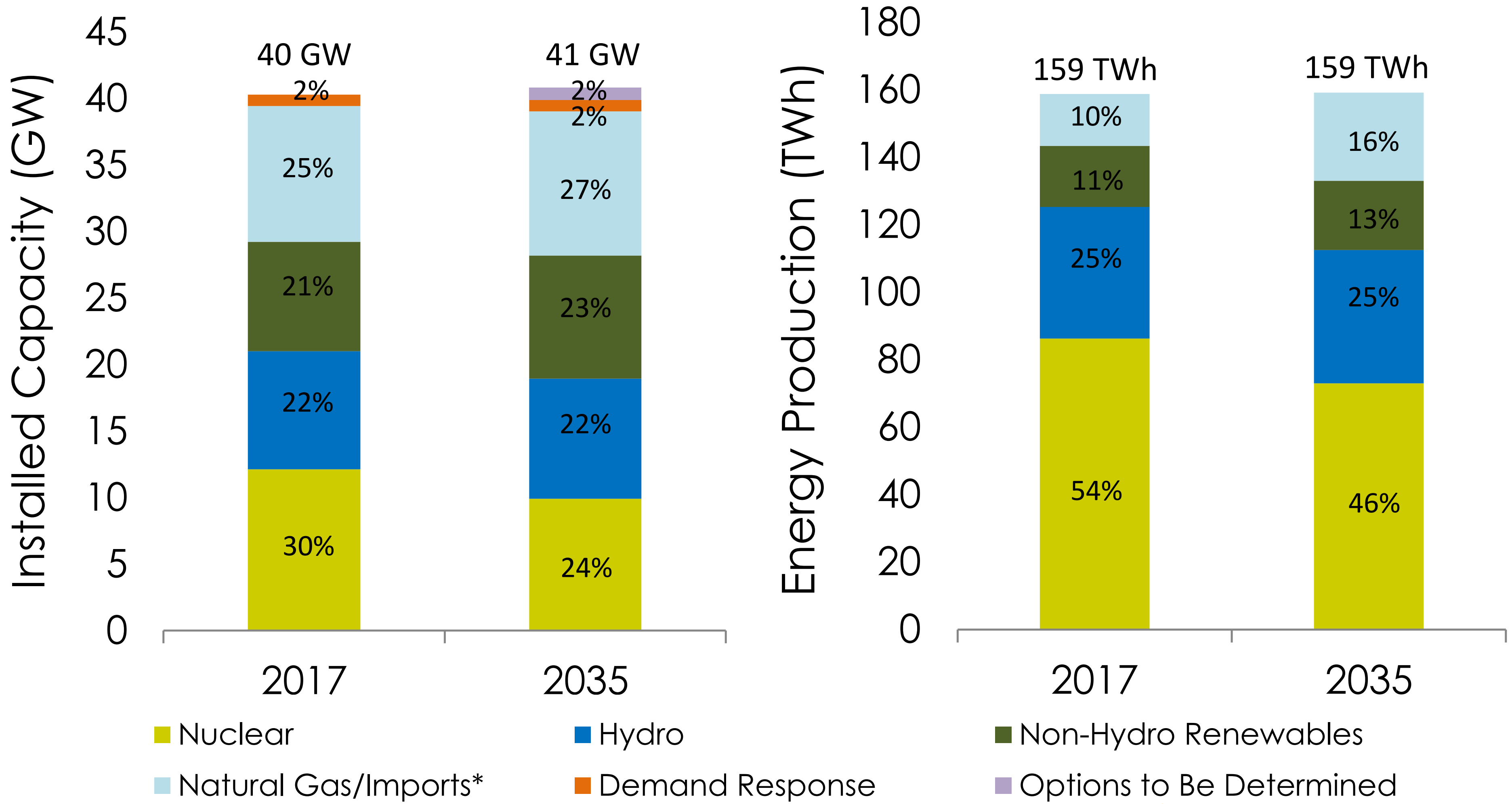
Relative to OPO Outlook B, the updated outlook sees peak demand increase by about 400 MW in the summer and 500 MW in the winter due to higher demand from electric vehicles. As illustrated in the OPO, in higher demand outlooks driven by growth in electric space heating, Ontario becomes a winter peaking jurisdiction.





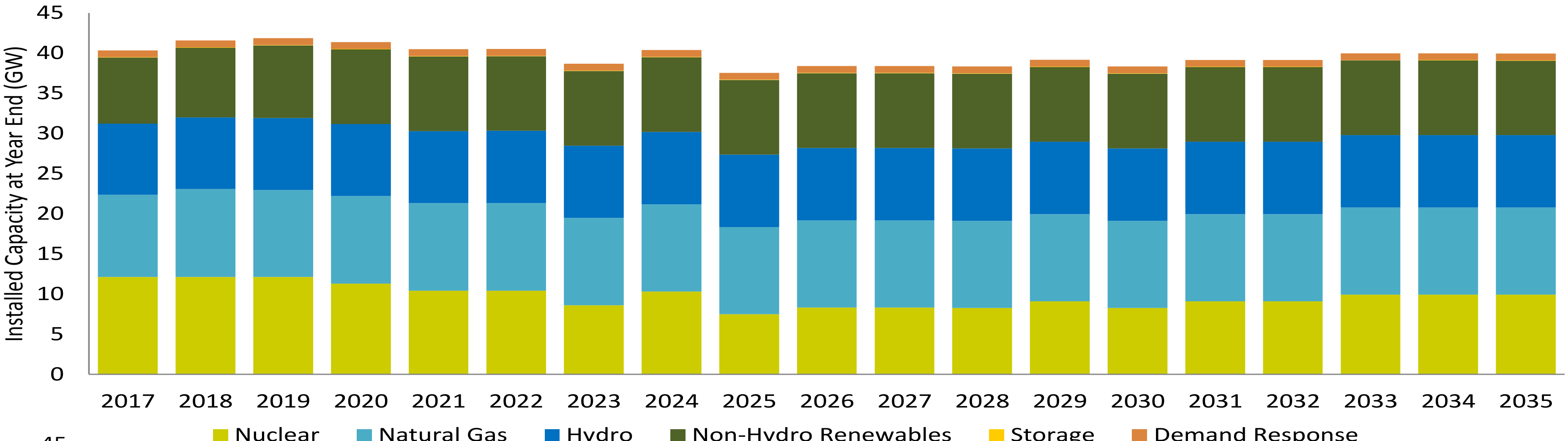

Outlooks A through D per 2016 Ontario Planning Outlook report.

