Ontario Electricity Cost Forecast

A Progress Assessment Against Costs to Rate Payers Identified in the LTEP

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STRATEGIC POLICY ECONOMICS

Executive Summary

This paper presents the results of an analysis of available public sources with the purpose of creating an evidence-based forecast of the costs that will arise if the Ministry of Energy's (MoE) Long Term Energy Plan (LTEP) for the next five years is fully implemented. The objective of this paper is to take a pulse on the emerging cost of this plan and compare it to the cost growth assumptions contained in the LTEP.

Several reports and sources have presented various cost assumptions and forecasted impacts on rate payers. However, the total costs portrayed have varied significantly and no discovered publicly available source appears to be definitive on this topic. Both the 2011 Auditor General Report[1] and the 2012 Drummond Report[2] expressed concern over the degree to which the costs of Ontario's energy system were forecast to rise in the LTEP and the lack of transparency behind the LTEP cost assumptions. Information contained herein has relied upon data actuals from OPA, IESO and the OEB. The forecast developed here also used data from the Auditor General's assessment of the LTEP, recent OPA forecasts, and the Conference Board of Canada, among others. The assumptions have been validated against those used by other forecasts such as Aegent, AMPCO, IESO, and the OEB Regulated Price Plan (RPP) analyses prepared by Navigant.

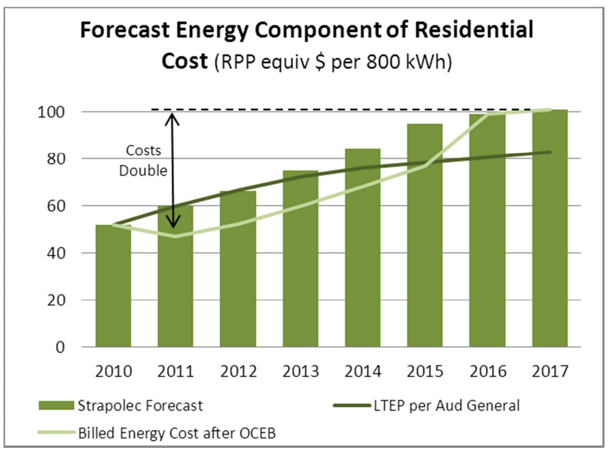
The results in this paper indicate:

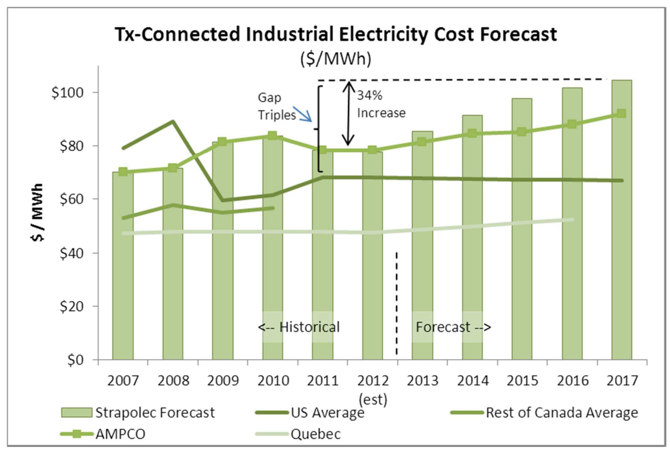
- Annual electricity system costs will grow by almost \$7B from 2011 to 2017. \$5.4B of this increase is due to energy supply costs, a likely material impact to Ontario's economy.
- Initiatives by the OEB, OPA, and IESO are containing near term cost levels in delivery and regulatory charges by challenging operating cost growth and investment requirements as well as reducing the regulated return on equity but may involve future risks. However, similar efforts are not apparent for costs associated with most generation capacity increases which are not regulated by the OEB[3].
- *Residential Bill Impacts*
    - Between 2011 to 2017, typical residential bill, prior to considering the Ontario Clean Energy Benefit (OCEB) subsidy, will grow by 52%, or \$67/month. In contrast, the LTEP predicted 38% growth for the same time frame. The energy portion of residential bills will increase by almost 70% from 2011 to 2017.
    - When the OCEB is removed in 2016, affected ratepayers will see a doubling of the energy portion of the bill from an average of \$47/month in 2011 to \$101/month. Adding this energy cost increase to that of delivery charges creates a total annual bill impact of about \$865 to households by 2016 → three years from now.
    - In 2017, the household impact is projected to be almost \$960/year, almost 70% higher than the Auditor General's quote from the OEB of \$570[4].

[1] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011) page 69*
[2] *Commission on the reform of Ontario's public services (2012) page 331*
[3] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011) page 74, Figure 5*
[4] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011,) page 95*

- *Fiscal Impacts*
  - To mitigate the short term impact to residential and small business rate payers, the OCEB will cost the provincial government, thus tax payers, close to \$6.5B by 2015. This is more than the \$5.5B implied by the \$1.1B/year cost in 2011 stated in the Auditor General[5] and Drummond[6] reports.
- *Industrial Rate Impacts*
  - Industrial rates will increase by 34% from 2012 to 2017 (from \$78 to \$105/MWh). This is a lower rate increase than for residential consumers due to the method by which the Global Adjustment is calculated. This rate of growth is twice that reflected on the AMPCO website[7].
  - Surrounding regions are not expecting similar increases. The gap between the US and Ontario grid connected industrial rates is expected to more than triple over the next 5 years from \$10 to \$37/MWh.

The figures below show the forecast cost of the energy component of a typical 800 kWh household and the total \$/MWh cost of electricity for Tx-connected large industrial users. The residential energy cost forecast is illustrated with the Auditor General's understanding of the assumptions in the LTEP[8], and the energy portion of the household bill after the Ontario Clean Energy Benefit (OCEB), expiring in 2015. The Industrial rate forecast is illustrated with the Association of Major Power Consumers of Ontario (AMPCO) forecast.





Based on informal consultation with many stakeholder groups representing rate payers in Ontario, Strategic Policy Economics (Strapolec) believes that the increases in the cost of electricity to Ontario citizens and businesses is an issue of broad based concern. This paper presents the results of Strapolec research into the cost drivers of electricity rates. The findings contained in this report shed light on the merits of the Drummond Report's suggestion that a period of "normalcy" may be warranted[9] while a robustly developed IPSP is prepared before additional cost commitments are made.

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[5] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page73*
[6] *Commission on the reform of Ontario's public services. (2012), page 328*
[7] *http://www.ampco.org/index.cfm?pagepath=Analysis/Power_Market_Outlook/Delivered_Costs&id=43464*
[8] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page 94*
[9] *Commission on the reform of Ontario's public services (2012), page 331*

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1.0 Introduction

The Ministry of Energy (MoE) released their Long Term Energy Plan (LTEP) in the fall of 2010[10]. The primary change compared to existing plans was the policy objective of increasing the renewable portion of the generation supply mix in the province. The costs of the system were identified as increasing by 46% between 2010 and 2014 with moderate cost growth after that time frame, slightly above assumed inflation. Integration of new renewable capacity was identified as responsible for 56% of the cost growth. The LTEP communicated these cost impacts through illustrative residential and commercial rate increases, but provided no further understanding of the breakdown of the expected costs to rate payers of MoE policy decisions represented by the LTEP.

Both the 2011 Auditor General Report[11] and the 2012 Drummond Report[12] expressed concern over the degree to which the costs of Ontario's energy system were forecast to rise in the LTEP and the lack of transparency behind the LTEP cost assumptions. Several reports and sources have presented various cost assumptions and forecasted impacts on rate payers. However, the total costs portrayed have varied significantly and no discovered publicly available source appears to be definitive.

Fundamental to the cost forecast is the capacity growth plan set out in the LTEP of 2010, which was detailed by the OPA in their spring 2011 IPSP consultation process[13]. The MoE has subsequently reaffirmed this capacity plan[14] following release of the FIT Review Report[15].

Strategic Policy Economics (Strapolec) has leveraged the work of Marc Brouillette that was conducted while he was the Ontario Energy Sector Lead Partner at SECOR Consulting. Early in 2012, SECOR captured that initial thinking by releasing two perspectives on the implications of Ontario electricity policy described in the LTEP [16]. In recent months, Strapolec has informally consulted with many stakeholders in Ontario around the cost implications of the planned capacity growth and has discovered a general concern about the lack of transparency of cost information available and the need for clarity around assumptions and implications. It was discovered that even for sources that sought to shed light on the cost implications, conclusions and assumptions varied widely, thereby contributing to a lack of awareness and understanding by Ontarians of the true cost implications of current energy policies. This situation was also recognized by the Auditor General who recommended efforts to improve consumer awareness[17].

In response to this articulated need by Ontarians, Strapolec has prepared the analysis presented in this report to encourage a dialog into what may be the best choices for future Ontario energy policy.

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[10] *Ontario's Long-Term Energy Plan (2010)*
[11] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page 69*
[12] *Commission on the reform of Ontario's public services (2012) page 331*
[13] *OPA IPSP Planning and Consultation Overview (May 2011)*
[14] *Ministry of Energy. (Nov 2012)*
[15] *Ontario's Feed-in Tariff Program Two-Year Review Report, MoE (March 2012)*
[16] *http://www.secorgroup.com/files//pdf/ontario_energy_future2012.pdf*
[17] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page 95*

Several reports and sources have presented various cost assumptions and forecasted impacts on rate payers. However, the total costs portrayed have varied significantly and no discovered publicly available source appears to be definitive on this topic. Information contained herein has relied upon actuals data from OPA, IESO and the OEB. Forecasts use data from the Auditor General's assessment of the LTEP, the recent OPA forecasts, and the Conference Board of Canada. The assumptions have been validated against those used by other forecasts such as Aegent, AMPCO, IESO, and the OEB Regulated Price Plan (RPP) analyses prepared by Navigant.

This document first summarizes the context set by the LTEP method of communicating cost growth and the underlying capacity plan for generation. The forecast total system costs associated with this capacity plan are explored looking at the drivers in the four categories of cost: Energy, Delivery, Regulatory, and Debt Retirement. Next, the paper discusses the evolving demand profile in Ontario. The paper closes with a discussion of implications on various ratepayer classes in Ontario in comparison to the LTEP and other forecasted rates.

2.0 Context –LTEP Cost Assumptions and Capacity Plan

This section provides an overview of the two key elements of the LTEP that have been used in this report to develop and portray the cost implications:

- LTEP cost assumptions
- Capacity planning assumptions

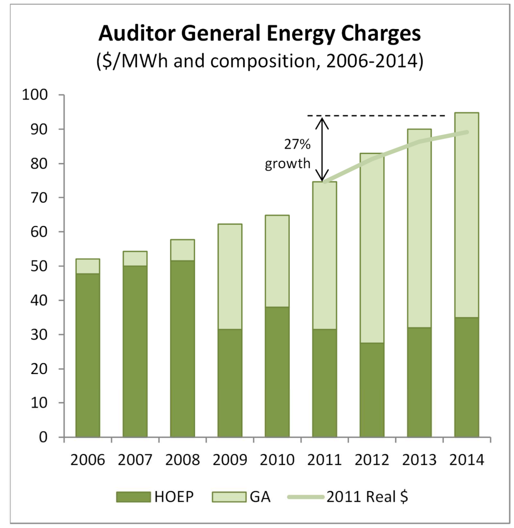
LTEP Cost Assumptions

In the LTEP, the MoE communicated expected cost increases using an illustrative bill for residential and commercial rate payers. Costs were forecast in both real and nominal dollars with the average inflation assumption being about 2% per year. A 2011 sample bill for residential consumer was provided; however, no insight was given to indicate how each component of the sample bill would increase to yield the overall total that was shown.

The Auditor General addressed this lack of clarity regarding the cost assumptions used by seeking additional information to help clarify cost expectations[18]. The resulting Ontario Power Authority (OPA) and Independent Electricity System Operator (IESO) information cited in the Auditor General's report shows a 46% increase in the energy portion of the bill expected between 2010 and 2014. Most of the increase from 2010-2011 was due to the change in the Global Adjustment[19] allocation for residential consumers who purchase their electricity directly from their Local Distribution Company (LDC) under the Regulated Price Plan (RPP)[20]. The more relevant change is the illustrated cost growth of 27% from 2011 to 2014.

