INTERROGATORY RESPONSE - SEC-1

1-SEC-1

EXHIBIT REFERENCE:

[Ex.1]

SUBJECT AREA: COVID-19

With respect to COVID-19:

a) Please provide details regarding the impact COVID-19 has had on Hydro Ottawa's operations to date.

b) Please provide details regarding the impact COVID-19 is expected to have on assumptions, forecasts and plans that underlie Hydro Ottawa's forecast budgets through the end of 2020. Please provide necessary revisions to those forecasts, as required.

c) Please provide details regarding the impact COVID-19 is expected to have on the assumptions, forecasts and plans that underlie Hydro Ottawa's budgets for the 2021-2025 Custom IR term. Please provide necessary revisions to those forecasts, as required.

d) If Hydro Ottawa believes that COVID-19 will have an impact on the assumptions, forecasts, and plans that underlie budgets for the 2021-2025 Custom IR term, but is unable to quantify those impacts at this time, please explain how Hydro Ottawa proposes that they be incorporated into its rate-setting proposal.

RESPONSE:

a) Hydro Ottawa has taken significant measures to ensure the health and safety of the public and its employees as well as actions to ensure that the power stays on and that

core work activities continue. Hydro Ottawa was prepared and had key elements in place to help address the challenges presented by the COVID-19 pandemic.

As an example, in mid-January 2020 Hydro Ottawa began monitoring the developing novel coronavirus ("COVID-19") situation in China. In February 2020, Hydro Ottawa reviewed and activated its Pandemic Plan in anticipation of the continued spread of the COVID-19 novel coronavirus.

Hydro Ottawa's Pandemic Plan is one of the specific Incident Management Plans under its Business Continuity Management Program. The Pandemic Plan was originally developed and activated for the H1N1 influenza pandemic in 2009.

According to internal data metrics, the number of Hydro Ottawa's commercial customers struggling to pay their bills is the highest on record, with increases from March 2020 to April 2020 in multiple metric categories highlighting a troubling trajectory. For example, in the month of April, the value of Hydro Ottawa's small commercial accounts in arrears increased by a factor of five; for all other commercial accounts, the increase has been a factor of four.

According to the IESO, more than 80% of commercial load is being impacted by measures taken to combat the COVID-19 pandemic, with the largest reductions in demand and energy use in any segment of the customer base coming from distribution-connected commercial and industrial loads (e.g. malls, retail, office, small industrial).[1]

Similarly, Hydro Ottawa has seen load reduction in its own service territory, with an overall 10-11% drop in electricity consumption in April, with the biggest decline in electricity usage happening early in the morning.

[1] Independent Electricity System Operator webinar, "An overview of COVID-19 impacts on electricity system operations" (April 23, 2020), slide 19.

b) Hydro Ottawa Management is currently developing a 2020 forecast that has not yet been reviewed by the Executive Management Team. This forecast, however, contains many uncertainties and high-level assumptions with respect to impacts and a return to normal operations.

c) Hydro Ottawa cannot provide an update for the impact of the COVID-19 pandemic. At this time, there is not enough information, analysis, or understanding of the potential impacts of the pandemic to accurately forecast what the impact on the 2021-2025 timeframe may be. It is Hydro Ottawa's belief that any material impact will be with respect to 2020 results, and that the forecasts for 2021-2025 need not be materially changed. If necessary, the Earnings Sharing Mechanism ("ESM"), Capital Variance Account, and Lost Revenue Adjustment Mechanism ("LRAM") will mitigate the impact on customers over the 2021-2025 period. In addition, the OEB has established three deferral accounts to deal with the incremental impacts in 2020.

In its "Provincial Outlook Spring 2020", the Conference Board of Canada stated the following: "In Ontario, real GDP is forecast to decline by 3.2% this year, one of the smallest declines among the provinces. A large concentration of professional service activities (which can be done remotely) and the retooling of some facilities to produce medical supplies are helping to lift the outlook for Ontario relative to other provinces. Next year, economic growth is forecast to hit 6.0%." Please see Attachment SEC-1(B): Conference Board of Canada Provincial Outlook Spring 2020 for more details.

Ottawa is the capital of Canada and home to large Federal Government campuses. The city has a large Municipalities, Universities, School Boards and Hospitals ("MUSH") sector presence, as well as many representative companies from the high-tech industry. In its "Major Cities Update - Ottawa" dated May 12, 2020, the Conference Board of Canada likewise stated the following: "Next year looks much better, with output growth forecast for all industries. Public administration growth should perk up, while a rekindling of housing markets should return the FIRE sector to growth. The winding down of the pandemic should lead to at least some resumption in travel and allow larger groups to

gather in public places, brightening the outlook for Ottawa's accommodation and food services industry and its arts and entertainment sector." Please see Attachment SEC-1(A): Conference Board of Canada Major Cities Update - Ottawa for more information.

d) Please see the response to part (c) above.

https://www.conferenceboard.ca/focus-areas/canadian-economics/major-city-insights/ottawa

Major City Insights

Ottawa



May 12, 2020

Ottawa key economic indicators

(forecast completed April 24, 2020)

	2019	2020	2021	2022	2023	2024
Real GDP (2012 $ millions)	80,820	78,909	82,744	84,564	86,010	87,595
	2.6	*–2.4*	*4.9*	*2.2*	*1.7*	*1.8*
Employment (000s)	774.0	756.1	799.3	819.8	835.1	853.0
	4.5	*–2.3*	*5.7*	*2.6*	*1.9*	*2.1*
Unemployment rate (per cent)	4.8	7.0	5.4	5.2	5.0	4.9
Personal income per capita ($)	54,057	54,624	56,924	58,782	60,764	62,815
	2.4	*1.0*	*4.2*	*3.3*	*3.4*	*3.4*
Population (000s)	1,441.1	1,463.3	1,480.8	1,497.8	1,514.8	1,531.9
	2.1	*1.5*	*1.2*	*1.2*	*1.1*	*1.1*
Housing starts (units)	11,203	10,044	10,052	9,516	9,297	9,121
Retail sales ($ millions)	23,746	23,132	23,934	24,682	25,482	26,292
	3.0	*–2.6*	*3.5*	*3.1*	*3.2*	*3.2*
Consumer price index (2002 = 1.00)	1.36	1.37	1.40	1.43	1.46	1.49
	2.0	*1.1*	*2.1*	*2.1*	*2.0*	*2.0*

Shaded area represents forecast data, italics indicate percentage change.
All data are seasonally adjusted at annual rates unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key findings

- Because it is home to the federal government, Ottawa doesn't always have the same economic outcomes as other places. The government's contribution to the local economy has enabled Ottawa's GDP growth to equal or exceed the national average for five straight years, and it will limit COVID-19's hit to the local economy in 2020. Still, the city's GDP, which expanded by 2.6 per cent last year and averaged 2.7 per cent growth annually during the past five years, will decline by 2.4 per cent this year as the pandemic's effects ripple through the economy. This includes a 4.6 per cent drop in the second quarter, a loss that will not be fully recovered by 2.3 per cent expansion in the third quarter. We forecast much better GDP growth of 4.9 per cent next year.

- The coronavirus has cooled a hot local labour market that saw employment grow by 4.5 per cent in 2019 (a 16-year high) and the unemployment rate average below 5 per cent for the second straight year. We expect employment to fall 2.3 per cent in 2020, boosting the unemployment rate to 7.0 per cent. The second quarter will be the downturn's low point, with employment dropping 6.0 per cent and the unemployment rate jumping to 12.6 per cent. We expect much firmer conditions in 2021, with job growth of 5.7 per cent and an unemployment rate of 5.4 per cent.

- A red-hot, pre-virus local housing market pushed housing starts to a 35-year high of 11,200 units in 2019 against a backdrop of low inventories of unsold new homes. The resale market favoured sellers, with year-over-year price growth nearing 20 per cent. Battered by the pandemic this year, housing starts and the resale market will both soften. But they will start to recover next year, fuelled by low interest rates, the absence of a foreign buyers' tax, and supportive federal programs. Starts will remain above 10,000 units both this year and next, and the resale market could quickly return to its previous sellers' state.

- Travel restrictions imposed to fight the pandemic will slash net in-migration to Ottawa

from its record high of 25,100 in 2019. We expect only about half that total (12,200) this year. Ottawa's population growth will accordingly drop to about 22,200 in 2020, down from almost 30,000 last year.

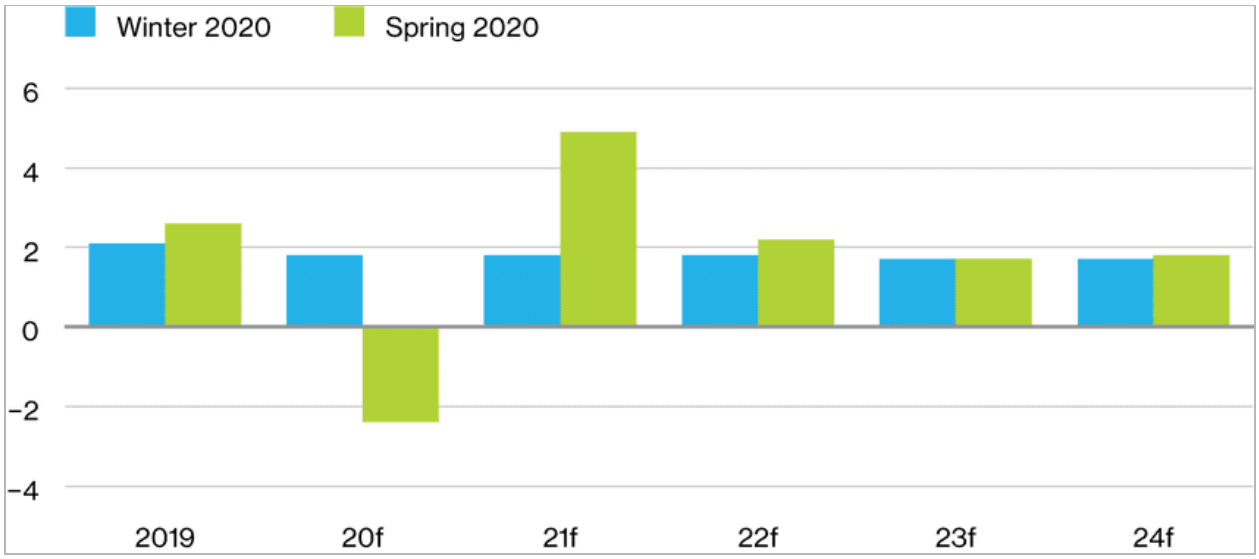
- Public administration is Ottawa's largest industry by a wide margin, and its continued growth (albeit a modest 0.4 per cent) this year is a key reason why Ottawa's economic contraction will be less severe than the national average. Health care, another publicly funded industry, will expand by 2.4 per cent, also helping to prop up the local economy. Meanwhile, the city's second-largest industry—finance, insurance, and real estate (FIRE)—will contract by 0.5 per cent. This is a slightly steeper drop than during the 2008–09 recession. Travel restrictions and social distancing imposed in response to the pandemic will cut output in Ottawa's accommodation and food service industry by 41.6 per cent and in its arts and entertainment industry by 18.0 per cent.

- The impact of COVID-19 on consumer confidence has been bad news for a retail sector already threatened by online shopping. The retail industry's local output will fall 3.4 per cent this year, the worst drop since 1991. We expect the retail trade industry to rebound next year with 5.2 per cent growth.

- Next year looks much better, with output growth forecast for all industries. Public administration growth should perk up, while a rekindling of housing markets should return the FIRE sector to growth. The winding down of the pandemic should lead to at least some resumption in travel and allow larger groups to gather in public places, brightening the outlook for Ottawa's accommodation and food services industry and its arts and entertainment sector.

Ottawa real GDP

(real GDP, percentage change*)



f = forecast
*based on 2012 $
Sources: The Conference Board of Canada; Statistics Canada

The Conference Board of Canada

Summary

Sharp Deep Unprecedented Provincial Outlook Spring 2020

April 15, 2020



Canada is in the midst of the worst economic downturn it has experienced in decades. The shutdown of non-essential businesses and the physical distancing measures in place across the country to slow the spread of COVID-19 have brought activity in many industries to a near standstill. On top of that, Canada's energy sector is dealing with plummeting demand for oil and a price war between Saudi Arabia and Russia.

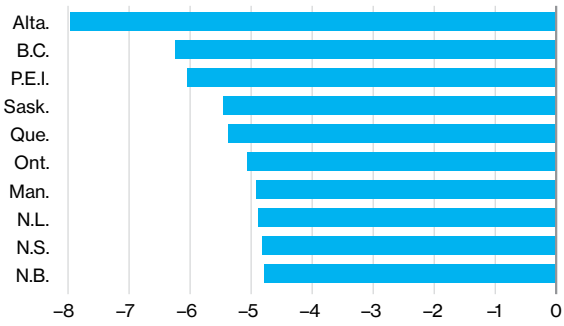
We estimate that real GDP declined at an annualized pace of nearly 5 per cent in the first quarter. In the second quarter, the decline in GDP is forecast to hit 25 per cent. This will be the steepest quarterly decline in economic output on record, based on modern statistics that date back to 1961.

The arrival of the COVID-19 pandemic has devastated the economic outlook for all provinces. The reduction in consumer and global demand will be felt across the country. On top of the havoc from the pandemic, the collapse in oil prices is amplifying economic hardship in the energy-producing provinces. Our forecast for 2020 calls for a steep decline in economic growth in every province. (See Chart 1.)

Chart 1

Change in our forecast for GDP growth in 2020

(percentage-point change from our February 2020 forecast, real GDP at basic prices)



Sources: The Conference Board of Canada; Statistics Canada.

Newfoundland and Labrador is set to enter a recession this year, with its economy contracting by 3.8 per cent as the province deals with the decline in oil prices and sharp reductions in global and domestic demand. While growth is forecast to rebound by 5.4 per cent next year, that is one of the weaker gains in our forecast.

In Prince Edward Island, the economy will contract by 3.0 per cent in 2020, with the contraction in tourism activity a key driver of this outcome. Although leisure travel will be slow to recover, the resumption of normal operations for businesses in the second half of the year will lay the foundation for a 5.7 per cent rebound in 2021.

Nova Scotia's economy is forecast to contract 3.6 per cent this year. Both export-intensive and domestic-oriented industries are seeing a massive drop in foreign demand due to the coronavirus pandemic. Fortunately, pent-up consumer demand and the start of construction on the $10-billion Goldboro LNG terminal will allow the economy to rebound 5.9 per cent next year.

The broad-based slowdown in global and domestic demand will see New Brunswick's economy shrink by 3.3 per cent this year. This revision to our previous forecast is the smallest among all provinces, as healthcare makes up a larger than average share of the New Brunswick economy. (Healthcare is one of the lone sectors expected to post positive growth this quarter.) Growth will bounce back to 4.8 per cent next year as the economy emerges from recession.

In an attempt to slow the spread of COVID-19, Quebec has shut down businesses deemed non-essential until at least May 4, 2020. With activity restricted and consumer and global demand falling, the province's real GDP will fall 3.8 per cent this year. Buoyed by various income support programs, Quebec's economy will bounce back next year, gaining 5.8 per cent.

In Ontario, real GDP is forecast to decline by 3.2 per cent this year, one of the smallest declines among the provinces. A large concentration of professional service activities (which can be done remotely) and the retooling of some facilities to produce medical supplies are helping to lift the outlook for Ontario relative to other provinces. Next year, economic growth is forecast to hit 6.0 per cent.

Manitoba's economy is set to contract by 3.9 per cent this year. The impacts of COVID-19 will reduce household spending and weigh on demand in key industries, such as transportation equipment manufacturing. The economy will recover over the second half of this year and into the next, boosting GDP growth to 6.0 per cent in 2021.

Saskatchewan will experience one of the largest declines in output this year as the negative impacts of COVID-19 are layered on top of the weakness in the province's mining industry. Overall, the province is looking at a decline in real GDP of 5.0 per cent this year before rebounding by 5.4 per cent in 2021.

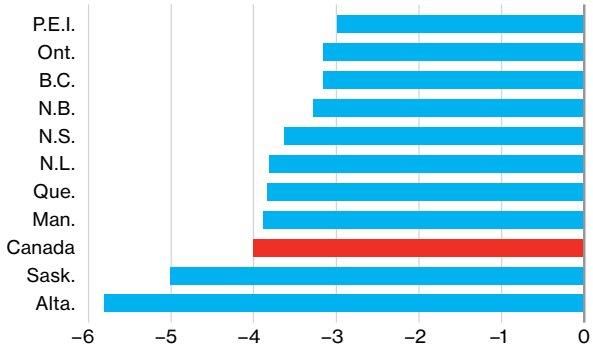
Alberta is grappling not only with COVID-19, but also with a severe contraction in oil prices resulting from the steep drop in global demand (due to the pandemic) and the price war between Russia and Saudi Arabia. We expect the economy to contract by 5.8 per cent in 2020, which would be the worst annual decline on record. Fortunately, the downturn will be temporary, and the economy will rebound with 6.1 per cent growth in 2021.

British Columbia's economy is projected to contract by 3.2 per cent this year. Some consumer-facing industries will see a near-halt to activity while the slowdown in international trade weighs on port and transportation activity. A rebound of 6.3 per cent is forecast in 2021 with construction activity on megaprojects, such as the LNG Canada liquefied gas project and the Site C hydroelectric complex, leading the way.

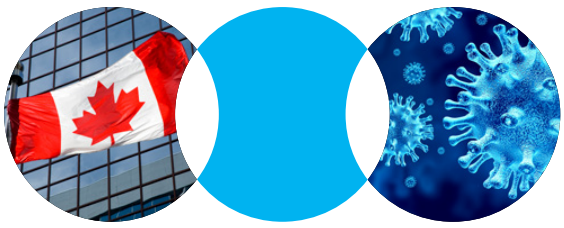
Chart 2

Real GDP by province, 2020

(real GDP at basic prices, percentage change*)



*based on 2012 $
Sources: The Conference Board of Canada; Statistics Canada.



INTERROGATORY RESPONSE - SEC-2

1-SEC-2

EXHIBIT REFERENCE:

[Ex.1]

SUBJECT AREA: Corporate Governance

Please provide all material provided to Hydro Ottawa's Board of Directors for their approval of this application and the underlying budgets.

RESPONSE:

Please refer to Attachment SEC-2(A): Materials Provided to the Hydro Ottawa Limited Board of Directors in relation to the approval of this Application and the underlying budgets. These reports rose to the Holding Company Board.

Board / Committee Report

To: Hydro Ottawa Limited Board of Directors

Date: 16 April 2019

Submitted by:

Gregory Van Dusen
Director, Regulatory Affairs

Geoff Simpson
Chief Financial Officer

Approved for Submission by:

Bryce Conrad
President and Chief Executive Officer

Agenda Item: 9 - Hydro Ottawa Limited 2021 to 2025 Rate Application Update

Report Recommendation(s):

That the Board of Directors receive the report of the Director, Regulatory Affairs and Chief Financial Officer dated April 16, 2019 comprising an update on Hydro Ottawa Limited's 2021 to 2025 Customer Incentive Rate Application.

BACKGROUND:

1. Hydro Ottawa Limited is planning to file its 2021 to 2025 Custom Incentive Rate Application in Q4, 2019.

DISCUSSION:

2. The presentation at Annex "A" contains an update on the preparations for Hydro Ottawa Limited's 2021 to 2025 Custom Incentive Rate Application.

SUPPORTING DOCUMENTATION:

Annex "A" – 2021 to 2025 HOL Rate Application Update

Annex “A”

2021-2025 HOL Rate Application Update

HOL & HOHI BOARD MEETINGS
April 16, 2019

CFO Division

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HydroOttawa

Agenda

1. 2021-2025 HOL Rate Application
   a) Schedule & Status
   b) Approval Process
   c) Next Steps

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Rate Application Schedule

Customer Engagement	Q1 / Q2 / Q3 2019
Special Studies completed	Q1 / Q2 2019
First draft DSP completed	Q1 2019
Divisional Plans updated	Q1 2019
HOL Business Planning Process	Q1 / Q2 2019
DSP Completed	Q2 2019
Development of evidence	Q2 / Q3 2019
Incorporate findings from Special Studies	Q3 2019
Filing of evidence	December 2019
Interrogatory Process	TBD – Spring 2020
Update of evidence (2019 Actuals)	TBD – April 2020
Technical Conference	TBD – mid summer 2020
Settlement Conference	TBD – late summer 2020
Oral Hearing	TBD – fall 2020
OEB Decision	Target – December 2020

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Rate Application Status

- Rate Application Working Group (RAWG) and Rate Application Steering Committees (RASC) meeting on a regular basis
- Budget and Rate Application planning assumptions for 2020-2025 have been established
- Budget process is underway; set to be completed by end of June 2019
- Evidence structure has been developed & confirmed with stakeholders
- Strategic approach to key pieces of evidence have been developed
  - Facilities
  - Benchmarking
  - Productivity and Continuous Improvement
  - Customer Engagement
  - 2021-2025 HOL Business Plan

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Rate Application Approval Process

- Fall 2019 – application reviewed by RAWG and RASC
- November 2019 – application approved by HOL & HOHI Boards
  - 2021-2025 HOL Business Plan will be filed with Rate Application
- December 2019 – application filed
- 2020 – OEB review process and approval

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Rate Application Next Steps

- Completion of 2020 Budget & 2021-2025 Business Plan (Q2 2019)
- Training for staff on new document management system & evidence preparation tool (AODoc's) (April 2019)
- Further development of key evidence (Q2 / Q3 2019)
- Development of customer engagement workbook (Q2 2019
- Completion of special studies (Q2 2019)
- Ongoing monitoring of provincial government energy policy & OEB policy changes impacting rate applications

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Summary – Key Themes & Take-aways

- Preparation of HOL rate application is progressing well
  - Already shifted into high gear
  - More staff being engaged
  - Core components in motion; where we want to be

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Questions or Comments?

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Preparing for the 2021-25 Rate Application

Rate Application Steering Committee (RASC)

- Bryce Conrad (Chair)
- Geoff Simpson
- Julie Lupinacci
- Lance Jeffries / Guillaume Paradis
- Mark Fernandes
- Lyne Parent-Garvey
- Tina Tardioli
- Greg Van Dusen (Secretary)

RASC Mandate

- Approves over-all rate case strategy
- Approves over-all revenue requirement / rate change request
- Reviews critical pieces of evidence
- Provides advice and guidance to the RAWG
- Meets twice a year in 2018 and then at least quarterly in 2019

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Preparing for the 2021-25 Rate Application

Rate Application Working Group (RAWG)

- Greg Van Dusen (Chair) – *Regulatory Affairs*
- April Barrie, Patrick Brown and Laurie Elliott – *Regulatory Affairs*
- Meghan Fee – *Project Manager – Regulatory Affairs*
- Angela Collier & Mike Grue - *Finance*
- Seb Oran – *Customer Group*
- Director – *Engineering & Asset Management*
- Joseph Muglia – *Distribution Operations*
- Shaefann Sieuraj – *Executive Office*
- Bruce Lang – *Human Resources*
- Andrew Willis - *IT representative*

RAWG Mandate

- Reviews issues and recommends solutions
- Reviews material going to the RASC
- Monitors progress of the rate application process
- Provides an overall quality assurance role to the rate application process
- Provides advice and guidance to HOL staff involved in the rate application process
- Meets twice a year in 2018 and then at least quarterly in 2019 & 2020

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Benchmarking Studies

#	Topic / Subject	Consultant
1	Total Cost	Clear Spring Energy
2	Unit Costs	UMS
3	IT Budget	Gartner Consulting
4	Compensation	Mercer's
5	DSP – Third-Party Review	Navigant Consulting
6	Asset Condition Assessment – Third-Party Review	METSCO

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Other External Studies

#	Topic / Subject	Consultant
1	Customer consultation	Innovative Research Group
2	Metering Roadmap	Black & Veatch
3	Climate change vulnerability assessment	Stantec
4	Local Achievable Potential Study	SNC-Lavalin (IESO-funded)
5	ISO55001 Gap Assessment	EA Technology
6	Lead / Lag Study	Navigant
7	Load Forecast	Itron
8	Cost Allocation and Rate Design	Elenchus
9	HR Costing Assumptions 2020 to 2025	Mercer's
10	Facilities Implementation Plan Evidence	Elenchus

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Board / Committee Report

To: Hydro Ottawa Limited Board of Directors

Date: 18 June 2019

Submitted by:

Gregory Van Dusen
Director, Regulatory Affairs

Geoff Simpson
Chief Financial Officer

Approved for Submission by:

Bryce Conrad
President and Chief Executive Officer

Agenda Item: 6 - Hydro Ottawa Limited 2021-2025 Rate Application Quarterly Status Update

Report Recommendation(s):

That the Board of Directors receive the report of the Director, Regulatory Affairs and the Chief Financial Officer dated June 18, 2019 comprising updates on i) Regulatory Construct 101, ii) Hydro Ottawa Limited's 2021-2025 Rate Application, iii) the Ontario Energy Board, and iv) the provincial government.

BACKGROUND:

1. Hydro Ottawa Limited is planning to file its 2021 to 2025 Rate Application in Q4, 2019.
2. A Rate Application status update is provided to the Board on a quarterly basis.

DISCUSSION:

3. The presentation attached at Annex "A" provides an update on i) Regulatory Construct 101, ii) Hydro Ottawa Limited's 2021-2025 Rate Application, iii) the Ontario Energy Board, and iv) the provincial government.

SUPPORTING DOCUMENTATION:

Annex "A" – Regulatory Update

Annex “A”

Regulatory Update

HOL BOARD MEETING
June 18, 2019

CFO Division

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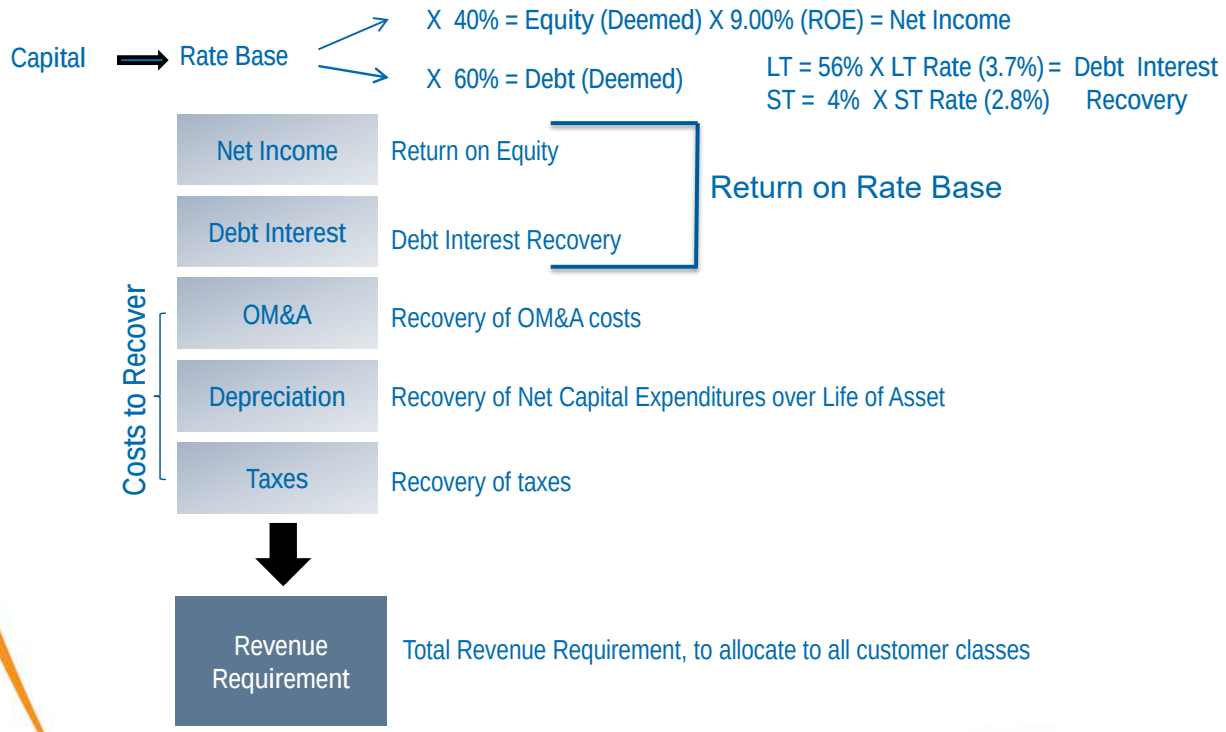
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Agenda

1. Regulatory Construct 101
2. Rate Application
3. OEB Update
4. Government Update
5. Next Steps

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Regulatory Construct 101
How HOL Makes Money



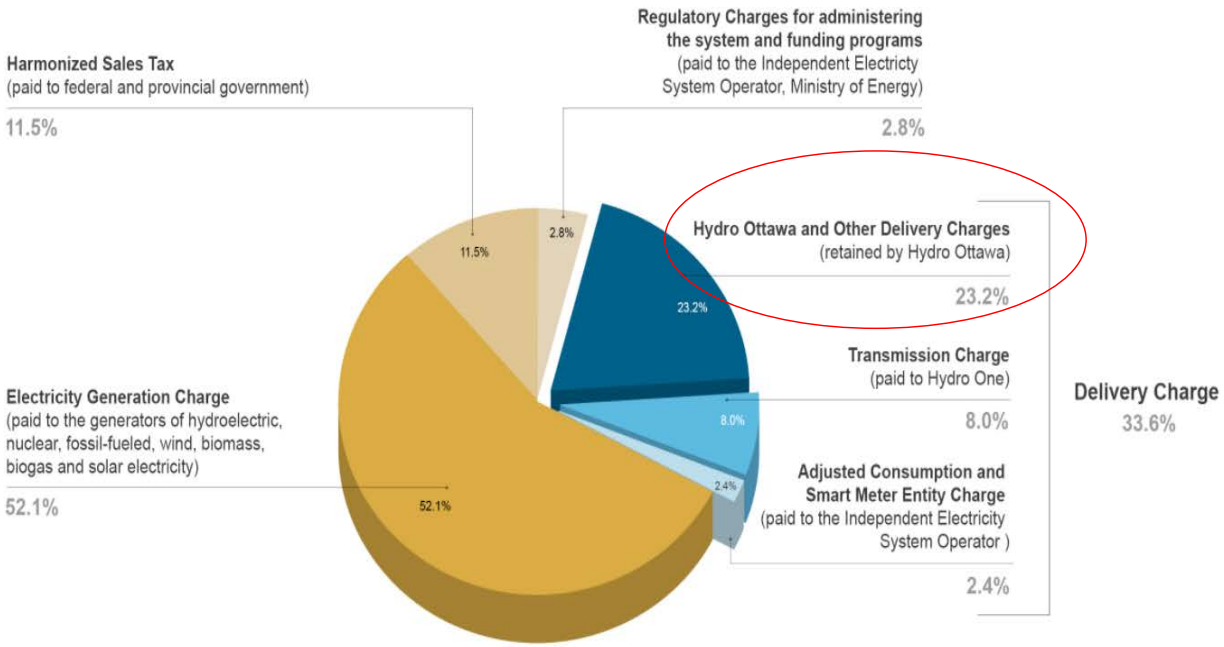
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Regulatory Construct 101

Our Share of the Over-all Bill

Break-down of Charges effective January 1, 2018



* For the average Standard Supply Service residential customer using 750 kWh per month. The percentage above does not include the 8% Provincial Rebate.

The 2021 to 2025 Rate Application
Status Update

- Evidence preparation has started
- New document management system in place
- Evidence and document management system training completed
- Key evidence:
  - Executive Summary
  - Business Plan
  - Distribution System Plan
  - Facilities
  - Productivity and Continuous Improvement
  - Customer Engagement
  - Benchmarking Studies

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The 2021 to 2025 Rate Application

Key Dates

First draft of DSP completed	Q1 2019
Divisional Plans updated	Q1 2019
Customer Engagement (CE) – DSP	Q1 / Q2 2019
Customer Engagement - Rate Application	Q1 / Q2 2019
Special Studies completed	Q1 / Q2 2019
HOL Business Planning Process	**Q1 / Q2 2019**
DSP Completed	**Q2 2019**
Development of evidence	**Q2 / Q3 2019**
Incorporate findings from CE and Studies	Q3 2019
HOL & HOHI Board Approval of Application	Q3 2019
Filing of Rate Application with OEB	December 2019
Interrogatory Process	TBD – Spring 2020
Update of evidence (2019 Actuals)	TBD – April 2020
Technical Conference	TBD – mid summer 2020
Settlement Conference	TBD – late summer 2020
Oral Hearing	TBD – fall 2020
OEB Decision	Target – December 2020

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Ontario Energy Board (OEB)
Update

- OEB Chair has left – temporary Chair in place
- Only a few Board Members remain
- OEB governance changes underway (as per Bill 87)
- On-going Policy Initiatives:
  - Advisory Committee on Innovation; early implementation phases will focus on Utility Remuneration & Distributed Energy Resources (DER)
  - Commercial & Industrial Rate Design
  - Review of Customer Service Rules
  - Corporate Governance Guidance
  - Activity & Program Based Benchmarking
  - New Performance Standards for Processing Applications
  - Regulated Price Plan (RPP) Roadmap

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Provincial Government
Update

- Bill 87 has received Royal Assent (changes to CDM Framework, OEB Governance, Rate Relief)
- Waiting on further action to reduce electricity bills (by 12%)
- Further action could include:
  - Changes in allowed Return on Equity (ROE) and/or Capital Structure
  - Rates held to the level of inflation
- Potential for major changes
  - Changes could be 'significant and disproportional' (relative to LDC's share of the overall customer bill)
- Consultations have started on industrial electricity pricing
- Budget 2019 expressed interest in exploring ways to promote efficiency and modernization in the distribution sector

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Questions or Comments?

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Board / Committee Report

To: Hydro Ottawa Limited Board of Directors

Date: 23 September 2019

Submitted by:

Gregory Van Dusen
Director, Regulatory Affairs

Geoff Simpson
Chief Financial Officer

Approved for Submission by:

Bryce Conrad
President and Chief Executive Officer

Agenda Item: 8 - Hydro Ottawa Limited 2021-2025 Rate Application Update

Report Recommendation(s):

That the Board of Directors receive the report of the Director, Regulatory Affairs and the Chief Financial Officer dated September 23, 2019 comprising an update on Hydro Ottawa Limited's 2021-2025 Rate Application.

BACKGROUND:

1. Hydro Ottawa Limited is planning to file its 2021 to 2025 Rate Application in Q4, 2019.
2. A Rate Application status update is provided to the Board on a quarterly basis.

DISCUSSION:

3. The presentation attached at Annex "A" provides an update on Hydro Ottawa Limited's 2021-2025 Rate Application.

SUPPORTING DOCUMENTATION:

Annex "A" – Hydro Ottawa Limited 2021-2025 Rate Application Update

Annex “A”

Hydro Ottawa Limited 2021-2025 Rate Application Update

HOL BOARD MEETING
September 23, 2019

CFO Division

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HydroOttawa

Agenda

1. 2021 to 2025 Rate Application Update
2. OEB Update
3. Provincial Government Update

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Rate Application Update
Planning Process

- The HOL budget process gathered information for the 2020 budget and for the 2021 to 2025 rate application
- Capital planning guidelines have been refined
- Divisions submit OM&A spending requirements
- OM&A and Capital spending levels were reviewed in detail by the Executive Management Team
- Customer rate impacts were developed from the preliminary information
- The Rate Application Steering Committee reviewed information prepared to date and provides the recommendations outlined in this presentation

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Rate Application Update

Summary of Financial Results / Rate Impacts

- *Preliminary* (*) residential distribution rate changes (at 750 kWh consumption) in the 2021 to 2025 period based on budget results are:

2021	2022	2023	2024	2025	Average
7.9%	7.5%	4.7%	3.0%	1.0%	4.8%

- Rate changes reflect impact of:
  - Facilities Renewal Project in 2021 & Cambrian Station in 2022
  - OM&A increases over the period ($98.1m in 2021 to $112.5m in 2025)
  - 2021 forecast OM&A vs 2020 OEB approved ($98m vs $89m)
  - An average of $95m CAPEX program in 2021 through 2025
  - Capital in service additions in 2016 to 2020 higher by $65m vs. OEB approved
  - Lower 'other' revenues (change in OEB Customer Service Rules & CDM)
  - Accelerated depreciation / PILs impact (decreases rates)
- Rate pattern similar to one HOL submitted for the 2016 to 2020 period

(*) Does not include rate riders. Cost Allocation, Rate Design, Load Forecast and Lead / Lag study results not incorporated. Preliminary Tax , Depreciation information used. OM&A not adjusted for escalation factor. OM&A and CAPEX not adjusted for results of special studies

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Rate Application Update

OM&A Escalation Factor

- Need to apply an OM&A escalation factor to ensure the application is accepted as a 'custom' approach as defined by the Ontario Energy Board
  - Budget results need to be reduced to account for productivity gains
- The Escalation factor is a combination of Inflation, Productivity & Growth
- Special studies commissioned by HOL determine the values of these factors
- The recommended escalation factor approach is:

$$Escalator = Inflation - Productivity + Growth$$

- The recommended Escalation Factor Value is 2.5% = 2.4% – 0.15% +0.25%

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Rate Application Update

OM&A Escalation Factor

Results after applying recommended OM&A escalation Factor

- Residential distribution rate changes (at 750 kWh consumption) in the 2021 to 2025 period with an OM&A escalation factor of 2.5%

2021	2022	2023	2024	2025	Average
7.9%	6.7%	4.4%	2.4%	0.9%	4.5%

- An OM&A Escalation Factor of 2.5% will mean a reduction of approx. $12m in OM&A over the period 2021 to 2025
- It is recommended that HOL apply the escalation factor to the 2021 forecast level of OM&A

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Rate Application Update

Big Picture Considerations

- Rate increases in the early years
- Current regulatory processes vs. potential new processes
- Potential Direction in the Fall from:
  - OEB
  - Provincial Government
  - Federal Government

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Rate Application Update

Overall Recommendations

- Submit with the existing CAPEX forecast
- Submit with the existing OM&A forecast (as adjusted by an OM&A escalation factor)
  - Use an OM&A escalation factor of 2.50%
  - Use the HOL 2021 forecast OM&A level as the base year
- Incorporate results of Specials Studies, if appropriate
- Review approach if new direction received from Government and / or the OEB
- Continue to prepare evidence on a time-line to file the 2021 to 2025 Rate Application in December 2019

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Rate Application Update

Customer Engagement

- A Customer Engagement Workbook was distributed to residential and small commercial (<50 kW) customers
- The survey was open from August 20 to September 20, 2019
- As of September 10th, over 15,000 customers completed the survey
- Response to date has been heavily weighted in support of our proposed plans or spending more than plan for certain services.
  - 86% were left with a favourable impression of the Workbook exercise; 77% indicated the amount of information was appropriate
  - 94% of customers agreed with the planning principles HOL adopted
  - 48% of customers supported the proposed plan; 36% were willing to spend more and 9% supported reducing the plan. 7% did not know
- Stakeholder engagement session with remaining customer groups (>50kW) held on September 17th

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Rate Application Update

Next Steps

- First full draft of all evidence available by Oct 18th
- Update provided at Board Strategy Session (Oct 30th)
- Approval of rate application at the November 28th Board Meeting
- Application filed with the OEB by the middle of December

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Rate Application Update

Schedule

Event	Date
First draft of DSP completed	Q1 2019
Divisional Plans updated	Q1 2019
Customer Engagement on DSP	Q1 - Q2 2019
Customer Engagement on Rate Application	Q1 - Q3 2019
Special Studies completed	Q1 - Q2 2019
HOL Business Planning Process	Q1 - Q2 2019
DSP Completed	Q2 - Q3 2019
Development of Evidence	Q2 - Q4 2019
Incorporate findings from Special Studies	Q2 - Q3 2019
Federal Election	October 21st
Provincial Legislature Resumes	October 28th
Board Strategy Session – Regulatory Update	October 30th
Rate Changes / Changes to bill presentation	November 1, 2019
HOL & HOHI Board Approval of Application	November 2019
2021 -25 Rate Application filed with OEB	December 2019
Implementation of 2020 Rate Changes	January 1, 2020
Interrogatory Process	TBD – Winter 2020
Update of evidence (2019 Actuals)	TBD – Spring 2020
Technical Conference	TBD – mid summer 2020
Settlement Conference	TBD – late summer 2020
Oral Hearing	TBD – fall 2020
OEB Decision	Target – December 2020

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Ontario Energy Board Update

- Most critical activity remains governance overhaul
  - Public Appointments Secretariat is recruiting for new Chair
  - New governance structure expected to be in place by Fall
  - Amidst transition, some OEB activities are on hold
- Other key initiatives & activities include the following:
  - Consultation on utility remuneration & responding to DERs; Hydro Ottawa set to participate in Sep. 17-18 forum
  - Parallel consultation on connection of DERs by LDCs
  - Annual LDC Scorecards set to be released by end of Sep.
  - HOL applications – 2020 rate adjustment, Sec. 92 Cambrian

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Provincial Government Update

- Legislature will re-convene Oct. 28, after federal election
- Further action is pending on reducing electricity bills by 12% and industrial electricity pricing
- Nov. 1, 2019 – effective date for new on-bill rebate; Ministry is engaging LDCs on proposed regulations
- IESO has recalibrated Market Renewal initiative
  - Energy market reforms are moving forward
  - Original capacity auction proposal has been shelved; IESO still proceeding with transitional capacity auction

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Questions or Comments?

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Board / Committee Report

To: Hydro Ottawa Limited Board of Directors

Date: 28 November 2019

Submitted by:

Gregory Van Dusen
Director, Regulatory Affairs

Geoff Simpson
Chief Financial Officer

Approved for Submission by:

Bryce Conrad
President and Chief Executive Officer

Agenda Item: 7 - Hydro Ottawa Limited 2021-2025 Rate Application

Report Recommendation(s):

That the Board of Directors of Hydro Ottawa Limited:

a. approve the 2021 to 2025 Hydro Ottawa Limited Custom Incentive Rate Setting Application to the Ontario Energy Board (OEB) including the 2021 to 2025 Hydro Ottawa Limited Business Plan as set out in the report of the Director, Regulatory Affairs and Chief Financial Officer dated November 28, 2019, and

b. recommend that the Board of Directors of Hydro Ottawa Holding Inc. authorize the President and Chief Executive Officer of HOL to submit the 2021 to 2025 Hydro Ottawa Limited Custom Incentive Rate Setting Application to the OEB including the 2021 to 2025 Hydro Ottawa Limited Business Plan as set out in the report of the Director, Regulatory Affairs and Chief Financial Officer dated November 28, 2019.

BACKGROUND:

1. Hydro Ottawa Limited is planning to file its 2021 to 2025 Rate Application in Q4, 2019.
2. A Rate Application status update is provided to the Board on a quarterly basis.

DISCUSSION:

3. The presentation attached at Annex "A" provides an update and overview on Hydro Ottawa Limited's 2021-2025 Rate Application.
4. Annex "B" – The Hydro Ottawa Limited Business Plan forms part of the overall rate application and is being submitted for approval by the Board consistent with its charter responsibilities.
5. Annex "C" – The Customer Summary also forms part of the rate application and is being submitted for information.

SUPPORTING DOCUMENTATION:

Annex "A" – Update on the 2021 to 2025 Rate Application

Annex "B" – Hydro Ottawa Limited Business Plan (Exhibit 1-1-9)

Annex "C" – Customer Summary (Exhibit 1-1-8)

Annex “A”

Update on the 2021 to 2025 Rate Application

Hydro Ottawa Limited Board Meeting
November 28th, 2019

Greg Van Dusen: Director – Regulatory Affairs – CFO Division

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Agenda

1. Status of Application
2. Updated Bill Impacts
3. Update Bill Impacts by Customer Class
4. Regulatory Landscape
5. Board Approval
6. Next Steps

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The 2021 to 2025 Rate Application
Status of Application

- All evidence nearing completion
- Rate Application Steering Committee has reviewed the following evidence;
  - Hydro Ottawa Limited Business Plan
  - Executive Summary
  - Productivity Initiatives
  - Facilities Evidence
  - Digital Strategy
  - Customer Summary
  - Customer Engagement Overview
  - Customer Strategy

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The 2021 to 2025 Rate Application

Updated Bill Impacts

- Initial Residential Bill Impacts *(Oct 30th)*

2021	2022	2023	2024	2025	Average
7.9%	6.7%	4.4%	2.4%	0.9%	4.5%

- Updated Residential Bill Impacts (Nov 28th) (*)

2021	2022	2023	2024	2025	Average
5.8%	8.3%	4.8%	3.7%	2.6%	5.0%

(*) Bill impacts are still being finalized for updates to the load forecast, cost allocation and rate design

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The 2021 to 2025 Rate Application
Updated Bill Impacts by Customer Class (*)

	Year over Year Distribution % change					
Rate Class	**2021**	**2022**	**2023**	**2024**	**2025**	**Average**
Residential	5.8%	8.3%	4.8%	3.7%	2.6%	5.0%
GS < 50 kW	6.0%	8.4%	4.8%	3.6%	2.7%	5.1%
GS > 50 to 1,499 kW	5.7%	8.3%	4.8%	3.7%	2.5%	5.0%
GS > 1,500 to 4,999 kW	4.8%	8.3%	4.8%	3.7%	2.5%	4.8%
Large Use	6.0%	8.3%	4.8%	3.7%	2.5%	5.1%
Street Lighting	2.0%	8.2%	4.8%	3.7%	2.5%	4.3%
Sentinel Lighting	4.3%	8.2%	4.8%	3.7%	2.5%	4.7%
Unmetered Scattered Load	5.1%	8.4%	4.6%	3.7%	2.5%	4.9%
Standby Power	8.8%	8.3%	4.8%	3.7%	2.5%	5.6%

(*) Bill impacts are still being finalized for updates to the load forecast, cost allocation and rate design

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The 2021 to 2025 Rate Application

Changes to Bill Impacts

- Changes will include:
  - The Return on Equity (ROE) has been updated from 8.98% in each year to specific values for each year *(*)*

Year	2021	2022	2023	2024	2025
ROE	9.00%	9.25%	9.35%	9.45%	9.45%

  - Adjustments to OM&A & CAPEX levels
  - Updates to:
    - Interest
    - Depreciation
    - Taxes
    - Other Revenue
    - Miscellaneous changes
  - Impacts as a result of preliminary OEB direction on our 2020 rates

(*) Calculated consistent with the OEB's formulaic approach

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The 2021 to 2025 Rate Application
Regulatory Landscape

- OEB Decision on HOL's 2020 rates may impact the 2021 to 2025 rate application and filing date
- Toronto Hydro Decision may be out before the end of the year
- Government has indicated that they will hire OEB Chair & CEO by the end of the year
- Government has signalled action on a further 12% reduction in electricity prices has 'not been forgotten'
- Significant unknowns & risks face the application, including;
  - Regulatory process is adversarial and prolonged by design
  - Significant HOL time, effort and expense will be required
  - New OEB leadership

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The 2021 to 2025 Rate Application
Board Approval

- Your approval of this Report and the Hydro Ottawa Limited Business Plan will constitute approval of the 2021 to 2025 Rate Application in its entirety

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The 2021 to 2025 Rate Application
Next Steps

- Refine and finalize all evidence
- File application with the OEB: Target date - December 20, 2019
- The 2020 HOL and OEB process:
  - HOL witness selection & training,
  - Interrogatories,
  - Technical Conference,
  - Settlement Conference, and
  - Oral Hearing

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Questions or Comments?

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Annex "B"

Hydro Ottawa Limited Business Plan

2021-2025

November 2019

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1. INTRODUCTION

Hydro Ottawa Limited (Hydro Ottawa) has prepared a formal Business Plan that serves as the basis for the company's overall strategy and goals, highlights the intersection between these goals and the proposals set forth in its 2021-2025 Custom Incentive Rate-setting (Custom IR) application, and speaks to the benefits that will accrue to customers as a result of the plan's execution.

This Business Plan has been prepared in conformance with the requirements set forth in the Ontario Energy Board's *Handbook for Utility Rate Applications*.

2. COMPANY OVERVIEW

Mission

To create long-term value for our shareholder, benefitting our customers and the communities we serve

Organizational Values

Teamwork, Integrity, Excellence, Service

Vision

Hydro Ottawa – a leading partner in a smart energy future

Hydro Ottawa is a regulated electricity distribution company serving approximately 335,000 customers within the City of Ottawa and the Village of Casselman, as of the end of 2018. As the third-largest municipally owned electrical utility in Ontario, the company maintains one of the safest, most reliable, and cost-effective electricity distribution systems in the province. Its service territory stretches over 1,100 square kilometres and is comprised of a dense urban core, large areas of suburban development, and a vast rural area that represents 60% of the overall footprint.

Hydro Ottawa and its predecessor utilities have proudly served communities in the National Capital Region for over 100 years. The company's unique customer base includes residential customers, commercial businesses, farms, and large institutional and industrial customers. As the national seat of government, Ottawa is home to the federal parliament and key institutions within the Government of Canada. Moreover, the city is the second largest in the Province of Ontario and the sixth largest in the country.

The company is a wholly-owned subsidiary of Hydro Ottawa Holding Inc., which is 100% owned by the City of Ottawa and governed by an independent Board of Directors.

3. INTEGRATED BUSINESS PLANNING & PERFORMANCE MANAGEMENT FRAMEWORK

For more than a decade, the larger corporate enterprise of which Hydro Ottawa is a member has successfully administered an integrated business planning and corporate performance management framework. This framework links the strategic and business planning, budgeting, performance measurement, management reporting, and employee alignment activities into one continuous business and improvement cycle. Applying this framework in whole, Hydro Ottawa is able to chart its course for a five-year period, implement and operate in accordance with annual plans and budgets, and monitor and report performance and progress against these plans and budgets.

In accordance with its charter, Hydro Ottawa's Board of Directors (the Board) is responsible for developing and approving a business plan which indicates the overarching strategy that the utility intends to pursue. The Board must regularly review the integrity of the business plan. At any time, if the Board is of the opinion that the then-existing business plan is no longer appropriate, the Board – in conjunction with the Chief Executive Officer – must develop a revised business plan. What's more, on an ongoing basis, the Board is likewise responsible for monitoring the company's implementation of the plan and the progress toward achieving it. Similarly, the Board is tasked with approving the annual budget, and monitoring its progress and achievement at each regular meeting.

The key components of the integrated planning and performance management framework are as follows:

a. An enterprise strategic plan approved by the holding company Board that sets the course for the enterprise for a five-year period;

b. Annual business plans that are approved at both the holding company and regulated distribution company levels, which are comprised of the following: (1) corporate performance scorecard and (2) budget. These elements operationalize the strategic plan in a given year and cascade to employees through individual contribution and performance appraisal systems. The annual business plans are informed by, and draw upon, updated plans for each administrative division within the company which are prepared by the applicable member of the Executive Management Team;

c. Regular monitoring and reporting of performance and progress against annual plans and budget, including:

    i. Monthly reviews by the Executive Management Team of financials, status of priorities and critical projects, and performance measures and targets as established for each key area of focus in the annual Corporate Performance Scorecard,

    ii. Monthly updates to the Shareholder,

    iii. A quarterly President and CEO Report to the holding company and regulated distribution company Boards of progress against the Corporate Performance Scorecard, including enterprise risk management reporting,

    iv. Quarterly financial reports to the Shareholder,

v. Review by the holding company and regulated distribution company Boards of annual results against the Corporate Performance Scorecard and financial results in April, and

vi. An annual report to the Shareholder in June.

d. As part of the development of the annual plan for the next year, an annual review of the critical issues and opportunities facing the company by the Executive Management Team, and subsequently by the Board of Directors, to determine whether an adjustment to the five-year plan is required.

In addition, a key input into the process is a set of formal guidelines from the Chief Financial Officer for the preparation of five-year budgets for Hydro Ottawa's subsequent distribution rate period. This guidance is circulated approximately one year in advance of the expected filing date of the rate application. The document lays out a timeline for budget development; identifies constraints and expectations relevant to such matters as compensation, headcount, and capital and operational expenditure levels; and stipulates requirements related to productivity, continuous improvement, cost control, and alignment of spending to company priorities.

A copy of the memorandum setting forth guidelines for 2020-2025 budgets and priorities is included as Appendix B below.

4. CUSTOMER NEEDS & PREFERENCES

Providing customers with value for money and facilitating a customer experience that is driven by choice are cornerstones of Hydro Ottawa's business planning. In step with its overall business strategy to put the customer at the centre of everything it does, the company endeavours to ensure that its capital and operational investment plans are guided and informed by customer needs, preferences, and priorities.

4.1 ONGOING CUSTOMER ENGAGEMENT

Hydro Ottawa avails itself of numerous tools, activities, and interactions to engage customers and to reflect their input in the company's planning and plans on an ongoing basis. These reflect an evergreen posture on Hydro Ottawa's part to develop a genuine understanding of customers' interests through a fluid and continuous feedback loop. This helps inform and sharpen the company's service delivery as a matter of established routine, and embed a customer-centric culture across the organization.

Hydro Ottawa's approach to customer engagement represents a blend of activities that are either aligned with industry best practice or are homegrown, having been formulated and customized internally in order to suit the particular needs of the company and its unique customer base. Key channels for interaction include telephone, in person, email, web chat, social media, website, and community events. Focus groups, surveys, and analytics are also important research tools for gleaning broader insights and trends.

The following serve as illustrative – but by no means comprehensive – examples of specific instruments used by Hydro Ottawa to identify customer needs and preferences, and to incorporate them into the company's plans for providing electricity distribution services:

- **Social media platforms** – Hydro Ottawa uses social media channels to engage in two-way conversations with customers on a daily basis. Channels are monitored during business hours and, in particular, during prolonged power outages in order to answer customer questions or concerns. Recent trends indicate that many customers have a strong preference to use social media to share information or ask questions related to outages, and that they value real-time responses to their inquiries.

- **Transactional surveys** – every week, customers who phoned Hydro Ottawa's call centre during the previous week are automatically invited to rate their experience with the service received. Based upon the survey results, Hydro Ottawa is able to enhance the customer experience and adapt processes in a timely and responsive manner. More recently, Hydro Ottawa added email and web chat features to this survey, in keeping

with the company's commitment to engage customers through the channel of their choice.

- **Annual customer satisfaction survey** – survey questions cover a wide variety of topics, including overall satisfaction with Hydro Ottawa, reliability, customer service, power outages, billing, cost of electricity, and corporate image. Feedback from these surveys is incorporated into Hydro Ottawa's planning process, and ultimately forms the basis of plans which address customer needs as well as service improvements and offerings.

- **Key Accounts program** – customers are categorized as a Key Account based on their size of service, financial impact, and impact on the community and the grid. Hydro Ottawa works proactively with these large business and institutional customers on a range of priorities, including billing, load profile, rates analysis, power quality, energy management, and education and awareness of provincial regulations.

- **Project-specific open houses** – these are hosted by Hydro Ottawa when major system projects have the potential to impact customers and their community. Based on customer feedback, these consultations have resulted in the evaluation of additional design options, the use of less impactful equipment, and/or the scheduling of mutually agreeable timelines for project completion. Between 2016 and 2019, Hydro Ottawa held 35 such open houses.

- **Collaboration with contractors and developers** – this takes the form of routine information sharing and participation in dedicated associations and forums with members of this unique stakeholder group. These engagements offer valuable insights into customer expectations around Hydro Ottawa's communications, processes, standards, specifications, costing, and Conditions of Service.

- **Conditions of Service (COS) revisions** – Hydro Ottawa's compiles suggested edits to the COS on an ongoing basis, in response to customer feedback. Prior to the filing of any revised COS, Hydro Ottawa solicits customer comments through its website and social media accounts. All customers likewise receive notification of the review period through an on-bill message. In addition, contractors, City of Ottawa contacts, and Key Accounts are directly notified of the review period by letter.

- **Engagement with the City of Ottawa** – given the impact of municipal planning, services, and regulations on customer needs, the relationship with the City is a vital one. Accordingly, Hydro Ottawa frequently interacts with numerous divisions across the municipal government. These interactions serve as platforms for discussing critical matters, such as long-term planning, capital programs, permitting, standards, and servicing. In turn, they play a valuable role in enhancing communications and coordination, sharing of lessons learned, identifying opportunities for improvement, and building mutual understanding.

4.2 CUSTOMER CONSULTATION ON THE 2021-2025 RATE APPLICATION

As a complement to, and extension of, the foregoing activities, Hydro Ottawa undertook targeted customer outreach activities to inform the development of the specific plans and proposals set forth in its 2021-2025 rate application. Consisting of a mix of qualitative and quantitative methodologies, this engagement was launched in January 2019 and extended through September 2019.

Phase One of this consultation focused on low-volume customers (residential and small business), seeing as these segments represent approximately 99% of the total customer base. This initial phase focused on gathering general insights on customer priorities, preferences, and needs.

Consistent findings were yielded across low-volume customer classes. To begin, the clear majority of these customers expressed satisfaction with the current service they receive from

Hydro Ottawa. In addition, ensuring reliability, maintaining reasonable rates, and investing in technology in order to help reduce future costs constituted the top three priorities for customers. Moreover, these customers generally held favourable views on making proactive investments in aging infrastructure and grid modernization at the present time, with the understanding that this may lead to near-term costs but will result in future savings. With respect to reliability outcomes, above all customers placed a premium on accelerating restoration times following extreme weather events. Minimizing the number and duration of outages in general was flagged as the next most pressing priority.

Based upon the feedback received during Phase One, Hydro Ottawa undertook a second, more expansive phase of engagement, in which the company surveyed customers for their detailed feedback on proposed plans for capital and operational investments over the 2021-2025 period. A series of expenditure options were presented – namely, a reference case outlining the company's proposed course of action, along with scenarios which either accelerated and expanded the proposal, or which scaled back the scope and timing of the proposal. Customers were thus able to express their views on a range of alternative proposals, as well as their respective trade-offs, outcomes, and rate impacts.

For residential and small business customer classes, the response was heavily weighted in support of Hydro Ottawa's proposed plans or spending more than proposed for certain services. Nearly one-half of customers in both segments (48% and 47%, respectively) identified that "Hydro Ottawa should maintain the forecasted annual increase to deliver a program which delivers on the stated priorities." A further 35% of residential and 29% of small business customers, respectively, expressed support for further improvements in service, even if this entailed additional rate increases. What's more, a majority of respondents called for investments above and beyond the reference case for purposes of renewing the overhead and underground portions of the grid, while more than 75% of customers signalled a willingness to pay more on their monthly bill in order to enable Hydro Ottawa to undertake measures to prepare for the effects of severe weather.

Of note, the number of low-volume customers who participated in this engagement exercise – over 20,000 residential and almost 800 small business – was the largest in the history of any Hydro Ottawa rate application. In itself, this result was encouraging and instilled confidence in the quality of the information gleaned and the representativeness of the sample pool of customers. Beyond this, however, Hydro Ottawa was buoyed by the fact that the rate of response (i.e. number of respondents as a percentage of the total customer base) exceeded that which has been observed in any rate filing from an OEB-regulated distributor in recent memory.

With respect to participants from large customer segments, these voices expressed concern over the rate increases being proposed and were open to potential decreases in service reliability if this equated to reductions in forecasted bill increases. This feedback was highly valuable, insofar as it emphasized the critical importance of a balanced plan – one which maximizes the impact of investments to match residential customer expectations without exacerbating rate pressures on business customers (and all while relentlessly pursuing efficiency and productivity improvements).

5. STRATEGIC CONTEXT

Hydro Ottawa has formulated its corporate vision and objectives against the backdrop of numerous trends and shifts that are unfolding in the operational, business, and policy environments in which the company carries out its activity.

5.1 OPERATIONAL CHALLENGES

5.1.1 Aging Infrastructure

Foremost among the operational pressures facing the company is the advanced age of a significant subset of its asset base. Large segments of the system were constructed in the 1960s through the 1980s. With most assets having a lifespan of approximately 50 years, a considerable proportion of the system is approaching or has exceeded the anticipated end of life.

For example, nearly 17% of all assets have reached their expected service life and now pose a higher risk of failure. This includes approximately 40% of stations and 21% of overhead system assets (i.e. poles, transformers, and switches). Another 11% of the asset population is within 10 years of reaching end of life.

In the absence of critical system renewal investments, the increased potential of failures posed by these aging assets will impact Hydro Ottawa's ability to maintain grid reliability.

5.1.2 An Expanding Customer Base

Compounding the challenge of replacing aging infrastructure is the sustained growth which the City of Ottawa continues to experience. This trend has translated into a steady expansion in the number of customers served by the company and the number of new customers requiring connection to Hydro Ottawa's network on an annual basis.

Similar to the patterns observed throughout 2016 to 2020, Hydro Ottawa anticipates a comparable level of growth over the course of the planned 2021-2025 rate period. (In fact, projections from the provincial government forecast an increase of over 20% in Ottawa's population by 2031, relative to 2017 levels). This growth is expected to take several distinct forms, especially the development of new mixed commercial/residential communities; intensification of development within the urban core of the service territory; continued suburban growth in the east, west, and southern regions; and former rural areas fed by long distribution lines becoming suburban centres. Alongside this development, major infrastructure projects such as the Stage 2 expansion of Ottawa's Light Rail Transit system are also set to overlap with the company's upcoming rate period.

5.1.3 Extreme Weather Effects

In a 2019 report examining Canada's top climate change risks, the Council of Canadian Academies found that "climate change is very likely to cause significant negative impacts across many natural and human systems in Canada over the next 20 years." The report concluded that adaptation action will need to be pursued through effective partnerships among

government, the private sector, communities, and individuals, in order to avoid the worst damages stemming from climate change.

Over the last five years, Hydro Ottawa and its customers experienced firsthand the growing frequency of severe weather events and their adverse impacts on the distribution grid. During a six-month span in 2018 alone, there were three major weather events that affected the Ottawa area (including a multiple-tornado event during the month of September) which caused considerable damage and heavily impacted spending on emergency replacement of assets. This series of events was bookended on either side by historic flooding along the Ottawa River in 2017 and 2019, which resulted in tens of millions of dollars in economic losses and prolonged disruptions to customers in affected areas.

In light of these findings and events, and in view of the rising trend of extreme weather, Hydro Ottawa will be compelled to enhance adaptation and risk mitigation measures within the design, operation, and maintenance of its system, in order to help protect infrastructure, service delivery, and occupational health and safety. To that end, the company has already commissioned and received a formal distribution system climate risk and vulnerability assessment, and is undertaking a multi-year action plan to implement the recommendations.

5.1.4 Technological Complexity

The operational and informational technology systems that underpin utilities' performance are rapidly evolving and becoming increasingly complex. The business systems and processes supporting frontline operations and back-office functions are steadily migrating towards digital, mobile-friendly, and cloud-based solutions. Core operational systems continue their convergence with enterprise information systems. Automation is on the rise, with the frontier into artificial intelligence likewise being crossed. And while utilities are navigating this shifting terrain, they are simultaneously compelled to mitigate the risk of technologies becoming obsolete – whether as a result of third-party providers discontinuing maintenance services for legacy solutions or existing tools having reached the end of their useful lives (as in the case of first-generation smart meters).

Meanwhile, the implementation of smart grid equipment and devices, alongside the proliferation of distributed energy resources ("DERs"), has fostered a more dynamic ecosystem of transactions, participants, and flows of energy, information, and communications. What's more, a central tenet of the "Smart City" movement is that utilities will enable the connectivity which harnesses the power of data and technology to enhance the quality of life for communities.

Taken together, the aforementioned technological trends and pressures introduce a wide spectrum of both risk and opportunity for the company.

5.1.5 Cyber Security

The critical nature of the services provided by utilities makes for a double-edged sword. On the one hand, there is widespread recognition of the indispensable role played by electricity distributors in the quality of life that is enjoyed by consumers. Conversely, the essential role played by electricity means that utilities rank among the most high-value targets for malicious actors in cyberspace. This risk is magnified for a distributor like Hydro Ottawa, which serves the capital city of a G7 country and a multitude of customers with unique service quality and data confidentiality needs.

The risks faced by utilities in Ontario in relation to cyber security are set to amplify exponentially over the coming five-year horizon and beyond, in light of the rising complexity of operational and informational technology systems noted in the foregoing section. Further reflection of the shifting risk landscape is the OEB's recent implementation of a cyber security framework for utilities under its jurisdiction, as well as the expansion of the Independent Electricity System Operator's (IESO) mandate to provide cyber security information services to licensed transmitters and distributors.

5.1.6 Workforce Retirements

Hydro Ottawa has long maintained that its strength and success as a company is derived from the quality of its employees. Like many companies in the electricity sector, though, Hydro

Ottawa faces challenging workforce demographics. During the 2021-2025 rate term, XXX employees will be eligible for retirement, representing XX% of the overall workforce and XX% of tradespeople and professional staff who are directly involved in distribution system operations and maintenance. Depending on the pace of employee retirements, the company may be challenged in its ability to build a sustainable workforce and fulfill its business objectives.

5.2 BUSINESS ENVIRONMENT

5.2.1 State of the Economy

The state of the local, provincial, national, and international economies can have a significant impact on Hydro Ottawa's business through factors such as inflation, customer credit risk, weakening demand for electricity and/or value-added services, and availability of market capital to fund growth. The economic climate can also have an effect on the stability and performance of some of the company's key business partners. While near- and mid-term indicators in Ottawa, Ontario, and Canada are generally positive, the prospect of economic headwinds and uncertainty lingers, especially in relation to competitiveness and regulatory and tax burdens.

5.2.2 Evolution of the Utility Business Model

It is widely acknowledged across industry, academic, and government circles that the sector is in the midst of a historic transition. In some corners, this transformation is attributed to the confluence of key factors known as the "three Ds" – decentralization, decarbonisation, and digitization. Innovative tools, technologies, and data sets are introducing new options to enhance customers' control, understanding, and supply of energy. In turn, this is cultivating higher customer expectations for leading-edge services and solutions. Moreover, the economics of supply options have evolved significantly. Maturing forms of non-emitting resources are approaching cost parity with conventional generation resources, while the appeal of DERs has also grown.

Against this backdrop of change, the prevailing consensus favours the view that the utility has no choice but to abandon its conventional business model. What ought to replace it, however, remains a subject of contentious debate. It is a question that every utility will be compelled to

address and resolve in short order. If an effective and viable response is not forthcoming, the risk emerges of actors and forces beyond the utility's control making the decision instead.

5.2.3 Customer Interest in Choice & Sustainability

As signalled in the foregoing section, the engine that is fueling the transformation unfolding in the sector is the changing role of the customer. Whereas this role has historically been passive in nature, it has become much more influential in the new landscape. The opportunities and expectations for customized service, control, and convenience continue to expand. A prominent example in this regard is the rising level of customer interest in sourcing power from clean sources of energy and the manifestation of this appetite in the steady proliferation of DERs across Ontario.

The shifting sands of customers' needs and choices present an exciting opportunity for offering new products and services to enhance customer value and service. To realize these opportunities, utilities will need to continuously improve the way they do business, with a particular focus on creating a more effortless and engaging customer experience. As the preferences and priorities of customers continue to evolve, Hydro Ottawa must be ready, willing, and able to fulfill them. Maintaining a business strategy that puts the customer at the centre of everything the company does will be a fundamental prerequisite for success.

5.2.4 Consolidation & Shared Services in the Distribution Sector

The business environment of Ontario's electricity distribution sector is unique, in terms of the number of participating members. Over 60 local distributors provide electricity to the province's 5.2 million customers. For many years, public policy has sought to encourage and incentivize consolidation within the distribution community. What's more, numerous aspects of the sector's evolution and the changing utility business model seem to favour economies of scale in a distributor's operations and activities. It is therefore not altogether surprising that, since the filing of Hydro Ottawa's last rebasing application in 2015, the sector has witnessed a steady succession of consolidations, along with an uptick in the entry into shared services agreements.

The footprint and dispersion of distribution utilities throughout Eastern Ontario means that Hydro Ottawa remains well-positioned to pursue consolidation opportunities. Similarly, the company's range of experience with shared services has underscored the value of targeted collaboration and partnership with utility peers, where appropriate. As such, going forward, these options will remain important parts of the company's toolkit to provide the most cost-effective solutions to customers.

5.2.5 Market Renewal

Hydro Ottawa is a registered participant in the provincial electricity market administered by the IESO. In its capacity as a market participant, the company purchases electricity from the IESO on behalf of the vast majority of its customers. Accordingly, Hydro Ottawa has a direct stake in an efficient and reliable market, which is able to supply customers with power at the lowest possible cost. Since 2016, the IESO has been exploring a series of enhancements to the design and administration of Ontario's markets. Several of these proposals contemplate fundamental changes to the structures and methodologies for determining the wholesale pricing of electricity. Under the IESO's project management timeline for Market Renewal, the initial group of these proposals is slated to take effect in March 2023, near the mid-point of Hydro Ottawa's next five-year rate term.

For electricity distributors, the reforms emanating from Market Renewal may represent a double-edged sword. On the one hand, they may pose certain administrative challenges, especially from a settlements and billing perspective. Concurrently, however, to the extent that Market Renewal serves as a platform for developing new product and service offerings, the initiative could also open the door to new business and revenue opportunities.

5.3 POLICY & REGULATORY ENVIRONMENT

5.3.1 Policy & Regulatory Uncertainty

Over the course of Hydro Ottawa's 2016-2020 rate period, there were numerous policy and regulatory developments which had profound effects on the company and the sector at large: establishment and subsequent cancellation of a provincial cap-and-trade program;

implementation and subsequent modification of the Fair Hydro Plan; changes to the OEB's customer service rules, including the institution of a moratorium on residential disconnections during winter; adoption of the Ontario Cyber Security Framework; issuance of OEB guidance on corporate governance; cancellation of Ontario's conservation framework; and reforms to the OEB's governance structure.

What's more, extending a backward glance beyond the filing of Hydro Ottawa's 2016 rate application reveals another timeframe of immensely consequential policy actions, such as the direction to transition residential distribution rates to a fixed monthly charge and the expression by government of support for extensive consolidation within the distribution sector.

And with respect to the primary vehicle driving provincial energy policy of late, the Long-Term Energy Plan (LTEP), it warrants observation that a total of three LTEPs have been issued over the past seven years. In each iteration, the LTEP moved the public policy goalposts to an appreciable degree, thereby leaving a lasting imprint on the policy landscape. Assuming the current legislative framework for LTEP development remains in place, two new LTEPs are set to be released over the course of Hydro Ottawa's 2021-2025 rate term.

Collectively, these policy developments have engendered uncertainty with respect to the future operations, activities, investments, and structure of the distribution sector. Present signals portend that this outlook is not set to diminish during the company's forthcoming rate period.

5.3.2 Affordability & Cost Reduction

While in recent years the broader policy landscape has been fluid, one aspect has remained firm – an enduring interest on the part of policymakers and regulators in placing downward pressure on customers' rates and bills. This objective has taken shape in varying forms, whether rate rebates and mitigation, assistance for customers struggling to pay their bills, dedicated programs for commercial and industrial ratepayers, subsidies for the purchase of energy efficient equipment, or pilot programs to test alternative pricing structures. Depending upon the future direction and constraints of public policy in this regard, rate-regulated utilities

may face challenges, such as barriers or resistance to approvals for cost recovery of operational and capital expenditures.

5.3.3 GHG Emissions Reduction & Electrification

Across all levels of government, there is a crystallizing consensus that greenhouse gas (GHG) emissions ought to be lowered. Where sharp differences in policy prescriptions do exist is in regards to the means for achieving this end. And yet, even in this respect, there are common threads woven by policy actors that are of significant relevance to the electricity distribution industry in Ontario. Foremost among these is growing policy interest in the electrification of various economic sectors, especially transportation. This enthusiasm can be seen on display in a range of federal government climate change initiatives as well as in the province's projections for a steady uptick in the deployment of electric vehicles. Hydro Ottawa is also in the unique vantage point of having a shareholder, the City of Ottawa, which views electrification as a critical means of supporting its "Energy Evolution" strategy for reducing GHGs and boosting renewable energy use.

With the arc of GHG reduction policy bending in a direction that is increasingly favourable to enhanced electrification, both the implications and opportunities for distributors are numerous. In the former context, localized impacts on distribution infrastructure could be significant, depending upon the scale and pace of electrification. As for the latter, the embrace of electrification is advantageous to distributors, insofar as it bolsters their position to serve as a trusted energy advisor for customers and as an enabler of smart energy solutions.

5.3.4 Policy Action on Utility Revenue & Ratemaking

Looking ahead to the next five-year rate term for Hydro Ottawa, the outlook is decidedly mixed with respect to the revenue and ratemaking models for Ontario distributors. Grounds for optimism, in relation to the prospect of expanded business interests and opportunities, include provisions of the *Ontario Energy Board Act* which have relaxed restrictions on permissible business activity for distributors, as well as signals from the regulator that it is open to reducing barriers to new utility business models and examining approaches to remuneration that incent

cost-effective innovation. At the same time, however, any conversation around utility remuneration will feature some degree of risk that other actors may seek outcomes that are at odds with the goal of enlarging the playing field in which distributors can compete. What's more, the prospect lingers of policy action on electricity pricing and bill reduction which may have adverse consequences for distributors from a financial health perspective.

6. STRATEGIC OBJECTIVES & CORPORATE PERFORMANCE GOALS

6.1 STRATEGIC OBJECTIVES

Hydro Ottawa's vision is to be a leading partner in a smart energy future and to serve as the trusted energy advisor for our customers. To achieve this vision, the company has organized its business strategy around four critical areas of performance and supporting strategic objectives for several years – as represented in the figure below.

Hydro Ottawa will maintain continuity in its core objectives heading into the 2021-2025 period. Consistent with past years, the renewed strategic objectives are being formally adopted at the holding company level and will cascade across the enterprise, and will therefore serve to guide the business and operations of the regulated distribution company.

The rationale underlying this approach includes such key factors as the level of success achieved during the preceding five-year rate term, the trajectory of the business and policy landscape in which Hydro Ottawa operates (as described in the preceding section on Strategic Context), and the input received from customers regarding the company's performance and direction.



- **Customer Value:** we will deliver value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates.

- **Organizational Effectiveness:** we will achieve performance excellence by cultivating a culture of innovation and continuous improvement.

- **Financial Strength:** we will create sustainable growth in our business and our earnings by improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people.

- **Corporate Citizenship:** we will contribute to the well-being of the community by acting at all times as a responsible and engaged corporate citizen.

Of these objectives, the most important driver of Hydro Ottawa's business strategy will remain Customer Value, with the company striving to put the customer at the centre of everything it does.

6.2 CORPORATE PERFORMANCE GOALS

Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship serve as the overarching four key areas of focus around which Hydro Ottawa anchors and organizes its business activity. With respect to the design and execution of plans to achieve strategic objectives in each of these areas of performance, a critical step is the establishment of a corporate performance scorecard. This scorecard establishes qualitative performance goals and priorities, along with quantitative measures and targets, in each of the four strategic areas of focus. Similar to the adoption of the strategic objectives, the corporate performance goals are established by the parent company, and in turn, are cascaded across the enterprise.

The table below depicts the planned alignment between the strategic objectives and corporate performance goals for Hydro Ottawa's regulated electricity distribution business, for the 2021-2025 rate term.

Table 1 – Alignment of Corporate Strategic Objectives & Corporate Performance Goals

5-Year Enterprise Strategic Objectives and Outcomes (2021-2025)		Corporate Performance Goals
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	• ***Assist customers in managing their energy consumption and electricity costs*** • ***Deliver on customer expectations for service quality and responsiveness*** • ***Maintain overall distribution system reliability***

Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	• ***Continue to enhance operational performance and productivity*** • ***Maintain leading health and safety record*** • ***Enhance organizational and employee capability***
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	• ***Grow revenues from new sources*** • ***Enhance / protect revenues from existing business lines***
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well-being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services*	• ***Enhance our brand image in the community and the industry*** • ***Continue to improve our environmental performance and reduce our impact on the environment***

	Positive community impact	

7. CAPITAL & OPERATIONAL PLANS

This business strategy's centre of gravity is the set of plans which will organize and govern Hydro Ottawa's proposed investments in capital and operational programs over the 2021-2025 period.