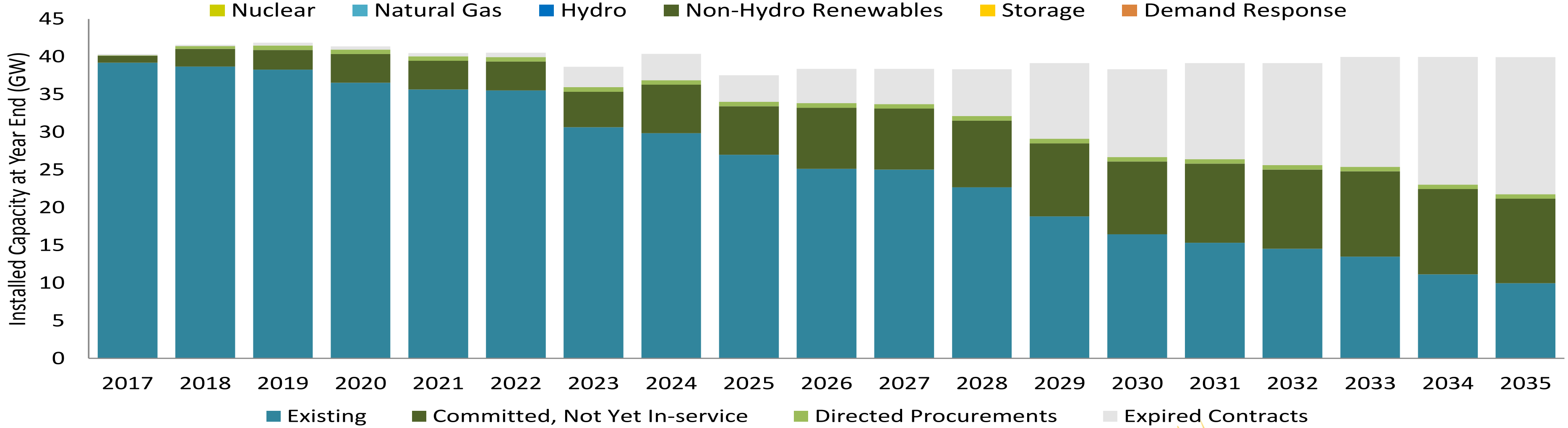
## Although total installed supply and energy production from the supply mix remain relatively stable over the planning horizon, changes do take place within the supply mix. Share of nuclear declines over time while supply from renewable resources increases. Natural gas balances the difference.




*"imports" represent economic (non-firm) imports that take place in the real-time electricity market.

In addition to changes to the supply mix, sizeable amounts of resource turnover is also taking place. This includes commissioning and retirement of generation facilities, refurbishment of the nuclear fleet resulting in some temporary supply reductions in the mid-2020s, and about 18 GW of supply reaching the end of contract term which provide opportunities for reinvestment or divestment.

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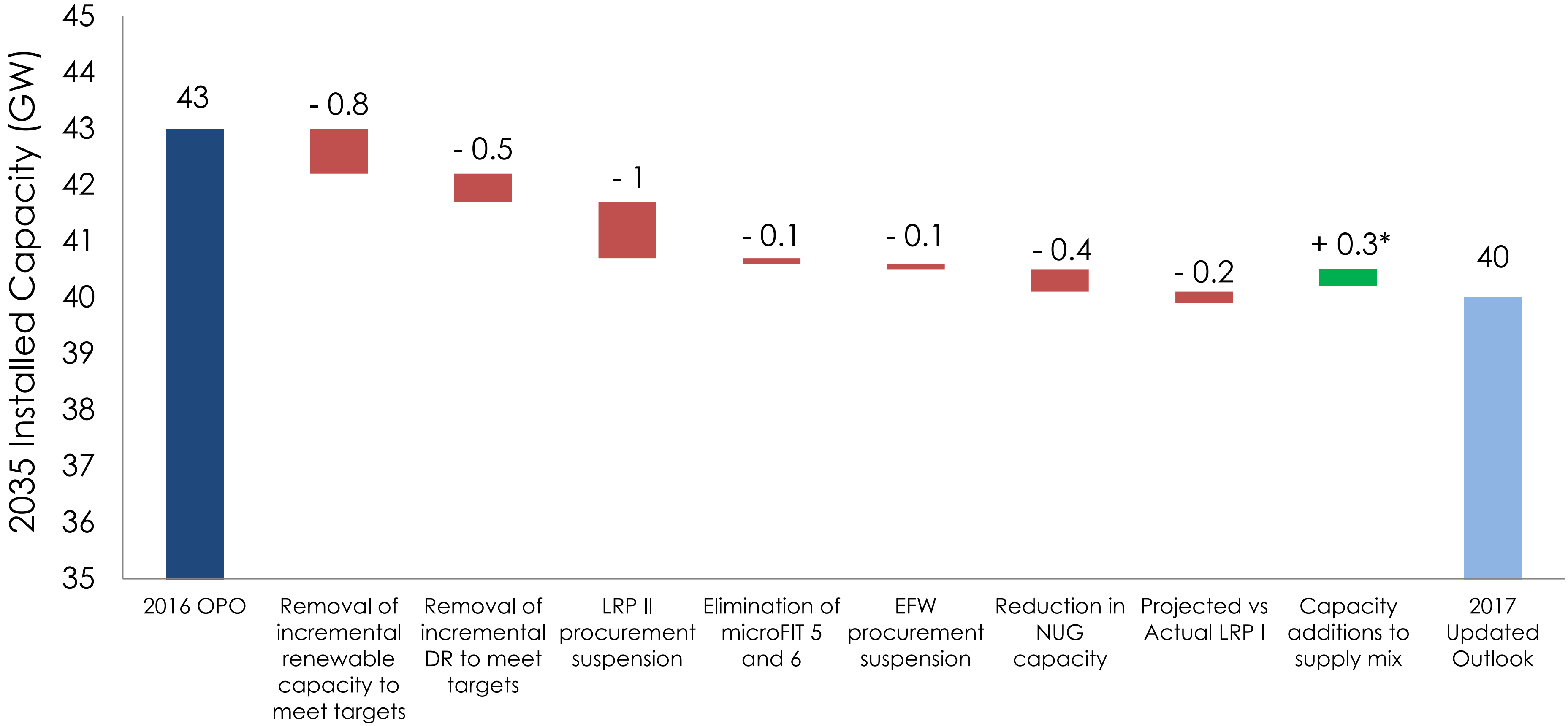
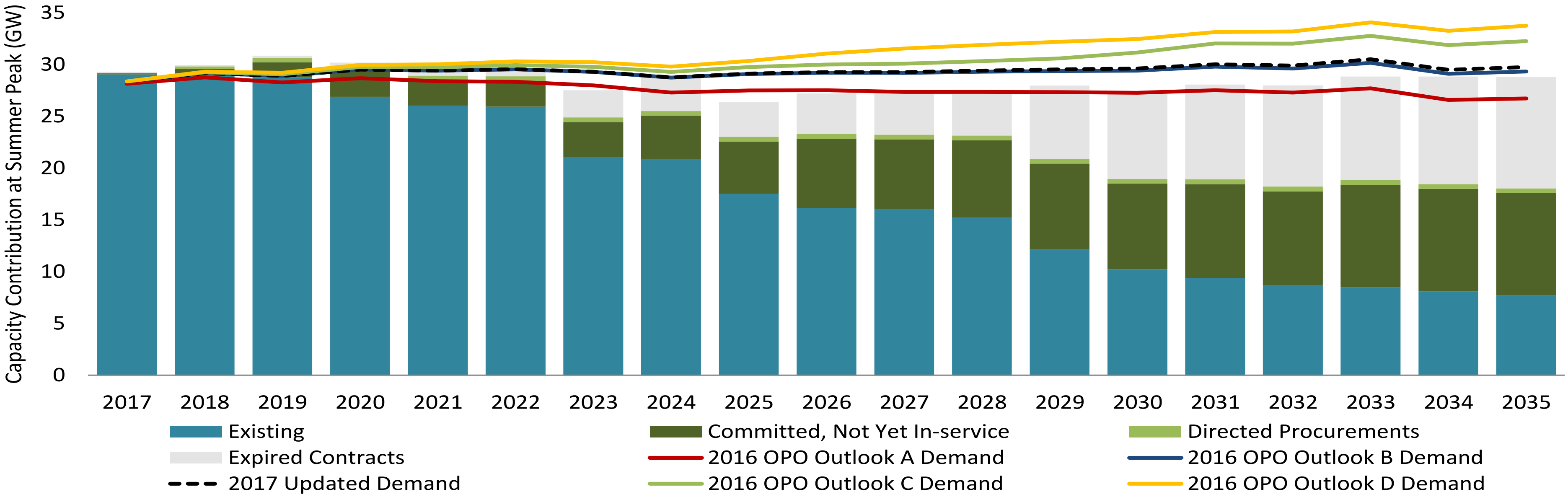
# Since the 2016 OPO, there has been a 3 GW reduction in supply resources, driven by changes to the outlook for procurements and resource targets