With this expected growth in the energy portion of the residential monthly bill, the implied cost growth for delivery charges necessary to realize the total bill increase has been estimated. Figure 1 below shows the LTEP forecasted residential consumer rate increase with the derived breakdown of the components of the bill for the first four years.

[18] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page 94*
[19] *Global Adjustment components is described in the Auditor General Report, the RPP Price Plan with further perspectives provided in the CCRE Commentary, July 2012*
[20] *OEB Regulated Price Plan Price Report, April 2011*



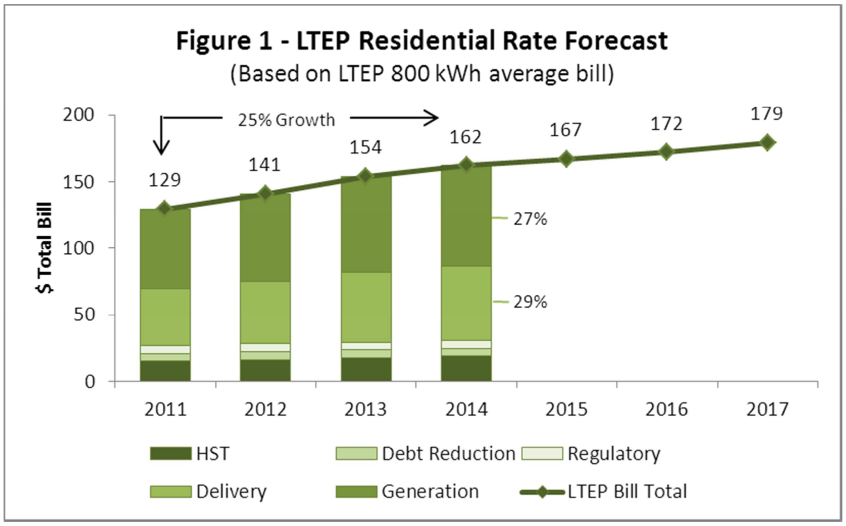
SOURCE: OPA/IESO data per Aud Gen Report

The Auditor General cited the above data that had been requested from the OPA to help understand the costs underpinning the LTEP forecasted rate increases and the MoE's statement that costs will rise by 46%.

The energy portion of the bill consists of two costs: the Hourly Ontario Electricity Price (HOEP) and the Global Adjustment (GA). **The HOEP** is an hourly market price that arises through the competitive bidding process managed by IESO whereby generators bid prices to meet market demand. **The GA** collects the costs of OPA and Ontario Electricity Financial Corporation (OEFC) administered contracts and the difference between the market price and any regulated or contracted prices.

Note that most of the 2010-2011 cost increase relates to the change in the method for GA allocation that occurred between 2010 and 2011. From 2011 to 2014, a 27% energy cost increase was forecast.

Overlaid on this chart is the relative real cost increases implied by the LTEP residential rate forecast. The implied rate of inflation in the LTEP is about 2%/year. In real terms, the cost increase in above forecast is just over 19% from 2011 to 2014.

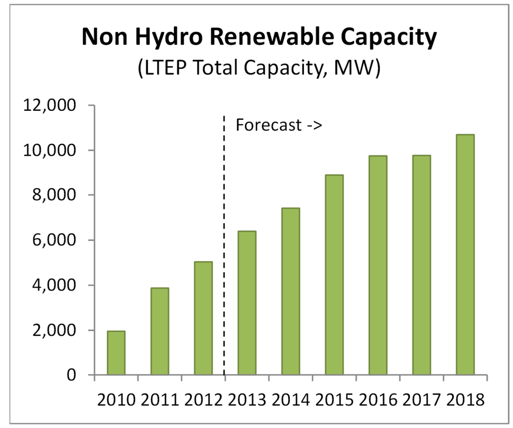


If the LTEP assumption was the energy cost growth cited by the Auditor General, then it appears that Delivery costs were assumed to grow at a similar rate of 29% between 2011 and 2014. After 2014, an average rate growth of 3% (nominal terms) is forecast to 2017, which equates to 1% per year real cost growth. The residential rate cost increase profile portrayed in the LTEP also implies that the costs were expected to arise primarily in the 2012 to 2014 time frame. In contrast, the forecast renewables capacity growth continues to 2018 suggesting cost implications beyond the 2014 horizon.

The LTEP stated that 56% of the cost increase would come from the introduction of renewables into the supply mix, with the rest of the costs arising from Nuclear, Gas and Transmission. Driving these assumptions is the MoE supply mix directive[21].

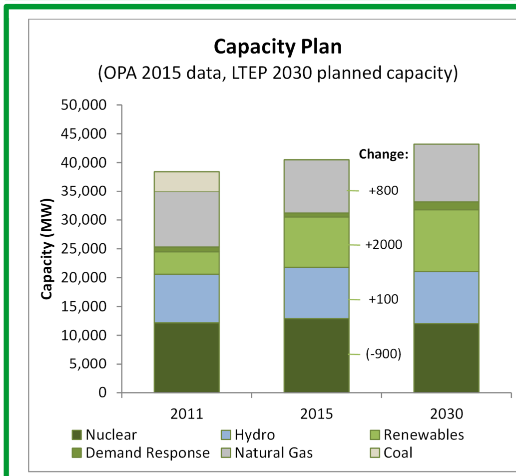
LTEP Capacity Plan

The OPA recently presented the capacity rollout expected by 2015[22]. Beyond this 2015 scenario, an additional 2000 MWs of renewables (as well as 800 MW of gas fired generation) would still be required to meet the LTEP targets for 2030. The capacity planning details behind the supply mix directive were provided by the OPA[23].



SOURCE: OPA 2011 IPSP II Consultation Overview

The OPA's 2011 forecast for renewables integration in response to the LTEP shows that only 50% of the expected growth in renewables will be achieved by 2014 (total of 7400 MW, 5400 MW more than existed in 2010. An additional 3300 MW were expected by 2018.



SOURCE: OPA 2011 IPSP Consultation Overview, OPA APPrO 2012

[21] *MoE Supply Mix Directive (Feb 2011)*
[22] *OPA, Outlook for Electricity Demand and Supply in Ontario (2012 APPrO Conference)*
[23] *IPSP Planning and Consultation Overview (May 2011)*

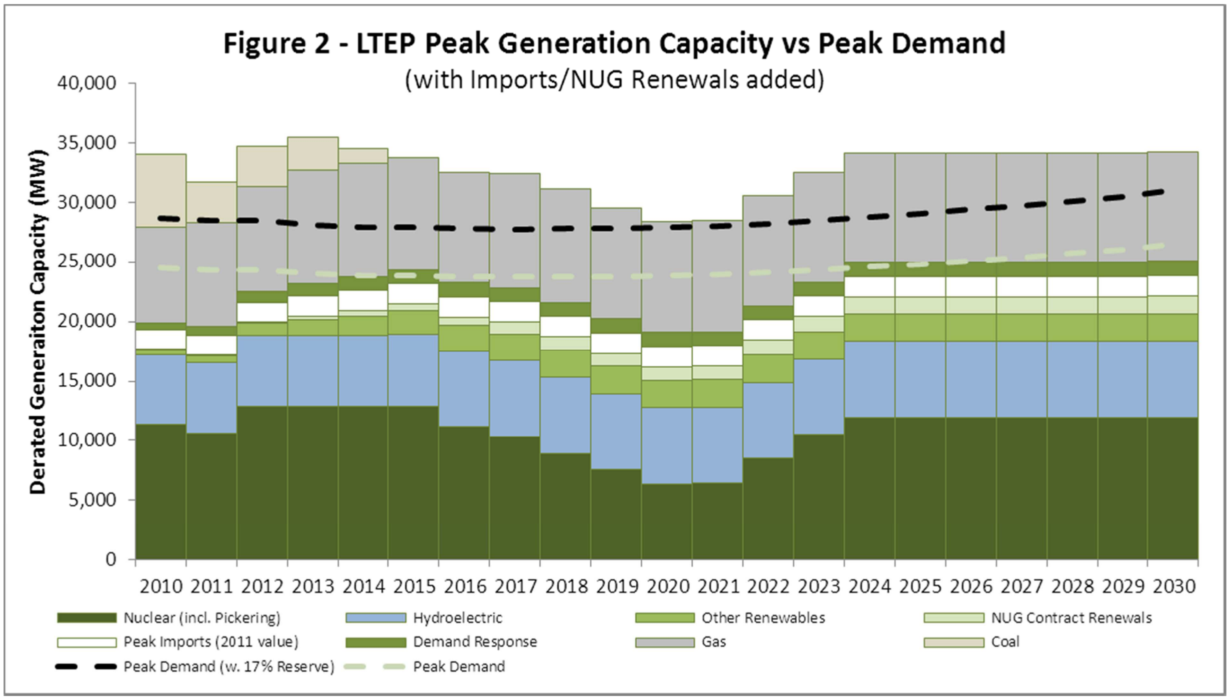


Figure 2 illustrates the de-rated peak capacity forecast produced by the OPA contrasted against the expected peak demand and reserve requirements. The overall objectives behind the capacity plan responded to several requirements:

1. The MoE's supply directive in support of the LTEP
2. The Ontario Government's decision to phase out coal
3. Complying with NPCC reserve adequacy criteria (17% in LTEP)[24]

To meet these overall objectives for summer peak conditions, system capacity planning considered the implications of the evolving supply conditions in order to:

1. Balance capacity in the near-term as coal is phased out
2. Ensure adequate supply during nuclear refurbishment
3. Plan for a long-term supply mix that could also accommodate the potential for higher demand growth

Furthermore, the MoE directed the OPA to "pursue the initiative of seeking new contracts for the non-utility generators"[25]. Following the

Explanation of Figure 2

Figure 2 differs from the equivalent figures in the OPAs IPSP Planning and Consultation Overview (Figures 9 and 10) in that Figure 2 has a graphical reordering of the supply types. The traditional baseload capacity (eg. Nuclear and Hydro) are placed at the bottom of the figure while the peaking supply (eg. Gas) is placed at the top. To reflect the MoE's directive regarding NUG contract renewals, the potentially retained capacity is shown. As imports have historically been a material peak supply option, 2011 import levels are added.

Overlaid on this picture is the LTEP expected peak demand with reserve as well as the peak demand without reserve. From a system reliability perspective, per NPCC criteria, the LTEP indicated a planning challenge in meeting peak demand with reserve during nuclear refurbishment. Figure 2 indicates that this is somewhat mitigated if imports and NUG renewals are considered. From an operational perspective, the net capacity above the normal peak has a low likelihood of becoming actual production. Operationally, a supply problem in 2020 is unlikely. Capacity above the peak with reserve is not needed by definition.

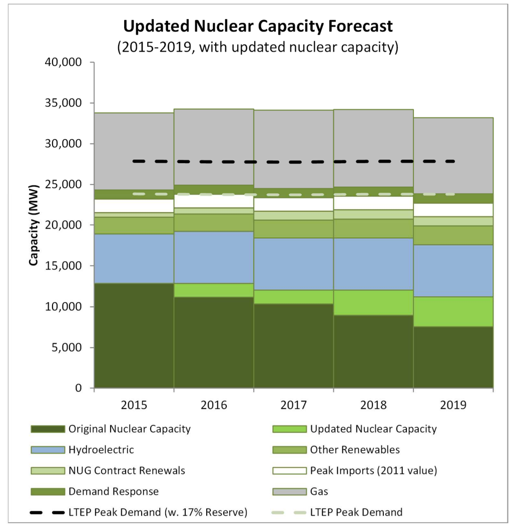
[24] *IESO, Methodology to Perform Long Term Assessments (June 2012)*
[25] *Ministry of Energy Directive on Negotiating New Contracts with Non-Utility Generators (Nov 2010)*

FIT Two Year Review[26], the MoE produced a directive to reiterate its policy to continue with LTEP capacity build out[27], suggesting that this capacity plan is still being pursued. So far, the Strapolec research team has not discovered in the public domain any directive that would indicate policy is diverging from that forecast.