Capital expenditures relate to items that, once purchased, have lasting benefits over many years. These include the overhead and underground infrastructure (stations, poles, wires) that serve as the backbone of the distribution system, as well as supporting assets and equipment, such as facilities, vehicles, and computer systems. Operating expenditures pertain to recurring expenses that are incurred in the day-to-day management of Hydro Ottawa's activities, like maintenance of assets and equipment, tree trimming, customer billing, workforce training, and employee payroll.

Based upon customer feedback, Hydro Ottawa has crafted capital and operational plans that emphasize the following four core principles:

1. Minimize rate increases

2. Maintain reliability and service quality

3. Address key pressures to the system, including:
   - 3.1 Aging infrastructure
   - 3.2 An expanding customer base and continued population growth
   - 3.3 The effects of severe weather events

4. Make prudent investments in emerging technologies to enhance service offerings and/or reduce operation costs.

7.1 CAPITAL PLAN

Hydro Ottawa's assessments of its capital needs, and its proposed expenditures for meeting them, are captured in the company's Distribution System Plan (DSP). The DSP details how capital investments will be prioritized, paced, and optimized, while minimizing rate impacts for customers and facilitating continuous improvement and productivity. The DSP is a core deliverable emerging from multiple internal and external planning processes related to capital investment, asset management, regional planning, customer engagement, and business strategy.

The investment proposals set forth in the DSP are organized into four categories – System Access, System Renewal, System Service, and General Plant. Projected expenditures, as well as the breakdown of programs, within each of these categories are outlined in the tables below.

Table 2 – Annual Capital Investments ($ Millions)

Investment Category	2021	2022	2023	2024	2025
System Access	17.8	17.8	17.7	15.6	15.2
System Renewal	43.3	44	40.2	39.4	40.5
System Service	28.9	25.7	24.3	25.1	23.9
General Plant	31.7	11.3	7.3	16.9	16.4
TOTAL	**121.8**	**98.9**	**89.6**	**97.5**	**96**

7.1.1 System Access

System Access – Capital Programs
- Plant Relocation & Upgrade
- Residential Subdivision
- Commercial Development
- System Expansion
- Embedded Generation
- Infill Service (Residential & Small Commercial)
- Metering

This category encompasses those investments that allow Hydro Ottawa to meet its obligation to connect customers to the grid. These expenditures are subdivided into specific programs focused on connecting customers (such as new residential and commercial developments, and customer-driven electric generation projects), relocating equipment to accommodate municipal infrastructure needs like road widening, and installing meters.

Major projects expected in this investment category during 2021-2025 include residential and commercial connections consistent with recent historical expenditures, system expansion, plant relocation (especially in relation to Stage 2 of Light Rail Transit in the City of Ottawa), and retrofits of bulk metered buildings to unit metering.

With the City of Ottawa continuing to experience a steady level of growth, and with the company having recently averaged upwards of 4,000-5,000 new connections every year, system access expenditures remain crucial to achieving positive outcomes in relation to customer expectations for service quality and responsiveness. Likewise, they will be critical to the success of flagship local infrastructure projects over the 2021-2025 period. There is also a nexus between this category of investment and the environmental benefits that accrue to customers and the community from increased deployment of distributed renewable generation, including net metered projects.

7.1.2 System Renewal

System Renewal – Capital Programs
- Station Assets Renewal
- Overhead Distribution Assets Renewal
- Underground Distribution Assets Renewal
- Corrective Renewal
- Damage to Plant

Included under the scope of this category is the replacement and refurbishment of system assets, in order to extend their original service life or

replace them on an emergency basis. Of note, this activity touches the parts of Hydro Ottawa's grid that are either most visible (poles, wires, transformers, and stations) or least visible (underground cable and vaults) to the public. Together, these programs are aimed at alleviating one of the most significant pressures on the system – namely, mitigating the risk of the potential failure of end-of-life assets and equipment. The primacy of system renewal is underscored by the fact that this grouping represents the largest share of the broader capital funding envelope.

Planned projects of note under this investment category include renewal of distribution poles, transformers, and stations, emergency replacement of overhead assets following severe weather events, rehabilitation of underground chamber assets, replacement of underground cable, and upgrades of various types of metering equipment that have reached end of life.

Key outcomes associated with system renewal expenditures are improvements to overall system reliability, as well as reductions in the average duration and frequency of outages.

7.1.3 System Service

System Service – Capital Programs
- Capacity Upgrades
- Distribution Enhancements
- Station Enhancements
- Grid Technologies
- Metering

The purpose of these infrastructure upgrades and modifications is to enhance reliability and capacity on the grid, and ensure that the system continues to meet operational objectives while addressing future customer needs. Similar to the foregoing categories, system service is comprised of its own unique set of programs. Expenditures revolve around capacity upgrades that are intended to relieve constraints caused by load growth; system and station enhancements that improve operating characteristics, add redundancy, and strengthen the resilience against severe weather events; and deployment of grid technologies that augment the technological and communication capabilities of the system.

Major station projects in this category will be the development of new stations in the south Nepean and east Leitrim regions of the City of Ottawa, which are needed to accommodate

customer load growth and to increase supply capacity in growing suburbs that have already reached the limits of local transformation capacity. Other major projects include upgrades to the functionality of Hydro Ottawa's Supervisory Control and Data Acquisition (SCADA) system, enhancements to the Outage Management System, the installation of field area network infrastructure to enable greater automation in communications, roll-out of the next phase of the company's MiGen transactive energy project, deployment of cyber security and monitoring equipment at stations, and upgrades to customer meters to enable remote disconnections.

Maintaining current levels of reliability, while targeting those pockets of the system whose reliability performance is below average, are principal objectives driving this basket of investments.

7.1.4 General Plant

Whereas the three system-related categories discussed above relate to investments in the core components of Hydro Ottawa's distribution grid, general plant covers expenditures on assets that are not part of the system. These include facilities, land, fleet, tools, equipment, information technology hardware and software, and other rolling stock that is used to support essential business activities.

General Plant – Capital Programs
- Buildings – Facilities
- Customer Service
- Enterprise Resource Planning System
- Fleet Replacement
- IT New Initiatives
- IT Life Cycle & Enhancements
- Operation Initiatives
- Tools Replacement
- Facilities Implementation

Successful completion of General Plant projects is a key determinant of the efficiency and effectiveness of the company's overall business performance. In many instances, the ability to follow through on commitments to customers and to safeguard employee health and safety hinges upon program expenditures in this category.

Key projects planned in this investment category for 2021-2025 include deployment of a digital Customer Relationship Management system enabling a 360-degree view of customer activity, migration of the enterprise resource planning system to a cloud-based platform, adoption of enhanced equipment and software to support crews in the field, replacement of critical IT

infrastructure, implementation of cyber security safeguards, and upgrades to the numerous business systems responsible for collecting, processing, and validating incoming meter data.

Similarly, several of these investments will have multi-faceted value streams, insofar as they will enable Hydro Ottawa to achieve multiple performance outcomes at the same time. For example, enhancements to the Customer Care & Billing (CC&B) system will better position Hydro Ottawa to assist customers in managing their energy needs, offer a more personalized experience, and ensure satisfaction with the utility's services. Beyond this, however, upgraded CC&B functionality will also introduce new options to customers for obtaining value-added products or services (e.g. direct deposit of credits into customer's bank account, a wider range of options for payment methods and bill due dates), while simultaneously opening doors to opportunities for shared services with other utilities and services to third parties. The availability of this solution will expand customer choice and convenience as well as carve out space for growing revenue from new sources.

Finally, certain projects in this portfolio are set to serve as unique illustrations of the best-in-class innovation culture which Hydro Ottawa continuously seeks to foster. Examples include the deployment of artificial intelligence solutions in order to automate a number of business processes and enhance their efficiency and accuracy.

7.2 OPERATIONAL PLAN

Hydro Ottawa's responsibility to manage a safe and reliable distribution system, serve customers in a manner that is responsive to their needs and preferences, and maintain compliance with a broad range of legislative and regulatory requirements compel the company to incur a level of costs that is proportionate to the magnitude of its operational obligations. These costs are spread across 14 different Operations, Maintenance and Administration (OM&A) program categories that serve to structure the myriad of activities which are part and parcel of keeping the lights on. Annual OM&A expenditures for the 2021-2025 rate term are outlined in the table below.

Table 3 – Annual OM&A Program Expenditures ($ Millions)

2021	2022	2023	2024	2025
93.9	96.3	98.7	101.2	103.7

The principal cost drivers underlying Hydro Ottawa's forecasted OM&A expenses include costs associated with legislative and regulatory compliance; operational investments needed for safety and reliability; employee compensation and training; ongoing support, maintenance, licensing, and protection of the company's IT systems; fuel; market priced contracts; and inflation.

Of note, during the internal budgeting process, the initial levels of OM&A submitted by the various divisions within the company resulted in an overall OM&A compound annual growth rate (CAGR) of 3.5% over the 2021-2025 period. In step with its commitment to continuous improvement and customer preferences for minimizing rate increases, Hydro Ottawa then applied a custom OM&A escalation factor to contain upward pressure on operational expenses and to embed productivity expectations throughout the 2021-2025 period. This lowered the overall OM&A CAGR to 2.5% and achieved a reduction of $12 million in OM&A spending over the course of the rate term.

Moreover, Hydro Ottawa staff levels will not increase between 2021 and 2025, relative to staffing levels from 2019. Similarly, heading into this next Custom IR period, Hydro Ottawa is set to serve a larger number of customers than at the outset of its previous five-year rate plan (~323,000 as of the end of 2015 vs. ~335,000 as of the end of 2018 – an increase of almost 4%). Both of these data points attest to the effectiveness of the company's ongoing productivity and efficiency initiatives.

Hydro Ottawa's total operating costs are reported every year to the OEB and benchmarked against other distribution companies in Ontario. In the last year of publicly available data collected by the OEB, Hydro Ottawa's total operating cost per customer was $260. Consistent with the pattern of recent years, this result compared favourably to the average cost per customer across all electricity distributors in the province ($316).

7.3 INCORPORATING CUSTOMER FEEDBACK & PREFERENCES

Hydro Ottawa has designed its capital and operational plans to reflect the needs and priorities of customers, in both general and specific ways. Examples of how the company has sought to incorporate the insights gleaned from extensive engagement with customers include the following:

- Certain proposals for capital spending have been deferred, as part of an asset needs rationalization process which was undertaken in order to prioritize the most critical projects for system reliability and maintenance and to identify opportunities for minimizing rate impacts.

- To further support efforts to defer capital spending and lower costs for customers, the use of non-wire alternatives is planned. In the Kanata North area, for example, a mix of conservation, load transfers, and voltage reductions solutions will be deployed to enable the deferral of a transmission-connected substation that had originally been identified as a need through the latest regional planning cycle.

- Critical investments in reliability-related projects are being paced in accordance with customer expectations for an appropriate level of service. One illustration in this regard is the prioritization of the construction of the new Cambrian Municipal Transformer Station in the early years of the rate period. This reflects the imperative to ensure sufficient capacity is available in an area which is forecasted to continue experiencing significant load growth over the next decade.

- A selective portfolio of prudent investments is planned in new technologies and solutions that will enhance the menu of service offerings available to customers and, in many cases, lead to reduced operational costs. These will open up new channels for customers to engage and transact with Hydro Ottawa, and continue the company's movement to digital and cloud-based platforms which help eliminate the need for costly, on-premise IT infrastructure.

- Several steps are being taken to more formally incorporate climate change risk management into system planning processes and decision-making practices. The range of actions will include augmenting vegetation management practices, developing new anti-cascade standards for utility poles, and investing in greater automation capability for remote isolation and restoration of faulted system components.

Alongside the aforementioned examples, the ongoing implementation of productivity and efficiency initiatives will play a crucial role in minimizing operating costs. Specific examples of productivity are discussed in the ensuing section.

8. PRODUCTIVITY AND CONTINUOUS IMPROVEMENT

Responsibly controlling costs and focusing on cost-effective delivery of outcomes that matter to customers remain core priorities for Hydro Ottawa. Amidst the unique confluence of demands, pressures, and constraints on operations, the company is placing increased emphasis on incorporating productivity and continuous improvement gains, so as to offset increasing expenditures and boost organizational capacity. Hydro Ottawa is therefore committed to ensuring that productivity and continuous improvement serve as hallmarks of its 2021-2025 rate plan.

8.1 2016-2020 INITIATIVES

A retrospective glance at the outcomes and efficiencies derived from productivity initiatives during the preceding five-year rate period demonstrates that there is a firm foundation upon

which to build. During the 2016-2020 period, Hydro Ottawa successfully executed a wide spectrum of initiatives which resulted in tangible savings to customers – and at no expense to service quality or system reliability. Headlining this deep pool of initiatives were the following:

- Enhancements to the customer contact centre, giving customers an improved experience through access to more efficient service and a broad range of options for communicating with Hydro Ottawa through the channel of their choice;

- Introduction of new digital tools, such as a mobile application and Smart Speaker skills (a first in the Canadian electric utility sector), to take customer service to the next level of convenience and sophistication;

- Movement away from manual, paper-based processes and adoption of electronic solutions to support core business systems and practices, including the enterprise resource planning platform, field crew scheduling, fleet management, and planned outage communications;

- Consolidation and modernization of administrative and operational facilities; and

- Workforce stabilization and optimization, through such measures as reallocation of vacant positions to trades hiring and reduction of both on-call and overtime costs.

8.2 2021-2025 INITIATIVES

Whether through harnessing the potential of new technologies and solutions to better serve customers, elevating standards of business performance and excellence, or rationalizing and re-purposing resources, Hydro Ottawa is set to continue strengthening its culture of continuous improvement over the course of its next five-year rate term.

In accordance with internal guidelines for the preparation of plans and budgets for the 2021-2025 period, each administrative division within the company was mandated to

demonstrate productivity savings in a quantitative and/or qualitative fashion, and to identify initiatives dedicated to continuous improvement. This provides assurance that productivity and cost control objectives are firmly integrated into the business planning process.

A survey of the productivity initiatives planned over the next rate plan horizon reveals the following highlights:

- Movement of enterprise resource planning system to a cloud-based solution, thereby enabling greater administrative efficiency, reduced system maintenance costs, and timely access to new functionality;

- Integration of the recent SCADA system upgrade with the existing Outage Management System and a new Distribution Management System, enabling superior functionality and automation, and providing control room operators with line of sight and situational awareness through a single interface;

- Deployment of a digital platform for Customer Relationship Management, enabling a 360-degree view of customer activity across the company;

- Increased deployment and further innovation in voice-activated digital assistance technology, for use in customer service and experience applications;

- Implementation of robotic process automation capabilities across multiple business units and programs, in order to more efficiently and expeditiously execute highly transactional activities;

- Renegotiation of contracts with external service providers for underground cable locates and vegetation management, with projected annual savings of $200,000 and $100,000, respectively;

- Reduction in phone lines for advanced metering infrastructure systems, resulting in annual savings of $150,000;

- Deployment of a cloud-based platform to optimize the use and value of advanced metering infrastructure data analytics, as a means of driving operational efficiencies across a wide range of core business functions;

- Increase in the number of Alternate Locate Agreements, generating annual savings of $50,000;

- Enhanced productivity and reduced overtime costs for crews, on account of the implementation of seasonal construction schedules which aim to shift work away from the winter season, during which construction is more costly and inefficient due to environmental and operational constraints;

- Achievement of 4% increase in daily available wrench time for crews; and

- Administration of internal programs dedicated to optimizing the lifecycle management and enhancement of IT assets.

8.3 BENCHMARKING

The preparation of this business plan was supported by year-over-year comparisons of Hydro Ottawa's costs and outcomes, along with evaluations of the company's performance against its peers. Tracking and analysis of trends in the achievement of system reliability, customer value, and financial strength outcomes have informed the scope and substance of particular capital and OM&A programs. Similarly, the benchmarking of Hydro Ottawa's expenditures and performance relative to samples of utilities across Ontario, Canada, and the United States has yielded valuable insights into areas in which the company performs well and those in which there is room for improvement. These findings have been internalized and incorporated into

specific work programs, and will serve as important baselines and points of reference against which to measure the company's progress.

As the implementation of Hydro Ottawa's capital and operational plans unfolds over the 2021-2025 period, the use of internal and external benchmarking will remain a vital tool for monitoring and measuring performance. The company fully anticipates undertaking additional benchmarking analysis during the rate term, as a means of supporting its broader performance management and business planning framework, as well as its system and asset management planning processes.

9. ALIGNMENT WITH THE RENEWED REGULATORY FRAMEWORK

The primary objectives animating Hydro Ottawa's corporate vision are wholly consistent with the main performance outcomes promoted under the OEB's Renewed Regulatory Framework (RRF). Hydro Ottawa views this broad alignment as a competitive advantage and remains committed to firmly entrenching RRF principles and objectives throughout its operations and business.

The table below illustrates the alignment between the company's overarching objectives and the key categories of performance outcomes under the RRF. For additional context, the table also shows the congruence of Hydro Ottawa's high-level performance goals and strategic outcomes – which are utilized to measure progress in achieving the strategic objectives – with the RRF's areas of focus.

Table 4 – Alignment of Corporate Strategic Objectives with RRF Performance Outcomes

OEB RRF Performance Outcomes	Hydro Ottawa		
	Key Area of Focus	**Corporate Performance Goal**	**Strategic Outcome**
Customer Focus	Customer Value	● Assist customers in managing their energy consumption and electricity costs ● Deliver on customer expectations for service quality and responsiveness ● Maintain overall distribution system reliability	● Customer satisfaction
Operational Effectiveness	Organizational Effectiveness	● Continue to enhance operational performance and productivity ● Maintain leading health and safety record ● Enhance organizational and employee capability	● Efficient and effective operations ● Safe and healthy work environment ● Engaged, aligned and prepared workforce
Public Policy Responsiveness	Corporate Citizenship	● Enhance our brand image in the community and the industry ● Continue to improve our environmental performance and reduce our impact on the environment	● Leading governance and business practices ● Engaged stakeholders ● Safe, secure and environmentally responsible services ● Positive community impact
Financial Performance	Financial Strength	● Grow revenues from new sources ● Enhance / protect revenues from existing business lines	● Growth in shareholder value

9.1 PERFORMANCE MEASUREMENTS

In accordance with the RRF's emphasis on achieving outcomes that provide value to customers, Hydro Ottawa is committing to a robust performance measurement and reporting framework for the upcoming five-year rate period. This framework expands and builds upon the success of the one that was in place for 2016-2020, and will maintain the approach of

combining standard OEB performance measures with others that are customized for Hydro Ottawa's unique use.

As displayed in the table below, an integral component of this framework is the set of measures that will form the basis of Hydro Ottawa's 2021-2025 Custom Performance Scorecard. These measures have been selected based upon a variety of factors and drivers, including responsiveness to customer preferences, alignment with core RRF and corporate strategic objectives, and correlation to key findings from the benchmarking analyses performed in support of this business plan.

Table 5 – Hydro Ottawa's Custom Performance Scorecard Measures for 2021-2025

Outcome	OEB Reporting Category	Hydro Ottawa Custom Measures	New/Existing	Target
Customer Focus	Customer Satisfaction	Contact Centre Transaction Satisfaction – Survey Results	New	
		Number of MyAccount Customers	New	
		Number of Online Billing Accounts	New	
Operational Effectiveness	System Reliability	Customer Average Interruption Duration Index	Existing	
		Feeders Experiencing Multiple Sustained Interruptions	Existing	
		Worst Feeder Analysis	Existing	

		System Average Root Mean Square Variation Frequency Index	Existing	
		Stations Exceeding Planning Capacity	Existing	
		Feeders Exceeding Planning Capacity	Existing	
		Stations Approaching Rated Capacity	Existing	
		Feeders Approaching Rated Capacity	Existing	
	Cost Control	Productive Time	Existing	
		Labour Allocation	Modified	
		Average Cost per Pole – Wood Pole Replacement	New	
		Average Cost per Meter – Underground Cable	New	
		Average Cost per Kilometer – Vegetation Management	New	
		Average Cost per Pole – Pole Test and Inspection	New	
	Asset Efficiency	Technology Infrastructure Cost per Employee	New	
Public Policy Responsiveness	Environment	Annual Oil Spills & Costs of Remediation	Existing	
		GHG Emissions per 50,000 Hours Worked (Tonnes)	New	

		Non-Hazardous Waste Diversion Rate	New	
		Percentage of Green Suppliers	New	
Financial Performance	Financial Ratios	OM&A per Customer	New	
		Bad Debt as a Percentage of Total Electricity Revenue	New	
		Cumulative Capital Additions per Investment Category	New	
		Annual Capital Spending per Investment Category	Existing	

Consistent with the prescriptions of the RRF, this proposed reporting regime is intended to equip the OEB, customers, and other stakeholders with the ability to better monitor and understand diverse aspects of Hydro Ottawa's performance, and to demonstrate the company's accountability in transparently communicating the outcomes achieved under its performance management framework.

10. CONCLUSION

The 2021-2025 period represents a unique moment in time for Hydro Ottawa. It follows on the heels of what was, by numerous measures, a highly successful five-year window in which the company executed its first-ever Custom IR rate plan. With the benefit of the outcomes and knowledge gained over the course of 2016-2020, the company is poised to enter the next chapter of its journey towards a smart energy future in a position of strength and with a positive track record.

However, the landscape has shifted appreciably since the OEB last approved a rebasing application from Hydro Ottawa. Despite the robust progress made in replacing aging infrastructure, with over 17% of assets having reached the end of their useful lives, continued investment to mitigate the risk of asset failure remains a critical priority. At the same time, the steady level of growth which the City of Ottawa is experiencing means that expanding the distribution grid and ensuring access for new customers are urgent imperatives as well. Together with the demands posed by more frequent and more acute severe weather events, heightened customer expectations for greater convenience and choice, and the rapid evolution of operational technologies and threats, these pressures present an immensely challenging landscape for Hydro Ottawa to navigate. Against the backdrop of an increasingly complex and fluid policy environment, these pressures are magnified even further.

Accordingly, the company requires a comprehensive, data-driven, customer-sanctioned roadmap through which it can chart its course for the next five years. Hydro Ottawa is confident that this Business Plan will effectively fulfill this need. The company welcomes the opportunity to move this strategy forward and to deliver the attendant benefits to its customers and community.

11. APPENDICES

APPENDIX A – REVENUE REQUIREMENT & BILL IMPACTS

Table 1 - Bill Impacts by Customer Class

	Year over Year Distribution % Change					
Rate Class	**2021**	**2022**	**2023**	**2024**	**2025**	**Average**
Residential	5.8%	8.3%	4.8%	3.7%	2.6%	*5.0%*
GS < 50 kW	6.0%	8.4%	4.8%	3.6%	2.7%	*5.1%*
GS > 50 to 1,499 kW	5.7%	8.3%	4.8%	3.7%	2.5%	*5.0%*
GS > 1,500 to 4,999 kW	4.8%	8.3%	4.8%	3.7%	2.5%	*4.8%*
Large Use	6.0%	8.3%	4.8%	3.7%	2.5%	*5.1%*
Street Lighting	2.0%	8.2%	4.8%	3.7%	2.5%	*4.3%*
Sentinel Lighting	4.3%	8.2%	4.8%	3.7%	2.5%	*4.7%*
Unmetered Scattered Load	5.1%	8.4%	4.6%	3.7%	2.5%	*4.9%*
Standby Power	8.8%	8.3%	4.8%	3.7%	2.5%	*5.6%*

Table 2 – Revenue Sufficiency/Deficiency

	2021 ($000)	2022 ($000)	2023 ($000)	2024 ($000)	2025 ($000)
Return on Rate Base					
Distribution Expenses (not including amortization)					
Amortization					
Payment in Lieu of Taxes					
Service Revenue Requirement					
Less Revenue Offsets: Per Approved Settlement Agreement Adjustment per Pole Attachment Decision					
Base Revenue Requirement					
Transformer Ownership Allowance					
Revenue Requirement from Rates					
Forecasted Load at 2020 Rates					
Cumulative Revenue Deficiency (over 2020)					
Yearly Revenue Deficiency over 2020					

Finalization in Process

Table 3 – Summary of Rate Impacts

Rate Class		2020 Approved	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed	2025 Proposed
Residential (800 kWh)	Distribution Charge						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
Residential (750 kWh)	Distribution Charge						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
Residential (640 kWh)	Distribution Charge						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
Residential (232 kWh)	Distribution Charge						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
General Service < 50 kW (2,000 kWh)	Distribution Charge						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
General Service 50 to 1,499 kW	Distribution Charge						
	Change in Distribution Charge						

Finalization in Process

(250 kW)	**% Distribution Increase**						
	% Increase of Total Bill						
General Service 1,500 to 4,999 kW (2,500 kW)	**Distribution Charge**						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
Large Use (7,500 kW)	**Distribution Charge**						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
Sentinel Lighting (1 kW)	**Distribution Charge**						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						
Unmetered Scattered Load (470 kWh)	**Distribution Charge**						
	Change in Distribution Charge						
	% Distribution Increase						
	% Increase of Total Bill						

Finalization in Process

APPENDIX B – CHIEF FINANCIAL OFFICER MEMORANDUM TO EXECUTIVE MANAGEMENT TEAM RE: 2020-2025 PRIORITIES AND BUDGET GUIDELINES (DATED JANUARY 31, 2019)

Hydro Ottawa Limited
3025 Albion Road North, PO Box 8700
Ottawa, Ontario K1G 3S4
Tel.: (613) 738-5499 ext. 3924
Fax: (613) 738-5486
geoffsimpson@hydroottawa.com

Hydro Ottawa limitée
3025, chemin Albion Nord, C.P. 8700
Ottawa (Ontario) K1G 3S4
Tél. : (613) 738-5499 poste 3924
Téléc. : (613) 738-5486
geoffsimpson@hydroottawa.com

To: Executive Management Team (EMT)

Date: January 31, 2019

Subject: 2020-2025 Priorities and Budget Guidelines

Background:

The purpose of this memorandum is to set guidelines to be used in preparation of the Hydro Ottawa Limited (HOL) 2020 to 2025 Priorities and Budgets. These guidelines and high-level timelines were presented to the Executive Management Team on June 28, 2018 and to your divisional senior management team in a series of meetings last July along with wider audience rate application updates since then.

Overview:

As you are aware, HOL will file its 2021 - 2025 rate application in December 2019 in order to have new distribution rates in place on January 1, 2021. Following are the specifics.

- This will be a Custom Incentive Regulation application covering rates for 2021-2025.
- The filing will include the 2020 Budget (referred to as the Bridge year) and budgeted data for the 2021 to 2025 period (referred to as the Test years).
- The filing will also include Actuals for 2015, 2016, 2017 and 2018 as compared to the OEB Approved Rate Application levels.
- The 2019 Budget will also be filed in December 2019 with an update to 2019 Actuals filed with the OEB at the end of April 2020 subsequent to the HOL Board approval of the audited 2019 Actuals.
- The information submitted by each business unit for the 2021 to 2025 period will need to be at a detailed level (i.e. consistent with the level of detail required for a normal budget year).
- Each of the business unit plans will need to outline the major projects and programs being undertaken and their tie to the company's strategic direction with particular focus on the alignment with our customers' interests. There will also need to be a discussion of all of the major projects and programs and the outcomes that are expected from them.
- The Budget for 2020 to 2025 will be entered into our financial system at the detailed Business Unit (BU) level.
- Please keep in mind that there will need to be detailed variance explanations for year over year changes from 2015 through to 2025 for major projects and programs.

Key Milestones:

- Compensation Assumptions are due February 22, 2019.
- High-level position approach by division is due by March 29, 2019 – subject to outcome of discussions at EMT meeting of February 20, 2019.
- The first draft of the 2020 and the 2021 to 2025 budgets is due March 29, 2019 (both OPEX and CAPEX).
- The first draft of the Distribution System Plan (DSP) write-up is also due March 29, 2019.
- The Rate Application Working Group and Steering Committee will review the draft budgets on April 2019.
- The second draft of the budgets (up to EBITDA) is due May 31, 2019 (CAPEX and OPEX numbers will be locked as of this date).
- The final budgets - Full P&L and Capex – are due June 28, 2019 (All numbers will be locked as of this date).
- The Regulatory Affairs Group will release the detailed schedule of due dates on evidence writing under separate cover.
- Revenue requirement and rate impacts are due July 31, 2019.
- Final HOL Board approval will occur in November 2019.
- Filing of the 2021 to 2025 Rate Application will occur in December 2019.

Alignment of Spending to Company Priorities

All spending must align to our enterprise strategic objectives, outcomes and performance goals for each of our four key areas of focus as summarized in Appendix A. It should be noted that the company's current four key areas of focus and associated strategic objectives, outcomes and performance goals will carry forward to 2025. It should also be noted that Hydro Ottawa's four key areas of focus align closely to the Ontario Energy Board's (OEB) policy and direction established under the Handbook and the Renewed Regulatory Framework (RRF) as described in Appendix B.

Productivity, Continuous Improvement and Cost Control

Productivity, continuous improvement and cost control remain a key corporate priority.
Each program area should consider a focus on cost effective delivery of outcomes that matter to customers, with appropriate pacing and prioritization to control costs and manage risks. All divisions must show productivity savings in a quantitative and / or qualitative manner and identify continuous improvement initiatives.

Compensation & Positions

Compensation and benefit estimates will be provided by the Chief Human Resources Officer Division and will be based on the renewed collective agreement and anticipated increases beyond the existing term.

All requests for permanent/regular trades hiring are subject to workforce modelling. All other permanent/regular position requests must be supported by a business case (Appendix C).

Technology

Divisions are responsible for liaising with the CITO Division (IT) through their IT Prime Contacts to communicate and coordinate technology requirements to ensure alignment with company priorities. All new technology requirements must first be supported by an IT Project Request (Appendix D) and for any project greater than $750K, the Material Investment Plan documentation (Appendix E) must also be completed – this is a joint responsibility between the Division requesting the IT Project and the IT Prime Contact. The first draft of the Material Investment Plan is due by March 29, 2019. IT will consolidate all requests from each Division and will prioritize which projects are to move forward for EMT approval prior to inclusion in the budgets.

Inflation Rate

The inflation rate will be applied corporately. No automatic inflationary factors are to be applied until the review is completed by April 2019, therefore please budget in constant dollars.

Non-Compensation OM&A

Non-compensation OM&A spending should be split into two groups: one group that remains relatively flat and generally would only increase with the rate of inflation (to be applied corporately as noted above); and the second group that is based on anticipated changes in programs, volume or contract pricing negotiated / anticipated to be higher than inflation with supporting evidence.

All new or expansion of existing funding must be supported and approved by EMT.

Capital

Capital investment should provide for customer growth and the replacement of aging infrastructure to maintain plant reliability as per the needs analysis documented in the Distribution System Plan.

Capital investment key considerations include but are not restricted to the following:

- Affordability;
- Maintaining reliability;
- Efficient, reliable and cost effective and more prepared for technological changes;
- Planned investments related to accommodating the connection of renewable energy generation;
- Planned investments for the development and implementation of the smart grid to support grid modernization and expenditures as required by legislation;
- Provide more customer choice and address customers' preferences and expectations;
- Coordination of infrastructure planning with customers, the transmitter, other distributors, and the Independent Electric System Operator (IESO) or other third parties where appropriate.

In Q3 /Q4 2018, high-level capital expenditure levels for the period 2021 to 2025 were developed by each division. Subsequently an exercise was followed using the following criteria for rationalization of the submitted forecasts:

- Requirements for typical asset operation;
- Spending levels taking into account financing structure (D/E ratio);
- Rate impacts;

- Safety;
- Reliability; and
- Customer Growth.

An average forecast of CAPEX of $95M per year for years 2021 to 2025 resulted from this process, as such the CAPEX that is to be uploaded in the financial system by March 29, 2019 should be at this rationalized level per each of the categories noted below:

	Average
System Renewal and Service excl CCRAs	68.1
System Access Net	14.8
IT General Plant	8.0
Other General Plant excl CCRAs	4.1
TOTAL	**95.0**

For any capital projects exceeding $750K, the first draft of the Material Investment Plan documentation must also be completed by March 29, 2019 (Appendix E).

Thank you.

Geoff Simpson
Chief Financial Officer

cc: Tina Tardioli – Director, Corporate Planning & Governance
Angela Collier – Director, Finance
Louisa Yeung – Manager, Corporate Financial Planning and Analysis
Greg Van Dusen – Director, Regulatory Affairs
April Barrie – Manager, Rates and Revenue
Laurie Elliott - Manager, Regulatory Compliance and Reporting
Patrick Brown – Manager, Regulatory Policy and Research
Jeannine Ladouceur – Director, Human Resources Services
Audrey Lizotte – Director, Labour Relations and Compensation
Sarah Green – Director, Planning and Program Management for IM & IT
Management Accountants [1]
HR Partners [1]
IT Prime Contacts [1]

[1] Refer to Appendix F for divisional partner list

Appendix A

Enterprise Strategic Objectives, Outcomes and Performance Goals

	Enterprise Strategic Objectives and Outcomes	Corporate Performance Goals
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	1. *Grow revenues from new sources* 2. *Enhance / protect revenues from existing business lines*
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	3. *Assist customers in managing their energy consumption and electricity costs* 4. *Deliver on customer expectations for service quality and responsiveness* 5. *Maintain overall distribution system reliability*
Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	6. *Continue to enhance operational performance and productivity* 7. *Maintain leading health and safety record* 8. *Enhance organizational and employee capability*
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services* *Positive community impact*	9. *Enhance our brand image in the community and the industry* 10. *Continue to improve our environmental performance and reduce our impact on the environment*

Appendix B

The OEB established a new framework for electricity distribution rate regulation in 2012. The Renewed Regulatory Framework for Electricity is a foundational policy: it articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities. Key principles of the RRFE include the expectation for continuous improvement, robust integrated planning and asset management that paces and prioritizes investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

The OEB set out its goals for the RRFE as follows:

> *The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.*

An important aspect of the RRFE is the evolution to an outcomes-based approach. The OEB "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. **There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, financial performance and public policy responsiveness:**

• **Customer Focus:** Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.

• **Operational Effectiveness:** Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance. The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities. Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs.

• **Public Policy Responsiveness:** Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities. These obligations may evolve over time and therefore this Handbook does not provide a comprehensive list of all requirements. Utilities are expected to demonstrate that they have considered Conservation First in their investment decisions. The OEB will expect to see proposals for how distributors are supporting low income customers through programs such as LEAP and/or OESP, or through other distributor-specific programs. Electricity distributors and transmitters are expected to expand or reinforce their systems to accommodate the connection to their system for renewable energy generation facilities and the OEB expects their system plans to include details on how they will meet this requirement.

• **Financial Performance:** Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return. The OEB will monitor the financial performance of each utility to assess continuing financial viability and to determine whether returns are excessive. Utilities have a choice of rate-setting methods to meet their particular needs. Additional tools are available to support infrastructure investment. Utilities must report comprehensive and consistent information, allowing for comparisons over time and across utilities. The OEB will act on its obligations to ensure a financially viable sector where performance indicates that a regulatory response is needed.[i]

[i] Handbook to Utility Rate Applications, October 13, 2016, Section 2

Appendix C

Business Case for Additional Headcount/Position*

*Full-time regular non-trades only

TITLE OF POSITION REQUESTED:

1. **ISSUE STATEMENT**
   Describe the business issue that this staffing action(s) will address. The issue may be process, technology, or product/service oriented. This section should not include any discussion related to the recommendation.

2. **RECOMMENDATION**
   Summarize the approach for how the staffing action(s) will address the business issue. This section should also describe how desirable results will be achieved by moving forward with the staffing action(s).

3. **ORGANIZATIONAL IMPACT**
   Describe how the proposed recommendation and associated staffing action(s) will support business goals and objectives and explain how existing roles may change as a result of the staffing action(s), if applicable.

   Also describe how the staffing action(s) will modify or affect the organizational processes, tools, hardware, and/or software.

4. **ANTICIPATED OUTCOMES**
   Describe the anticipated outcome(s) if the proposed staffing action(s) is/are approved. It should include how the staffing action(s) will benefit the business and describe the expected end state.

5. **STRATEGIC ALIGNMENT**
   All proposals should support Hydro Ottawa's 2016-2020 Strategic Direction in order to add value and maintain executive and organizational support. Provide an overview of the related roadmap(s) and how the staffing action(s) supports delivery against the roadmap and the 2016-2020 Strategic Direction.

6. **COST BENEFIT ANALYSIS**
   Quantify the financial benefits of the staffing action(s) as much as possible by completing a cost benefit analysis to illustrate the costs of the staffing action(s) and compare it with the benefits and savings to determine if it is worth pursuing.

7. **ALTERNATIVES ANALYSIS**
   Business issues may be addressed by any number of alternatives. Provide a brief summary of the alternatives that were considered, one of which should be the status quo or doing nothing. The reasons for not selecting the alternatives should also be included.

8. JUSTIFICATION

Justify why the recommended staffing action(s) should be approved and why the recommendation was selected over other alternatives. Where applicable, quantitative support should be provided and the impact of not approving the staffing action(s) should also be included.

Signature of Executive

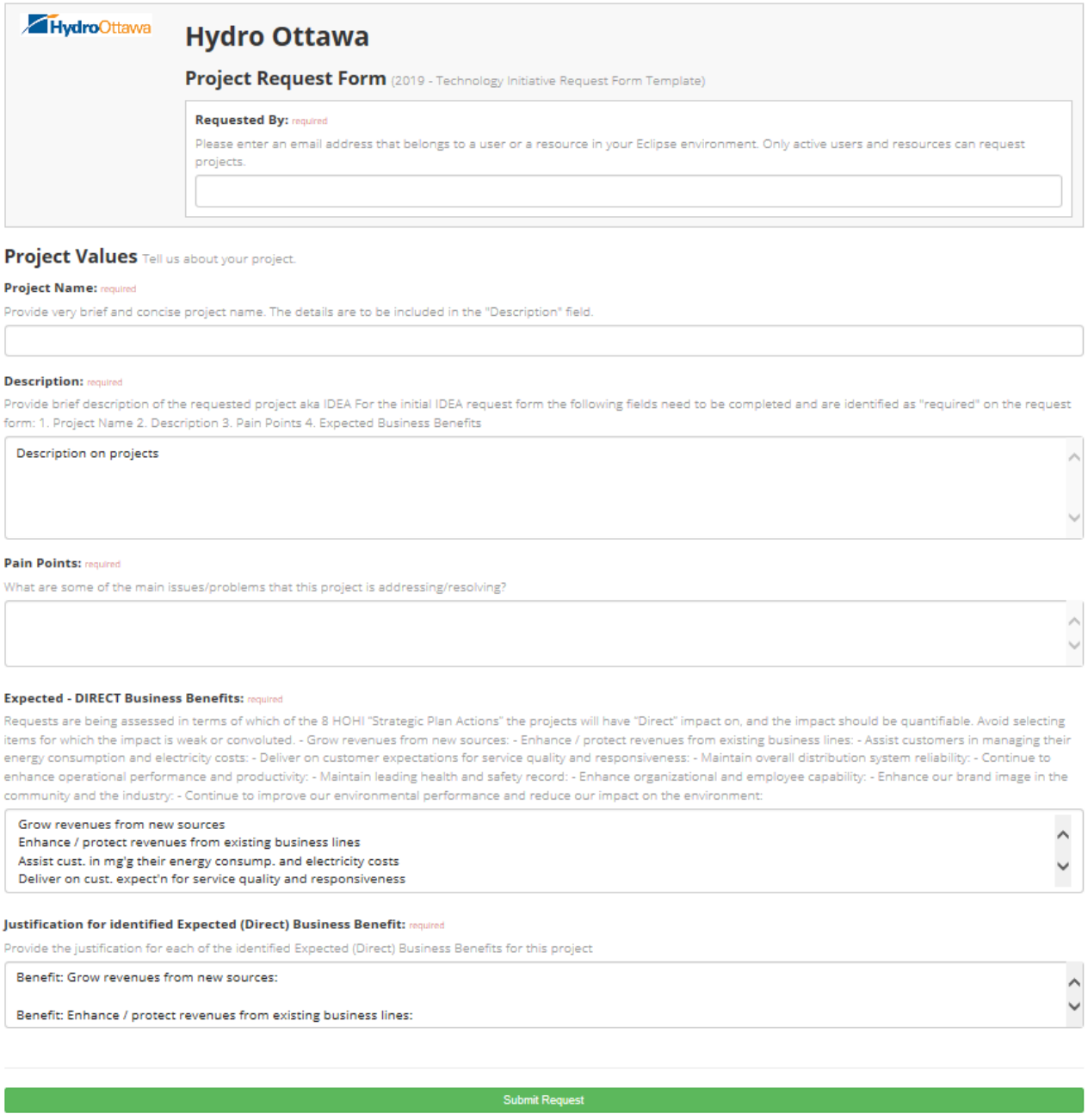
Name	Title	Signature	Date

Appendix D

IT Project Request Template

Please input the data using the electronic template (see link below)

https://eod2.ecl.eclipseppm.com/api/projectrequest/form?environmentid=1109&formuniqueid=008b4e41-7f8d-480d-b53b-00177970de3b



Hydro Ottawa

Project Request Form (2019 - Technology Initiative Request Form Template)

Requested By: required

Please enter an email address that belongs to a user or a resource in your Eclipse environment. Only active users and resources can request projects.

Project Values Tell us about your project.

Project Name: required

Provide very brief and concise project name. The details are to be included in the "Description" field.

Description: required

Provide brief description of the requested project aka IDEA For the initial IDEA request form the following fields need to be completed and are identified as "required" on the request form: 1. Project Name 2. Description 3. Pain Points 4. Expected Business Benefits

Description on projects

Pain Points: required

What are some of the main issues/problems that this project is addressing/resolving?

Expected - DIRECT Business Benefits: required

Requests are being assessed in terms of which of the 8 HOHI "Strategic Plan Actions" the projects will have "Direct" impact on, and the impact should be quantifiable. Avoid selecting items for which the impact is weak or convoluted. - Grow revenues from new sources: - Enhance / protect revenues from existing business lines: - Assist customers in managing their energy consumption and electricity costs: - Deliver on customer expectations for service quality and responsiveness: - Maintain overall distribution system reliability: - Continue to enhance operational performance and productivity: - Maintain leading health and safety record: - Enhance organizational and employee capability: - Enhance our brand image in the community and the industry: - Continue to improve our environmental performance and reduce our impact on the environment:

Grow revenues from new sources
Enhance / protect revenues from existing business lines
Assist cust. in mg'g their energy consump. and electricity costs
Deliver on cust. expect'n for service quality and responsiveness

Justification for identified Expected (Direct) Business Benefit: required

Provide the justification for each of the identified Expected (Direct) Business Benefits for this project

Benefit: Grow revenues from new sources:

Benefit: Enhance / protect revenues from existing business lines:

Submit Request

Appendix E

Enter Project/Program Name

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1 Project/Program Summary

Summary is a snapshot of the information that will be explained in further details throughout the business case.

2 Project/Program Description

2.1 Current Issues

Describe the current situation and the existing issues in current system that will be addressed by this program. (For example, capacity limitations, load growth, etc.)

2.2 Program/Project Scope

Describe the scope of the project/program.

Where applicable, describe HOL's participation in the regional planning process and any regional electricity infrastructure requirements identified in this process that affected the initiation or final configuration of this program/project.; also provide information on the corresponding distribution of the benefits and responsibility for project costs.

If applicable, describe how advanced technology has been incorporated into the project.

2.3 Main and Secondary Drivers

Please identify the main and secondary (if applicable) drivers for this project. Make sure to align these definitions with examples provided by the OEB (see Table1 in Ch5 Filing Requirements).

2.4 Performance Targets and Objectives

Please define the objectives to be achieved by implementing the project. This should also include a discussion on any additional planning objectives that are met by the project have intentionally been combined into the project, and if so, what objectives and why. For instance, a system upgrades project meeting system renewal objectives.

3 Project/Program Justification

3.1 Alternatives Evaluation

3.1.1 Alternatives Considered

Please provide description of alternatives considered to address the drivers and achieve the objectives, including the "Do-Nothing" option, the preferred option, and other technically feasible alternatives that will meet the same objectives as the proposed project.

3.1.2 Evaluation Criteria

Provide a description of evaluation criteria that were used to compare alternatives.

3.1.3 Preferred Alternative

- *Restate what the preferred alternative is*
- *What was the ranking of the preferred alternative relative to other alternatives?*
- *Explain why the proposed project was given this ranking?*
- *Using the tools and methods described in 5.4.2© of the DSP, analyze project benefits and costs comparing the preferred alternative to other feasible alternatives*
- *Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project*

3.2 Project/Program Timing & Expenditure

Please provide a description that addresses the following:

- *What were the expenditures for projects in the historical period that were equivalent to this project? Briefly describe the scope of these projects.*
- *What are the future expenditures for the project?*
- *How has HOL minimized the controllable costs in this project?*

	Historical ($M)					Future ($M)				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Expenditure										
Units										

3.3 Benefits

Please describe the benefits of the project using, where applicable, quantitative and/or qualitative analyses of the project.

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Please describe the effect of the investment on system operation efficiency and cost-effectiveness, as well as identify and set targets for key performance indicators that will be affected by the investment. Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
Customer	Please describe here the net benefits accruing to customers as a result of the investment, and the impact of the investment on reliability performance including on the frequency and duration of outages. This can be done by identifying and setting targets for key performance indicators that will be affected by the investment. Where measurable, include an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable.
Safety	Please describe the effect of the investment on health and safety protections and performance.
Cyber-Security, Privacy	Please provide, where applicable, information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection.
Co-ordination,	If applicable, please explain how the investment applies recognized standards,

Interoperability	referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry
Economic Development	If applicable, please describe the effect of the investment on Ontario economic growth and job creation.
Environment	If applicable, please describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.

4 Prioritization

4.1 Consequences of Deferral

If applicable, please identify and describe the consequences / risks of deferring the project, including implication on O&M costs and system operations, customer impact, safety, cyber-security, coordination / interoperability, economic development and environment.

4.2 Priority

Please provide a description of the priority level of the project that addresses the following:

- *What is the priority level of the project compared to other projects in this and other categories? (i.e. High, Medium, Low)*
- *What are the reasons for its priority? (Make sure this discussion is tie to section 5.4.2c of the DSP on HOL's approach for identifying, selecting, prioritizing, and pacing projects in each investment category)*

5 Execution Path

5.1 Implementation Plan

Please describe the implementation strategy for the project/program, for instance, the order in which stations/feeders/geographic areas will be addressed, and the rationale for this decision.

5.2 Risks to Completion and Risk Mitigation Strategies

Please identify any risks that might prevent HOL from completing the project as planned and describe HOL's risk mitigation strategy for each.

5.3 Timing Factors

Please identify and describe factors that might affect the timing/priority of the project.

5.4 Cost Factors

Please identify and describe factors that might affect the final cost of the project.

Include any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.

5.5 Other Factors

Please identify and describe any other factors that might have an impact on the project, such as factors relating to customer preferences or input from customers and other third parties.

6 Renewable Energy Generation (if applicable)

If applicable, please provide in this section information on the following where applicable:

- *Total capital and O&M costs associated with REG investment*
- *How is the REG investment expected to improve the system's ability to accommodate the connection of REG facilities?*
- *The nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered.*

7 Leave-To-Construct (if applicable)

Where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter4 of the filing requirements (sections 4.3 and 4.4 in particular).

If not applicable, enter "N/A".

8 Project Details and Justification

(For each project in the program, please fill out information in the following table)

Project Name:	*Enter Project Name*
Capital Cost:	*Enter Project Capital*
O&M:	*Enter Project O&M*
Start Date:	*Enter Project Start Date*
In-Service Date:	*Enter Project In-Service Date*
Investment Category:	*Enter Investment Category*
Main Driver:	*Enter Main Driver*
Secondary Driver(s):	*Enter Secondary Driver(s)*
Customer/Load Attachment	*Enter Number of Customers/Load Attached*
Project Scope	
Enter Description of Project Scope	
Work Plan	
Enter Description of Work Plan	
Customer Impact	
Enter Description of Customer Impact, including where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where applicable.	

Appendix F

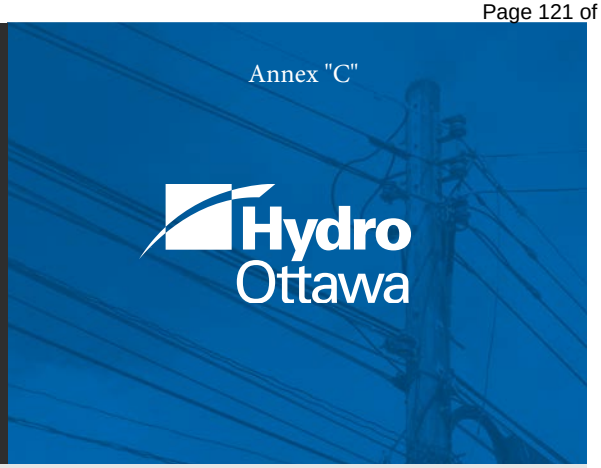
Divisional Partners

Portfolio	HR Partner	Safety Partner	Management Accountant	Information Technology Prime Contact
Distribution Engineering and Asset Management Group	Judy Muldoon	Shawn Diceman	Kirk Thomson	Sally Barakat for Metering Charles Berndt for all other inquiries
Chief Customer Officer Division	Judy Muldoon	Sylvain Pinard	Tressa Valdivia	Sally Barakat for Billing, Collections and Meter Data Services David Ricottone for all other inquiries
Distribution Operations Group	Maureen Daly	Dave Stephens	Kirk Thomson	Sally Barakat for Business Performance & Scheduling Charles Berndt for all other inquiries
Chief Financial Officer Division	Shannon Nicholson	Jean Belanger	Lauren Blake	Andrew Willis for Internal Audit Sally Barakat for Regulatory Michelle Pharand for all other inquiries

Portfolio	HR Partner	Safety Partner	Management Accountant	Information Technology Prime Contact
Chief Information and Technology Officer Division	Shannon Nicholson	Jean Belanger	Lauren Blake	N/A
Chief Human Resources Officer Division	Shannon Nicholson	Jean Belanger	Tressa Valdivia	Michelle Pharand
Chief Electricity Generation Officer Division	Cathy DeMelo	Sylvain Pinard	Liza Kheirallah	Jojo Maalouf
Chief Energy and Infrastructure Services Officer Division	Cathy DeMelo	Sylvain Pinard	Andrea Brennan	Andrew Willis
Chief Executive Officer, Legal Counsel and Governance and Planning Groups	Cathy DeMelo	Sylvain Pinard	Lauren Blake	Sarah Green

Annex "C"

Understanding Hydro Ottawa's 2021-2025 Rate Application



ABOUT HYDRO OTTAWA

Hydro Ottawa is the third largest municipally-owned electricity distributor in Ontario. We distribute electricity to approximately 335,000 customers, serving a population of more than one million people in the City of Ottawa and the Village of Casselman. We are a private business corporation that is 100% owned by our shareholder, the City of Ottawa.

It's our responsibility to transport power from the provincial transmission grid and deliver it safely and reliably to homes and businesses across our service territory. We own and operate a large, complex distribution network consisting of 50,000 poles, 2,700 km of overhead lines, 3,000 km of underground cable, and 45,000 transformers.

OUR FIVE-YEAR BUSINESS PLAN

Hydro Ottawa is seeking approval from the Ontario Energy Board (OEB) for the distribution rates that will be charged to customers for the 2021-2025 period.

The electricity industry in Ontario is regulated by the OEB. One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates that they charge customers.

Between 2016 and 2020, Hydro Ottawa invested in distribution system capacity as well as the replacement of aging infrastructure to maintain operational effectiveness and efficiency. Upgrades to our fibre optic network and Customer Care and Billing System were also a focus, in addition to consolidating employees in two new buildings from end-of-life facilities.

How does Hydro Ottawa plan?

Hydro Ottawa is proposing a plan that is responsive to:

- **Legal and regulatory requirements** by continuing to meet our obligations.
- **Internal business planning** based on expert analysis and professional judgment to develop construction and operations programs that address safety, business, technical, and operational needs.
- **Customer feedback** collected throughout our consultation on the application and ongoing customer engagements.

Over the course of 2021 to 2025, Hydro Ottawa will need to continue to invest in our infrastructure, equipment, and workforce.

These needs are being driven by a diverse set of factors, such as aging infrastructure, sustained population and economic growth in the Ottawa area, an increasing number of severe weather events, technological evolution, cyber security threats, and workforce retirements. The plan forward includes major asset replacement and upgrades, vehicle replacements, systems and software for resource planning programs, data analytics, and productivity improvements.



As a result, key initiatives that we have planned include:

- building new distribution stations in growing areas of the city,
- connecting thousands of new customers every year,
- supporting local infrastructure projects like Light Rail Transit,
- upgrading and modifying infrastructure to enhance reliability and capacity on the grid,
- replacing equipment that has reached end of life,
- strengthening the grid's ability to withstand the effects of severe weather,
- investing in digital solutions to enhance customer service,
- renewing our vehicle fleet, and
- recruiting and retaining a new generation of highly-skilled employees.

To learn more about Hydro Ottawa's plan, see Exhibit 1-1-9 Business Plan in the application.

HOW CUSTOMERS HELPED INFORM OUR PLAN

Our goal is to put the customer at the centre of everything we do. Hydro Ottawa is committed to engaging with our customers, understanding their needs and preferences, and operating in an efficient and cost effective manner. In preparing our business plan, we reached out directly to customers, to better understand their priorities and expectations for the electricity services they receive. Price, reliability and investing in new technology ranked as the top three priorities.

Together with the customer feedback that we receive on an ongoing basis, we took this input and developed a plan emphasizing four principles:

01 Minimize rate increases
02 Maintain reliability and service quality
03 Address key pressures to the distribution system
04 Make prudent investments in emerging technologies to enhance service offerings and/or reduce operating costs

Nearly 21,000 customers shared their thoughts on our preliminary plan through the completion of an online survey. The majority of residential customers (83%), small business customers (76%) and mid-market and key account customers (69%) shared that they supported Hydro Ottawa's planned increase or even spending a bit more to improve service based on the priorities above.

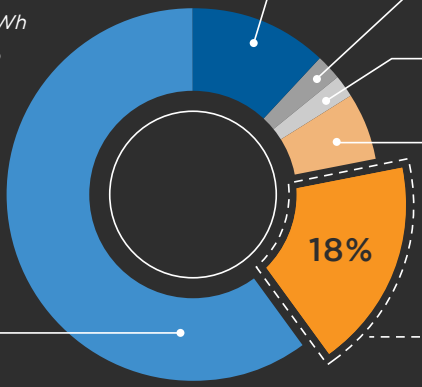
To learn more on how Hydro Ottawa engages customers and responds to their needs, see Exhibit 1-2-1 Customer Engagement in the application.

Electricity distributors like Hydro Ottawa are funded through the distribution rates paid by customers. We do not receive taxpayer money to fund our operations or investments in the distribution system. While Hydro Ottawa is responsible for collecting payment for the entire electricity bill, we retain only a portion of the delivery charge representing less than 20% of the bill.

Figure 1

Hydro Ottawa Bill Breakdown (November 1, 2019)

For the average Standard Supply Service residential customer using 700 kWh per month. These percentages do not inlcude the Ontario Electricity Rebate.



DOLLARS AND CENTS – EXPECTED COSTS OF THE PLAN

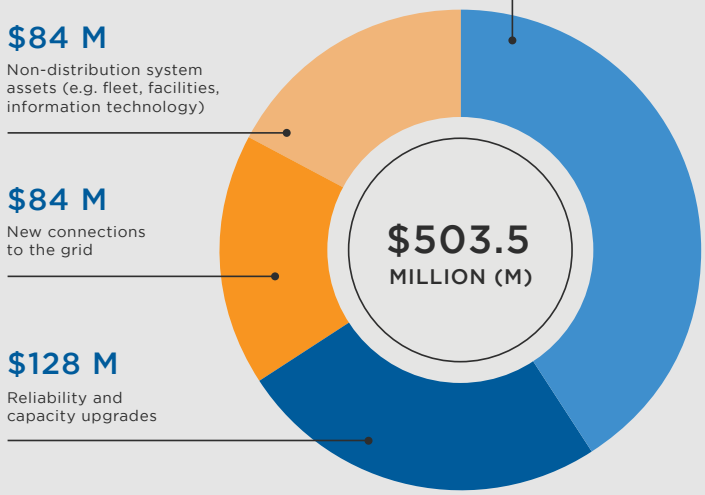
Like most businesses, Hydro Ottawa manages both a capital and an operating budget.

Capital expenditures are items that have lasting benefits over many years, while operating expenditures are recurring expenses in day-to-day management of the company (e.g. tree trimming and billing).

For the 2021-2025 period, the capital required to maintain system reliability and safety, and invest in infrastructure and equipment priorities is $503.5 million. For operations, a budget envelope of $493.6 million is needed.

Figure 2

2021-2025 Forecasted Capital Investments





In order to move forward with our proposals, we're seeking approval from the OEB to change our rates.

A typical Hydro Ottawa customer using 700 kWh a month will see an after tax total bill increase of $X.XX or $X.XX% in 2021.

The expected impacts on customer bills over the five-year rate period are shown in the table below.

Bill Impacts

	Usage (kWh)	Change in Bill	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed	2025 Proposed	Average ($)
Residential (typical)	700	$/30 days	x	x	x	x	x	x
		%	5.8%	8.3%	4.8%	3.7%	2.6%	5.0%

Some Data to be Finalized

DELIVERING VALUE FOR MONEY – EXPECTED BENEFITS FOR CUSTOMERS

Moving forward on our five-year plan will enable us to maintain a high level of reliability for customers, while ensuring that we keep costs low and continuously improve the way we do business.

Some of the ways in which customers and communities are expected to benefit from the proposals in our plan include the following:

- Improved system reliability (fewer and shorter outages, quicker restoration times, enhanced resilience to severe weather)
- Greater electricity supply capacity for growing areas of the city
- Greater personalization, choice, convenience, and self-serve capability in the services provided to customers
- More options and solutions to help customers manage and monitor energy use with ongoing development of the Hydro Ottawa app and MyAccount
- Stronger protections for grid assets and customer data against cyber threats
- Increased ability to connect more renewable energy resources to the grid
- Lower costs, relative to alternative investment scenarios



HAVE YOUR SAY

The OEB will review Hydro Ottawa's plan and proposed rates in an open and transparent public process.

For more information on how you can participate in that process, please visit hydroottawa.com/active-applications.

INTERROGATORY RESPONSE - SEC-3

1-SEC-3

EXHIBIT REFERENCE: [Ex.1]

SUBJECT AREA: Custom Incentive Rate-Setting Framework

Please provide copies of all benchmarking studies, reports, and analyses that Hydro Ottawa has conducted itself, undertaken by a third-party, or participated in, since 2016, that is not already included in the application.

RESPONSE:

Table A below identifies all of the benchmarking studies, reports, and analyses that Hydro Ottawa has conducted itself, undertaken by a third-party, or participated in since 2016 that are not already included in the Application.

1 **Table A – Benchmarking Studies Not Included in the Application**

Study Name / Title	Author	Publication Date	Topic / Notes
Comparison of Electricity Prices in Major North American Cities	Hydro-Québec	2016, 2017, 2018, 2019	This annual report compares the monthly electricity bills of Hydro-Québec's customers with customers in over 20 major North American cities. Hydro Ottawa has participated in the report's survey every year since 2016, as well as in years prior to 2016.
Final Verified CDM Summary Report	IESO	2016, 2017	These reports summarized the results achieved by Ontario electricity distributors under the province's former Conservation First Framework ("CFF"). A section of this report – the tab entitled "LDC Rankings" – compares and ranks distributors under various categories associated with verified annual energy savings and program spending.
Summary of Canadian Electricity Bills	Manitoba Hydro	2017	Similar to the Hydro-Québec report referenced above, Manitoba Hydro regularly produces a report comparing the monthly electricity bills of customers in different cities. The scope of Manitoba Hydro's report is limited to major cities in Canada. Hydro Ottawa last participated in this survey in 2017.
OEB Wireline Pole Attachment Rates and Policy Framework (EB-2015-0304)	Nordicity	December 2017	Nordicity was retained by the OEB to provide expert input and analysis in support of the work of the OEB's Pole Attachment Working Group. Among their deliverables was the preparation of a report that reviewed the methodologies used by select Ontario distributors (including Hydro Ottawa) that had applied to the OEB for an increase in their respective wireline pole attachment charges. Hydro Ottawa provided its installed poles data for the 2005-2015 period. The utility likewise served as a member of the PAWG.
Cybersecurity Program and Maturity Assessment	KTL Group	January 2016	KTL Group was engaged to perform a cybersecurity program assessment on Hydro Ottawa's program and provide recommendations on a modernized cybersecurity framework to adopt (i.e. movement from an ISO 27001 information security management framework to the National Institute of Standards and Technology's ["NIST"] Cybersecurity Framework). As part of the assessment, benchmarking was performed against other entities, resulting in recommendations for maturity targets for the utility. The benchmarking and maturity targets were used as a guideline to continue maturing Hydro Ottawa's cybersecurity program.
Stratejm CIS Top 20 Control Assessment	Stratejm	March 2018	As part of Stratejm's engagement with Hydro Ottawa as the utility's managed security service provider, Stratejm performed an assessment against the Center for Internet Security Top 20 controls and assigned the utility a rating. Stratejm provided a target score, an actual score, and a benchmark against other entities which Stratejm manages in the electric utility sector.

Study Name / Title	Author	Publication Date	Topic / Notes
PwC Cybersecurity Program and Maturity Assessment	PwC	October 2018	PwC was engaged to perform a cybersecurity maturity and program assessment of Hydro Ottawa's program for both the corporate information technology and operational technology environments, using the NIST Cybersecurity Framework. As part of the assessment, benchmarking was performed for both environments using comparisons to other electric utilities. This benchmarking and maturity scoring continues to be used as a performance measurement tool and presented to Hydro Ottawa's Board of Directors on a quarterly basis.
Report of the Ontario Energy Board - Energy Retailer Service Charges (EB-2015-0304)	OEB	November 29, 2018	This report sets forth the conclusions of the OEB following its review of energy retailer service charges for electricity and natural gas distributors. Hydro Ottawa was one of the electricity distributors whose retail services expenses and revenues were analyzed and compared to those of other distributors, as part of the OEB's review. In addition, Hydro Ottawa served as a member of the OEB working group that guided the consultation process.
Electric Utility Customer Satisfaction Survey	Utility PULSE	2016, 2017, 2018, 2019	This annual survey measures the levels of satisfaction expressed by a sample of Hydro Ottawa's residential and small business customers with the services provided by the utility. A key component of the survey is a comparison of Hydro Ottawa's scores in specific categories with Ontario and national averages.
Electric Utility Large Customer Satisfaction Survey	Utility PULSE	2017, 2019	This annual survey measures the levels of satisfaction expressed by a sample of Hydro Ottawa's large commercial and industrial customers with the services provided by the utility. A key component of the survey is a comparison of Hydro Ottawa's scores in specific categories with Ontario averages.
National Public Attitudes Survey	Innovative Research Group	2017	The Canadian Electricity Association ("CEA"), of which Hydro Ottawa is a member, commissioned Innovative Research Group to conduct the CEA's Annual National Public Attitudes Survey. The focus of the survey is public attitudes towards the electricity companies serving customers in all 10 Canadian provinces.
National Electricity Customer Satisfaction Report	Innovative Research Group	2018, 2019	CEA commissioned Innovative Research Group to conduct the association's Annual National Customer Satisfaction Survey. The focus of the survey is public attitudes towards the electricity companies serving customers in all 10 Canadian provinces.

Appended to this interrogatory response are copies of the following reports referenced in Table A above:

- Attachment SEC-3(A): Hydro-Québec Survey 2016
- Attachment SEC-3(B): Hydro-Québec Survey 2017
- Attachment SEC-3(C): Hydro-Québec Survey 2018
- Attachment SEC-3(D): Hydro-Québec Survey 2019
- Attachment SEC-3(E): IESO Final Verified Annual 2016 CDM Summary Report - LDC Rankings
- Attachment SEC-3(F): IESO Final Verified Annual 2017 CDM Summary Report - LDC Rankings
- Attachment SEC-3(G): Manitoba Hydro Survey 2017
- Attachment SEC-3(H): OEB Wireline Pole Attachment Rates and Policy Framework
- Attachment SEC-3(I): OEB Report - Energy Retailer Services Charges
- Attachment SEC-3(J): 2017 National Public Attitudes Survey
- Attachment SEC-3(K): 2018 National Electricity Customer Satisfaction Report
- Attachment SEC-3(L): 2019 National Electricity Customer Satisfaction Report

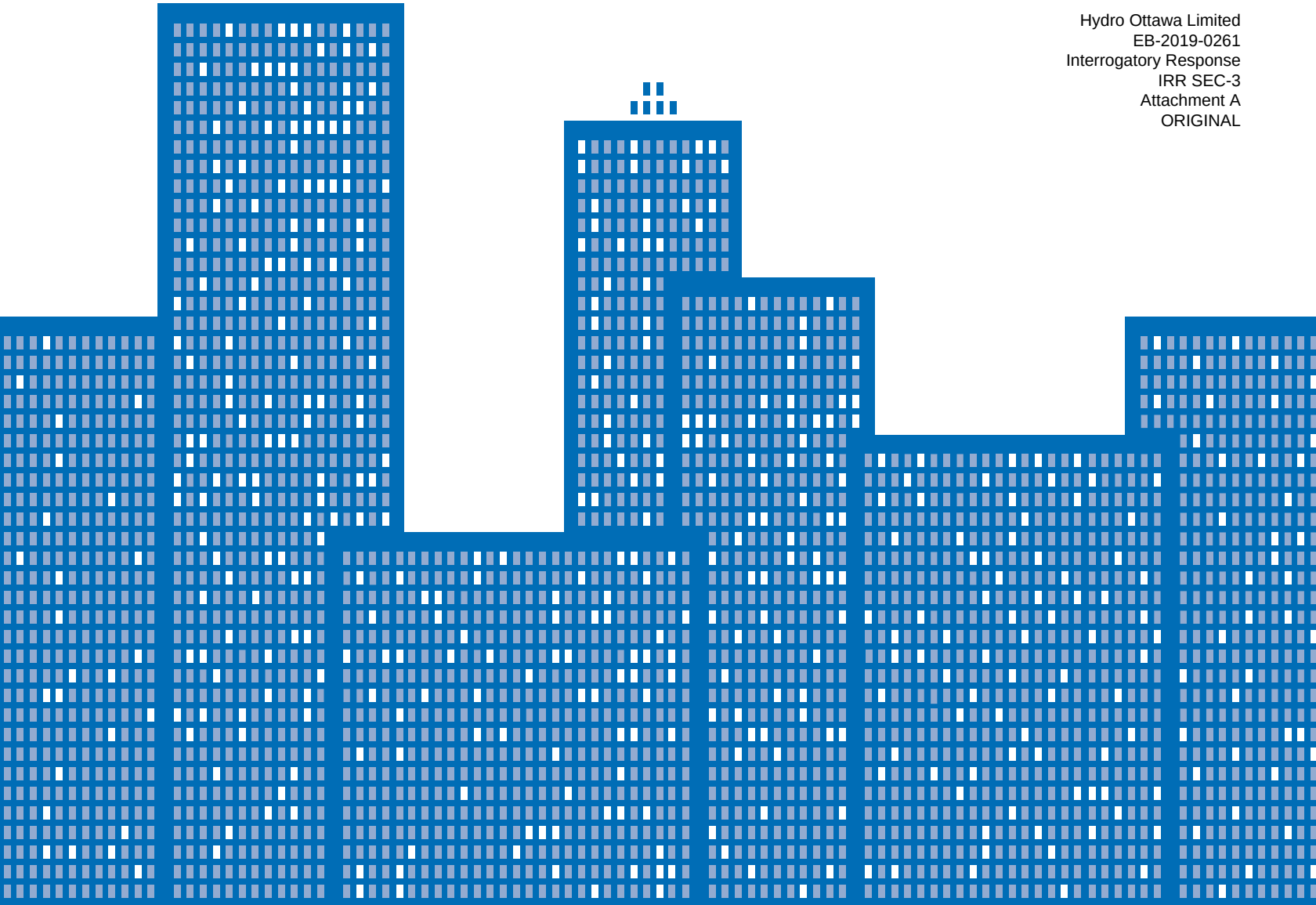
With respect to the IESO reports, please note that the segments of these reports which provide high-level summaries of CFF program results had previously been filed as part of Hydro Ottawa's original Application (see Attachment 4-5-1(C): IESO Final Verified 2016 CDM Summary Report and Attachment 4-5-1(D): IESO Final Verified 2017 CDM Summary Report). For purposes of this interrogatory response, the attachments being submitted consist only of the "LDC Rankings" tabs from the respective reports.

With respect to the annual customer satisfaction surveys prepared by UtilityPULSE, copies are available in Attachments CCC-14(A) through (F).

With respect to the aforementioned reports pertaining to Hydro Ottawa's internal cybersecurity program, in light of the highly confidential and sensitive nature of their contents the utility is not able to provide copies of these materials.

In addition to the studies listed above in Table A, Hydro Ottawa is required by the OEB to administer the Electrical Safety Authority's Public Awareness of Electrical Safety survey

("PAESS") on a bi-annual basis. The goal of PAESS is to benchmark the effectiveness of an electricity distributor's public education efforts related to electrical safety and set targets for continuous improvement. There have been three instances of this survey since 2016: March 2016, March 2018, and March 2020.



COMPARISON OF ELECTRICITY PRICES IN MAJOR NORTH AMERICAN CITIES

Rates in effect April 1, 2016

Hydro Québec

Hydro Ottawa Limited
EB-2019-0261
Interrogatory Response
IRR SEC-3
Attachment A
ORIGINAL

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INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2016. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third section presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1] (IN ¢/KWH)[2]



1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2016.
2) In Canadian currency.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1] (IN ¢/KWH)[2]



1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2016.
2) In Canadian currency.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the nine other Canadian provinces, and 10 utilities in American states. The results are based, in part, on a survey to which 12 utilities responded, and in part on estimates of bills calculated by Hydro-Québec and confirmed in most cases by the utilities concerned.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2016. The most recent rate adjustments applied by the utilities in the study between April 1, 2015, and April 1, 2016, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the Detailed Tables.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists taxes applicable on April 1, 2016, by customer category; those which may be partially or fully refundable are also indicated.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes offer different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2016.

TIME-OF-USE RATES

The rates offered by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates which are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include adjustment clauses that allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2015, and April 1, 2016, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.7665 (CA$1 = US$0.7665), the rate in effect at noon on April 1, 2016. The Canadian dollar had thus depreciated by 2.64% relative to the U.S. dollar on April 1, 2015.

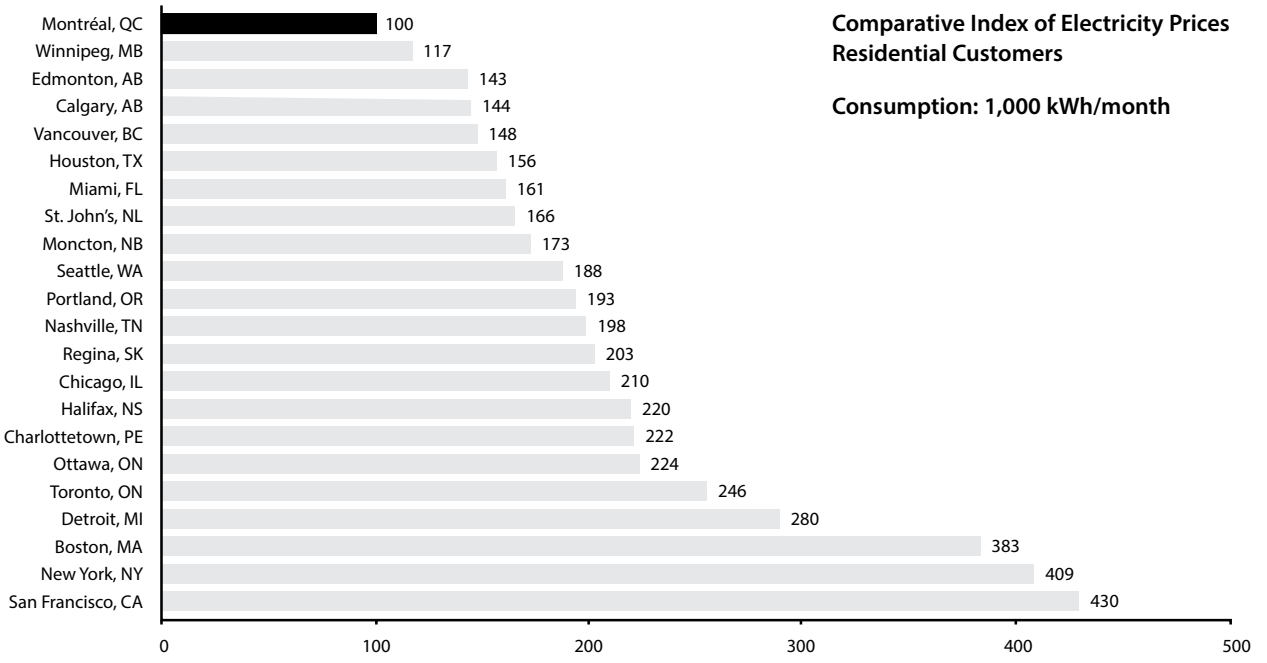
HIGHLIGHTS

The *Electricity Rates* effective April 1, 2016 sets out Hydro-Québec's rates, as approved by the Régie de l'énergie (the Québec energy board) in accordance with Decision D-2016-047. Three types of rates are in effect: domestic rates, for residential customers, the industrial rate, for large-power industrial customers, and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kWh, Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

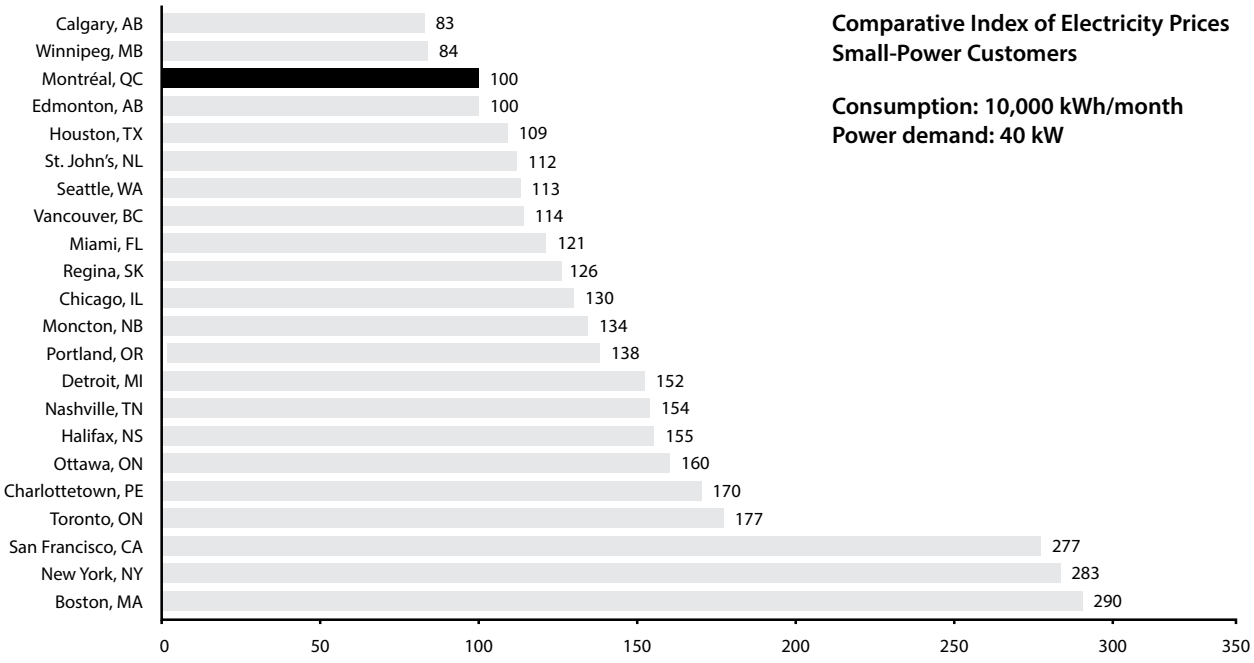
FIGURE 1



SMALL-POWER CUSTOMERS (LESS THAN 100 KW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kW. Montréal holds *third* place followed closely by Edmonton. Figure 2 shows the comparative index of electricity prices.