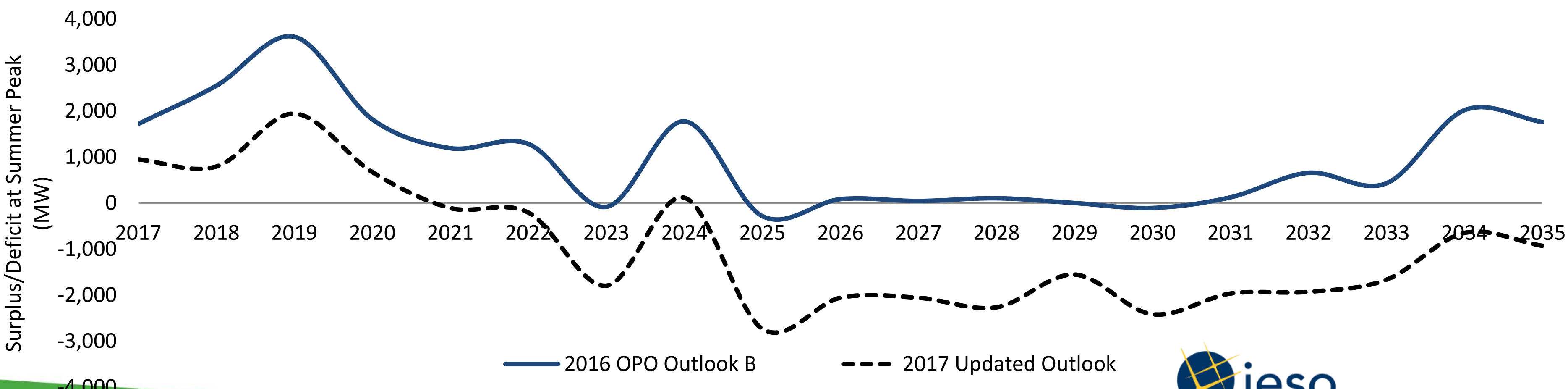



- The reduction in supply is attributable to reductions in the outlook for directed resources – resources that were assumed to be acquired to meet procurement directives and targets established in the 2013 LTEP (for example. LRP II, future FIT/mFIT, etc).

*0.3 GW of capacity additions is comprised of the in-service of renewable resources and capacity uprates since the 2016 OPO.

## The OPO Outlook B saw Ontario having sufficient resources to meet demand throughout the planning outlook. In the updated outlook, Ontario sees a need for additional resources in the mid 2020s attributable to the reduction in directed resources and higher demand from electric vehicles (as described in the previous slides).