The Nuclear capacity situation warrants specific mention. The LTEP reduces the nuclear fleet footprint from the current 12,900 MW to 12,000 MW by 2024 while assuming a new build of 2000 MW. The reduction in nuclear capacity results from the pending closure of the Pickering Generating stations scheduled after 2019, assuming the stated life extensions proceed. In the LTEP, sustaining of the nuclear fleet will be achieved through their refurbishment. Taking the units to be refurbished offline has been forecast to begin in 2016 and with a maximum offline capacity in 2020 as illustrated in Figure 2 above. This refurbishment created the medium term supply challenge that helped justifying the build-up of gas-fired generation in order to meet the NPCC reserve adequacy requirements. Recent presentations[28,29] suggest that the nuclear refurbishment plans may have evolved to be different than contemplated by LTEP, potentially mitigating the medium term need for gas capacity to fill the gap.

Operationally, the oversupply situation evident in the LTEP plan for the 2013 to 2015 periods is likely to continue until 2017. As a result, the identified 2020supply shortfall, which drove gas-fired generation capacity development, may not manifest itself to the same extent.

The focus of the cost discussion presented in this report is on the five year plan to 2017. The cost situation after that is uncertain in the medium term where it relates to nuclear refurbishment implications as well as NUG contract renewals. For the purpose of the costs analysis presented here, the nuclear fleet refurbishment is assumed to begin in 2017, with cost of the reduced production removed from the forecast. This may not be reasonable if partial financing of the refurbishments will come from rate payers. Similarly for cost modelling purposes, NUG contract renewals have not been assumed.



SOURCE: OPA 2011 IPSP Consultation Overview, OPG, Bruce Power, Strapolec Analysis

The presentation by OPG at the OCI AGM on Nov 20, 2012 and Bruce Power's 2012 promotional flyer suggest that the refurbishment plans may have evolved to be different than contemplated by LTEP. This is a potential mitigation of the medium term need to build long term gas capacity. Strapolec understands that the Darlington refurbishment project may not cause the units to come offline before late 2016, thus missing the summer peak demand period. Furthermore, Bruce Power has been widely communicating the merits of its Asset Life Management program which suggests that extended outages of the Bruce B units may not be required before 2020 either. Assuming this means Bruce Power may have the ability to plan outages to avoid summer shutdowns during peak demand periods, it would appear that medium term peak supply risks related to nuclear refurbishment may have been largely mitigated.

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26 *Ontario's Feed-in Tariff Program Two-Year Review Report, MoE (March 2012)*
27 *Ministry of Energy Directive on Renewable Energy Program Re-Launch (Nov 2012)*
28 *Darlington Refurbishment Project – Challenges and Opportunities, OPG (2012)*
29 *Bruce Power Promotional Brochure "Revitalizing the Bruce Power site" (2012)*

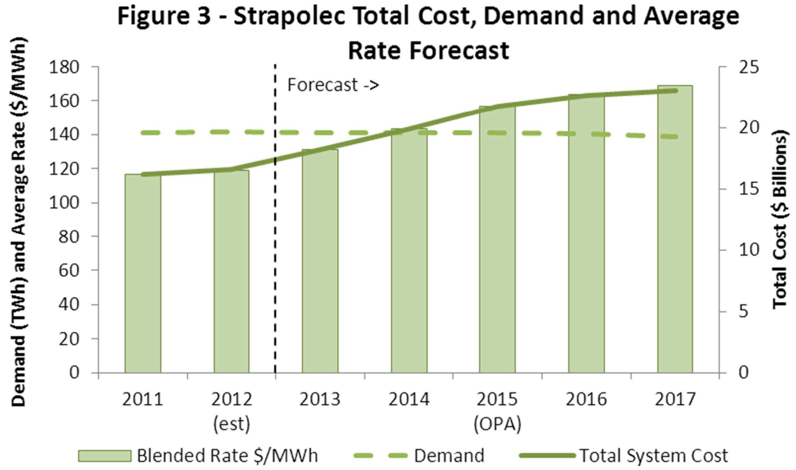
3.0 Total System Cost Forecast

The purpose of this section is to describe the cost drivers for the four main elements of the electricity system[30]. The main findings of this section are:

- Energy costs will increase by $5.4B between 2011 and 2017, or almost 55%, without any substantive increase in useable energy generation.
- Delivery cost growth forecast of $1.4B is being constrained in the short term by the OEB.
- There is no basis for predicting cost growth in regulatory or debt retirement costs.

Fundamental to rate-payer cost increases is growth in total costs of the electricity system. The other factor is demand. Figure 3 shows Strapolec's forecast for total system cost and demand and the resulting illustrative blended impact on average $/MWh costs.

Figure 3 - Strapolec Total Cost, Demand and Average Rate Forecast



From 2012 to 2017, total system cost, which includes energy, delivery, regulatory and debt retirement, is expected to grow by almost $7B, or 42%, to over $23B. At the same time, 2017 demand is projected to be 2% lower than 2011 (see Section 4.0). Given the expected decline in demand and the fixed nature of the majority of system costs, the illustrative net growth in average rate payer cost of electricity is

[30] *The fifth component of the bill relevant to rate payers is the application of HST which is self-explanatory and therefore not explicitly addressed.*

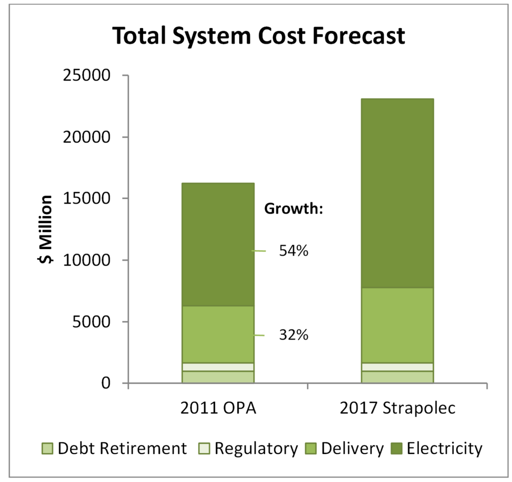
projected to be 45% between 2011 and 2017. In contrast, the LTEP projected a 38% rate growth for residential customers. Specific rate payer impacts are explained in Section 5.

In 2011, the total system costs were just over $16B. There are four main categories that make up the total system cost:

- Energy costs – Global Adjustment components and HOEP
- Delivery costs – Includes Distribution and Transmission
- Regulatory costs – Cost of managing supply and electricity system
- Debt Retirement – A surcharge aimed at reducing legacy debt

The largest contributor to total system cost growth is the cost of energy production which will grow by 54% or $5.4B between 2011 and 2017. The main driver of energy cost growth is the capacity plan stemming from the LTEP as Ontario transitions from historical low cost energy to more expensive sources of clean power. Delivery costs are the second largest contributor and are projected to see 32% or $1.4B growth over the 6 year period.

Each of the four contributing factors to overall system cost growth is discussed in the following sections.

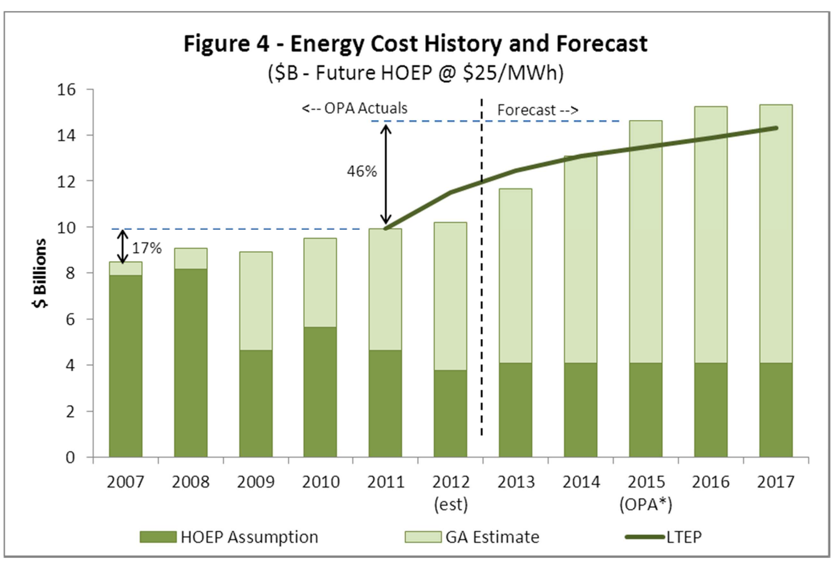


SOURCE: OPA 2011 IPSP Consultation Overview, Aegent, OPA presentations, OEB filings and annual reports, Strapolec Analysis

Growth in costs is primary in energy. The energy portion of the total costs will grow from 61% to 66%. Delivery charge share of total cost will reduce from 29% to 27%, Regulatory and Debt Retirement charges have been assumed static, resulting in a 30% drop in total share for these costs.

3.1 Energy Cost Growth

The historical and forecast costs of energy are provided in Figure 4.

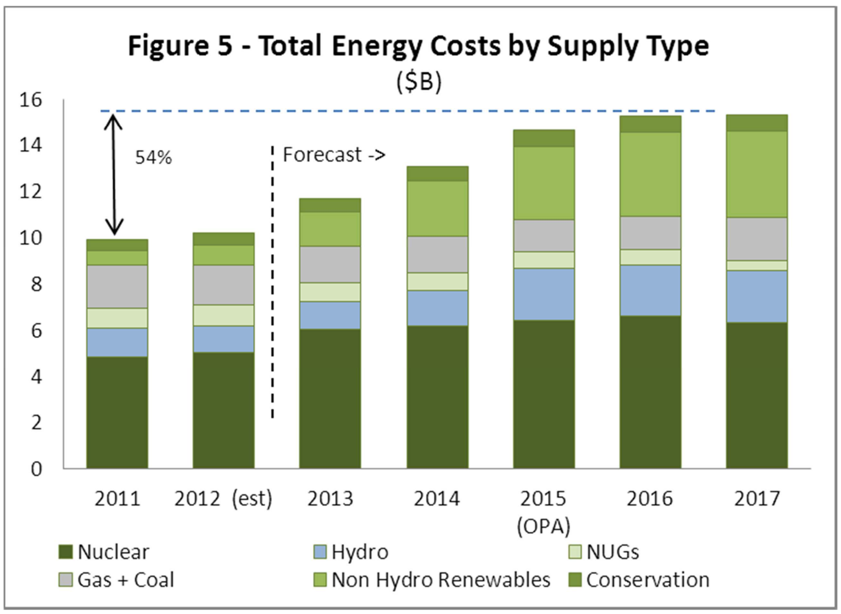


SOURCE: OPA, Auditor General, Aegent, AMPCO, Strapolec Analysis

* The OPA defined the expected total energy costs in 2015 to be $13.7B in 2010$. That value has been escalated by 6.5% to account for rate increases since 2010. This assumed escalation is less than 1.5%/year, and lower than the LTEP inflation assumption of approximately 2%/year.

The total energy portion of system cost grew 17% from 2007 to just under $10B in 2011. It is forecast to grow an additional 46% to over $14B by 2015 according to the OPA's recent estimate[31]. An additional 8% growth is expected by 2017 as the completion of LTEP renewable capacity is realized and the commissioning of the LTEP gas capacity is achieved. Growth rate in energy costs to 2017 is 24% greater than the growth rate anticipated by the LTEP (based on analysis of the implied assumptions in Auditor General report).

To develop the cost forecast, the capacity, cost and production of each energy supply type was modelled and assumptions validated against several sources (see side bar). The resulting forecast to 2017 is shown in Figure 5. 2012 costs are only marginally higher than 2011 due to the delayed restart of Bruce Power's refurbished units.