FIGURE 2

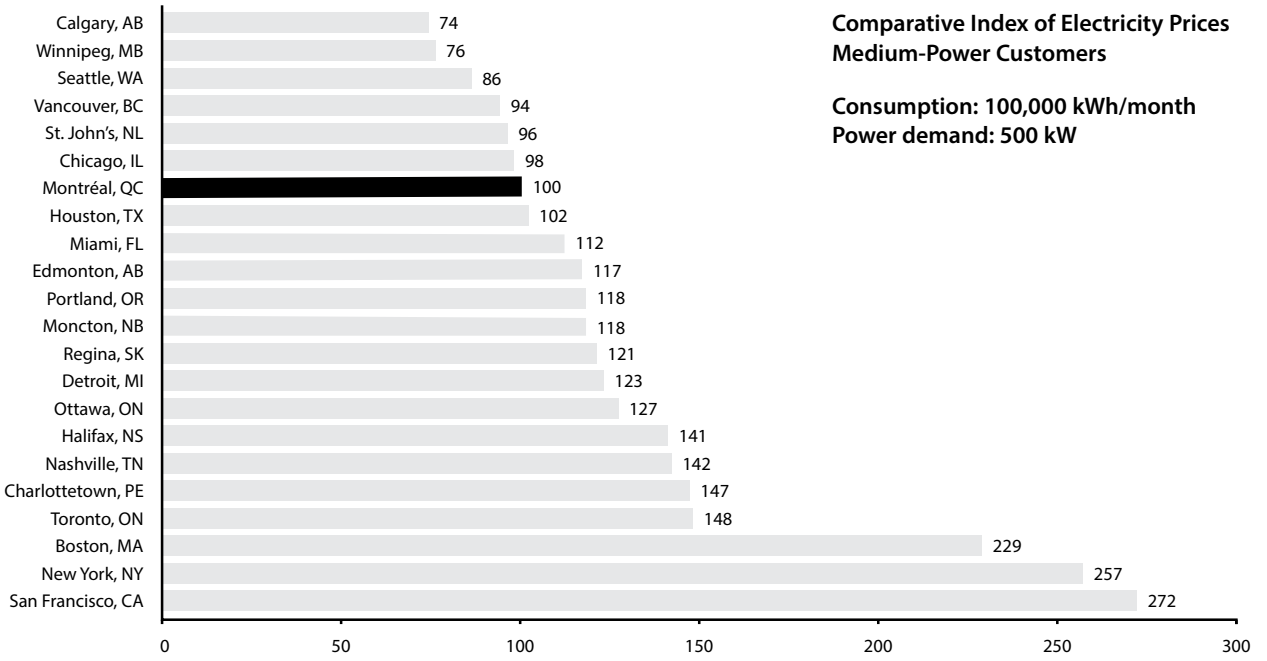


MEDIUM-POWER CUSTOMERS (100 TO 5,000 KW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

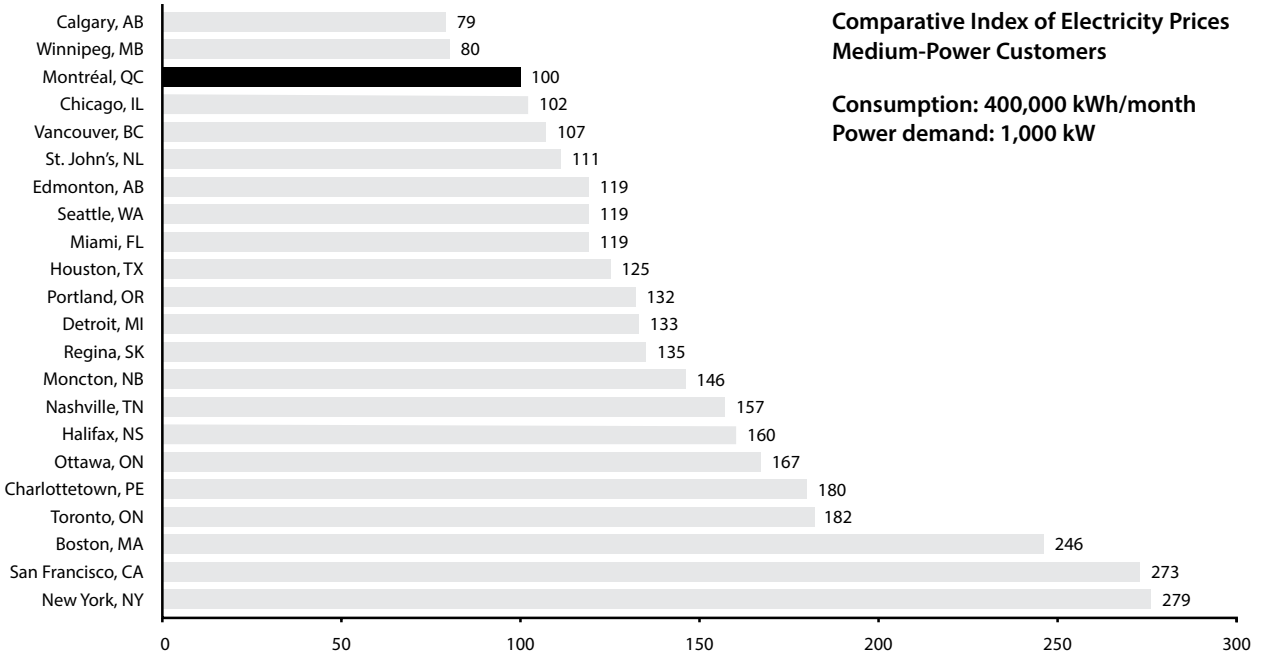
For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal is in *seventh* place, whereas it held sixth place last year.

FIGURE 3



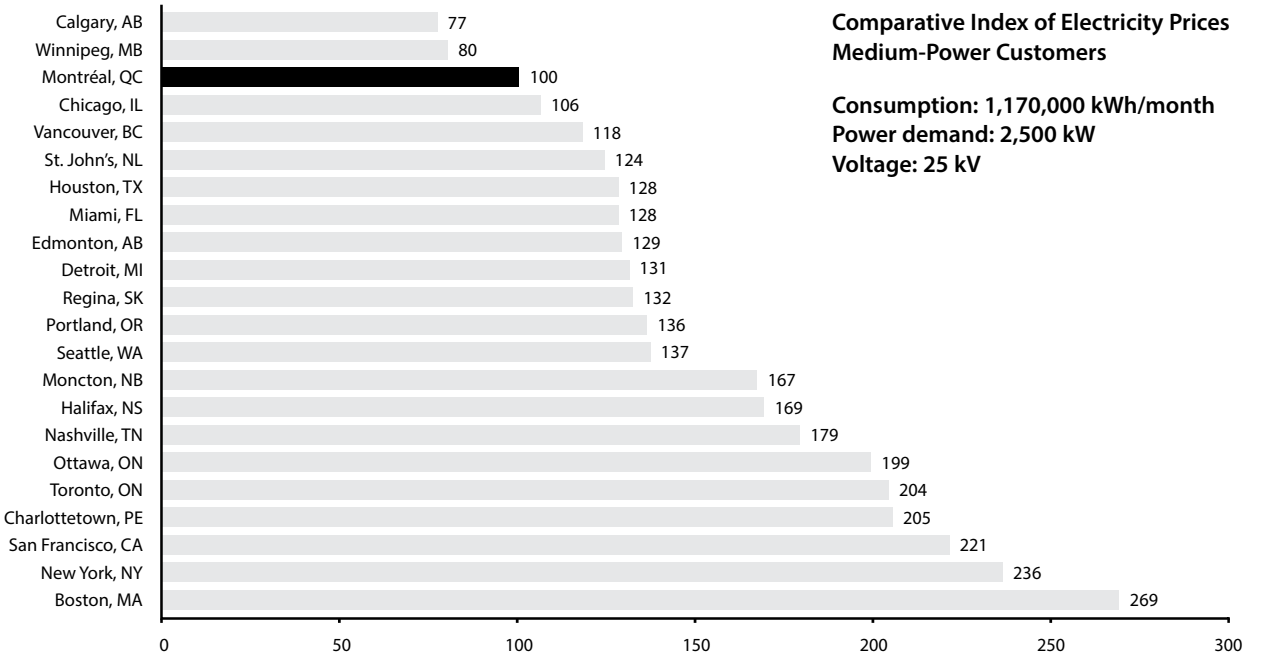
For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal is in *third* place, as was the case last year.

FIGURE 4



In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal holds *third* place.

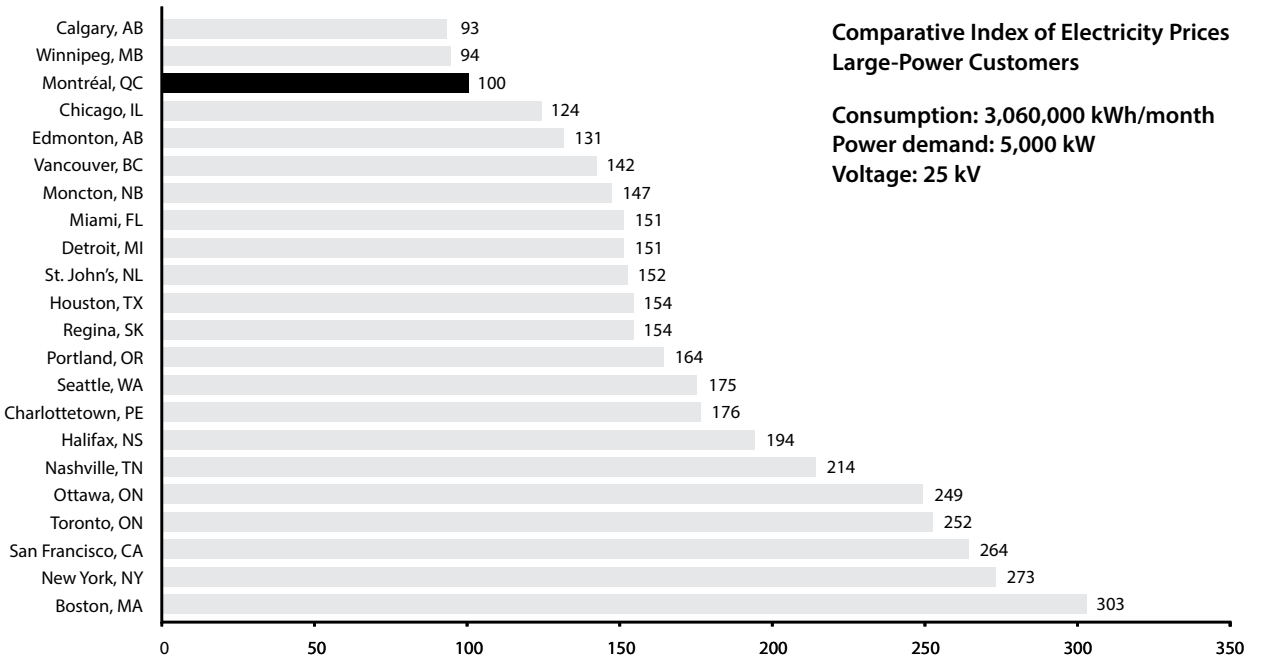
FIGURE 5



LARGE-POWER CUSTOMERS (5,000 KW OR MORE)

Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. Montréal is in *third* place, as was the case last year.

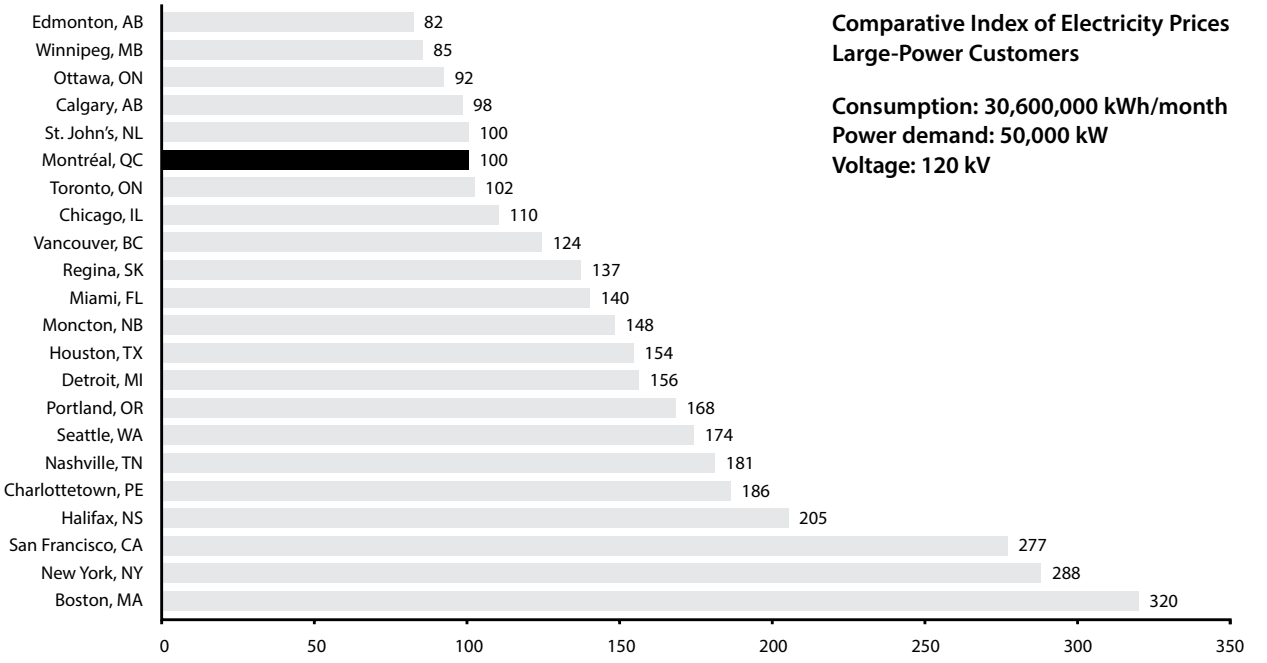
FIGURE 6



Hydro-Québec = 100
Monthly bill (excluding tax)
Rates in effect April 1, 2016

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal went from fifth to *sixth* rank with a bill slightly higher than St. John's.

FIGURE 7



01

DETAILED RESULTS

SUMMARY TABLES (EXCLUDING TAXES)

Monthly Bills
Average Prices
Comparative Index

MONTHLY BILLS ON APRIL 1, 2016

(in CA$)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	**72.26**	**983.33**	**12,000.00**	**31,677.00**	**78,519.75**	**158,317.50**	**1,498,275.00**
Calgary, AB	104.00	818.88	8,860.12	24,894.19	60,775.12	147,544.56	1,469,424.30
Charlottetown, PE[3]	160.17	1,670.17	17,657.97	57,072.97	161,147.97	279,050.00	2,790,500.00
Edmonton, AB[4]	103.69	987.29	14,029.91	37,673.66	100,982.06	207,432.27	1,230,495.47
Halifax, NS	158.83	1,521.36	16,919.13	50,621.54	132,540.38	306,632.99	3,066,353.91
Moncton, NB	124.98	1,316.65	14,153.65	46,403.65	131,388.65	232,564.22	2,218,680.00
Ottawa, ON	161.52	1,576.30	15,293.41	52,882.77	156,328.50	394,959.15	1,381,901.88
Regina, SK	146.45	1,240.42	14,504.30	42,612.50	104,021.73	243,810.19	2,052,428.20
St. John's, NL[5]	119.64	1,103.14	11,537.03	35,262.28	96,995.26	241,144.89	1,498,150.00
Toronto, ON[3]	178.08	1,737.21	17,815.79	57,595.60	160,523.79	399,157.95	1,526,728.08
Vancouver, BC	107.03	1,119.03	11,255.87	33,899.12	92,438.53	224,920.25	1,859,722.96
Winnipeg, MB	84.29	826.31	9,146.15	25,466.90	62,902.00	148,452.00	1,278,750.00
American Cities							
Boston, MA	276.87	2,852.54	27,492.64	77,787.96	211,535.12	480,083.77	4,798,053.91
Chicago, IL[3]	151.92	1,282.88	11,729.48	32,263.46	83,333.09	196,792.14	1,651,153.67
Detroit, MI[3]	202.40	1,491.77	14,773.37	42,189.93	103,136.65	239,572.95	2,330,869.94
Houston, TX[3]	112.53	1,074.99	12,294.85	39,463.27	100,483.50	243,180.66	2,306,468.61
Miami, FL[3]	116.69	1,190.33	13,399.05	37,789.11	100,527.16	238,569.12	2,097,066.41
Nashville, TN[3]	142.81	1,510.64	17,018.08	49,641.23	140,556.79	339,262.82	2,707,857.88
New York, NY[3]	295.22	2,780.54	30,887.92	88,353.30	185,213.17	431,632.98	4,315,105.75
Portland, OR[3]	139.43	1,359.42	14,153.18	41,748.39	106,779.54	259,365.83	2,513,733.42
San Francisco, CA[3]	310.48	2,719.77	32,658.12	86,370.53	173,852.10	417,276.53	4,149,618.26
Seattle, WA	136.17	1,106.39	10,320.18	37,681.16	107,526.55	277,794.35	2,607,258.22
AVERAGE	**154.79**	**1,466.79**	**15,813.64**	**46,788.66**	**120,523.06**	**277,614.41**	**2,334,027.08**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2016

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal. QC	**7.23**	**9.83**	**12.00**	**7.92**	**6.71**	**5.17**	**4.90**
Calgary, AB	10.40	8.19	8.86	6.22	5.19	4.82	4.80
Charlottetown, PE[4]	16.02	16.70	17.66	14.27	13.77	9.12	9.12
Edmonton, AB[5]	10.37	9.87	14.03	9.42	8.63	6.78	4.02
Halifax, NS	15.88	15.21	16.92	12.66	11.33	10.02	10.02
Moncton, NB	12.50	13.17	14.15	11.60	11.23	7.60	7.25
Ottawa, ON	16.15	15.76	15.29	13.22	13.36	12.91	4.52
Regina, SK	14.65	12.40	14.50	10.65	8.89	7.97	6.71
St. John's, NL[6]	11.96	11.03	11.54	8.82	8.29	7.88	4.90
Toronto, ON[4]	17.81	17.37	17.82	14.40	13.72	13.04	4.99
Vancouver, BC	10.70	11.19	11.26	8.47	7.90	7.35	6.08
Winnipeg, MB	8.43	8.26	9.15	6.37	5.38	4.85	4.18
American Cities							
Boston, MA	27.69	28.53	27.49	19.45	18.08	15.69	15.68
Chicago, IL[4]	15.19	12.83	11.73	8.07	7.12	6.43	5.40
Detroit, MI[4]	20.24	14.92	14.77	10.55	8.82	7.83	7.62
Houston, TX[4]	11.25	10.75	12.29	9.87	8.59	7.95	7.54
Miami, FL[4]	11.67	11.90	13.40	9.45	8.59	7.80	6.85
Nashville, TN[4]	14.28	15.11	17.02	12.41	12.01	11.09	8.85
New York, NY[4]	29.52	27.81	30.89	22.09	15.83	14.11	14.10
Portland, OR[4]	13.94	13.59	14.15	10.44	9.13	8.48	8.21
San Francisco, CA[4]	31.05	27.20	32.66	21.59	14.86	13.64	13.56
Seattle, WA	13.62	11.06	10.32	9.42	9.19	9.08	8.52
AVERAGE	**15.48**	**14.67**	**15.81**	**11.70**	**10.30**	**9.07**	**7.63**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2016

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	144	83	74	79	77	93	98
Charlottetown, PE[3]	222	170	147	180	205	176	186
Edmonton, AB[4]	143	100	117	119	129	131	82
Halifax, NS	220	155	141	160	169	194	205
Moncton, NB	173	134	118	146	167	147	148
Ottawa, ON	224	160	127	167	199	249	92
Regina, SK	203	126	121	135	132	154	137
St. John's, NL[5]	166	112	96	111	124	152	100
Toronto, ON[3]	246	177	148	182	204	252	102
Vancouver, BC	148	114	94	107	118	142	124
Winnipeg, MB	117	84	76	80	80	94	85
American Cities							
Boston, MA	383	290	229	246	269	303	320
Chicago, IL[3]	210	130	98	102	106	124	110
Detroit, MI[3]	280	152	123	133	131	151	156
Houston, TX[3]	156	109	102	125	128	154	154
Miami, FL[3]	161	121	112	119	128	151	140
Nashville, TN[3]	198	154	142	157	179	214	181
New York, NY[3]	409	283	257	279	236	273	288
Portland, OR[3]	193	138	118	132	136	164	168
San Francisco, CA[3]	430	277	272	273	221	264	277
Seattle, WA	188	113	86	119	137	175	174
AVERAGE	**214**	**149**	**132**	**148**	**153**	**175**	**156**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
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4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

DETAILED RESULTS

SUMMARY TABLES (INCLUDING TAXES)

Monthly Bills
Average Prices
Comparative Index

MONTHLY BILLS ON APRIL 1, 2016

(in CA$)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal. QC	83.08	1,130.59	13,797.00	36,420.63	90,278.09	182,025.55	1,722,641.68
Calgary, AB	109.19	859.83	9,303.13	26,138.90	63,813.88	154,921.79	1,542,895.51
Charlottetown, PE[3]	182.59	1,903.99	20,130.09	65,063.19	183,708.69	318,117.00	3,181,170.00
Edmonton, AB[4]	108.87	1,036.65	14,731.41	39,557.34	106,031.16	217,803.88	1,292,020.24
Halifax, NS	166.77	1,749.56	19,457.00	58,214.77	152,421.44	352,627.94	3,526,307.00
Moncton, NB	141.23	1,487.81	15,993.62	52,436.12	148,469.17	262,797.57	2,507,108.40
Ottawa, ON	182.51	1,781.21	17,281.55	59,757.53	176,651.20	446,303.84	1,561,549.13
Regina, SK	168.42	1,494.71	17,477.68	51,348.06	125,346.18	293,791.28	2,473,175.98
St. John's, NL[5]	135.20	1,246.55	13,036.84	39,846.38	109,604.64	272,493.73	1,648,507.28
Toronto, ON[3]	201.23	1,963.04	20,131.85	65,083.02	181,391.88	451,048.48	1,725,202.73
Vancouver, BC	114.38	1,253.31	12,606.58	37,967.02	103,531.16	251,910.68	2,082,889.71
Winnipeg, MB	97.46	977.11	10,815.32	30,114.61	70,356.00	166,044.00	1,430,281.00
American Cities							
Boston, MA	276.87	2,989.24	28,795.06	80,986.21	219,890.35	497,363.28	4,970,675.10
Chicago, IL[3]	171.33	1,434.53	13,087.20	37,390.46	97,774.35	232,912.03	1,971,664.50
Detroit, MI[3]	224.67	1,655.86	16,398.44	46,830.82	114,481.68	265,925.98	2,587,265.64
Houston, TX[3]	113.65	1,160.07	13,192.22	42,261.12	108,713.06	263,340.99	2,498,430.62
Miami, FL[3]	133.68	1,460.24	16,467.12	46,163.95	122,584.64	290,254.54	2,529,419.08
Nashville, TN[3]	142.81	1,616.39	18,209.34	53,116.12	150,395.76	363,011.21	2,897,407.93
New York, NY[3]	321.30	3,103.11	34,471.40	98,599.20	206,687.16	481,677.73	4,815,410.53
Portland, OR[3]	141.57	1,380.41	14,372.51	42,391.68	108,451.03	263,435.44	2,553,243.23
San Francisco, CA[3]	310.86	2,927.53	35,145.32	92,999.66	187,333.70	449,730.06	4,472,417.54
Seattle, WA	136.17	1,106.39	10,320.18	37,681.16	107,526.55	277,794.35	2,607,258.22
AVERAGE	**166.54**	**1,623.55**	**17,510.04**	**51,834.91**	**133,429.17**	**307,060.52**	**2,572,588.23**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2016

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	8.31	11.31	13.80	9.11	7.72	5.95	5.63
Calgary, AB	10.92	8.60	9.30	6.53	5.45	5.06	5.04
Charlottetown, PE[4]	18.26	19.04	20.13	16.27	15.70	10.40	10.40
Edmonton, AB[5]	10.89	10.37	14.73	9.89	9.06	7.12	4.22
Halifax, NS	16.68	17.50	19.46	14.55	13.03	11.52	11.52
Moncton, NB	14.12	14.88	15.99	13.11	12.69	8.59	8.19
Ottawa, ON	18.25	17.81	17.28	14.94	15.10	14.59	5.10
Regina, SK	16.84	14.95	17.48	12.84	10.71	9.60	8.08
St. John's, NL[6]	13.52	12.47	13.04	9.96	9.37	8.91	5.39
Toronto, ON[4]	20.12	19.63	20.13	16.27	15.50	14.74	5.64
Vancouver, BC	11.44	12.53	12.61	9.49	8.85	8.23	6.81
Winnipeg, MB	9.75	9.77	10.82	7.53	6.01	5.43	4.67
American Cities							
Boston, MA	27.69	29.89	28.80	20.25	18.79	16.25	16.24
Chicago, IL[4]	17.13	14.35	13.09	9.35	8.36	7.61	6.44
Detroit, MI[4]	22.47	16.56	16.40	11.71	9.78	8.69	8.46
Houston, TX[4]	11.37	11.60	13.19	10.57	9.29	8.61	8.16
Miami, FL[4]	13.37	14.60	16.47	11.54	10.48	9.49	8.27
Nashville, TN[4]	14.28	16.16	18.21	13.28	12.85	11.86	9.47
New York, NY[4]	32.13	31.03	34.47	24.65	17.67	15.74	15.74
Portland, OR[4]	14.16	13.80	14.37	10.60	9.27	8.61	8.34
San Francisco, CA[4]	31.09	29.28	35.15	23.25	16.01	14.70	14.62
Seattle, WA	13.62	11.06	10.32	9.42	9.19	9.08	8.52
AVERAGE	**16.65**	**16.24**	**17.51**	**12.96**	**11.40**	**10.03**	**8.41**

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2) Supply voltage of 25 kV, customer-owned transformer.
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6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2016

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	131	76	67	72	71	85	90
Charlottetown, PE[3]	220	168	146	179	203	175	185
Edmonton, AB[4]	131	92	107	109	117	120	75
Halifax, NS	201	155	141	160	169	194	205
Moncton, NB	170	132	116	144	164	144	146
Ottawa, ON	220	158	125	164	196	245	91
Regina, SK	203	132	127	141	139	161	144
St. John's, NL[5]	163	110	94	109	121	150	96
Toronto, ON[3]	242	174	146	179	201	248	100
Vancouver, BC	138	111	91	104	115	138	121
Winnipeg, MB	117	86	78	83	78	91	83
American Cities							
Boston, MA	333	264	209	222	244	273	289
Chicago, IL[3]	206	127	95	103	108	128	114
Detroit, MI[3]	270	146	119	129	127	146	150
Houston, TX[3]	137	103	96	116	120	145	145
Miami, FL[3]	161	129	119	127	136	159	147
Nashville, TN[3]	172	143	132	146	167	199	168
New York, NY[3]	387	274	250	271	229	265	280
Portland, OR[3]	170	122	104	116	120	145	148
San Francisco, CA[3]	374	259	255	255	208	247	260
Seattle, WA	164	98	75	103	119	153	151
AVERAGE	**200**	**144**	**127**	**142**	**148**	**169**	**149**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

DETAILED RESULTS

RESIDENTIAL

Monthly Bills
Average Prices
Comparative Index

RESIDENTIAL

Monthly Bills on April 1, 2016
(in CA$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	47.88	55.02	72.26	159.06	245.86
Calgary, AB	73.03	83.35	104.00	186.57	269.15
Charlottetown, PE[1]	109.32	126.27	160.17	295.77	403.67
Edmonton, AB	73.13	83.32	103.69	185.17	266.65
Halifax, NS	103.33	121.83	158.83	306.84	454.84
Moncton, NB	85.91	98.93	124.98	229.18	333.38
Ottawa, ON	106.32	124.72	161.52	308.71	455.91
Regina, SK	99.11	114.89	146.45	272.68	398.91
St. John's, NL[2]	80.59	93.61	119.64	223.75	327.87
Toronto, ON[1]	120.20	139.50	178.08	332.43	486.77
Vancouver, BC	60.26	74.40	107.03	237.55	368.06
Winnipeg, MB	55.52	65.11	84.29	161.01	237.73
American Cities					
Boston, MA	176.19	209.78	276.87	545.35	813.83
Chicago, IL[1]	102.23	118.79	151.92	252.79	368.53
Detroit, MI[1]	126.09	151.53	202.40	405.92	609.43
Houston, TX[1]	85.99	99.16	112.53	217.92	323.31
Miami, FL[1]	76.78	90.09	116.69	250.84	384.99
Nashville, TN[1]	95.05	110.97	142.81	270.19	397.57
New York, NY[1]	192.27	226.58	295.22	569.76	844.30
Portland, OR[1]	92.35	108.04	139.43	305.44	471.44
San Francisco, CA[1]	174.53	233.87	310.48	785.25	1,260.01
Seattle, WA	74.67	95.18	136.17	300.17	464.17
AVERAGE	**100.49**	**119.32**	**154.79**	**309.20**	**463.02**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL

Average Prices on April 1, 2016
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	7.66	7.34	7.23	7.95	8.20
Calgary, AB	11.68	11.11	10.40	9.33	8.97
Charlottetown, PE[2]	17.49	16.84	16.02	14.79	13.46
Edmonton, AB	11.70	11.11	10.37	9.26	8.89
Halifax, NS	16.53	16.24	15.88	15.34	15.16
Moncton, NB	13.75	13.19	12.50	11.46	11.11
Ottawa, ON	17.01	16.63	16.15	15.44	15.20
Regina, SK	15.86	15.32	14.65	13.63	13.30
St. John's, NL[3]	12.89	12.48	11.96	11.19	10.93
Toronto, ON[2]	19.23	18.60	17.81	16.62	16.23
Vancouver, BC	9.64	9.92	10.70	11.88	12.27
Winnipeg, MB	8.88	8.68	8.43	8.05	7.92
American Cities					
Boston, MA	28.19	27.97	27.69	27.27	27.13
Chicago, IL[2]	16.36	15.84	15.19	12.64	12.28
Detroit, MI[2]	20.17	20.20	20.24	20.30	20.31
Houston, TX[2]	13.76	13.22	11.25	10.90	10.78
Miami, FL[2]	12.29	12.01	11.67	12.54	12.83
Nashville, TN[2]	15.21	14.80	14.28	13.51	13.25
New York, NY[2]	30.76	30.21	29.52	28.49	28.14
Portland, OR[2]	14.78	14.41	13.94	15.27	15.71
San Francisco, CA[2]	27.92	31.18	31.05	39.26	42.00
Seattle, WA	11.95	12.69	13.62	15.01	15.47
AVERAGE	**16.08**	**15.91**	**15.48**	**15.46**	**15.43**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL

Comparative Index on April 1, 2016
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	153	151	144	117	109
Charlottetown, PE[1]	228	229	222	186	164
Edmonton, AB	153	151	143	116	108
Halifax, NS	216	221	220	193	185
Moncton, NB	179	180	173	144	136
Ottawa, ON	222	227	224	194	185
Regina, SK	207	209	203	171	162
St. John's, NL[2]	168	170	166	141	133
Toronto, ON[1]	251	254	246	209	198
Vancouver, BC	126	135	148	149	150
Winnipeg, MB	116	118	117	101	97
American Cities					
Boston, MA	368	381	383	343	331
Chicago, IL[1]	214	216	210	159	150
Detroit, MI[1]	263	275	280	255	248
Houston, TX[1]	180	180	156	137	132
Miami, FL[1]	160	164	161	158	157
Nashville, TN[1]	199	202	198	170	162
New York, NY[1]	402	412	409	358	343
Portland, OR[1]	193	196	193	192	192
San Francisco, CA[1]	365	425	430	494	512
Seattle, WA	156	173	188	189	189
AVERAGE	**210**	**217**	**214**	**194**	**188**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

DETAILED RESULTS

SMALL POWER

Monthly Bills
Average Prices
Comparative Index

SMALL POWER

Monthly Bills on April 1, 2016
(in CA$)

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	85.16	206.53	983.33	1,806.00	2,669.50
Calgary, AB	98.01	194.84	818.88	1,328.52	1,766.37
Charlottetown, PE[1]	149.37	357.37	1,670.17	2,911.97	4,110.97
Edmonton, AB	87.46	209.05	987.29	1,971.20	2,547.93
Halifax, NS	118.37	288.51	1,521.36	2,683.59	3,803.41
Moncton, NB	117.85	277.35	1,316.65	2,290.65	3,286.15
Ottawa, ON	135.12	329.88	1,576.30	2,584.37	3,781.29
Regina, SK	118.58	270.18	1,240.42	2,384.54	3,238.75
St. John's, NL[2]	99.43	258.40	1,103.14	1,988.72	2,826.97
Toronto, ON[1]	164.02	379.24	1,737.21	2,939.18	4,181.74
Vancouver, BC	95.38	241.86	1,119.03	1,911.99	2,768.55
Winnipeg, MB	80.95	181.67	826.31	1,651.16	2,161.89
American Cities					
Boston, MA	210.92	540.84	2,852.54	5,570.59	7,552.07
Chicago, IL[1]	113.84	261.34	1,282.88	2,104.43	3,093.65
Detroit, MI[1]	123.54	311.18	1,491.77	2,082.06	3,705.37
Houston, TX[1]	91.60	303.36	1,074.99	1,957.02	2,640.04
Miami, FL[1]	97.20	242.35	1,190.33	2,254.08	2,936.21
Nashville, TN[1]	149.80	340.36	1,510.64	3,074.13	4,001.85
New York, NY[1]	238.85	804.07	2,780.54	5,416.47	6,880.82
Portland, OR[1]	127.76	301.83	1,359.42	2,287.05	3,339.16
San Francisco, CA[1]	221.45	569.11	2,719.77	4,549.99	6,529.37
Seattle, WA	82.98	221.28	1,106.39	1,535.63	2,504.37
AVERAGE	**127.62**	**322.30**	**1,466.79**	**2,603.79**	**3,651.20**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL POWER

Average Prices on April 1, 2016
(in ¢/kWh)[1]

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	11.35	10.33	9.83	12.90	10.68
Calgary, AB	13.07	9.74	8.19	9.49	7.07
Charlottetown, PE[2]	19.92	17.87	16.70	20.80	16.44
Edmonton, AB	11.66	10.45	9.87	14.08	10.19
Halifax, NS	15.78	14.43	15.21	19.17	15.21
Moncton, NB	15.71	13.87	13.17	16.36	13.14
Ottawa, ON	18.02	16.49	15.76	18.46	15.13
Regina, SK	15.81	13.51	12.40	17.03	12.95
St. John's, NL[3]	13.26	12.92	11.03	14.21	11.31
Toronto, ON[2]	21.87	18.96	17.37	20.99	16.73
Vancouver, BC	12.72	12.09	11.19	13.66	11.07
Winnipeg, MB	10.79	9.08	8.26	11.79	8.65
American Cities					
Boston, MA	28.12	27.04	28.53	39.79	30.21
Chicago, IL[2]	15.18	13.07	12.83	15.03	12.37
Detroit, MI[2]	16.47	15.56	14.92	14.87	14.82
Houston, TX[2]	12.21	15.17	10.75	13.98	10.56
Miami, FL[2]	12.96	12.12	11.90	16.10	11.74
Nashville, TN[2]	19.97	17.02	15.11	21.96	16.01
New York, NY[2]	31.85	40.20	27.81	38.69	27.52
Portland, OR[2]	17.03	15.09	13.59	16.34	13.36
San Francisco, CA[2]	29.53	28.46	27.20	32.50	26.12
Seattle, WA	11.06	11.06	11.06	10.97	10.02
AVERAGE	**17.02**	**16.11**	**14.67**	**18.60**	**14.60**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL POWER

Comparative Index on April 1, 2016
(Hydro-Québec = 100)

Power demand **Consumption** **Load factor**	**6 kW** **750 kWh** **17%**	**14 kW** **2,000 kWh** **20%**	**40 kW** **10,000 kWh** **35%**	**100 kW** **14,000 kWh** **19%**	**100 kW** **25,000 kWh** **35%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	115	94	83	74	66
Charlottetown, PE[1]	175	173	170	161	154
Edmonton, AB	103	101	100	109	95
Halifax, NS	139	140	155	149	142
Moncton, NB	138	134	134	127	123
Ottawa, ON	159	160	160	143	142
Regina, SK	139	131	126	132	121
St. John's, NL[2]	117	125	112	110	106
Toronto, ON[1]	193	184	177	163	157
Vancouver, BC	112	117	114	106	104
Winnipeg, MB	95	88	84	91	81
American Cities					
Boston, MA	248	262	290	308	283
Chicago, IL[1]	134	127	130	117	116
Detroit, MI[1]	145	151	152	115	139
Houston, TX[1]	108	147	109	108	99
Miami, FL[1]	114	117	121	125	110
Nashville, TN[1]	176	165	154	170	150
New York, NY[1]	280	389	283	300	258
Portland, OR[1]	150	146	138	127	125
San Francisco, CA[1]	260	276	277	252	245
Seattle, WA	97	107	113	85	94
AVERAGE	**150**	**156**	**149**	**144**	**137**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

05

DETAILED RESULTS

MEDIUM POWER

Monthly Bills
Average Prices
Comparative Index

MEDIUM POWER

Monthly Bills on April 1, 2016
(in CA$)

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	12,000.00	17,045.00	24,000.00	31,677.00	78,519.75
Calgary, AB	8,860.12	12,722.98	17,168.47	24,894.19	60,775.12
Charlottetown, PE[2]	17,657.97	28,557.97	35,272.97	57,072.97	161,147.97
Edmonton, AB[3]	14,029.91	19,893.61	25,946.26	37,673.66	100,982.06
Halifax, NS	16,919.13	25,310.77	33,838.27	50,621.54	132,540.38
Moncton, NB	14,153.65	23,203.65	28,303.65	46,403.65	131,388.65
Ottawa, ON	15,293.41	26,541.51	30,386.56	52,882.77	156,328.50
Regina, SK	14,504.30	21,313.30	28,994.50	42,612.50	104,021.73
St. John's, NL[4]	11,537.03	18,713.74	21,391.51	35,262.28	96,995.26
Toronto, ON[2]	17,815.79	29,111.76	35,215.57	57,595.60	160,523.79
Vancouver, BC	11,255.87	16,883.87	22,643.12	33,899.12	92,438.53
Winnipeg, MB	9,146.15	12,838.15	18,082.90	25,466.90	62,902.00
American Cities					
Boston, MA	27,492.64	39,002.70	54,767.84	77,787.96	211,535.12
Chicago, IL[2]	11,729.48	16,181.06	23,696.16	32,263.46	83,333.09
Detroit, MI[2]	14,773.37	21,302.43	29,530.70	42,189.93	103,136.65
Houston, TX[2]	12,294.85	18,462.55	27,127.85	39,463.27	100,483.50
Miami, FL[2]	13,399.05	18,934.89	26,717.42	37,789.11	100,527.16
Nashville, TN[2]	17,018.08	24,946.74	33,783.91	49,641.23	140,556.79
New York, NY[2]	30,887.92	44,200.16	61,728.81	88,353.30	185,213.17
Portland, OR[2]	14,153.18	21,804.60	27,076.02	41,748.39	106,779.54
San Francisco, CA[2]	32,658.12	45,664.58	62,329.74	86,370.53	173,852.10
Seattle, WA	10,320.18	19,126.90	20,197.47	37,681.16	107,526.55
AVERAGE	**15,813.64**	**23,716.50**	**31,281.80**	**46,788.66**	**120,523.06**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM POWER

Average Prices on April 1, 2016
(in ¢/kWh)[1]

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[2] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	12.00	8.52	12.00	7.92	6.71
Calgary, AB	8.86	6.36	8.58	6.22	5.19
Charlottetown, PE[3]	17.66	14.28	17.64	14.27	13.77
Edmonton, AB[4]	14.03	9.95	12.97	9.42	8.63
Halifax, NS	16.92	12.66	16.92	12.66	11.33
Moncton, NB	14.15	11.60	14.15	11.60	11.23
Ottawa, ON	15.29	13.27	15.19	13.22	13.36
Regina, SK	14.50	10.66	14.50	10.65	8.89
St. John's, NL[5]	11.54	9.36	10.70	8.82	8.29
Toronto, ON[3]	17.82	14.56	17.61	14.40	13.72
Vancouver, BC	11.26	8.44	11.32	8.47	7.90
Winnipeg, MB	9.15	6.42	9.04	6.37	5.38
American Cities					
Boston, MA	27.49	19.50	27.38	19.45	18.08
Chicago, IL[3]	11.73	8.09	11.85	8.07	7.12
Detroit, MI[3]	14.77	10.65	14.77	10.55	8.82
Houston, TX[3]	12.29	9.23	13.56	9.87	8.59
Miami, FL[3]	13.40	9.47	13.36	9.45	8.59
Nashville, TN[3]	17.02	12.47	16.89	12.41	12.01
New York, NY[3]	30.89	22.10	30.86	22.09	15.83
Portland, OR[3]	14.15	10.90	13.54	10.44	9.13
San Francisco, CA[3]	32.66	22.83	31.16	21.59	14.86
Seattle, WA	10.32	9.56	10.10	9.42	9.19
AVERAGE	**15.81**	**11.86**	**15.64**	**11.70**	**10.30**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM POWER

Comparative Index on April 1, 2016
(Hydro-Québec = 100)

Power demand **Consumption** **Load factor**	**500 kW** **100,000 kWh** **28%**	**500 kW** **200,000 kWh** **56%**	**1,000 kW** **200,000 kWh** **28%**	**1,000 kW** **400,000 kWh** **56%**	**2,500 kW**[1] **1,170,000 kWh** **65%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	74	75	72	79	77
Charlottetown, PE[2]	147	168	147	180	205
Edmonton, AB[3]	117	117	108	119	129
Halifax, NS	141	148	141	160	169
Moncton, NB	118	136	118	146	167
Ottawa, ON	127	156	127	167	199
Regina, SK	121	125	121	135	132
St. John's, NL[4]	96	110	89	111	124
Toronto, ON[2]	148	171	147	182	204
Vancouver, BC	94	99	94	107	118
Winnipeg, MB	76	75	75	80	80
American Cities					
Boston, MA	229	229	228	246	269
Chicago, IL[2]	98	95	99	102	106
Detroit, MI[2]	123	125	123	133	131
Houston, TX[2]	102	108	113	125	128
Miami, FL[2]	112	111	111	119	128
Nashville, TN[2]	142	146	141	157	179
New York, NY[2]	257	259	257	279	236
Portland, OR[2]	118	128	113	132	136
San Francisco, CA[2]	272	268	260	273	221
Seattle, WA	86	112	84	119	137
AVERAGE	**132**	**139**	**130**	**148**	**153**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

06

DETAILED RESULTS

LARGE POWER

Monthly Bills
Average Prices
Comparative Index

LARGE POWER

Monthly Bills on April 1, 2016
(in CA$)

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[1]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	134,845.50	158,317.50	287,919.00	871,581.00	1,263,555.00	1,498,275.00
Calgary, AB	119,369.64	147,544.56	280,331.48	849,050.87	1,187,675.02	1,469,424.30
Charlottetown, PE[2]	230,450.00	279,050.00	533,800.00	1,617,600.00	2,304,500.00	2,790,500.00
Edmonton, AB[3]	173,954.46	207,432.27	244,071.33	726,780.22	1,093,191.66	1,230,495.47
Halifax, NS	249,338.10	306,632.99	584,618.54	1,772,965.90	2,493,404.95	3,066,353.91
Moncton, NB	195,804.98	232,564.22	425,628.00	1,288,956.00	1,856,520.00	2,218,680.00
Ottawa, ON	313,994.31	394,959.15	558,558.24	955,926.67	1,225,864.91	1,381,901.88
Regina, SK	199,717.39	243,810.19	396,372.70	1,188,621.85	1,662,116.20	2,052,428.20
St. John's, NL[4]	191,210.12	241,144.89	451,284.22	867,180.00	1,226,350.00	1,498,150.00
Toronto, ON[2]	320,081.69	399,157.95	579,325.46	1,040,454.58	1,389,576.86	1,526,728.08
Vancouver, BC	185,006.48	224,920.25	355,026.26	1,076,363.55	1,521,420.52	1,859,722.96
Winnipeg, MB	123,454.00	148,452.00	244,487.00	740,973.00	1,053,534.00	1,278,750.00
American Cities						
Boston, MA	399,644.31	480,083.77	919,638.50	2,785,110.04	3,993,659.39	4,798,053.91
Chicago, IL[2]	165,949.85	196,792.14	336,831.49	955,186.13	1,342,730.72	1,651,153.67
Detroit, MI[2]	205,727.89	239,572.95	450,040.05	1,360,076.18	1,999,464.66	2,330,869.94
Houston, TX[2]	198,384.26	243,180.66	440,937.20	1,333,317.22	1,865,897.51	2,306,468.61
Miami, FL[2]	200,768.31	238,569.12	404,355.94	1,220,004.28	1,762,082.08	2,097,066.41
Nashville, TN[2]	282,758.87	339,262.82	544,031.20	1,581,347.02	2,325,622.53	2,707,857.88
New York, NY[2]	370,290.34	431,632.98	832,458.63	2,517,551.44	3,701,679.39	4,315,105.75
Portland, OR[2]	212,113.87	259,365.83	483,060.78	1,458,195.95	2,075,175.42	2,513,733.42
San Francisco, CA[2]	344,369.06	417,276.53	795,527.43	2,405,741.00	3,420,543.59	4,149,618.26
Seattle, WA	215,184.76	277,794.35	492,670.01	1,496,862.79	2,020,825.17	2,607,258.22
AVERAGE	**228,746.28**	**277,614.41**	**483,680.61**	**1,368,629.35**	**1,944,790.44**	**2,334,027.08**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Average Prices on April 1, 2016
(in ¢/kWh)[1]

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[2]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	5.76	5.17	5.00	4.97	5.40	4.90
Calgary, AB	5.10	4.82	4.87	4.85	5.08	4.80
Charlottetown, PE[3]	9.85	9.12	9.27	9.23	9.85	9.12
Edmonton, AB[4]	7.43	6.78	4.24	4.15	4.67	4.02
Halifax, NS	10.66	10.02	10.15	10.12	10.66	10.02
Moncton, NB	8.37	7.60	7.39	7.36	7.93	7.25
Ottawa, ON	13.42	12.91	9.70	5.46	5.24	4.52
Regina, SK	8.53	7.97	6.88	6.78	7.10	6.71
St. John's, NL[5]	8.17	7.88	7.83	4.95	5.24	4.90
Toronto, ON[3]	13.68	13.04	10.06	5.94	5.94	4.99
Vancouver, BC	7.91	7.35	6.16	6.14	6.50	6.08
Winnipeg, MB	5.28	4.85	4.24	4.23	4.50	4.18
American Cities						
Boston, MA	17.08	15.69	15.97	15.90	17.07	15.68
Chicago, IL[3]	7.09	6.43	5.85	5.45	5.74	5.40
Detroit, MI[3]	8.79	7.83	7.81	7.76	8.54	7.62
Houston, TX[3]	8.48	7.95	7.66	7.61	7.97	7.54
Miami, FL[3]	8.58	7.80	7.02	6.96	7.53	6.85
Nashville, TN[3]	12.08	11.09	9.44	9.03	9.94	8.85
New York, NY[3]	15.82	14.11	14.45	14.37	15.82	14.10
Portland, OR[3]	9.06	8.48	8.39	8.32	8.87	8.21
San Francisco, CA[3]	14.72	13.64	13.81	13.73	14.62	13.56
Seattle, WA	9.20	9.08	8.55	8.54	8.64	8.52
AVERAGE	**9.78**	**9.07**	**8.40**	**7.81**	**8.31**	**7.63**

1) In Canadian currency.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Comparative Index on April 1, 2016
(Hydro-Québec = 100)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	89	93	97	97	94	98
Charlottetown, PE[2]	171	176	185	186	182	186
Edmonton, AB[3]	129	131	85	83	87	82
Halifax, NS	185	194	203	203	197	205
Moncton, NB	145	147	148	148	147	148
Ottawa, ON	233	249	194	110	97	92
Regina, SK	148	154	138	136	132	137
St. John's, NL[4]	142	152	157	99	97	100
Toronto, ON[2]	237	252	201	119	110	102
Vancouver, BC	137	142	123	123	120	124
Winnipeg, MB	92	94	85	85	83	85
American Cities						
Boston, MA	296	303	319	320	316	320
Chicago, IL[2]	123	124	117	110	106	110
Detroit, MI[2]	153	151	156	156	158	156
Houston, TX[2]	147	154	153	153	148	154
Miami, FL[2]	149	151	140	140	139	140
Nashville, TN[2]	210	214	189	181	184	181
New York, NY[2]	275	273	289	289	293	288
Portland, OR[2]	157	164	168	167	164	168
San Francisco, CA[2]	255	264	276	276	271	277
Seattle, WA	160	175	171	172	160	174
AVERAGE	**170**	**175**	**168**	**157**	**154**	**156**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

APPENDIX

RATE ADJUSTMENTS

Average Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

All Categories

	Before April 2015		Between April 1, 2015 and April 1, 2016	
	Year	%	Date	%
Canadian Utilities				
Hydro-Québec, QC	2015	2.8	April 1, 2016	0.6
ENMAX, AB	2015	3.1	April 1, 2016	n.a.
Maritime Electric, PE	2015	2.2	March 1, 2016	2.3
EPCOR, AB	2015	n.a.	January 1, 2016	n.a.
Nova Scotia Power, NS	2015	0.0	January 1, 2016	-1.0
NB Power, NB	2014	2.0	October 1, 2015	1.63
Hydro Ottawa, ON	2015	n.a.	January 1, 2016	5.8
SaskPower, SK	2015	3.0	September 1, 2015	2.0
Newfoundland Power, NL[1]	2014	2.0	July 1, 2015	-5.25
Newfoundland and Labrador Hydro, NL[1]	—	—	July 1, 2015	2.7
Toronto Hydro, ON	2014	n.a.	March 1, 2016	n.a.
BC Hydro, BC	2015	6.0	April 1, 2016	4.0
Manitoba Hydro, MB	2014	2.8	August 1, 2015	3.95

Data concerning American utilities not available.

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2015, and April 1, 2016)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2016	0.7	0.7[1] 0.6[2] 0.7[3]	—	0.6
ENMAX, AB	April 1, 2016	n.a.	n.a.	n.a.	n.a.
Maritime Electric, PE	March 1, 2016	2.3	2.3	2.3	2.3
EPCOR, AB	January 1, 2016	n.a.	n.a.	n.a.	n.a.
Nova Scotia Power, NS	January 1, 2016	-0.9	-2.2[1] -1.3[2] — [3]	-1.8[4] — [5] — [6]	-1.0
NB Power, NB	October 1, 2015	1.63	1.63	1.63	1.63
Hydro Ottawa, ON	January 1, 2016	5.7	10.6	1.2	5.8
SaskPower, SK	September 1, 2015	1.8	2.2	2.3	2.0
Newfoundland Power, NL[7]	July 1, 2015	-4.88	-6.28	-8.15	-5.25
Newfoundland and Labrador Hydro, NL[7]	July 1, 2015	n.a.	n.a.	2.7	n.a.
Toronto Hydro, ON	March 1, 2016	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2016	4.0	4.0	4.0	4.0
Manitoba Hydro, MB	August 1, 2015	3.95	3.94	3.96	3.95

Data concerning American utilities not available.

n.a.: Not available.

1) Small power.
2) Medium power.
3) Large power.
4) Small industrial.
5) Medium industrial.
6) Large industrial.
7) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

APPENDIX

TIME-OF-USE RATES ADJUSTMENT CLAUSES

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2016 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	14–10,000 kW
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	Residential General: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Advanced Metering System Surcharge Distribution Cost Recovery Factor Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge Remand of Energy Efficiency Cost Recovery Factor Surcharge System Benefit Fund Charge Transition Charges Transmission Cost Recovery Factor
Commonwealth Edison, IL	Capacity Charge Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund Energy Efficiency and Demand Response Adjustments Environmental Cost Recovery Adjustment Hourly Purchased Electricity Adjustment Factor Miscellaneous Procurement Components Charge PJM Services Charges Purchased Electricity Adjustment Factor Purchased Electricity Charges Renewable Energy Resources and Coal Technology Development Assistance Charge Residential Real Time Pricing Program Cost Recovery Charges Uncollectible Cost Factors
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Billing and Payment Processing Delivery Revenue Surcharge Market Supply Charge Merchant Function Charge Monthly Adjustment Clause Renewable Portfolio Standard Program Revenue Decoupling Mechanism Adjustment Surcharge to Collect Assessments under Section 18-a of the Public Service Law System Benefits Charge Temporary Rate Adjustment
DTE Electric, MI	Energy Optimization Surcharge Low Income Energy Assistance Fund Factor Nuclear Surcharge Power Supply Cost Recovery Clause Renewable Energy Plan Surcharge Securitization Bond Charge and Securitization Bond Tax Charge Transitional Recovery Mechanism Vulnerable Household Warmth Fund/Low Income Energy Efficiency Fund Refund

ENMAX, AB	Balancing Pool Allocation Refund Rider Local Access Fee Transmission Access Charge Deferral Account Rider
EPCOR, AB	Balancing Pool Rider Local Access Fee Transmission Charge Deferral Account True-Up Rider
Eversource Energy, MA	Attorney General Consultant Expenses Provision Default Service Adjustment Demand-Side Management Charge Energy Conservation Charge Energy Efficiency Reconciliation Factor Long Term Renewable Contract Adjustment Net Metering Recovery Surcharge Pension Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Smart Grid Adjustment Factor Storm Cost Recovery Adjustment Transition Cost Adjustment Transmission Service Cost Adjustment
Florida Power and Light, FL	Energy Conservation Cost Recovery Clause Capacity Payment Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Bond Repayment Charge and Storm Bond Tax Charge
Hydro Ottawa, ON	Debt Retirement Charge Disposition of Deferral/Variance Accounts (2016) Disposition of Global Adjustment Account (2016) Lost Revenue Adjustment Mechanism Ontario Electricity Support Program Charge Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	TVA Fuel Cost Adjustment
Newfoundland and Labrador Hydro, NL	Municipal Tax Adjustment Rate Stabilization Adjustment
Nova Scotia Power, NS	Base Cost of Fuel Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	California Climate Credit Competition Transition Charges DWR Bond Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments

Pacific Power and Light, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning Conservation Act Energy Conservation Charge Adjustment to Remove Deer Creek Mine Investment from Rate Base Deer Creek Mine Undepreciated Investment Adjustment Generation Investment Adjustment Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Klamath Dam Removal Surcharges Low Income Bill Payment Assistance Fund Oregon Solar Incentive Program Deferral Property Sales Balancing Account Adjustment Public Purpose Charge Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral TAM Adjustment for Other Revenues
Toronto Hydro, ON	Application of IFRS – 2014 Derecognition Application of Operations Center Consolidation Plan Sharing Debt Retirement Charge Disposition of PILS and Tax Variance Disposition of PILS and Tax Variance – HST Disposition of LRAM Variance Account Disposition of Post Employment Benefit – Tax Savings Disposition of Residual Regulatory Asset Recovery Account Ontario Electricity Support Program Charge Recovery of 2008-2010 Smart Meter Costs Recovery of Foregone Revenue Recovery of Hydro One Capital Contributions Variance Recovery of Incremental Capital Module Costs Recovery of Incremental Smart Meter Revenue Requirement Recovery of Low Voltage Variance Recovery of Stranded Meter Assets Recovery of the Gain on the Sale of Named Properties Recovery of 2015 Foregone Revenue Recovery of 2016 Foregone Revenue Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge


C
APPENDIX
APPLICABLE TAXES
Residential Sector
General Sector
Industrial Sector

TAXES APPLICABLE TO RESIDENTIAL SERVICE

On April 1, 2016

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	13	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	5.1073	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.15	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL SERVICE

On April 1, 2016

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	13	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	5	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (companies other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	7	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL SERVICE (cont'd)

On April 1, 2016

	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.5642	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.15	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL SERVICE

On April 1, 2016

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	14	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	13	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	5	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	13	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (companies other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	3	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	7	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL SERVICE (cont'd)

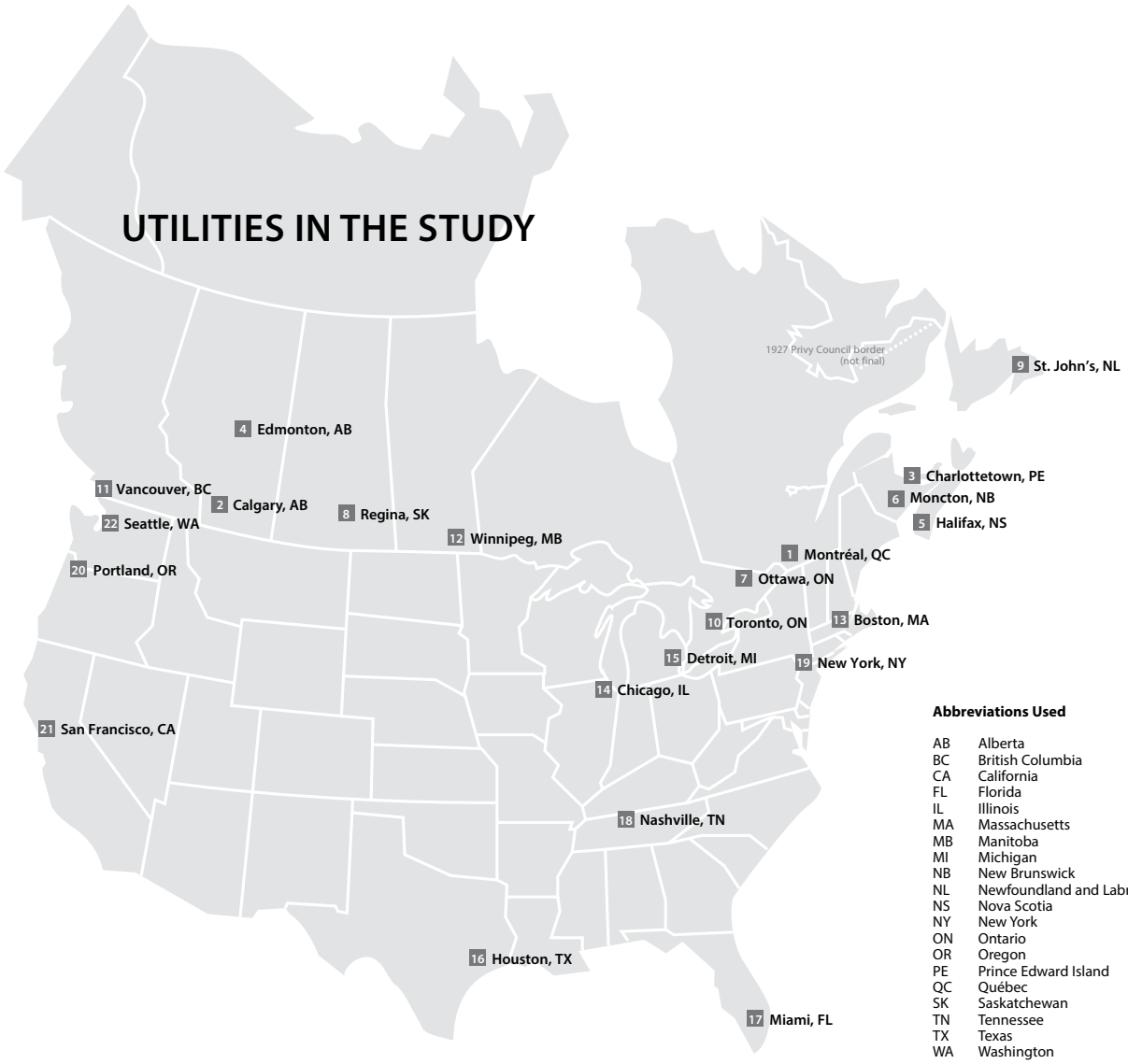
On April 1, 2016

	Tax	% (or other)	Applicable
Nashville, TN	State sales tax	7	To base amount of bill (companies other than manufacturing)
	State sales tax	1.5	To base amount of bill (manufacturing companies)
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.5642	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.15	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	7.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

APPENDIX

UTILITIES IN THE STUDY

UTILITIES IN THE STUDY



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro
(customers with a power demand of 30,000 kW or more)
Newfoundland Power
(all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

A government-owned company whose lines of business have been unbundled, Hydro-Québec is one of the largest electric utilities in North America, with an installed capacity of 36,912 MW; 99% of electricity is generated using waterpower. Its transmission and distribution activities are regulated. The utility distributes electricity to more than 4.2 million residential, commercial, institutional and industrial customer accounts throughout Québec and delivers electricity to nine municipal systems and one regional cooperative. Hydro-Québec also does business with many electric utilities in the Northeastern United States, Ontario and New Brunswick.

The *Act respecting the Régie de l'énergie* (Québec energy board) established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution. The division also purchases electricity on the market, primarily through calls for tenders. The average supply cost of heritage pool electricity, set at a fixed price of 2.79¢/kWh since 1998, is indexed on January 1 since 2014 at a rate corresponding to the annual variation in the all-item consumer price index for Québec, with the exception of the large-power industrial rate (Rate L), which is exempt from the indexation of heritage pool electricity.

The Régie de l'énergie approved an average increase of 0.7% in the rates of Hydro-Québec Distribution, effective April 1, 2016, with the exception of Rate L, which remains the same.

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

A subsidiary of Fortis Inc., Maritime Electric is the principal supplier of electricity on Prince Edward Island, with about 78,000 customers. Since its two power plants (with a total capacity of 150 MW) are operated strictly for reserve purposes, it purchases most of its electricity from NB Power, with which it has long-term contracts, and through additional short-term contracts on the New England wholesale market. Maritime Electric also purchases nearly 52 MW of wind-generated electricity from private producers.

Since the adoption of the *Electric Power Act* on January 1, 2004, Maritime Electric has had to submit all requests for rate increases to the Island Regulatory and Appeals Commission (IRAC). The IRAC has approved a 2.3% annual rate increase for each of the next three years.

ENMAX
EPCOR
Calgary, Alberta
Edmonton, Alberta

ENMAX Corporation is a wholly owned subsidiary of the City of Calgary. It generates, transmits and distributes electricity to nearly 835,000 customers throughout the province. In addition to its active participation in Alberta's restructured electricity industry, ENMAX serves customers who are eligible for the City of Calgary's regulated rate option tariff.

EPCOR Utilities, whose sole shareholder is the City of Edmonton, transmits and distributes electricity to nearly 369,000 residential and business customers in Edmonton. It also supplies more than 600,000 customers throughout the province who are eligible for both rate regulated and contract electricity services.

Since July 1, 2010, prices under the regulated rate option tariff have fluctuated monthly with market forecasts, so customers' electricity bills have varied more.

NOVA SCOTIA POWER
Halifax, Nova Scotia

Nova Scotia Power, a subsidiary of Emera, is the principal supplier of electricity in Nova Scotia, meeting most of the province's needs for electricity generation, transmission and distribution. It supplies electricity to 500,000 customers. Its generating facilities have an installed capacity in excess of 2,400 MW.

The open access transmission tariff came into effect on November 1, 2005. Under the province's energy policy, eligible customers have nondiscriminatory access to the utility's transmission system.

NB POWER
Moncton, New Brunswick

A subsidiary of provincial Crown corporation NB Power Group, NB Power Distribution and Customer Service Corporation directly serves more than 349,000 customers and sells electricity to the province's municipal systems, which together supply nearly 42,000 customers. NB Power has a generating capacity of about 3,500 MW under the management of NB Power Generation and NB Power Nuclear.

The New Brunswick electricity market has been partially open to competition since October 1, 2004. Large industrial customers and three municipal electricity distribution utilities are free to choose their supplier. Other retail market customers continue to be served by NB Power.

SASKPOWER
Regina, Saskatchewan

Crown utility SaskPower serves nearly 522,000 customers and sells wholesale electricity to municipal systems in Saskatchewan. The utility operates 17 power plants and also buys power from third parties, such that its total available generating capacity exceeds 4,400 MW.

In Saskatchewan, the wholesale electricity market has been open to competition since 2001.

NEWFOUNDLAND AND LABRADOR HYDRO
(customers with a power demand of 30,000 kW or more)

NEWFOUNDLAND POWER (all other customer categories)
St. John's, Newfoundland and Labrador

Newfoundland Power, a subsidiary of Fortis Inc., serves about 259,000 customers on the island of Newfoundland. Since it operates only small generating stations with a total installed capacity of nearly 140 MW, it purchases 90% of its electricity from Newfoundland and Labrador Hydro (NLH), a subsidiary of Nalcor Energy that operates generating facilities with an installed capacity of 1,626 MW and a transmission system that serves the whole province. NLH also supplies remote regions, Labrador and large industrial customers. Aside from Newfoundland and Labrador Hydro, Nalcor Energy operates generating facilities with an installed capacity in excess of 5,600 MW.

TORONTO HYDRO
HYDRO OTTAWA
Toronto, Ontario
Ottawa, Ontario

A subsidiary of Hydro Ottawa Holding, whose sole shareholder is the City of Ottawa, Hydro Ottawa serves more than 315,000 customers. Toronto Hydro-Electric System is a subsidiary of city-owned Toronto Hydro Corporation and serves about 740,000 customers, or 18% of Ontario electricity consumers.

In Ontario, the wholesale and retail markets have been open to competition since May 2002. Electricity generation is the responsibility of Ontario Power Generation, while transmission service is supplied by Hydro One.

Following the adoption of the *Electricity Restructuring Act* in December 2004, the Ontario Energy Board was given the mandate to regulate the supply of electricity and has produced a plan in this regard (Regulated Price Plan or RPP). Prices have been reviewed on May 1 each year since 2006 and adjusted six months later, if necessary. With advanced metering, the vast majority of residential customers are now billed according to a time-of-use rate.

BC HYDRO
Vancouver, British Columbia

BC Hydro, a provincial Crown corporation, operates generating facilities with a total capacity of more than 12,000 MW. About 90% of electricity is generated using waterpower. The utility distributes electricity to about 1.9 million customers.

The wholesale market in British Columbia is open to competition, as is the retail market for some large industrial companies. When the market was opened up, generation, transmission and distribution were made into separate entities. The *Clean Energy Act* grouped transmission and distribution in July 2010 to ensure coordinated supply planning for the province. In November 2013, the government published a 10-year plan which provides for upgrading aging infrastructure, implementing new generation projects to meet growing demand and minimizing the impact of these activities on electricity rates.

AMERICAN UTILITIES

MANITOBA HYDRO
Winnipeg, Manitoba

Manitoba Hydro is a Crown utility serving nearly 562,000 customers throughout the province. Virtually all the electricity it generates and distributes comes from its 15 hydropower plants, which have a total capacity of 5,700 MW.

The wholesale electricity market has been open to competition since 1997 and Manitoba Hydro joined Midwest ISO, a regional transmission organization, in 2001.

EVERSOURCE ENERGY
Boston, Massachusetts

Eversource, a merger between NSTAR Electric & Gas and Northeast Utilities, serves 3.1 million residential, commercial and industrial customers in the states of Massachusetts, Connecticut and New Hampshire. The utility purchases electricity on the market and concentrates on transmission and distribution.

Since March 1, 2005, the basic service rates are applied to customers who have chosen not to purchase electricity from a competitor. These rates are adjusted every six months, or every three months in the case of large industrial customers. The rates reflect the average market price of electricity.

COMMONWEALTH EDISON (ComEd)
Chicago, Illinois

ComEd, a subsidiary of Exelon Corporation, purchases, transmits and distributes electricity on the wholesale and retail markets. On the retail market, it serves more than 3.8 million customers in northern Illinois, or about 70% of the state's population.

Since May 1, 2002, the retail market has been fully open for residential, commercial and industrial customers. However, it is only since 2011 that residential customers have actually exercised their right to choose distributors other than the two companies that were in place when deregulation was implemented: ComEd and Ameren.

DTE ELECTRIC
Detroit, Michigan

DTE Electric operates generating facilities with a total installed capacity of nearly 11,100 MW. A subsidiary of DTE Energy, it serves 2.1 million customers in southeastern Michigan.

Under the June 2000 legislation that restructured the electricity industry, all retail market customers in Michigan have been able to choose their electricity supplier since January 1, 2002.

CENTERPOINT ENERGY
Houston, Texas

CenterPoint Energy concentrates on electricity transmission and distribution and delivering natural gas. It sells electricity to about 2.3 million customers in the Houston area.

The majority of Texas consumers have had access to an open retail market since January 1, 2002. As of January 2007, electricity distributors with effective monopolies are no longer obliged to maintain their rates above the "price to beat" designed to encourage new market entrants. Customers who have opted to continue doing business with the same distributor pay a monthly rate that varies according to the market price.

FLORIDA POWER AND LIGHT (FPL)
Miami, Florida

FPL's vast transmission and distribution system supplies more than 4.8 million customers. A subsidiary of NextEra Energy, the utility operates generating facilities with an installed capacity of 25,000 MW.

On April 1, 2010, FPL released its 2010–2019 strategic plan, in which it proposes to upgrade some of its nuclear plants and add new generating facilities using thermal and renewable energy. It will also rely on energy efficiency measures to meet the demand for power during the strategic plan time frame. In April 2016, FPL submitted its Ten Year Power Plant Site Plan for the years 2016–2025 in which it maintains its commitment to modernize its generating stations.

NASHVILLE ELECTRIC SERVICE
Nashville, Tennessee

Nashville Electric Service, whose sole shareholder is the City of Nashville, distributes the electricity that it purchases from the Tennessee Valley Authority (TVA) to more than 370,000 customers. A federal agency, the TVA supplies 155 distributors and nearly 60 large industrial and federal customers.

Close to 40% of the electricity produced by the TVA comes from its 10 coal-fired plants, with the rest from gas, nuclear and hydro plants. The TVA has also included renewables, including solar, wind and biomass, into its generation portfolio.

CONSOLIDATED EDISON (ConEd)
New York, New York

ConEd of New York delivers electricity to 3.3 million customers and natural gas to about 1.1 million customers in and around New York City and Westchester County. This ConEd subsidiary operates the largest underground system in the world, which represents 72% of its distribution system.

When the electricity market was opened to competition in 1998, ConEd had to dispose of a large part of its generating capacity, which is now limited to about 700 MW. Rates, which continue to be regulated by the New York State Public Service Commission, are adjusted monthly to reflect the market price of electricity.

PACIFIC POWER AND LIGHT
Portland, Oregon

Pacific Power and Light, a subsidiary of PacifiCorp, serves about 740,000 customers across three states, including more than 567,000 in Oregon. PacifiCorp operates generating facilities with an installed capacity of about 10,900 MW.

On March 1, 2002, the Oregon state government opened its retail market to competition for large commercial and industrial customers. Residential and small commercial customers have fewer suppliers to choose from, but they do have a range of options, including market-based rates, regulated rates or rates applicable to green energy.

PACIFIC GAS AND ELECTRIC (PG&E)
San Francisco, California

Pacific Gas and Electric concentrates on the transmission and distribution of electricity and natural gas. A subsidiary of PG&E Corporation, it has 5.1 million electric customer accounts.

In 2001, California adopted emergency measures to mitigate the price volatility that followed the opening of the electricity market. Those measures allowed it to reinstate regulatory authority over production costs and to give responsibility for electricity purchases to the California Department of Water and Resources. Since January 1, 2003, PG&E has been authorized to again purchase energy and directly supply its customers.

SEATTLE CITY LIGHT

Seattle, Washington

Seattle City Light, whose shareholder is the City of Seattle, serves about 415,000 customers in the city of Seattle and certain surrounding communities. It produces nearly 50% of the electricity it needs and purchases the rest from the Bonneville Power Administration (BPA), a northwestern U.S. federal agency that wholesales electricity produced by some 30 hydropower stations.

Six electric utilities in the Pacific Northwestern states, including Seattle City Light and BPA, got together in early 2006 to form the nonprofit ColumbiaGrid. The group's objective is to develop an integrated approach to the use and expansion of the region's interconnected transmission system.

Sources:
Annual reports and Web sites of the Canadian and American utilities in the study.