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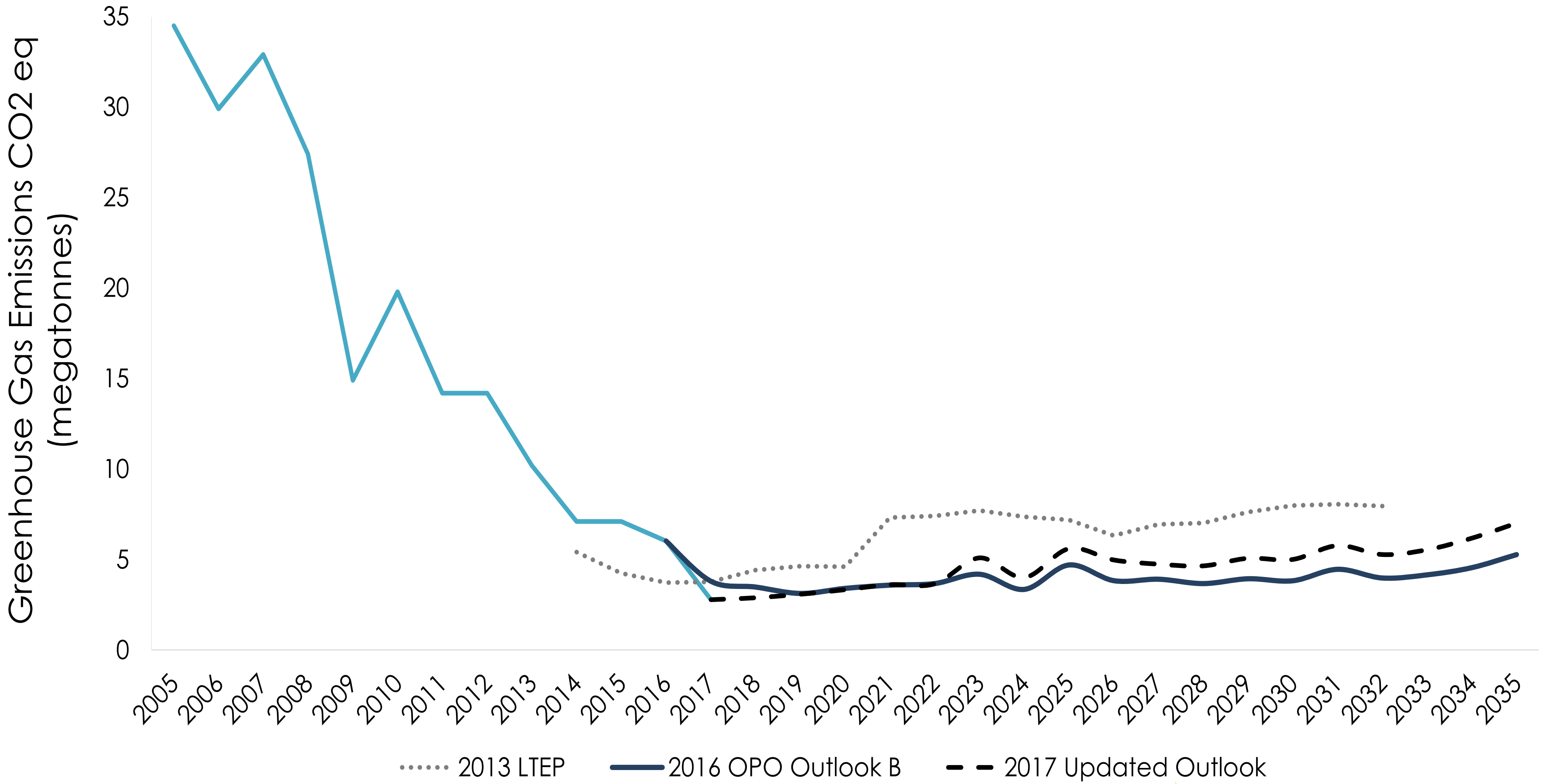
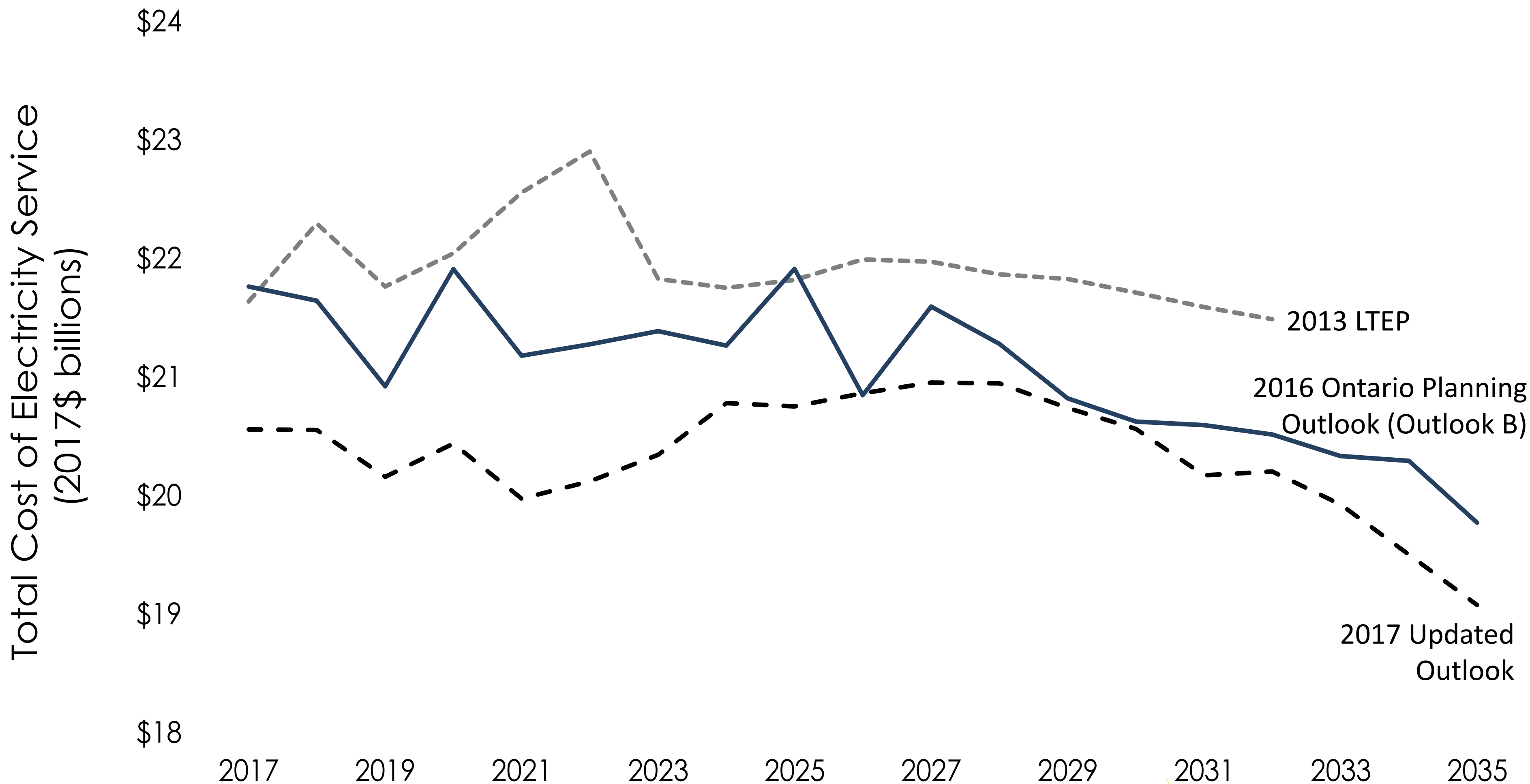
Greenhouse gas emissions continue to remain significantly lower than historical levels and is less than that projected in the 2013 LTEP. Relative to the 2016 OPO, the updated outlook sees an increase in GHG emissions driven by higher electricity demand and reduction in non-carbon emitting resources.



Outlooks for the total cost of electricity service have been trending lower with each iteration of the outlook. The 2013 LTEP saw cost of electricity service averaging $22B/year over the planning horizon. This reduced to $21B/year in the 2016 OPO Outlook B and $20B/year in the updated outlook.