The primary measure of the validity of these cost forecasts is the anchoring of the 2015 costs to OPA's estimates produced in the summer of 2012[32].

It appears that one of the drivers of the OPA's 2015 cost estimate relates to the issue of surplus baseload and how to manage it. When the IPSP consultation document was produced, it was evident that a

Cost Forecast Methodology

The forecast is anchored on the OPAs 2015 cost forecast found in their June presentation. With the detail available from various OPA materials, the underlying assumptions have been validated against many sources to confirm alignment with the OPA breakdown for 2015 generation capacity, production and rates. Renewables costs are based on forecast capacities at expected operating factors using rates for FIT, RESOP, etc. The Auditor General report provides a summary of many rates. OPG regulated hydro and nuclear rates are public domain. Bruce Power's rates as described in the RPP report have been applied with the associated rate increases. The RPP report has discussion and references to many relevant parameters. Average gas fixed costs were derived from OPA published gas costs in 2011 and OEFC data for NUGs and Coal. NUG production levels have been extracted from IESO hourly generation data and the forecast capacity resulting from the anticipated expiration of the NUG contracts has been reflected.

Further assumptions were supplemented by and validated against AMPCOs reports and the framework of assumptions developed by Aegent. The Aegent report provided a detailed backdrop for assessing many assumptions including rates and production efficiency. Aegent offered their framework as a useful reference, which it is. They identified where their assumptions and exclusions required validation which Strapolec has pursued.

Embedded generation has been modelled using IESO forecasts for 2012 installation and the 2011 Energy Conservation Progress Report.

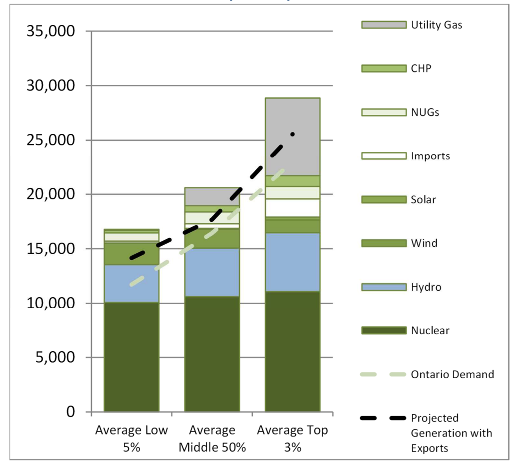
[31] OPA, *Outlook for Electricity Demand and Supply in Ontario (Nov 2012 APPrO Conference)*
[32] *OPA, Current and Future Components of Global Adjustment (June 2012)*

surplus supply problem was going to arise by 2013, remain until the nuclear refurbishments began, and then resume when refurbishment completed. As mentioned earlier in this report, this situation is best exemplified by the 2015 expected normal peak demand being below the available peak capacity of the generation supply mix before considering gas supply (see Figure 2).

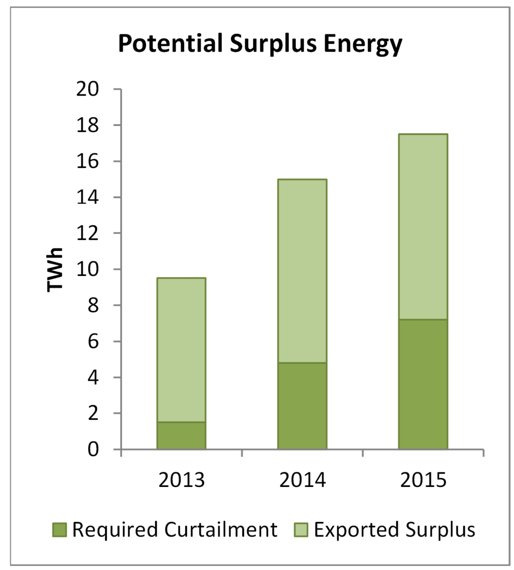
To illustrate the effects of excess supply, IESO hourly generation data for 2011 was scaled up by the relevant LTEP capacity plans and contrasted against the future demand level (see side bar). This method retains the 2011 operational utilization capacity factors. Assuming OPA contracted gas capacity is the only easily curtailed generation, then any other production indicated in the illustration that is above the "Exports" line (arguably above the "Ontario Demand" line) is surplus generation that is not needed. Several implications arise from this portrayal: (1) surplus power generation will exist for over 70% of the year; (2) Gas generation will rarely be needed; (3) wind energy is in greatest supply when demand is low and the system is already in surplus. To further corroborate this last observation, the Auditor General report cited that 86% of wind generation occurs when the system is already in a surplus situation[33]. One observation that arises from this portrayal is that capacity planning should consider the profile of generation regarding the diurnal needs of the energy system and the impact on surplus baseload.

At the APPrO 2012 conference, the OPA presented its production forecast to 2020 in which the growing issue of what was referred to as "Potential Surplus Energy" (PSE) was discussed. PSE is energy whose production cannot be reasonably eliminated and requires the overall system to seek solutions to address the resulting over-supply. It appears that the OPA's 2015 cost scenario considers how much fixed production can be reasonably eliminated, what must be physically produced and paid for, how much can be exported, and what can be curtailed. By 2015, over 17 TWh of PSE is anticipated, of which 40% may need to be curtailed through forced hydro spilling, renewables dispatching, and nuclear manoeuvring/ outages. The growth in PSE is equivalent to and directly a result of new renewables generation coming on line.

Illustrative Future Surplus Generation
(MW)



Source: IESO, LTEP/OPA capacities, Strapolec Analysis



SOURCE: OPA presentations,

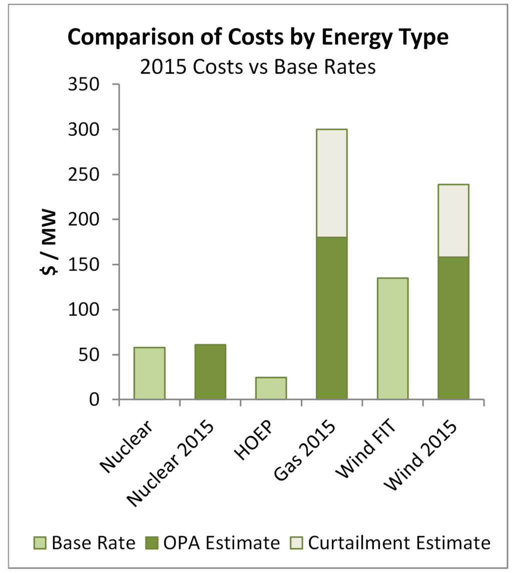
2015 generation is projected to be over 12% more than forecasted demand producing approximately 17.5TWhs of PSE. This is equivalent to the total expected non-hydro renewables production in 2015. 60% of this excess is considered exportable. 40% must be curtailed. Of the exports, much is forced and will likely be sold at below prevailing market prices. This is a main driver behind low $20 range HOEP forecasts for the foreseeable future, despite recovering neighboring prices.

[33] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page 112*

While the OPA suggested that this challenge will begin to abate after 2015 due to the planned Nuclear refurbishments, it was pointed out earlier in this report that the refurbishment schedules are evolving. If refurbishments are delayed or their concurrency reduced from the LTEP assumptions, the 2015 PSE situation could persist into 2017.

In the OPA's 2015 cost forecast, it appears that the fixed cost for the curtailed energy is accounted for. This factor is contributing to over 5% growth in total consumer costs of electricity. The reason the cost arises, is that the fixed costs that are associated with the build up of capacity do not go away if production is curtailed. As a result, the average unit cost for curtailed energy supply increases with the associated reduction in production.

The OPA recently released updated costs of different energy types in Ontario based on the 2015 forecast utilization scenario[34]. The OPA's assessment of the impact of production curtailment on the cost per MWh of energy actually used is higher than would be typically expected (see side bar). Most supply types have $/MWh costs similar to the values identified in OPA's IPSP Consultation Overview. For example, Nuclear will realize marginal per MWh cost increase due to relatively small curtailment as a percentage of its overall level of production. However, due to relatively small gas and renewables production, the curtailment implications are far more severe with rates potentially approaching $300 and $240/MWh respectively for energy actually used. These outcomes result from the capacity build up that has been occurring in the presence of softening demand.



SOURCE: OPA June presentation

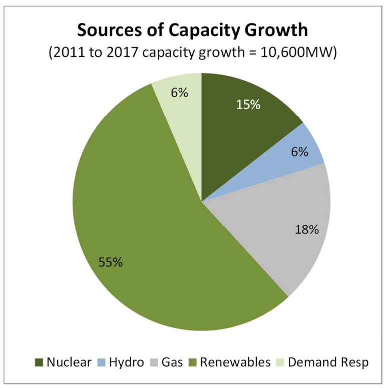
$300/MWh gas estimate based on removing NUG production at NUG rates. $240/MWh wind costs based on attributing nuclear curtailment costs to useable wind production.

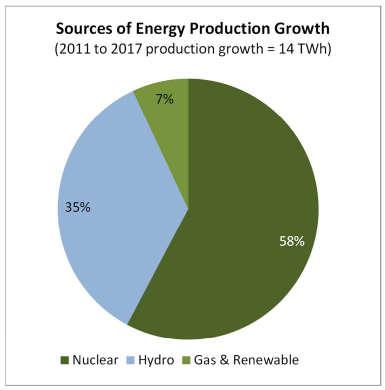
One of the reasons gas-fired generation per MWh costs are increasing dramatically is that required production volumes for the Gas fired generation is expected to be less than half that seen in 2011. Considering that NUG generation cannot be curtailed implies that the OPA contracted gas plant production will drop by 70%. Natural Gas generation appears to have the highest per MWh production cost, consistent with the earlier prediction that gas assets will be underutilized as a result of the overbuilt capacity plan.

In the period from 2011 to 2017, 61% of the expected energy cost growth is attributable to non-hydro renewables and 7% to gas fired generation (see side bar next page). This does not align with the 56%

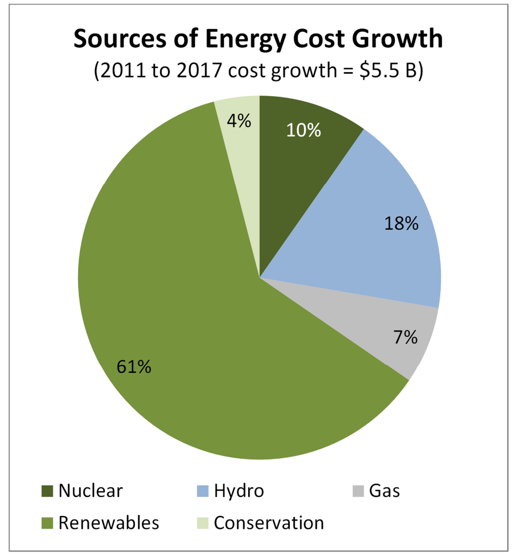
[34] *OPA, Current and Future Components of Global Adjustment (June 2012)*

renewables share of cost growth stated in the LTEP or cited in the Auditor General report. Non-hydro renewables do account for 55% of the capacity growth but in combination with gas production reduction, the net output of the two only contribute 7% of the expected production increase in 2017 as illustrated below. Nuclear and Hydro, which represent 10% and 18% of the added cost respectively, are forecast to generate 58% and 35% of the increase in production. In contrast to the forecast soft demand, increases in production from Nuclear, Hydro, and renewables arise due to coal plant closures, NUG contract expiry, gas production reduction, and the reality of PSE described above.





SOURCE: IESO, OPA, LTEP, Strapolec Analysis



SOURCE: OPA, Strapolec Analysis

Of the total system cost growth that has been expected between 2011 and 2017, over 60% is attributable to non-hydro renewables. Nuclear through the restart of Bruce A units accounts for 10%. Hydro accounts for 18% due in large part to the major projects for the Lower Mattagami and Niagara Tunnel. CDM cost growth will have a small impact on total cost.