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2017

Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2017

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Hydro Ottawa Limited
EB-2019-0261
Interrogatory Response
IRR SEC-3
Attachment B
ORIGINAL

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INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2017. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third section presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1] (IN ¢/kWh)[2]



1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2017.
2) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1] (IN ¢/kWh)[2]



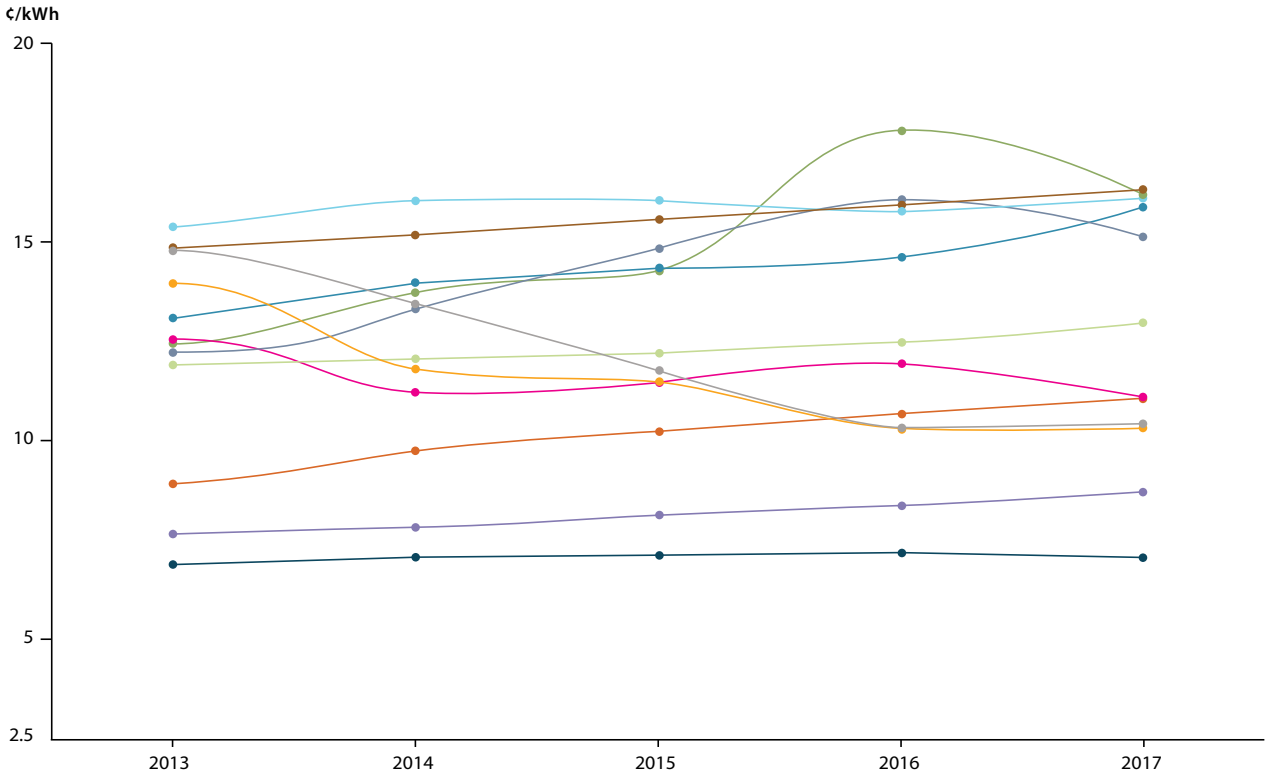
1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2017.
2) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh) – 2013 TO 2017[1,2,3]



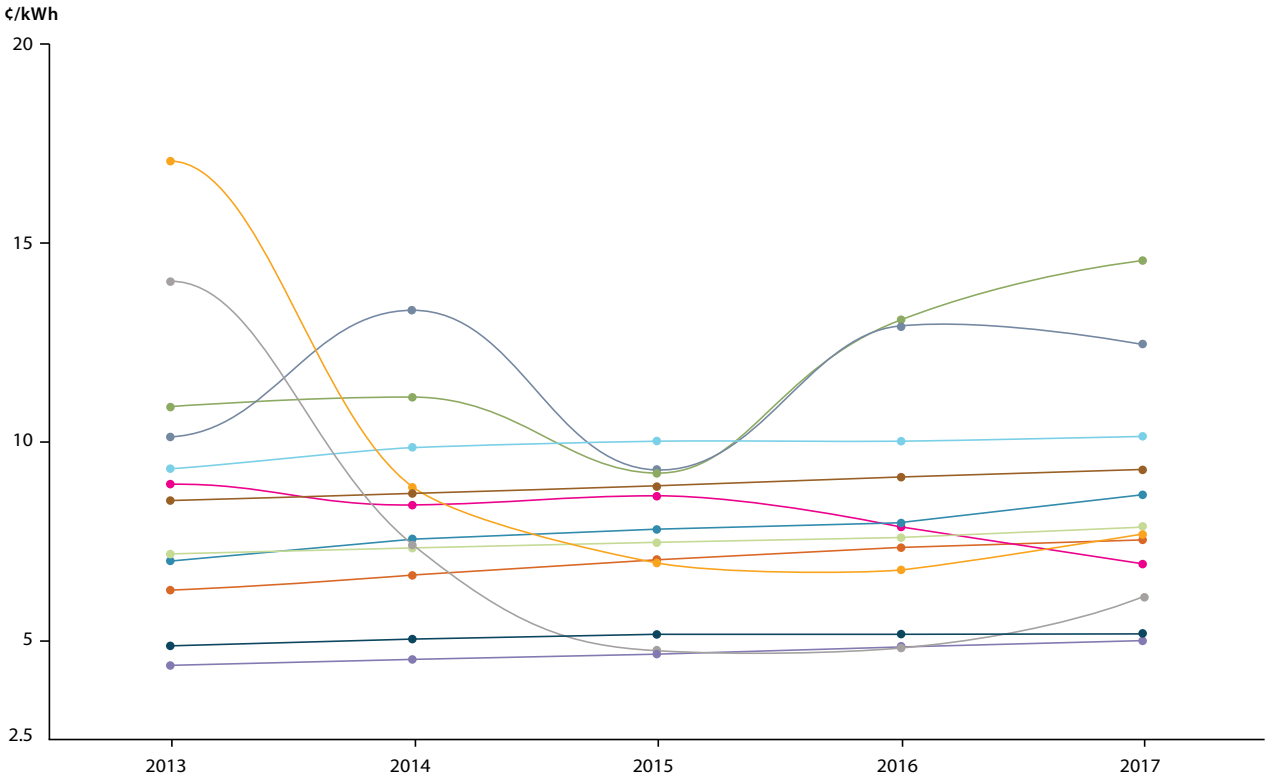
AVERAGE PRICES FOR A RESIDENTIAL CUSTOMER (IN ¢/kWh)[1,2,3]

	2013	2014	2015	2016	2017
Canadian cities					
Montréal, QC	**6.87**	**7.06**	**7.19**	**7.23**	**7.07**
Calgary, AB	14.81	13.41	11.66	10.40	10.45
Charlottetown, PE	14.87	15.24	15.62	16.02	16.42
Edmonton, AB	13.90	11.88	11.55	10.37	10.34
Halifax, NS	15.45	16.03	16.03	15.88	16.15
Moncton, NB	11.82	12.06	12.30	12.50	12.97
Ottawa, ON	12.39	13.45	14.86	16.15	15.21
Regina, SK	13.15	13.95	14.37	14.65	15.94
St. John's, NL	12.55	11.34	11.55	11.96	11.15
Toronto, ON	12.48	13.78	14.31	17.81	16.32
Vancouver, BC	8.91	9.71	10.29	10.70	11.08
Winnipeg, MB	7.63	7.89	8.11	8.43	8.71

1) For a monthly consumption of 1,000 kWh.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2013 to 2017.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh) – 2013 TO 2017[1,2,3]



AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh)[1,2,3]

	2013	2014	2015	2016	2017
Canadian cities					
Montréal, QC	**4.88**	**5.05**	**5.17**	**5.17**	**5.18**
Calgary, AB	14.04	7.42	4.76	4.82	6.09
Charlottetown, PE	8.53	8.71	8.90	9.12	9.31
Edmonton, AB	17.06	8.87	6.97	6.78	7.68
Halifax, NS	9.33	9.86	10.02	10.02	10.14
Moncton, NB	7.19	7.34	7.48	7.60	7.86
Ottawa, ON	10.13	13.31	9.30	12.91	12.46
Regina, SK	7.01	7.56	7.81	7.97	8.67
St. John's, NL	8.94	8.42	8.65	7.88	6.95
Toronto, ON	10.89	11.13	9.22	13.04	14.55
Vancouver, BC	6.28	6.66	7.04	7.35	7.54
Winnipeg, MB	4.39	4.54	4.67	4.85	5.01

1) For a monthly consumption of 3,060,000 kWh and power demand of 5,000 kW.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2013 to 2017.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the 9 other Canadian provinces, and 10 utilities in American states. The results are based, in part, on a survey to which 13 utilities responded, and in part on estimates of bills calculated by Hydro-Québec and confirmed in most cases by the utilities concerned.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2017. The most recent rate adjustments applied by the utilities in the study between April 1, 2016, and April 1, 2017, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the Detailed Tables.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists taxes applicable on April 1, 2017, by customer category; those which may be partially or fully refundable are also indicated.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes offer different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2017.

TIME-OF-USE RATES

The rates offered by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates which are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include adjustment clauses that allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2016, and April 1, 2017, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is 0.7468 (CA$1 = US$0.7468), the rate in effect at noon on April 3, 2017. The Canadian dollar had thus depreciated by 2.57% relative to the U.S. dollar on April 1, 2016.

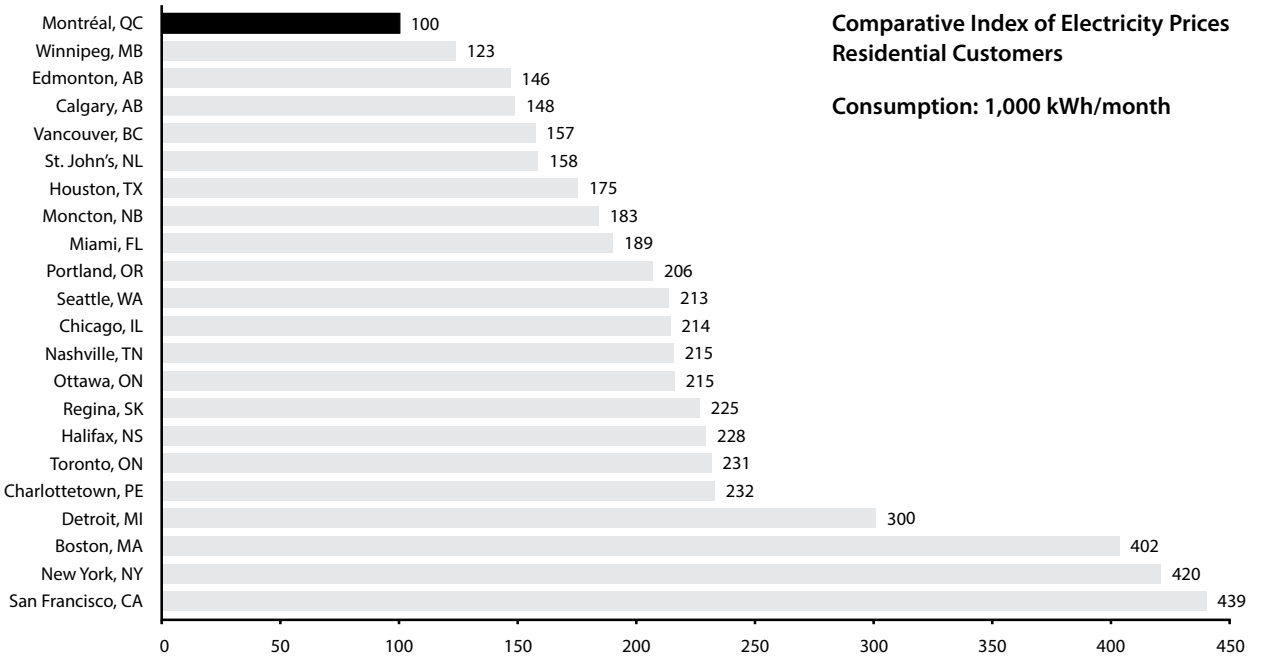
HIGHLIGHTS

The *Electricity Rates* effective April 1, 2017 sets out Hydro-Québec's rates, as approved by the Régie de l'énergie (the Québec energy board) in accordance with Decision D-2017-034. Three types of rates are in effect: domestic rates, for residential customers, the industrial rate, for large-power industrial customers, and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kWh, Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

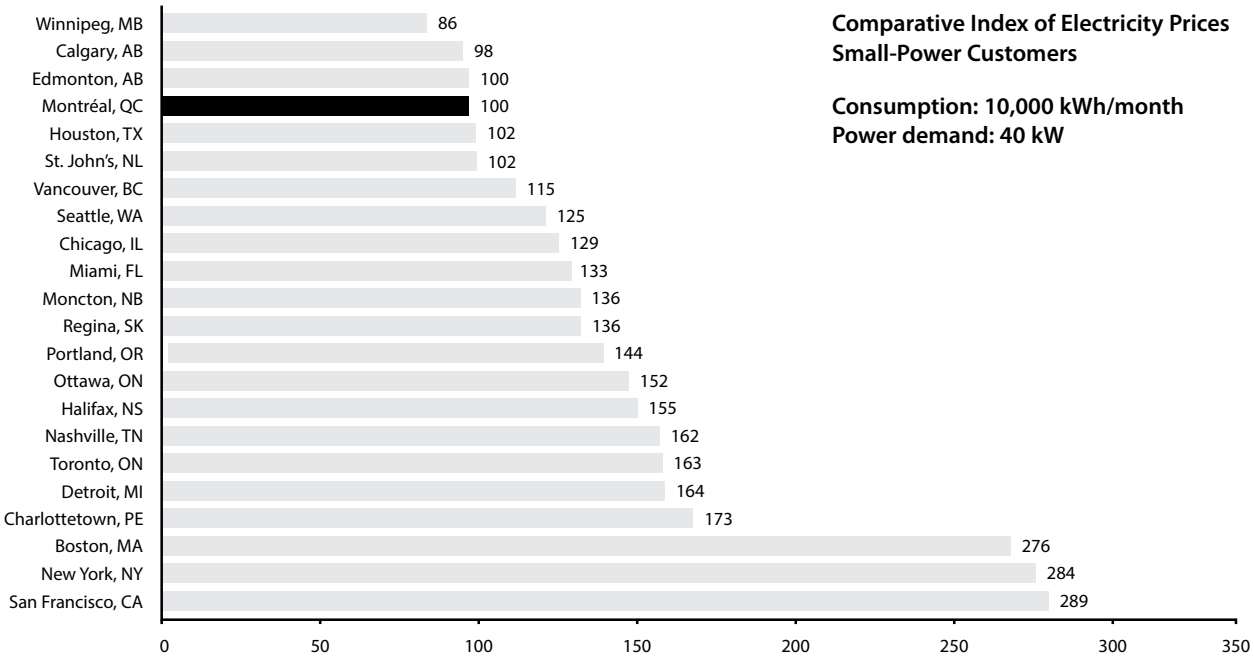
FIGURE 1



SMALL-POWER CUSTOMERS (LESS THAN 100 kW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kW. Montréal is in *fourth* place coming in just behind Edmonton. Figure 2 shows the comparative index of electricity prices.

FIGURE 2

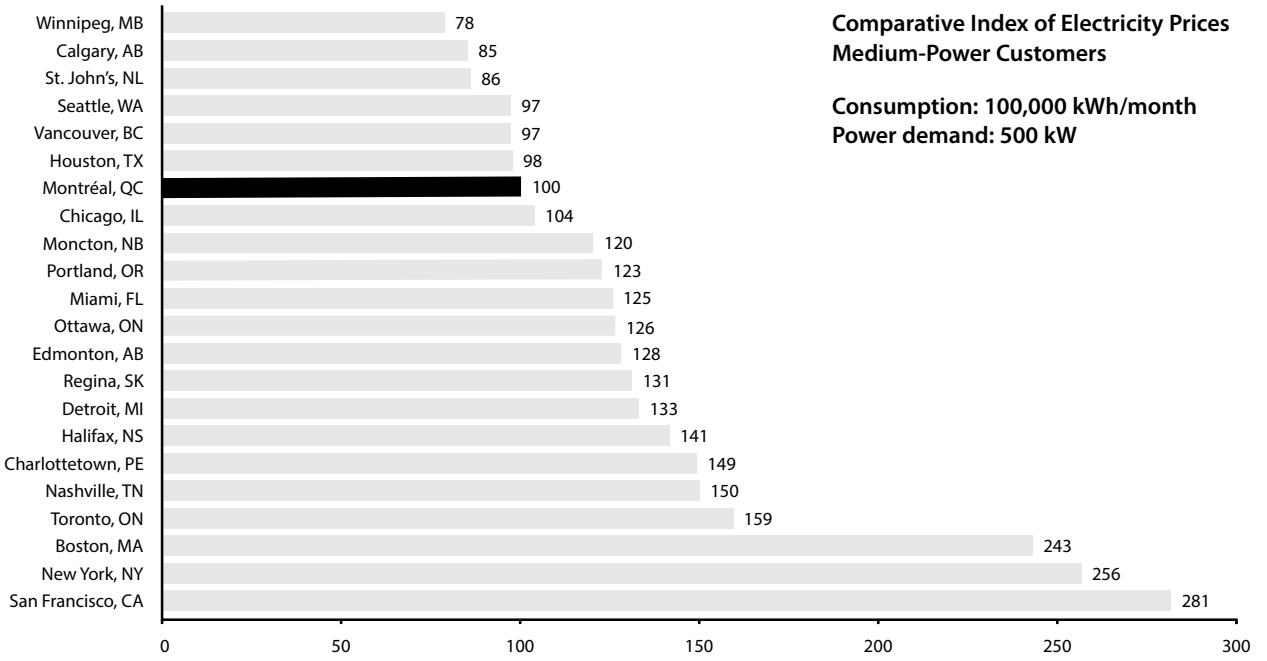


MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

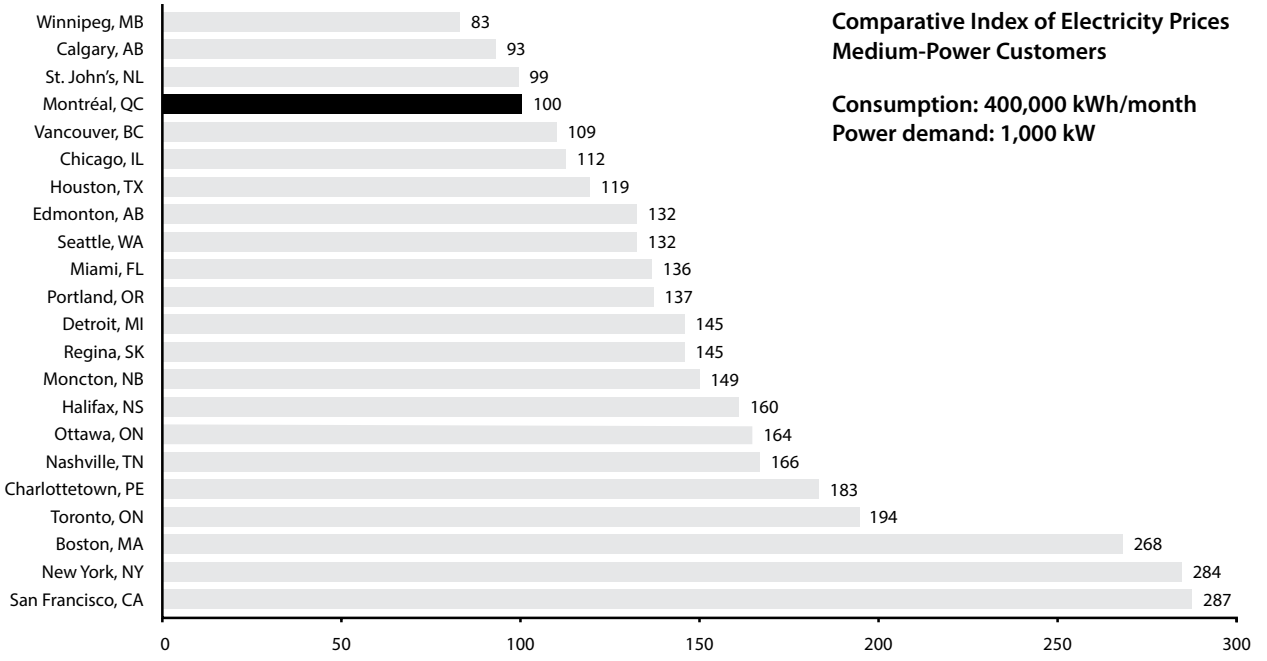
For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal remains in *seventh* place.

FIGURE 3



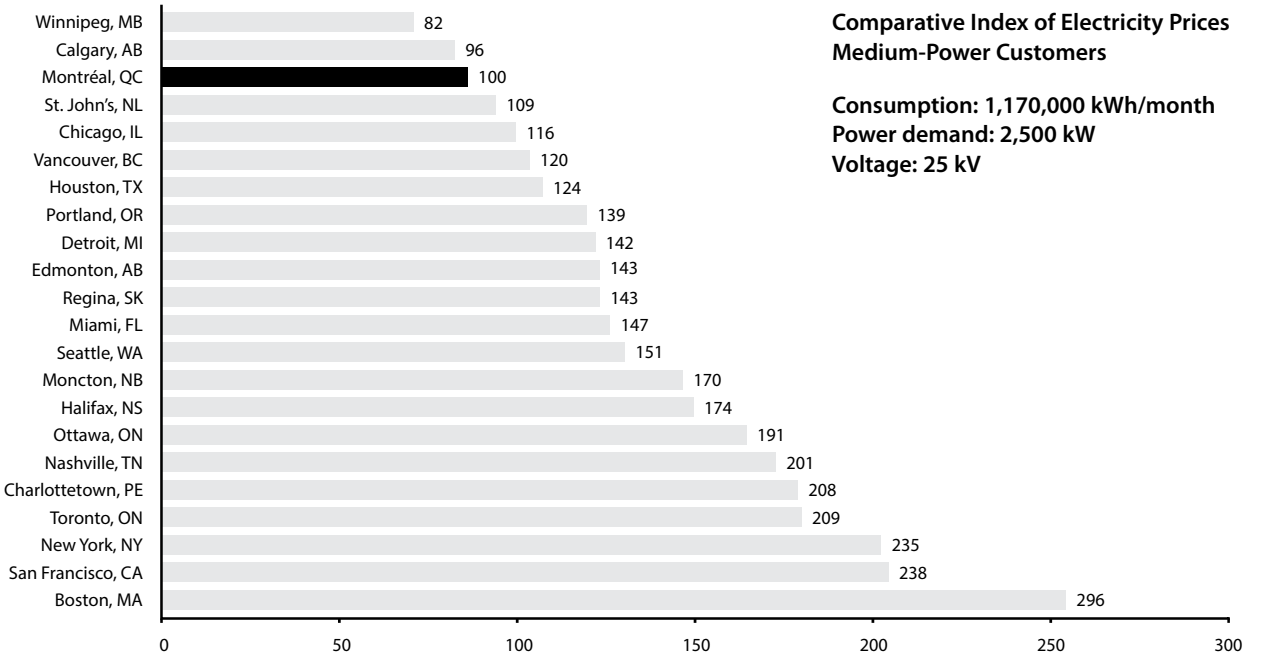
For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal is in *fourth* place, compared with third place last year.

FIGURE 4



In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal holds *third* place.

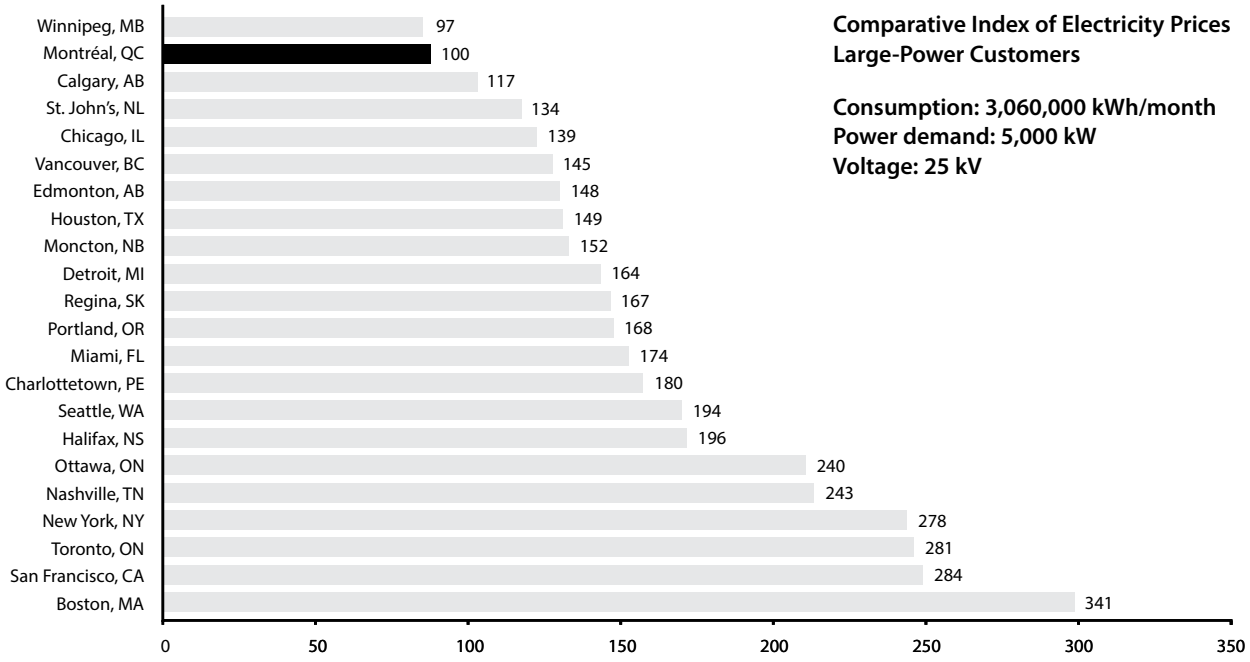
FIGURE 5



LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. This year, Montréal has climbed the rankings to *second* place, over third place last year.

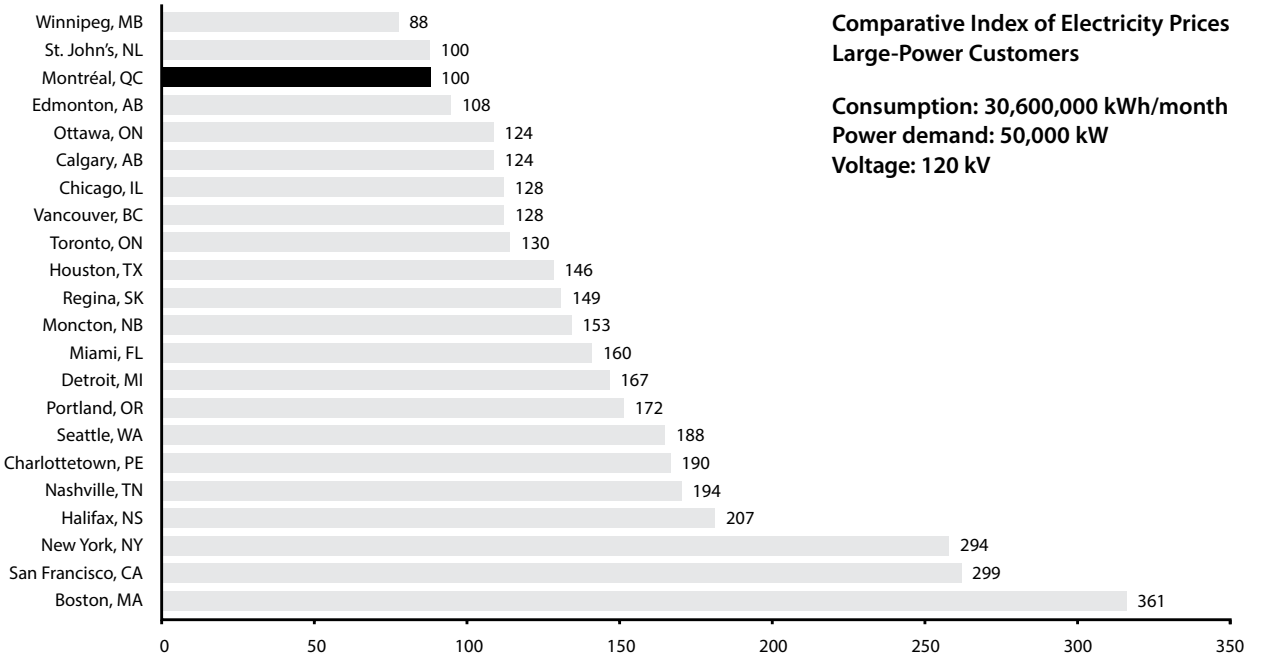
FIGURE 6



Hydro-Québec = 100
Monthly bill (excluding tax)
Rates in effect April 1, 2017

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal has made significant headway, moving from sixth to *third* place.

FIGURE 7



01

Detailed Results

Summary Tables (excluding taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2017

(in CA$)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	**70.70**	**990.33**	**12,070.00**	**31,878.00**	**79,039.50**	**158,619.00**	**1,501,290.00**
Calgary, AB	104.53	968.62	10,256.24	29,522.74	75,714.87	186,278.39	1,855,748.69
Charlottetown, PE[3]	164.17	1,711.17	17,959.97	58,244.97	164,552.97	284,864.00	2,848,640.00
Edmonton, AB[4]	103.40	988.14	15,391.90	42,033.09	113,206.98	234,924.09	1,617,047.62
Halifax, NS	161.46	1,532.70	17,032.50	51,075.00	137,388.45	310,347.09	3,103,494.84
Moncton, NB	129.70	1,348.70	14,498.70	47,533.70	134,587.70	240,543.40	2,294,700.00
Ottawa, ON	152.13	1,503.31	15,229.17	52,308.41	151,226.51	381,151.52	1,854,238.03
Regina, SK	159.41	1,350.07	15,787.48	46,381.55	113,215.14	265,355.66	2,233,810.73
St. John's, NL[5]	111.52	1,014.23	10,355.84	31,565.26	86,123.23	212,566.50	1,498,150.00
Toronto, ON[3]	163.18	1,609.67	19,192.41	61,871.17	165,400.55	445,324.24	1,946,356.79
Vancouver, BC	110.79	1,138.40	11,660.25	34,878.26	94,890.23	230,721.49	1,924,954.57
Winnipeg, MB	87.12	854.10	9,454.71	26,325.06	65,020.92	153,453.67	1,321,932.24
American Cities							
Boston, MA	284.50	2,736.12	29,283.08	85,284.37	233,920.20	541,573.36	5,412,876.90
Chicago, IL[3]	150.97	1,277.96	12,506.66	35,768.17	91,452.92	220,949.15	1,915,683.32
Detroit, MI[3]	212.20	1,619.69	16,019.32	46,260.28	112,121.15	259,696.04	2,507,789.57
Houston, TX[3]	123.39	1,012.60	11,776.02	37,900.14	98,233.42	236,393.91	2,191,986.53
Miami, FL[3]	133.86	1,320.82	15,114.84	43,341.53	115,897.06	276,242.12	2,407,245.80
Nashville, TN	151.88	1,604.69	18,053.42	52,992.91	158,845.20	385,869.66	2,910,445.48
New York, NY[3]	296.71	2,814.94	30,902.96	90,457.95	186,106.15	441,541.51	4,413,795.01
Portland, OR[3]	145.67	1,421.48	14,802.20	43,567.62	109,929.76	267,083.12	2,588,811.27
San Francisco, CA[3]	310.48	2,857.43	33,924.44	91,482.02	187,867.55	450,911.88	4,485,365.02
Seattle, WA	150.53	1,237.14	11,726.09	42,108.12	119,608.49	307,323.39	2,821,027.64
AVERAGE	**158.10**	**1,496.01**	**16,499.92**	**49,217.29**	**127,015.86**	**295,078.78**	**2,529,790.46**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2017

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	**7.07**	**9.90**	**12.07**	**7.97**	**6.76**	**5.18**	**4.91**
Calgary, AB	10.45	9.69	10.26	7.38	6.47	6.09	6.06
Charlottetown, PE[4]	16.42	17.11	17.96	14.56	14.06	9.31	9.31
Edmonton, AB[5]	10.34	9.88	15.39	10.51	9.68	7.68	5.28
Halifax, NS	16.15	15.33	17.03	12.77	11.74	10.14	10.14
Moncton, NB	12.97	13.49	14.50	11.88	11.50	7.86	7.50
Ottawa, ON	15.21	15.03	15.23	13.08	12.93	12.46	6.06
Regina, SK	15.94	13.50	15.79	11.60	9.68	8.67	7.30
St. John's, NL[6]	11.15	10.14	10.36	7.89	7.36	6.95	4.90
Toronto, ON[4]	16.32	16.10	19.19	15.47	14.14	14.55	6.36
Vancouver, BC	11.08	11.38	11.66	8.72	8.11	7.54	6.29
Winnipeg, MB	8.71	8.54	9.45	6.58	5.56	5.01	4.32
American Cities							
Boston, MA	28.45	27.36	29.28	21.32	19.99	17.70	17.69
Chicago, IL[4]	15.10	12.78	12.51	8.94	7.82	7.22	6.26
Detroit, MI[4]	21.22	16.20	16.02	11.57	9.58	8.49	8.20
Houston, TX[4]	12.34	10.13	11.78	9.48	8.40	7.73	7.16
Miami, FL[4]	13.39	13.21	15.11	10.84	9.91	9.03	7.87
Nashville, TN	15.19	16.05	18.05	13.25	13.58	12.61	9.51
New York, NY[4]	29.67	28.15	30.90	22.61	15.91	14.43	14.42
Portland, OR[4]	14.57	14.21	14.80	10.89	9.40	8.73	8.46
San Francisco, CA[4]	31.05	28.57	33.92	22.87	16.06	14.74	14.66
Seattle, WA	15.05	12.37	11.73	10.53	10.22	10.04	9.22
AVERAGE	**15.81**	**14.96**	**16.50**	**12.30**	**10.86**	**9.64**	**8.27**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2017

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	148	98	85	93	96	117	124
Charlottetown, PE[3]	232	173	149	183	208	180	190
Edmonton, AB[4]	146	100	128	132	143	148	108
Halifax, NS	228	155	141	160	174	196	207
Moncton, NB	183	136	120	149	170	152	153
Ottawa, ON	215	152	126	164	191	240	124
Regina, SK	225	136	131	145	143	167	149
St. John's, NL[5]	158	102	86	99	109	134	100
Toronto, ON[3]	231	163	159	194	209	281	130
Vancouver, BC	157	115	97	109	120	145	128
Winnipeg, MB	123	86	78	83	82	97	88
American Cities							
Boston, MA	402	276	243	268	296	341	361
Chicago, IL[3]	214	129	104	112	116	139	128
Detroit, MI[3]	300	164	133	145	142	164	167
Houston, TX[3]	175	102	98	119	124	149	146
Miami, FL[3]	189	133	125	136	147	174	160
Nashville, TN	215	162	150	166	201	243	194
New York, NY[3]	420	284	256	284	235	278	294
Portland, OR[3]	206	144	123	137	139	168	172
San Francisco, CA[3]	439	289	281	287	238	284	299
Seattle, WA	213	125	97	132	151	194	188
AVERAGE	**224**	**151**	**137**	**154**	**161**	**186**	**169**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

Detailed Results

Summary Tables (including taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2017

(in CA$)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	81.29	1,138.64	13,877.48	36,651.73	90,875.67	182,372.20	1,726,108.18
Calgary, AB	109.76	1,017.05	10,769.05	30,998.88	79,500.61	195,592.31	1,948,536.13
Charlottetown, PE[3]	188.80	1,967.85	20,653.97	66,981.72	189,235.92	327,593.60	3,275,936.00
Edmonton, AB[4]	108.57	1,037.55	16,161.50	44,134.74	118,867.33	246,670.29	1,697,900.00
Halifax, NS	169.53	1,762.61	19,587.38	58,736.25	157,996.72	356,899.15	3,569,019.07
Moncton, NB	149.16	1,551.01	16,673.51	54,663.76	154,775.86	276,624.91	2,638,905.00
Ottawa, ON	173.62	1,715.73	17,208.96	59,108.50	170,885.95	430,701.22	2,095,288.98
Regina, SK	183.32	1,641.69	19,197.57	56,399.97	137,669.61	322,672.48	2,716,313.85
St. John's, NL[5]	128.25	1,166.36	11,909.22	36,300.05	99,041.71	244,451.48	1,722,872.50
Toronto, ON[3]	186.24	1,837.12	21,687.43	69,914.42	186,902.62	503,216.39	2,199,383.18
Vancouver, BC	118.33	1,275.01	13,059.48	39,063.65	106,277.06	258,408.07	2,155,949.12
Winnipeg, MB	100.74	1,009.98	11,180.20	31,129.38	72,725.90	171,637.93	1,478,581.21
American Cities							
Boston, MA	284.50	2,899.99	31,041.90	90,329.12	247,705.07	573,237.46	5,729,339.39
Chicago, IL[3]	170.89	1,433.60	13,899.97	41,029.56	106,272.72	258,015.85	2,244,595.67
Detroit, MI[3]	231.30	1,797.86	17,781.45	51,348.91	124,454.48	288,262.61	2,783,646.42
Houston, TX[3]	124.62	1,095.50	12,657.45	40,612.24	106,375.87	256,174.69	2,375,117.03
Miami, FL[3]	157.68	1,665.15	19,096.69	54,436.09	145,309.91	345,580.95	2,983,528.89
Nashville, TN	151.88	1,717.02	19,317.16	56,702.41	169,964.36	412,880.54	3,114,176.66
New York, NY[3]	322.70	3,140.47	34,477.15	100,913.01	207,609.29	492,548.91	4,923,680.94
Portland, OR[3]	147.97	1,444.24	15,040.54	44,263.94	111,732.02	271,471.82	2,631,421.82
San Francisco, CA[3]	310.86	3,104.20	36,846.84	99,413.30	204,290.58	490,427.53	4,878,502.44
Seattle, WA	150.53	1,237.14	11,726.09	42,108.12	119,608.49	307,323.39	2,821,027.64
AVERAGE	**170.48**	**1,666.17**	**18,356.86**	**54,783.62**	**141,276.26**	**327,852.90**	**2,804,992.28**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2017

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	8.13	11.39	13.88	9.16	7.77	5.96	5.64
Calgary, AB	10.98	10.17	10.77	7.75	6.79	6.39	6.37
Charlottetown, PE[4]	18.88	19.68	20.65	16.75	16.17	10.71	10.71
Edmonton, AB[5]	10.86	10.38	16.16	11.03	10.16	8.06	5.55
Halifax, NS	16.95	17.63	19.59	14.68	13.50	11.66	11.66
Moncton, NB	14.92	15.51	16.67	13.67	13.23	9.04	8.62
Ottawa, ON	17.36	17.16	17.21	14.78	14.61	14.08	6.85
Regina, SK	18.33	16.42	19.20	14.10	11.77	10.54	8.88
St. John's, NL[6]	12.83	11.66	11.91	9.08	8.47	7.99	5.63
Toronto, ON[4]	18.62	18.37	21.69	17.48	15.97	16.44	7.19
Vancouver, BC	11.83	12.75	13.06	9.77	9.08	8.44	7.05
Winnipeg, MB	10.07	10.10	11.18	7.78	6.22	5.61	4.83
American Cities							
Boston, MA	28.45	29.00	31.04	22.58	21.17	18.73	18.72
Chicago, IL[4]	17.09	14.34	13.90	10.26	9.08	8.43	7.34
Detroit, MI[4]	23.13	17.98	17.78	12.84	10.64	9.42	9.10
Houston, TX[4]	12.46	10.96	12.66	10.15	9.09	8.37	7.76
Miami, FL[4]	15.77	16.65	19.10	13.61	12.42	11.29	9.75
Nashville, TN	15.19	17.17	19.32	14.18	14.53	13.49	10.18
New York, NY[4]	32.27	31.40	34.48	25.23	17.74	16.10	16.09
Portland, OR[4]	14.80	14.44	15.04	11.07	9.55	8.87	8.60
San Francisco, CA[4]	31.09	31.04	36.85	24.85	17.46	16.03	15.94
Seattle, WA	15.05	12.37	11.73	10.53	10.22	10.04	9.22
AVERAGE	**17.05**	**16.66**	**18.36**	**13.70**	**12.07**	**10.71**	**9.17**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2017

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	135	89	78	85	87	107	113
Charlottetown, PE[3]	232	173	149	183	208	180	190
Edmonton, AB[4]	134	91	116	120	131	135	98
Halifax, NS	209	155	141	160	174	196	207
Moncton, NB	183	136	120	149	170	152	153
Ottawa, ON	214	151	124	161	188	236	121
Regina, SK	226	144	138	154	151	177	157
St. John's, NL[5]	158	102	86	99	109	134	100
Toronto, ON[3]	229	161	156	191	206	276	127
Vancouver, BC	146	112	94	107	117	142	125
Winnipeg, MB	124	89	81	85	80	94	86
American Cities							
Boston, MA	350	255	224	246	273	314	332
Chicago, IL[3]	210	126	100	112	117	141	130
Detroit, MI[3]	285	158	128	140	137	158	161
Houston, TX[3]	153	96	91	111	117	140	138
Miami, FL[3]	194	146	138	149	160	189	173
Nashville, TN	187	151	139	155	187	226	180
New York, NY[3]	397	276	248	275	228	270	285
Portland, OR[3]	182	127	108	121	123	149	152
San Francisco, CA[3]	382	273	266	271	225	269	283
Seattle, WA	185	109	84	115	132	169	163
AVERAGE	**210**	**146**	**132**	**149**	**155**	**180**	**163**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

Detailed Results

Residential

Monthly Bills

Average Prices

Comparative Index

RESIDENTIAL

Monthly Bills on April 1, 2017
(in CA$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	48.57	55.84	70.70	159.90	249.10
Calgary, AB	72.84	83.40	104.53	189.04	273.54
Charlottetown, PE[1]	111.82	129.27	164.17	303.77	414.57
Edmonton, AB	73.29	83.33	103.40	183.68	263.96
Halifax, NS	104.97	123.80	161.46	312.09	462.72
Moncton, NB	89.16	102.68	129.70	237.80	345.90
Ottawa, ON	101.17	118.16	152.13	288.01	423.89
Regina, SK	107.89	125.06	159.41	296.81	434.21
St. John's, NL[2]	75.63	87.60	111.52	207.23	302.94
Toronto, ON[1]	111.95	129.03	163.18	299.81	436.43
Vancouver, BC	62.37	77.01	110.79	245.93	381.06
Winnipeg, MB	57.38	67.30	87.12	166.42	245.72
American Cities					
Boston, MA	181.05	215.56	284.50	560.40	836.29
Chicago, IL[1]	102.28	118.51	150.97	236.70	343.40
Detroit, MI[1]	132.87	159.32	212.20	423.76	635.32
Houston, TX[1]	93.19	107.69	123.39	239.45	355.52
Miami, FL[1]	87.62	103.03	133.86	283.97	434.07
Nashville, TN	100.86	117.87	151.88	287.91	423.95
New York, NY[1]	193.35	227.81	296.71	572.32	847.93
Portland, OR[1]	96.38	112.81	145.67	319.01	492.36
San Francisco, CA[1]	183.69	229.90	310.48	779.79	1,317.21
Seattle, WA	84.90	106.78	150.53	325.57	500.61
AVERAGE	**103.33**	**121.90**	**158.10**	**314.52**	**473.67**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL

Average Prices on April 1, 2017
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	7.77	7.45	7.07	8.00	8.30
Calgary, AB	11.65	11.12	10.45	9.45	9.12
Charlottetown, PE[2]	17.89	17.24	16.42	15.19	13.82
Edmonton, AB	11.73	11.11	10.34	9.18	8.80
Halifax, NS	16.80	16.51	16.15	15.60	15.42
Moncton, NB	14.27	13.69	12.97	11.89	11.53
Ottawa, ON	16.19	15.75	15.21	14.40	14.13
Regina, SK	17.26	16.67	15.94	14.84	14.47
St. John's, NL[3]	12.10	11.68	11.15	10.36	10.10
Toronto, ON[2]	17.91	17.20	16.32	14.99	14.55
Vancouver, BC	9.98	10.27	11.08	12.30	12.70
Winnipeg, MB	9.18	8.97	8.71	8.32	8.19
American Cities					
Boston, MA	28.97	28.74	28.45	28.02	27.88
Chicago, IL[2]	16.37	15.80	15.10	11.84	11.45
Detroit, MI[2]	21.26	21.24	21.22	21.19	21.18
Houston, TX[2]	14.91	14.36	12.34	11.97	11.85
Miami, FL[2]	14.02	13.74	13.39	14.20	14.47
Nashville, TN	16.14	15.72	15.19	14.40	14.13
New York, NY[2]	30.94	30.37	29.67	28.62	28.26
Portland, OR[2]	15.42	15.04	14.57	15.95	16.41
San Francisco, CA[2]	29.39	30.65	31.05	38.99	43.91
Seattle, WA	13.58	14.24	15.05	16.28	16.69
AVERAGE	**16.53**	**16.25**	**15.81**	**15.73**	**15.79**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL

Comparative Index on April 1, 2017
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	150	149	148	118	110
Charlottetown, PE[1]	230	232	232	190	166
Edmonton, AB	151	149	146	115	106
Halifax, NS	216	222	228	195	186
Moncton, NB	184	184	183	149	139
Ottawa, ON	208	212	215	180	170
Regina, SK	222	224	225	186	174
St. John's, NL[2]	156	157	158	130	122
Toronto, ON[1]	230	231	231	187	175
Vancouver, BC	128	138	157	154	153
Winnipeg, MB	118	121	123	104	99
American Cities					
Boston, MA	373	386	402	350	336
Chicago, IL[1]	211	212	214	148	138
Detroit, MI[1]	274	285	300	265	255
Houston, TX[1]	192	193	175	150	143
Miami, FL[1]	180	185	189	178	174
Nashville, TN	208	211	215	180	170
New York, NY[1]	398	408	420	358	340
Portland, OR[1]	198	202	206	200	198
San Francisco, CA[1]	378	412	439	488	529
Seattle, WA	175	191	213	204	201
AVERAGE	**213**	**218**	**224**	**197**	**190**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

Detailed Results

Small Power

Monthly Bills

Average Prices

Comparative Index

SMALL POWER

Monthly Bills on April 1, 2017
(in CA$)

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	85.68	207.93	990.33	1,815.80	2,685.50
Calgary, AB	101.79	201.08	968.62	1,536.00	2,093.50
Charlottetown, PE[1]	153.35	367.97	1,711.17	2,964.57	4,195.47
Edmonton, AB	88.03	209.66	988.14	2,020.79	2,596.42
Halifax, NS	120.48	294.14	1,532.70	2,699.46	3,831.75
Moncton, NB	120.73	284.10	1,348.70	2,346.50	3,366.20
Ottawa, ON	128.86	314.59	1,503.31	2,340.96	3,757.29
Regina, SK	129.07	294.07	1,350.07	2,595.56	3,525.30
St. John's, NL[2]	92.94	241.04	1,014.23	1,818.15	2,532.67
Toronto, ON[1]	156.06	352.77	1,609.67	2,915.91	4,498.43
Vancouver, BC	100.27	249.77	1,138.40	1,817.96	2,834.36
Winnipeg, MB	83.67	187.78	854.10	1,706.82	2,234.71
American Cities					
Boston, MA	202.27	519.63	2,736.12	5,380.38	7,250.63
Chicago, IL[1]	114.35	258.09	1,277.96	2,085.16	2,997.70
Detroit, MI[1]	136.48	339.73	1,619.69	2,259.68	4,019.63
Houston, TX[1]	75.88	285.24	1,012.60	1,849.71	2,489.15
Miami, FL[1]	106.98	262.96	1,320.82	2,460.23	3,251.85
Nashville, TN	157.81	360.17	1,604.69	3,246.11	4,247.24
New York, NY[1]	243.06	809.16	2,814.94	5,367.55	6,946.74
Portland, OR[1]	133.28	315.53	1,421.48	2,383.99	3,492.61
San Francisco, CA[1]	232.59	598.25	2,857.43	4,788.10	6,866.46
Seattle, WA	92.79	247.43	1,237.14	1,783.68	2,826.42
AVERAGE	**129.84**	**327.32**	**1,496.01**	**2,644.69**	**3,751.82**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL POWER

Average Prices on April 1, 2017
(in ¢/kWh)[1]

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	11.42	10.40	9.90	12.97	10.74
Calgary, AB	13.57	10.05	9.69	10.97	8.37
Charlottetown, PE[2]	20.45	18.40	17.11	21.18	16.78
Edmonton, AB	11.74	10.48	9.88	14.43	10.39
Halifax, NS	16.06	14.71	15.33	19.28	15.33
Moncton, NB	16.10	14.21	13.49	16.76	13.46
Ottawa, ON	17.18	15.73	15.03	16.72	15.03
Regina, SK	17.21	14.70	13.50	18.54	14.10
St. John's, NL[3]	12.39	12.05	10.14	12.99	10.13
Toronto, ON[2]	20.81	17.64	16.10	20.83	17.99
Vancouver, BC	13.37	12.49	11.38	12.99	11.34
Winnipeg, MB	11.16	9.39	8.54	12.19	8.94
American Cities					
Boston, MA	26.97	25.98	27.36	38.43	29.00
Chicago, IL[2]	15.25	12.90	12.78	14.89	11.99
Detroit, MI[2]	18.20	16.99	16.20	16.14	16.08
Houston, TX[2]	10.12	14.26	10.13	13.21	9.96
Miami, FL[2]	14.26	13.15	13.21	17.57	13.01
Nashville, TN	21.04	18.01	16.05	23.19	16.99
New York, NY[2]	32.41	40.46	28.15	38.34	27.79
Portland, OR[2]	17.77	15.78	14.21	17.03	13.97
San Francisco, CA[2]	31.01	29.91	28.57	34.20	27.47
Seattle, WA	12.37	12.37	12.37	12.74	11.31
AVERAGE	**17.31**	**16.37**	**14.96**	**18.89**	**15.01**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL POWER

Comparative Index on April 1, 2017
(Hydro-Québec = 100)

Power demand **Consumption** **Load factor**	**6 kW** **750 kWh** **17%**	**14 kW** **2,000 kWh** **20%**	**40 kW** **10,000 kWh** **35%**	**100 kW** **14,000 kWh** **19%**	**100 kW** **25,000 kWh** **35%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	119	97	98	85	78
Charlottetown, PE[1]	179	177	173	163	156
Edmonton, AB	103	101	100	111	97
Halifax, NS	141	141	155	149	143
Moncton, NB	141	137	136	129	125
Ottawa, ON	150	151	152	129	140
Regina, SK	151	141	136	143	131
St. John's, NL[2]	108	116	102	100	94
Toronto, ON[1]	182	170	163	161	168
Vancouver, BC	117	120	115	100	106
Winnipeg, MB	98	90	86	94	83
American Cities					
Boston, MA	236	250	276	296	270
Chicago, IL[1]	133	124	129	115	112
Detroit, MI[1]	159	163	164	124	150
Houston, TX[1]	89	137	102	102	93
Miami, FL[1]	125	126	133	135	121
Nashville, TN	184	173	162	179	158
New York, NY[1]	284	389	284	296	259
Portland, OR[1]	156	152	144	131	130
San Francisco, CA[1]	271	288	289	264	256
Seattle, WA	108	119	125	98	105
AVERAGE	**152**	**157**	**151**	**146**	**140**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

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Detailed Results

Medium Power

Monthly Bills

Average Prices

Comparative Index

MEDIUM POWER

Monthly Bills on April 1, 2017
(in CA$)

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	12,070.00	17,155.00	24,140.00	31,878.00	79,039.50
Calgary, AB	10,256.24	15,093.37	19,848.49	29,522.74	75,714.87
Charlottetown, PE[2]	17,959.97	29,149.97	35,864.97	58,244.97	164,552.97
Edmonton, AB[3]	15,391.90	22,122.40	28,572.10	42,033.09	113,206.98
Halifax, NS	17,032.50	25,537.50	34,065.00	51,075.00	137,388.45
Moncton, NB	14,498.70	23,768.70	28,993.70	47,533.70	134,587.70
Ottawa, ON	15,229.17	26,254.33	30,258.09	52,308.41	151,226.51
Regina, SK	15,787.48	23,198.48	31,559.55	46,381.55	113,215.14
St. John's, NL[4]	10,355.84	16,413.59	19,583.72	31,565.26	86,123.23
Toronto, ON[2]	19,192.41	31,273.85	37,935.93	61,871.17	165,400.55
Vancouver, BC	11,660.25	17,443.01	23,328.26	34,878.26	94,890.23
Winnipeg, MB	9,454.71	13,270.71	18,693.06	26,325.06	65,020.92
American Cities					
Boston, MA	29,283.08	42,753.75	58,343.02	85,284.37	233,920.20
Chicago, IL[2]	12,506.66	18,042.59	25,005.06	35,768.17	91,452.92
Detroit, MI[2]	16,019.32	23,343.03	32,018.91	46,260.28	112,121.15
Houston, TX[2]	11,776.02	17,589.16	26,273.85	37,900.14	98,233.42
Miami, FL[2]	15,114.84	21,720.97	30,129.27	43,341.53	115,897.06
Nashville, TN	18,053.42	26,626.40	35,846.95	52,992.91	158,845.20
New York, NY[2]	30,902.96	45,259.18	61,745.50	90,457.95	186,106.15
Portland, OR[2]	14,802.20	22,840.35	28,230.95	43,567.62	109,929.76
San Francisco, CA[2]	33,924.44	47,579.72	65,713.30	91,482.02	187,867.55
Seattle, WA	11,726.09	21,241.65	23,129.36	42,108.12	119,608.49
AVERAGE	**16,499.92**	**24,894.44**	**32,694.50**	**49,217.29**	**127,015.86**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM POWER

Average Prices on April 1, 2017
(in ¢/kWh)[1]

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[2] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	12.07	8.58	12.07	7.97	6.76
Calgary, AB	10.26	7.55	9.92	7.38	6.47
Charlottetown, PE[3]	17.96	14.57	17.93	14.56	14.06
Edmonton, AB[4]	15.39	11.06	14.29	10.51	9.68
Halifax, NS	17.03	12.77	17.03	12.77	11.74
Moncton, NB	14.50	11.88	14.50	11.88	11.50
Ottawa, ON	15.23	13.13	15.13	13.08	12.93
Regina, SK	15.79	11.60	15.78	11.60	9.68
St. John's, NL[5]	10.36	8.21	9.79	7.89	7.36
Toronto, ON[3]	19.19	15.64	18.97	15.47	14.14
Vancouver, BC	11.66	8.72	11.66	8.72	8.11
Winnipeg, MB	9.45	6.64	9.35	6.58	5.56
American Cities					
Boston, MA	29.28	21.38	29.17	21.32	19.99
Chicago, IL[3]	12.51	9.02	12.50	8.94	7.82
Detroit, MI[3]	16.02	11.67	16.01	11.57	9.58
Houston, TX[3]	11.78	8.79	13.14	9.48	8.40
Miami, FL[3]	15.11	10.86	15.06	10.84	9.91
Nashville, TN	18.05	13.31	17.92	13.25	13.58
New York, NY[3]	30.90	22.63	30.87	22.61	15.91
Portland, OR[3]	14.80	11.42	14.12	10.89	9.40
San Francisco, CA[3]	33.92	23.79	32.86	22.87	16.06
Seattle, WA	11.73	10.62	11.56	10.53	10.22
AVERAGE	**16.50**	**12.45**	**16.35**	**12.30**	**10.86**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM POWER

Comparative Index on April 1, 2017
(Hydro-Québec = 100)

Power demand **Consumption** **Load factor**	**500 kW** **100,000 kWh** **28%**	**500 kW** **200,000 kWh** **56%**	**1,000 kW** **200,000 kWh** **28%**	**1,000 kW** **400,000 kWh** **56%**	**2,500 kW**[1] **1,170,000 kWh** **65%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	85	88	82	93	96
Charlottetown, PE[2]	149	170	149	183	208
Edmonton, AB[3]	128	129	118	132	143
Halifax, NS	141	149	141	160	174
Moncton, NB	120	139	120	149	170
Ottawa, ON	126	153	125	164	191
Regina, SK	131	135	131	145	143
St. John's, NL[4]	86	96	81	99	109
Toronto, ON[2]	159	182	157	194	209
Vancouver, BC	97	102	97	109	120
Winnipeg, MB	78	77	77	83	82
American Cities					
Boston, MA	243	249	242	268	296
Chicago, IL[2]	104	105	104	112	116
Detroit, MI[2]	133	136	133	145	142
Houston, TX[2]	98	103	109	119	124
Miami, FL[2]	125	127	125	136	147
Nashville, TN	150	155	148	166	201
New York, NY[2]	256	264	256	284	235
Portland, OR[2]	123	133	117	137	139
San Francisco, CA[2]	281	277	272	287	238
Seattle, WA	97	124	96	132	151
AVERAGE	**137**	**145**	**135**	**154**	**161**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

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Detailed Results

Large Power

Monthly Bills

Average Prices

Comparative Index

LARGE POWER

Monthly Bills on April 1, 2017
(in CA$)

Power demand **Consumption** **Voltage**[1] **Load factor**	**5,000 kW** **2,340,000 kWh** **25 kV** **65%**	**5,000 kW** **3,060,000 kWh** **25 kV** **85%**	**10,000 kW** **5,760,000 kWh** **120 kV** **80%**	**30,000 kW** **17,520,000 kWh** **120 kV** **81%**	**50,000 kW** **23,400,000 kWh** **120 kV** **65%**	**50,000 kW** **30,600,000 kWh** **120 kV** **85%**
Canadian Cities						
Montréal, QC	135,075.00	158,619.00	288,486.00	873,306.00	1,265,850.00	1,501,290.00
Calgary, AB	149,113.44	186,278.39	353,191.45	1,070,402.20	1,484,099.15	1,855,748.69
Charlottetown, PE[2]	234,896.00	284,864.00	544,744.00	1,650,888.00	2,348,960.00	2,848,640.00
Edmonton, AB[3]	195,831.98	234,924.09	317,234.97	948,913.53	1,394,979.32	1,617,047.62
Halifax, NS	252,178.29	310,347.09	591,609.77	1,794,230.91	2,521,806.84	3,103,494.84
Moncton, NB	202,541.80	240,543.40	440,220.00	1,333,140.00	1,920,300.00	2,294,700.00
Ottawa, ON	303,816.22	381,151.52	565,809.67	1,183,707.04	1,567,145.52	1,854,238.03
Regina, SK	217,367.66	265,355.66	431,402.73	1,293,666.73	1,809,010.73	2,233,810.73
St. John's, NL[4]	169,432.95	212,566.50	397,517.19	867,180.00	1,226,350.00	1,498,150.00
Toronto, ON[2]	410,578.94	445,324.24	575,258.58	1,234,403.81	1,658,314.46	1,946,356.79
Vancouver, BC	189,765.19	230,721.49	367,478.63	1,114,116.84	1,574,775.37	1,924,954.57
Winnipeg, MB	127,612.87	153,453.67	252,745.12	766,000.88	1,089,156.24	1,321,932.24
American Cities						
Boston, MA	446,069.09	541,573.36	1,035,077.17	3,136,431.45	4,457,834.17	5,412,876.90
Chicago, IL[2]	182,201.97	220,949.15	391,091.57	1,104,677.07	1,528,211.48	1,915,683.32
Detroit, MI[2]	223,682.63	259,696.04	484,350.81	1,463,702.98	2,154,692.72	2,507,789.57
Houston, TX[2]	193,688.03	236,393.91	419,469.19	1,267,880.69	1,779,108.33	2,191,986.53
Miami, FL[2]	231,492.86	276,242.12	463,887.08	1,399,441.84	2,013,159.33	2,407,245.80
Nashville, TN	319,459.15	385,869.66	583,381.94	1,698,617.44	2,492,837.21	2,910,445.48
New York, NY[2]	372,032.28	441,541.51	848,148.40	2,567,254.91	3,718,702.67	4,413,795.01
Portland, OR[2]	218,376.42	267,083.12	497,452.26	1,501,678.71	2,136,596.08	2,588,811.27
San Francisco, CA[2]	372,312.54	450,911.88	859,884.78	2,600,575.50	3,699,371.61	4,485,365.02
Seattle, WA	239,359.90	307,323.39	533,737.56	1,621,170.02	2,200,234.99	2,821,027.64
AVERAGE	**244,858.42**	**295,078.78**	**511,008.13**	**1,476,881.21**	**2,092,795.28**	**2,529,790.46**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Average Prices on April 1, 2017
(in ¢/kWh)[1]

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[2]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	5.77	5.18	5.01	4.98	5.41	4.91
Calgary, AB	6.37	6.09	6.13	6.11	6.34	6.06
Charlottetown, PE[3]	10.04	9.31	9.46	9.42	10.04	9.31
Edmonton, AB[4]	8.37	7.68	5.51	5.42	5.96	5.28
Halifax, NS	10.78	10.14	10.27	10.24	10.78	10.14
Moncton, NB	8.66	7.86	7.64	7.61	8.21	7.50
Ottawa, ON	12.98	12.46	9.82	6.76	6.70	6.06
Regina, SK	9.29	8.67	7.49	7.38	7.73	7.30
St. John's, NL[5]	7.24	6.95	6.90	4.95	5.24	4.90
Toronto, ON[3]	17.55	14.55	9.99	7.05	7.09	6.36
Vancouver, BC	8.11	7.54	6.38	6.36	6.73	6.29
Winnipeg, MB	5.45	5.01	4.39	4.37	4.65	4.32
American Cities						
Boston, MA	19.06	17.70	17.97	17.90	19.05	17.69
Chicago, IL[3]	7.79	7.22	6.79	6.31	6.53	6.26
Detroit, MI[3]	9.56	8.49	8.41	8.35	9.21	8.20
Houston, TX[3]	8.28	7.73	7.28	7.24	7.60	7.16
Miami, FL[3]	9.89	9.03	8.05	7.99	8.60	7.87
Nashville, TN	13.65	12.61	10.13	9.70	10.65	9.51
New York, NY[3]	15.90	14.43	14.72	14.65	15.89	14.42
Portland, OR[3]	9.33	8.73	8.64	8.57	9.13	8.46
San Francisco, CA[3]	15.91	14.74	14.93	14.84	15.81	14.66
Seattle, WA	10.23	10.04	9.27	9.25	9.40	9.22
AVERAGE	**10.46**	**9.64**	**8.87**	**8.43**	**8.94**	**8.27**

1) In Canadian currency.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Comparative Index on April 1, 2017
(Hydro-Québec = 100)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	110	117	122	123	117	124
Charlottetown, PE[2]	174	180	189	189	186	190
Edmonton, AB[3]	145	148	110	109	110	108
Halifax, NS	187	196	205	205	199	207
Moncton, NB	150	152	153	153	152	153
Ottawa, ON	225	240	196	136	124	124
Regina, SK	161	167	150	148	143	149
St. John's, NL[4]	125	134	138	99	97	100
Toronto, ON[2]	304	281	199	141	131	130
Vancouver, BC	140	145	127	128	124	128
Winnipeg, MB	94	97	88	88	86	88
American Cities						
Boston, MA	330	341	359	359	352	361
Chicago, IL[2]	135	139	136	126	121	128
Detroit, MI[2]	166	164	168	168	170	167
Houston, TX[2]	143	149	145	145	141	146
Miami, FL[2]	171	174	161	160	159	160
Nashville, TN	237	243	202	195	197	194
New York, NY[2]	275	278	294	294	294	294
Portland, OR[2]	162	168	172	172	169	172
San Francisco, CA[2]	276	284	298	298	292	299
Seattle, WA	177	194	185	186	174	188
AVERAGE	**181**	**186**	**177**	**169**	**165**	**169**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

Appendix

Rate Adjustments

Average Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

All Categories

	Before April 2016		Between April 1, 2016 and April 1, 2017		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2016	0.7	April 1, 2017	0.7	
ENMAX, AB	2016	n.a.	January 1, 2017	14.38	Applicable to distribution portion only
Maritime Electric, PE	2016	2.3	March 1, 2017	2.3	
EPCOR, AB	2016	n.a.	April 1, 2017	n.a.	
Nova Scotia Power, NS	2016	-1.0	January 1, 2017	1.5	
NB Power, NB	2016	1.63	July 1, 2016 April 1, 2017	1.66 2.05	
Hydro Ottawa, ON	2016	5.8	January 1, 2017	n.a.	
SaskPower, SK	2015	2.0	July 1, 2016 January 1, 2017	5.0 3.5	
Newfoundland Power, NL[1]	2015	-5.25	July 1, 2016	-7.93	
Newfoundland and Labrador Hydro, NL[1]	2015	2.7	—	—	
Toronto Hydro, ON	2016	n.a.	January 1, 2017	n.a.	
BC Hydro, BC	2016	4.0	April 1, 2017	3.5	
Manitoba Hydro, MB	2015	3.95	August 1, 2016	3.36	

Data concerning American utilities not available.

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2016, and April 1, 2017)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2017	0.7	0.7[1] 0.6[2] 0.7[3]	0.2	0.7
ENMAX, AB	January 1, 2017	15.62[4]	n.a.	n.a.	14.38[4]
Maritime Electric, PE	March 1, 2017	n.a.	n.a.	n.a.	2.3
EPCOR, AB	April 1, 2017	n.a.	n.a.	n.a.	n.a.
Nova Scotia Power, NS	January 1, 2017	1.7	1.8[1] 0.9[2] 3.7[3]	1.2[5] 1.6[6] 1.4[7]	1.5
NB Power, NB	July 1, 2016 April 1, 2017	1.66 1.66	1.66 0.8	1.66 1.77	1.66 2.05
Hydro Ottawa, ON	January 1, 2017	-6.47	-5.88	-6.16	n.a.
SaskPower, SK	July 1, 2016 January 1, 2017	5 3.5	5 3.5	5 3.5	5 3.5
Newfoundland Power, NL[8]	July 1, 2016	-7.07	-9.88	-11.11	-7.93
Newfoundland and Labrador Hydro, NL[8]	—	—	—	—	—
Toronto Hydro, ON	January 1, 2017	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2017	3.5	3.5	3.5	3.5
Manitoba Hydro, MB	August 1, 2016	3.36	3.36[1] 3.37[2] 3.37[3]	n.a.	3.36

Data concerning American utilities not available.

n.a.: Not available.

1) Small power
2) Medium power
3) Large power
4) Distribution charge only
5) Small industrial
6) Medium industrial
7) Large industrial
8) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

Appendix

Time-of-use Rates
Adjustment Clauses

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2017 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	Residential General: 14–10,000 kW
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	Residential General: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Distribution Cost Recovery Factor Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge Remand of Energy Efficiency Costs Recovery Factor Surcharge System Benefit Fund Charge Transition Charges Transmission Cost Recovery Factor
Commonwealth Edison, IL	Capacity Charge Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund Energy Efficiency and Demand Response Adjustments Environmental Cost Recovery Adjustment Hourly Purchased Electricity Adjustment Factor Miscellaneous Procurement Components Charge PJM Services Charges Purchased Electricity Adjustment Factor Purchased Electricity Charges Renewable Energy Resources and Coal Technology Development Assistance Charge Residential Real Time Pricing Program Cost Recovery Charges Uncollectible Cost Factors
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Billing and Payment Processing Delivery Revenue Surcharge Clean Energy Standard Delivery Surcharge Market Supply Charge Merchant Function Charge Monthly Adjustment Clause Revenue Decoupling Mechanism Adjustment Surcharge to Collect Assessments under Section 18-a of the Public Service Law System Benefits Charge
DTE Electric, MI	Energy Optimization Surcharge Low Income Energy Assistance Fund Factor Nuclear Surcharge Power Supply Cost Recovery Clause Renewable Energy Plan Surcharge
ENMAX, AB	Balancing Pool Allocation Refund Rider Local Access Fee Transmission Access Charge Deferral Account Rider

EPCOR, AB	Balancing Pool Rider DAS True-up Rider Local Access Fee SAS True-up Rider Transmission Charge Deferral Account True-Up Rider
Eversource Energy, MA	Attorney General Consultant Expenses Provision Basic Service Adjustment Default Service Adjustment Demand-Side Management Charge Energy Conservation Charge Energy Efficiency Reconciliation Factor Long Term Renewable Contract Adjustment Net Metering Recovery Surcharge Pension Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Storm Cost Recovery Adjustment Transition Cost Adjustment Transmission Service Cost Adjustment
Florida Power and Light, FL	2017 Interim Storm Restoration Recovery Charge Energy Conservation Cost Recovery Clause Capacity Payment Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Bond Repayment Charge and Storm Bond Tax Charge
Hydro Ottawa, ON	Debt Retirement Charge Disposition of Class B WMS – Sub Accounts CBR Disposition of Deferral/Variance Accounts Disposition of Global Adjustment Account (2017) Disposition of Group 2 Accounts Ontario Electricity Support Program Charge Rural or Remote Electricity Rate Protection Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	TVA Fuel Cost Adjustment
Newfoundland and Labrador Hydro, NL	Municipal Tax Adjustment Rate Stabilization Adjustment
Nova Scotia Power, NS	Base Cost of Fuel Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	California Climate Credit Competition Transition Charges DWR Bond Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments

Pacific Power and Light, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act
	Energy Conservation Charge
	Adjustment to Remove Deer Creek Mine Investment from Rate Base
	Deer Creek Mine Undepreciated Investment Adjustment
	Deferred Accounting Adjustment
	Generation Investment Adjustment
	Independent Evaluator Cost Adjustment
	Intervenor Funding Adjustment
	Klamath Dam Removal Surcharges
	Oregon Solar Incentive Program Deferral
	Pilot Program Cost Adjustment
	Property Sales Balancing Account Adjustment
	Public Purpose Charge
	Rate Mitigation Adjustment
	Renewable Adjustment Clause
	Renewable Resource Deferral Adjustment
	TAM Adjustment for Other Revenues
Toronto Hydro, ON	Application of IFRS – 2014 Derecognition
	Application of Operations Center Consolidation Plan Sharing
	Debt Retirement Charge
	Disposition of Capacity Based Recovery Class B Variance Sub-account
	Disposition of Class B Post 2011 Global Adjustment Variance Account
	Disposition of Deferral/Variance Account
	Disposition of LRAM Variance Account
	Disposition of Post Employment Benefit – Tax Savings
	Disposition of Pre 2011 Global Adjustment Variance Account
	Ontario Electricity Support Program Charge
	Recovery of 2008-2010 Smart Meter Costs
	Recovery of Hydro One Capital Contributions Variance
	Recovery of Stranded Meter Assets
	Recovery of the Gain on the Sale of Named Properties
	Recovery of 2015 Foregone Revenue
	Recovery of 2016 Foregone Revenue
	Rural or Remote Electricity Rate Protection Charge
	Smart Metering Entity Charge

C

Appendix

Applicable Taxes

Residential Sector

General Sector

Industrial Sector

TAXES APPLICABLE TO RESIDENTIAL SERVICE

On April 1, 2017

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	15	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	6	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	5.0517	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.23	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL SERVICE

On April 1, 2017

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	6	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL SERVICE (cont'd)

On April 1, 2017

	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.5109	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.23	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	8.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL SERVICE

On April 1, 2017

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	7	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	6	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL SERVICE (cont'd)

On April 1, 2017

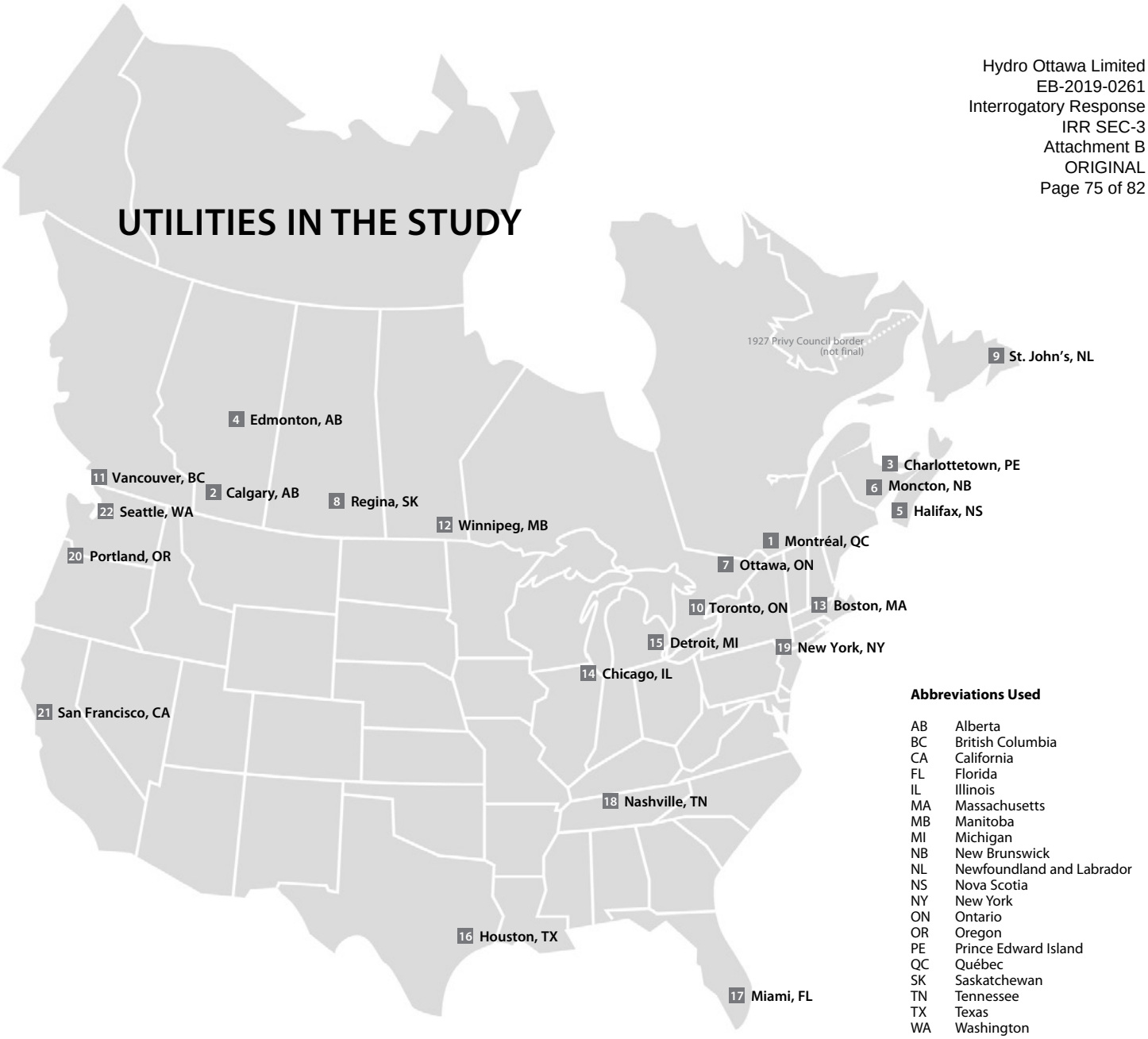
	Tax	% (or other)	Applicable
Nashville, TN	State sales tax	7	To base amount of bill (companies other than manufacturing)
	State sales tax	1.5	To base amount of bill (manufacturing companies)
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.5109	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.23	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	8.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

D

Appendix

Utilities in the Study

UTILITIES IN THE STUDY



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro
(customers with a power demand of 30,000 kW or more)
Newfoundland Power
(all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC

Montréal, Québec

A government-owned company whose lines of business have been unbundled, Hydro-Québec is one of the largest electric utilities in North America, with an installed capacity of 36,908 MW; 99% of electricity is generated using waterpower. Its transmission and distribution activities are regulated. The utility distributes electricity to more than 4.2 million residential, commercial, institutional and industrial customer accounts throughout Québec and delivers electricity to nine municipal systems and one regional cooperative. Hydro-Québec also does business with many electric utilities in the Northeastern United States, Ontario and New Brunswick.

The *Act respecting the Régie de l'énergie* (Québec energy board) established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution. The division also purchases electricity on the market, primarily through calls for tenders. The average supply cost of heritage pool electricity, set at a fixed price of 2.79¢/kWh since 1998, is indexed on January 1 since 2014 at a rate corresponding to the annual variation in the all-item consumer price index for Québec, with the exception of the large-power industrial rate (Rate L), which is exempt from the indexation of heritage pool electricity.

The Régie de l'énergie approved an average increase of 0.7% in the rates of Hydro-Québec Distribution, effective April 1, 2017, with the exception of large power customers, for which the approved increase is of 0.2%.

MARITIME ELECTRIC

Charlottetown, Prince Edward Island

A subsidiary of Fortis Inc., Maritime Electric is the principal supplier of electricity on Prince Edward Island, with about 78,000 customers. Since its two power plants (with a total capacity of 150 MW) are operated strictly for reserve purposes, it purchases most of its electricity from NB Power, with which it has long-term contracts, and through additional short-term contracts on the New England wholesale market. Maritime Electric also purchases nearly 52 MW of wind-generated electricity from private producers.

Since the adoption of the *Electric Power Act* on January 1, 2004, Maritime Electric has had to submit all requests for rate increases to the Island Regulatory and Appeals Commission (IRAC). In 2016, the IRAC approved a 2.3% annual rate increase for each of the next three years.

ENMAX
EPCOR

Calgary, Alberta
Edmonton, Alberta

ENMAX Corporation is a wholly owned subsidiary of the City of Calgary. It generates, transmits and distributes electricity to nearly 946,000 customers throughout the province. In addition to its active participation in Alberta's restructured electricity industry, ENMAX serves customers who are eligible for the City of Calgary's regulated rate option tariff.

EPCOR Utilities, whose sole shareholder is the City of Edmonton, transmits and distributes electricity to nearly 379,000 residential and business customers in Edmonton. It also supplies more than 600,000 customers throughout the province who are eligible for both rate regulated and contract electricity services.

Since July 1, 2010, prices under the regulated rate option tariff have fluctuated monthly with market forecasts. In recent years, the Alberta government has embarked upon a major reform of the province's electricity market.

NOVA SCOTIA POWER

Halifax, Nova Scotia

Nova Scotia Power, a subsidiary of Emera, is the principal supplier of electricity in Nova Scotia, meeting most of the province's needs for electricity generation, transmission and distribution. It supplies electricity to 500,000 customers. Its generating facilities have an installed capacity in excess of 2,400 MW.

The open access transmission tariff came into effect on November 1, 2005. Under the province's energy policy, eligible customers have nondiscriminatory access to the utility's transmission system.

NB POWER
Moncton, New Brunswick

A subsidiary of provincial Crown corporation NB Power Group, NB Power Distribution and Customer Service Corporation directly serves more than 356,000 customers and sells electricity to the province's municipal systems, which together supply nearly 45,000 customers. NB Power has a generating capacity of about 3,500 MW under the management of NB Power Generation and NB Power Nuclear.

The New Brunswick electricity market has been partially open to competition since October 1, 2004. Large industrial customers and three municipal electricity distribution utilities are free to choose their supplier. Other retail market customers continue to be served by NB Power.

SASKPOWER
Regina, Saskatchewan

Crown utility SaskPower serves nearly 522,000 customers and sells wholesale electricity to municipal systems in Saskatchewan. The utility operates 25 power plants and also buys power from third parties, such that its total available generating capacity exceeds 4,400 MW.