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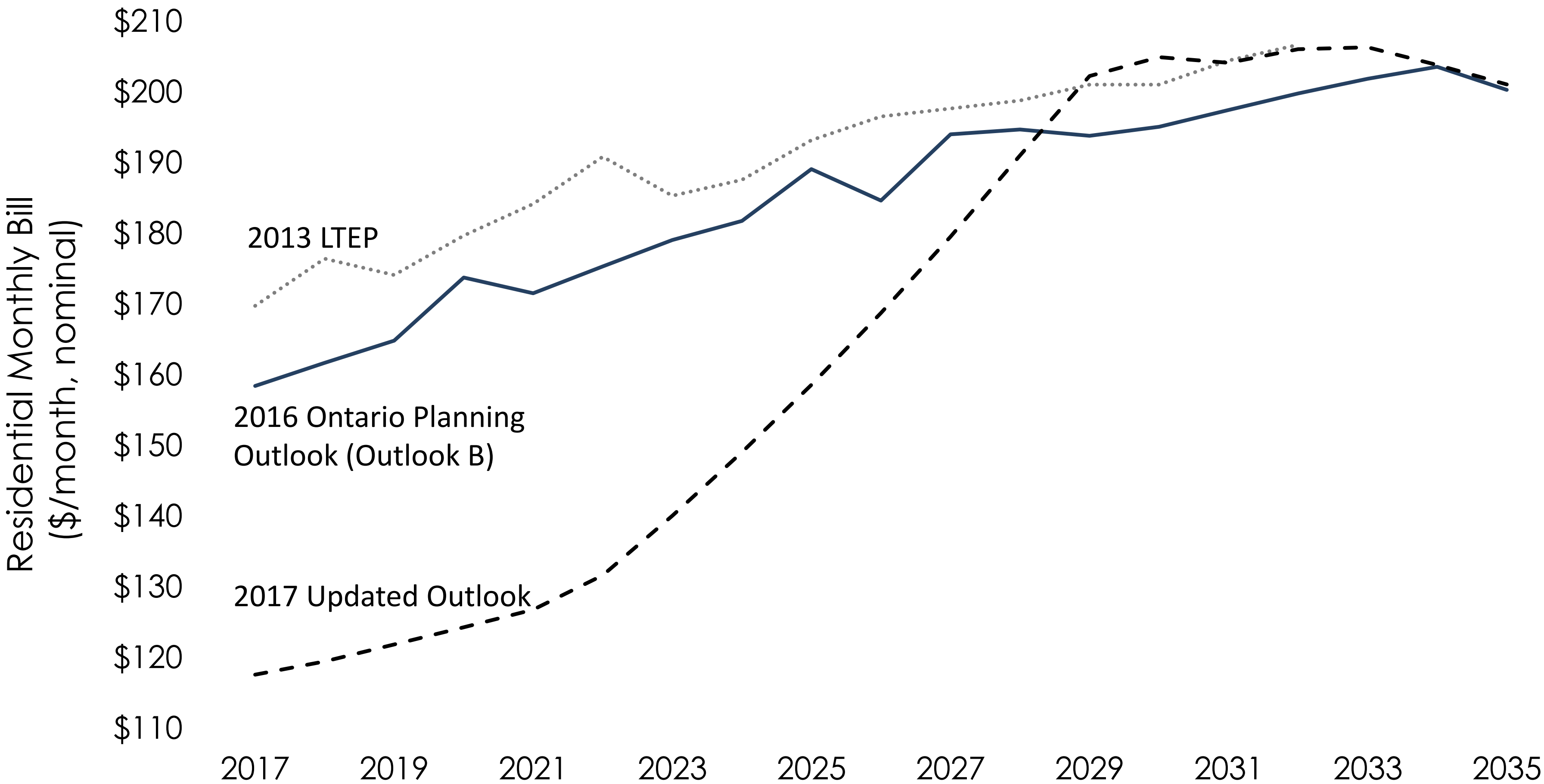
## In the near-term, the outlook for residential bills is lower than the 2013 LTEP and 2016 OPO Outlook B. This is mostly due to the Fair Hydro Plan. Towards the end of the planning horizon, the updated cost outlook is similar to the 2013 LTEP and 2016 OPO Outlook B.

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# At the request of the Ministry of Energy, the IESO assessed additional outlooks for consideration and cost control options

- The IESO has analyzed a range of electricity system outlooks to inform the development of the 2017 LTEP. Beyond the outlook presented in previous slides which reflect the conservation savings outlined in the 2013 LTEP, the IESO considered higher levels of long-term conservation savings, informed by the 2016 Market Achievable Potential ("MAP") study:
  - Conservation savings of 30 TWh by 2032, per the 2013 LTEP and consistent with the 2016 Ontario Planning Outlook (31 TWh by 2035)
  - Conservation savings of 41 TWh by 2032, consistent with the 2016 MAP study (46 TWh by 2035)

- Further, the IESO examined options to reduce residential electricity bills. Five scenarios are explored:

  Case 1: A basecase (the updated planning outlook which reflects achievement of 2013 LTEP CDM targets)

  Case 2: Replacement of Thunder Bay and Atikokan generating stations at a more competitive cost at contract expiry

  Case 3: Funding conservation through the GGRA starting in 2018

  Case 4: Funding a percentage (10%) of renewables costs through the GGRA starting in 2017

  Case 5: Not proceeding with MicroFit 2017 and FIT 5, and exiting LRP1 contracts

  - The above are analyzed cumulatively: each scenario incorporates the cost control measures of all scenarios that precede it. Residential bills are projected for each scenario, total costs and industrial rates are also reported.

  - Additional options are considered conceptually, pending completion of analysis underway at this time. These include revisiting ICI eligibility and adapting plans for Pickering extended operations.

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**Summary of the IESO's assessment of higher levels of conservation:** Pursuing all of the CDM identified in the MAP study under the current framework for conservation delivery would result in higher electricity costs. Further work is needed to improve understanding of conservation potential and to enhance the value of this resource in long-term electricity system plans.

- Higher levels of conservation savings per the Market Achievable Potential (MAP) as compared to current levels of targeted conservation result in:
  - Generally no change in the timing of capacity needs but a reduction in longer-term resource needs
  - Reduction in greenhouse gas emissions by an average of about 0.7 MT per year between 2017 and 2035
  - Average cost for incremental greenhouse gas emission reduction ranging from $100 - $200/tonne
  - Increases in surplus energy by an average of about 2 TWh per year starting in 2021
  - Increases in total system costs by an annual average of about $100M to $200 M per year, but ranges from an increase of $600 M per year in the earlier years of 2021 to a decrease of $300 M per year by 2035
  - Increase in average residential bills by $11/month and industrial rates by $1/MWh to $3/MWh

- Opportunities exist to improve understanding of CDM potential and enhance value of this resource:
  - Better targeting and right-sizing conservation could help improve cost-effectiveness and reduce surpluses
  - Better optimizing supply system adaptations to higher levels of conservation could help improve cost-effectiveness and reduce surpluses
  - Opportunities exist to enhance value of conservation by pursuing additional savings through codes/standards and improving allocation/funding of program budgets/expenditures

- The Ministry of Energy could consider reaffirming commitments to current conservation targets in the 2017 LTEP but continue to explore options to best realize higher levels of conservation in view of opportunities for reductions in electricity costs and emissions

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**Summary of the IESO's assessment of cost control considerations:** the current projection for residential electricity bills is generally, but not always, lower than in the 2013 LTEP. Cost control measures could reduce residential bills to below 2013 LTEP projections.

- Base case with OFHP but without further cost control measures: currently projected residential bills are lower than in the 2013 LTEP for most years, except in 2029 and 2030, where they are higher by roughly $1/Month and $4/Month, respectively