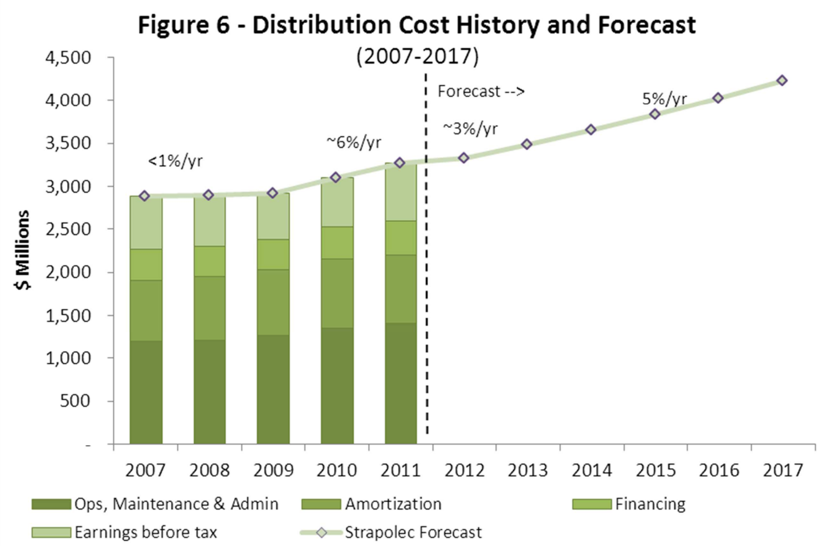
For gas fired generation, the costs reflect the gas generation growth defined in the LTEP. Cost reductions from coal plant closures and NUG contract expiry are not considered in the above chart.

3.2 Delivery Cost Growth

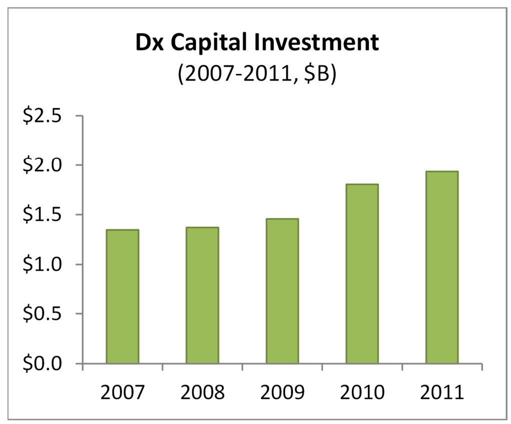
Delivery costs have two main components: Distribution and Transmission. The cost of Distribution represents the costs of the Local Distribution Companies (LDCs) to bring the low voltage electricity to consumer and business locations. LDC costs represent about 70% of the costs contained in Delivery. Transmission costs are those incurred to connect and deliver the high voltage power from generators connected to the Grid and deliver it to the LDCs and large consumers. Transmission costs represent about 30% of the total Delivery costs.

Distribution Cost Forecast

The OEB compiles an annual yearbook that captures relevant statistics on Ontario's LDCs. Figure 6 below shows the total distribution costs and its components over the last few years along with Strapolec's forecast to 2017. Historically, costs had risen modestly up until 2008 but saw an upward trend to 6% between 2009 and 2011.



One of the drivers of recent cost growth has been the increased capital expenditures. Capital expenditures have been approaching \$2B/year for the last two years, a 30% increase over the previous three. Capital programs are required at LDCs due to ageing equipment, capacity additions to accommodate embedded renewables, as well as normal asset additions where population or customer growth warrants.



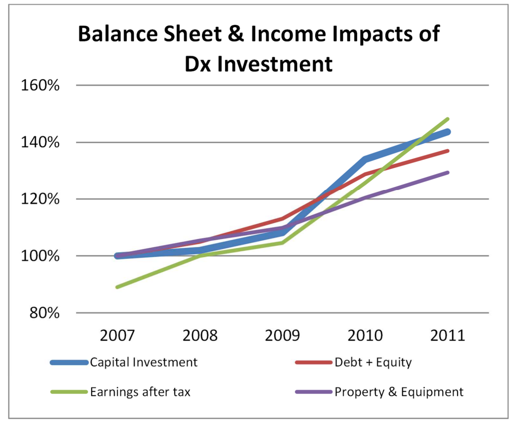
SOURCE: OEB Yearbook 2011

After the release of the LTEP, the Conference Board reported that it estimates that \$20B of investment is required in Ontario's distribution system[35]. The recent LDC report[36] cited this finding as well and appeared to support the notion that such distribution investments are likely required. As such, it can be anticipated that the capital expenditure levels of the last few years could persist for some time.

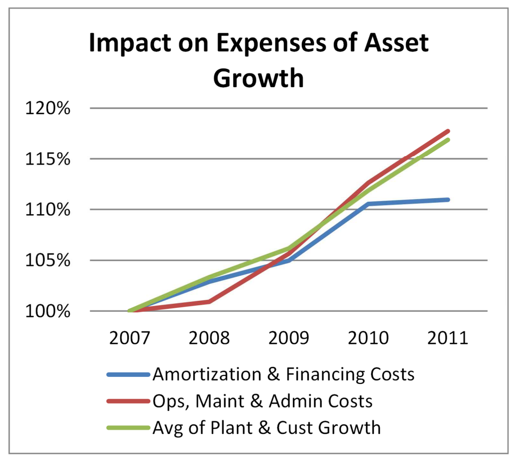
[35] *Shedding light on the economic impact of investing in electricity infrastructure (2012)*
[36] *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First (2012)*

Increases in capital spending have impacts on LDC financials in several areas. Increased debt drives financing costs, the resulting plant and equipment increase amortization costs, and shareholder equity impacts the dollar magnitude of return on equity. Furthermore, increasing the footprint of plan and equipment being operated has related impacts on the costs to operate and maintain the new assets.

Comparing the trends in Capital Investment to growth rates on the balance sheet and expense items on the income statement shows a strong correlation between the recent rate increase of about 6% in the last two years (see side bar). If capital expenditures at 2011 levels are assumed to continue, then a 5% increase in distribution rates for the next few years can be expected.



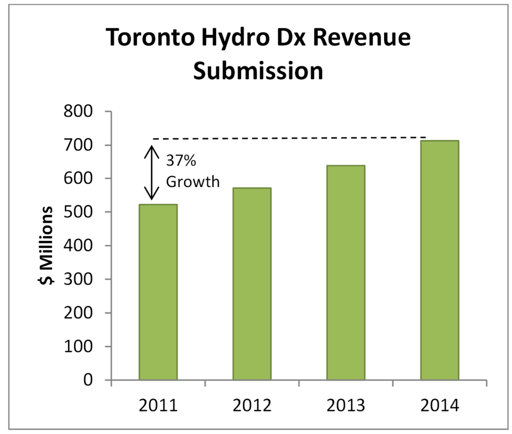
SOURCE: OEB Yearbook 2011, Strapolec Analysis



For illustrative purposes, consider $10B of investment (or 50% of the Conference Board's estimate). If 50% of this is financed at 5%, it would create $250M in interest charges. If the other 50% earns 8% RoE, another $400M will be required. If the life of the $10B in assets is 40 years, a $250M/year depreciation costs would be added to the income statement and revenue requirement representing the cash to pay down the debt and/or return equity to shareholders. Ignoring for the moment that declining depreciation on existing assets may offset the latter, the total of $900M/year would represent an almost 30% rate increase. If capitalization of these investments arises over a five period, this alone would equate to more than a 5%/year rate increase. Furthermore, some of these investments, such as smart grid technologies, will have much less than 40 year amortization. An additional potential upward cost pressure risk to both Transmission and Distribution, is the Conference Board suggestion that some of the investment levels they identified may be low given uncertainty over the implications of smart grid and new generation integration. As such, the 5% projected growth rates assumed here are likely conservatively low.

Offsetting this trend is the OEBs recent downward adjustment of the regulated rate of return on equity and the focus on operating cost growth in its recent rate decisions.

A relevant data point on current OEB efforts to help contain cost growth in the distribution sector is exemplified by the Toronto Hydro submissions for 2012 to 2014. The submissions originally contained an investment plan with an associated revenue requirement increase request that totalled 37% over that 3 year period. This is almost 30% higher than the 29% growth indicated for the LTEP by the analysis presented earlier (see side bar). The OEB rejection of this proposal and associated rate increase has resulted in a 1.5% increase for 2012[37,38], with increases for 2013 and 2014 currently expected at less than 1% in each year based on their revenue requirement. It remains to be seen if or when the underlying need for Toronto Hydro's originally requested cost increases and capital spending will return.



SOURCE: Toronto Hydro 2012 Quarterly Report,

This OEB downward directional adjustment in ROE is assumed to impact both Dx and Tx costs on a go forward basis. The effects on overall rate increases are likely to be worked out by 2013. The overall distribution forecast cost increase used here for 2012 and 2013 are thus moderated from the expected 5% to reflect these near term decisions. The near term increases used in the forecast reflect the average of bill impacts contained in the OEBs 2012 and 2013 Bill Impact reports from Nov and Dec 2012. The average Delivery charge bill impacts for the sample of LDCs included were 1.2% and 3.25% for 2012 and 2013 respectively. Our growth assumption has increased these by 35% to account for the approximate blended ratio of distribution to transmission cost components of Delivery charges. Afterwards, a 5% rate of growth in Dx costs is expected to continue for the last three years of this forecast. This is consistent with the assumptions contained in Aegent's report submitted to the OEB[39].

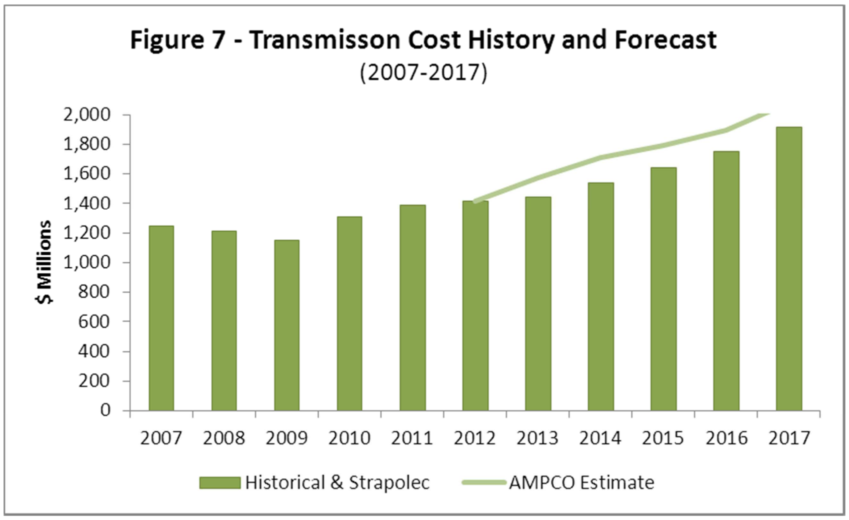
Finally, the recent review of LDCs raised the possibility of cost savings through consolidation[40]. The investment costs identified in that report to achieve consolidation have not been reflected in this forecast and, for the purpose of this analysis, the realization of any potential benefits are assumed to be outside the forecast horizon of this report.

[37] *Toronto Hydro Consolidated Financial Statements - Sep 30, 2012 (2012)*
[38] *Toronto Hydro Management's Discussion and Analysis - Sep 30, 2012 (2012)*
[39] *Ontario Electricity Price Increase Forecast - December 2011 to December 2016 (2012)*
[40] *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First (2012)*

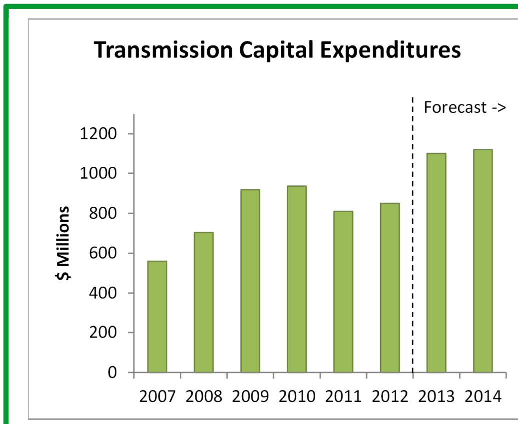
Transmission Costs

Future transmission costs are expected to rise due to investments in replacing ageing infrastructure and the accommodation of renewable generation. Figure 7 shows the forecasted growth in Hydro One's transmission costs to 2017.