In Saskatchewan, the wholesale electricity market has been open to competition since 2001.

NEWFOUNDLAND AND LABRADOR HYDRO
(customers with a power demand of 30,000 kW or more)

NEWFOUNDLAND POWER (all other customer categories)
St. John's, Newfoundland and Labrador

Newfoundland Power, a subsidiary of Fortis Inc., serves about 264,000 customers on the island of Newfoundland. Since it operates only small generating stations with a total installed capacity of nearly 140 MW, it purchases 93% of its electricity from Newfoundland and Labrador Hydro (NLH), a subsidiary of Nalcor Energy that operates generating facilities with an installed capacity of 1,763 MW and a transmission system that serves the whole province. NLH also supplies remote regions, Labrador and large industrial customers. Aside from Newfoundland and Labrador Hydro, Nalcor Energy operates generating facilities with an installed capacity in excess of 7,200 MW.

TORONTO HYDRO
HYDRO OTTAWA
Toronto, Ontario
Ottawa, Ontario

A subsidiary of Hydro Ottawa Holding, whose sole shareholder is the City of Ottawa, Hydro Ottawa serves more than 324,000 customers. Toronto Hydro-Electric System is a subsidiary of city-owned Toronto Hydro Corporation and serves about 761,000 customers, or 19% of Ontario electricity consumers.

In Ontario, the wholesale and retail markets have been open to competition since May 2002. Electricity generation is the responsibility of Ontario Power Generation, while transmission service is supplied by Hydro One.

Following the adoption of the *Electricity Restructuring Act* in December 2004, the Ontario Energy Board was given the mandate to regulate electricity supply cost and has produced a plan in this regard (Regulated Price Plan or RPP). Prices have been reviewed on May 1 each year since 2006 and adjusted six months later, if necessary. With advanced metering, the vast majority of residential customers are now billed according to a time-of-use rate. In recent years, Ontario consumers have seen their electricity bills increase significantly. In 2017, this led the Ontario government to propose measures to reduce electricity bills by 25% for residential and agricultural customers, as well as small businesses.

BC HYDRO
Vancouver, British Columbia

BC Hydro, a provincial Crown corporation, operates generating facilities with a total capacity of more than 12,000 MW. About 98% of electricity is generated using waterpower. The utility distributes electricity to about 1.9 million customers.

The wholesale market in British Columbia is open to competition, as is the retail market for some large industrial companies. When the market was opened up, generation, transmission and distribution were made into separate entities. The *Clean Energy Act* grouped transmission and distribution in July 2010 to ensure coordinated supply planning for the province. In November 2013, the government published a 10-year plan which provides for upgrading aging infrastructure, implementing new generation projects to meet growing demand and minimizing the impact of these activities on electricity rates.

MANITOBA HYDRO
Winnipeg, Manitoba

Manitoba Hydro is a Crown utility serving nearly 568,000 customers throughout the province. Virtually all the electricity it generates and distributes comes from its 15 hydropower plants, which have a total capacity of 5,690 MW.

The wholesale electricity market has been open to competition since 1997 and Manitoba Hydro joined Midwest ISO, a regional transmission organization, in 2001.

AMERICAN UTILITIES

EVERSOURCE ENERGY
Boston, Massachusetts

Eversource, a merger between NSTAR Electric & Gas and Northeast Utilities, serves 3.6 million residential, commercial and industrial customers in the states of Massachusetts, Connecticut and New Hampshire. The utility purchases electricity on the market and concentrates on transmission and distribution.

Since March 1, 2005, the basic service rates are applied to customers who have chosen not to purchase electricity from a competitor. These rates are adjusted every six months, or every three months in the case of large industrial customers. The rates reflect the average market price of electricity.

COMMONWEALTH EDISON (ComEd)
Chicago, Illinois

ComEd, a subsidiary of Exelon Corporation, purchases, transmits and distributes electricity on the wholesale and retail markets. On the retail market, it serves more than 3.8 million customers in northern Illinois, or about 70% of the state's population.

Since May 1, 2002, the retail market has been fully open for residential, commercial and industrial customers. However, it is only since 2011 that residential customers have actually exercised their right to choose distributors other than the two companies that were in place when deregulation was implemented: ComEd and Ameren.

DTE ELECTRIC
Detroit, Michigan

DTE Electric operates generating facilities with a total installed capacity of nearly 11,100 MW. A subsidiary of DTE Energy, it serves 2.2 million customers in southeastern Michigan.

Under the June 2000 legislation that restructured the electricity industry, all retail market customers in Michigan have been able to choose their electricity supplier since January 1, 2002.

CENTERPOINT ENERGY

Houston, Texas

CenterPoint Energy concentrates on electricity transmission and distribution and delivering natural gas. It sells electricity to 2.3 million customers in the metropolitan Houston area.

The majority of Texas consumers have had access to an open retail market since January 1, 2002. As of January 2007, electricity distributors with effective monopolies are no longer obliged to maintain their rates above the "price to beat" designed to encourage new market entrants. Customers who have opted to continue doing business with the same distributor pay a monthly rate that varies according to the market price.

FLORIDA POWER AND LIGHT (FPL)

Miami, Florida

FPL's vast transmission and distribution system supplies about 4.9 million customers. A subsidiary of NextEra Energy, the utility operates generating facilities with an installed capacity of 45,900 MW.

On April 1, 2010, FPL released its 2010–2019 strategic plan, in which it proposes to upgrade some of its nuclear plants and add new generating facilities using thermal and renewable energy. It will also rely on energy efficiency measures to meet the demand for power during the strategic plan time frame. In April 2016, FPL submitted its Ten Year Power Plant Site Plan for the years 2016–2025 in which it maintains its commitment to modernize its generating stations.

NASHVILLE ELECTRIC SERVICE

Nashville, Tennessee

Nashville Electric Service, whose sole shareholder is the City of Nashville, distributes the electricity that it purchases from the Tennessee Valley Authority (TVA) to more than 380,000 customers. Serving seven states, this federal agency supplies 154 distributors and nearly 58 large industrial and federal customers.

Close to 24% of the electricity produced by the TVA comes from its 8 coal-fired plants, with the rest from gas, nuclear and hydro plants. Over the years, the company has proceeded to the decomissioning of some of its most polluting coal-fired plants, and has integrated renewable energy sources such as solar, wind, and biomass.

CONSOLIDATED EDISON (ConEd)

New York, New York

ConEd of New York delivers electricity to 3.4 million customers and natural gas to about 1.1 million customers in and around New York City and Westchester County. This ConEd subsidiary operates one of the largest underground systems in the world, which represents 74% of its distribution system.

When the electricity market was opened to competition in 1998, ConEd had to dispose of a large part of its generating capacity, which is now limited to about 700 MW. Rates, which continue to be regulated by the New York State Public Service Commission, are adjusted monthly to reflect the market price of electricity.

PACIFIC POWER AND LIGHT

Portland, Oregon

Pacific Power and Light, a subsidiary of PacifiCorp, serves about 740,000 customers across three states, including more than 574,000 in Oregon. PacifiCorp operates generating facilities with an installed capacity of about 10,900 MW.

On March 1, 2002, the Oregon state government opened its retail market to competition for large commercial and industrial customers. Residential and small commercial customers have fewer suppliers to choose from, but they do have a range of options, including market-based rates, regulated rates or rates applicable to green energy.

PACIFIC GAS AND ELECTRIC (PG&E)

San Francisco, California

Pacific Gas and Electric concentrates on the transmission and distribution of electricity and natural gas. A subsidiary of PG&E Corporation, it has 5.4 million electric customer accounts.

In 2001, California adopted emergency measures to mitigate the price volatility that followed the opening of the electricity market. Those measures allowed it to reinstate regulatory authority over production costs and to give responsibility for electricity purchases to the California Department of Water and Resources. Since January 1, 2003, PG&E has been authorized to again purchase energy and directly supply its customers.

In 2017, PG&E undertook a rate reform to simplify the structure of residential electricity rates.

SEATTLE CITY LIGHT
Seattle, Washington

Seattle City Light, whose shareholder is the City of Seattle, serves about 423,000 customers in the city of Seattle and certain surrounding communities. It produces a little over 40% of the electricity it needs and purchases the rest from the Bonneville Power Administration (BPA), a northwestern U.S. federal agency that wholesales electricity produced by some 30 hydropower stations.

Six electric utilities in the Pacific Northwestern states, including Seattle City Light and BPA, got together in early 2006 to form the nonprofit ColumbiaGrid. The group's objective is to develop an integrated approach to the use and expansion of the region's interconnected transmission system.

Sources:
Annual reports and Web sites of the Canadian and American utilities in the study.

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2017G1382A

100%



2018

Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2018

hydro quebec .com

Hydro Ottawa Limited
EB-2019-0261
Interrogatory Response
IRR SEC-3
Attachment C
ORIGINAL

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INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2018. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1] (IN ¢/kWh)[2]



1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2018.
2) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1] (IN ¢/kWh)[2]



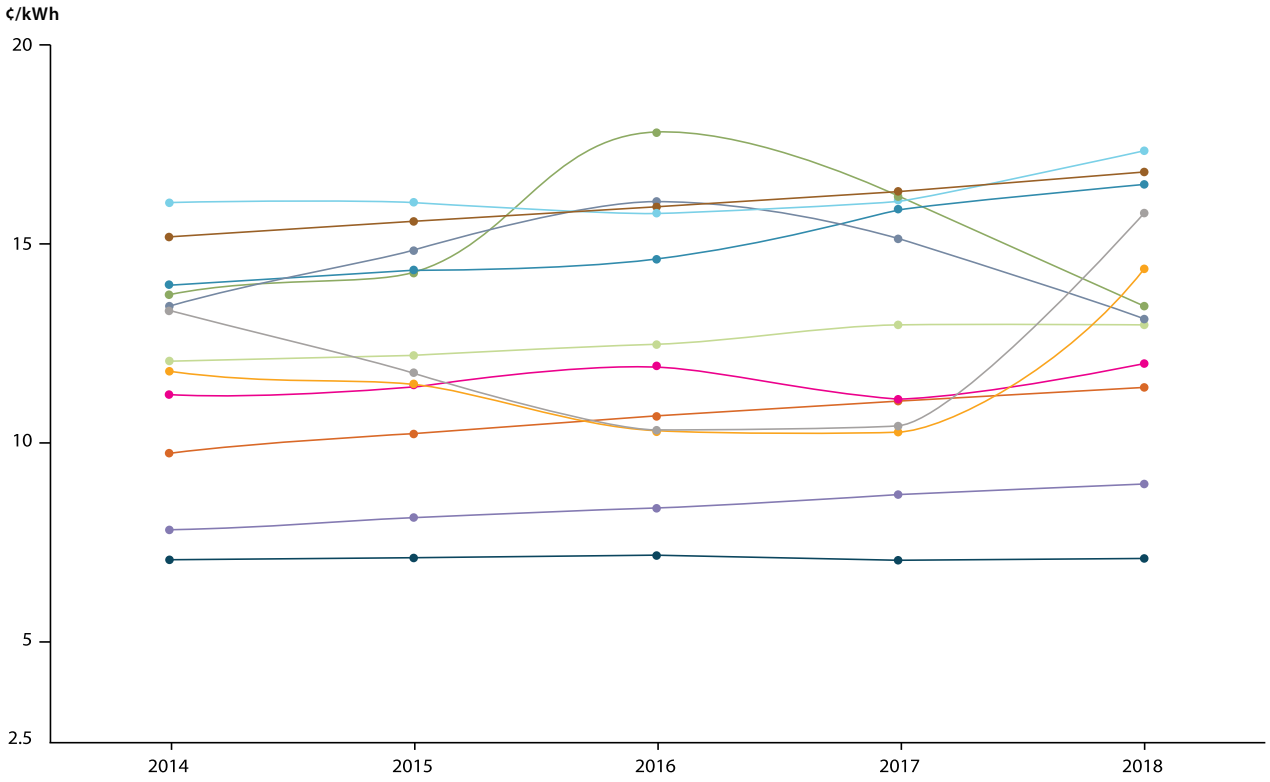
1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2018.
2) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh) – 2014 TO 2018[1,2,3]



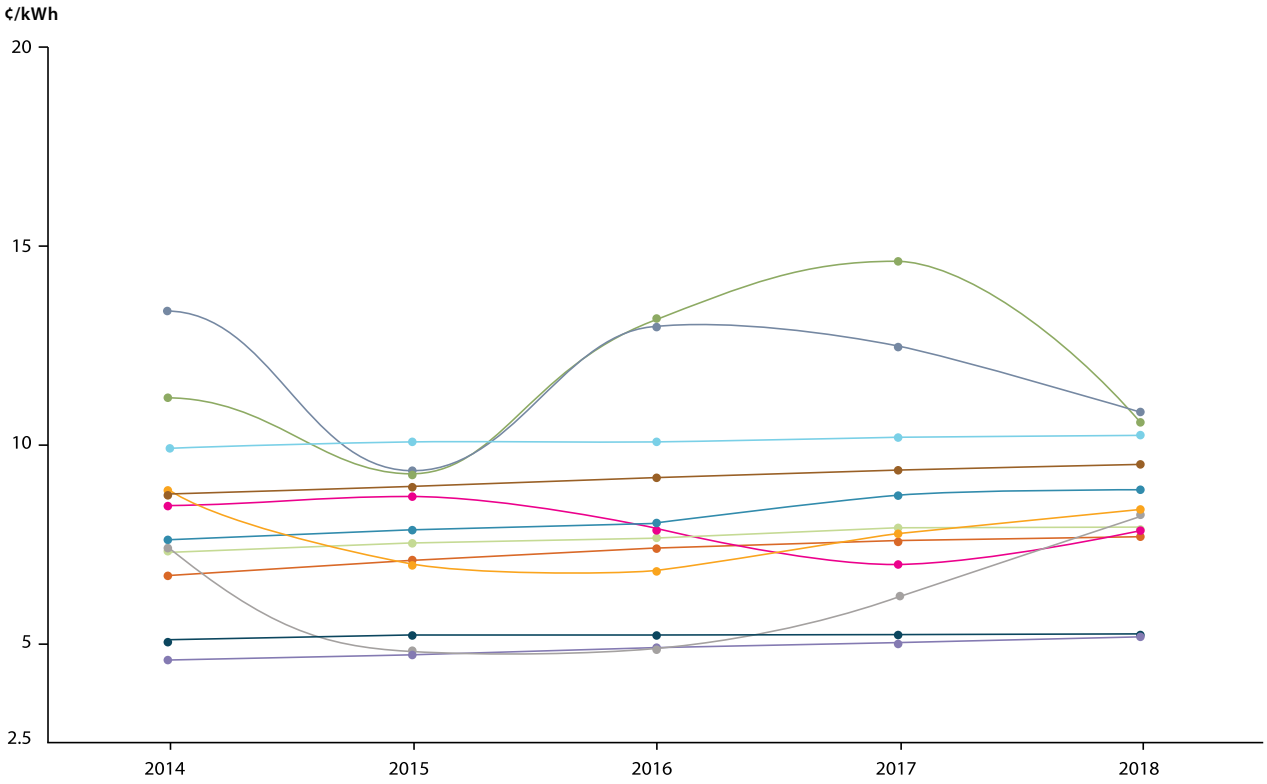
AVERAGE PRICES FOR A RESIDENTIAL CUSTOMER (IN ¢/KWH)[1,2,3]

	2014	2015	2016	2017	2018
Canadian Cities					
Montréal, QC	**7.06**	**7.19**	**7.23**	**7.07**	**7.13**
Calgary, AB	13.41	11.66	10.40	10.45	15.79
Charlottetown, PE	15.24	15.62	16.02	16.42	16.83
Edmonton, AB	11.88	11.55	10.37	10.34	14.35
Halifax, NS	16.03	16.03	15.88	16.15	16.41
Moncton, NB	12.06	12.30	12.50	12.97	12.97
Ottawa, ON	13.45	14.86	16.15	15.21	12.16
Regina, SK	13.95	14.37	14.65	15.94	16.51
St. John's, NL	11.34	11.55	11.96	11.15	12.03
Toronto, ON	13.78	14.31	17.81	16.32	13.24
Vancouver, BC	9.71	10.29	10.70	11.08	11.42
Winnipeg, MB	7.89	8.11	8.43	8.71	9.00

1) For a monthly consumption of 1,000 kWh.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2014 to 2018.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh) – 2014 TO 2018[1,2,3]



AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/KWH)[1,2,3]

	2014	2015	2016	2017	2018
Canadian Cities					
Montréal, QC	**5.05**	**5.17**	**5.17**	**5.18**	**5.18**
Calgary, AB	7.42	4.76	4.82	6.09	8.32
Charlottetown, PE	8.71	8.90	9.12	9.31	9.51
Edmonton, AB	8.87	6.97	6.78	7.68	8.53
Halifax, NS	9.86	10.02	10.02	10.14	10.26
Moncton, NB	7.34	7.48	7.60	7.86	7.86
Ottawa, ON	13.31	9.30	12.91	12.46	10.80
Regina, SK	7.56	7.81	7.97	8.67	8.98
St. John's, NL	8.42	8.65	7.88	6.95	7.84
Toronto, ON	11.13	9.22	13.04	14.55	10.66
Vancouver, BC	6.66	7.04	7.35	7.54	7.77
Winnipeg, MB	4.54	4.67	4.85	5.01	5.18

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2014 to 2018.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the 9 other Canadian provinces, and 10 utilities in American states. The results are based, in part, on a survey to which 14 utilities responded, and in part on estimates of bills calculated by Hydro-Québec and confirmed in most cases by the utilities concerned.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2018. The most recent rate adjustments applied by the Canadian utilities in the study between April 1, 2017, and April 1, 2018, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the Detailed Tables.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists taxes applicable on April 1, 2018, by customer category; those which may be partially or fully refundable are also indicated.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes offer different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2018.

TIME-OF-USE RATES

The rates offered by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates which are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include adjustment clauses that allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2017, and April 1, 2018, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.7747 (CA$1 = US$0.7747), the rate in effect at noon on April 2, 2018. The Canadian dollar had thus appreciated by 3.74% relative to the U.S. dollar on April 1, 2017.

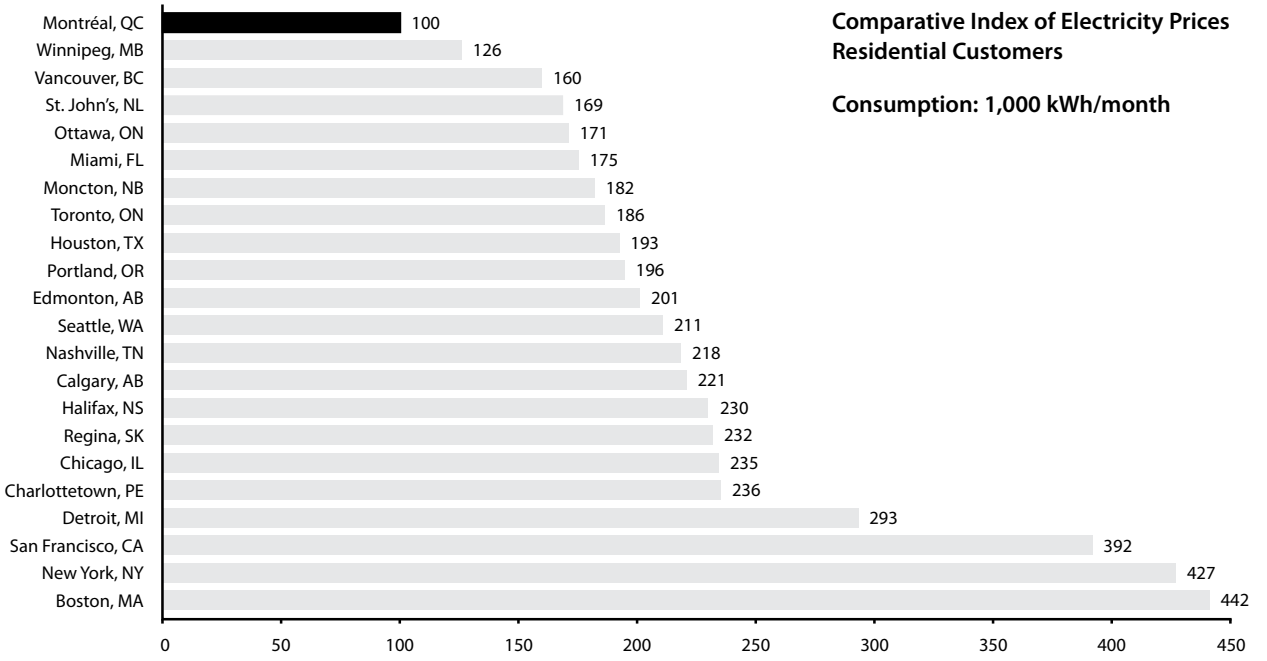
HIGHLIGHTS

The *Electricity Rates Effective April 1, 2018* sets out Hydro-Québec's rates, as approved by the Régie de l'énergie (the Québec energy board) in accordance with Decision D-2018-030. Three types of rates are in effect: domestic rates, for residential customers, the industrial rate, for large-power industrial customers, and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kWh, Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

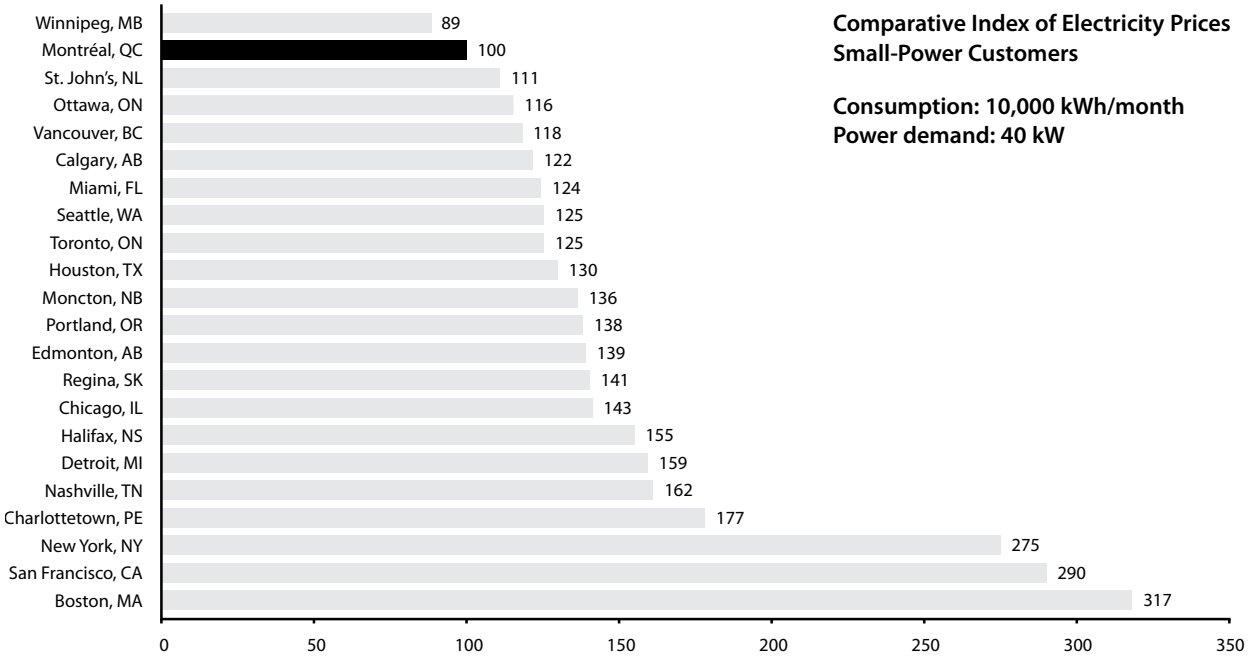
FIGURE 1



SMALL-POWER CUSTOMERS (LESS THAN 100 kW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kW. Montréal is in *second* place this year, improving its position from last year. Figure 2 shows the comparative index of electricity prices.

FIGURE 2

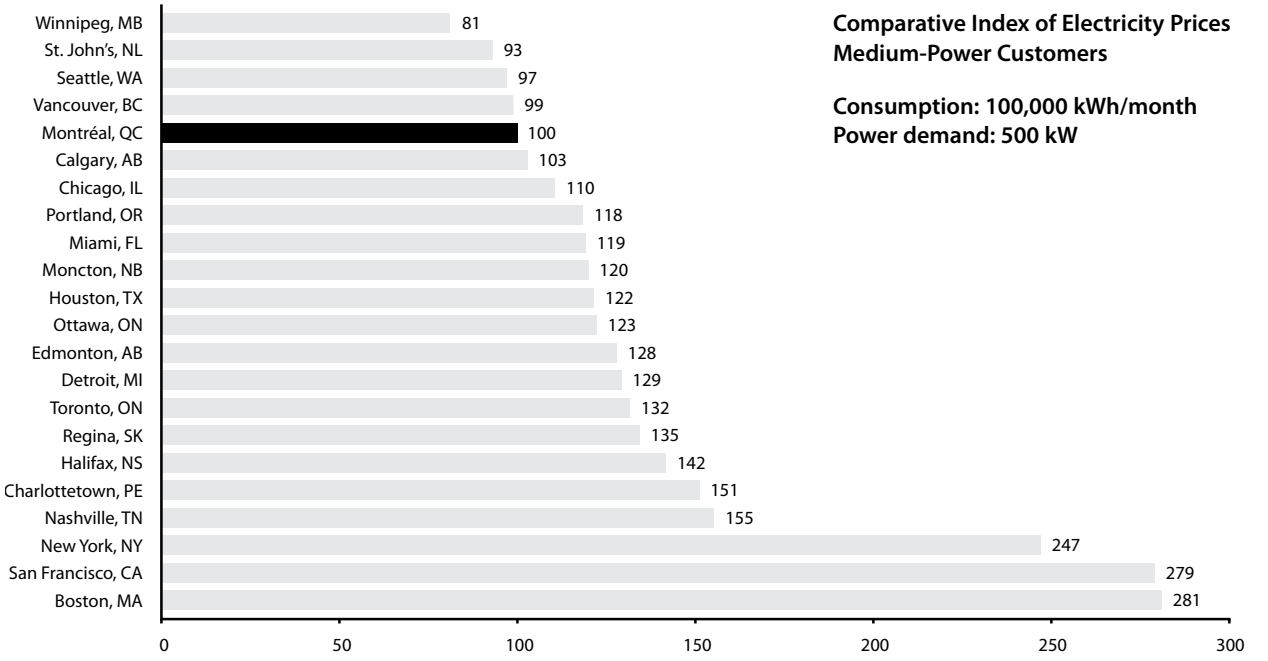


MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

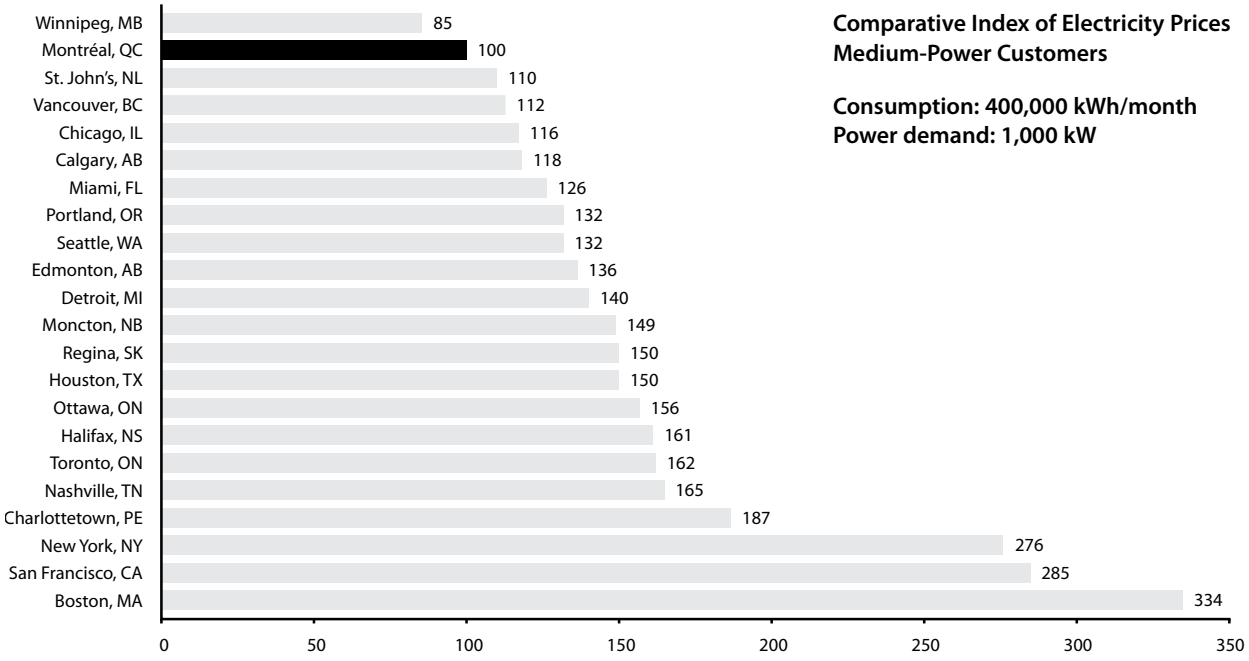
For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal is in *fifth* place, compared with seventh last year.

FIGURE 3



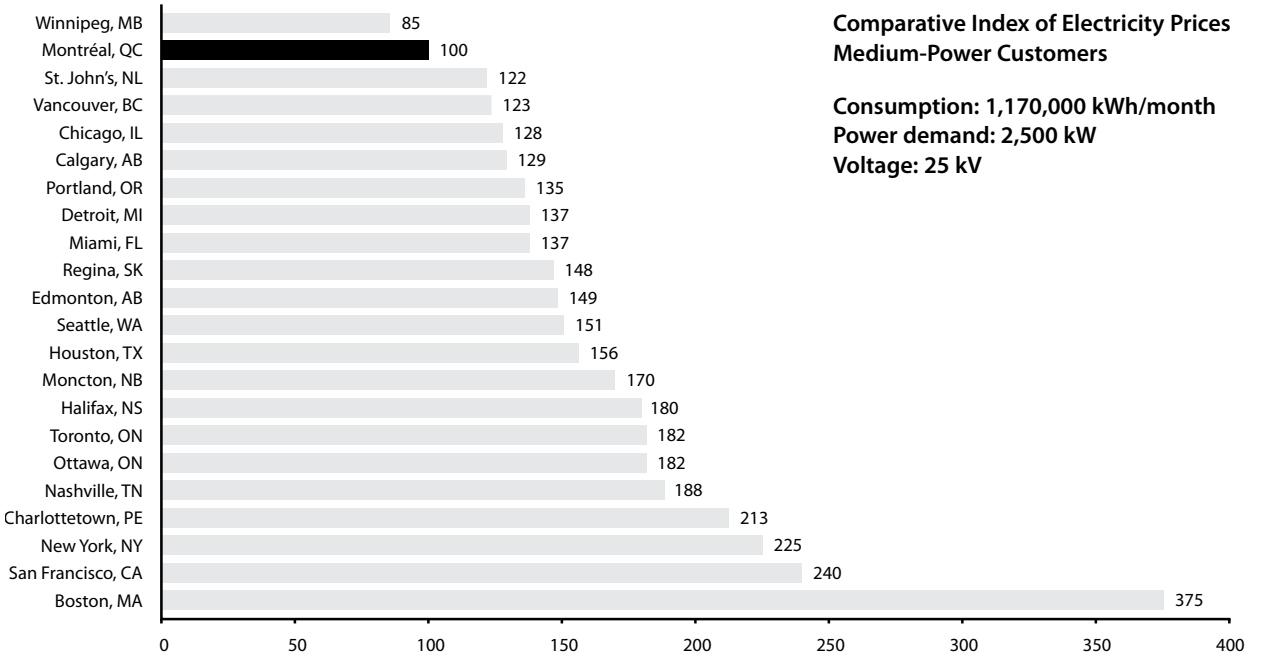
For medium-power customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal has climbed the ranking to *second* place, over fourth last year.

FIGURE 4



In the case of medium-power customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal has moved up from third to *second* place.

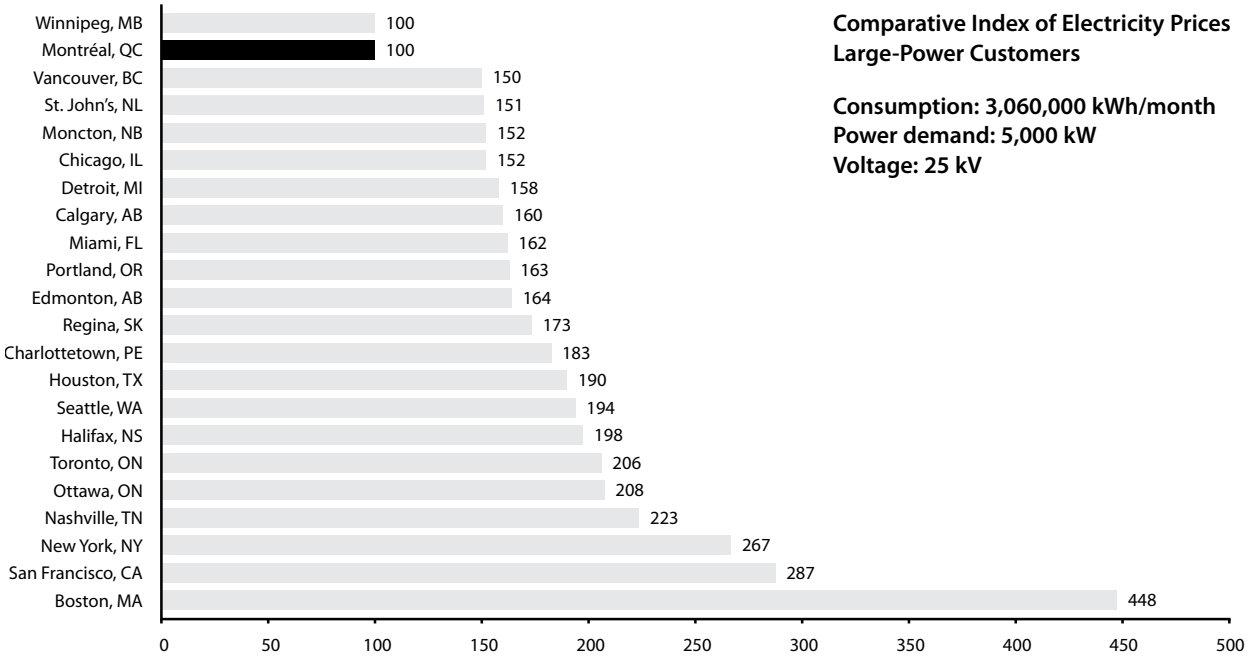
FIGURE 5



LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

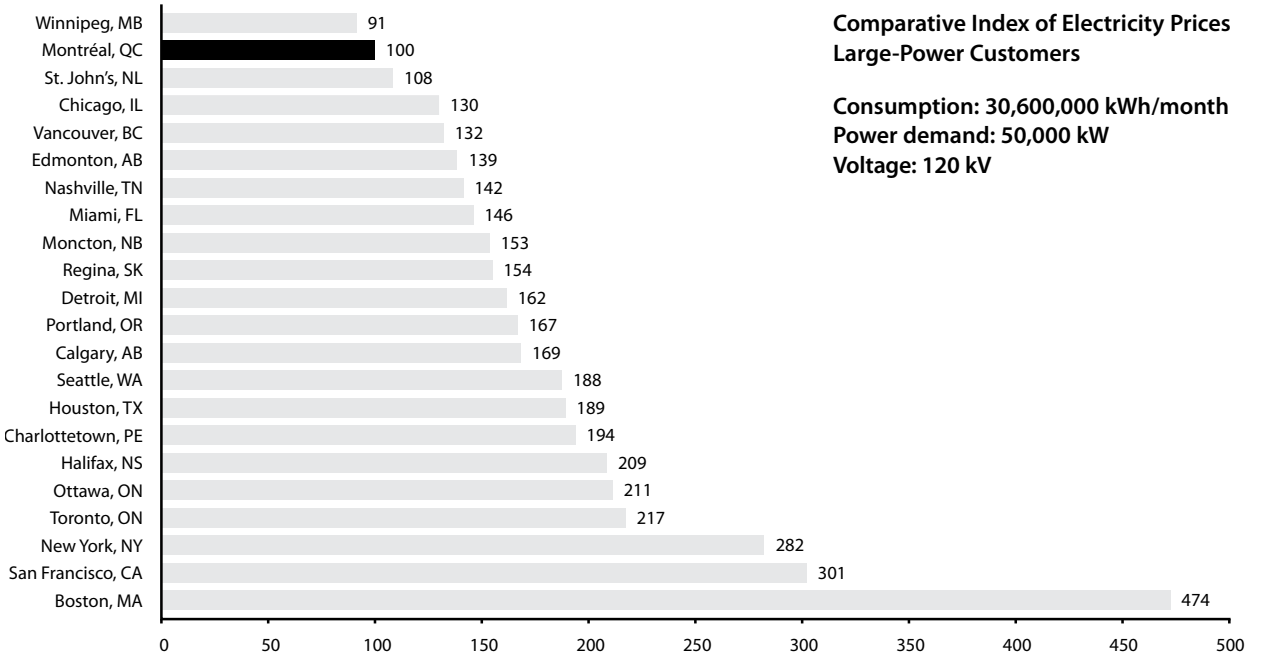
Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. This year, Montréal is in *second* place, coming in just behind Winnipeg.

FIGURE 6



For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal has improved this year, moving up from third to *second* place.

FIGURE 7



01

Detailed Tables

Summary Tables (excluding taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2018

(in CA$)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	**71.29**	**993.33**	**12,100.00**	**31,969.00**	**79,252.50**	**158,619.00**	**1,501,290.00**
Calgary, AB	157.87	1,207.51	12,456.45	37,574.49	101,886.58	254,451.70	2,536,658.02
Charlottetown, PE[3]	168.27	1,753.67	18,317.47	59,652.47	168,655.47	290,984.00	2,909,840.00
Edmonton, AB[4]	143.48	1,380.44	15,495.71	43,509.28	117,902.04	260,907.36	2,091,322.12
Halifax, NS	164.14	1,544.00	17,145.50	51,527.00	142,407.75	314,080.29	3,140,826.84
Moncton, NB	129.70	1,348.70	14,498.70	47,533.70	134,587.70	240,543.40	2,294,700.00
Ottawa, ON	121.57	1,153.03	14,830.21	49,963.30	144,276.05	330,454.62	3,167,462.08
Regina, SK	165.07	1,398.04	16,347.97	48,027.97	117,239.17	274,788.38	2,312,973.29
St. John's, NL[5]	120.29	1,101.54	11,228.01	35,111.88	96,509.82	239,757.92	1,620,826.00
Toronto, ON[3]	132.36	1,244.13	15,946.13	51,800.44	143,874.48	326,204.60	3,258,364.68
Vancouver, BC	114.15	1,172.23	12,025.24	35,949.49	97,826.70	237,867.75	1,982,712.74
Winnipeg, MB	90.04	882.81	9,773.08	27,210.58	67,202.76	158,599.31	1,366,338.96
American Cities							
Boston, MA	315.20	3,145.28	34,047.00	106,650.20	297,316.07	711,189.41	7,108,989.78
Chicago, IL	167.48	1,422.04	13,294.27	37,117.63	101,681.21	241,038.57	1,951,434.94
Detroit, MI[3]	208.62	1,582.19	15,650.15	44,670.28	108,401.65	251,255.54	2,427,046.85
Houston, TX[3]	137.54	1,294.61	14,792.51	48,056.37	123,342.87	301,036.84	2,842,240.83
Miami, FL[3]	125.07	1,232.92	14,432.95	40,397.39	108,464.12	256,428.26	2,192,549.38
Nashville, TN	155.33	1,605.71	18,743.28	52,882.36	148,732.56	354,124.91	2,136,464.48
New York, NY[3]	304.56	2,734.03	29,923.58	88,183.45	178,585.32	423,350.35	4,231,884.37
Portland, OR[3]	139.87	1,373.06	14,297.63	42,113.20	106,630.40	258,921.91	2,510,145.78
San Francisco, CA[3]	279.49	2,885.57	33,717.93	91,226.53	189,921.40	454,557.86	4,522,678.12
Seattle, WA	150.20	1,239.17	11,765.64	42,124.59	119,712.33	307,666.04	2,824,135.83
AVERAGE	**161.89**	**1,531.55**	**16,855.88**	**50,602.35**	**131,564.04**	**302,128.55**	**2,769,585.69**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2018

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	**7.13**	**9.93**	**12.10**	**7.99**	**6.77**	**5.18**	**4.91**
Calgary, AB	15.79	12.08	12.46	9.39	8.71	8.32	8.29
Charlottetown, PE[4]	16.83	17.54	18.32	14.91	14.41	9.51	9.51
Edmonton, AB[5]	14.35	13.80	15.50	10.88	10.08	8.53	6.83
Halifax, NS	16.41	15.44	17.15	12.88	12.17	10.26	10.26
Moncton, NB	12.97	13.49	14.50	11.88	11.50	7.86	7.50
Ottawa, ON	12.16	11.53	14.83	12.49	12.33	10.80	10.35
Regina, SK	16.51	13.98	16.35	12.01	10.02	8.98	7.56
St. John's, NL[6]	12.03	11.02	11.23	8.78	8.25	7.84	5.30
Toronto, ON[4]	13.24	12.44	15.95	12.95	12.30	10.66	10.65
Vancouver, BC	11.42	11.72	12.03	8.99	8.36	7.77	6.48
Winnipeg, MB	9.00	8.83	9.77	6.80	5.74	5.18	4.47
American Cities							
Boston, MA	31.52	31.45	34.05	26.66	25.41	23.24	23.23
Chicago, IL	16.75	14.22	13.29	9.28	8.69	7.88	6.38
Detroit, MI[4]	20.86	15.82	15.65	11.17	9.27	8.21	7.93
Houston, TX[4]	13.75	12.95	14.79	12.01	10.54	9.84	9.29
Miami, FL[4]	12.51	12.33	14.43	10.10	9.27	8.38	7.17
Nashville, TN	15.53	16.06	18.74	13.22	12.71	11.57	6.98
New York, NY[4]	30.46	27.34	29.92	22.05	15.26	13.83	13.83
Portland, OR[4]	13.99	13.73	14.30	10.53	9.11	8.46	8.20
San Francisco, CA[4]	27.95	28.86	33.72	22.81	16.23	14.85	14.78
Seattle, WA	15.02	12.39	11.77	10.53	10.23	10.05	9.23
AVERAGE	**16.19**	**15.32**	**16.86**	**12.65**	**11.24**	**9.87**	**9.05**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2018

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	221	122	103	118	129	160	169
Charlottetown, PE[3]	236	177	151	187	213	183	194
Edmonton, AB[4]	201	139	128	136	149	164	139
Halifax, NS	230	155	142	161	180	198	209
Moncton, NB	182	136	120	149	170	152	153
Ottawa, ON	171	116	123	156	182	208	211
Regina, SK	232	141	135	150	148	173	154
St. John's, NL[5]	169	111	93	110	122	151	108
Toronto, ON[3]	186	125	132	162	182	206	217
Vancouver, BC	160	118	99	112	123	150	132
Winnipeg, MB	126	89	81	85	85	100	91
American Cities							
Boston, MA	442	317	281	334	375	448	474
Chicago, IL	235	143	110	116	128	152	130
Detroit, MI[3]	293	159	129	140	137	158	162
Houston, TX[3]	193	130	122	150	156	190	189
Miami, FL[3]	175	124	119	126	137	162	146
Nashville, TN	218	162	155	165	188	223	142
New York, NY[3]	427	275	247	276	225	267	282
Portland, OR[3]	196	138	118	132	135	163	167
San Francisco, CA[3]	392	290	279	285	240	287	301
Seattle, WA	211	125	97	132	151	194	188
AVERAGE	**227**	**154**	**139**	**158**	**166**	**190**	**184**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

Detailed Tables

Summary Tables (including taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2018

(in CA$)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	81.96	1,142.08	13,911.98	36,756.36	91,120.57	182,372.20	1,726,108.18
Calgary, AB	165.77	1,267.88	13,079.27	39,453.21	106,980.91	267,174.29	2,663,490.92
Charlottetown, PE[3]	193.51	2,016.72	21,065.09	68,600.34	193,953.79	334,631.60	3,346,316.00
Edmonton, AB[4]	150.65	1,449.46	16,270.50	45,684.74	123,797.14	273,952.73	2,195,888.23
Halifax, NS	172.35	1,775.60	19,717.33	59,256.05	163,768.91	361,192.33	3,611,950.87
Moncton, NB	149.16	1,551.01	16,673.51	54,663.76	154,775.86	276,624.91	2,638,905.00
Ottawa, ON	138.75	1,315.95	16,758.14	56,458.53	163,031.94	373,413.72	3,579,232.15
Regina, SK	189.83	1,700.02	19,879.13	58,402.01	142,562.83	334,142.67	2,812,575.52
St. John's, NL[5]	138.34	1,266.77	12,912.21	40,378.66	110,986.29	275,721.61	1,863,949.90
Toronto, ON[3]	151.07	1,419.93	18,019.13	58,534.50	162,578.16	368,611.20	3,681,952.09
Vancouver, BC	121.85	1,271.87	13,047.39	39,005.20	106,141.97	258,086.51	2,151,243.32
Winnipeg, MB	104.10	1,043.92	11,556.67	32,176.52	75,166.29	177,393.33	1,528,250.13
American Cities							
Boston, MA	315.20	3,333.06	36,086.92	112,963.77	314,868.53	752,945.44	7,526,368.62
Chicago, IL	179.85	1,522.25	14,206.92	40,578.31	111,412.60	265,390.60	2,163,055.20
Detroit, MI[3]	227.39	1,756.23	17,371.67	49,584.01	120,325.83	278,893.65	2,694,022.00
Houston, TX[3]	138.92	1,396.46	15,866.25	51,525.01	133,500.31	326,115.49	3,079,746.46
Miami, FL[3]	147.60	1,556.93	18,268.28	50,834.88	136,271.84	321,448.04	2,722,257.63
Nashville, TN	155.33	1,718.11	20,055.31	56,584.12	159,143.84	378,913.66	2,286,017.00
New York, NY[3]	331.35	3,049.74	33,379.37	98,362.01	199,194.49	472,200.21	4,720,195.55
Portland, OR[3]	142.22	1,396.31	14,541.06	42,824.73	108,479.90	263,422.99	2,553,854.84
San Francisco, CA[3]	279.86	3,134.58	36,621.39	99,130.52	206,502.69	494,340.73	4,918,560.32
Seattle, WA	150.20	1,239.17	11,765.64	42,124.59	119,712.33	307,666.04	2,824,135.83
AVERAGE	**173.88**	**1,696.55**	**18,684.23**	**56,085.54**	**145,648.96**	**333,847.91**	**3,058,548.90**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2018

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	8.20	11.42	13.91	9.19	7.79	5.96	5.64
Calgary, AB	16.58	12.68	13.08	9.86	9.14	8.73	8.70
Charlottetown, PE[4]	19.35	20.17	21.07	17.15	16.58	10.94	10.94
Edmonton, AB[5]	15.07	14.49	16.27	11.42	10.58	8.95	7.18
Halifax, NS	17.24	17.76	19.72	14.81	14.00	11.80	11.80
Moncton, NB	14.92	15.51	16.67	13.67	13.23	9.04	8.62
Ottawa, ON	13.88	13.16	16.76	14.11	13.93	12.20	11.70
Regina, SK	18.98	17.00	19.88	14.60	12.18	10.92	9.19
St. John's, NL[6]	13.83	12.67	12.91	10.09	9.49	9.01	6.09
Toronto, ON[4]	15.11	14.20	18.02	14.63	13.90	12.05	12.03
Vancouver, BC	12.19	12.72	13.05	9.75	9.07	8.43	7.03
Winnipeg, MB	10.41	10.44	11.56	8.04	6.42	5.80	4.99
American Cities							
Boston, MA	31.52	33.33	36.09	28.24	26.91	24.61	24.60
Chicago, IL	17.98	15.22	14.21	10.14	9.52	8.67	7.07
Detroit, MI[4]	22.74	17.56	17.37	12.40	10.28	9.11	8.80
Houston, TX[4]	13.89	13.96	15.87	12.88	11.41	10.66	10.06
Miami, FL[4]	14.76	15.57	18.27	12.71	11.65	10.50	8.90
Nashville, TN	15.53	17.18	20.06	14.15	13.60	12.38	7.47
New York, NY[4]	33.13	30.50	33.38	24.59	17.03	15.43	15.43
Portland, OR[4]	14.22	13.96	14.54	10.71	9.27	8.61	8.35
San Francisco, CA[4]	27.99	31.35	36.62	24.78	17.65	16.15	16.07
Seattle, WA	15.02	12.39	11.77	10.53	10.23	10.05	9.23
AVERAGE	**17.39**	**16.97**	**18.68**	**14.02**	**12.45**	**10.91**	**10.00**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2018

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	202	111	94	107	117	146	154
Charlottetown, PE[3]	236	177	151	187	213	183	194
Edmonton, AB[4]	184	127	117	124	136	150	127
Halifax, NS	210	155	142	161	180	198	209
Moncton, NB	182	136	120	149	170	152	153
Ottawa, ON	169	115	120	154	179	205	207
Regina, SK	232	149	143	159	156	183	163
St. John's, NL[5]	169	111	93	110	122	151	108
Toronto, ON[3]	184	124	130	159	178	202	213
Vancouver, BC	149	111	94	106	116	142	125
Winnipeg, MB	127	91	83	88	82	97	89
American Cities							
Boston, MA	385	292	259	307	346	413	436
Chicago, IL	219	133	102	110	122	146	125
Detroit, MI[3]	277	154	125	135	132	153	156
Houston, TX[3]	169	122	114	140	147	179	178
Miami, FL[3]	180	136	131	138	150	176	158
Nashville, TN	190	150	144	154	175	208	132
New York, NY[3]	404	267	240	268	219	259	273
Portland, OR[3]	174	122	105	117	119	144	148
San Francisco, CA[3]	341	274	263	270	227	271	285
Seattle, WA	183	109	85	115	131	169	164
AVERAGE	**212**	**149**	**134**	**153**	**160**	**183**	**177**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

Detailed Tables

Residential

Monthly Bills

Average Prices

Comparative Index

RESIDENTIAL

Monthly Bills on April 1, 2018
(in CA$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	49.13	56.52	71.29	159.92	251.12
Calgary, AB	108.13	124.71	157.87	290.51	423.14
Charlottetown, PE[1]	114.38	132.35	168.27	311.97	426.17
Edmonton, AB	98.67	113.61	143.48	262.97	382.46
Halifax, NS	106.65	125.81	164.14	317.45	470.76
Moncton, NB	89.16	102.68	129.70	237.80	345.90
Ottawa, ON	83.34	96.09	121.57	223.51	325.46
Regina, SK	111.72	129.50	165.07	307.35	449.63
St. John's, NL[2]	81.13	94.19	120.29	224.72	329.14
Toronto, ON[1]	94.29	106.98	132.36	233.90	335.43
Vancouver, BC	64.26	79.34	114.15	253.38	392.61
Winnipeg, MB	59.31	69.55	90.04	172.00	253.96
American Cities					
Boston, MA	200.38	238.67	315.20	621.37	927.53
Chicago, IL	113.07	131.21	167.48	312.54	457.61
Detroit, MI[1]	130.94	156.84	208.62	415.75	622.87
Houston, TX[1]	101.45	117.76	137.54	268.02	398.50
Miami, FL[1]	82.04	96.38	125.07	265.85	406.64
Nashville, TN	105.26	121.95	155.33	288.86	422.38
New York, NY[1]	197.94	233.48	304.56	588.88	873.20
Portland, OR[1]	92.49	108.28	139.87	307.01	474.15
San Francisco, CA[1]	154.20	199.37	279.49	758.50	1,317.97
Seattle, WA	86.02	107.41	150.20	321.36	492.52
AVERAGE	**105.64**	**124.67**	**161.89**	**324.71**	**489.96**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL

Average Prices on April 1, 2018
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	7.86	7.54	7.13	8.00	8.37
Calgary, AB	17.30	16.63	15.79	14.53	14.10
Charlottetown, PE[2]	18.30	17.65	16.83	15.60	14.21
Edmonton, AB	15.79	15.15	14.35	13.15	12.75
Halifax, NS	17.06	16.77	16.41	15.87	15.69
Moncton, NB	14.27	13.69	12.97	11.89	11.53
Ottawa, ON	13.33	12.81	12.16	11.18	10.85
Regina, SK	17.87	17.27	16.51	15.37	14.99
St. John's, NL[3]	12.98	12.56	12.03	11.24	10.97
Toronto, ON[2]	15.09	14.26	13.24	11.69	11.18
Vancouver, BC	10.28	10.58	11.42	12.67	13.09
Winnipeg, MB	9.49	9.27	9.00	8.60	8.47
American Cities					
Boston, MA	32.06	31.82	31.52	31.07	30.92
Chicago, IL	18.09	17.49	16.75	15.63	15.25
Detroit, MI[2]	20.95	20.91	20.86	20.79	20.76
Houston, TX[2]	16.23	15.70	13.75	13.40	13.28
Miami, FL[2]	13.13	12.85	12.51	13.29	13.55
Nashville, TN	16.84	16.26	15.53	14.44	14.08
New York, NY[2]	31.67	31.13	30.46	29.44	29.11
Portland, OR[2]	14.80	14.44	13.99	15.35	15.80
San Francisco, CA[2]	24.67	26.58	27.95	37.93	43.93
Seattle, WA	13.76	14.32	15.02	16.07	16.42
AVERAGE	**16.90**	**16.62**	**16.19**	**16.24**	**16.33**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL

Comparative Index on April 1, 2018
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	220	221	221	182	169
Charlottetown, PE[1]	233	234	236	195	170
Edmonton, AB	201	201	201	164	152
Halifax, NS	217	223	230	199	187
Moncton, NB	181	182	182	149	138
Ottawa, ON	170	170	171	140	130
Regina, SK	227	229	232	192	179
St. John's, NL[2]	165	167	169	141	131
Toronto, ON[1]	192	189	186	146	134
Vancouver, BC	131	140	160	158	156
Winnipeg, MB	121	123	126	108	101
American Cities					
Boston, MA	408	422	442	389	369
Chicago, IL	230	232	235	195	182
Detroit, MI[1]	267	277	293	260	248
Houston, TX[1]	207	208	193	168	159
Miami, FL[1]	167	171	175	166	162
Nashville, TN	214	216	218	181	168
New York, NY[1]	403	413	427	368	348
Portland, OR[1]	188	192	196	192	189
San Francisco, CA[1]	314	353	392	474	525
Seattle, WA	175	190	211	201	196
AVERAGE	**215**	**221**	**227**	**203**	**195**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

Detailed Tables

Small Power

Monthly Bills

Average Prices

Comparative Index

SMALL POWER

Monthly Bills on April 1, 2018
(in CA$)

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	85.91	208.53	993.33	1,820.00	2,693.50
Calgary, AB	150.47	318.75	1,207.51	1,868.67	2,651.77
Charlottetown, PE[1]	157.10	377.97	1,753.67	3,021.07	4,290.47
Edmonton, AB	117.73	288.36	1,380.44	2,533.65	3,501.10
Halifax, NS	122.62	299.86	1,544.00	2,715.28	3,860.00
Moncton, NB	120.73	284.10	1,348.70	2,346.50	3,366.20
Ottawa, ON	103.00	244.90	1,153.03	2,310.26	3,638.82
Regina, SK	133.66	304.52	1,398.04	2,687.72	3,650.47
St. John's, NL[2]	99.54	258.47	1,101.54	1,938.97	2,751.38
Toronto, ON[1]	125.31	276.68	1,244.13	2,408.42	3,744.94
Vancouver, BC	103.27	257.22	1,172.23	1,872.16	2,918.59
Winnipeg, MB	86.48	194.09	882.81	1,764.28	2,309.88
American Cities					
Boston, MA	229.73	596.83	3,145.28	6,009.16	8,295.77
Chicago, IL	178.38	378.41	1,422.04	2,385.05	3,484.44
Detroit, MI[1]	133.17	331.70	1,582.19	2,207.43	3,926.85
Houston, TX[1]	101.94	351.33	1,294.61	2,321.97	3,195.71
Miami, FL[1]	100.61	246.39	1,232.92	2,328.04	3,033.01
Nashville, TN	174.43	381.04	1,605.71	3,428.01	4,351.51
New York, NY[1]	247.42	783.62	2,734.03	5,181.64	6,743.49
Portland, OR[1]	128.65	304.62	1,373.06	2,302.05	3,373.62
San Francisco, CA[1]	229.44	590.65	2,885.57	4,858.64	6,946.75
Seattle, WA	92.94	247.83	1,239.17	1,782.34	2,828.79
AVERAGE	**137.39**	**342.08**	**1,531.55**	**2,731.42**	**3,888.96**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL POWER

Average Prices on April 1, 2018
(in ¢/kWh)[1]

Power demand Consumption Load factor	6 kW 750 kWh 17%	14 kW 2,000 kWh 20%	40 kW 10,000 kWh 35%	100 kW 14,000 kWh 19%	100 kW 25,000 kWh 35%
Canadian Cities					
Montréal, QC	11.45	10.43	9.93	13.00	10.77
Calgary, AB	20.06	15.94	12.08	13.35	10.61
Charlottetown, PE[2]	20.95	18.90	17.54	21.58	17.16
Edmonton, AB	15.70	14.42	13.80	18.10	14.00
Halifax, NS	16.35	14.99	15.44	19.39	15.44
Moncton, NB	16.10	14.21	13.49	16.76	13.46
Ottawa, ON	13.73	12.25	11.53	16.50	14.56
Regina, SK	17.82	15.23	13.98	19.20	14.60
St. John's, NL[3]	13.27	12.92	11.02	13.85	11.01
Toronto, ON[2]	16.71	13.83	12.44	17.20	14.98
Vancouver, BC	13.77	12.86	11.72	13.37	11.67
Winnipeg, MB	11.53	9.70	8.83	12.60	9.24
American Cities					
Boston, MA	30.63	29.84	31.45	42.92	33.18
Chicago, IL	23.78	18.92	14.22	17.04	13.94
Detroit, MI[2]	17.76	16.58	15.82	15.77	15.71
Houston, TX[2]	13.59	17.57	12.95	16.59	12.78
Miami, FL[2]	13.41	12.32	12.33	16.63	12.13
Nashville, TN	23.26	19.05	16.06	24.49	17.41
New York, NY[2]	32.99	39.18	27.34	37.01	26.97
Portland, OR[2]	17.15	15.23	13.73	16.44	13.49
San Francisco, CA[2]	30.59	29.53	28.86	34.70	27.79
Seattle, WA	12.39	12.39	12.39	12.73	11.32
AVERAGE	**18.32**	**17.10**	**15.32**	**19.51**	**15.56**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL POWER

Comparative Index on April 1, 2018
(Hydro-Québec = 100)

Power demand **Consumption** **Load factor**	**6 kW** **750 kWh** **17%**	**14 kW** **2,000 kWh** **20%**	**40 kW** **10,000 kWh** **35%**	**100 kW** **14,000 kWh** **19%**	**100 kW** **25,000 kWh** **35%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	175	153	122	103	98
Charlottetown, PE[1]	183	181	177	166	159
Edmonton, AB	137	138	139	139	130
Halifax, NS	143	144	155	149	143
Moncton, NB	141	136	136	129	125
Ottawa, ON	120	117	116	127	135
Regina, SK	156	146	141	148	136
St. John's, NL[2]	116	124	111	107	102
Toronto, ON[1]	146	133	125	132	139
Vancouver, BC	120	123	118	103	108
Winnipeg, MB	101	93	89	97	86
American Cities					
Boston, MA	267	286	317	330	308
Chicago, IL	208	181	143	131	129
Detroit, MI[1]	155	159	159	121	146
Houston, TX[1]	119	168	130	128	119
Miami, FL[1]	117	118	124	128	113
Nashville, TN	203	183	162	188	162
New York, NY[1]	288	376	275	285	250
Portland, OR[1]	150	146	138	126	125
San Francisco, CA[1]	267	283	290	267	258
Seattle, WA	108	119	125	98	105
AVERAGE	**160**	**164**	**154**	**150**	**144**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

05

Detailed Tables

Medium Power

Monthly Bills

Average Prices

Comparative Index

MEDIUM POWER

Monthly Bills on April 1, 2018
(in CA$)

Power demand **Consumption** **Load factor**	**500 kW** **100,000 kWh** **28%**	**500 kW** **200,000 kWh** **56%**	**1,000 kW** **200,000 kWh** **28%**	**1,000 kW** **400,000 kWh** **56%**	**2,500 kW**[1] **1,170,000 kWh** **65%**
Canadian Cities					
Montréal, QC	12,100.00	17,210.00	24,200.00	31,969.00	79,252.50
Calgary, AB	12,456.45	19,158.55	24,170.28	37,574.49	101,886.58
Charlottetown, PE[2]	18,317.47	29,857.47	36,572.47	59,652.47	168,655.47
Edmonton, AB[3]	15,495.71	22,917.21	28,666.26	43,509.28	117,902.04
Halifax, NS	17,145.50	25,763.50	34,291.00	51,527.00	142,407.75
Moncton, NB	14,498.70	23,768.70	28,993.70	47,533.70	134,587.70
Ottawa, ON	14,830.21	25,081.77	29,460.17	49,963.30	144,276.05
Regina, SK	16,347.97	24,021.97	32,679.97	48,027.97	117,239.17
St. John's, NL[4]	11,228.01	18,177.18	21,349.46	35,111.88	96,509.82
Toronto, ON[2]	15,946.13	26,192.43	31,512.77	51,800.44	143,874.48
Vancouver, BC	12,025.24	17,978.74	24,042.49	35,949.49	97,826.70
Winnipeg, MB	9,773.08	13,717.08	19,322.58	27,210.58	67,202.76
American Cities					
Boston, MA	34,047.00	53,428.36	67,887.47	106,650.20	297,316.07
Chicago, IL	13,294.27	18,652.07	26,402.02	37,117.63	101,681.21
Detroit, MI[2]	15,650.15	22,514.89	31,281.22	44,670.28	108,401.65
Houston, TX[2]	14,792.51	22,735.58	32,170.24	48,056.37	123,342.87
Miami, FL[2]	14,432.95	20,248.01	28,767.29	40,397.39	108,464.12
Nashville, TN	18,743.28	26,573.27	37,222.37	52,882.36	148,732.56
New York, NY[2]	29,923.58	44,122.25	59,786.11	88,183.45	178,585.32
Portland, OR[2]	14,297.63	22,073.41	27,272.13	42,113.20	106,630.40
San Francisco, CA[2]	33,717.93	47,396.13	65,518.17	91,226.53	189,921.40
Seattle, WA	11,765.64	21,278.84	23,108.21	42,124.59	119,712.33
AVERAGE	**16,855.88**	**25,584.88**	**33,394.38**	**50,602.35**	**131,564.04**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM POWER

Average Prices on April 1, 2018
(in ¢/kWh)[1]

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[2] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	12.10	8.61	12.10	7.99	6.77
Calgary, AB	12.46	9.58	12.09	9.39	8.71
Charlottetown, PE[3]	18.32	14.93	18.29	14.91	14.41
Edmonton, AB[4]	15.50	11.46	14.33	10.88	10.08
Halifax, NS	17.15	12.88	17.15	12.88	12.17
Moncton, NB	14.50	11.88	14.50	11.88	11.50
Ottawa, ON	14.83	12.54	14.73	12.49	12.33
Regina, SK	16.35	12.01	16.34	12.01	10.02
St. John's, NL[5]	11.23	9.09	10.67	8.78	8.25
Toronto, ON[3]	15.95	13.10	15.76	12.95	12.30
Vancouver, BC	12.03	8.99	12.02	8.99	8.36
Winnipeg, MB	9.77	6.86	9.66	6.80	5.74
American Cities					
Boston, MA	34.05	26.71	33.94	26.66	25.41
Chicago, IL	13.29	9.33	13.20	9.28	8.69
Detroit, MI[3]	15.65	11.26	15.64	11.17	9.27
Houston, TX[3]	14.79	11.37	16.09	12.01	10.54
Miami, FL[3]	14.43	10.12	14.38	10.10	9.27
Nashville, TN	18.74	13.29	18.61	13.22	12.71
New York, NY[3]	29.92	22.06	29.89	22.05	15.26
Portland, OR[3]	14.30	11.04	13.64	10.53	9.11
San Francisco, CA[3]	33.72	23.70	32.76	22.81	16.23
Seattle, WA	11.77	10.64	11.55	10.53	10.23
AVERAGE	**16.86**	**12.79**	**16.70**	**12.65**	**11.24**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM POWER

Comparative Index on April 1, 2018
(Hydro-Québec = 100)

Power demand Consumption Load factor	500 kW 100,000 kWh 28%	500 kW 200,000 kWh 56%	1,000 kW 200,000 kWh 28%	1,000 kW 400,000 kWh 56%	2,500 kW[1] 1,170,000 kWh 65%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	103	111	100	118	129
Charlottetown, PE[2]	151	173	151	187	213
Edmonton, AB[3]	128	133	118	136	149
Halifax, NS	142	150	142	161	180
Moncton, NB	120	138	120	149	170
Ottawa, ON	123	146	122	156	182
Regina, SK	135	140	135	150	148
St. John's, NL[4]	93	106	88	110	122
Toronto, ON[2]	132	152	130	162	182
Vancouver, BC	99	104	99	112	123
Winnipeg, MB	81	80	80	85	85
American Cities					
Boston, MA	281	310	281	334	375
Chicago, IL	110	108	109	116	128
Detroit, MI[2]	129	131	129	140	137
Houston, TX[2]	122	132	133	150	156
Miami, FL[2]	119	118	119	126	137
Nashville, TN	155	154	154	165	188
New York, NY[2]	247	256	247	276	225
Portland, OR[2]	118	128	113	132	135
San Francisco, CA[2]	279	275	271	285	240
Seattle, WA	97	124	95	132	151
AVERAGE	**139**	**149**	**138**	**158**	**166**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

06

Detailed Tables

Large Power

Monthly Bills

Average Prices

Comparative Index

LARGE POWER

Monthly Bills on April 1, 2018
(in CA$)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	135,075.00	158,619.00	288,486.00	873,306.00	1,265,850.00	1,501,290.00
Calgary, AB	201,346.61	254,451.70	481,476.46	1,460,387.57	2,005,607.09	2,536,658.02
Charlottetown, PE[2]	239,576.00	290,984.00	556,264.00	1,685,928.00	2,395,760.00	2,909,840.00
Edmonton, AB[3]	213,764.69	260,907.36	406,114.05	1,219,604.52	1,750,903.26	2,091,322.12
Halifax, NS	255,033.09	314,080.29	598,636.97	1,815,605.31	2,550,354.84	3,140,826.84
Moncton, NB	202,541.80	240,543.40	440,220.00	1,333,140.00	1,920,300.00	2,294,700.00
Ottawa, ON	315,458.22	330,454.62	638,179.47	1,889,074.07	3,017,498.03	3,167,462.08
Regina, SK	225,093.98	274,788.38	446,691.58	1,339,513.04	1,873,125.29	2,312,973.29
St. John's, NL[4]	190,213.21	239,757.92	448,697.18	941,659.20	1,356,514.00	1,620,826.00
Toronto, ON[2]	311,549.99	326,204.60	647,364.43	1,938,678.14	3,103,603.78	3,258,364.68
Vancouver, BC	195,645.53	237,867.75	378,504.75	1,147,545.72	1,622,025.14	1,982,712.74
Winnipeg, MB	131,894.51	158,599.31	261,233.98	791,729.27	1,125,714.96	1,366,338.96
American Cities						
Boston, MA	575,584.16	711,189.41	1,354,253.49	4,107,316.82	5,752,937.26	7,108,989.78
Chicago, IL	202,546.05	241,038.57	373,864.14	1,111,986.92	1,566,509.64	1,951,434.94
Detroit, MI[2]	216,314.72	251,255.54	468,669.05	1,416,450.77	2,084,423.09	2,427,046.85
Houston, TX[2]	243,895.09	301,036.84	541,791.35	1,640,112.37	2,276,018.50	2,842,240.83
Miami, FL[2]	216,632.38	256,428.26	423,141.39	1,275,812.90	1,843,104.01	2,192,549.38
Nashville, TN	296,336.31	354,124.91	422,076.83	1,245,238.27	1,812,003.65	2,136,464.48
New York, NY[2]	356,990.73	423,350.35	813,340.99	2,461,783.03	3,568,288.22	4,231,884.37
Portland, OR[2]	211,830.99	258,921.91	482,381.79	1,456,177.08	2,072,836.27	2,510,145.78
San Francisco, CA[2]	376,543.19	454,557.86	867,563.89	2,623,607.56	3,742,531.46	4,522,678.12
Seattle, WA	239,567.86	307,666.04	534,296.71	1,622,888.44	2,202,070.14	2,824,135.83
AVERAGE	**252,428.82**	**302,128.55**	**539,693.11**	**1,608,979.32**	**2,313,999.03**	**2,769,585.69**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Average Prices on April 1, 2018
(in ¢/kWh)[1]

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[2]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	5.77	5.18	5.01	4.98	5.41	4.91
Calgary, AB	8.60	8.32	8.36	8.34	8.57	8.29
Charlottetown, PE[3]	10.24	9.51	9.66	9.62	10.24	9.51
Edmonton, AB[4]	9.14	8.53	7.05	6.96	7.48	6.83
Halifax, NS	10.90	10.26	10.39	10.36	10.90	10.26
Moncton, NB	8.66	7.86	7.64	7.61	8.21	7.50
Ottawa, ON	13.48	10.80	11.08	10.78	12.90	10.35
Regina, SK	9.62	8.98	7.76	7.65	8.00	7.56
St. John's, NL[5]	8.13	7.84	7.79	5.37	5.80	5.30
Toronto, ON[3]	13.31	10.66	11.24	11.07	13.26	10.65
Vancouver, BC	8.36	7.77	6.57	6.55	6.93	6.48
Winnipeg, MB	5.64	5.18	4.54	4.52	4.81	4.47
American Cities						
Boston, MA	24.60	23.24	23.51	23.44	24.59	23.23
Chicago, IL	8.66	7.88	6.49	6.35	6.69	6.38
Detroit, MI[3]	9.24	8.21	8.14	8.08	8.91	7.93
Houston, TX[3]	10.42	9.84	9.41	9.36	9.73	9.29
Miami, FL[3]	9.26	8.38	7.35	7.28	7.88	7.17
Nashville, TN	12.66	11.57	7.33	7.11	7.74	6.98
New York, NY[3]	15.26	13.83	14.12	14.05	15.25	13.83
Portland, OR[3]	9.05	8.46	8.37	8.31	8.86	8.20
San Francisco, CA[3]	16.09	14.85	15.06	14.97	15.99	14.78
Seattle, WA	10.24	10.05	9.28	9.26	9.41	9.23
AVERAGE	**10.79**	**9.87**	**9.37**	**9.18**	**9.89**	**9.05**

1) In Canadian currency.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Comparative Index on April 1, 2018
(Hydro-Québec = 100)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	149	160	167	167	158	169
Charlottetown, PE[2]	177	183	193	193	189	194
Edmonton, AB[3]	158	164	141	140	138	139
Halifax, NS	189	198	208	208	201	209
Moncton, NB	150	152	153	153	152	153
Ottawa, ON	234	208	221	216	238	211
Regina, SK	167	173	155	153	148	154
St. John's, NL[4]	141	151	156	108	107	108
Toronto, ON[2]	231	206	224	222	245	217
Vancouver, BC	145	150	131	131	128	132
Winnipeg, MB	98	100	91	91	89	91
American Cities						
Boston, MA	426	448	469	470	454	474
Chicago, IL	150	152	130	127	124	130
Detroit, MI[2]	160	158	162	162	165	162
Houston, TX[2]	181	190	188	188	180	189
Miami, FL[2]	160	162	147	146	146	146
Nashville, TN	219	223	146	143	143	142
New York, NY[2]	264	267	282	282	282	282
Portland, OR[2]	157	163	167	167	164	167
San Francisco, CA[2]	279	287	301	300	296	301
Seattle, WA	177	194	185	186	174	188
AVERAGE	**187**	**190**	**187**	**184**	**183**	**184**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

Appendix

Rate Adjustments

Average Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

All Categories

	Before April 2017		Between April 1, 2017, and April 1, 2018		
	Year	**%**	**Date**	**%**	**Comments**
Canadian Utilities					
Hydro-Québec, QC	2017	0.7	April 1, 2018	0.3	
ENMAX, AB	2017	14.38	January 1, 2018	3.08	Applicable to distribution portion only
Maritime Electric, PE	2017	2.3	March 1, 2018	2.3	
EPCOR, AB	2017	n.a.	—	—	
Nova Scotia Power, NS	2017	1.5	January 1, 2018	n.a.	
NB Power, NB	2017	2.05	—	—	
Hydro Ottawa, ON	2017	n.a.	January 1, 2018	n.a.	
SaskPower, SK	2017	3.5	January 1, 2018	3.5	
Newfoundland Power, NL[1]	2016	-7.93	July 1, 2017	8.5	
Newfoundland and Labrador Hydro, NL[1]	2015	2.7	July 1, 2017 April 1, 2018	n.a. n.a.	
Toronto Hydro, ON	2017	n.a.	January 1, 2018	n.a.	
BC Hydro, BC	2017	3.5	April 1, 2018	3.0	
Manitoba Hydro, MB	2016	3.36	August 1, 2017	3.34	
Data concerning American utilities not available.					

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2017, and April 1, 2018)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2018	0.3	0.3[1] 0.3[2] 0.3[3]	—	0.3
ENMAX, AB	January 1, 2018	2.28[4]	n.a.	n.a.	3.08[4]
Maritime Electric, PE	March 1, 2018	n.a.	n.a.	n.a.	2.3
EPCOR, AB	—	—	—	—	—
Nova Scotia Power, NS	January 1, 2018	1.7	1.9[1] 0.9[2] 3.8[3]	1.3[5] 1.6[6] 1.5[7]	n.a.
NB Power, NB	—	—	—	—	—
Hydro Ottawa, ON	May 1, 2017	-9.04	-9.05	13.50	n.a.
	July 1, 2017	-11.39	11.40	-11.32	n.a.
	January 1, 2018	1.09	1.73	1.03	n.a.
SaskPower, SK	March 1, 2018	3.5	3.5	3.5	3.5
Newfoundland Power, NL[8]	July 1, 2017	8.1	9.3	11.9	8.5
Newfoundland and Labrador Hydro, NL[8]	July 1, 2017	—	—	10.5	—
	April 1, 2018	—	—	1.2	—
Toronto Hydro, ON	January 1, 2018	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2018	3.0	3.0	3.0	3.0
Manitoba Hydro, MB	August 1, 2017	3.35	3.36[1] 3.36[2] 3.36[3]	n.a.	3.34

Data concerning American utilities not available.

n.a.: Not available.