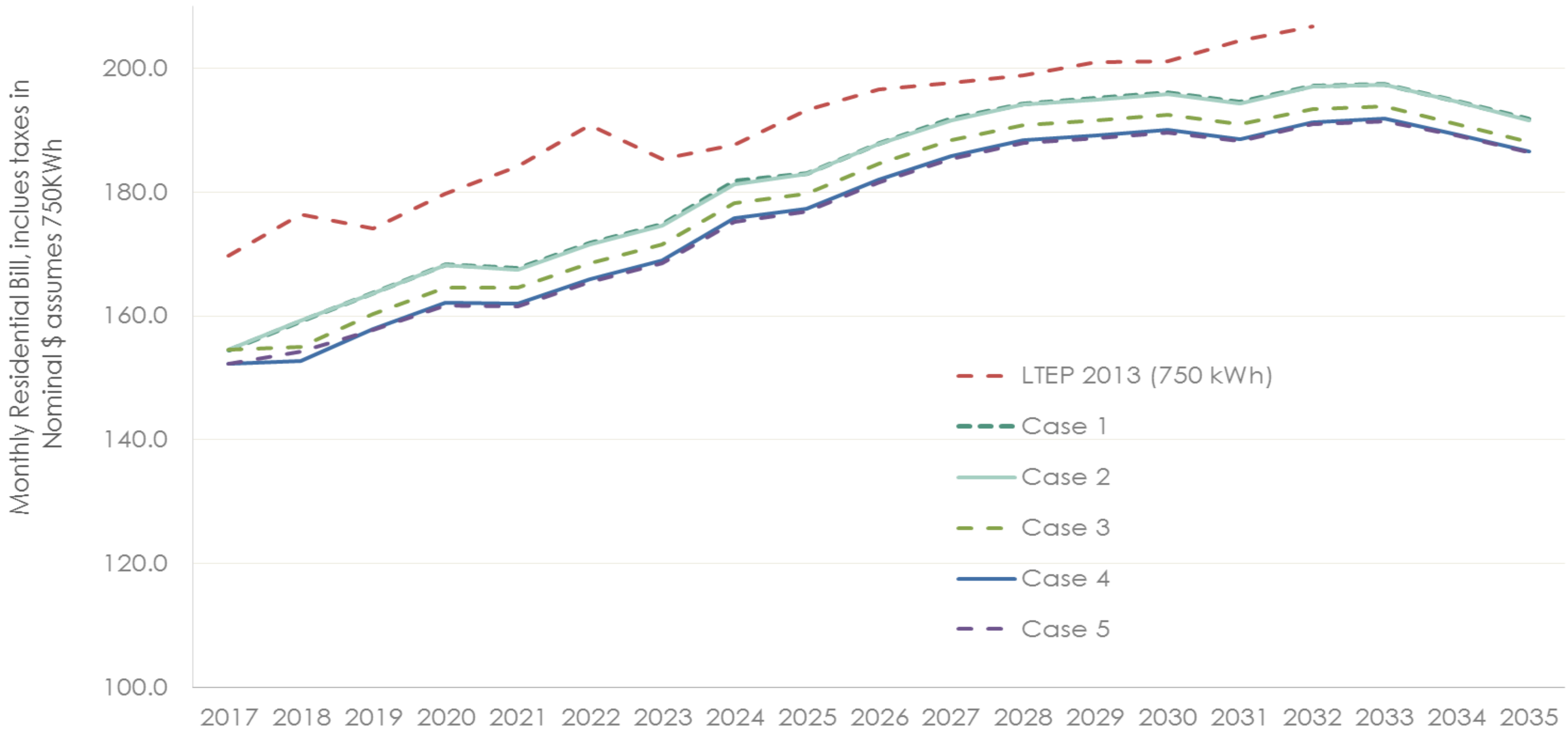
- In conjunction with the OFHP, replacing the Thunder Bay and Atikokan generating stations at a more competitive cost and also funding conservation through the GGRA starting in 2018 would result in lower residential monthly bills than projected in the 2013 LTEP in all years over the planning period

- Cost control measures as identified in Cases 3 to 5 could reduce residential bills by up to $5 per month compared to the 2013 LTEP by 2032. This difference is interpreted as within the range of modelling approximation.

- The cost control options considered here generally fall into four categories:
  a. Reducing investment and operating costs (i.e. buying less and/or buying-operating at a lower cost)
  b. Deferring ratepayer costs (i.e. OFHP)
  c. Shifting ratepayer costs (i.e. GGRA)
  d. Reallocating costs among ratepayer classes (i.e. revisiting ICI eligibility)

- Of the five scenarios considered, most fall into the "deferring" and "shifting" categories outline above: this is a function of Ontario's current state of electricity resource commitment. Options that fall into category "a" include not proceeding with FIT5 and Microfit2017 and replacing Thunder Bay and Atikokan at a lower cost. Limiting the scope of ICI eligibility might not only reallocate costs, but also reduce total costs.

## **Overview of all Cases without OFHP:** residential bills under all cases would remain below 2013 LTEP projections in all years, prior to accounting for the OFHP

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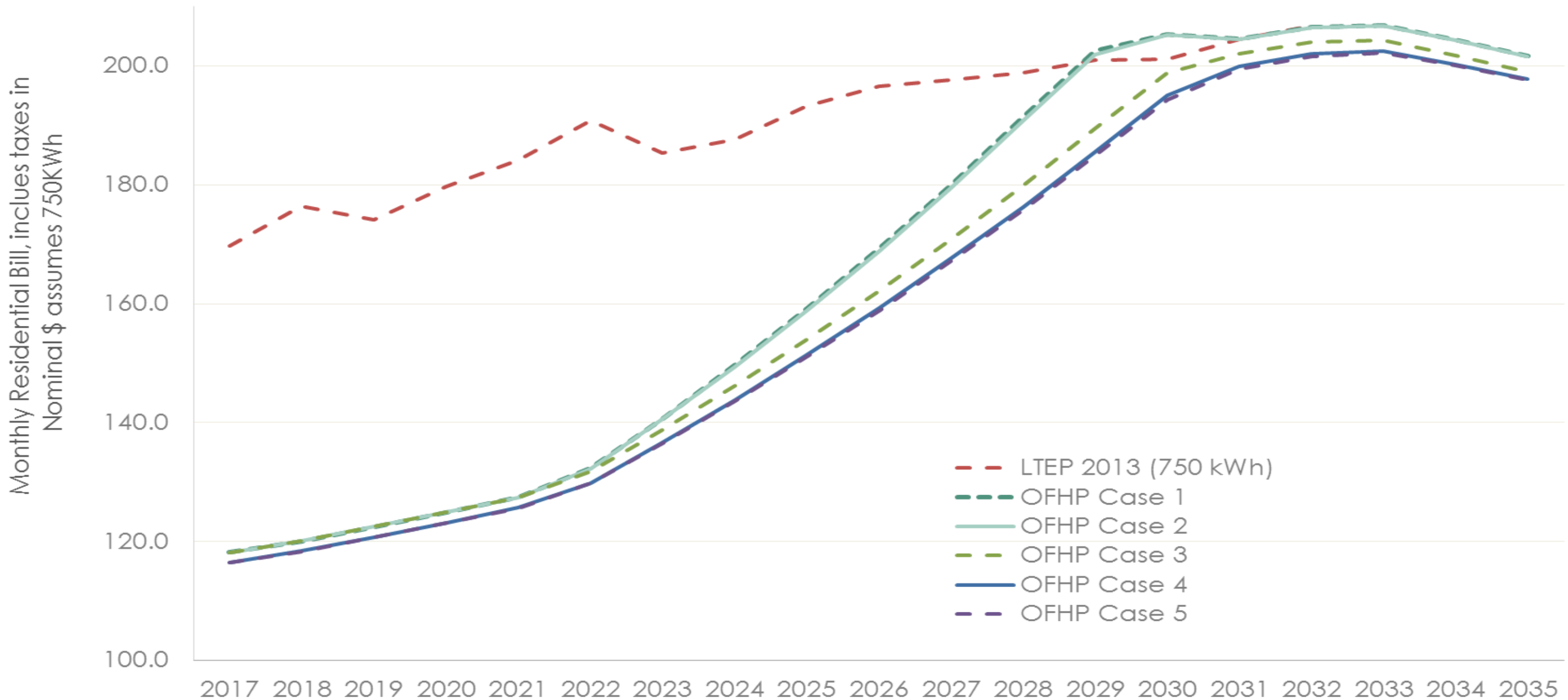
**Overview of all cases with OFHP:** After accounting for the OFHP, bills would be notably lower relative to 2013 LTEP projections over the next decade or so, then would return to bills consistent with the 2013 LTEP projection. Cases 1 and 2 would exceed the 2013 LTEP projections in some years; cases 3 through 5 would remain below 2013 LTEP projections in all years, and by 2032 it will lower the bills by about $5/month.