Recent rate submissions for 2012, 2013, and 2014 were 8%, 1%, and 6.6% respectively.



As with the forecast Dx costs, much of the rate implications are related to capital investment. Capital investment is forecast for Tx assets at levels over 35% higher than seen in 2011 (see side bar). The Conference Board report suggests $5.6B in Tx investments are required to meet the objectives of the LTEP. The LTEP stated $9B would be required for transmission. Assuming these investments will be made by 2017 leads to the assumption that capital investments will continue at the levels requested by Hydro One. As such, it is anticipated that rates will continue at the 7% level approved for 2014 for the forecast period. Using the same illustration mentioned above for distribution investment implications, if $5B is invested in transmission, this would translate to a $450M/year impact on transmission revenue requirements. That would represent an approximately 35% rate increase, further supporting that the 7% assumption used in this forecast may be conservatively low. Absent



SOURCE: Hydro One Annual Report and Rate submissions the 2013 rate decision, the forecast presented here is consistent over the long term with the forecast by AMPCO[41].

While the forecast for both Dx and Tx delivery charges for the latter three years of the period is somewhat speculative and primarily based on recent history, informal feedback received during the development of this report suggests that the forecast is conservatively low. The rationale for these comments has not been independently validated and, as a result, the comments have not been accommodated.

3.3 Regulatory Charges

Regulatory charges consist of the three components

- Wholesale Market Service Charge
- Standard Supply Service Charge
- Rural and Remote Electricity Rate Protection

Wholesale Market Services Charge (WMSC)

The WMSC covers the cost of services required to operate the electricity system and run the wholesale market. The WMSC has been steady for some time having been set back when the IMO was established. At that time, the recurring costs were identified to be approximately $770M/year (see side bar on next page). A recent OPA presentation[42] suggests this cost has dropped to around $690M, but on a smaller demand base. For the purpose of this forecast, it is assumed that the WMSC will remain at the current levels.

There are several factors that impact on the potential reasonableness of this assumption:

1) Ancillary services
    a. The largest components of the WMSC are related to uplift and the ancillary services. There has been much discussion in the market about the implications of integrating renewables.

Purpose of the WMSC

Physical Limitations and Losses
These are losses that occur as electricity flows across transmission lines. The IESO also collects other costs incurred in operating the power grid, such as when it must take actions to avoid overloads on the transmission system in cases of surges in demand.

Energy Reliability
There may be occasions when the balance between generation and demand is affected by an unanticipated event, such as equipment failure or a surge in consumption. The IESO purchases a certain level of spare capacity or reserve that is available on short notice to restore the balance.

IESO Administration Service
The IESO charges administrative costs to manage the power system and operate the wholesale electricity market in Ontario and includes the costs to operate the OPA.

SOURCE: IESO Website

[41] *http://www.ampco.org/index.cfm?pagepath=Analysis/Power_Market_Outlook/Delivered_Costs&id=43464*
[42] *OPA, Outlook for Electricity Demand and Supply in Ontario (Nov 2012 APPrO Conference)*

There are potential cost implications and efficiency losses associated with managing the variability of renewables.

b. Since WMSC is currently about 5% of total electricity costs, a 1% loss in overall grid efficiency could translate to a 10% increase in WMSC.

2) OPA and IESO Costs
   a. IESO costs are running an 8% deficit and have accumulated a debt of over $200M[43]. At some point this deficit and debt have to be reduced through increased revenue requirements which will eventually equate to a 15%/year rate increase in IESO costs for many years.
   b. The IESO 2011-2014 Business plan had forecast a 5%/year cost growth.
   c. The OPA has been managing to hold operating costs steady for several years and continues to face cost management pressures.
   d. There has been discussion of OPA/IESO merger and potential synergies that may arise. However total IESO and OPA budgets are less than $200M, so even a 10% saving would yield about $20M. This is considered a negligible amount to the total system costs being forecast in this report.

IMO Estimate 2002

WMSC Component	
IMO	153.4
Losses	189.2
Ancillary services	425.7
Total	**768.3**
TWh	147.5
$/MWh	**5.2**

SOURCE: WMSC_report_191001.pdf

Standard Supply Service Charge

Standard Supply Service Charge covers administrative costs incurred by LDCs in serving customers who subscribe to the RPP and purchase their electricity directly from the LDC. This charge is not applied to customers who make use of the services of a licensed electricity retailer. The supply service charge is set at $0.25 per account per month.

Rural or Remote Electricity Rate Protection charge

The Rural or Remote Electricity Rate Protection charge is used to offset the higher cost of providing electricity in rural and remote areas of the province. The costs have been prescribed at $156M[44] and are not expected to change for the purpose of this analysis. The Rural and Remote Electricity Rate charge of 0.12¢/kWh is in effect as of Jan. 1, 2013.

[43] *IESO 2011 Annual Report – Reliable Power for Ontario's Future (2012)*
[44] *OEB, Dec 2012 RRRP Decisions with Reasons and Rate Order*

3.4 Debt Retirement Charge

The debt retirement charge is fixed at $7/MWh as set by the Ministry of Finance with the funds accruing to the OEFC to pay down the debt from the former Ontario Hydro. There is currently some uncertainty over when the debt will be retired. Both the Auditor General and the Drummond reports have addressed this issue.

There are many issues that may impact how the debt is paid down. Declining demand will reduce Debt Retirement fee revenues. Suppressed HOEP will lower profits by OPG on its unregulated assets. The closure of the coal plants and other OPG assets over time will reduce OPGs revenues and equity and hence profits. Decreasing regulated rates of return will impact OPG, Hydro One profits as well as LDC PILs.

While it is not considered likely that these pressures will translate into a debt retirement rate increase, they may extend the time horizon over which the debt is paid down. The LTEP appears to have assumed the debt retirement charge would not end before 2018 and so the impact of these issues is considered outside the forecast horizon of this report.

For the purposes of this forecast, it is assumed that there will be no change to the Debt Retirement charge in the forecast period.

3.5 Additional Cost Considerations

During the course of developing the cost forecasts, research and feedback from reviewers has identified several considerations that have cost implications for which assumptions have not been included in the forecasts described in this report. The following five categories are discussed in Appendix 1.

1) Potential Innovations to optimize use of surplus energy
2) Managing the integration of renewables
3) Regulated entity implications of lower RoE and deferred risk
4) HOEP Implications on unregulated asset profits and demand
5) Other Considerations of known but quantified costs

In Strapolec's opinion, considering the above list, the probability that additional costs will be introduced to the electricity system, over and above those assumed in the forecast, is higher than the likelihood of any offsetting cost savings being realized. However, the magnitude has not been assessed.

It is also clear that the cost problem driving all of the above ideas is the build up of capacity that will not be used as demand declines. It appears that focussed attention on reducing the capacity cost is what is in the best interest of Ontarians.

4.0 Demand Forecast

The purpose of this section is to assess emerging trends in demand as they compare to the assumptions contained in the LTEP.

The primary finding is that demand can be expected to be 6% less than forecast in the LTEP which will have an upward pressure on electricity rates in order to pass on the fixed costs of Ontario's evolving energy system. This change in demand accounts for a large portion of the increased rate implications discussed in Section 5.

Since the minor recovery after the sudden drop during the 2008 recession, demand has continued to decline (see side bar). Overall demand for the three largest LDC customer groups has dropped modestly since 2006 and tracks similarly to residential consumption. Commercial customer demand has dropped dramatically for small consumers but has demonstrated an increasing trend for larger consumers who represent over 50% of LDC demand, up by 9% over 2006 levels.

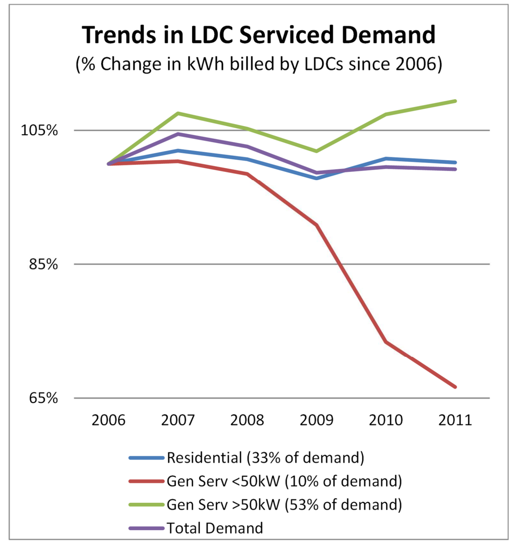
When the LTEP was originally developed in 2010, demand projections were developed that included low, medium and high growth scenarios. The nominal forecast was the medium growth.

IESO releases 18-month forecasts on a quarterly basis. The recent trends indicate that Ontario demand is evolving more in line with the LTEP low growth scenario rather than the medium growth scenario upon which the LTEP was based (see side bar).

At the APPrO 2012 conference, the OPA acknowledged Ontario's lower demand, and produced a forecast to 2020 showing demand projections very close to the low-growth scenario[45]. The OPA also forecasted that Class B consumption as a percentage of total demand will decrease slightly in the forecast period to 86% from the current 87%.

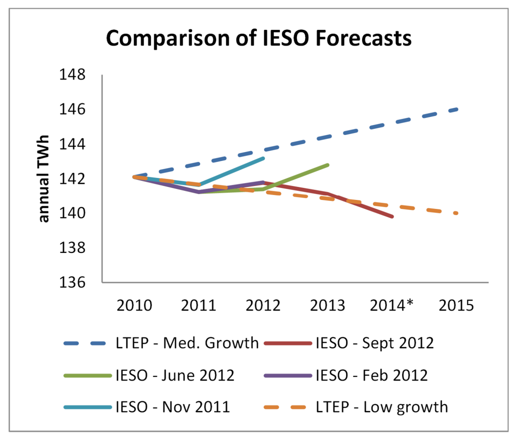
The Strapolec has derived its forecast from recent IESO actuals and reflects the OPA APPrO 2012 long term demand forecast.

[45] *OPA, Outlook for Electricity Demand and Supply in Ontario (Nov 2012 APPrO Conference)*



SOURCE: OEB Yearbook 2011

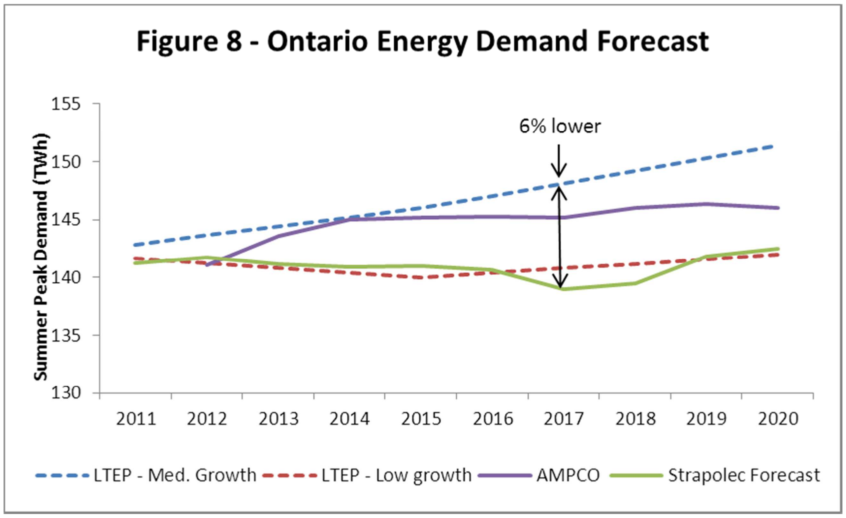
Note that residential and low Gen Serv users are both Class B rate payers. The larger Gen Serv group is a mix of Class A/B rate payers. Chart does not include energy purchased from retailers.