1) Small power.
2) Medium power.
3) Large power.
4) Distribution charge only.
5) Small industrial.
6) Medium industrial.
7) Large industrial.
8) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

Appendix

Time-of-Use Rates
Adjustment Clauses

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2018 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	Residential General: 14–10,000 kW
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	Residential General: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Distribution Cost Recovery Factor Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge System Benefit Fund Charge Transition Charges Transmission Cost Recovery Factor
Commonwealth Edison, IL	Energy Efficiency and Demand Response Adjustments Environmental Cost Recovery Adjustment Franchise Cost Addition Miscellaneous Procurement Components Charge PJM Services Charges Renewable Portfolio Standard Retail Customer Assessments Zero Emission Standard
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Billing and Payment Processing Clean Energy Standard Delivery Surcharge Market Supply Charge Merchant Function Charge Monthly Adjustment Clause Revenue Decoupling Mechanism Adjustment System Benefits Charge
DTE Electric, MI	Energy Waste Reduction Surcharge Low Income Energy Assistance Fund Factor Nuclear Surcharge Power Supply Cost Recovery Clause Renewable Energy Plan Surcharge Transitional Recovery Mechanism U-18014 Self-Implementation Refund U-18255 Self-Implementation Refund
ENMAX, AB	Balancing Pool Allocation Refund Rider DAS Adjustment Rider Local Access Fee Transmission Access Charge
EPCOR, AB	Balancing Pool Rider DAS True-up Rider Local Access Fee SAS True-up Rider Short Term Adjustment Rider

Eversource Energy, MA	Attorney General Consultant Expenses Provision Basic Service Cost Adjustment Energy Efficiency Charge Long Term Renewable Contract Adjustment Net Metering Recovery Surcharge Pension Adjustment Mechanism Performance Based Revenue Adjustment Renewable Energy Charge Reconciling Rate Adjustment Residential Assistance Adjustment Clause Revenue Decoupling Adjustment Mechanism Solar Program Cost Adjustment Storm Cost Recovery Adjustment Mechanism Transition Service Cost Adjustment
Florida Power and Light, FL	Energy Conservation Cost Recovery Clause Capacity Payment Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Restoration Charge
Hydro Ottawa, ON	Disposition of Deferral/Variance Accounts (2018) Disposition of Global Adjustment Account (2018) Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	TVA Fuel Cost Adjustment
Newfoundland and Labrador Hydro, NL	CDM Cost Recovery Adjustment Rate Stabilization Plan Adjustment
Nova Scotia Power, NS	Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	California Climate Credit Competition Transition Charges DWR Bond Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments

Pacific Power and Light, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning Conservation Act Energy Conservation Charge Deer Creek Mine Undepreciated Investment Adjustment Deferred Accounting Adjustment Generation Investment Adjustment Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Klamath Dam Removal Surcharges Oregon Solar Incentive Program Deferral Pilot Program Cost Adjustment Property Sales Balancing Account Adjustment Public Purpose Charge Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral Adjustment TAM Adjustment for Other Revenues
Toronto Hydro, ON	Application of IFRS – 2014 Derecognition Application of Operations Center Consolidation Plan Sharing Disposition of Capacity Based Recovery Disposition of Deferral/Variance Account Disposition of LRAM Variance Account Disposition of Post Employment Benefit – Tax Savings Disposition of Global Adjustment Account Recovery of Hydro One Capital Contributions Variance Recovery of Stranded Meter Assets Recovery of the Gain on the Sale of Named Properties Recovery of 2015 Foregone Revenue Recovery of 2016 Foregone Revenue Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge

C

Appendix

Applicable Taxes

Residential Sector

General Sector

Industrial Sector

TAXES APPLICABLE TO RESIDENTIAL SERVICE

On April 1, 2018

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	15	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	4	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	6.047	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	4.9892	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.33	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL SERVICE

On April 1, 2018

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	3.5	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	6.047	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL SERVICE (cont'd)

On April 1, 2018

	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4822	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.33	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	8.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL SERVICE

On April 1, 2018

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
	Provincial sales tax	3.5	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
	Franchise cost	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
	County tax	0.5	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	6.047	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL SERVICE (cont'd)

On April 1, 2018

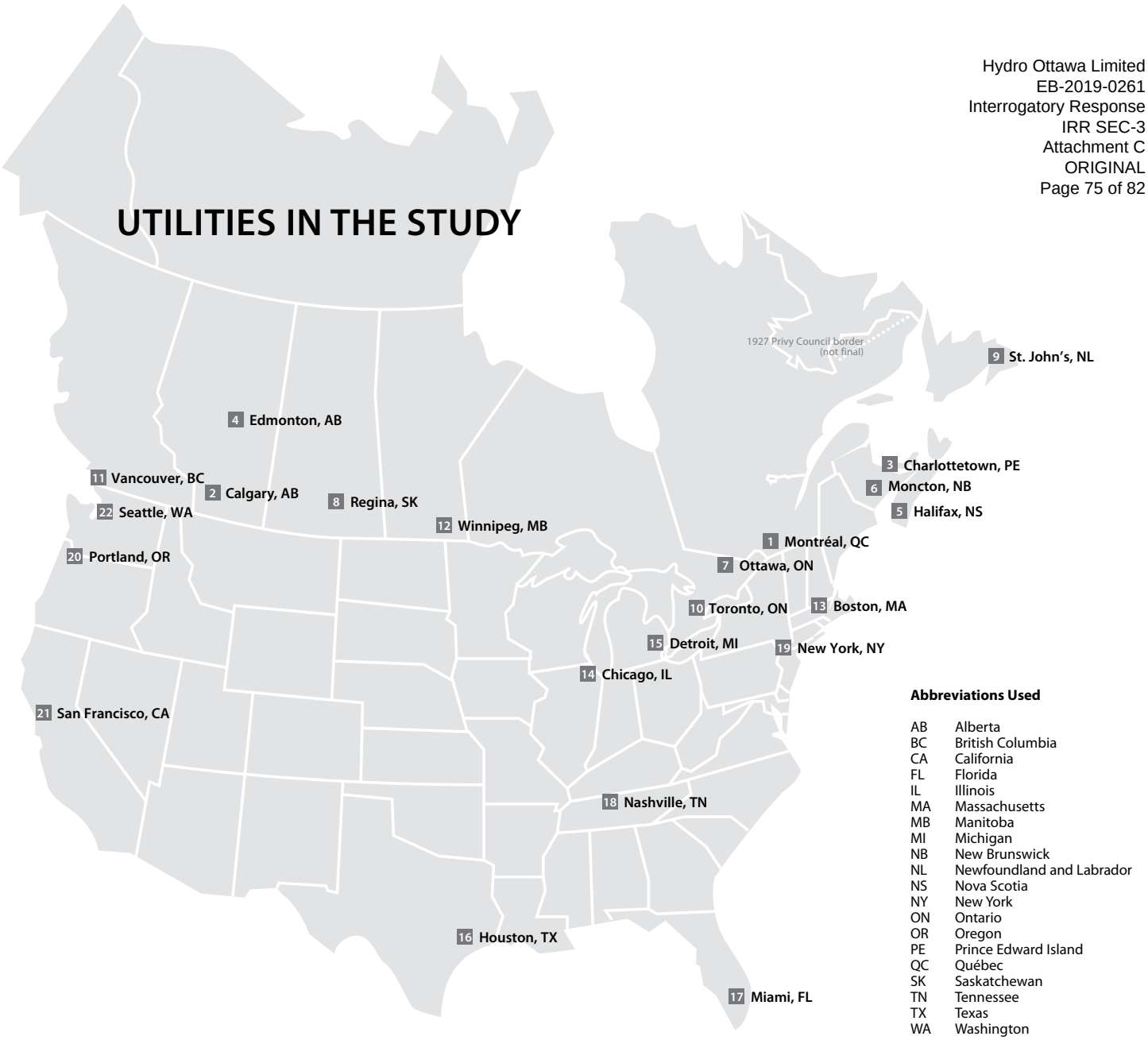
	Tax	% (or other)	Applicable
Nashville, TN	State sales tax	7	To base amount of bill (companies other than manufacturing)
	State sales tax	1.5	To base amount of bill (manufacturing companies)
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4822	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.33	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	0.029¢	To energy consumption
	San Francisco utility users' tax	8.5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

D

Appendix

Utilities in the Study

UTILITIES IN THE STUDY



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro
(customers with a power demand of 30,000 kW or more)
Newfoundland Power
(all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

A government-owned company whose lines of business have been unbundled, Hydro-Québec is one of the largest electric utilities in North America, with a total installed capacity of 37,309 MW; 99% of its electricity is produced from clean, renewable sources. Its transmission and distribution activities are regulated. The utility distributes electricity to more than 4.2 million residential, commercial, institutional and industrial customer accounts throughout Québec and delivers electricity to nine municipal systems and one regional cooperative. Hydro-Québec also does business with many electric utilities in the Northeastern United States, Ontario and New Brunswick.

The *Act respecting the Régie de l'énergie* (Québec energy board) established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution. The division also purchases electricity on the market, primarily through calls for tenders. The average supply cost of heritage pool electricity, set at a fixed price of 2.79¢/kWh since 1998, is indexed on January 1 since 2014 at a rate corresponding to the annual variation in the all-item consumer price index for Québec, with the exception of the large-power industrial rate (Rate L), which is exempt from the indexation of heritage pool electricity.

The Régie de l'énergie approved an average increase of 0.3% in the rates of Hydro-Québec Distribution, effective April 1, 2018, with the exception of large power customers, for which the rate remains the same.

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

A subsidiary of Fortis Inc., Maritime Electric is the principal supplier of electricity on Prince Edward Island, with about 80,000 customers. Since its two power plants (with a total capacity of 145 MW) are operated strictly for reserve purposes, it purchases most of its electricity from NB Power, with which it has long-term contracts, and through additional short-term contracts on the New England wholesale market. Maritime Electric also purchases 92 MW of wind-generated electricity from public producers.

Since the adoption of the *Electric Power Act* on January 1, 2004, Maritime Electric has had to submit all requests for rate increases to the Island Regulatory and Appeals Commission (IRAC). In 2016, the IRAC approved a 2.3% annual rate increase for each of the following three years.

ENMAX
EPCOR
Calgary, Alberta
Edmonton, Alberta

ENMAX Corporation is a wholly owned subsidiary of the City of Calgary. It generates, transmits and distributes electricity to more than 946,000 customers throughout the province. In addition to its active participation in Alberta's restructured electricity industry, ENMAX serves customers who are eligible for the City of Calgary's regulated rate option tariff.

EPCOR Utilities, whose sole shareholder is the City of Edmonton, transmits and distributes electricity to 600,000 customers throughout the province, including 379,000 residential and business customers in Edmonton, who are eligible for both rate regulated and contract electricity services.

Since July 1, 2010, prices under the regulated rate option tariff have fluctuated monthly with market forecasts. To protect residential and small business customers against market price volatility, on June 1, 2017, the Alberta government introduced a four-year price cap of 6.8¢/kWh on the electricity component of the Regulated Rate Option.

NOVA SCOTIA POWER
Halifax, Nova Scotia

Nova Scotia Power, a subsidiary of Emera, is the principal supplier of electricity in Nova Scotia, meeting most of the province's needs for electricity generation, transmission and distribution. It supplies electricity to 500,000 customers. Its generating facilities have an installed capacity in excess of 2,400 MW.

The open access transmission tariff came into effect on November 1, 2005. Under the province's energy policy, eligible customers have nondiscriminatory access to the utility's transmission system.

NB POWER
Moncton, New Brunswick

A subsidiary of provincial Crown corporation NB Power Group, NB Power Distribution and Customer Service Corporation directly and indirectly serves more than 390,000 customers. NB Power has a generating capacity of about 2,850 MW.

The New Brunswick electricity market has been partially open to competition since October 1, 2004. As a result, large industrial customers and three municipal electricity distribution utilities are free to choose their supplier. Other retail market customers continue to be served by NB Power.

SASKPOWER
Regina, Saskatchewan

Crown utility SaskPower directly serves more than 528,000 customers and sells wholesale electricity to municipal systems in Saskatchewan. The utility operates 17 power plants and also buys power from third parties, such that its total available generating capacity is almost 4,500 MW.

In Saskatchewan, the wholesale electricity market has been open to competition since 2001.

NEWFOUNDLAND AND LABRADOR HYDRO
(customers with a power demand of 30,000 kW or more)

NEWFOUNDLAND POWER (all other customer categories)
St. John's, Newfoundland and Labrador

Newfoundland Power, a subsidiary of Fortis Inc., serves about 262,000 customers on the island of Newfoundland. Since it operates only small generating stations, it purchases 93% of its electricity from Newfoundland and Labrador Hydro (NLH), a subsidiary of Nalcor Energy that operates generating facilities with an installed capacity of 1,763 MW and a transmission system that serves the whole province. NLH also supplies remote regions, Labrador and large industrial customers. Aside from Newfoundland and Labrador Hydro, Nalcor Energy operates generating facilities with an installed capacity in excess of 7,200 MW.

TORONTO HYDRO
HYDRO OTTAWA
Toronto, Ontario
Ottawa, Ontario

Toronto Hydro-Electric System, a subsidiary of city-owned Toronto Hydro Corporation, serves about 768,000 customers, or 19% of Ontario electricity consumers. A subsidiary of Hydro Ottawa Holding, whose sole shareholder is the City of Ottawa, Hydro Ottawa serves more than 331,000 customers.

In Ontario, the wholesale and retail markets have been open to competition since May 2002. Electricity generation is the responsibility of Ontario Power Generation, while transmission service is mainly supplied by Hydro One.

Following the adoption of the *Electricity Restructuring Act* in December 2004, the Ontario Energy Board was given the mandate to regulate electricity supply cost and has produced a plan in this regard (Regulated Price Plan or RPP). Prices are reviewed on May 1 of each year since 2006 and then adjusted six months later, if necessary. With advanced metering, the vast majority of residential customers are now billed according to a time-of-use rate. In recent years, Ontario consumers have seen their electricity bill increase significantly. In 2017, this led the Ontario government to propose measures to reduce electricity bills by 25% for the residential and agricultural customers, as well as for small businesses.

BC HYDRO
Vancouver, British Columbia

BC Hydro, a provincial Crown corporation, operates generating facilities with a total capacity of more than 12,000 MW. About 98% of its electricity is generated using waterpower. The utility distributes electricity to about 2 million customers.

The wholesale market in British Columbia is open to competition, as is the retail market for some large industrial companies. When the market was opened up, generation, transmission and distribution were made into separate entities. The *Clean Energy Act* grouped transmission and distribution in July 2010 to ensure coordinated supply planning for the province. In November 2013, the government published a 10-year plan which provides for upgrading aging infrastructure, implementing new generation projects to meet growing demand and minimizing the impact of these activities on electricity rates.

MANITOBA HYDRO
Winnipeg, Manitoba

Manitoba Hydro is a Crown utility serving nearly 573,000 customers throughout the province. Virtually all the electricity it generates and distributes comes from its 15 hydropower plants, which have a total capacity of 5,690 MW.

The wholesale electricity market has been open to competition since 1997 and Manitoba Hydro joined Midwest ISO, a regional transmission organization, in 2001.

AMERICAN UTILITIES

EVERSOURCE ENERGY
Boston, Massachusetts

Eversource, a merger between NSTAR Electric & Gas and Northeast Utilities, serves 3.1 million residential, commercial and industrial customers in the states of Massachusetts, Connecticut and New Hampshire. The utility purchases electricity on the market and concentrates on transmission and distribution.

Since March 1, 2005, the basic service rates are applied to customers who have chosen not to purchase electricity from a competitor. These rates are adjusted every six months, or every three months in the case of large industrial customers. The rates reflect the average market price of electricity.

COMMONWEALTH EDISON (ComEd)
Chicago, Illinois

ComEd, a subsidiary of Exelon Corporation, purchases, transmits and distributes electricity on the wholesale and retail markets. On the retail market, it serves more than 4 million customers in northern Illinois, or about 70% of the state's population.

Since May 1, 2002, the retail market has been fully open for residential, commercial and industrial customers. However, it is only since 2011 that residential customers have actually exercised their right to choose distributors other than the two companies that were in place when deregulation was implemented: ComEd and Ameren.

DTE ELECTRIC
Detroit, Michigan

DTE Electric operates generating facilities with a total installed capacity of nearly 11,100 MW. A subsidiary of DTE Energy, it delivers electricity to 2.2 million customers in southeastern Michigan.

Under the June 2000 legislation that restructured the electricity industry, all retail market customers in Michigan have been able to choose their electricity supplier since January 1, 2002.

CENTERPOINT ENERGY
Houston, Texas

CenterPoint Energy concentrates on electricity transmission and distribution and delivering natural gas. It sells electricity to over 2.5 million customers in the metropolitan Houston area.

The majority of Texas consumers have had access to an open retail market since January 1, 2002. As of January 2007, electricity distributors with effective monopolies are no longer obliged to maintain their rates above the "price to beat" designed to encourage new market entrants. Customers who have opted to continue doing business with the same distributor pay a monthly rate that varies according to the market price.

FLORIDA POWER AND LIGHT (FPL)
Miami, Florida

FPL's vast transmission and distribution system supplies about 4.9 million customers. A subsidiary of NextEra Energy, the utility operates generating facilities with an installed capacity of close to 25,000 MW.

On April 1, 2010, FPL released its 2010–2019 strategic plan, in which it proposed to upgrade some of its nuclear plants and add new generating facilities using thermal and renewable energy. It also relied on energy efficiency measures put in place to meet the demand for power during the strategic plan time frame. In April 2016, FPL submitted its Ten Year Power Plant Site Plan for the years 2016–2025 in which it maintains its commitment to modernize its generating stations.

NASHVILLE ELECTRIC SERVICE
Nashville, Tennessee

Nashville Electric Service, whose sole shareholder is the City of Nashville, distributes the electricity that it purchases from the Tennessee Valley Authority (TVA) to more than 385,000 customers. A federal agency, the TVA serves seven states, supplying 154 distributors and 54 large industrial and federal customers.

Close to 24% of the electricity produced by the TVA comes from its seven coal-fired plants, with the rest from gas, nuclear and hydro plants. Over the years, the company has proceeded to the decommissioning of some of its most polluting coal-fired plants, and has integrated renewable energy sources such as solar, wind and biomass.

CONSOLIDATED EDISON (ConEd)
New York, New York

ConEd of New York delivers electricity to 3.3 million customers and natural gas to about 1.1 million customers in and around New York City and Westchester County. This ConEd subsidiary operates one of the largest underground systems in the United States, which represents 72% of its distribution system.

When the electricity market was opened to competition in 1998, ConEd had to dispose of a large part of its generating capacity, which is now limited to about 732 MW. Rates, which continue to be regulated by the New York State Public Service Commission, are adjusted monthly to reflect the market price of electricity.

PACIFIC POWER AND LIGHT
Portland, Oregon

Pacific Power and Light, a subsidiary of PacifiCorp, serves about 750,000 customers across three states, including more than 574,000 in Oregon. PacifiCorp operates generating facilities with an installed capacity of close to 10,900 MW.

On March 1, 2002, the Oregon state government opened its retail market to competition for large commercial and industrial customers. Residential and small commercial customers have fewer suppliers to choose from, but they do have a range of options, including market-based rates, regulated rates or rates applicable to green energy.

PACIFIC GAS AND ELECTRIC (PG&E)
San Francisco, California

Pacific Gas and Electric concentrates on the transmission and distribution of electricity and natural gas. A subsidiary of PG&E Corporation, it has 5.4 million electric customer accounts.

In 2001, California adopted emergency measures to mitigate the price volatility that followed the opening of the electricity market. Those measures allowed it to reinstate regulatory authority over production costs and to give responsibility for electricity purchases to the California Department of Water and Resources. Since January 1, 2003, PG&E has been authorized to again purchase energy and directly supply its customers.

In 2017, PG&E undertook a rate reform to simplify the structure of residential electricity rates.

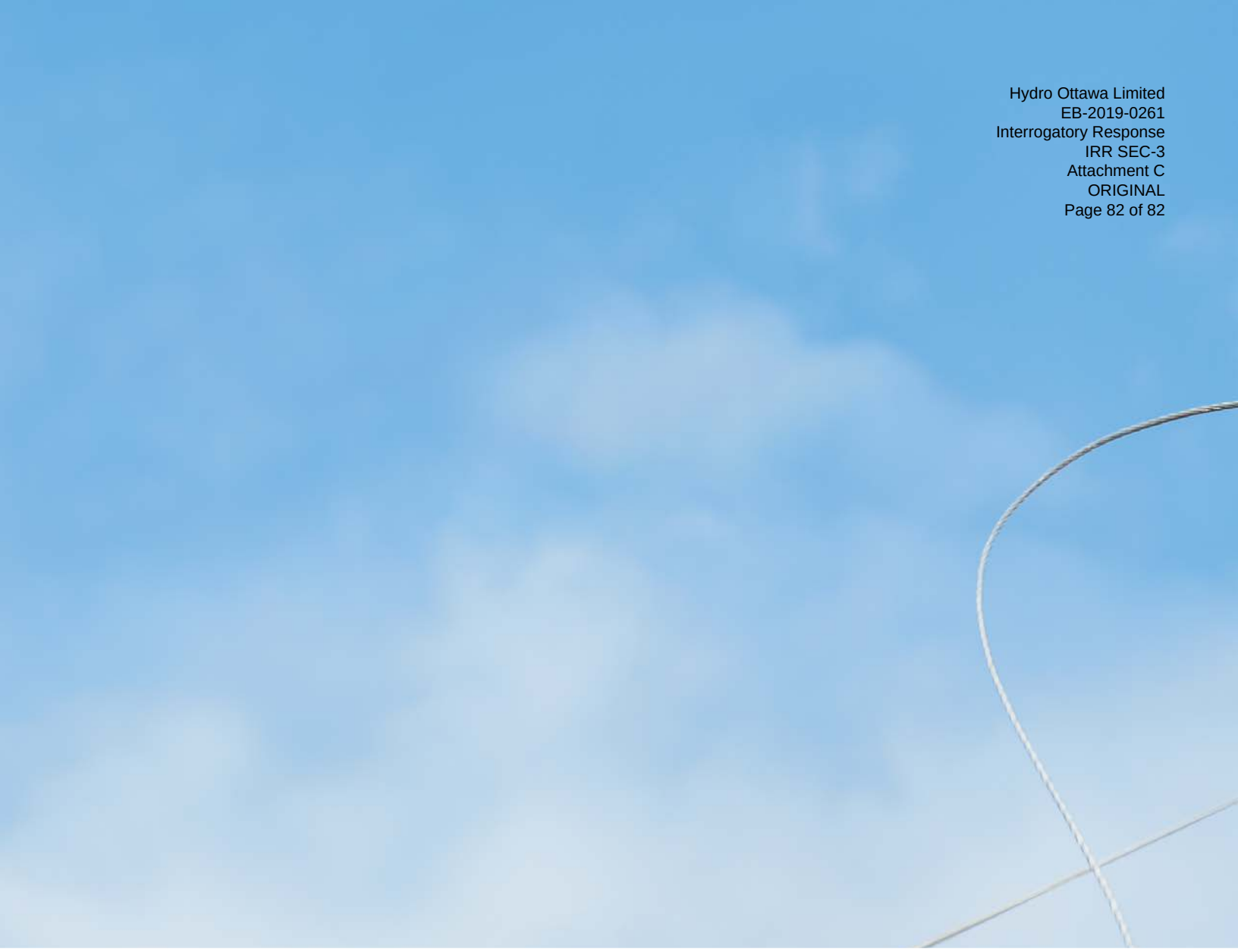
SEATTLE CITY LIGHT

Seattle, Washington

Seattle City Light, whose shareholder is the City of Seattle, serves about 447,000 customers in the city of Seattle and certain surrounding communities. It produces nearly 50% of the electricity it needs and purchases the rest from the Bonneville Power Administration (BPA), a northwestern U.S. federal agency that wholesales electricity produced by some 30 hydropower stations.

Six electric utilities in the Pacific Northwestern states, including Seattle City Light and BPA, got together in early 2006 to form the nonprofit ColumbiaGrid. The group's objective is to develop an integrated approach to the use and expansion of the region's interconnected transmission system.

Sources:
Annual reports and Web sites of the Canadian and American utilities in the study.



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Ce document est également publié en français.

Hydro Québec

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2019

Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2019

hydro quebec .com

Hydro Ottawa Limited
EB-2019-0261
Interrogatory Response
IRR SEC-3
Attachment D
ORIGINAL

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INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2019. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1,2] (IN ¢/kWh)[3]



1) For a monthly consumption of 1,000 kW h; rates in effect April 1, 2019.
2) Average prices excluding taxes.
3) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1,2] (IN ¢/kWh)[3]



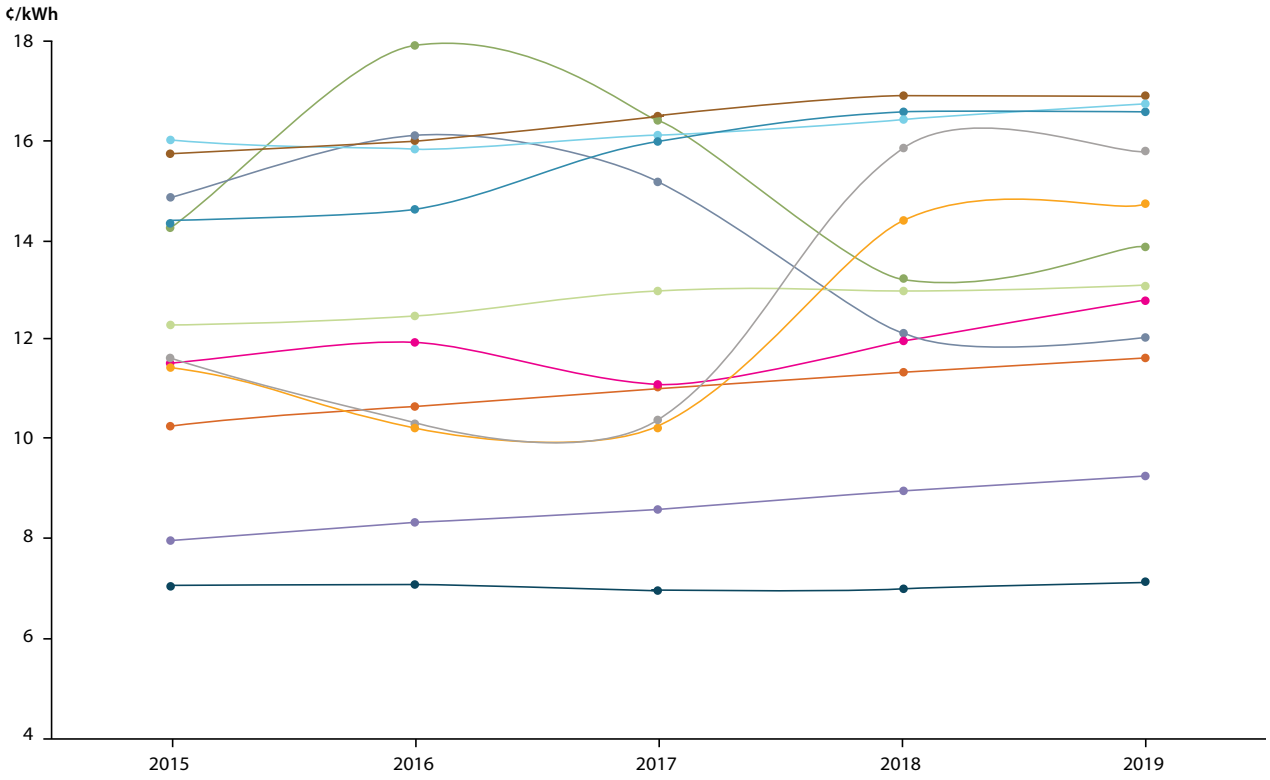
1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2019.
2) Average prices excluding taxes.
3) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh) – 2015 TO 2019[1,2,3,4]



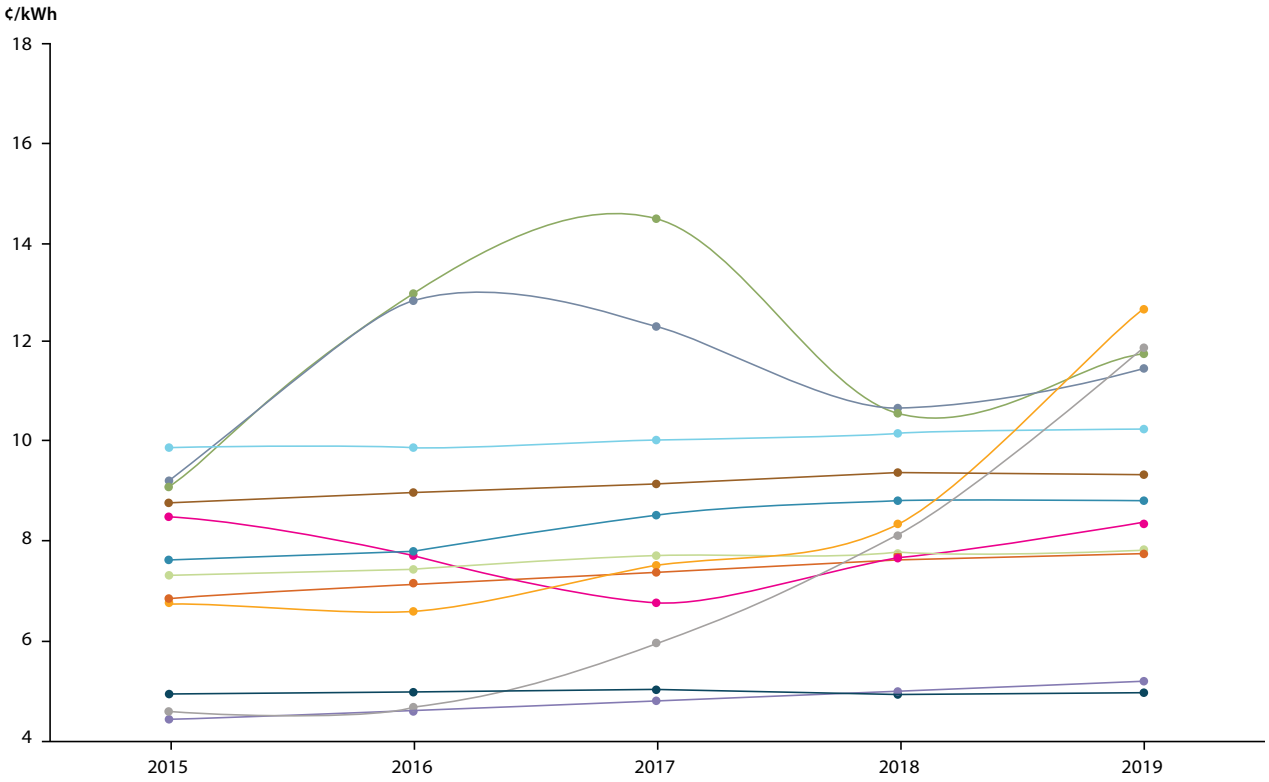
AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh)[1,2,3,4]

	2015	2016	2017	2018	2019
Canadian Cities					
Montréal, QC	7.19	7.23	7.07	7.13	7.30
Calgary, AB	11.66	10.40	10.45	15.79	15.74
Charlottetown, PE	15.62	16.02	16.42	16.83	16.83
Edmonton, AB	11.55	10.37	10.34	14.35	14.68
Halifax, NS	16.03	15.88	16.15	16.41	16.69
Moncton, NB	12.30	12.50	12.97	12.97	13.10
Ottawa, ON	14.86	16.15	15.21	12.16	12.04
Regina, SK	14.37	14.65	15.94	16.51	16.51
St. John's, NL	11.55	11.96	11.15	12.03	12.80
Toronto, ON	14.31	17.81	16.32	13.24	13.89
Vancouver, BC	10.29	10.70	11.08	11.42	11.62
Winnipeg, MB	8.11	8.43	8.71	9.00	9.37

1) For a monthly consumption of 1,000 kWh.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2015-2019.
4) Average prices excluding taxes.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh) – 2015 TO 2019[1,2,3,4]



AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh)[1,2,3,4]

	2015	2016	2017	2018	2019
Canadian Cities					
Montréal, QC	5.17	5.17	5.18	5.18	5.20
Calgary, AB	4.76	4.82	6.09	8.32	11.97
Charlottetown, PE	8.90	9.12	9.31	9.51	9.51
Edmonton, AB	6.97	6.78	7.68	8.53	12.80
Halifax, NS	10.02	10.02	10.14	10.26	10.39
Moncton, NB	7.48	7.60	7.86	7.86	7.93
Ottawa, ON	9.30	12.91	12.46	10.80	11.57
Regina, SK	7.81	7.97	8.67	8.98	8.98
St. John's, NL	8.65	7.88	6.95	7.84	8.52
Toronto, ON	9.22	13.04	14.55	10.66	11.91
Vancouver, BC	7.04	7.35	7.54	7.77	7.91
Winnipeg, MB	4.67	4.85	5.01	5.18	5.39

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2015-2019.
4) Average prices excluding taxes.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the 9 other Canadian provinces, and 10 utilities in American states. The results are based, in part, on a survey to which 15 utilities responded, and in part on estimates of bills calculated by Hydro-Québec.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2019. The most recent rate adjustments applied by the Canadian utilities in the study between April 1, 2018, and April 1, 2019, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the Detailed Tables.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists taxes applicable on April 1, 2019, by customer category; those which may be partially or fully refundable are also indicated.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes offer different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2019.

TIME-OF-USE RATES

The rates offered by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates which are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include adjustment clauses that allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2018, and April 1, 2019, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.7498 (CA$1 = US$0.7498), the rate in effect at noon on April 1, 2019. The Canadian dollar had thus depreciated by 3.21% relative to the U.S. dollar on April 1, 2018.

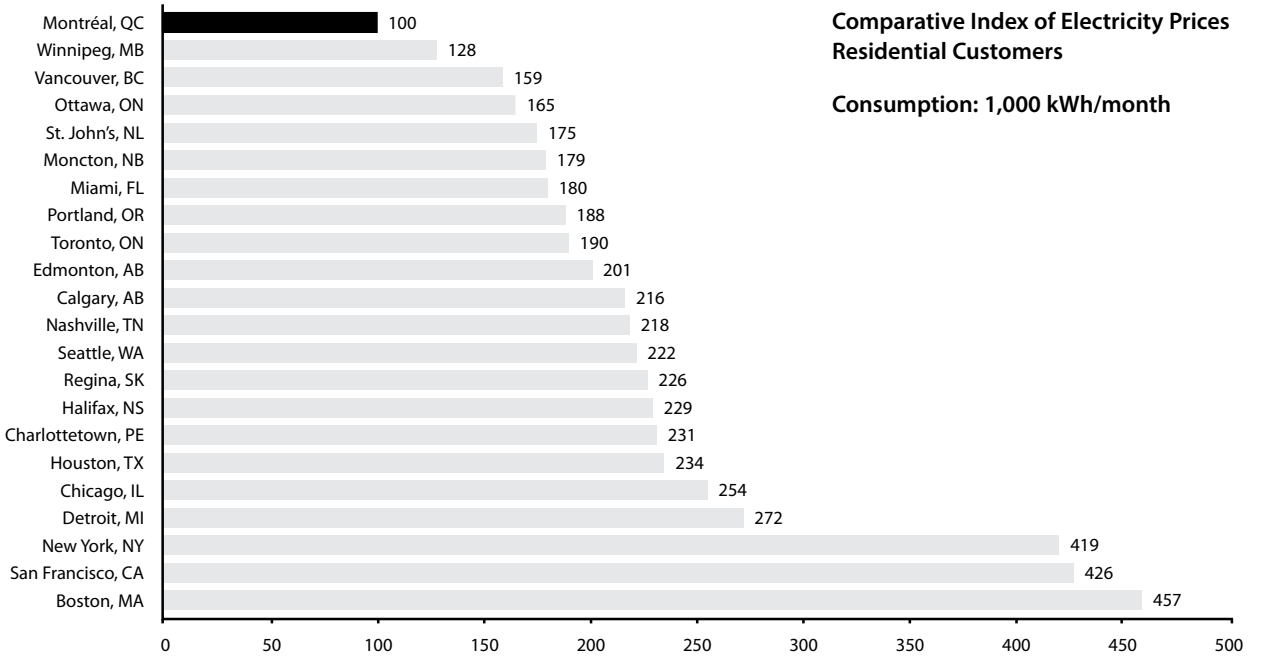
HIGHLIGHTS

The *Electricity Rates* effective April 1, 2019 sets out Hydro-Québec's rates, as approved by the Régie de l'énergie (the Québec energy board) in accordance with Decision D-2019-037. Three types of rates are in effect: domestic rates, for residential customers, the industrial rate, for large-power industrial customers, and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kWh, Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

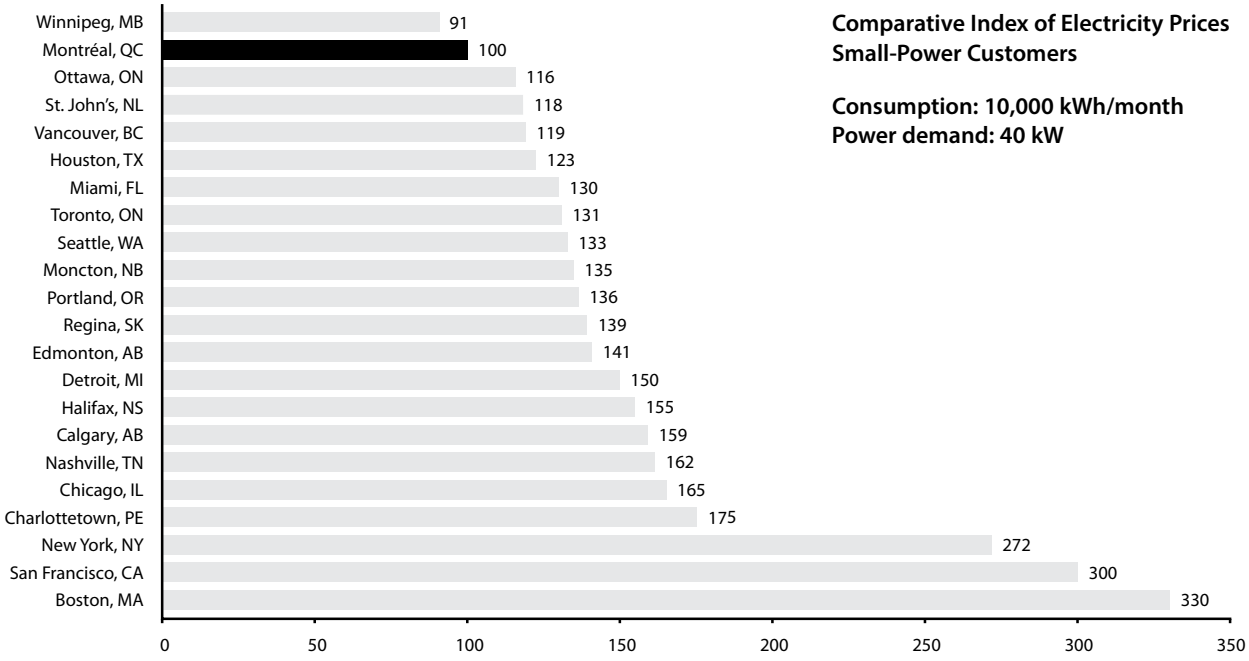
FIGURE 1



SMALL-POWER CUSTOMERS (LESS THAN 100 kW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kW. Montréal is in *second* place, as was the case last year. Figure 2 shows the comparative index of electricity prices.

FIGURE 2

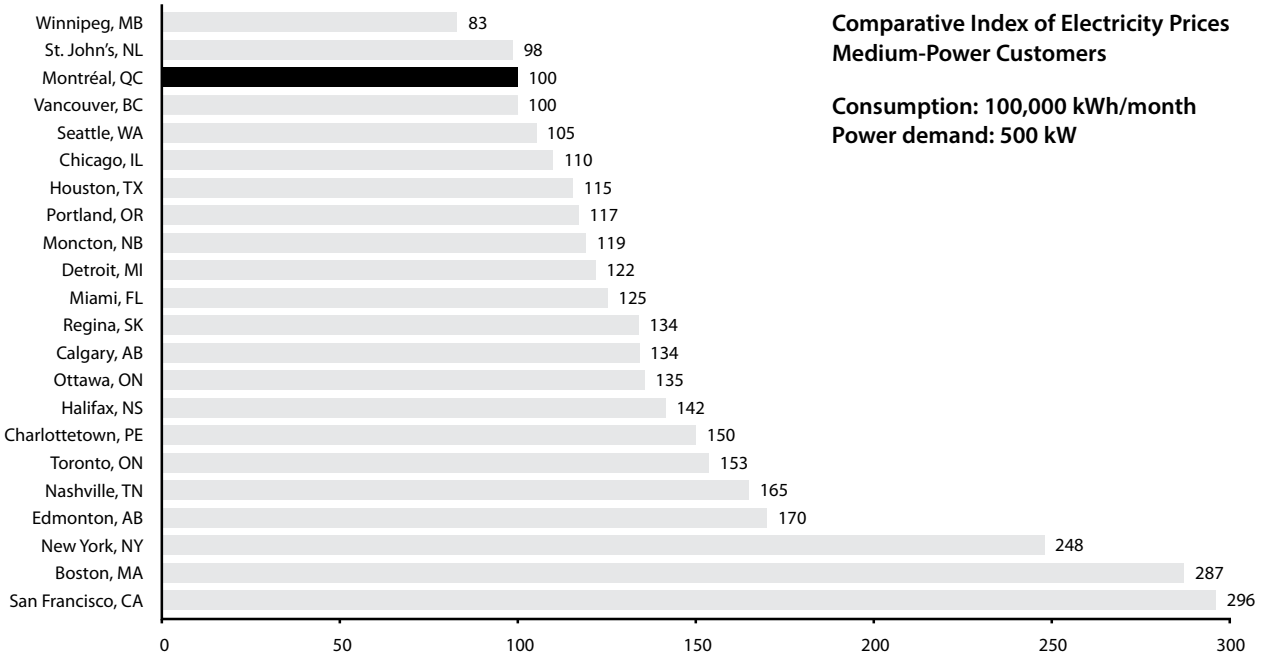


MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

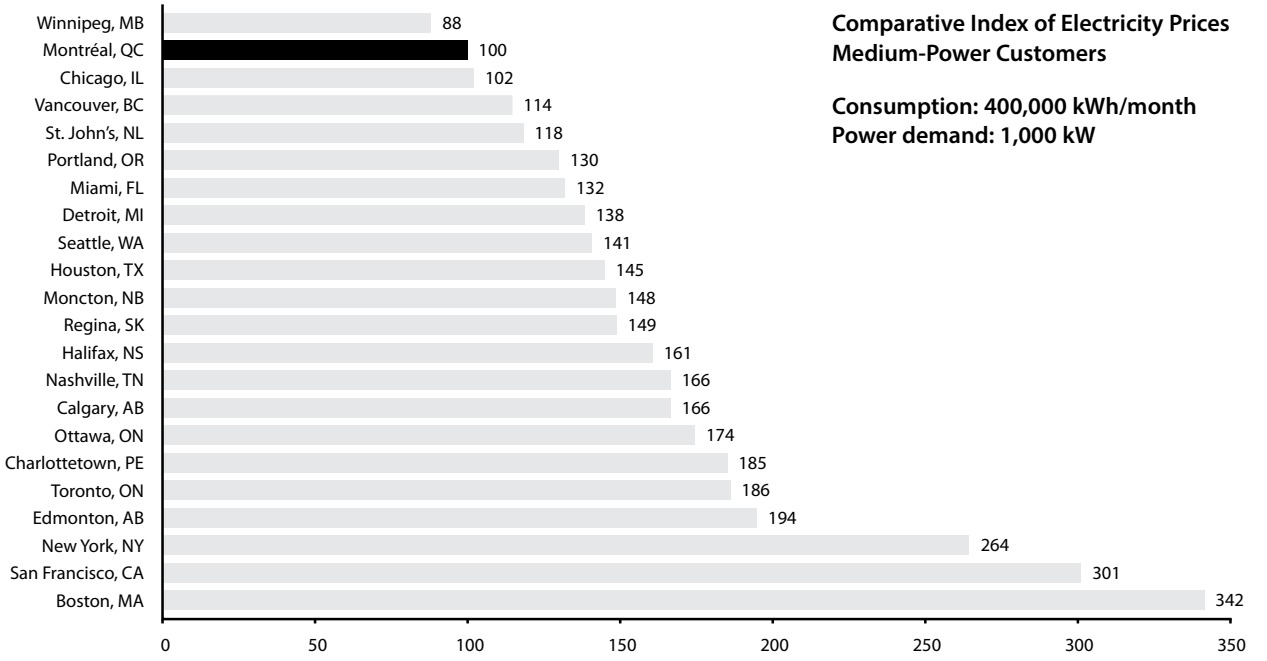
For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal has climbed the ranking to *third* place, and is followed closely by Vancouver.

FIGURE 3



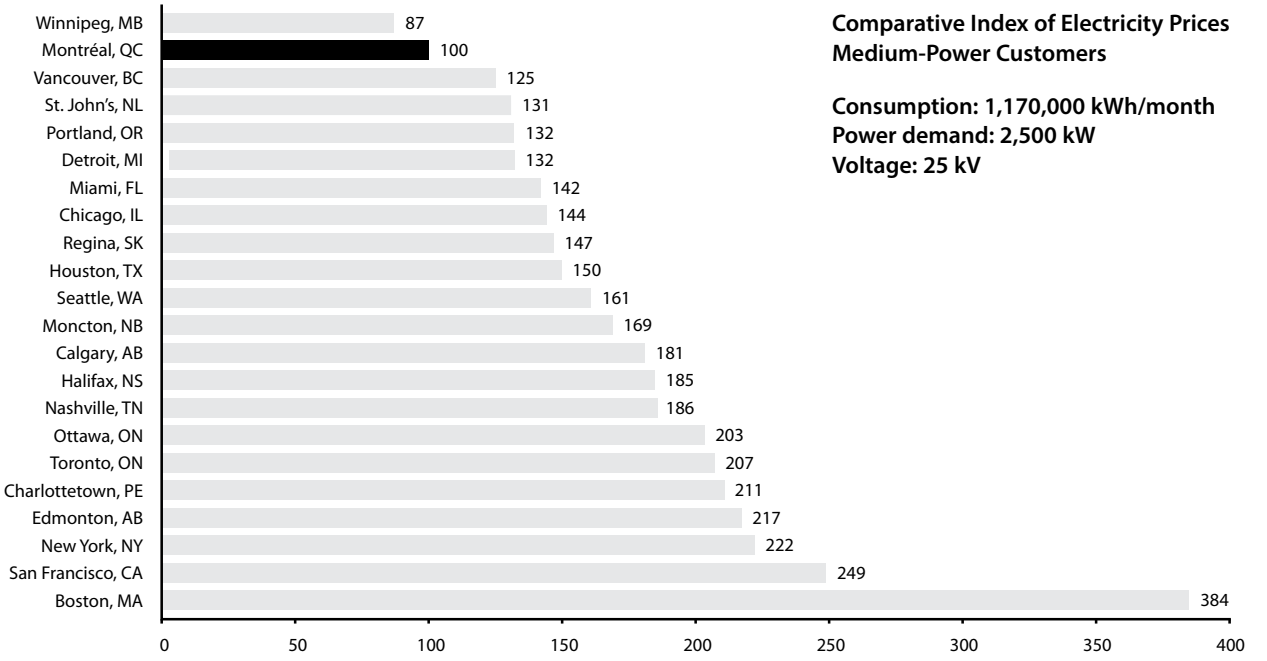
For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal is in *second* place.

FIGURE 4



In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal holds *second* place, as was the case last year.

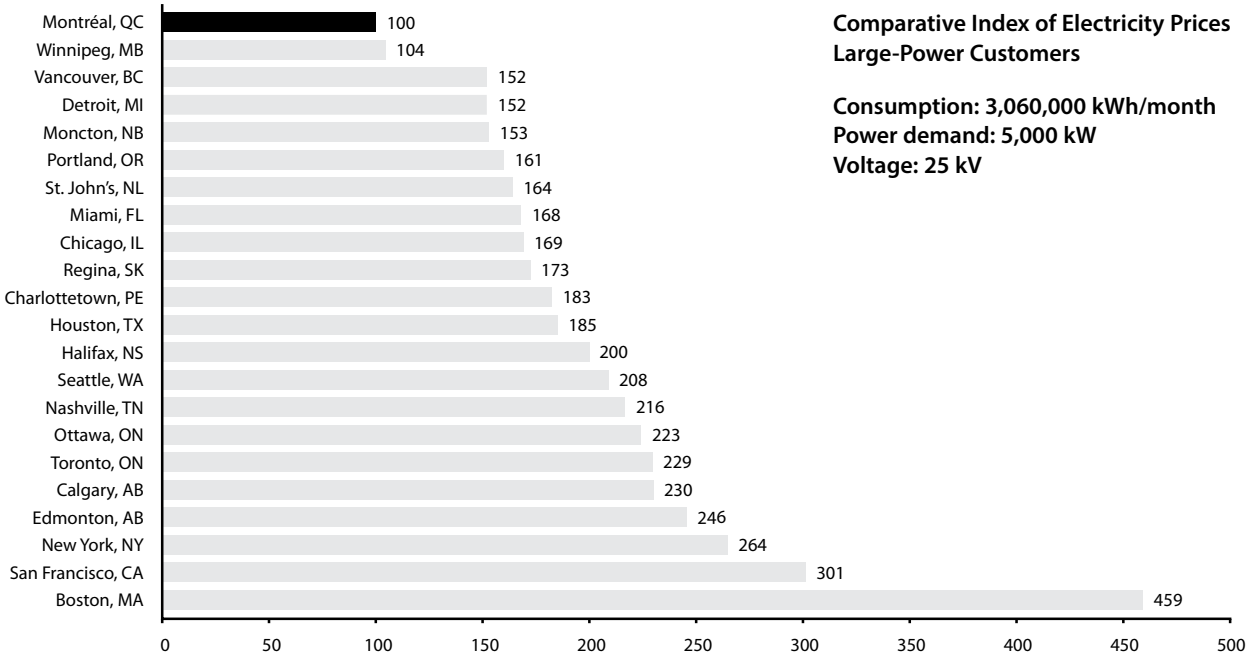
FIGURE 5



LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. This year, Montréal has improved, moving up from second to *first* place.

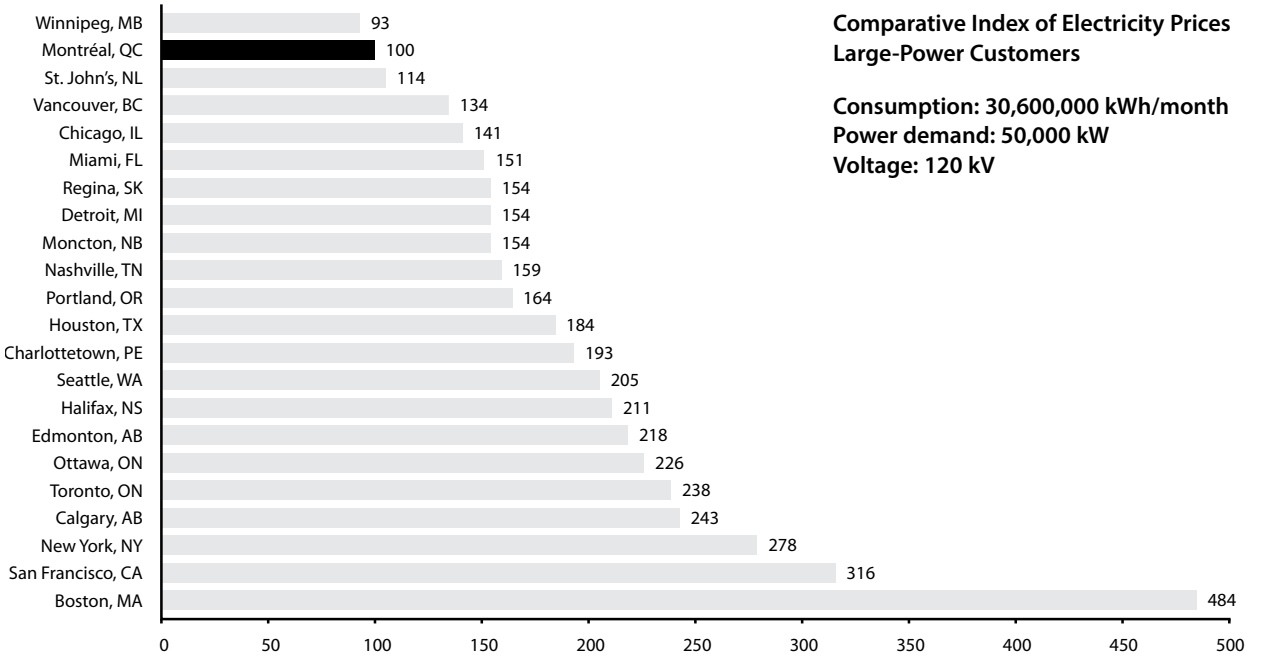
FIGURE 6



Hydro-Québec = 100
Monthly bill (excluding taxes)
Rates in effect April 1, 2019

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal is in *second* place, coming in just behind Winnipeg.

FIGURE 7



Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2019

01

Detailed Tables

Summary Tables (excluding taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2019

(in CA$)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	72.99	1,002.33	12,195.00	32,230.00	79,924.50	159,075.00	1,505,850.00
Calgary, AB	157.42	1,593.12	16,373.70	53,591.59	144,590.04	366,251.39	3,654,994.48
Charlottetown, PE[3]	168.27	1,753.67	18,317.47	59,652.47	168,655.47	290,984.00	2,909,840.00
Edmonton, AB[4]	146.83	1,415.16	20,746.76	62,680.48	173,122.98	391,595.82	3,283,225.24
Halifax, NS	166.86	1,555.50	17,260.50	51,987.00	147,637.65	317,874.69	3,178,770.84
Moncton, NB	130.95	1,354.09	14,558.49	47,733.49	135,155.49	242,808.73	2,316,500.00
Ottawa, ON	120.39	1,161.20	16,439.73	56,090.89	161,917.98	353,949.10	3,402,406.84
Regina, SK	165.07	1,398.04	16,347.97	48,027.97	117,239.17	274,788.38	2,312,973.29
St. John's, NL[5]	128.02	1,179.13	11,994.65	37,910.29	104,588.13	260,590.26	1,717,898.00
Toronto, ON[3]	138.90	1,313.64	18,603.42	59,981.65	165,088.07	364,478.60	3,583,733.35
Vancouver, BC	116.20	1,192.93	12,238.13	36,588.13	99,608.73	242,186.97	2,017,728.50
Winnipeg, MB	93.68	910.67	10,177.17	28,339.77	69,930.06	165,031.36	1,407,771.36
American Cities							
Boston, MA	333.73	3,304.45	35,043.86	110,096.05	306,736.75	729,677.32	7,293,772.35
Chicago, IL	185.36	1,651.16	13,361.18	32,959.81	115,016.87	268,649.27	2,130,349.34
Detroit, MI[3]	198.61	1,500.09	14,817.63	44,586.79	105,625.62	242,397.21	2,316,274.13
Houston, TX[3]	171.03	1,233.61	13,979.54	46,595.82	119,901.07	293,891.45	2,776,948.62
Miami, FL[3]	131.57	1,300.78	15,222.73	42,396.87	113,485.53	267,716.47	2,274,380.42
Nashville, TN	159.21	1,620.73	20,132.69	53,556.55	148,508.75	343,196.67	2,393,476.25
New York, NY[3]	305.61	2,727.64	30,286.86	84,940.68	177,641.80	419,178.54	4,190,053.43
Portland, OR[3]	137.56	1,365.28	14,307.32	41,914.48	105,515.16	255,341.82	2,471,716.84
San Francisco, CA	311.08	3,006.87	36,086.13	97,101.48	199,321.54	478,610.04	4,762,438.83
Seattle, WA	161.91	1,337.70	12,776.85	45,398.01	128,870.92	330,320.43	3,081,818.37
AVERAGE	168.24	1,585.35	17,784.90	53,380.01	140,367.38	320,845.16	2,953,769.11

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2019

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	7.30	10.02	12.20	8.06	6.83	5.20	4.92
Calgary, AB	15.74	15.93	16.37	13.40	12.36	11.97	11.94
Charlottetown, PE[4]	16.83	17.54	18.32	14.91	14.41	9.51	9.51
Edmonton, AB[5]	14.68	14.15	20.75	15.67	14.80	12.80	10.73
Halifax, NS	16.69	15.56	17.26	13.00	12.62	10.39	10.39
Moncton, NB	13.10	13.54	14.56	11.93	11.55	7.93	7.57
Ottawa, ON	12.04	11.61	16.44	14.02	13.84	11.57	11.12
Regina, SK	16.51	13.98	16.35	12.01	10.02	8.98	7.56
St. John's, NL[6]	12.80	11.79	11.99	9.48	8.94	8.52	5.61
Toronto, ON[4]	13.89	13.14	18.60	15.00	14.11	11.91	11.71
Vancouver, BC	11.62	11.93	12.24	9.15	8.51	7.91	6.59
Winnipeg, MB	9.37	9.11	10.18	7.08	5.98	5.39	4.60
American Cities							
Boston, MA	33.37	33.04	35.04	27.52	26.22	23.85	23.84
Chicago, IL	18.54	16.51	13.36	8.24	9.83	8.78	6.96
Detroit, MI[4]	19.86	15.00	14.82	11.15	9.03	7.92	7.57
Houston, TX[4]	17.10	12.34	13.98	11.65	10.25	9.60	9.07
Miami, FL[4]	13.16	13.01	15.22	10.60	9.70	8.75	7.43
Nashville, TN	15.92	16.21	20.13	13.39	12.69	11.22	7.82
New York, NY[4]	30.56	27.28	30.29	21.24	15.18	13.70	13.69
Portland, OR[4]	13.76	13.65	14.31	10.48	9.02	8.34	8.08
San Francisco, CA	31.11	30.07	36.09	24.28	17.04	15.64	15.56
Seattle, WA	16.19	13.38	12.78	11.35	11.01	10.79	10.07
AVERAGE	16.82	15.85	17.78	13.35	12.00	10.49	9.65

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2019

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	216	159	134	166	181	230	243
Charlottetown, PE[3]	231	175	150	185	211	183	193
Edmonton, AB[4]	201	141	170	194	217	246	218
Halifax, NS	229	155	142	161	185	200	211
Moncton, NB	179	135	119	148	169	153	154
Ottawa, ON	165	116	135	174	203	223	226
Regina, SK	226	139	134	149	147	173	154
St. John's, NL[5]	175	118	98	118	131	164	114
Toronto, ON[3]	190	131	153	186	207	229	238
Vancouver, BC	159	119	100	114	125	152	134
Winnipeg, MB	128	91	83	88	87	104	93
American Cities							
Boston, MA	457	330	287	342	384	459	484
Chicago, IL	254	165	110	102	144	169	141
Detroit, MI[3]	272	150	122	138	132	152	154
Houston, TX[3]	234	123	115	145	150	185	184
Miami, FL[3]	180	130	125	132	142	168	151
Nashville, TN	218	162	165	166	186	216	159
New York, NY[3]	419	272	248	264	222	264	278
Portland, OR[3]	188	136	117	130	132	161	164
San Francisco, CA	426	300	296	301	249	301	316
Seattle, WA	222	133	105	141	161	208	205
AVERAGE	230	158	146	166	176	202	196

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

Detailed Tables

Summary Tables (including taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2019

(in CA$)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	83.92	1,152.43	14,021.20	37,056.44	91,893.20	182,896.48	1,731,351.04
Calgary, AB	165.29	1,672.78	17,192.38	56,271.17	151,819.54	384,563.96	3,837,744.20
Charlottetown, PE[3]	193.51	2,016.72	21,065.09	68,600.34	193,953.79	334,631.60	3,346,316.00
Edmonton, AB[4]	154.17	1,485.92	21,784.10	65,814.50	181,779.13	411,175.61	3,447,386.50
Halifax, NS	175.20	1,788.83	19,849.58	59,785.05	169,783.30	365,555.89	3,655,586.47
Moncton, NB	150.59	1,557.20	16,742.26	54,893.51	155,428.81	279,230.04	2,663,975.00
Ottawa, ON	137.40	1,325.28	18,576.89	63,382.70	182,967.32	399,962.48	3,844,719.73
Regina, SK	193.08	1,731.78	20,196.75	59,672.51	145,982.97	343,087.66	2,902,025.44
St. John's, NL[5]	147.22	1,356.00	13,793.85	43,596.83	120,276.35	299,678.80	1,975,582.70
Toronto, ON[3]	158.53	1,499.27	21,021.86	67,779.26	186,549.52	411,860.82	4,049,618.69
Vancouver, BC	124.00	1,252.58	12,850.04	38,417.54	104,589.17	254,296.32	2,118,614.93
Winnipeg, MB	108.31	1,076.86	12,034.50	33,511.78	78,216.77	184,587.58	1,574,592.27
American Cities							
Boston, MA	333.73	3,501.42	37,138.57	116,594.94	324,790.14	772,359.05	7,720,402.08
Chicago, IL	198.13	1,754.71	14,304.16	36,535.51	125,071.69	293,810.64	2,349,002.84
Detroit, MI[3]	216.49	1,665.10	16,447.57	49,491.34	117,244.44	269,060.91	2,571,064.29
Houston, TX[3]	172.74	1,328.96	14,982.89	49,852.48	129,401.05	317,356.67	2,998,751.19
Miami, FL[3]	155.30	1,643.03	19,270.62	53,367.69	142,635.98	335,743.72	2,825,362.38
Nashville, TN	159.21	1,734.19	21,541.98	57,305.51	158,904.36	367,220.44	2,561,019.58
New York, NY[3]	332.88	3,042.21	33,780.09	94,734.12	198,112.71	467,479.68	4,672,864.80
Portland, OR[3]	139.73	1,387.11	14,537.39	42,583.00	107,244.49	259,536.43	2,512,391.47
San Francisco, CA	311.48	3,161.21	37,930.45	102,116.60	209,755.74	503,764.87	5,012,804.13
Seattle, WA	161.91	1,337.70	12,776.85	45,398.01	128,870.92	330,320.43	3,081,818.37
AVERAGE	**180.58**	**1,748.70**	**19,629.05**	**58,943.68**	**154,785.06**	**353,099.09**	**3,247,863.37**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2019

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	8.39	11.52	14.02	9.26	7.85	5.98	5.66
Calgary, AB	16.53	16.73	17.19	14.07	12.98	12.57	12.54
Charlottetown, PE[4]	19.35	20.17	21.07	17.15	16.58	10.94	10.94
Edmonton, AB[5]	15.42	14.86	21.78	16.45	15.54	13.44	11.27
Halifax, NS	17.52	17.89	19.85	14.95	14.51	11.95	11.95
Moncton, NB	15.06	15.57	16.74	13.72	13.28	9.13	8.71
Ottawa, ON	13.74	13.25	18.58	15.85	15.64	13.07	12.56
Regina, SK	19.31	17.32	20.20	14.92	12.48	11.21	9.48
St. John's, NL[6]	14.72	13.56	13.79	10.90	10.28	9.79	6.46
Toronto, ON[4]	15.85	14.99	21.02	16.94	15.94	13.46	13.23
Vancouver, BC	12.40	12.53	12.85	9.60	8.94	8.31	6.92
Winnipeg, MB	10.83	10.77	12.03	8.38	6.69	6.03	5.15
American Cities							
Boston, MA	33.37	35.01	37.14	29.15	27.76	25.24	25.23
Chicago, IL	19.81	17.55	14.30	9.13	10.69	9.60	7.68
Detroit, MI[4]	21.65	16.65	16.45	12.37	10.02	8.79	8.40
Houston, TX[4]	17.27	13.29	14.98	12.46	11.06	10.37	9.80
Miami, FL[4]	15.53	16.43	19.27	13.34	12.19	10.97	9.23
Nashville, TN	15.92	17.34	21.54	14.33	13.58	12.00	8.37
New York, NY[4]	33.29	30.42	33.78	23.68	16.93	15.28	15.27
Portland, OR[4]	13.97	13.87	14.54	10.65	9.17	8.48	8.21
San Francisco, CA	31.15	31.61	37.93	25.53	17.93	16.46	16.38
Seattle, WA	16.19	13.38	12.78	11.35	11.01	10.79	10.07
AVERAGE	**18.06**	**17.49**	**19.63**	**14.74**	**13.23**	**11.54**	**10.61**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2019

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential	Small Power	Medium Power			Large Power	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	197	145	123	152	165	210	222
Charlottetown, PE[3]	231	175	150	185	211	183	193
Edmonton, AB[4]	184	129	155	178	198	225	199
Halifax, NS	209	155	142	161	185	200	211
Moncton, NB	179	135	119	148	169	153	154
Ottawa, ON	164	115	132	171	199	219	222
Regina, SK	230	150	144	161	159	188	168
St. John's, NL[5]	175	118	98	118	131	164	114
Toronto, ON[3]	189	130	150	183	203	225	234
Vancouver, BC	148	109	92	104	114	139	122
Winnipeg, MB	129	93	86	90	85	101	91
American Cities							
Boston, MA	398	304	265	315	353	422	446
Chicago, IL	236	152	102	99	136	161	136
Detroit, MI[3]	258	144	117	134	128	147	149
Houston, TX[3]	206	115	107	135	141	174	173
Miami, FL[3]	185	143	137	144	155	184	163
Nashville, TN	190	150	154	155	173	201	148
New York, NY[3]	397	264	241	256	216	256	270
Portland, OR[3]	167	120	104	115	117	142	145
San Francisco, CA	371	274	271	276	228	275	290
Seattle, WA	193	116	91	123	140	181	178
AVERAGE	**215**	**152**	**140**	**159**	**168**	**193**	**188**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

Detailed Tables

Residential

Monthly Bills

Average Prices

Comparative Index

RESIDENTIAL

Monthly Bills on April 1, 2019
(in CA$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	50.19	57.79	72.99	160.19	253.99
Calgary, AB	107.48	124.13	157.42	290.60	423.78
Charlottetown, PE[1]	114.38	132.35	168.27	311.97	426.17
Edmonton, AB	101.11	116.36	146.83	268.74	390.65
Halifax, NS	108.35	127.85	166.86	322.89	478.92
Moncton, NB	90.04	103.68	130.95	240.05	349.15
Ottawa, ON	83.91	96.08	120.39	217.68	314.98
Regina, SK	111.72	129.50	165.07	307.35	449.63
St. John's, NL[2]	85.94	99.97	128.02	240.19	352.37
Toronto, ON[1]	100.73	113.45	138.90	240.71	342.52
Vancouver, BC	65.42	80.77	116.20	257.90	399.60
Winnipeg, MB	61.70	72.36	93.68	178.95	264.22
American Cities					
Boston, MA	212.08	252.64	333.73	658.13	982.52
Chicago, IL	125.09	145.17	185.36	346.03	506.73
Detroit, MI[1]	124.46	149.18	198.61	396.35	594.10
Houston, TX[1]	122.90	143.36	171.03	334.76	498.49
Miami, FL[1]	86.37	101.44	131.57	279.50	427.44
Nashville, TN	110.29	126.60	159.21	289.67	425.46
New York, NY[1]	198.82	234.41	305.61	590.41	875.21
Portland, OR[1]	91.21	106.66	137.56	303.27	468.99
San Francisco, CA	174.14	219.82	311.08	850.52	1,490.82
Seattle, WA	95.59	117.70	161.91	338.76	515.61
AVERAGE	**110.09**	**129.60**	**168.24**	**337.48**	**510.52**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL

Average Prices on April 1, 2019
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	8.03	7.71	7.30	8.01	8.47
Calgary, AB	17.20	16.55	15.74	14.53	14.13
Charlottetown, PE[2]	18.30	17.65	16.83	15.60	14.21
Edmonton, AB	16.18	15.51	14.68	13.44	13.02
Halifax, NS	17.34	17.05	16.69	16.14	15.96
Moncton, NB	14.41	13.82	13.10	12.00	11.64
Ottawa, ON	13.43	12.81	12.04	10.88	10.50
Regina, SK	17.87	17.27	16.51	15.37	14.99
St. John's, NL[3]	13.75	13.33	12.80	12.01	11.75
Toronto, ON[2]	16.12	15.13	13.89	12.04	11.42
Vancouver, BC	10.47	10.77	11.62	12.90	13.32
Winnipeg, MB	9.87	9.65	9.37	8.95	8.81
American Cities					
Boston, MA	33.93	33.69	33.37	32.91	32.75
Chicago, IL	20.01	19.36	18.54	17.30	16.89
Detroit, MI[2]	19.91	19.89	19.86	19.82	19.80
Houston, TX[2]	19.66	19.12	17.10	16.74	16.62
Miami, FL[2]	13.82	13.53	13.16	13.98	14.25
Nashville, TN	17.65	16.88	15.92	14.48	14.18
New York, NY[2]	31.81	31.26	30.56	29.52	29.17
Portland, OR[2]	14.59	14.22	13.76	15.16	15.63
San Francisco, CA	27.86	29.31	31.11	42.53	49.69
Seattle, WA	15.29	15.69	16.19	16.94	17.19
AVERAGE	**17.61**	**17.28**	**16.82**	**16.87**	**17.02**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL

Comparative Index on April 1, 2019
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	214	215	216	181	167
Charlottetown, PE[1]	228	229	231	195	168
Edmonton, AB	201	201	201	168	154
Halifax, NS	216	221	229	202	189
Moncton, NB	179	179	179	150	137
Ottawa, ON	167	166	165	136	124
Regina, SK	223	224	226	192	177
St. John's, NL[2]	171	173	175	150	139
Toronto, ON[1]	201	196	190	150	135
Vancouver, BC	130	140	159	161	157
Winnipeg, MB	123	125	128	112	104
American Cities					
Boston, MA	423	437	457	411	387
Chicago, IL	249	251	254	216	200
Detroit, MI[1]	248	258	272	247	234
Houston, TX[1]	245	248	234	209	196
Miami, FL[1]	172	176	180	174	168
Nashville, TN	220	219	218	181	168
New York, NY[1]	396	406	419	369	345
Portland, OR[1]	182	185	188	189	185
San Francisco, CA	347	380	426	531	587
Seattle, WA	190	204	222	211	203
AVERAGE	**219**	**224**	**230**	**211**	**201**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

Detailed Tables

Small Power

Monthly Bills

Average Prices

Comparative Index

SMALL POWER

Monthly Bills on April 1, 2019
(in CA$)

Power demand	**6 kW**	**14 kW**	**40 kW**	**100 kW**	**100 kW**
Consumption	**750 kWh**	**2,000 kWh**	**10,000 kWh**	**14,000 kWh**	**25,000 kWh**
Load factor	**17%**	**20%**	**35%**	**19%**	**35%**
Canadian Cities					
Montréal, QC	86.58	210.33	1,002.33	1,834.20	2,715.50
Calgary, AB	141.36	298.25	1,593.12	2,409.30	3,632.65
Charlottetown, PE[1]	157.10	377.97	1,753.67	3,021.07	4,290.47
Edmonton, AB	120.82	295.72	1,415.16	2,617.72	3,602.11
Halifax, NS	124.81	305.70	1,555.50	2,731.38	3,888.75
Moncton, NB	121.19	285.19	1,354.09	2,355.89	3,379.99
Ottawa, ON	104.02	246.88	1,161.20	2,526.13	4,033.44
Regina, SK	133.66	304.52	1,398.04	2,687.72	3,650.47
St. John's, NL[2]	105.31	274.53	1,179.13	2,054.03	2,940.57
Toronto, ON[1]	131.88	291.58	1,313.64	2,816.96	4,351.42
Vancouver, BC	105.06	261.69	1,192.93	1,905.33	2,970.13
Winnipeg, MB	87.79	198.99	910.67	1,830.95	2,404.49
American Cities					
Boston, MA	246.41	631.60	3,304.45	6,218.35	8,684.39
Chicago, IL	194.75	427.96	1,651.16	2,765.37	4,064.97
Detroit, MI[1]	127.38	316.31	1,500.09	2,091.98	3,719.68
Houston, TX[1]	95.92	331.56	1,233.61	2,175.29	3,041.86
Miami, FL[1]	106.13	259.59	1,300.78	2,466.65	3,199.31
Nashville, TN	188.09	404.62	1,620.73	3,769.17	4,577.09
New York, NY[1]	242.29	814.08	2,727.64	5,376.88	6,720.68
Portland, OR[1]	127.91	301.37	1,365.28	2,303.78	3,352.14
San Francisco, CA	245.44	632.61	3,006.87	5,001.49	7,241.12
Seattle, WA	100.33	267.54	1,337.70	1,943.20	3,065.51
AVERAGE	**140.65**	**351.75**	**1,585.35**	**2,859.22**	**4,069.40**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL POWER

Average Prices on April 1, 2019
(in ¢/kWh)[1]

Power demand	**6 kW**	**14 kW**	**40 kW**	**100 kW**	**100 kW**
Consumption	**750 kWh**	**2,000 kWh**	**10,000 kWh**	**14,000 kWh**	**25,000 kWh**
Load factor	**17%**	**20%**	**35%**	**19%**	**35%**
Canadian Cities					
Montréal, QC	11.54	10.52	10.02	13.10	10.86
Calgary, AB	18.85	14.91	15.93	17.21	14.53
Charlottetown, PE[2]	20.95	18.90	17.54	21.58	17.16
Edmonton, AB	16.11	14.79	14.15	18.70	14.41
Halifax, NS	16.64	15.29	15.56	19.51	15.56
Moncton, NB	16.16	14.26	13.54	16.83	13.52
Ottawa, ON	13.87	12.34	11.61	18.04	16.13
Regina, SK	17.82	15.23	13.98	19.20	14.60
St. John's, NL[3]	14.04	13.73	11.79	14.67	11.76
Toronto, ON[2]	17.58	14.58	13.14	20.12	17.41
Vancouver, BC	14.01	13.08	11.93	13.61	11.88
Winnipeg, MB	11.71	9.95	9.11	13.08	9.62
American Cities					
Boston, MA	32.85	31.58	33.04	44.42	34.74
Chicago, IL	25.97	21.40	16.51	19.75	16.26
Detroit, MI[2]	16.98	15.82	15.00	14.94	14.88
Houston, TX[2]	12.79	16.58	12.34	15.54	12.17
Miami, FL[2]	14.15	12.98	13.01	17.62	12.80
Nashville, TN	25.08	20.23	16.21	26.92	18.31
New York, NY[2]	32.31	40.70	27.28	38.41	26.88
Portland, OR[2]	17.05	15.07	13.65	16.46	13.41
San Francisco, CA	32.73	31.63	30.07	35.72	28.96
Seattle, WA	13.38	13.38	13.38	13.88	12.26
AVERAGE	**18.75**	**17.59**	**15.85**	**20.42**	**16.28**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL POWER

Comparative Index on April 1, 2019
(Hydro-Québec = 100)

Power demand	**6 kW**	**14 kW**	**40 kW**	**100 kW**	**100 kW**
Consumption	**750 kWh**	**2,000 kWh**	**10,000 kWh**	**14,000 kWh**	**25,000 kWh**
Load factor	**17%**	**20%**	**35%**	**19%**	**35%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	163	142	159	131	134
Charlottetown, PE[1]	181	180	175	165	158
Edmonton, AB	140	141	141	143	133
Halifax, NS	144	145	155	149	143
Moncton, NB	140	136	135	128	124
Ottawa, ON	120	117	116	138	149
Regina, SK	154	145	139	147	134
St. John's, NL[2]	122	131	118	112	108
Toronto, ON[1]	152	139	131	154	160
Vancouver, BC	121	124	119	104	109
Winnipeg, MB	101	95	91	100	89
American Cities					
Boston, MA	285	300	330	339	320
Chicago, IL	225	203	165	151	150
Detroit, MI[1]	147	150	150	114	137
Houston, TX[1]	111	158	123	119	112
Miami, FL[1]	123	123	130	134	118
Nashville, TN	217	192	162	205	169
New York, NY[1]	280	387	272	293	247
Portland, OR[1]	148	143	136	126	123
San Francisco, CA	283	301	300	273	267
Seattle, WA	116	127	133	106	113
AVERAGE	**162**	**167**	**158**	**156**	**150**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

05

Detailed Tables

Medium Power

Monthly Bills

Average Prices

Comparative Index

MEDIUM POWER

Monthly Bills on April 1, 2019
(in CA$)