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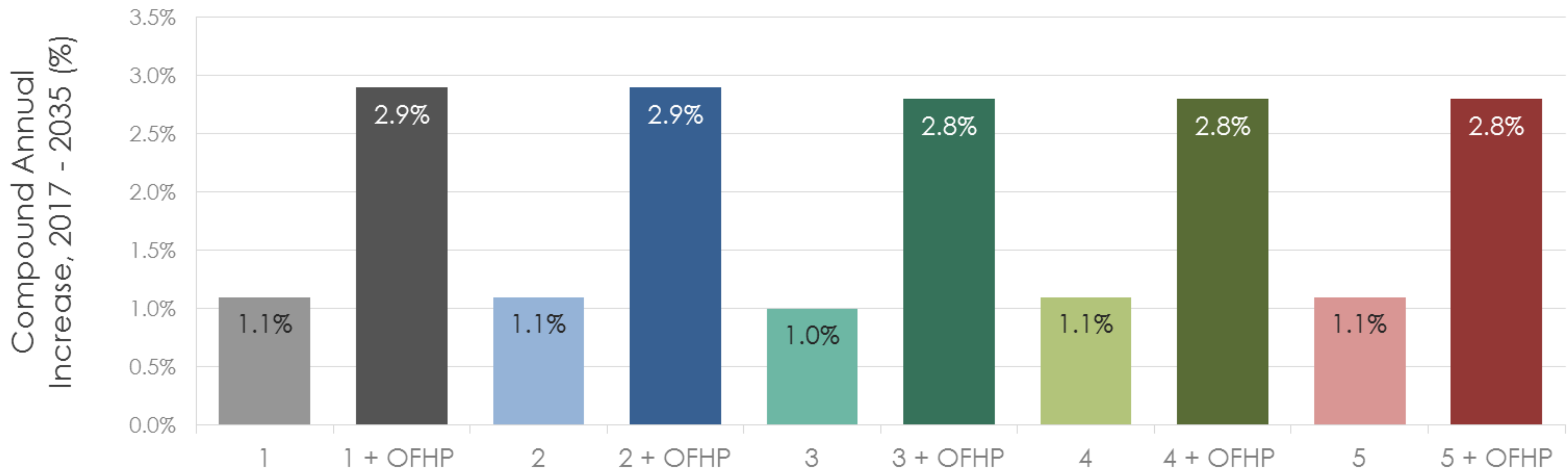
**Overview of all residential cases, continued:** without the OFHP, all monthly residential bills projections would increase at less than the rate of inflation. For all projections with the OFHP, compound annual residential rate increases would exceed inflation, since rates would start from a lower level.

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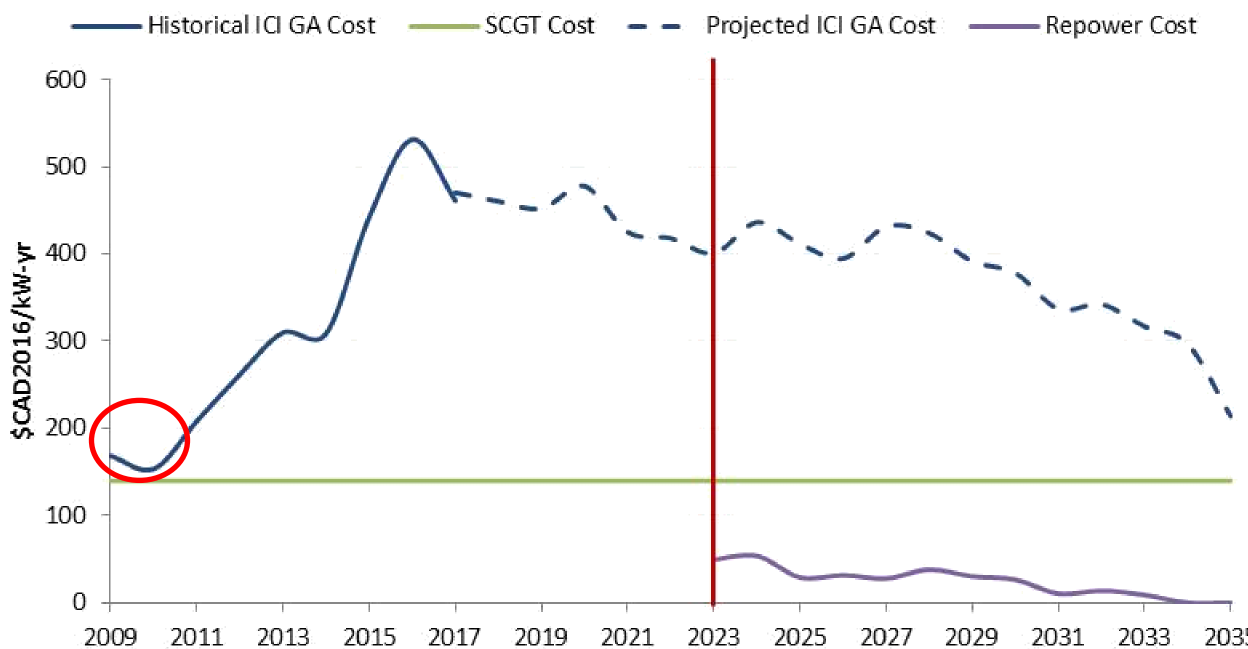
**Additional considerations:** the effect on costs of an alternative scope of Pickering extended operations is not well understood at this time. Work is underway to get a better sense of implications of a longer or shorter extended operations period. Work is also underway to better understand cost impacts of revisiting ICI eligibility. Some preliminary considerations are outlined below.

- Pickering extended operations: Previous IESO assessments have shown that Pickering extended operations has the potential to reduce costs, but is not without its potential pitfalls: its economic merits are sensitive to variables such as Pickering cost and performance, natural gas price and capacity and energy needs. The IESO has also noted that extending all Pickering units to the end of 2024 can lead to a disbenefit and that reducing the number of units extended would be worth exploring in light of Pickering's contribution to surpluses, etc.