SOURCE: IESO 18 month outlooks, LTEP, OPA

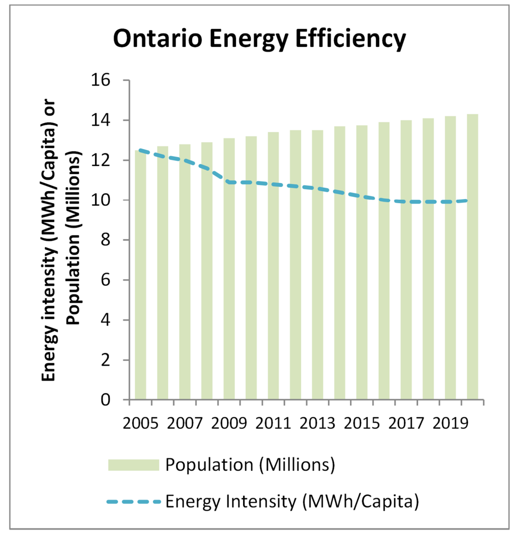
The trends in IESO 18 month forecasts over the last four reports and particularly the last one indicate that demand in Ontario is emerging more in line with the LTEP low-growth scenario. From these reports, some hesitance to accept that the short term declines were indicative of a longer term trend is evident. The earlier forecasts repeatedly projected demand growth to recover medium-growth LTEP projection levels. The most recent IESO forecast has acknowledged that a slow decline in demand is likely to extend into 2014, almost tracking the low–growth LTEP scenario.

Figure 8 compares the Medium and Low Growth LTEP demand scenarios with Strapolec's adopted OPA demand forecast overlaid.



For illustrative purposes, the demand forecast depicted by AMPCO in 2011 is included above to emphasize how recently the accepted change in demand outlook has occurred.

Declining demand increases expected rates due to the largely fixed cost nature of Ontario's electricity system. These fixed costs will need to be recovered over a smaller rate base. The main driver of lower demand is the decline in consumer energy use intensity that is outpacing population growth (see side bar)[46].



SOURCE: OPA

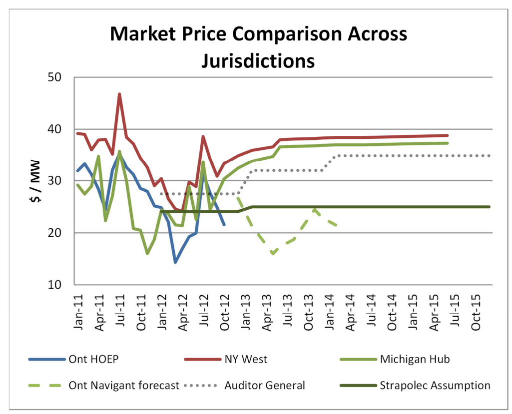
[46] *OPA, Outlook for Electricity Demand and Supply in Ontario (Nov 2012 APPrO Conference)*

5.0 Implications to Rate Payers

The purpose of this section is to illustrate implications to rate payers of the cost and demand forecasts. Each major rate payer group is addressed. The key findings of this section are:

- Residential rate payers will see a 52% cost increase by 2017, representing an $80/month increase to what they paid after OCEB in 2011. That is a total bill impact of $960/year.
- LDC Connected Class A Commercial rates are forecast to track closely to LTEP projections seeing a 35% rate increase or $30/MWh over 2012.
- Industrial Tx connected users were not modelled in the LTEP but will similarly see a 34% increase or $27/MWh more by 2017 as compared to 2012. The gap of $10/MWh between Ontario and US industrial rates will more than triple over the next 5 years to over $35/MWh.

Fundamental to the cost implications for rate payers is the introduction in January 2011 of a change in the way the Global Adjustment (GA) is applied. The new formula assigns approximately 90% of the cost of the Global Adjustment to Class B rate payers and the remainder to Class A rate payers. Residential consumers and small businesses are typically Class B while very large energy consumers are Class A. Class B rate payers currently consume approximately 84% of the energy. The current formula for the GA recovery assigns a Class B consumer rate that is almost twice that for Class A consumers. Furthermore, reductions in the HOEP translate to a higher Global Adjustment. While HOEP changes accrue equally to all rate payers, Class B rate payers bear a higher portion of the GA increase than Class A rate payers. This is relevant as the current HOEP forecasts are lower than those envisaged at the time of the LTEP.

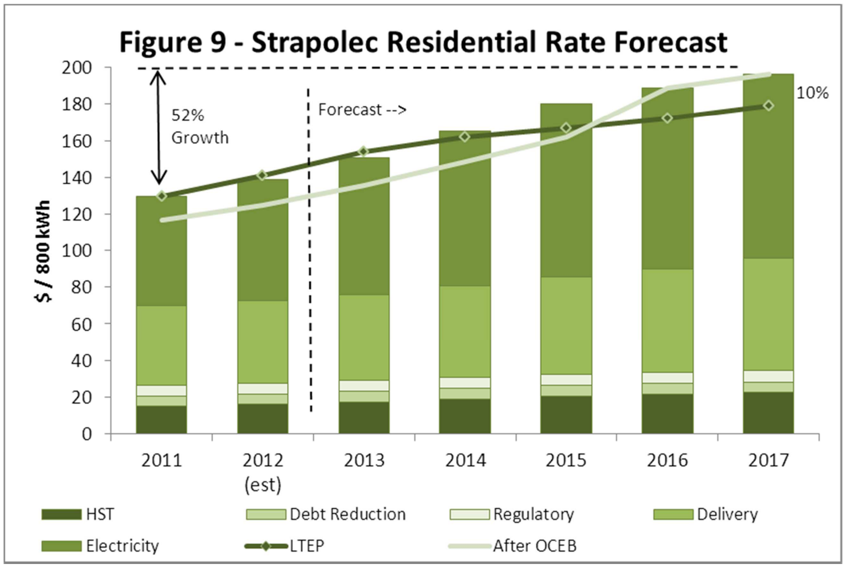


SOURCE: IESO, Navigant, US Hubs, Aud Gen, Strapolec Analysis

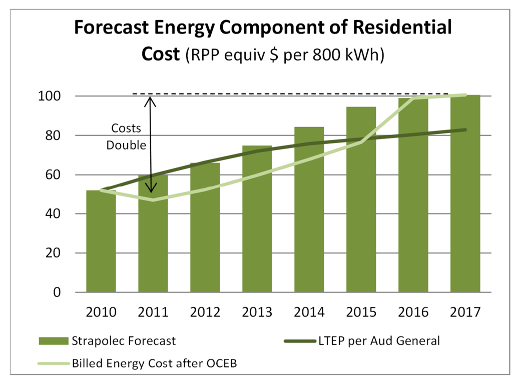
Recent Ontario HOEP forecast continue to suggest that the HOEP will remain depressed while the equivalent in other jurisdictions will rise to reflect stabilized operating conditions.

5.1 Implications to Residential Rate Payers

The forecast residential rates for a typical 800kWh household are provided in Figure 9. A typical residential bill is expected to grow to $196/mth by 2017, more than 50% above the LTEP base rate in 2011 of $129/mth ($116 after the OCEB). Expected residential rates should be approximately what the LTEP forecast for 2014 but increase to about 10% higher than predicted by 2017, a difference of about $17/month or about 25% more growth than reflected by the LTEP scenario.



This cost growth over the LTEP predictions is largely due to less growth in delivery costs which are offsetting the much higher energy cost growth. The energy portion of a residential bill is expected to double over the forecast period to 2017. If the Ontario Clean Energy Benefit, which is a 10% discount off of the total bill, is attributed to the growth in clean energy costs and hence assigned against the energy portion of the bill, then, when the OCEB is removed in 2016, the net effect is a doubling of the energy costs from 2011 to 2016. This will translate to residential rate payers paying over $625/year more three years from now from what they paid in 2011, just for the energy portion of their bill.



SOURCE: LTEP, Auditor General, Strapolec Analysis

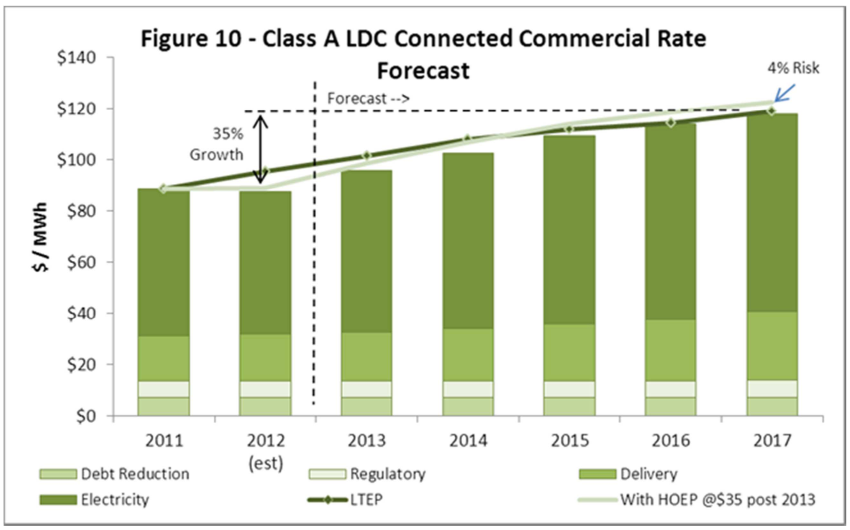
The 2012 costs reflect the RPP which earlier in 2012 assumed a restart to the Bruce Power Units. The resulting overcharge is being credited against the first few months of 2013 RPP rates.

The above portrayal of residential rates reflects the impacts to rate payers who are under the RPP and purchasing their energy directly from their LDC, assuming the illustrative total bill assumed in the LTEP. The Auditor General identified that approximately 15% of rate payers use energy retailers to purchase the energy portion of their bill and pay between 35% and 65% more for their electricity[47]. Given the increase in the GA portion of the energy bill forecasted here due to the lower HOEP assumptions, these premiums will likely increase.

[47] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), pages 70, 82-84*

5.2 Implications to LDC Connected Class A Rate Payers

The forecast of rates for commercial rate payers is provided in Figure 10. Forecast costs include energy, delivery, regulatory and debt retirement charges. Overall, by 2017 Class A commercial rates are forecast to grow by 35%. Unlike for residential rate payers, the forecast is lower than LTEP contemplated until 2016. The primary difference is due to the lower forecast HOEP of $25/MWh that was used in the analysis. As mentioned above, the GA formula is favourable to Class A customers when the HOEP drops. This is the main reason that estimated rates for 2012 are shown as similar to 2011. The other reason for the rates dropping in 2012 from 2011 is the delayed restart of the refurbished Bruce Power units. Those costs will materialize fully in 2013.

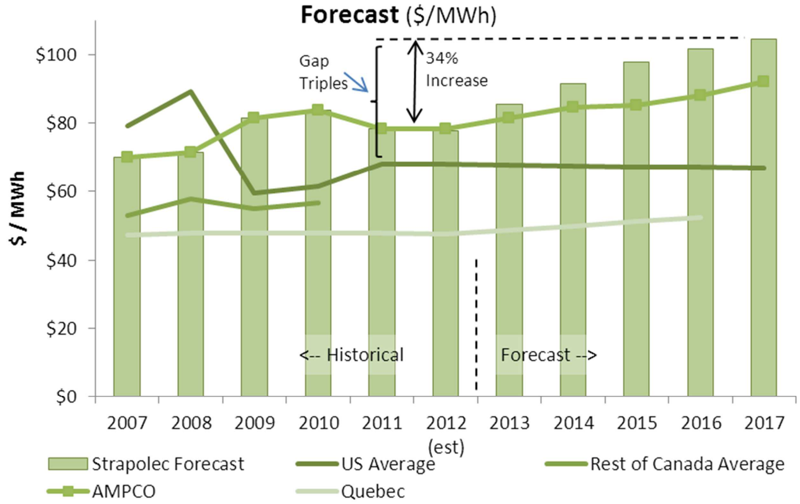


To illustrate the effect of HOEP changes, a scenario has been included where HOEP is assumed to migrate up to $35/MWh. This migration has very little effect on total costs as there is only a small portion of supply that is truly variable with HOEP. However there is an inverse relationship between HOEP and the GA. If HOEP goes up, the total GA goes down as costs accumulated under the GA are largely the difference between contracted rates and the HOEP. As class A consumers pay only 10% of the GA but use 16% of the energy, they benefit from low HOEP. Under this scenario, the forecast increase is almost 40%, or 4% more than Strapolec's baseline forecast that assumes a $25 HOEP.