Power demand	**500 kW**	**500 kW**	**1,000 kW**	**1,000 kW**	**2,500 kW**[1]
Consumption	**100,000 kWh**	**200,000 kWh**	**200,000 kWh**	**400,000 kWh**	**1,170,000 kWh**
Load factor	**28%**	**56%**	**28%**	**56%**	**65%**
Canadian Cities					
Montréal, QC	12,195.00	17,350.00	24,390.00	32,230.00	79,924.50
Calgary, AB	16,373.70	27,148.83	32,041.31	53,591.59	144,590.04
Charlottetown, PE[2]	18,317.47	29,857.47	36,572.47	59,652.47	168,655.47
Edmonton, AB[3]	20,746.76	32,561.12	39,051.77	62,680.48	173,122.98
Halifax, NS	17,260.50	25,993.50	34,521.00	51,987.00	147,637.65
Moncton, NB	14,558.49	23,868.49	29,113.49	47,733.49	135,155.49
Ottawa, ON	16,439.73	28,145.57	32,679.20	56,090.89	161,917.98
Regina, SK	16,347.97	24,021.97	32,679.97	48,027.97	117,239.17
St. John's, NL[4]	11,994.65	19,607.72	22,831.91	37,910.29	104,588.13
Toronto, ON[2]	18,603.42	30,326.22	36,770.49	59,981.65	165,088.07
Vancouver, BC	12,238.13	18,298.13	24,468.13	36,588.13	99,608.73
Winnipeg, MB	10,177.17	14,285.17	20,123.77	28,339.77	69,930.06
American Cities					
Boston, MA	35,043.86	55,154.72	69,874.32	110,096.05	306,736.75
Chicago, IL	13,361.18	16,578.68	26,524.83	32,959.81	115,016.87
Detroit, MI[2]	14,817.63	22,513.92	29,614.90	44,586.79	105,625.62
Houston, TX[2]	13,979.54	21,857.49	30,839.91	46,595.82	119,901.07
Miami, FL[2]	15,222.73	21,251.06	30,340.22	42,396.87	113,485.53
Nashville, TN	20,132.69	26,910.56	40,000.82	53,556.55	148,508.75
New York, NY[2]	30,286.86	42,503.15	60,508.10	84,940.68	177,641.80
Portland, OR[2]	14,307.32	21,876.04	27,379.34	41,914.48	105,515.16
San Francisco, CA	36,086.13	50,611.21	69,747.48	97,101.48	199,321.54
Seattle, WA	12,776.85	22,979.65	25,173.03	45,398.01	128,870.92
AVERAGE	**17,784.90**	**26,986.39**	**35,238.48**	**53,380.01**	**140,367.38**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM POWER

Average Prices on April 1, 2019
(in ¢/kWh)[1]

Power demand **Consumption** **Load factor**	**500 kW** **100,000 kWh** **28%**	**500 kW** **200,000 kWh** **56%**	**1,000 kW** **200,000 kWh** **28%**	**1,000 kW** **400,000 kWh** **56%**	**2,500 kW**[2] **1,170,000 kWh** **65%**
Canadian Cities					
Montréal, QC	12.20	8.68	12.20	8.06	6.83
Calgary, AB	16.37	13.57	16.02	13.40	12.36
Charlottetown, PE[3]	18.32	14.93	18.29	14.91	14.41
Edmonton, AB[4]	20.75	16.28	19.53	15.67	14.80
Halifax, NS	17.26	13.00	17.26	13.00	12.62
Moncton, NB	14.56	11.93	14.56	11.93	11.55
Ottawa, ON	16.44	14.07	16.34	14.02	13.84
Regina, SK	16.35	12.01	16.34	12.01	10.02
St. John's, NL[5]	11.99	9.80	11.42	9.48	8.94
Toronto, ON[3]	18.60	15.16	18.39	15.00	14.11
Vancouver, BC	12.24	9.15	12.23	9.15	8.51
Winnipeg, MB	10.18	7.14	10.06	7.08	5.98
American Cities					
Boston, MA	35.04	27.58	34.94	27.52	26.22
Chicago, IL	13.36	8.29	13.26	8.24	9.83
Detroit, MI[3]	14.82	11.26	14.81	11.15	9.03
Houston, TX[3]	13.98	10.93	15.42	11.65	10.25
Miami, FL[3]	15.22	10.63	15.17	10.60	9.70
Nashville, TN	20.13	13.46	20.00	13.39	12.69
New York, NY[3]	30.29	21.25	30.25	21.24	15.18
Portland, OR[3]	14.31	10.94	13.69	10.48	9.02
San Francisco, CA	36.09	25.31	34.87	24.28	17.04
Seattle, WA	12.78	11.49	12.59	11.35	11.01
AVERAGE	**17.78**	**13.49**	**17.62**	**13.35**	**12.00**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM POWER

Comparative Index on April 1, 2019
(Hydro-Québec = 100)

Power demand	**500 kW**	**500 kW**	**1,000 kW**	**1,000 kW**	**2,500 kW**[1]
Consumption	**100,000 kWh**	**200,000 kWh**	**200,000 kWh**	**400,000 kWh**	**1,170,000 kWh**
Load factor	**28%**	**56%**	**28%**	**56%**	**65%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	134	156	131	166	181
Charlottetown, PE[2]	150	172	150	185	211
Edmonton, AB[3]	170	188	160	194	217
Halifax, NS	142	150	142	161	185
Moncton, NB	119	138	119	148	169
Ottawa, ON	135	162	134	174	203
Regina, SK	134	138	134	149	147
St. John's, NL[4]	98	113	94	118	131
Toronto, ON[2]	153	175	151	186	207
Vancouver, BC	100	105	100	114	125
Winnipeg, MB	83	82	83	88	87
American Cities					
Boston, MA	287	318	286	342	384
Chicago, IL	110	96	109	102	144
Detroit, MI[2]	122	130	121	138	132
Houston, TX[2]	115	126	126	145	150
Miami, FL[2]	125	122	124	132	142
Nashville, TN	165	155	164	166	186
New York, NY[2]	248	245	248	264	222
Portland, OR[2]	117	126	112	130	132
San Francisco, CA	296	292	286	301	249
Seattle, WA	105	132	103	141	161
AVERAGE	**146**	**156**	**144**	**166**	**176**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

06

Detailed Tables

Large Power

Monthly Bills

Average Prices

Comparative Index

LARGE POWER

Monthly Bills on April 1, 2019
(in CA$)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	135,459.00	159,075.00	289,362.00	875,958.00	1,269,690.00	1,505,850.00
Calgary, AB	286,798.97	366,251.39	691,939.91	2,100,635.81	2,860,470.30	3,654,994.48
Charlottetown, PE[2]	239,576.00	290,984.00	556,264.00	1,685,928.00	2,395,760.00	2,909,840.00
Edmonton, AB[3]	315,260.31	391,595.82	630,966.76	1,902,847.48	2,667,466.84	3,283,225.24
Halifax, NS	257,934.69	317,874.69	605,779.37	1,837,330.11	2,579,370.84	3,178,770.84
Moncton, NB	204,441.73	242,808.73	444,400.00	1,345,800.00	1,938,500.00	2,316,500.00
Ottawa, ON	331,635.61	353,949.10	681,509.88	2,021,504.33	3,179,271.93	3,402,406.84
Regina, SK	225,093.98	274,788.38	446,691.58	1,339,513.04	1,873,125.29	2,312,973.29
St. John's, NL[4]	206,308.09	260,590.26	487,977.03	998,541.60	1,441,922.00	1,717,898.00
Toronto, ON[2]	341,329.60	364,478.60	708,979.06	2,125,588.91	3,357,180.99	3,583,733.35
Vancouver, BC	199,209.45	242,186.97	385,189.42	1,167,812.16	1,650,672.50	2,017,728.50
Winnipeg, MB	137,246.56	165,031.36	269,156.78	815,740.27	1,159,875.36	1,407,771.36
American Cities						
Boston, MA	589,411.55	729,677.32	1,388,888.33	4,212,753.39	5,891,114.72	7,293,772.35
Chicago, IL	229,082.01	268,649.27	411,933.20	1,232,690.38	1,734,676.73	2,130,349.34
Detroit, MI[2]	210,676.81	242,397.21	448,214.27	1,353,827.35	2,006,272.11	2,316,274.13
Houston, TX[2]	237,099.11	293,891.45	528,976.66	1,601,404.73	2,214,498.67	2,776,948.62
Miami, FL[2]	226,655.58	267,716.47	439,179.34	1,323,894.04	1,915,625.79	2,274,380.42
Nashville, TN	293,531.82	343,196.67	440,156.77	1,294,038.08	1,950,927.98	2,393,476.25
New York, NY[2]	355,091.16	419,178.54	806,120.95	2,439,340.42	3,549,179.63	4,190,053.43
Portland, OR[2]	209,552.98	255,341.82	475,476.60	1,434,805.95	2,048,544.82	2,471,716.84
San Francisco, CA	395,233.80	478,610.04	912,902.90	2,761,242.65	3,928,676.50	4,762,438.83
Seattle, WA	257,894.15	330,320.43	583,346.47	1,771,666.59	2,409,084.46	3,081,818.37
AVERAGE	**267,478.32**	**320,845.16**	**574,245.97**	**1,711,039.24**	**2,455,541.25**	**2,953,769.11**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Average Prices on April 1, 2019
(in ¢/kWh)[1]

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[2]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	5.79	5.20	5.02	5.00	5.43	4.92
Calgary, AB	12.26	11.97	12.01	11.99	12.22	11.94
Charlottetown, PE[3]	10.24	9.51	9.66	9.62	10.24	9.51
Edmonton, AB[4]	13.47	12.80	10.95	10.86	11.40	10.73
Halifax, NS	11.02	10.39	10.52	10.49	11.02	10.39
Moncton, NB	8.74	7.93	7.72	7.68	8.28	7.57
Ottawa, ON	14.17	11.57	11.83	11.54	13.59	11.12
Regina, SK	9.62	8.98	7.76	7.65	8.00	7.56
St. John's, NL[5]	8.82	8.52	8.47	5.70	6.16	5.61
Toronto, ON[3]	14.59	11.91	12.31	12.13	14.35	11.71
Vancouver, BC	8.51	7.91	6.69	6.67	7.05	6.59
Winnipeg, MB	5.87	5.39	4.67	4.66	4.96	4.60
American Cities						
Boston, MA	25.19	23.85	24.11	24.05	25.18	23.84
Chicago, IL	9.79	8.78	7.15	7.04	7.41	6.96
Detroit, MI[3]	9.00	7.92	7.78	7.73	8.57	7.57
Houston, TX[3]	10.13	9.60	9.18	9.14	9.46	9.07
Miami, FL[3]	9.69	8.75	7.62	7.56	8.19	7.43
Nashville, TN	12.54	11.22	7.64	7.39	8.34	7.82
New York, NY[3]	15.17	13.70	14.00	13.92	15.17	13.69
Portland, OR[3]	8.96	8.34	8.25	8.19	8.75	8.08
San Francisco, CA	16.89	15.64	15.85	15.76	16.79	15.56
Seattle, WA	11.02	10.79	10.13	10.11	10.30	10.07
AVERAGE	**11.43**	**10.49**	**9.97**	**9.77**	**10.49**	**9.65**

1) In Canadian currency.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE POWER

Comparative Index on April 1, 2019
(Hydro-Québec = 100)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	212	230	239	240	225	243
Charlottetown, PE[2]	177	183	192	192	189	193
Edmonton, AB[3]	233	246	218	217	210	218
Halifax, NS	190	200	209	210	203	211
Moncton, NB	151	153	154	154	153	154
Ottawa, ON	245	223	236	231	250	226
Regina, SK	166	173	154	153	148	154
St. John's, NL[4]	152	164	169	114	114	114
Toronto, ON[2]	252	229	245	243	264	238
Vancouver, BC	147	152	133	133	130	134
Winnipeg, MB	101	104	93	93	91	93
American Cities						
Boston, MA	435	459	480	481	464	484
Chicago, IL	169	169	142	141	137	141
Detroit, MI[2]	156	152	155	155	158	154
Houston, TX[2]	175	185	183	183	174	184
Miami, FL[2]	167	168	152	151	151	151
Nashville, TN	217	216	152	148	154	159
New York, NY[2]	262	264	279	278	280	278
Portland, OR[2]	155	161	164	164	161	164
San Francisco, CA	292	301	315	315	309	316
Seattle, WA	190	208	202	202	190	205
AVERAGE	**197**	**202**	**198**	**195**	**193**	**196**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

Appendix

Rate Adjustments

Average Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

All Categories

	Before April 2018		Between April 1, 2018, and April 1, 2019		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2018	0.3	April 1, 2019	0.9	
ENMAX, AB	2018	3.08	January 1, 2019	1.17	Applicable to distribution portion only
Maritime Electric, PE	2018	2.3	—	—	
EPCOR, AB	2017	n.a.	—	—	
Nova Scotia Power, NS	2018	n.a.	January 1, 2019	n.a.	
NB Power, NB	2017	2.05	August 1, 2018	0.88	
Hydro Ottawa, ON	2018	n.a.	January 1, 2019	n.a.	
SaskPower, SK	2018	3.5	—	—	
Newfoundland Power, NL[1]	2017	8.5	July 1, 2018	6.8	
Newfoundland and Labrador Hydro, NL[1]	2018	n.a.	January 1, 2019	n.a.	
Toronto Hydro, ON	2018	n.a.	January 1, 2019	n.a.	
BC Hydro, BC	2018	3.0	April 1, 2019	6.85	
Manitoba Hydro, MB	2017	3.34	June 1, 2018	3.6	
Data concerning American utlities not available.					

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2018, and April 1, 2019)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2019	0.9	0.9[1]	0.3	0.9
			0.8[2]		
			0.9[3]		
ENMAX, AB	January 1, 2019	1.96[4]	n.a.	n.a.	1.17[4]
Maritime Electric, PE	—	—	—	—	—
EPCOR, AB	—	—	—	—	—
Nova Scotia Power, NS	January 1, 2019	1.7	1.9[1]	1.3[5]	n.a.
			0.9[2]	1.6[6]	
			3.8[3]	1.5[7]	
NB Power, NB	August 1, 2018	0.96	0.4	0.96	0.88
Hydro Ottawa, ON	January 1, 2019	0.12	0.94	7.37	n.a.
	May 1, 2018	-0.13	-0.13	14.18	n.a.
	April 1, 2018	-0.21	-5.03	0.74	n.a.
SaskPower, SK	—	—	—	—	—
Newfoundland Power, NL[8]	July 1, 2018	6.6	7.2	8.3	6.8
Newfoundland and Labrador Hydro, NL[8]	January 1, 2019	—	—	4.6	—
Toronto Hydro, ON	January 1, 2019	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2019	6.85	6.85	6.85	6.85
Manitoba Hydro, MB	June 1, 2018	4.04	3.64	3.3	3.6
Data concerning American utlities not available.					

n.a.: Not available.
1) Small power.
2) Medium power.
3) Large power.
4) Distribution charge only.
5) Small industrial.
6) Medium industrial.
7) Large industrial.
8) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

Appendix

Time-of-Use Rates

Adjustment Clauses

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2019 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	Residential General: 14–10,000 kW
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	Residential General: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Distribution Cost Recovery Factor Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge System Benefit Fund Charge Transition Charges Transmission Cost Recovery Factor
Commonwealth Edison, IL	Energy Efficiency Pricing & Performance Energy Efficiency Demand Response Balancing Adjustment Mechanism Environmental Cost Recovery Adjustment Franchise Cost Addition Renewable Energy Adjustment Retail Customer Assessments Zero Emission Adjustment
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Billing and Payment Processing Charge Clean Energy Standard Supply Surcharge Delivery Revenue Surcharge Dynamic Load Management Surcharge Market Supply Charge Market Supply Charge Capacity Merchant Function Charge Monthly Adjustment Clause Revenue Decoupling Mechanism Adjustment Statement of Tax Sur-Credit System Benefits Charge
DTE Electric, MI	Energy Waste Reduction Surcharge Low Income Energy Assistance Fund Factor Nuclear Surcharge Power Supply Cost Recovery Clause Renewable Energy Plan Surcharge Tax Credit B
ENMAX, AB	Balancing Pool Allocation Rider DAS Adjustment Rider Local Access Fee Transmission Access Charge Deferral Account Rider

EPCOR, AB	Balancing Pool Rider DAS True-up Rider Local Access Fee SAS True-up Rider Transmission Charge Deferral Account True-Up Rider
Eversource Energy, MA	Attorney General Consultant Expense Basic Service Cost True-up Factor Distributed Solar (SMART) Energy Efficiency Charge Long Term Renewable Contract Adjustment Net Metering Recovery Surcharge Pension Adjustment Factor Renewable Energy Charge Residential Assistance Adjustment Factor Revenue Decoupling Adjustment Mechanism Solar Program Cost Adjustment Factor Solar Expansion Cost Recovery Factor Storm Cost Recovery Adjustment Factor Storm Reserve Adjustment Transition Cost Adjustment Transmission Service Cost Adjustment Vegetation Management Tax Act Credit Factor
Florida Power and Light, FL	Energy Conservation Cost Recovery Clause Capacity Payment Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Restoration Charge
Hydro Ottawa, ON	Capacity Based Recovery Disposition of Group 1 Deferral/Variance Accounts (2019) Disposition of Global Adjustment Account (2019) Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	TVA Fuel Cost Adjustment
Newfoundland and Labrador Hydro, NL	CDM Cost Recovery Adjustment Rate Stabilization Plan Adjustment
Nova Scotia Power, NS	Demand Side Management Cost Recovery Rider Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	California Climate Credit Competition Transition Charge DWR Bond Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments

Pacific Power and Light, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning Conservation Act
	Adjustment to Remove Deer Creek Mine Investment from Base Rate
	Base Supply Service
	Energy Conservation Charge
	Deferred Accounting Adjustment
	Federal Tax Act Adjustment
	Generation Investment Adjustment
	Independent Evaluator Cost Adjustment
	Intervenor Funding Adjustment
	Klamath Dam Removal Surcharges
	Net Power Costs
	Oregon Solar Incentive Program Deferral
	Pilot Program Cost Adjustment
	Property Sales Balancing Account Adjustment
	Public Purpose Charge
	Rate Mitigation Adjustment
	Renewable Adjustment Clause
	Renewable Resource Deferral Adjustment
	TAM Adjustment for Other Revenues
Toronto Hydro, ON	Application of IFRS – 2014 Derecognition
	Capacity Based Recovery (CBR)
	Disposition of Capacity Based Recovery Account (2019)
	Disposition of Deferral/Variance Accounts (2019)
	Disposition of Global Adjustment Account (2019)
	Disposition of LRAM Variance Account
	Recovery of Hydro One Capital Contributions Variance
	Recovery of Stranded Meter Assets
	Recovery of the Gain on the Sale of Named Properties
	Recovery of 2015 Foregone Revenue
	Recovery of 2016 Foregone Revenue
	Rural or Remote Electricity Rate Protection Charge
	Smart Metering Entity Charge

C

Appendix

Applicable Taxes

Residential Sector

General Sector

Industrial Sector

TAXES APPLICABLE TO RESIDENTIAL SERVICE

On April 1, 2019

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	15	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	4	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	5.997	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	4.9898	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.23	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL SERVICE

On April 1, 2019

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	5.997	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL SERVICE (cont'd)

On April 1, 2019

	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4562	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.23	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL SERVICE

On April 1, 2019

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable)[1]
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	8	To base amount of bill (industries other than mining and manufacturing)
		1.6	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
Miami, FL	Gross receipts tax	2.5641	To base amount of bill
	Franchise fee	5.997	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL SERVICE (cont'd)

On April 1, 2019

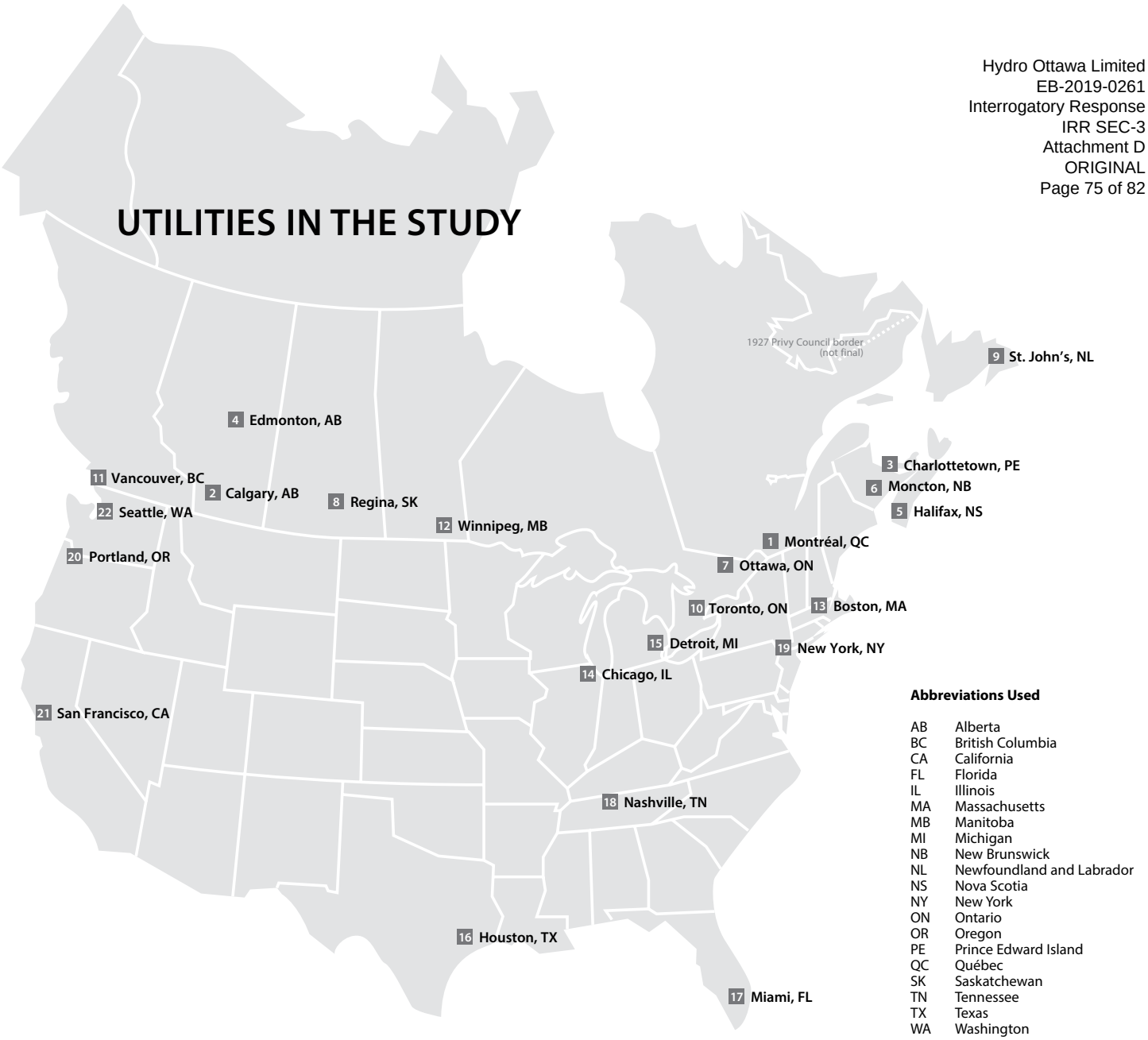
	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4562	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.23	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	Seattle occupation tax	6	Tax included in rate schedule prices

D

Appendix

Utilities in the Study

UTILITIES IN THE STUDY



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro
(customers with a power demand of 30,000 kW or more)
Newfoundland Power
(all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

A government-owned company whose lines of business are unbundled, Hydro-Québec is one of the largest electric utilities in North America.

The *Act respecting the Régie de l'énergie* [Québec energy board] established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution. The division also purchases electricity on the market, primarily through calls for tenders. The average supply cost of heritage pool electricity, set at a fixed price of 2.79¢/kWh since 1998, is indexed on January 1 since 2014 at a rate corresponding to the annual variation in the all-item consumer price index for Québec, with the exception of the large-power industrial rate (Rate L), which is exempt from the indexation of heritage pool electricity.

The Régie de l'énergie approved an average increase of 0.9% in the rates of Hydro-Québec Distribution, effective April 1, 2019, with the exception of large-power customers, for whom the approved increase is of 0.3%.

Activities: Generation, transmission and distribution

Installed capacity: 37,310 MW

Main sources: Hydroelectric generating stations and wind power purchases (more than 99% of power generated is clean and renewable)

Number of accounts: About 4.3 million residential, commercial, institutional and industrial customer accounts, nine municipal systems and one regional cooperative

Distribution regulator: Régie de l'énergie [Québec energy board]

Wholesale market: Open

Retail market: –

ENMAX
Calgary, Alberta

Activities: Generation, transmission and distribution

Installed capacity: 1,503 MW

Main sources: Natural gas (90%) and wind (10%)

Number of accounts: 667,700

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

Activities: Distribution

Installed capacity: About 145 MW for reserve purposes

Main sources: Purchased from NB Power

Number of accounts: About 80,000

Distribution regulator: Island Regulatory and Appeals Commission

Wholesale market: –

Retail market: –

EPCOR
Edmonton, Alberta

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchased on market

Number of accounts: About 600,000 customers throughout province of Alberta, including about 380,000 customers in Edmonton

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

NOVA SCOTIA POWER
Halifax, Nova Scotia

Activities: Generation, transmission and distribution

Installed capacity: 2,453 MW

Main sources: Coal, petroleum coke, wind, hydropower and others

Number of accounts: 500,000

Distribution regulator: Nova Scotia Utility and Review Board

Wholesale market: –

Retail market: –

NB POWER
Moncton, New Brunswick

Activities: Generation, transmission and distribution

Installed capacity: 3,515 MW

Main sources: Thermal (1,439 MW), hydroelectric (889 MW), nuclear (660 MW) and combustion turbines (525 MW)

Number of accounts: Over 400,000 direct and indirect customers

Distribution regulator: New Brunswick Energy and Utilities Board

Wholesale market: –

Retail market: –

HYDRO OTTAWA
Ottawa, Ontario

Activities: Distribution

Installed capacity: –

Main sources: Purchased from Ontario Power Generation

Number of accounts: Over 332,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but rate for the supply of electricity is regulated by Ontario Energy Board

SASKPOWER
Regina, Saskatchewan

Activities: Generation, transmission and distribution

Installed capacity: 4,493 MW

Main sources: Natural gas (40%), coal (34%), hydroelectric (20%), wind (5%) and other (1%)

Number of accounts: About 533,000

Distribution regulator: Saskatchewan Rate Review Panel reviews SaskPower's rate applications and advises government

Wholesale market: Partially open

Retail market: Partially open

NEWFOUNDLAND AND LABRADOR HYDRO
(customers with a power demand of 30,000 kW or more)
St. John's, Newfoundland and Labrador

Activities: Generation and distribution

Installed capacity: 1,763 MW

Main sources: Hydroelectric generating stations and fuel

Number of accounts: 38,000 direct customers

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: –

Retail market: –

NEWFOUNDLAND POWER
(all other customer categories)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 140 MW

Main sources: Purchased from Newfoundland and Labrador Hydro (93%)

Number of accounts: About 266,000 customers throughout the island of Newfoundland

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: –

Retail market: –

TORONTO HYDRO
Toronto, Ontario

Activities: Distribution

Installed capacity: –

Main sources: Purchased from Ontario Power Generation

Number of accounts: About 772,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but rate for the supply of electricity is regulated by Ontario Energy Board

BC HYDRO
Vancouver, British Columbia

Activities: Generation, transmission and distribution

Installed capacity: Almost 12,100 MW

Main sources: Hydroelectric generating stations (about 98%)

Number of accounts: More than 2 million

Distribution regulator: British Columbia Utilities Commission

Wholesale market: Open

Retail market: –

MANITOBA HYDRO
Winnipeg, Manitoba

Activities: Generation, transmission and distribution

Installed capacity: 5,648 MW

Main sources: Hydroelectric (about 96%), thermal and diesel

Number of accounts: Over 580,000

Distribution regulator: Manitoba Public Utilities Board

Wholesale market: –

Retail market: –

AMERICAN UTILITIES

EVERSOURCE ENERGY
Boston, Massachusetts

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchased from ISO New England.

Number of accounts: Close to 3.7 million residential, commercial and industrial customers in Massachusetts, Connecticut and New Hampshire

Distribution regulator: Massachusetts Department of Public Utilities

Wholesale market: Open

Retail market: Open

COMMONWEALTH EDISON (ComEd)
Chicago, Illinois

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchases from Midcontinent Independent System Operator

Number of accounts: Over 4 million customers in northern Illinois

Distribution regulator: Illinois Commerce Commission

Wholesale market: Open

Retail market: Open

DTE ELECTRIC
Detroit, Michigan

Activities: Generation, transmission and distribution

Installed capacity: 11,084 MW

Main sources: Coal, nuclear, natural gas, hydroelectric and other renewables

Number of accounts: 2.2 million customers in southeastern Michigan

Distribution regulator: Michigan Public Service Commission

Wholesale market: Open

Retail market: Partially open

CENTERPOINT ENERGY
Houston, Texas

Activities: Transmission and Distribution

Installed capacity: –

Main sources: Purchased from Texas ISO

Number of accounts: Over 2.4 million

Distribution regulator: Public Utility Commission of Texas

Wholesale market: Open

Retail market: Open

FLORIDA POWER AND LIGHT (FPL)
Miami, Florida

Activities: Generation, transmission and distribution

Installed capacity: Over 24,000 MW

Main sources: Nuclear, combined-cycle, coal, fuel and solar

Number of accounts: Over 5 million

Distribution regulator: Florida Public Service

Wholesale market: Open

Retail market: –

NASHVILLE ELECTRIC SERVICE
Nashville, Tennessee

Activities: Distribution

Installed capacity: –

Main sources: Purchased from Tennessee Valley Authority

Number of accounts: Over 385,000

Distribution regulator: Tennessee Valley Authority

Wholesale market: –

Retail market: –

CONSOLIDATED EDISON (ConEd)
New York, New York

Activities: Distribution

Installed capacity: –

Main sources: Purchased from New York Independent System Operator

Number of accounts: 3.5 million customers in and around New York City and Westchester County

Distribution regulator: New York State Public Service Commission

Wholesale market: Open

Retail market: Open

PACIFIC POWER AND LIGHT
Portland, Oregon

Activities: Generation, transmission and distribution

Installed capacity: Over 10,880 MW

Main sources: Coal, natural gas, hydroelectric, wind and geothermal

Number of accounts: Close to 764,000 customers across three states

Distribution regulator: Public Utility Commission of Oregon

Wholesale market: Open

Retail market: Partially open

PACIFIC GAS AND ELECTRIC (PG&E)
San Francisco, California

Activities: Generation, transmission and distribution

Installed capacity: 7,684 MW

Main sources: Purchased from California ISO and thermal, hydroelectric, solar and other generating stations

Number of accounts: 5.4 million

Distribution regulator: California Public Utilities Commission

Wholesale market: Open

Retail market: Partially open

SEATTLE CITY LIGHT
Seattle, Washington

Activities: Generation, transmission and distribution

Installed capacity: 1,968 MW

Main sources: Purchased from Bonneville Power Administration and hydroelectric, wind, biogas generating stations and others

Number of accounts: About 455,000 customers in city of Seattle and certain surrounding communities

Distribution regulator: City of Seattle

Wholesale market: Open

Retail market: –

Information sources
Annual reports and websites of the Canadian and American utilities in the study.

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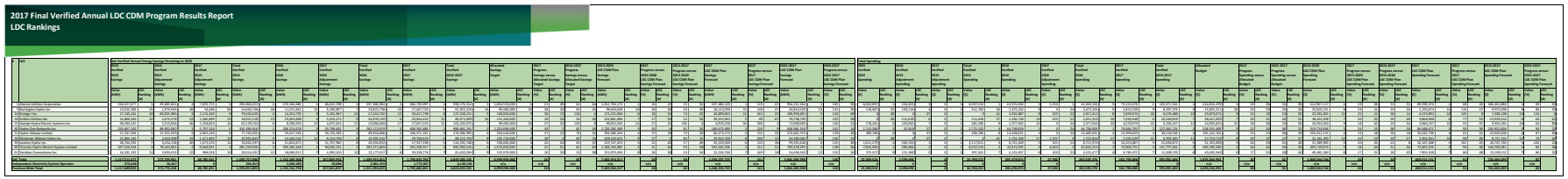
Hydro Québec

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Final Verified 2016 Annual LDC CDM Program Results Report

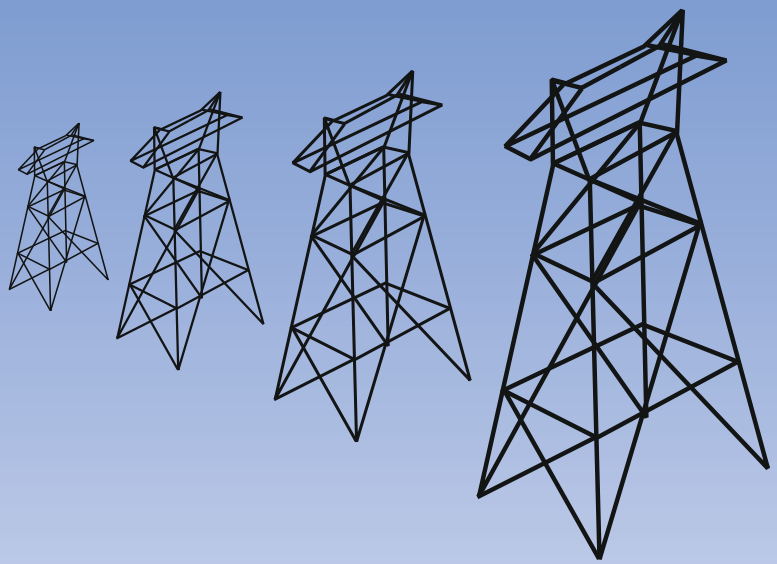
LDC Rankings

#	LDC	Net Verified Annual Energy Savings Persisting to 2020																																					
		2015 Verified Results		Verified 2015 Adjustment Results		Verified Adjusted 2015 Results		2016 Verified Results		2015-2016 Verified Results		Allocated Target		2015-2016 Progress versus Allocated Target		2015-2020 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2020 LDC CDM Plan Forecast		2016 LDC CDM Plan Forecast		2016 Progress versus 2016 LDC CDM Plan Forecast		2015-2016 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2016 LDC CDM Plan Forecast		Total Spending 2015 Verified Spending		Verified 2015 Adjustment Spending		Verified Adjusted 2015 Spending		2016 Verified Spending		2015-2016 Verified Spending		Allocated Budget		2015-2016 Progress versus Allocated Budget		2015-2020 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2020 LDC CDM Plan Forecast		2016 LDC CDM Plan Forecast		2016 Progress versus 2016 LDC CDM Plan Forecast		2015-2016 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2016 LDC CDM Plan Forecast	
		Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)
1	Algoma Power Inc.	1,031,011	57	25,818	58	1,056,828	58	1,285,402	52	2,342,230	56	7,510,000	54	31	45	11,100,760	47	21	66	836,284	54	157	16	1,777,226	53	132	34	39,320	22	59,951	99,271	20	344,836	47	444,108	42	2,107,963	53	21	3	3,449,717	45	13	24	683,154	43	50	51	737,814	43	60	37
2	Atikokan Hydro Inc.	109,769	67	2,444		112,213	67	189,357	68	301,570	68	1,140,000	67	26	54	1,139,590	67	26	52	127,788	71	148	18	170,828	71	177	17	0	30	0	0	43	50,265	66	50,265	66	311,330	67	16	9	374,405	70	13	19	56,766	71	89	8	56,772	71	89	10
3	Attawapiskat Power Corporation	35,822	70	2,343		38,165	70	0	69	38,165	70	510,000	70	7	71	556,816	69	7	71	209,344	66	0	69	209,344	68	18	70	0	30	0	0	43	0	69	0	69	148,832	70	0	69	386,748	52	0	69	386,748	52	0	69
4	Bluewater Power Distribution Corporation	7,755,327	21	268,687		8,024,013	26	5,570,598	28	13,594,611	30	62,370,000	19	22	65	62,370,000	19	22	64	7,092,037	25	79	58	14,839,910	25	92	57	5,119	29	0	5,119	41	1,340,938	26	1,346,056	27	15,838,687	20	8	56	15,838,687	20	8	54	2,579,261	19	52	48	2,584,380	21	52	50
5	Brantford Power Inc.	7,457,011	22	1,458,523		8,915,534	25	10,499,455	19	19,414,989	21	54,320,000	22	36	33	54,880,608	23	35	36	9,918,198	18	106	39	17,760,851	22	109	46	0	30	29,000	29,000	30	1,564,432	22	1,593,432	24	14,048,458	22	11	30	11,591,730	23	14	16	2,207,285	23	71	29	2,236,285	23	71	28
6	Burlington Hydro Inc.	12,832,309	18	1,975,945		14,808,254	18	11,531,861	15	26,340,115	16	99,040,000	13	26	55	99,040,000	14	26	53	11,672,695	15	99	47	18,200,840	21	144	24	118,667	17	193,116	311,783	12	2,472,234	12	2,784,017	13	15,825,521	13	11	37	15,890,159	12	11	38	3,893,532	15	63	35	4,897,008	12	57	43
7	Canadian Niagara Power Inc.	3,502,396	37	5,579,808		9,082,204	23	5,553,280	29	14,635,484	27	28,480,000	32	51	12	28,104,418	31	52	15	4,745,580	30	117	29	11,046,585	27	132	31	162,334	14	58,069	220,403	13	1,200,961	27	1,421,364	26	7,355,555	33	19	5	6,338,440	35	22	4	1,589,930	29	76	22	1,643,473	29	86	12
8	Centre Wellington Hydro Ltd.	1,581,029	53	109,971		1,690,999	53	1,548,975	50	3,239,975	52	8,730,000	59	37	30	8,729,845	59	37	33	2,771,886	40	56	62	4,123,814	39	79	60	0	30	0	0	43	276,194	40	276,194	40	2,252,724	51	12	26	2,252,724	51	12	29	651,826	44	42	59	651,826	44	42	58
9	Chapleau Public Utilities Corporation	275,333	54	3,485		278,818	64	191,711	67	470,529	66	1,050,000	68	45	18	1,057,696	68	44	21	134,983	70	142	21	508,197	62	93	58	0	30	3,354	3,354	42	19,890	68	23,244	68	298,764	68	8	40	298,764	71	8	39	57,618	69	35	64	57,618	69	40	67
10	COLLUS PowerStream Corp.	1,637,947	51	385,929		2,023,876	49	2,194,349	44	4,218,225	47	16,860,000	39	25	58	16,860,000	38	25	57	2,047,097	42	107	38	3,784,720	41	111	43	157,689	15	0	157,689	16	636,318	33	794,008	31	4,446,841	39	18	7	4,446,841	39	18	8	842,348	39	76	21	1,118,451	35	71	30
11	Cooperative Hydro Embrun Inc.	120,443	66	19,238		139,677	66	730,806	57	870,483	62	1,790,000	65	49	15	1,790,697	65	49	18	241,547	65	303	4	1,032,602	66	272	13	0	30	0	0	43	0	69	0	69	125,743	65	12	28	125,743	68	12	31	78,227	68	16	19	78,227	68	16	17
12	E.L.K. Energy Inc.	1,662,553	49	583,829		2,246,382	47	1,963,393	48	4,209,775	48	16,200,000	41	26	56	16,203,264	40	26	54	1,785,578	45	110	36	3,064,492	45	137	29	0	30	0	0	43	435,083	42	435,083	43	4,273,057	41	10	41	4,273,057	41	10	42	504,219	48	86	10	504,219	48	86	13
13	Energy+ Inc.	17,245,241	13	60,025,983		77,271,224	5	14,252,795	12	91,524,019	7	100,950,000	12	91	4	106,219,451	11	86	4	10,054,813	17	142	22	67,208,866	8	136	30	0	30	0	0	43	2,916,887	11	2,916,887	11	25,873,071	12	11	32	23,678,815	14	12	28	4,939,935	10	59	38	4,939,935	11	59	39
14	Enersource Hydro Mississauga Inc.	59,582,917	5	15,701,481		75,284,398	6	80,992,918	4	156,277,316	4	483,270,000	4	32	42	483,273,204	4	32	42	79,419,033	3	102	42	149,356,740	4	105	50	0	30	0	0	43	5,508,332	8	5,508,332	8	122,499,463	4	4	68	123,761,401	4	4	68	20,565,231	4	68	24	23,154,175	4	24	68
15	Entegrus Powerlines Inc.	38,558,192	8	3,536,019		42,094,211	9	14,186,934	13	56,281,145	11	56,830,000	21	99	3	62,079,147	20	91	9	5,611,768	27	253	4	34,007,927	14	165	21	374,365	8	60,099	434,464	8	2,370,550	14	2,805,014	12	14,695,867	21	19	6	13,843,474	21	20	6	2,447,799	20	97	5	3,048,339	19	92	6
16	Erie Thames Powerlines Corporation	14,809,440	15	2,675,379		17,484,819	16	29,365,888	9	46,850,707	12	153,300,000	10	31	47	152,851,848	10	31	45	44,722,046	5	66	61	64,562,240	5	73	62	0	30	111,618	111,618	19	2,430,728	13	2,542,346	13	38,421,929	10	7	64	38,421,929	10	7	64	11,447,244	8	21	67	11,447,244	8	22	67
17	Erie Thames Powerlines Corporation	5,180,177	27	922,335		6,102,511	30	2,555,215	40	8,657,726	34	27,630,000	33	31	44	39,589,797	26	22	63	3,215,423	37	70	55	21,956,460	19	39	68	23,149	25	19,384	42,533	26	561,528	39	604,060	37	7,104,954	34	9	55	7,020,999	33	9	52	1,352,450	30	42	60	1,524,690	30	40	63
18	Espanola Regional Hydro Distribution Corporation	502,006	61	14,537		516,543	62	339,978	65	856,521	63	2,410,000	64	36	34	1,998,806	64	43	23	328,608	64	103	40	328,608	65	261	10	5,306	28	0	5,306	40	57,969	65	63,275	63	685,489	64	9	48	759,788	67	8	57	141,751	63	41	61	141,751	64	45	58
19	Essex Powerlines Corporation	3,819,710	36	1,720,180		5,540,090	33	7,059,017	26	12,599,107	31	31,430,000	30	40	24	31,430,000	28	40	29	7,103,736	24	99	46	9,728,188	29	130	33	176,840	12	6,737	183,577	14	1,818,727	18	2,002,304	17	8,532,573	30	23	1	8,421,412	30	24	3	1,871,165	25	97	4	2,199,199	25	91	8
20	Festival Hydro Inc.	4,822,853	30	2,088,958		6,911,811	27	9,417,074	21	16,328,885	26	34,650,000	28	47	17	29,884,429	30	55	10	4,336,821	31	217	7	4,336,821	36	377	5	0	30	8,075	8,075	37	1,003,864	29	1,011,939	29	8,768,149	28	12	29	8,768,149	28	12	32	1,323,777	32	76	20	1,323,777	33	76	18
21	Port Albany Power Corporation	29,906	71	1,956		31,862	71	0	69	31,862	71	340,000	71	9	69	373,387	71	9	70	197,235	68	0	69	197,235	70	16	71	0	30	0	0	43	0	69	0	69	98,990	71	0	69	98,990	71	0	69	345,251	55	0	69	345,251	55	0	69
22	Port Frances Power Corporation	254,688	65	11,255		265,943	65	553,935	60	819,878	64	4,030,000	61	20	67	3,687,435	61	22	62	348,835	63	159	13	686,914	54	168	19	0	30	0	0	43	92,580	60	92,580	60	1,189,758	60	8	59	1,113,616	63	8	58	124,980	66	74	23	124,801	66	74	23
23	Greater Sudbury Hydro Inc.	6,959,582	23	3,141,790		10,101,372	22	9,312,088	22	19,413,460	22	34,740,000	27	56	7	23,985,670	34	81	5	3,943,302	34	236	5	3,943,302	40	492	2	112,497	18	0	112,497	18	1,425,683	24	1,538,180	25	9,672,498	26	16	10	9,117,459	27	17	10	1,701,015	28	84	12	1,701,015	28	90	9
24	Grimsby Power Incorporated	2,804,724	40	319,103		3,123,843	40	2,159,053	45	5,282,896	43	10,850,000	48	49	14	10,863,961	48	49	17	1,870,647	44	115	33	3,670,614	42	144	25	0	30	34,500	34,500	29	292,926	48	327,426	48	2,894,613	47	11	33	2,894,612	47	11	33	631,209	45	46	57	631,209	45	52	52
25	Guelph Hydro Electric Systems Inc.	58,594,547	6	2,215,864		60,810,411	8	8,394,053	24	69,204,463	9	99,040,000	13	70	5	99,040,001	13	70	7	7,470,386	22	112	35	59,741,607	11	116	41	278,441	10	103,065	381,506	11	1,377,942	25	1,759,447	20	24,920,625	14	7	62	23,290,402	15	8	60	3,782,778	16	36	63	4,255,743	16	41	61
26	Halton Hills Hydro Inc.	5,500,566	25	212,955		5,713,521	31	4,755,591	32	10,469,112	33	30,940,000	31	34	38	30,962,677	29	34	39	3,268,861	36	145	20	6,234,990	34	168	20	0	30	0	0	43	604,017	35	604,017	38	8,387,497	33	11	7	8,387,497	33	11	7	1,310,004	33	46	58	1,458,606	31	41	60
27	Hearst Power Distribution Company Limited	1,510,384	54	985,005		2,495,390	44	2,417,972	42	4,913,361	44	3,180,000	63	155	1	3,183,595	62	154	1	369,657	62	654	1	1,033,780	59	475	3	0	30	10,061	10,061	36	71,209	62	81,272	62	843,903	63	10	45	843,903	66	10	45	122,762	67	58	39	122,762	67	60	36
28	Horizon Utilities Corporation	70,835,688	4	6,703,611		77,539,298	4	44,884,274	6	122,423,572	6	330,680,000	6	37	31	366,197,247	6	33	41	41,674,275	7	108	37	116,705,818	5	105	49	2,679,921	3	194,944	2,874,865	3	10,061,393	5	12,936,258	5	84,830,304	6	15	12	84,830,304	6	15	13	14,826,453	6	68	32	17,664,321	5	73	25
29	Hydro 2000 Inc.	80,683	68	3,633		84,316	68	257,750	66	342,066	67	1,960,000	69	25	57	1,960,459	66	25	56	165,677	69	156	17	215,261	67	159	23	0	30	0	0	43	41,957	67	41,957	67	394,750	69	11	38	394,750	69	11	38	74,240	74	24	74	56,806	70	74	24
30	Hydro Hawkesbury Inc.	1,162,440	56	26,255		1,188,695	57	1,339,759	51	2,528,454	54	7,920,000	53	32	43	7,920,346	53	32	43	1,335,307	50	100	44	2,406,871	49	105	49	0	30	0	0	43	189,396	52	189,396	53	2,139,160	52	9	51	2,139,160	52	9	50	399,100	51	47	56	399,100	51	47	57
31	Hydro One Brampton Networks Inc.	29,578,103	9	6,302,266		35,880,369	10	41,650,660	7	77,531,030	8	255,160,000	7	30	49	255,160,000	7	30	46	40,763,367	8	102	41	70,364,866	7	110	45	363,847	9	139,709	503,556	7	7,314,450	7	7,818,006	7	46,798,531	7	12	27	46,798,530	7	12	30	14,629,427	7	50	52	14,994,829	7	52	49
32	Hydro One Networks Inc.	220,487,101	1	89,902,682		310,389,782	1	208,374,078	1	518,763,860	2	1,220,680,000	2	42	19	1,263,550,435	2	41	26	257,427,108	2	81	54	477,719,764	1	109	47	1,742,264	4	12,818	1,755,101	5	44,738,829	1	46,513,930	2	338,193,459	1	14	16	341,897,197	1	14	17	62,293,684	2	72	27	67,838,190	2	73	26
33	Hydro Ottawa Limited	57,247,836	7	15,553,923		72,801,765	7	59,247,505	1	132,049,269	5	394,540,000	5	33	40	394,559,846	5	33	40	42,147,373	6	141	23	99,489,881	6	133	32	389,296	7	0	389,296	10	13,469,631	4	13,858,927	4	105,242,155	5	5	13	105,242,156	5	5	13	21,214,251	5	78	17	17,591,400	6	79	16
34	InnPower Corporation	4,445,966	32	1,046,947		5,492,913	35	2,580,410	38	8,073,324	36	34,500,000	29	23	63	37,182,911	27	22	65	11,465,768	16	23	68	14,206,168	26	57	65	0	30	17,728	17,728	34	584,540	39	602,268	39	5,661,873	29	7	59	5,716,251	27	7	59	1,716,251	27	54	65	1,716,251	27	64	55
35	Kashechewan Power Corporation	40,200	69	2,229		42,829	69	0	69	42,829	69	520,000	69	8	70	438,286	70	10	69	209,344	66	0	69	209,344	68	20	69	0	30	0	0	43	0	69	0	69	155,968	69	0	69	155,968	69	0	69	358,436	54	0	69	358,436	54	0	69
36	Kenora Hydro Electric Corporation Ltd.	1,606,080	52	65,783		1,671,873	54	552,001	61	2,224,774	57	5,270,000	57	42	21	5,269,561	56	42	24	1,403,058	48	39	65	1,596,073	56	139	28	0	30	0	0	43	124,005	59	124,005	59	1,407,448	57	9	52	1,688,037	57	7	61	220,129	59	56	43	220,150	59	56	46
37	Kingston Hydro Corporation	4,445,966	32	1,046,947		5,492,913	35	2,580,410	38	8,073,324	36	34,500,000	29	23	63	37,182,911	27	22	65	11,465,768	16	23	68	14,206,168	26	57	65	0	30	17,728	17,728	34	584,540	39	602,268	39	5,661,873	29	7	59	5,716,251	27	7	59	1,716,251	27	54	65	1,716,251	27	64	55
38	Kitchener-Wilmot Hydro Inc.	21,865,242	11	2,654,908		24,520,150	12	14,184,542	14	38,704,692	14	105,710,000	11	37	32	105,712,088	12	37	34	17,127,724	12	83	52	27,136,429	16	143	27	0	30	0	0	43	1,754,249	20	1,754,249	21	27,710,719	11	6	65	27,710,719	11	6	65	4,634,072	14	38	64
39	Lakefront Utilities Inc.	2,239,136	44	280,605		2,519,741	43	1,185,986	53	3,705,727	50	12,170,000	45	30	48	12,201,915	44	30	47	1,739,771	46	68	60	3,639,829	43	102	51	0	30	0	0	43	265,025	50	265,025	51	3,077,834	45	9	53	3,077,834	46	9	51	511,743	46	52	49	511,744	46	52	51
40	Lakeland Power Distribution Ltd.	4,432,710	33	708,780		5,141,489	37	2,495,021	41	7,636,510	37	15,770,000	42	48	16	15,832,919	43	48	20	1,345,374	49	185	9	4,319,290	37	177	18	0	30	0	0	43	433,380	43	433,380	44	4,142,392	42	10	40	4,142,392	42	10	41	511,364	47	85	13	511,364	47	85	14
41	London Hydro Inc.	28,534,591	10	3,454,236		31,988,827	11	31,824,871	8	63,813,698	10	196,660,000	8	32	41	219,747,451	8	29	50	34,869,274	9	91	49	63,862,340	10	100	51	1,611,279	5	506,532	2,117,811	4	8,721,449	6	10,839,260	6	51,192,690	8	21	5	51,385,905	8	21	5	9,187,376	9	95	7	10,660,376	9	102	3
42	Midland Power Utility Corporation	2,860,953	39	301,878		3,162,831	39	2,402,206	43	5,565,036	41	10,830,000	49	51	13	10,830,000	49	51	16	1,433,109	47	168	14	3,062,541	46	182	14	0	30	0	0	43	345,045	46	345,045	47	2,739,690	49	13	26	432,669	49	80	14	432,684	49	80	13
43	Milton Hydro Distribution Inc.	9,889,501	19	476,099		10,365,601	21	16,866,689	27	26,866,689	25	45,360,000	24	37	29	45,363,753	24	37	32	5,584,323	28	116	30	9,970,719	28	169	16	0	30	41,699	41,699	27	1,563,222	29	1,604,921	29	15,491,972	24	13	17	15,908,171	22	13	18	2,051,830	24	76	18	2,205,823	24	73	27
44	Newmarket-Tay Power Distribution Ltd.	8,218,024	20	840,996		9,059,020	24	4,962,518	31	14,021,538	28	36,240,000	26	39	25	26,923,645	32	52	14	4,271,910	32	116	32	4,271,910	38	328	7	51,311	20	0	51,311	23	1,009,481	28	1,060,792	28	9,649,555	27	11	35	9,993,198	25	11	40	1,842,766	26	55	46	1,842,766	26	58	41
45	Niagara Peninsula Energy Inc.	12,742,252	17	1,752,111		14,494,363	19	10,838,434	17	25,332,796	18	74,440,000	17	34	37	74,440,000	17	34	38	7,449,258	23	145	19	20,191,139	20	125	36	0	30	40,000	40,000	28	2,317,811	15	2,357,811	16	19,056,865	18	6	57	19,056,865	18	6	57	2,378,879	20	90	11	2,378,879	20	90	11
46	Niagara-on-the-Lake Hydro Inc.	2,598,018	42	369,192		2,967,210	41	3,401,852	35	6,369,062	39	11,680,000	46	55	8	11,877,636	46	54	13	3,546,990	35	96	40	6,289,627	32	101	52	0	30	0	0	43	424,921	44	424,921	45	2,993,633	46	14	14	2,321,538	49	18	7	828,092	40	51	50	828,092	41	51	53
47	North Bay Hydro Distribution Limited	4,245,690	35	12,427,153		16,672,842	17	4,001,370	34	20,674,212	20	20,260,000	37	102	2	17,933,641	37	115	2	2,300,259	41	174	12	2,300,259	50	899	1	27,296	23	0	27,296	31	713,129	32	740,425	33	5,545,424	37	13	18	5,738,692	37	13	23	992,259	35	72	26	992,259	37	75	22
48	Northern Ontario Wires Inc.	509,731	60	38,057		547,788	60	907,761	58	1,455,549	59	4,310,000	59	34	39	2,988,209	63	49	16	492,913	61	184	10	492,913	63	295	8	6,212	27	0	6,212	39	156,126	56	162,339	56	1,174,934	59	14	15	1,139,682	62	14	15	214,627	61	85	76	214,627	61	86	78
49	Oakville Hydro Electricity Distribution Inc.	21,252,248	12	2,499,447		23,751,695	13	15,431,935	11	39,183,630	13	92,390,000	15	42	20	93,974,490	15	42	25	13,265,566	14	116	31	34,517,814	13	114	42	0	30	77,518	77,518	21	3,120,547	10	3,198,065	10	24,575,982	15	13	21	24,574,176	13	13	22	4,665,101	13	67	33	4,742,101	13	67	34
50	Orangeville Hydro Limited	3,398,117	38	314,840		3,712,958	38	2,056,808	46	5,769,766	40	14,150,000	43	43	22	14,301,698	42	40	27	1,194,829	51	172	13	2,889,637	47	200	11	0	30	0	0	43	229,432	51	229,432	52	3,705,603	43	6	66	3,705,604	43	6	66	412,100	53	56	44	412,100	53	56	47
51	Orillia Power Distribution Corporation	1,662,040	50	246,213		1,908,253	52	2,008,907	47	3,917,160	49	16,580,000	40	24	62	16,653,694	39	24	60	5,922,408	26	34	66	7,729,238	32	52	66	0	30	17,378	17,378	35	605,352	34	622,730	35	4,318,856	40	14	13	4,289,364	40	15	14	765,330	42	79	15	831,580	40	75	21
52	Oshawa PUC Networks Inc.	5,046,074	28	1,182,326		6,228,399	29	11,449,535	16	17,677,934	23	73,010,000	18	24	61	73,010,000	18	24	59	8,484,484	20	135	24	24,199,815	18	73	61	0	30	24,000	24,000	33	1,975,382	17	1,999,382	18	19,963,922	17	10	42	19,918,698	17	10	43	3,504,522	17	56	42	3,504,522	17	57	44
53	Ottawa River Power Corporation	2,779,858	41	156,363		2,936,220	42	1,812,492	49	4,748,712	45	8,720,000	51	54	9	8,724,047	51	54	11	985,681	52	184	11	1,671,361	48	236	15	0	30	0	0	43	353,106	45	353,106	46	2,282,373	50	15	12	2,282,373	50	15	12	366,122	51	96	5
54	Peterborough Distribution Incorporated	4,979,980	29	554,811		5,534,790	34	5,186,524	30	10,721,314	32	37,880,000	25	28	52	42,122,834	25	25	55	20,077,835	10	26	67	25,666,491	17	42	67	0	30	43,197	43,197	25



2017 Final Verified Annual LDC CDM Program Results Report
LDC Rankings

Survey of Canadian Electricity Bills



Rates and Regulatory Department

Effective May 1, 2017

Manitoba Hydro

Note

- Each participating utility calculates bills based on its rates as of May 1, 2017.
- All bills exclude federal, provincial or municipal taxes with the exception of Newfoundland Power.
- Newfoundland Power includes a Municipal Tax and Rate Stabilization Adjustment which is built into their rates. All bills include a 1.5% prompt payment credit.
- Ontario Residential and General Service Small bills include the 8% Provincial Rebate.

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Residential

One Month Bill For:

	375 kWh	750 kWh	1,000 kWh	2,000 kWh	5,000 kWh
Calgary AB[1]	$ 53.17	$ 84.88	$ 106.02	$ 190.57	$ 444.25
Edmonton AB[2]	$ 53.64	$ 84.16	$ 104.50	$ 185.88	$ 430.02
Halifax NS	$ 67.32	$ 123.80	$ 161.46	$ 312.09	$ 763.98
Moncton NB	$ 62.14	$ 102.68	$ 129.70	$ 237.80	$ 562.10
Montreal QC	$ 34.02	$ 55.84	$ 70.70	$ 159.90	$ 427.50
Ottawa, ON[3]	$ 61.87	$ 107.48	$ 137.90	$ 259.53	$ 624.49
Regina SK	$ 73.54	$ 125.06	$ 159.41	$ 296.81	$ 709.01
Saskatoon SK	$ 73.52	$ 125.03	$ 159.37	$ 296.74	$ 708.83
Saint John NB	$ 53.85	$ 91.09	$ 115.91	$ 215.21	$ 513.11
St. John's NL	$ 51.71	$ 87.60	$ 111.52	$ 207.23	$ 494.34
Vancouver BC	$ 39.85	$ 77.01	$ 110.79	$ 245.92	$ 651.33
Winnipeg MB	**$ 37.56**	**$ 67.30**	**$ 87.12**	**$ 166.42**	**$ 404.32**

Note:

1 Bills are based on a 12 month average Calgary Regulated Rate Option (RRO) energy charge of 3.9069 ¢/kWh.

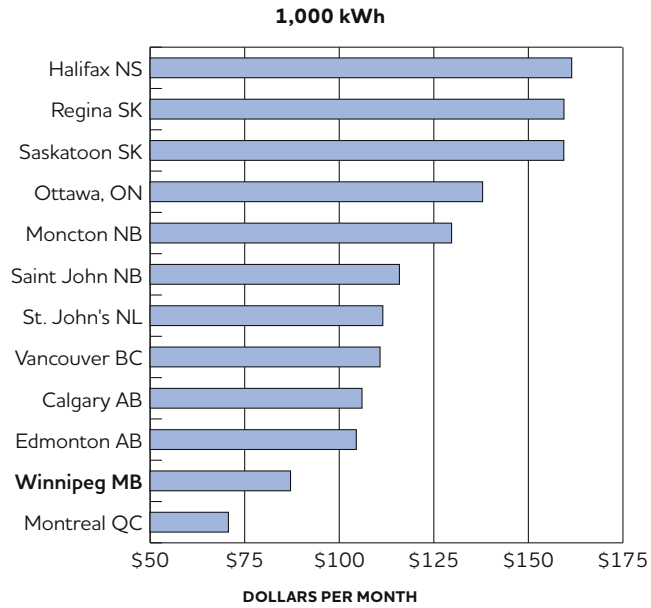
2 Bills are based on a 12 month average Edmonton Regulated Rate Option (RRO) energy charge of 3.9821 ¢/kWh.

3 Bills are based on the Time of Use (TOU) Summer commodity price.

Residential

One Month Bill For:

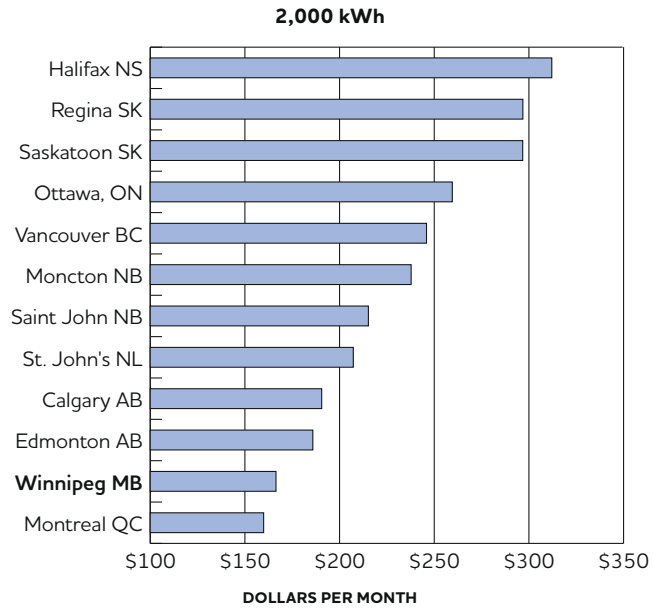
	1,000 kWh	¢/kWh
Halifax NS	$ 161.46	16.146
Regina SK	$ 159.41	15.941
Saskatoon SK	$ 159.37	15.937
Ottawa, ON	$ 137.90	13.790
Moncton NB	$ 129.70	12.970
Saint John NB	$ 115.91	11.591
St. John's NL	$ 111.52	11.152
Vancouver BC	$ 110.79	11.079
Calgary AB	$ 106.02	10.602
Edmonton AB	$ 104.50	10.450
Winnipeg MB	**$ 87.12**	**8.712**
Montreal QC	$ 70.70	7.070



Residential

One Month Bill For:

	2,000 kWh	¢/kWh
Halifax NS	$ 312.09	15.605
Regina SK	$ 296.81	14.841
Saskatoon SK	$ 296.74	14.837
Ottawa, ON	$ 259.53	12.977
Vancouver BC	$ 245.92	12.296
Moncton NB	$ 237.80	11.890
Saint John NB	$ 215.21	10.761
St. John's NL	$ 207.23	10.362
Calgary AB	$ 190.57	9.528
Edmonton AB	$ 185.88	9.294
Winnipeg MB	**$ 166.42**	**8.321**
Montreal QC	$ 159.90	7.995



Analysis of Residential Rates

Ranked in Order of Run-Off Rate

Location	No. of Blocks	kWh in Block	$ in Block	Fixed Charges	Run-off Rate ¢/kWh	Minimum Bill $
Halifax NS	0	0	$ 0.00	$ 10.83	15.063	$ 10.83
Regina SK	0	0	$ 0.00	$ 22.01	13.740	$ 22.01
Saskatoon SK	0	0	$ 0.00	$ 22.01	13.736	$ 22.01
Vancouver BC*	1	675	$ 57.92	$ 5.77	12.870	$ 5.77
Ottawa ON**	0	0	$ 0.00	$ 17.66	12.836	$ 17.66
Moncton NB	0	0	$ 0.00	$ 21.60	10.810	$ 21.60
Saint John NB	0	0	$ 0.00	$ 16.61	9.930	$ 16.61
St. John's NL	0	0	$ 0.00	$ 15.99	9.719	$ 15.99
Montreal QC	1	990	$ 57.62	$ 12.19	8.920	$ 12.19
Calgary AB	0	0	$ 0.00	$ 21.45	8.456	$ 21.45
Edmonton AB	0	0	$ 0.00	$ 23.12	8.138	$ 23.12
Winnipeg MB	**0**	**0**	**$ 0.00**	**$ 7.82**	**7.930**	**$ 7.82**

Note:

* Does not include the 5.0% Deferral Account Rate Rider which is applied to the total bill.

** Does not include the 8.0% Provincial Rebate which is applied to the total bill.

General Service – Small

One Month Bill For:

	6 kW (6.6 kVA) 750 kWh	7 kW (7.8 kVA) 1,000 kWh	20 kW (22.2 kVA) 5,000 kWh	40 kW (44.4 kVA) 10,000 kWh
Calgary AB[1]	$ 100.88	$ 120.88	$ 440.83	$ 854.82
Edmonton AB[2]	$ 88.86	$ 113.45	$ 507.09	$ 999.15
Halifax NS	$ 120.48	$ 155.21	$ 766.35	$ 1,532.70
Moncton NB	$ 120.73	$ 153.40	$ 676.20	$ 1,348.70
Montreal QC	$ 85.68	$ 110.13	$ 501.33	$ 990.33
Ottawa, ON[3]	$ 118.19	$ 151.77	$ 689.19	$ 1,360.97
Regina SK	$ 129.07	$ 162.07	$ 690.07	$ 1,350.07
Saskatoon SK	$ 129.07	$ 162.07	$ 690.07	$ 1,350.07
Saint John NB	$ 120.45	$ 154.92	$ 665.52	$ 1,314.02
St. John's NL	$ 92.94	$ 116.63	$ 528.83	$ 1,014.23
Vancouver BC	$ 100.27	$ 130.17	$ 608.55	$ 1,138.40
Winnipeg MB	**$ 83.67**	**$ 104.49**	**$ 437.65**	**$ 854.10**

Note:

1 Bills for loads ≤ 5,000 kWh are based on a 12 month average Calgary Regulated Rate Option (RRO) energy price of 3.9069 ¢/kWh. Loads > 5,000 kWh are based on the average energy price as determined by the utility.

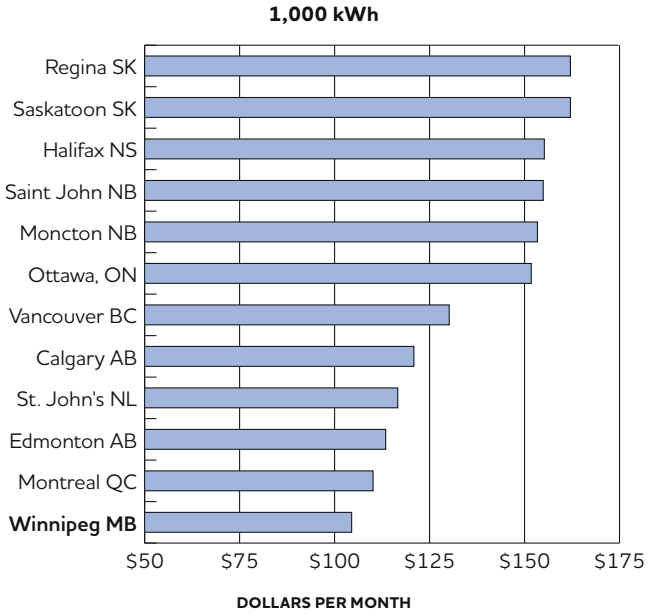
2 Bills are based on a 12 month average Edmonton Regulated Rate Option (RRO) energy charge of 3.9821 ¢/kWh.

3 Bills are based on the Time of Use (TOU) Summer commodity price.

General Service – Small

One Month Bill For:

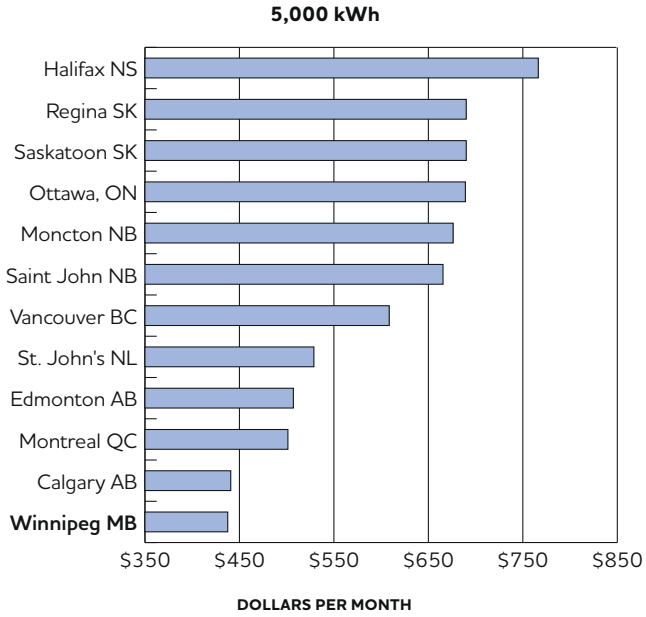
	7 kW (7.8 kVA) 1,000 kWh	¢/kWh
Regina SK	$ 162.07	16.207
Saskatoon SK	$ 162.07	16.207
Halifax NS	$ 155.21	15.521
Saint John NB	$ 154.92	15.492
Moncton NB	$ 153.40	15.340
Ottawa, ON	$ 151.77	15.177
Vancouver BC	$ 130.17	13.017
Calgary AB	$ 120.88	12.088
St. John's NL	$ 116.63	11.663
Edmonton AB	$ 113.45	11.345
Montreal QC	$ 110.13	11.013
Winnipeg MB	**$ 104.49**	**10.449**



General Service – Small

One Month Bill For:

	20 kW (22.2 kVA) 5,000 kWh	¢/kWh
Halifax NS	$ 766.35	15.327
Regina SK	$ 690.07	13.801
Saskatoon SK	$ 690.07	13.801
Ottawa, ON	$ 689.19	13.784
Moncton NB	$ 676.20	13.524
Saint John NB	$ 665.52	13.310
Vancouver BC	$ 608.55	12.171
St. John's NL	$ 528.83	10.577
Edmonton AB	$ 507.09	10.142
Montreal QC	$ 501.33	10.027
Calgary AB	$ 440.83	8.817
Winnipeg MB	**$ 437.65**	**8.753**



General Service – Medium

One Month Bill For:
Utility-Owned Transformation
Service at less than 750 Volts
90% Power Factor

	100 kW (111 kVA) 25,000 kWh	¢/kWh
Hydro Ottawa[1]	$ 4,271	17.084
Nova Scotia Power	$ 3,832	15.328
Saskatoon Light & Power	$ 3,525	14.100
SaskPower	$ 3,525	14.100
NB Power	$ 3,366	13.464
Saint John Energy	$ 3,260	13.040
BC Hydro	$ 2,834	11.337
Hydro Quebec	$ 2,686	10.744
Newfoundland Power[2]	$ 2,533	10.132
Manitoba Hydro	**$ 2,235**	**8.940**
ENMAX Corporation[3]	$ 1,842	7.368

Note:

1 Based on the average energy price which includes the Class B Global Adjustment of 9.642 ¢/kWh as determined by the corresponding utility.

2 Summer / Winter average bill.

3 Based on the average energy price as determined by the corresponding utility.

General Service – Medium

One Month Bill For:
Utility-Owned Transformation
Service at less than 750 Volts
90% Power Factor

	300 kW (333 kVA) 120,000 kWh	¢/kWh
Hydro Ottawa[1]	$18,298	15.248
Nova Scotia Power	$15,323	12.769
NB Power	$14,263	11.886
SaskPower	$13,910	11.592
Saskatoon Light & Power	$13,907	11.589
Saint John Energy	$13,871	11.559
BC Hydro	$10,469	8.724
Hydro Quebec	$10,293	8.578
Newfoundland Power[2]	$10,227	8.523
ENMAX Corporation[3]	$ 8,184	6.820
Manitoba Hydro	**$ 8,039**	**6.699**

Note:

1 Based on the average energy price which includes the Class B Global Adjustment of 9.642 ¢/kWh as determined by the corresponding utility.

2 Summer / Winter average bill.

3 Based on the average energy price as determined by the corresponding utility.

General Service – Medium

One Month Bill For:
Utility-Owned Transformation
Service at less than 750 Volts
90% Power Factor

	500 kW (556 kVA) 200,000 kWh	¢/kWh
Hydro Ottawa[1]	$30,364	15.182
Nova Scotia Power	$25,538	12.769
NB Power	$23,769	11.885
SaskPower	$23,198	11.599
Saskatoon Light & Power	$23,194	11.597
Saint John Energy	$23,107	11.554
BC Hydro	$17,443	8.722
Hydro Quebec	$17,155	8.578
Newfoundland Power[2]	$16,414	8.207
Manitoba Hydro	**$13,271**	**6.635**
ENMAX Corporation[3]	$13,255	6.628

Note:

1 Based on the average energy price which includes the Class B Global Adjustment of 9.642 ¢/kWh as determined by the corresponding utility.

2 Summer / Winter average bill.

3 Based on the average energy price as determined by the corresponding utility.

General Service – Large

One Month Bill For:
Customer-Owned Transformation
Service at Distribution Voltage less than 30 kV
90% Power Factor

	1,000 kW (1,111 kVA) 400,000 kWh	¢/kWh
Hydro Ottawa[1]	$60,527	15.132
Nova Scotia Power	$44,261	11.065
SaskPower	$43,221	10.805
Saskatoon Light & Power	$43,202	10.801
NB Power	$ 37,028	9.257
Saint John Energy	$34,930	8.733
BC Hydro	$ 34,616	8.654
Newfoundland Power[2]	$ 31,128	7.782
Hydro Quebec	$ 30,719	7.680
ENMAX Corporation[3]	$23,849	5.962
Manitoba Hydro	**$23,566**	**5.892**

Note:

1 Based on the average energy price which includes the Class B Global Adjustment of 9.642 ¢/kWh as determined by the corresponding utility.

2 Summer / Winter average bill.

3 Based on the average energy price as determined by the corresponding utility.

General Service – Large

One Month Bill For:
Customer-Owned Transformation
Service at Distribution Voltage less than 30 kV
90% Power Factor

	5,000 kW (5,556 kVA) 2,555,000 kWh	¢/kWh
Hydro Ottawa[1]	$378,018	14.795
Nova Scotia Power[2]	$ 243,888	9.546
SaskPower	$ 234,783	9.189
Saskatoon Light & Power	$ 234,773	9.189
NB Power	$ 214,435	8.393
BC Hydro	$ 205,099	8.027
Saint John Energy	$ 203,510	7.965
Newfoundland Power[3]	$ 183,872	7.197
ENMAX Corporation[4]	$ 141,288	5.530
Hydro Quebec	$ 138,648	5.427
Manitoba Hydro	**$ 137,758**	**5.392**

Note:

1 Based on the average energy price which includes the Class B Global Adjustment of 9.642 ¢/kWh as determined by the corresponding utility.

2 An interruptible credit has been applied.

3 Summer / Winter average bill.

4 Based on the average energy price as determined by the corresponding utility.

General Service – Large

One Month Bill For:
Customer-Owned Transformation
Service at Distribution Voltage less than 30 kV
90% Power Factor

	10,000 kW (11,111 kVA) 5,500,000 kWh	¢/kWh
Hydro Ottawa[1]	$ 575,907	10.471
Nova Scotia Power[2]	$ 517,731	9.413
SaskPower	$ 489,573	8.901
Saskatoon Light & Power	$ 489,546	8.901
BC Hydro	$ 432,713	7.868
NB Power	$ 426,700	7.758
Newfoundland Power[3]	$ 389,847	7.088
ENMAX Corporation[4]	$ 299,333	5.442
Hydro Quebec	$ 290,634	5.284
Manitoba Hydro	**$289,505**	**5.264**

Note:

1 Includes the Class A Global Adjustment as determined by the corresponding utility and is based on the utility's contribution to Ontario's peak demand.

2 An interruptible credit has been applied.

3 Summer / Winter average bill.

4 Based on the average energy price as determined by the corresponding utility.

General Service – Large Industrial

One Month Bill For:

Customer-Owned Transformation
Service at Transmission Voltage exceeding 100 kV
100% Power Factor

	20,000 kW / kVA 12,000,000 kWh	**¢/kWh**
Nova Scotia Power[1]	$ 1,093,260	9.111
NB Power	$ 905,400	7.545
SaskPower	$ 875,355	7.295
Hydro Ottawa[2]	$ 858,563	7.155
Newfoundland Power[3]	$ 816,677	6.806
BC Hydro	$ 749,574	6.246
Hydro Quebec	$ 592,668	4.939
Newfoundland & Labrador Hydro[4]	$ 590,200	4.918
Manitoba Hydro	**$ 514,360**	**4.286**

Note:

1 An interruptible credit has been applied.

2 Includes the Class A Global Adjustment as determined by the corresponding utility and is based on the utility's contribution to Ontario's peak demand.