- On May 24, 2017, the Ministry of Energy verbally indicated that extending some or all Pickering units to 2026 might be an emerging option. The economic merits of this option should be considered against the latest supply/demand outlook and reflect OPG's best available estimates of Pickering cost and performance. At this point, the effect of extending units to 2026 is unclear.

- ICI: The ICI program shifts some fixed costs away from participating customers and places those costs onto non-participating (e.g. residential) customers. The definition of who is eligible for ICI has expanded in recent times. Narrowing ICI eligibility could have the effect of reducing the amount of fixed costs passed on to residential customers. However, narrowing ICI eligibility could lead to lower ICI participation and therefore lower peak reductions. Lower peak reductions could increase the need for supply resources. As shown on the following slide, preliminary IESO analysis suggests the ICI is more expensive than alternative resource options. Narrowing ICI eligibility could therefore also reduce total costs (i.e. in addition to relieving non-participants from some fixed costs).

## **Additional considerations - Illustration:** the cost of ICI has historically been greater than Ontario's avoided capacity cost. Options such as a new-build plant, demand response or repowered plant could provide capacity at a lower cost than ICI.




- The cost of capacity through ICI program is decreasing (dashed blue line) however, it does not decrease below the cost of new build capacity within this timeframe. The cost of ICI capacity remains higher than system avoided cost.

- When ICI program was initiated, the avoided system cost of new capacity (SCGT Cost) was in-line with the cost of capacity through the ICI program (circled in red)
- The cost of capacity through ICI program has increased significantly (solid blue line)
- Capacity needs start in the mid 2020s
- This capacity need could be met through a combination of repowering expiring contracts (purple line) or new peaking capacity (represented by SCGT cost in green). The system avoided cost in these years would be somewhere between these lines.

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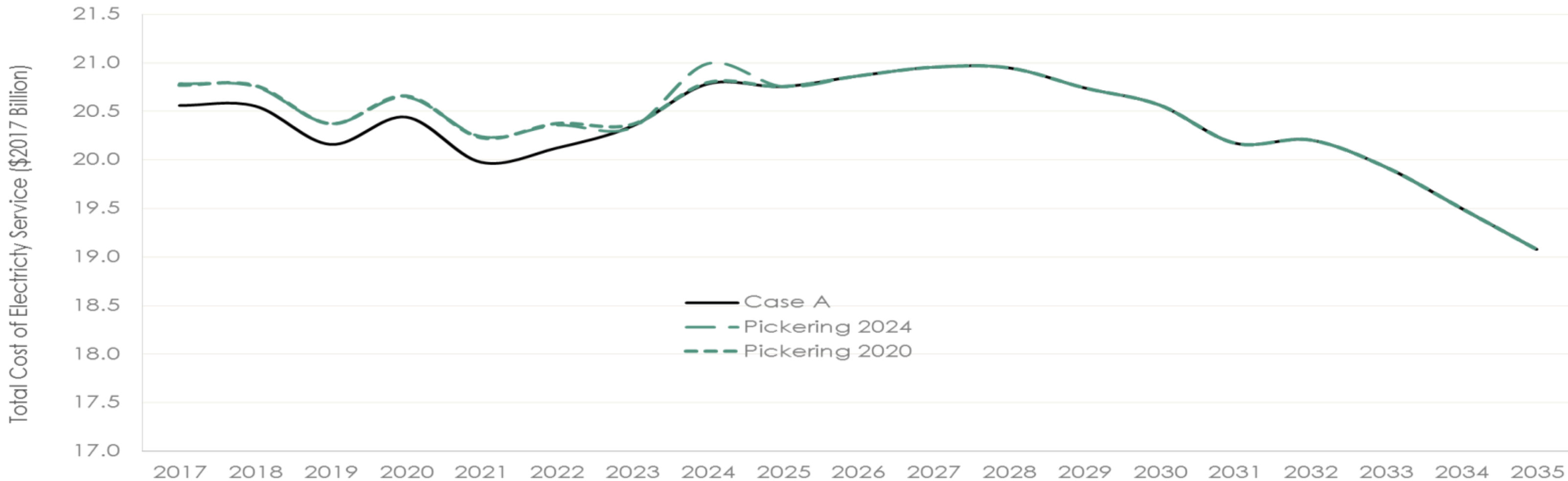
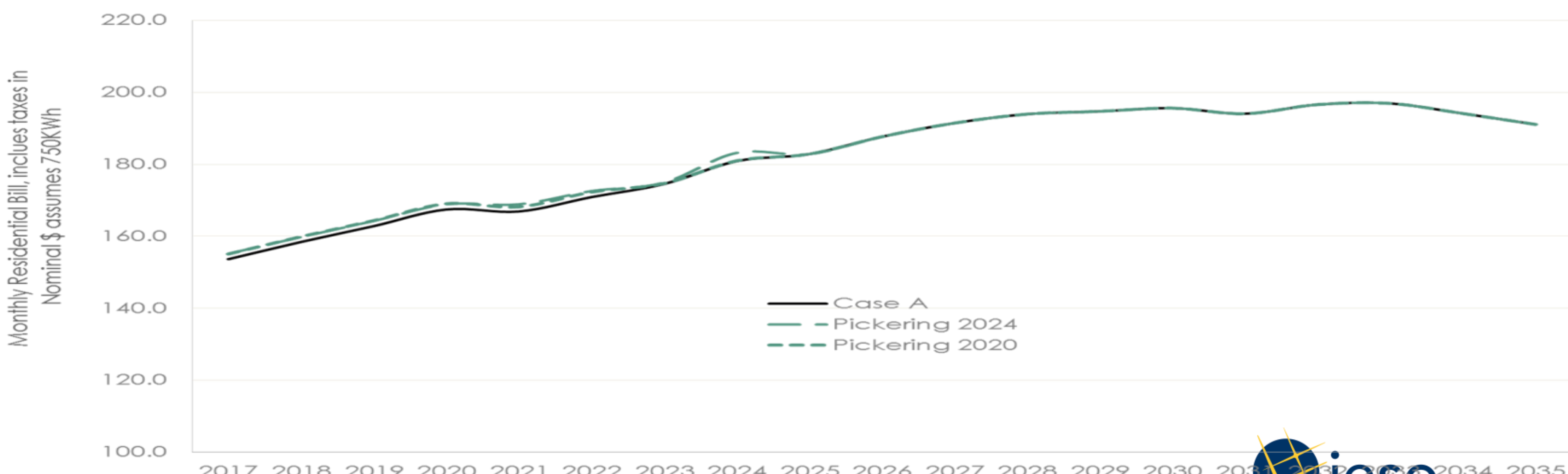
**Additional considerations - another illustration**: Two cases were considered with Pickering A units 1 & 4 retiring in 2020 and Pickering A units extended to 2024. Both scenarios resulted in a total cost increase and increase in monthly residential bills: the current extended operations schedule seems to have hit a sweet spot among options considered to date. Consideration of Pickering extended operations beyond 2024 will require the best available information from OPG.

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