5.3 Implications to Class A Industrial Direct Connect Customers

The forecast of rates for Industrial rate payers is provided in Figure 11. Energy, delivery, regulatory, and debt retirement costs have all been included. Overall, Industrial rates are also forecast to grow by 34% by 2017 or $27/MWh. There was no LTEP scenario related to Industrial direct connect customers. For comparison purposes, the forecast currently on AMPCO's website[48] has been used for reference. The Strapolec forecast developed here reflects more recent cost information and declining demand forecasts and shows almost twice the growth indicated by AMPCO in their 2011 study.

Figure 11 - Tx-Connected Industrial Electricity Cost Forecast ($/MWh)



The industrial rates in other jurisdictions are forecast to be flat over the next 5 years. Ontario has lost its competitive cost advantage in this area which in comparison to the US average was as high as $17/MWh in 2008. In 2009 this gap reversed as the price of natural gas dropped, the main driver for US electricity costs. The gap in electricity rates in both 2011 and 2012 was about $10/MWh. The gap by 2017 is forecast to grow to over $35/MWh. The disadvantage to economic competitiveness related to this energy cost gap for large industry is thus forecast to more than triple over the next 5 years.

[48] *http://www.ampco.org/index.cfm?pagepath=Analysis/Power_Market_Outlook/Delivered_Costs&id=43464*

6.0 Summary and Conclusion

The economic environment in Ontario has changed since the LTEP was formulated in 2010: Demand has declined and long term trends are more moderate; Costs are better understood and higher than anticipated; and, the implications of the interplay between renewables and other supply types, including the impacts on surplus base load power and potential surplus energy, are now clear.

The primary driver behind the LTEP is the evolution of Ontario's supply mix for which costs are growing faster and higher than originally expected. The OEB, IESO, and OPA are focussed on cost containment within the delivery and regulatory charge portions of the bill with less attention on costs associated with generation capacity increases outside of OPG. The Auditor General noted this challenge of energy cost growth and how the OEB's energy role is limited to setting rates for some of OPG's operations, and has no jurisdiction in the areas "based on government policy decisions"[49] where most cost growth is arising.

The results in this paper indicate:

- Annual electricity system costs will grow by over $7B by 2017. $5.7B of this increase is due to energy supply costs. This is likely a material impact to Ontario's economy.
- *Residential Bill Impacts*
  - When the OCEB is removed in 2016, affected ratepayers will see a total annual bill impact of about $865 to households that will arise by 2016 only three years from now.
  - By 2017 household annual impacts are projected to be $960, more than 70% higher than the Auditor General's quote from the OEB of $570[50].
- *Fiscal Impacts*
  - The OCEB will cost the government, and tax payers, close to $6.5B by 2015, more than the $5.5B implied by the 2011 $1.1B/year cost stated in the Auditor General[51] and Drummond[52] reports.
- *Industrial Rate Impacts*
  - Industrial rates will increase by 34% from 2012 to 2017 (from $78 to $106/MWh), twice the growth widely understood. Surrounding regions are not expecting similar increases.
  - The gap between the US and Ontario grid connected industrial rates is expected to more than triple over the next 5 years from $10 to $37/MWh.

With the above, it is clear that more capacity is profiled in the LTEP than Ontario needs to the end of this decade. Given the costs of the expected capacity and the implications to rate payers, there is strong evidence based support to the Drummond Report's recommendation of preparing an IPSP before additional capacity is committed to.

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[49] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011,) page 69*
[50] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011,) page 95*
[51] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page73*
[52] *Commission on the reform of Ontario's public services. (2012), page 328*

Acknowledgements

Overview of Strategic Policy Economics

Founded by Marc Brouillette in 2012 Strategic Policy Economics is focussed on addressing multi-stakeholder issues stemming from innovations in policy-driven regulated environments. Strapolec has clients in both the Energy and Gaming sectors. Strapolec specializes in framing strategic challenges for resolution, facilitating client teams in determining their alternatives, developing business cases and business models, and negotiating multi-stakeholder public/private agreements. Marc has been practicing strategy consulting for over 12 years and has 16 years of prior industry experience. Marc's consulting career has included CapGemini, Ernst & Young, leading his own practice, Strategic Gaming Innovations, and was most recently a Partner with SECOR Consulting, Canada's largest independent strategy boutique. At SECOR, he was the Ontario Sector lead for Energy and Gaming and led the development of SECOR's perspectives on Ontario's energy sector. Marc has helped inform federal and provincial government decision makers addressing strategic issues in gaming, science and energy policy. Marc has negotiated contract relationships with domestic and international stakeholders working directly with federal and provincial ministries, crown corporations and regulators, as well as with the private sector, municipalities, and non-profit organizations.

The Strategic Policy Economics team deployed to develop this report included:

- Marc Brouillette, Principal Consultant at Strategic Policy Economics.
- Neil Peet, former senior consultant at SECOR Consulting and currently a Master's candidate at the Munk School of Global Affairs. Neil was a colleague of Mr. Brouillette at SECOR working on multiple engagements in the energy sector and the primary resource that supported the development of SECOR's energy perspective on Ontario.
- Amir Naseri, Research Assistant at the University of Toronto and PhD candidate. Amir has worked with Marc and Neil on several projects including a global survey of research laboratory governance and funding models used to support the federal government.
- Jason Ng, Research Assistant at the University of Toronto and PhD candidate. Jason has worked with Marc and Neil on several projects including the global survey of research laboratory governance and funding models.
- Rory Johnston, Master's candidate at the Munk School of Global Affairs with a focus on global energy issues.

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List of Abbreviations

AMPCO – Association of Major Power Consumers of Ontario

APPrO – Association of Major Power Producers of Ontario

CDM – Conservation and Demand Management

CHP – Combined Heat and Power

FIT – Feed in Tariff

HOEP – Hourly Ontario Energy Price (wholesale market)

IESO – Independent Electricity System Operator

IMO – Independent Market Operator

IPSP – Integrated Power System Plan

GA – Global Adjustment

LDC – Local Distribution Company

LTEP – Long Term Energy Plan

MoE – Ontario Ministry of Energy

NPCC – Northeast Power Coordinating Council

NUG – Non-Utility Generator

OCEB – Ontario Clean Energy Benefit

OEB – Ontario Energy Board

OEFC – Ontario Electricity Financial Corporation

OPA – Ontario Power Authority

OPG – Ontario Power Generation Inc.

PIL – Profits In Lieu of Taxes

PSE – Potential Surplus Energy

RPP – Regulated Price Plan

RRRP – Rural or Remote Electricity Rate Protection

WMSC – Wholesale Market Service Charge

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Appendix 1 - Additional Cost Considerations

During the course of developing the cost forecasts, research and feedback from reviewers has identified several considerations that have cost implications for which assumptions have not been included in the forecasts described in this report. These considerations have been grouped into five categories for which a sample of related topics is provided below. This list is illustrative and not implied to be exhaustive. In the context of the team preparing this report, the bases of these suggestions have not been independently validated and the associated cost benefits have not been explored, their inclusion here and the implications suggested may be speculative.

1) Potential Innovations to optimize use of surplus energy
   - Development of storage technologies to make better use of variable renewable generation such as wind. This is a matter of global concern for which the extremely high costs are a barrier.
   - Hydrogen production using excess generation has been proposed in order to convert the electricity into hydrogen that can be re-used in the natural gas system[53]. This is a form of storage.
   - Further encouraging the matching of demand to supply. While this could entail approaches such as increasing the gap between off peak and on peak pricing, optimizing the duty cycle of energy intensive operations such as municipal water systems has been proposed as a mechanism of mitigating peak demand and improving the efficiency of the electricity system[54].
2) Managing the integration of renewables
   - The variability of renewables and the need to maintain backup supply that can quickly accommodate large fluctuations in renewable generation. The Auditor General cited IESO confirmation that consumers will have to pay twice for intermittent renewable energy and that this will add to ongoing operational costs[55]. Much of these costs are assumed to be already reflected in the OPA's cost forecasts used in this report. However, increased inefficiencies in the system will arise due to the ramping up and down of the backup generation and likely show up in the WMSC.
   - Similarly, there may be additional costs associated with congestion managements settlement credits agreements, particularly curtailments associated with PSE[56]. The increase in the number of distinct generators is an example of complexity that may have cost implications.
   - Much attention has been given to surplus baseload generation and the PSE. With declining demand, another issue may be emerging related to peak surplus energy which is partially being contributed to by solar[57].

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[53] *OPSE Event, Engineering The Grid, Sept 2012*
[54] *OPSE Event, Engineering The Grid, Sept 2012*
[55] *2011 Annual Report, Office of the Auditor General of Ontario (Fall 2011), page 113*
[56] *IESO, Congestion Management Settlement Credits Calculations for Variable Generators, Sept 2012*

- To enable baseload maneuverability to accommodate renewables, suggestions have been made that the requirements on nuclear new builds include this ability. Bruce Power has made such accommodations to vent steam but added cost to the system the cost is not known to the research team.

3) Regulated Entity implications
- The costs to achieve LDC consolidation, if pursued, are likely to precede the benefits and cause near term upward cost pressures.

- Similarly, OEB has regulatory pressures on OPG to constrain costs, and if enacted through lower ROEs may have a similar effect on debt retirement.

- Feedback from reviewers of draft versions of this report suggests that the Dx and Tx cost forecasts are likely low. Implications of deferred capital programs and other cost pressures may impact adoption rates of renewables, redevelopment of ageing infrastructure, and ultimately the reliability of the system which has the most tangible impact on rate payers. These issues potentially indicate deferred cost risks may be arising from the near term regulatory pressures to contain cost.

4) HOEP Implications
- The implications to OPG's unregulated operations that may arise from lower HOEP have not been assessed. These may manifest themselves in a reduced ability to service the debt. Additionally, considering OPG's unregulated hydro assets, a similar issue encountered by Bruce Power resulted in Floor Price agreements with the OPA. Floor price agreements were not required prior to the drop in HOEP that coincided with the 2008 recession.

- The negative impact that awareness of rising prices may have on future demand is an un-quantified rate growth risk. This could come in many forms such as additional conservation measures by consumers or in consumers seeking off grid solutions.

5) Other Considerations
- The cost impacts of new incentive programs of the provincial government such as the Industrial Conservation program and the Northern Industrial Electricity Rate Program have not been assessed.

- The $210M agreed to be paid to TransCanada for the turbines from the relocated Oakville plant has not been reflected in the current cost forecast[58]. It is also not clear how the recovery is planned for the overall cancellation costs of the two gas plants originally identified for the Mississauga and Oakville sites prior to the LTEP. The identified cost to tax payers of $40M[59] for

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[57] *OSPE, "Wind and the Electrical Grid", March 2012*
[58] *http://www.powerauthority.on.ca/news/opa%E2%80%93transcanada-energy-reach-deal-relocate-power-plant*
[59] *http://news.ontario.ca/mei/en/2012/09/statement-from-ontario-minister-of-energy-1.html*

Lennox implies rate payers will pay the rest, if any. Comments made by Vic Fedeli at the Liberal Leadership Convention on January 26, 2013, suggest the cancellation costs of the two gas plants could be as high as $1B.

In Strapolec's opinion, considering the above list, the probability that additional costs could be introduced to the electricity system, over and above those assumed in the forecast, is higher than the likelihood of any offsetting cost savings being realized. However, the magnitude has not been assessed.

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