3 Summer / Winter average bill.

4 Does not include annual charges for customer plant in service that may apply to specific customers.

General Service – Large Industrial

One Month Bill For:

Customer-Owned Transformation
Service at Transmission Voltage exceeding 100 kV
100% Power Factor

	50,000 kW / kVA 31,000,000 kWh	**¢/kWh**
Nova Scotia Power[1]	$2,809,980	9.064
NB Power	$ 2,315,500	7.469
SaskPower	$ 2,236,355	7.214
BC Hydro	$ 1,922,571	6.202
Hydro Ottawa[2]	$ 1,690,519	5.453
Hydro Quebec	$ 1,514,370	4.885
Newfoundland & Labrador Hydro[3]	$ 1,513,250	4.881
Manitoba Hydro	**$1,318,230**	**4.252**

Note:

1 An interruptible credit has been applied.

2 Includes the Class A Global Adjustment as determined by the corresponding utility and is based on the utility's contribution to Ontario's peak demand.

3 Does not include annual charges for customer plant in service that may apply to specific customers.

General Service – Large Industrial

One Month Bill For:

Customer-Owned Transformation
Service at Transmission Voltage exceeding 100 kV
100% Power Factor

	100,000 kW / kVA 62,000,000 kWh	**¢/kWh**
Nova Scotia Power[1]	$ 5,619,960	9.064
NB Power	$ 4,631,000	7.469
SaskPower	$ 4,465,355	7.202
BC Hydro	$ 3,845,142	6.202
Hydro Ottawa[2]	$ 3,055,761	4.929
Hydro Quebec	$ 3,028,740	4.885
Newfoundland & Labrador Hydro[3]	$ 3,026,500	4.881
Manitoba Hydro	**$2,636,460**	**4.252**

Note:

1 An interruptible credit has been applied.

2 Includes the Class A Global Adjustment as determined by the corresponding utility and is based on the utility's contribution to Ontario's peak demand.

3 Does not include annual charges for customer plant in service that may apply to specific customers.

Population Statistics

Location	Population	Metro population
Calgary AB	1 239 220	1 392 609
Edmonton AB	932 546	1 321 426
Halifax NS	403 131	403 390
Moncton NB	71 889	144 810
Montreal QC	1 704 694	4 098 927
Ottawa ON	934 243	991 726
Regina SK	215 106	236 481
Saint John NB	67 575	126 202
Saskatoon SK	246 376	295 095
St. John's NL	108 860	205 955
Vancouver BC	631 486	2 463 431
Winnipeg MB	**705 244**	**778 489**

Source: Statistics Canada 2016 Census web site www.statcan.gc.ca

Canadian Utilities Surveyed

Location	Utility
Calgary AB	ENMAX Corporation
Edmonton AB	EPCOR Energy Alberta Inc.
Halifax NS	Nova Scotia Power
Moncton NB	NB Power
Montreal QC	Hydro Quebec
Ottawa ON	Hydro Ottawa Limited
Regina SK	SaskPower
Saint John NB	Saint John Energy
Saskatoon SK	Saskatoon Light & Power
St. John's NL	Newfoundland Power
St. John's NL*	Newfoundland & Labrador Hydro
Vancouver BC	BC Hydro
Winnipeg MB	**Manitoba Hydro**

* Only Large Industrial Rates (≥ 20,000 kW) provided for the Island interconnected area.

Notes

Notes



Available in accessible formats upon request.

Manitoba Hydro

OEB Wireline Pole Attachment Rates and Policy Framework

Prepared for:

Ontario Energy Board (OEB)

Prepared by:

Nordicity

December 14, 2017

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Executive Summary

This report has been prepared for the Ontario Energy Board (OEB or Board), to establish a pole attachment rate framework for the Province of Ontario. The main objective of this report is to address the technical and policy issues associated with determining the rate for pole attachments by third parties to the wireline poles owned and operated by the Local Electricity Distribution Companies (LDCs) in the province.

In March 2005, the OEB established the pole attachment rate at $22.35 per year per pole attachment. Since then, the rate has not been updated. Recently (2014-15), however, as part of applications for electricity distribution rate approvals, three of the major LDCs in the province requested and were granted approval for a significant increase in the pole attachment rate, including Toronto Hydro ($42.00), Hydro One ($41.28), and Hydro Ottawa ($53.00). The third party attachers, such as telecom carriers, filed interventions and raised several issues associated with the cost estimation and rate calculation methodology. Given the significant differences in the position of LDCs versus carriers on those different issues, the OEB initiated the policy review process. Accordingly, in its November 5, 2015 letter the OEB invited different stakeholders to participate in a Pole Attachment Working Group (PAWG) as part of a consultation process. Based on the nominations received, the OEB formed the PAWG, which comprises representatives from three different types of stakeholder groups: LDCs, carriers, and rate payers. In May 2016, Nordicity was contracted to facilitate the PAWG process, which included facilitation of four PAWG meetings, and develop an expert report.

In the first PAWG meeting, held on May 20, 2015, Nordicity presented an overarching "pole attachment rate framework", which comprised the following three key elements:

- Costing approach (methodology)
- Cost Allocation methodology
- Rate Calculation Methodology

Nordicity has proposed a rate calculation framework, and the rates based on this framework are presented in Section 4. In terms of developing this framework, data was collected from LDCs during the PAWG process. Based on the data received from LDCs, detailed analysis was presented for discussion and feedback in the three PAWG meetings held on July 27, 2016, November 20, 2016 and January 31, 2017.

Based on the final analysis, a pole attachment rate of $42.19 per attacher was calculated using the OEB's current equal-sharing methodology to allocate indirect costs. This rate represents an increase of 88.8% from the $22.35 rate determined in the 2005 OEB Decision. This increase is due to the following two reasons:

- Increase in cost per pole including (a) 15.8% increase in the indirect cost per pole from $93.31 (2005) to $108.06, and (b) increase in direct (administration) cost from $0.69 (2005) to $3.63.
- Decrease in average number of telecom attachers per pole from 2.5 (2005) to current average of 1.3.

It is worth noting that the calculation of the new $42.19 rate is based on the most comprehensive data

and analysis of pole-related costs and specifications to date, covering a 10-year period (2005-15). The analysis encompasses all major LDCs that represent over 95% of the pole population in the province.

If Nordicity's proposed equal-sharing approach were used, this would result in an updated pole attachment rate of $38.70 per telecom attacher, instead of $42.19. This report provides a detailed rationale for use of the equal sharing methodology (both the OEB's current approach and Nordicity's proposed approach) instead of the other commonly-used approach of proportionate use.

The report provides recommendations for improving LDCs' reporting process. Nordicity believes that the improved process will facilitate automatic updates to the pole attachment rate model based on LDCs' annual general submissions to the OEB.

1 Introduction

This report attempts to address the technical and policy issues associated with determining the charges for "***pole attachments***" by third parties to the wireline poles owned and operated by LDCs (also referred to as "utilities") in the Province of Ontario. For this report, the term "***utilities***" refers to the entities such as LDCs and ILECs – Incumbent Local Exchange Carriers, which own and control poles and associated rights-of-way used, in whole or in part, for any wire communications. Accordingly, the term "attachment" (referred to as "pole attachment") typically means any attachment by a cable television or telecommunications service provider to a utility pole. Figure 1 below illustrates structure of a typical joint use utility pole used by two or more entities (referred to as "**attachers**").

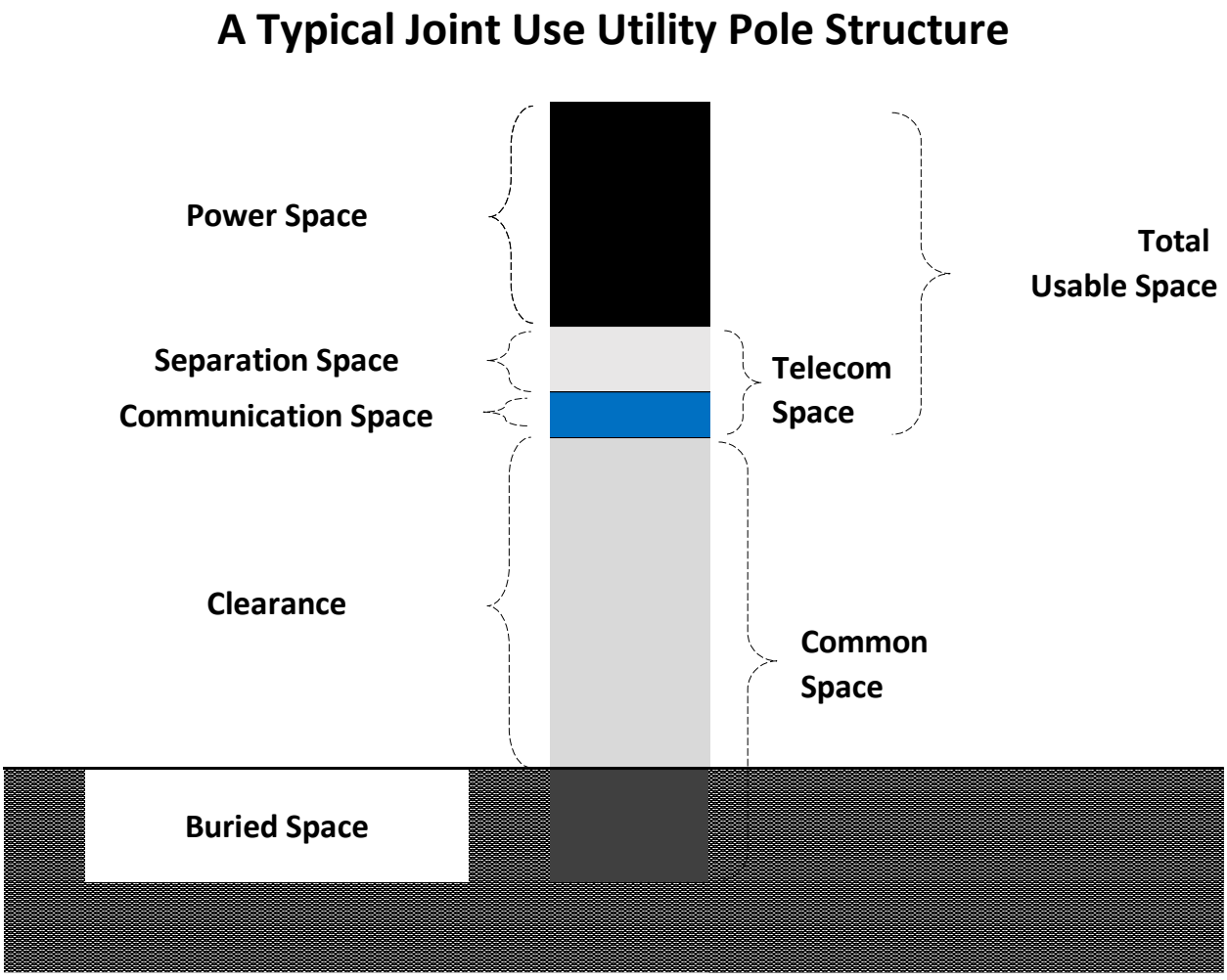


Figure 1: A Typical Joint-Use Utility Pole

A utility pole that is used by two or more attachers is referred to as a ***joint-use pole***. A typical joint-use pole supports three types of attachers: electric power, cable television, and telephone. Some joint-poles also support other attachers such as municipalities for street lights and traffic signals. The pole space allocated to cable television and telecommunications service providers is referred to as "communication space". In order for the utility (power attacher) and service providers (communications attachers) to

share the space, the joint-use pole is required to meet the Electrical Distribution Safety requirement of *Ontario Regulation 22/04*. This includes provision for separation space between the communication attachers and power attachers. The existence of joint-use poles infrastructure was prompted by the broad socio-economic policy objectives of: (a) avoiding duplication of pole infrastructure to preserve the physical appearance and aesthetic value of communities; and (b) reducing the cost of service to consumers of both types of attachers. This implies that, to serve their customers, communication attachers are dependent on the poles owned and controlled by utilities. Moreover, utilities are mandated to deploy and maintain joint-use pole infrastructure according to required standards. Pole attachments are regulated by the energy boards to ensure (a) communication attachers have access to the utility poles, and (b) utilities recover the cost of poles, based on "**just and reasonable"** rates. Accordingly, this report provides a framework to determine pole attachment rates on a "just and reasonable" basis.

This report comprises eleven sections:

Section 1 is an introduction which first provides description of the "just and reasonable" principle, followed by a detailed background on the developments in pole attachment rates since the OEB's 2005 Decision on pole attachment rates in Ontario. This section also outlines the consultative process followed to complete this report, including the formation of a PAWG (Pole Attachment Working Group) Committee.

Section 2 outlines key objectives of this study report including explanation of why a policy framework is required, followed by detailed analysis of the OEB's 2005 Decision.

Section 3 provides a detailed analysis of wireline pole infrastructure in Ontario, including the overall pole population, key trends in the past 10 years, and a description of standard pole specifications for attachment rate calculations.

Section 4 discusses in detail the key elements of a policy framework for determining pole attachment rates;

Sections 5, 6, and 7 provide detailed discussions and analysis on different cost elements associated with poles, leading to the determination of the average cost per pole;

Section 8 details the pole attachment rate model;

Section 9 provides a discussion and analysis of the issue of "overlashing";

Section 10 presents the proposed rate calculation framework; and finally,

Section 11 contains the conclusions and key recommendations of the report.

1.1 *"Just and Reasonable"* Rate Principle

Section 78(3) of the *Ontario Energy Board Act* (OEBA) mandates the OEB to approve or fix "just and reasonable" rates for transmitting or distributing electricity. The principle of "just and reasonable" rates originates in the U.S. Supreme Court case: *Federal Power Commission et al v. Hope Natural Gas Co. ("Hope"), 320 U.S. 591, 603 (1944)*. In this case, the U.S. Supreme Court noted, "*Under the statutory standard of 'just and reasonable', it is the result reached, not the method employed, which is*

controlling….It is not theory, but the impact of the rate order, which counts."

Drawing on the "*Hope*" case it can be argued that the principle entails consideration of two key elements of rate design:

- Recovery of cost: The rate should allow enough revenue not only to cover the operating cost of the utility but also yield a return for the capital cost of the utility[1]. That is, the return should be sufficient to assure confidence in the financial integrity of the utility so as to maintain its credit and to attract capital.[2]
- Rate payers' welfare: To protect the welfare of rate payers, the rate should allow the recovery of 'prudently incurrent costs'. That is, the rate must draw a balance between wealth and welfare. In this sense 'prudently incurred costs' should be interpreted as: *"the original cost minus any fraudulent, unwise, or extravagant expenditures that should not be a burden on the public."*[3]

In the context OEB's mandate to approve or fix "just and reasonable" rates requires a balancing of consumer and utility interests.[4]

1.2 Background

In March 2005, the OEB established a pole attachment rate of $22.35 per year per pole attacher. Since then, the rate has not been updated. In 2014, Toronto Hydro's application to increase its pole attachment rate led to OEB approval of an increase to $42 per year per pole attachment. Subsequently, in 2015 Hydro One (EB-2015-141), and Hydro Ottawa (EB-2015-004) also applied to increase their respective rates from the standard rate of $22.35 per year per pole attachment. The OEB approved rate increases to $41.28 for Hydro One and $53.00 for Hydro Ottawa.

On November 5, 2015 (EB-2015-0304), the OEB announced its initiative to undertake a generic policy review of electricity distributors' miscellaneous rates and charges[5]. As per the OEB's 2011 Accounting Procedures Handbook, the miscellaneous service charges (USoA # 4235) include the following items:

i) Fees for changing, connecting or disconnecting service, including reconnection charges and change of occupancy fees

[1] Capital carrying cost or cost of capital rate set by the OEB to determine regulated tariffs is an example of such rate of return
[2] See FPC v. Hope Nat. Gas Co. 320 U.S. 591 (1944)
[3] See C. Phillips, Jr., "The Regulation of Public Utilities 4 (1985).", as referenced by Sean P. Madden (1989), *Taking Clause Analysis of Utility Ratemaking Decisions: Measuring Hope's Investor Interest Factor*, Fordham Law Review, 58(3) Article 4, p. 427
[4] See http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Energy_Sector_Regulation-Overview.pdf
[5] During the oral hearing phase of Hydro Ottawa's application for electricity distribution rates for the period from January 1, 2016 to December 31, 2020, the OEB also informed parties that it plans to undertake a generic policy review of electricity distributors' miscellaneous rates and charges (the Policy Review) – see OEB's Decision and Rate Order: EB-2015-0004, Hydro Ottawa Limited, February 25, 2016, p.2.

ii) Profit on maintenance of appliances, wiring, piping or other distribution related installations on customers' premises

iii) Net credit or debit (cost less net salvage and less payment from customers) on closing of work orders for plant installed for temporary service of less than one year

iv) Recovery of expenses in connection with current diversion cases (billing for the electricity consumed shall be included in the appropriate electric revenue account)

v) Dispute meter test charges

vi) Account history research charges

vii) Disconnect of electricity service

viii) Reconnection of electricity

ix) Dispute involvement charge

x) Temporary electricity service

xi) Account setup charge

xii) Return cheque charge

xiii) Other specific service charges as approved by the Board

Given the many different categories of miscellaneous rates and charges as listed above, the OEB is conducting the review in different phases. The first phase covers specific charges, item # xiii) above. As per the OEB's 2006 Electricity Distribution Rate Handbook, Specific Service Charges include the following six categories:

a) Customer Administration Charges

b) Non-Payment of Account Charges

c) Service Call Charges

d) Temporary Electricity Service Charges

e) Specific Charge for Access to the Power Poles of a Distributor

f) Other Services and Charges

Due to significant differences among stakeholders (i.e. telecom carriers, LDCs, and rate payer groups), the OEB separated the review of item e) above (referred to as wireline pole attachment charges) from the other specific service charges. Accordingly, in its November 5, 2015 letter the OEB invited different stakeholders to express their interest in participating in a Pole Attachment Working Group (PAWG) .

In response to the OEB's invitation, the following organizations, categorized into three stakeholder groups: ***LDCs***, ***Carriers***, and ***Rate Payer Groups***, submitted their nominations for participation in the PAWG process as summarized in Table 1 below:

Table 1: Stakeholder Composition of the Pole Attachment Working Group (PAWG)

LDCs and Associations	Carriers	Rate Payer Groups
1) Horizon Utilities 2) Electricity Distributors Association 3) Burlington Hydro 4) Cornerstone Hydro Electric Concepts Association Inc 5) Hydro Ottawa 6) Toronto Hydro 7) Hydro One Networks 8) Enersource 9) London Hydro	1) Bragg Communications Inc. 2) Canadian Cable Systems Alliance 3) Cogeco Cable Canada LP 4) Independent Telecommunications Providers Association 5) Allstream Inc. 6) Niagara Regional Broadband Network 7) Packet-tel Corp. (o/a Packetworks) 8) Québecor Média Inc. 9) Rogers Communications Partnership 10) Shaw Communications Inc. 11) Tbaytel 12) TELUS Communications Company 13) BH Telecom	1) Energy Probe Research Foundation 2) Vulnerable Energy Consumers Coalition (VECC) 3) School Energy Coalition 4) Building Owners and Managers Association, Toronto 5) London Property Management Association

After review of all nominations, the OEB selected nine organizations to participate in the PAWG in order to keep the size of the group more conducive to discussion. Accordingly, the PAWG was formed with the parties summarized in Table 2 below.

To facilitate the PAWG process, in March 2016 the OEB issued a Request for Proposal (RFP) for expert consultancy services for the policy review of wireline pole attachment charges, with the following main objectives:

A. Assess a number of technical issues and details related to pole attachments;

B. Review of the current methodology for setting wireline rates for pole attachments in the province of Ontario;

C. Determine how to treat and allocate any revenues that wireline carriers may receive from third parties with respect to wireline pole attachments; and

D. Determine the appropriate treatment and allocation of other costs (e.g. vegetation removal).

Table 2: Nominations Submitted for the Pole Attachment Working Group (PAWG)

Organization	Primary Representative(s)
LDCs and Associations	
1) Hydro One Networks Inc.	John Boldt
2) CHEC - Cornerstone Hydro Electric Concepts Association Inc. Representing a group of fifteen (15) distributors: • Centre Wellington Hydro • InnPower Corporation • Orangeville Hydro • Rideau St. Lawrence Distribution • Wellington North Power • COLLUS PowerStream • Lakefront Utilities • Midland Power Utility • Lakeland Power • Wasaga Distribution • Orillia Power • Renfrew Hydro • Ottawa River Power • Niagara-on-the-Lake Hydro • West Coast Huron Energy	Roy Rogers (Midland Power)
3) Hydro Ottawa Limited	Casey Malone
4) London Hydro	Jagoda Borovickic
5) Horizon Utilities	David Haddock
6) Canadian Electricity Association	Arjun Devdas (Toronto Hydro)
Rate Payers Groups	
7) School Energy Coalition	Mark Rubenstein
8) Vulnerable Energy Consumers Coalition	William Harper
Carrier Companies	
9) BH Telecom	Kris Eby
10) The Carriers Representing a group of twelve (12) distributors: • Bragg Communications Inc. • Canadian Cable Systems Alliance Inc. • Cogeco Cable Canada LP • Independent Telecommunications Providers Association • Allstream Inc. • Niagara Regional Broadband Network • Packet-tel Corp. (o/a Packetworks) • Québecor Média Inc. • Rogers Communications Partnership • Shaw Communications Inc. • Tbaytel • TELUS Communications Company	Michael Piaskoski (Rogers) Tim Brown (Cogeco) David Willkie (Tbaytel)

In response to the RFP, Nordicity submitted its proposal and was selected to deliver the following two specific tasks:

Task 1: Facilitate four (4) Pole Attachment Working Group meetings along with OEB staff. Nordicity's role was to provide expert input and analysis of the key issues for discussion, and feedback of the group members.

Task 2: Produce an expert report, including at least the following items:

a) A detailed description on what wireline pole attachments are, including what makes up the charge and what kinds of attachments are considered wireline pole attachments;

b) Review of current methodologies used by Ontario distributors that have applied to the OEB for an increase in the wireline pole attachments charge (Toronto Hydro, Hydro One, Hydro Ottawa);

c) Identify and discuss any technical issues that should be taken into consideration in determining the wireline pole attachment charge;

d) In addition to distributors and carrier companies, a detailed description of what other parties have access to the poles and any related conditions to access;

e) A discussion and findings related to the treatment and allocation of various wireline costs (including, at a minimum, vegetation removal costs etc.)

f) A discussion and findings with respect to whether differences between distributors or regions would affect the setting of a province-wide wireline pole attachment charge;

g) A discussion and findings related to the direct and indirect cost used in calculating the wireline pole attachment charge, including, at a minimum, analysis related to the use of historical or forecasted costs;

h) Analysis and finding related to the appropriate treatment of any revenues that wireline carriers may receive from third parties;

i) Development of an appropriate methodology for setting wireline pole attachment charges by all electricity distributors;

j) Analysis related to parties wishing to use electricity distributor poles, including, at a minimum, the appropriate number of attachers, and the standard wireline attachment charge related to the number of attachers; and

k) Inclusion of any other issues to the objectives and scope of the project.

1.3 PAWG Meetings

As part of the PAWG process, four meetings of the participating members were held at the OEB's offices in Toronto, jointly facilitated by the Nordicity team and OEB staff. The meetings were held on the following dates:

a) PAWG Meeting # 1: May 20, 2016

b) PAWG Meeting # 2: July 27, 2016

c) PAWG Meeting # 3: November 24, 2016

d) PAWG Meeting # 4: January 31, 2017

Detailed minutes of each meeting were recorded and circulated among members for their review, comment, and sign off. The final minutes of the four meetings are available on the OEB website[6].

In the 1st PAWG meeting, the following key elements of the consultation process were discussed and agreed upon:

- Objectives of the process, which were to (a) develop a pole attachment rate model that is "just and reasonable" and based on best practice principles; and (b) clarify the OEB's mandate with reference to the outcome of this consultation process;
- A Typical Pole Structure, with pole height, power space, telecom space, separation space between power and telecom space, clearance space, buried space identified;
- Key Elements of the Pole Attachment Rate Model (Regulatory Framework; Costing Approaches; Allocation Methodologies; and Rate Methodologies; and,
- Relevant decisions: OEB (2015 and 2016; NBEUB-New Brunswick Energy and Utility Board (2016); and; CRTC (2010).

As an outcome of the roundtable discussion, the members agreed on the following four action items:

a) Utilities were to provide the following data: specifications of poles in use, distribution of total pole population, volume of attachments, and item-wise breakdown of cost base;

b) Nordicity was to develop a data template for utilities to populate;

c) Participants (PAWG members) could submit additional written comments on their positions on the key issues before the next meeting; and,

d) Nordicity was to present further literature review on best practices in the next meeting.

[6] See https://www.oeb.ca/industry/policy-initiatives-and-consultations/review-miscellaneous-rates-and-charges.

As per item a) above, Nordicity prepared a data collection template that was issued to LDCs in the first week of June 2016 and LDCs were requested to submit their response by June 30, 2016. Based on the data submitted by LDCs, Nordicity presented analysis at the 2nd PAWG meeting on July 27, 2016.

At the 2nd PAWG meeting, a round table discussion was also held to discuss the key issues identified in the 1st PAWG meeting and additional detailed issues submitted by Rogers. These items are summarized in Appendix A. Based on the detailed discussion of the issues, the PAWG members agreed that Nordicity would issue an additional data request template in order to allow further and more detailed analysis of the issues raised.

Accordingly, a second data request was issued to LDCs on September 13, 2016, and LDCs submitted their responses by September 30, 2016.

At the 3rd PAWG meeting on November 24, 2016, Nordicity presented detailed analysis based on the additional data received from LDCs. At that meeting, participants mainly focused on the critical issues associated with the following four key areas of the rate calculation:

- Embedded cost
- Maintenance cost
- Direct costs
- Average number of attachers

With respect to the above items, various issues were raised and discussed at length among the participants. For each issue, the participants stated their positions and their lines of reasoning, which were included in the summary attached to the 3rd PAWG minutes of meeting.

At the 4th PAWG meeting, the participants presented their positions on the key issues based on the final analysis of issues presented by OEB staff as well as Nordicity. Based on the discussion, OEB staff and Nordicity prepared a description of key issues critical to pole attachment rate calculation that required final input from the PAWG members. The issues were grouped in the following three categories:

- Cost allocation methodology
- Costing inputs
- Rate calculation methodology

As a follow up to the 4th PAWG meeting, OEB staff issued a questionnaire to PAWG members on February 16, 2017 in order to obtain their final comments on each identified issue. The members were requested to submit a single response for their respective groups: “carrier”, “LDC”, and “rate payers” in the specified format (1000 characters) by March 3, 2017. The three responses received are available at OEB website[7].

[7] see https://www.oeb.ca/industry/policy-initiatives-and-consultations/review-miscellaneous-rates-and-charges

1.4 Understanding the Current Standard Pole Attachment Rate of $22.35 per Pole Attacher

As stated above, in its March 7, 2005 OEB Decision and Order (RP-2003-0249) (2005 OEB Decision), the OEB established a province-wide rate of $22.35 per pole per year. This decision concluded a proceeding triggered by an application of the Canadian Cable Television Association "CCTA" to the OEB.

Historically, CCTA members had rented space on utilities' poles at negotiated rates under a private contract. That contract expired in 1996. After the expiry of the contract, the two parties - CCTA and the Electricity Distribution Association (EDA) - failed to renew or reach further agreement with respect to the pole attachment rates. In this regard, the OEB noted:

"*In the past, the CCTA members have rented space on the utilities' poles under private contract. That contract came to an end in 1996. Since then, the parties have been unable to reach further agreement with respect to rates".*[8]

In early 1997 the CCTA first applied to the Canadian Radio-television and Telecommunications Commission (CRTC) for access by cable companies to the poles of the Ontario electricity distributors[9]. After a lengthy proceeding, the CRTC in its September 28th, 1999 Decision ("*Telecom Decision CRTC 99-13*") determined an annual pole charge of $15.89, as detailed in Table 3 below.

However, in response to an appeal by the Ontario Municipal Electric Association (MEA), the Federal Court of Appeal in 2001 held that the CRTC did not have statutory authority under the *Telecommunications Act* to regulate access by cable operators and telecommunications carriers to power poles[10]. In 2003, the Supreme Court of Canada upheld the decision of the Federal Court of Appeals. As a result, on December 16, 2003 the CCTA filed an application with the Board to set the pole attachment rate.

In its 2005 application, the CCTA proposed a rate of $15.65 per pole per year. This proposed rate was based on a common cost allocation rate of 15.5% - as determined by the CRTC - compared to 21.9%, as later determined by the OEB. The "common cost" refers to costs associated with the pole space that is not used by attachers (whether power, or telecom) for their attachments but required to meet the requirements of public safety standards and by-laws.

As shown in Figure 6 below, the examples of such space include "buried space" and "clearance space". Both buried and clearance space constitute almost two-third of the pole height. Accordingly, the majority of pole costs are attributable to the common space. This raises the issue of how to allocate the common cost among different types of attachers, such as power and telecom service providers. As discussed later in the report, different methodologies can be applied to allocate the common costs, with proportionate use and equal sharing constituting the principal methodologies considered by economists in the literature, and applied by regulatory authorities.

[8] March 7, OEB 2005 Order (p.1).
[9] The CRTC established the rate of $15.89 per year per attachment (CRTC 99-13).
[10] Barrie Public Utilities v. Canadian Cable Television Association (2001) 4 F.C. 237.

As shown in Table 3 below, the allocation rate of 15.5% (CRTC) is based on proportionate use, and 21.9% (OEB) is based on an equal sharing methodology.

Table 3: Common Cost Allocation - 2005 OEB (Equal Sharing) vs. 1999 CRTC (Proportionate Use)

Pole Specs	2005 OEB (Equal Sharing)				1999 CRTC (Proportional)			
	Joint Pole Length (ft.)	Attachers	Length Per Attacher (ft.)	Explanation	Joint Pole Length (ft.)	Attachers	Length Per Attacher (ft.)	Explanation
A Power space	11.50 ÷	1.00		A	11.50 ÷	1.00		A
B Communication space	2.00 ÷	**2.50**	= 0.80	B	2.00 ÷	**2.00**	= 1.00	B
C Separation space	3.25 ÷	2.50	= 1.30	C	3.25 ÷	2.00	= 1.60	C
D Usable Space	**16.75**	**3.50**	**2.10**	= A + B + C	**16.75**		**2.60**	= A + B + C
E Clearance	17.25			E	17.25			E
F Buried	6.00			F	6.00			F
G Common Space	**23.25**	3.50	**6.64**	= D + E + F	**23.25**			= D + E + F
H Total Pole Length	**40.00**		**8.74**	= D + G	**40.00**		**2.60**	= D + G
I Allocation Rate			**21.9%**	= 8.74 ÷ 40.0			**15.50%**	= 2.60 ÷ 16.75
J **Common Cost**	**$93.31**		**$ 20.43**	= $93.21 x 21.9%	**$78.21**		**$ 12.12**	= $78.21 x 15.5%
K Direct Cost			**$ 1.92**				**$ 3.77**	
L **Total Rate**			**$ 22.35**	= J + K			**$ 15.89**	= J + K

As shown in Table 3 above, the main differences between OEB and CRTC allocation rates were due to:

a) the methodology –the CRTC used "proportional use" and OEB used "equal sharing approaches to allocate common space; and

b) the average number of attachers assumed for the communication space – (OEB: 2.5 attachers, and CRTC: 2 attachers)

The third difference was in the common cost base as detailed in Table 4, below:

Table 4: Direct and Indirect (Common) Cost Base - 2005 OEB vs. 1999 CRTC

Cost Components per Pole			2005 OEB (EB-2003-0249)	1999 CRTC (CRTC-99-13)
Direct Cost	Administration Cost	A	$ 0.69	$ 0.62
	Loss in Productivity	B	$ 1.23	$ 3.15
	Total Direct Cost	C = A+B	**$ 1.92**	
Indirect Cost	Net Embedded Cost per pole	D	**$ 478.00**	**$ 478.00**
	Capital Carrying Cost Rate %	E	11.42%	8.50%
	Depreciation Expense	F	$ 31.11	$ 31.11
	Pole Maintenance Expense	G	$ 7.61	$ 6.47
	Capital Carrying Cost	H = D x E	$ 54.59	$ 40.63
	Utility Tax Cost	I	-	-
	Loss in Productivity	J	incl. above	incl. above
	Total Indirect Cost	K=F+…+J	**$ 93.31**	**$ 78.21**

In the 2005 OEB proceedings, both parties- CCTA and EDA - submitted evidence in support of their respective positions on the cost allocation methodology:

- CCTA – based on testimony by Dr. Donald Ford advocated for "proportional use", and
- Electricity Distribution Association (EDA) – based on testimony by Dr. Bridger Mitchell, advocated for "equal sharing".

It is worth noting that in the 2005 proceeding, the OEB focused on the following key issues:

1. Is it necessary that the OEB set access charges?
2. Which parties should have access?
3. What is the appropriate methodology?
4. How many attachers should be assumed in calculating the rate?
5. Should there be a province-wide rate?
6. What costs should be used in calculating the rate?
7. Should new licence conditions impact existing contracts?

With respect to the above questions, the OEB concluded as follows[11]:

1. The OEB should set a specific (single) access charge[12]
2. The OEB determined that a single province-wide rate is in the public interest. The OEB also noted that a province-wide rate has the advantage that it is simple to administer. The OEB further noted that calculating different costs for ninety utilities would be a challenge for all concerned. However, the OEB stated that ***any LDC that believes that the province-wide rate is not appropriate could bring an application to have the rates modified based on its own costing.***
3. "Equal sharing" should be the preferred methodology to allocate common costs.
4. 2.5 attachers was assumed to be reasonable, instead of the 2 attachers assumed in the CRTC 1999 decision.[13]
5. While the OEB recognized local costs vary, there were advantages to having a province-wide rate.
6. The rate should to a maximum extent possible, be based upon representative costs. The OEB accepted the costs as detailed in Table 5 below.

[11] Question 7: "Should new licence conditions impact existing contracts?", was not addressed in the OEB's determination.
[12] The OEB did not accept the submission of EDA et al to set a range of rate instead of a specific rate. The OEB determined that there was no rationale for a range of rates in the given circumstances.
[13] "The OEB considers 2.5 attachers to be reasonable. Things have changed since the days of the CRTC decision. If anything, there will be more than 2.5 attachers in the future" (OEB 2005, p. 7).

Table 5: 2005 OEB Decision and Order – Cost Breakdown

	Price Component - Per Pole	$	Explanation
	DIRECT COST		
A	Administration Costs	$ 0.69	CRTC estimate 1999 $0.62, plus inflation
B	Loss in Productivity	$ 1.23	MEA estimate 1991 - $3.08, plus inflation, and divided between 2.5 pole attachers
C	Total Direct Costs	**$ 1.92**	A + B
	INDIRECT COST		
D	Net Embedded Cost per pole	**$ 478.00**	Milton Hydro 1995 = $478
E	Depreciation Expense	$ 31.11	Milton Hydro 1995 = $31.11
F	Pole Maintenance Expense	$ 7.61	Milton Hydro 1995 = $6.47, plus inflation
G	Capital Carrying Cost	$ 54.59	Pre-tax weighted average cost of capital 11.42% applied to net embedded cost per pole (D)
H	Total Indirect Costs per Pole	**$ 93.31**	E + F + G
I	Allocation Factor	21.9%	Allocation based on 2.5 attachers
J	Indirect Cost Allocated	$ 20.43	H x I
K	Annual Pole Rental Charge	**$ 22.35**	C + J
Note: Reproduced Appendix 2 (page 13) of OEB 2005 Decision and Order (RP-2003-0249), dated March 7, 2005.			

Subsequent to the 2005 OEB Decision, the OEB recently approved the following three LDC-specific pole attachment rates:

- Toronto Hydro (EB-2014-0116): $42 per pole per year, effective May 1, 2015[14]
- Hydro Ottawa (EB-2015-0004): $53 per pole per year, effective January 1, 2016
- Hydro One (EB-2015-0141): $ 41.28 per pole per year, effective January 1, 2015

Compared to the 2005 OEB Decision, the main differences in the calculations of the rate in the recent three applications stated above, were as follows:

- Inclusion of specific costs submitted by the LDC, instead of representative costs accepted in the 2005 OEB Decision
- Inclusion of a utility-specific actual average number of attachers instead of 2.5 attachers assumed in the 2005 OEB Decision

[14] $42 per pole per year for Toronto Hydro was determined based on a settlement process.

1.5 Decisions in other Canadian jurisdictions

Since the Federal Court of Appeal held in 2001 that the CRTC did not have statutory authority to regulate access by cable operators and telecommunication carriers to power poles, there have been relatively few rate decisions by provincial energy regulators in the last two decades. The pole attachment rate decisions in different Canadian jurisdictions varied with respect to the following factors:

1) Estimates of different cost items, associated with the poles, used to determine annual cost per pole – such as capital cost, annual maintenance cost, and annual capital carrying cost. The differences in costs are attributable to factors such as LDCs' specific cost structure, geography and weather conditions, and applicable public safety standards, regulations and by laws in each jurisdiction;

2) Type of poles used in the rate calculation, such as joint-use poles only or the total number of poles, including power only poles;

3) Methodology to allocate common costs[15] between the two types of attachers – such as equal sharing[16] versus proportionate use;[17]

4) Number of average attachers (presumption average versus actual average) used in the rate calculation; and,

5) Costing approach such as historical cost of the LDC itself or historical cost of another utility assumed to fairly represent the cost of LDCs in the province ("representative cost")

For the cost estimates for items included in 1) above, the same cost categories were used to determine the annual common cost of the pole, which include (a) annual depreciation, (b) capital carrying cost, (c) maintenance cost. However, the dollar value of the cost estimates typically varies across different jurisdictions for common reasons such as:

- Difference in embedded (historical) cost per pole due to the relative age-mix and installation cost of poles in each jurisdiction;
- Difference in annual depreciation rate due to different average useful life assumed in the rate calculation; and,
- Difference in capital carrying cost due to different cost of capital rates (weighted average cost of capital) applicable to a specific utility or a province.

[15] Common costs typically include annual depreciation, maintenance and capital carrying costs.
[16] The common costs are equally divided among the attachers.
[17] The common costs are divided according to the ratio of space occupied by an attacher to the total usable space of the pole. That is clearance and buried space are not considered as usable space so not included in the allocation ratio.

In terms of the above five factors, Table 6 below provides a comparative summary of pole attachment rate decisions by different Canadian energy boards and the CRTC [18]:

Table 6: Summary of Decisions in Canadian Jurisdictions

Year	Canadian Jurisdiction	Annual Common Cost	Annual Rate	Pole Population	Costing Approach	Allocation Methodology	Rate Methodology	
							Communication Space Attachers	#
1999	CRTC - Power Utility Poles (CRTC 99-13)	$78.21	$15.89	Joint Use	Historical *(representative)*	Proportional	Presumptive Attachers	2.00
2000	AEUB - Alberta Energy and Utilities Board (2000-86)	$51.00	$18.36	Joint Use	Historical cost	Equal Sharing (1) (implied)	Presumptive Attachers	2.00
2002	NSURB - Nova Scotia Utility and Review Board (2002)	$75.11	$14.15	Joint Use	Historical *(representative)*	Proportional	Presumptive Attachers	2.00
2005	OEB (RP-2003-0249)	$93.31	$22.35	Joint Use	Historical *(representative)*	Equal Sharing	Presumptive Attachers	2.50
2006	New Brunswick (2006)	n.a.	$18.00	*Interim order based on decisions in other jurisdictions*				n.a.
2010	CRTC – Telephone Poles Ontario and Quebec (CRTC 2010-900) - Bell Canada and Aliant	$62.78	$12.48	Joint Use	Historical	Proportional	Actual Attachers	1.70
2015	New Brunswick Energy and Utilities (matter # 272) - NB Power	$79.91	$20.77	Total	Historical	Proportional	Actual Attachers	1.40
2015	OEB (EB-2015-0004) Hydro Ottawa	$169.69	$53.00	Total	Historical	Equal Sharing	Actual Attachers	1.74
2015	OEB (EB-2015-0141) – Hydro One	$108.71	$41.28	Total	Historical	Equal Sharing	Actual Attachers	1.30
2016	OEB (EB-2014-0116) Toronto Hydro	$144.53	$42.00	Total	*Not available (agreed upon in a settlement agreement)*			1.61
2016	CRTC 2016-228 - TELUS	$62.26	$19.33	Joint Use	Historical	Proportional	Actual Attachers	1.32

(1): Alberta Energy and Utilities OEB accepted TransAlta's cost sharing methodology, based on "a simplified hypothetical system where each utility constructs its own system without regard for existing facilities. Each utility's share of the combined cost of the three systems was applied to TransAlta's embedded pole cost to arrive at a preliminary share by utility" (EUB 2008-86, Section 3.1, p. 17).

[18] The decisions listed in the Table 6 are only for reference purpose only.

There are certain specific cost factors associated with pole infrastructure that can cause significant differences in annual cost per pole across different jurisdictions - for example, inclusion of extraordinary vegetation and storm recovery cost in the rate calculation. The New Brunswick Energy and Utilities Board in its 2016 Decision (matter # 272- NB Power), for example, allowed for inclusion of planned and storm-related vegetation expenditures and storm-related repair expenses in the annual maintenance cost. Inclusion of other associated costs such as the cost of neutrals can also cause significant differences in the embedded cost per pole. To the best of Nordicity's knowledge, such costs have not been included in the decision cited in Table 6 above. In the case of the New Brunswick Energy and Utilities Board's (matter # 272) NB Power proceeding, this issue was raised and the NBEUB ruled as follows:

"The Board ruled on June 23 that it would not consider, in the absence of a cost analysis, the issue of whether secondary and neutral costs should be included in the cost allocation methodology. Accordingly, this matter proceeded without reference to the pre-filed evidence on this issue. The Board indicated that NB Power may bring this issue forward in future rate applications. The remaining costs presented by NB Power below are based on its revised evidence." (matter no. 272, November 16, 2015, para 9, p. 2)

Table 7 below illustrates the cost differences contained in four regulatory board decisions cited in Table 6 above.

Table 7: Pole Cost Comparison of Selected Poles Attachment Rate Decisions in Canadian Jurisdictions

Cost Components per Pole			2005 OEB (EB-2003-0249)	2005 OEB (Hydro Ottawa EB-2015-0004)	2016 NBEUB (matter 272)	1999 CRTC (CRTC-99-13)
Direct Cost	Administration Cost	A	$ 0.69	$ 2.28	$ 0.62	$ 0.62
	Loss in Productivity	B	$ 1.23	$ 1.96	incl. below	$ 3.15
	Total Direct Cost	C = A+B	**$ 1.92**	**$ 4.23**	**$ 0.62**	**$ 3.77**
Indirect Cost	Net Embedded Cost per pole	D	$ 478.00	$ 1,479.02	$ 346.68	$ 478.00
	Capital Carrying Cost Rate %	E	11.42%	8.04%	5.13%	8.50%
	Depreciation Expense	F	$ 31.11	$ 38.89	$ 19.34	$ 31.11
	Pole Maintenance Expense	G	$ 7.61	$ 11.89	$ 30.93	$ 6.47
	Capital Carrying Cost	H = D x E	$ 54.59	$ 118.91	$ 17.78	$ 40.63
	Utility Tax Cost	I	-	-	$ 6.43	-
	Loss in Productivity	J	incl. above	incl. above	$ 5.43	incl. above
	Total Indirect Cost	K=F+…+J	**$ 93.31**	**$ 169.69**	**$ 79.91**	**$ 78.21**

2 Key Objectives

2.1 Why a policy framework is required

Wireline poles are an essential part of both electrical distribution and telecommunications networks.

With the rapid uptake of bandwidth by subscribers necessary to support a myriad of everyday applications and increasing competition in the telecom sector, there has been an increasing need for third-party attachments to wireline poles. Municipal governments have always promoted the sharing of pole infrastructure for efficiency and aesthetic considerations. Given that the predominant location of poles is on public land, municipal intervention has been able to significantly increase the sharing of poles - owned by both power and communication operators - and correspondingly, reduce wasteful duplication in overall pole infrastructure.

For example, the OEB in its 2005 order noted:

"*Duplication of poles is neither viable nor in the public interest*" (p. 3).

Earlier, in its 99-13 decision, the CRTC made a similar observation in the following words:

"By allowing access to existing supporting structures irrespective of the type of utility owning or controlling such a structure, the adverse environmental, economic and aesthetic impacts associated with unnecessary duplication of aerial supporting structures is avoided." (para. 124)

In this context, it is important to ensure the rates charged to third party users of the wireline poles are "***just and reasonable*"** based on the following principles:

(a) communication attachers have access to the utility poles, and

(b) utilities are able to recover the cost of their poles, based on just and reasonable rates.

In its seminal 2014 decision, the Public Utilities Commission of Ohio (Case No. 13-579-AU-ORD) defined the just and reasonable principle as follows:

"A rate is just and reasonable if it assures a utility the recovery of not less than the additional costs of providing pole attachments, nor more than an amount determined by multiplying the percentage of the total usable space, or the percentage of the total duct or conduit capacity, which is occupied by the pole attachment by the sum of the operating expenses and actual capital costs of the public utility attributable to the entire pole, duct, conduit, or right-of-way."

Therefore, an effective policy framework is required to ensure pole attachment rates that are just and reasonable are developed and maintained moving forward.

To achieve this overarching objective, in Nordicity's view the issues to be addressed within a policy framework include:

a) Development of an appropriate costing methodology;

b) Determination of a representative pole specifications: type, dimensions, spacing, useful life and so forth;

c) Determination of a cost-sharing and allocation methodology;

d) Identification of cost elements (e.g. vegetation management costs) for inclusion in the rate;

e) Determination of the basis to calculate the rate per attacher, e.g. determining the number of attachments per pole;

f) Determination of the relevant pole population to be used as the basis for rate calculations: e.g. total pole population or only those poles with third party attachments;

g) Treatment of revenue generated through third party pole attachment rates, make-ready cost charges[19] etc.;

h) Treatment of potential revenue, if any, received by a third party (host) attacher by allowing another third party attacher to "overlash"[20] on the its attachment on the utility pole;

i) Application of economic principles of efficiency, fairness and reasonableness to all items listed above; and

j) Rate of return rate determination: e.g., based on cost recovery of poles infrastructure cost or on utility specific capital structure and financial risk.

2.2 2005 OEB Order Analysis

James Bonbright, an economist recognized for developing practical solutions to utility problems, recommended certain key attributes of a sound rate structure for a utility, which can be summarized into the following key six criteria[21] :

1) The rate should be simple and feasible to implement;

2) The rate has public acceptability and is free from controversies as to proper interpretation;

3) **The rate should be effective in yielding total revenue requirement under the fair-return standard;**

4) **The rate should provide revenue stability from year to year, with minimum unexpected changes;**

5) The rate should be based on fair allocation of total cost among different customers; and

6) The rate should avoid undue discrimination and promote efficiency in use of services

[19] Make-ready charges represent the onetime charges an attacher is to pay to an LDC in order to prepare the pole for a requested attachment in full conformance with the applicable safety code, engineering standards and by-laws. For example, the age of the pole and condition of the pole is assessed to determine with if the pole can support the additional attachments being requested.

[20] "Overlashing" refers to the process of physically attaching additional cables to the cables that are already attached to a utility pole. For example, an existing attacher A (called as host attacher) allows to attach cable of another attacher B.

[21] Bonbright, James C, "Principles of Public Utility Rates", Columbia University Press, New York NY, 1961, p.21.

Nordicity examined the 2005 OEB Decision, in terms of the criteria as set out above, by Bonbright by answering the following question:

Does this OEB approach ensure rate stability and effectively yield revenue requirement under the fair return standard?

The direct cost as shown in Table 7 above, is directly attributable (causal) to the attacher. The indirect cost, which constitutes 91% of the total annual cost, since it is not directly attributable, needs to be allocated to the attachers using a specific allocation methodology. The indirect cost is associated with the common pole space (buried and clearance), which accounts for over two-third of the total pole height. For this reason, the methodology used to estimate indirect cost and subsequently to allocate to the attachers, can have a major impact on the pole attachment rate. For this reason, Nordicity analysed the annual indirect cost.

As shown in Table 7 above, the annual indirect cost of $93.31 per pole used in the 2005 OEB Rate Order, is based on the following cost inputs:

(A) Net Embedded Cost[22]: **$478.00**

(B) Depreciation Expense: **$31.11**

(C) Maintenance Expense: **$7.61**

(D) Pre-tax cost of capital: **11.42%**

(E) Capital Carrying Cost[23]: **$54.59** [= 11.42% (A) x $478.00 (D)]

Based on the above cost items, the indirect cost per pole determined in the 2005 OEB Decision was the sum of (B), (C) and (E) for a total of $93.31 (= $31.11 + $7.61 + $54.59).

Notwithstanding the cost inputs used in the OEB rate calculation, it is important to examine the OEB Rate Order in terms of the criteria set out by Bonbright, in the following question:

> *Does the OEB approach ensure rate stability and effectively yields the revenue requirement under the 'fair return' standard?*

As an illustration, using the approach from the 2005 OEB Rate Order, annual indirect costs are calculated from year-to-year over the 25-year life assumed in the Decision. That is, based on a 25-year useful life of a pole, and annual (straight line) depreciation of $31.11 shown above, the total average embedded cost

[22] Net Embedded Cost = Total (gross) embedded cost minus accumulated depreciation. ***Embedded cost*** is referred to as the total installed cost averaged over the pole population, and ***net embedded cost*** is referred to as the undepreciated value of those poles averaged over the pole population. (*for example, see New Brunswick Power evidence NBP1.03 submitted on November 21, 2014 to New Brunswick Energy and Utility OEB for matter no. 272).*

[23] Capital Carrying Cost = $478.00 (Net Embedded Cost) x Pre-tax weighted average cost of capital 11.42%.

per pole is calculated to be **$777.75** (= $ 31.11 x 25 years)[24].

The OEB applied the "**half-year rule"** to account for depreciation expense and the capital carrying cost in the initial and last year of the asset's useful life[25]. For example, for a 25-year useful life, the depreciation expense in year 1 is one-half (50%) of the annual depreciation expense, and as a result, the remaining one-half of the depreciation will be recorded in the 26th calendar year. Using the 2005 OEB Rate Order capital carrying cost of 11.42% per annum, and annual maintenance cost of $7.61, the year-to-year total average annual costs per pole - calculated for years 1-25, are provided in Table 8 below.

Table 8: Year-over-year Total Annual Indirect Cost Per Pole (based on 2005 OEB Rate Order)

Year (N)	Embedded	Depreciation	Accumulated Depreciation	Net Embedded	Carrying Cost	Maintenance	Total Annual Cost
	A	B	C = C (Previous Year) + B	D = A – C	E = D x 11.42%	F	G = B + E + F
0	$ 777.75	-	-	$ 777.75	-	-	-
1	$ 777.75	**$ 19.76**	$ 19.76	$ 757.99	**$ 43.28**	**$ 7.61**	**$ 70.65**
2	$ 777.75	**$ 31.11**	$ 50.87	$ 726.88	**$ 83.01**	**$ 7.61**	**$ 121.73**
3	$ 777.75	**$ 31.11**	$ 81.98	$ 695.77	**$ 79.46**	**$ 7.61**	**$ 118.18**
4	$ 777.75	**$ 31.11**	$ 113.09	$ 664.66	**$ 75.90**	**$ 7.61**	**$ 114.62**
5	$ 777.75	**$ 31.11**	$ 144.20	$ 633.55	**$ 72.35**	**$ 7.61**	**$ 111.07**
6	$ 777.75	**$ 31.11**	$ 175.31	$ 602.44	**$ 68.80**	**$ 7.61**	**$ 107.52**
7	$ 777.75	**$ 31.11**	$ 206.42	$ 571.33	**$ 65.25**	**$ 7.61**	**$ 103.97**
8	$ 777.75	**$ 31.11**	$ 237.53	$ 540.22	**$ 61.69**	**$ 7.61**	**$ 100.41**
9	$ 777.75	**$ 31.11**	$ 268.64	$ 509.11	**$ 58.14**	**$ 7.61**	**$ 96.86**
10	$ 777.75	**$ 31.11**	$ 299.75	**$ 478.00**	**$ 54.59**	**$ 7.61**	**$ 93.31**
11	$ 777.75	**$ 31.11**	$ 330.86	$ 446.89	**$ 51.03**	**$ 7.61**	**$ 89.75**
12	$ 777.75	**$ 31.11**	$ 361.97	$ 415.78	**$ 47.48**	**$ 7.61**	**$ 86.20**
13	$ 777.75	**$ 31.11**	$ 393.08	$ 384.67	**$ 43.93**	**$ 7.61**	**$ 82.65**
14	$ 777.75	**$ 31.11**	$ 424.19	$ 353.56	**$ 40.38**	**$ 7.61**	**$ 79.10**
15	$ 777.75	**$ 31.11**	$ 455.30	$ 322.45	**$ 36.82**	**$ 7.61**	**$ 75.54**
16	$ 777.75	**$ 31.11**	$ 486.41	$ 291.34	**$ 33.27**	**$ 7.61**	**$ 71.99**
17	$ 777.75	**$ 31.11**	$ 517.52	$ 260.23	**$ 29.72**	**$ 7.61**	**$ 68.44**
18	$ 777.75	**$ 31.11**	$ 548.63	$ 229.12	**$ 26.17**	**$ 7.61**	**$ 64.89**
19	$ 777.75	**$ 31.11**	$ 579.74	$ 198.01	**$ 22.61**	**$ 7.61**	**$ 61.33**
20	$ 777.75	**$ 31.11**	$ 610.85	$ 166.90	**$ 19.06**	**$ 7.61**	**$ 57.78**
21	$ 777.75	**$ 31.11**	$ 641.96	$ 135.79	**$ 15.51**	**$ 7.61**	**$ 54.23**
22	$ 777.75	**$ 31.11**	$ 673.07	$ 104.68	**$ 11.95**	**$ 7.61**	**$ 50.67**
23	$ 777.75	**$ 31.11**	$ 704.18	$ 73.57	**$ 8.40**	**$ 7.61**	**$ 47.12**
24	$ 777.75	**$ 31.11**	$ 735.29	$ 42.46	**$ 4.85**	**$ 7.61**	**$ 43.57**
25	$ 777.75	**$ 31.11**	$ 766.40	**$ 11.35**	**$ 1.30**	**$ 7.61**	**$ 40.02**
26	$ 777.75	**$ 11.35**	$ 777.75	-	-	**$ 7.61**	**$ 18.96**
Total		**$ 777.75**			**$ 1,054.95**	**$ 197.86**	**$ 2,030.56**

[24] To arrive at the net embedded cost of $478.00 in Year 10, as determined in 2005 OEB Order, the depreciation in Year 1 was estimated to be $19.76 - balancing amount added to half-year rule amount ($31.11 ÷ 2) applied in the first year.

[25] The "half-year rule" is used to represent that since not all assets in the common pool, such as poles are commissioned on day 1 (January 1) of their initial year of service. Similarly, not all assets are decommissioned in the last year of their useful life. Half-year rule represents the overall average of asset's service in the first and last year of their useful life.

It is worth noting that $93.31 annual indirect cost per pole in year 10 generates the same value as that was determined in the 2005 OEB Decision (see Table 5 above). This confirms that the indirect cost base used in OEB's current rate methodology is accurately simulated in Table 8 over the useful life assumed in the OEB 2005 Decision[26]. Figure 2 below shows the annual cost per pole for all 1-25 years.

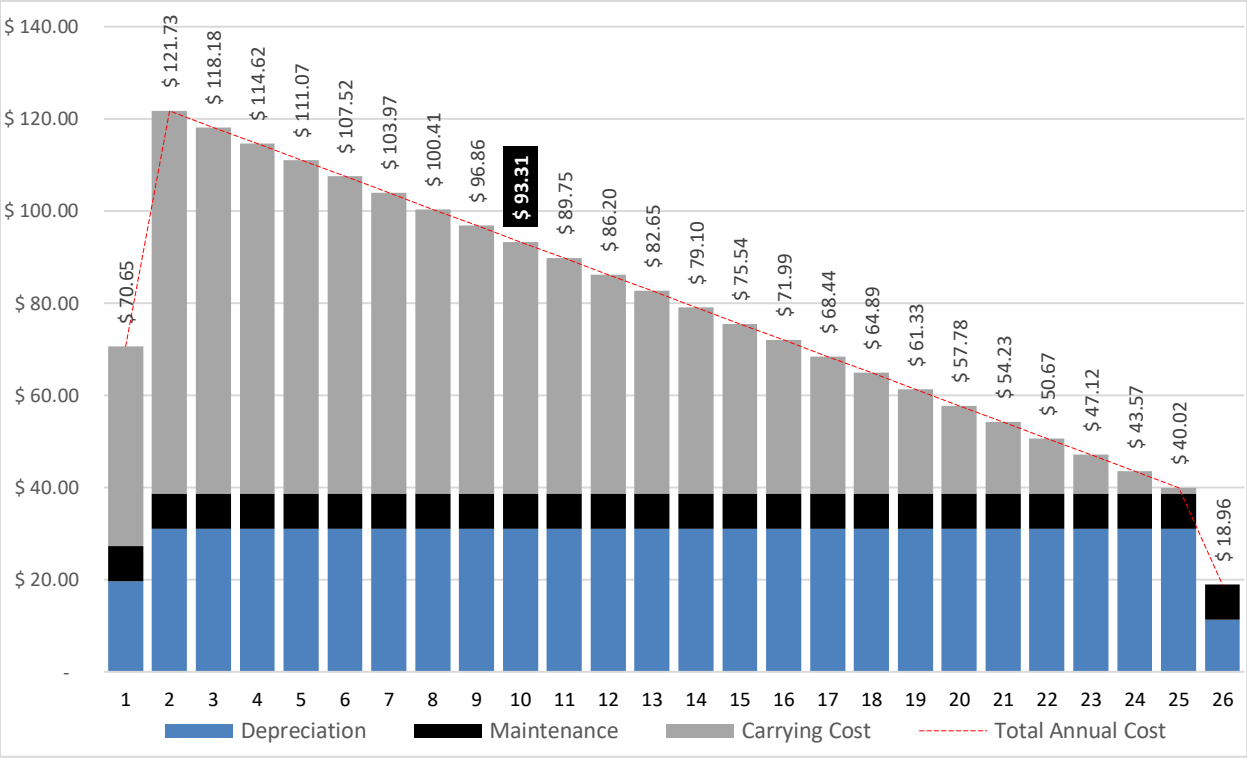


Figure 2: Annual indirect cost per pole ***(over 25-year useful life based on 2005 OEB Rate Order Formula)***

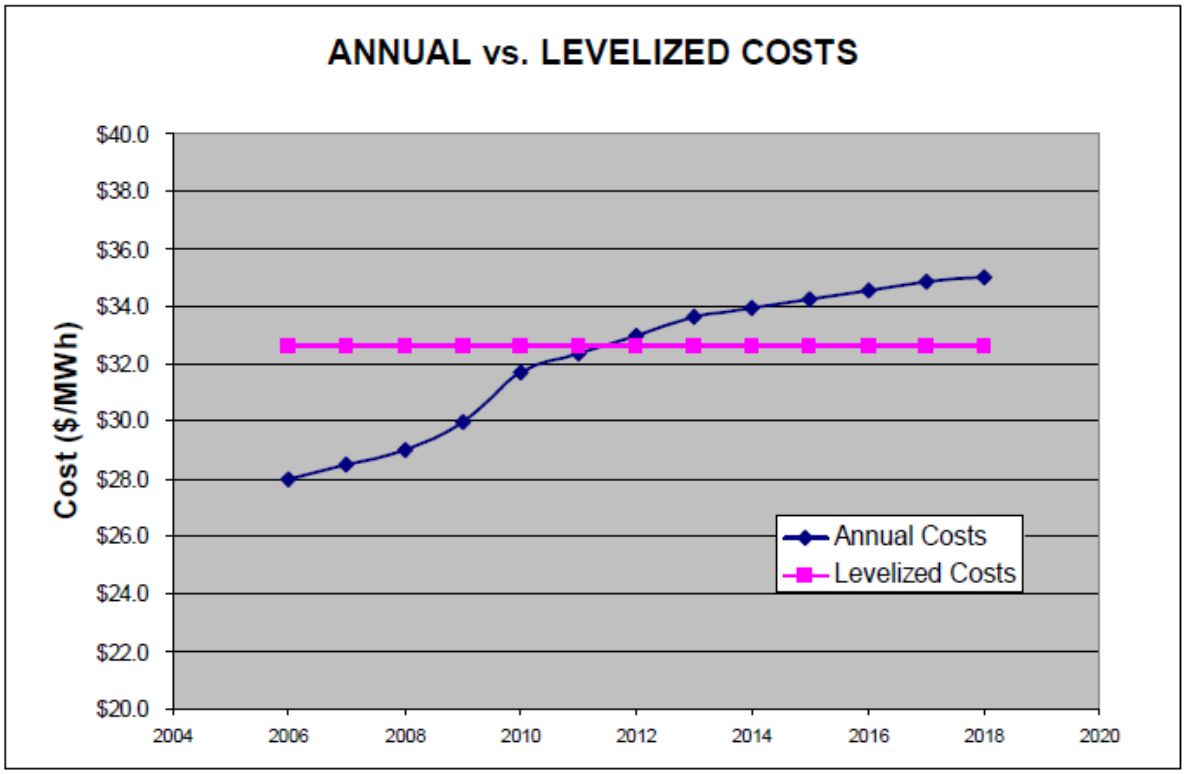
It is evident from Figure 2 above, that the annual indirect cost per pole correspondingly decreases from year- to-year as net embedded cost progressively reduces in succeeding years. Furthermore, significant fluctuation in the annual cost can occur as result of major pole replacement programs undertaken by LDCs in certain years. This fluctuation could be avoided if the age of individual poles were uniformly distributed – that is, if replacement occurred at a consistent rate each year-over-year throughout the economic life of the pole asset. However, this would be difficult for LDCs to realize in practical terms given their operational uncertainties.

[26] The 2005 OEB Decision used $31.11 as annual depreciation. This number was based on Milton Hydro's cost inputs cited in CRTC99-13 Decision. Milton Hydro based their calculations on pole's useful lie of 25 years..

In this context, a "levelized cost-based" rate could provide a practical alternative solution to validate the current methodology and avoid the problems described above by providing a single rate from year to year[27]. "Levelised cost" is a widely used concept in the electricity literature, which is entirely based on discounted cash flows concept and is calibrated as the minimum average price that a firm should receive to justify investment in a production facility[28]:

"Levelized costs [rate] are uniform annual costs that determine the estimated annual revenue required to recover all costs over the life of the project"[29].

In other words, a levelized cost is the constant annual cost that is equivalent on a present value basis to the actual annual costs, which are themselves variable, as illustrated in Figure 3 below[30]:



Source: Energy Commission

Figure 3: **Variable Annual Cost Vs. Levelised (Annualized) Cost**

[27] For example, California Energy Commission (CEC) uses levelized rate approach since several years ago.
[28] Reichelstein, S. and Rohlfing-Bastian, A. "Levelized Product Cost: Concept and Decision Relevance", The Accounting Review, American Accounting Association, Vol. 90 (40), 2015.
[29] Bemis, Gerald R, and DeAngelis, Michael, "*Levelized cost of Electricity Generation Technologies*", Contemporary Policy Issues, July 1990 (8,3).
[30] California Energy Commission (CEC) draft staff report (June 2007, CEC-200-2007-011-SD), p. 4.

As shown in Figure 3 above, the levelized cost approach, by providing costs that are consistent across all years, could ensure rate stability and an effective yield to recover the initial cost of the pole on a just and reasonable basis.

For example, in terms of the above rate calculation the capital cost of the pole must be fully recovered through depreciation expense ($31.11), and capital carrying cost (calculated at 11.42% of respective year embedded cost), included in the rate base i.e. annual indirect cost per pole. That is, the present value of depreciation expense and capital carrying cost must equal to $777.75, embedded (initial) capital cost per pole.

As shown in Table 9 below at 11.42% cost of capital, the present value of depreciation is $244.66 and carrying cost is $466.30 resulting in a total cost of $710.96, which is less than $777.75 embedded (initial) cost i.e. by only $66.79. This slight difference may be attributed to the application of the half-year depreciation rule and straight-line amortization of embedded (initial) cost of the pole over its assumed 25-year useful life.

In summary, Nordicity has identified the following potential issues with the current OEB rate structure:

- It results in significant variation in rate from year to year, as shown in Table 8 above. That is, it results in very high rate in the initial years of poles useful life (e.g. annual indirect cost of $113.9 in Year 1, and $121.7 in Year 2) and an extremely low rate in the last years of poles' useful life (e.g. annual indirect cost of only $43.6 in Year 24, and $50.1 in Year 25). However, this issue could be addressed by ensuring an optimum average age of pole infrastructure is maintained through replacement of poles at a consistent year over year rate.[31]
- Application of the half-year depreciation rule in Year 1, and straight-line depreciation causes a slight understatement of revenue requirement on present value basis. However, this issue has negligible impact on the resulting pole attachment rate.

[31] Extraordinary, non-recurring expenditures such as disaster recovery due to major storms are difficult to forecast. Inclusion of any such cost in the regular rate only causes uncertainty. The recovery of such extraordinary expenditures may be made through ad hoc rate increases for a defined period of time, to be based on actual expenditure evidence submitted by the LDCs.

Table 9: 2005 OEB Model Present Value Analysis – Recovery of Initial Capital Cost

Year (N)	Embedded	Depreciation	Accumulated Depreciation	Net Embedded	Carrying Cost	Maintenance	Total Annual Cost	Investment Repayment	Present Value Factor	Present Value Factor
	A	B	C = C (Previous Year) + B	D = A - C	E = D x 11.42%	F	G = B + E + F	H = B + E	I = 1/(1+11.42%)^N	J = H x G
0	$ 777.75	-	-	$ 777.75	-	-	-		1.0000	-
1	$ 777.75	**$ 19.76**	$ 19.76	$ 757.99	**$ 43.28**	**$ 7.61**	**$ 70.65**	**$ 63.04**	0.8975	$ 56.58
2	$ 777.75	**$ 31.11**	$ 50.87	$ 726.88	**$ 83.01**	**$ 7.61**	**$ 121.73**	**$ 114.12**	0.8055	$ 91.93
3	$ 777.75	**$ 31.11**	$ 81.98	$ 695.77	**$ 79.46**	**$ 7.61**	**$ 118.18**	**$ 110.57**	0.7230	$ 79.93
4	$ 777.75	**$ 31.11**	$ 113.09	$ 664.66	**$ 75.90**	**$ 7.61**	**$ 114.62**	**$ 107.01**	0.6489	$ 69.44
5	$ 777.75	**$ 31.11**	$ 144.20	$ 633.55	**$ 72.35**	**$ 7.61**	**$ 111.07**	**$ 103.46**	0.5824	$ 60.25
6	$ 777.75	**$ 31.11**	$ 175.31	$ 602.44	**$ 68.80**	**$ 7.61**	**$ 107.52**	**$ 99.91**	0.5227	$ 52.22
7	$ 777.75	**$ 31.11**	$ 206.42	$ 571.33	**$ 65.25**	**$ 7.61**	**$ 103.97**	**$ 96.36**	0.4691	$ 45.20
8	$ 777.75	**$ 31.11**	$ 237.53	$ 540.22	**$ 61.69**	**$ 7.61**	**$ 100.41**	**$ 92.80**	0.4210	$ 39.07
9	$ 777.75	**$ 31.11**	$ 268.64	$ 509.11	**$ 58.14**	**$ 7.61**	**$ 96.86**	**$ 89.25**	0.3779	$ 33.72
10	$ 777.75	**$ 31.11**	$ 299.75	**$ 478.00**	**$ 54.59**	**$ 7.61**	**$ 93.31**	**$ 85.70**	0.3391	$ 29.06
11	$ 777.75	**$ 31.11**	$ 330.86	$ 446.89	**$ 51.03**	**$ 7.61**	**$ 89.75**	**$ 82.14**	0.3044	$ 25.00
12	$ 777.75	**$ 31.11**	$ 361.97	$ 415.78	**$ 47.48**	**$ 7.61**	**$ 86.20**	**$ 78.59**	0.2732	$ 21.47
13	$ 777.75	**$ 31.11**	$ 393.08	$ 384.67	**$ 43.93**	**$ 7.61**	**$ 82.65**	**$ 75.04**	0.2452	$ 18.40
14	$ 777.75	**$ 31.11**	$ 424.19	$ 353.56	**$ 40.38**	**$ 7.61**	**$ 79.10**	**$ 71.49**	0.2200	$ 15.73
15	$ 777.75	**$ 31.11**	$ 455.30	$ 322.45	**$ 36.82**	**$ 7.61**	**$ 75.54**	**$ 67.93**	0.1975	$ 13.42
16	$ 777.75	**$ 31.11**	$ 486.41	$ 291.34	**$ 33.27**	**$ 7.61**	**$ 71.99**	**$ 64.38**	0.1773	$ 11.41
17	$ 777.75	**$ 31.11**	$ 517.52	$ 260.23	**$ 29.72**	**$ 7.61**	**$ 68.44**	**$ 60.83**	0.1591	$ 9.68
18	$ 777.75	**$ 31.11**	$ 548.63	$ 229.12	**$ 26.17**	**$ 7.61**	**$ 64.89**	**$ 57.28**	0.1428	$ 8.18
19	$ 777.75	**$ 31.11**	$ 579.74	$ 198.01	**$ 22.61**	**$ 7.61**	**$ 61.33**	**$ 53.72**	0.1281	$ 6.88
20	$ 777.75	**$ 31.11**	$ 610.85	$ 166.90	**$ 19.06**	**$ 7.61**	**$ 57.78**	**$ 50.17**	0.1150	$ 5.77
21	$ 777.75	**$ 31.11**	$ 641.96	$ 135.79	**$ 15.51**	**$ 7.61**	**$ 54.23**	**$ 46.62**	0.1032	$ 4.81
22	$ 777.75	**$ 31.11**	$ 673.07	$ 104.68	**$ 11.95**	**$ 7.61**	**$ 50.67**	**$ 43.06**	0.0926	$ 3.99
23	$ 777.75	**$ 31.11**	$ 704.18	$ 73.57	**$ 8.40**	**$ 7.61**	**$ 47.12**	**$ 39.51**	0.0831	$ 3.29
24	$ 777.75	**$ 31.11**	$ 735.29	$ 42.46	**$ 4.85**	**$ 7.61**	**$ 43.57**	**$ 35.96**	0.0746	$ 2.68
25	$ 777.75	**$ 31.11**	$ 766.40	**$ 11.35**	**$ 1.30**	**$ 7.61**	**$ 40.02**	**$ 32.41**	0.0670	$ 2.17
26	$ 777.75	**$ 11.35**	$ 777.75	-	-	**$ 7.61**	**$ 18.96**	**$ 11.35**	0.0601	$ 0.68
Total		**$ 777.75**			**$ 1,054.95**	**$ 197.86**	**$ 2,030.56**	**$ 1,832.70**		**$ 710.96**

Theoretically, since both approaches use historical (actual - embedded) costs and the same economic parameters (carrying cost or cost of capital), they should produce the same outcome - full recovery of actual cost on a fair return standard. However, this only occurs if all factors are incorporated adequately. As illustrated in Table 10 below, the levelized cost approach provides a constant rate and certainty from year to year, and full cost recovery over 25 years (i.e. the present value of $777.75 exactly equates to the initial capital cost of the pole).

Table 10: Levelized Cost Base (Annual Indirect Cost per Pole)

Year (N)	Principal	Amortization	Accumulated Amortization	Principal Outstanding	Carrying Cost	Maintenance	Total Annual Cost	Investment Repayment	Present Value Factor	Present Value Factor
	A	B	C = C (Previous Year) + B	D = A - C	E = D x 11.42%	F	G = B + E + F	H = A ÷ sum(I)	I = 1/(1+11.42%)^N	J = H x G
0	$ 777.75	-	-	$ 777.75		-	-			
1	$ 777.75	**$ 6.38**	$ 6.38	$ 771.37	**$ 88.82**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.8975	$ 85.44
2	$ 777.75	**$ 7.10**	$ 13.48	$ 764.27	**$ 88.09**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.8055	$ 76.68
3	$ 777.75	**$ 7.92**	$ 21.39	$ 756.36	**$ 87.28**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.7230	$ 68.82
4	$ 777.75	**$ 8.82**	$ 30.21	$ 747.54	**$ 86.38**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.6489	$ 61.77
5	$ 777.75	**$ 9.83**	$ 40.04	$ 737.71	**$ 85.37**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.5824	$ 55.44
6	$ 777.75	**$ 10.95**	$ 50.99	$ 726.76	**$ 84.25**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.5227	$ 49.75
7	$ 777.75	**$ 12.20**	$ 63.19	$ 714.56	**$ 83.00**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.4691	$ 44.66
8	$ 777.75	**$ 13.59**	$ 76.78	$ 700.97	**$ 81.60**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.4210	$ 40.08
9	$ 777.75	**$ 15.14**	$ 91.92	$ 685.83	**$ 80.05**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.3779	$ 35.97
10	$ 777.75	**$ 16.87**	$ 108.80	$ 668.95	**$ 78.32**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.3391	$ 32.28
11	$ 777.75	**$ 18.80**	$ 127.60	$ 650.15	**$ 76.39**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.3044	$ 28.97
12	$ 777.75	**$ 20.95**	$ 148.54	$ 629.21	**$ 74.25**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.2732	$ 26.00
13	$ 777.75	**$ 23.34**	$ 171.88	$ 605.87	**$ 71.86**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.2452	$ 23.34
14	$ 777.75	**$ 26.00**	$ 197.89	$ 579.86	**$ 69.19**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.2200	$ 20.95
15	$ 777.75	**$ 28.97**	$ 226.86	$ 550.89	**$ 66.22**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1975	$ 18.80
16	$ 777.75	**$ 32.28**	$ 259.15	$ 518.60	**$ 62.91**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1773	$ 16.87
17	$ 777.75	**$ 35.97**	$ 295.12	$ 482.63	**$ 59.22**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1591	$ 15.14
18	$ 777.75	**$ 40.08**	$ 335.20	$ 442.55	**$ 55.12**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1428	$ 13.59
19	$ 777.75	**$ 44.66**	$ 379.85	$ 397.90	**$ 50.54**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1281	$ 12.20
20	$ 777.75	**$ 49.75**	$ 429.61	$ 348.14	**$ 45.44**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1150	$ 10.95
21	$ 777.75	**$ 55.44**	$ 485.04	$ 292.71	**$ 39.76**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.1032	$ 9.83
22	$ 777.75	**$ 61.77**	$ 546.81	$ 230.94	**$ 33.43**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.0926	$ 8.82
23	$ 777.75	**$ 68.82**	$ 615.63	$ 162.12	**$ 26.37**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.0831	$ 7.92
24	$ 777.75	**$ 76.68**	$ 692.31	$ 85.44	**$ 18.51**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.0746	$ 7.10
25	$ 777.75	**$ 85.44**	$ 777.75	($ 0.00)	**$ 9.76**	**$ 7.61**	**$ 102.80**	**$ 95.19**	0.0670	$ 6.38
Total		**$ 777.75**			**$ 1,602.12**	**$ 190.25**	**$ 2,570.12**	**$ 2,379.87**	8.1701	**$ 777.75**

In summary, a levelized approach would provide a practical solution for the OEB and other energy utility regulators to meet the criteria of fair return and revenue stability set out by Bonbright. Adoption of the levelized approach may not be consistent with the rate design methodology followed the OEB for other services. In this context, implementation of the levelized approach for pole attachment rate calculation would be a significant step and may increase the complexity of the overall rate design process within the OEB. However, the levelized approach would provide a practical solution for the OEB and other energy utility regulators to further validate their current methodology. This would ensure the rate outcome of the current process meets the principles of fair return and revenue stability as set out by Bonbright. That is, the levelized approach may be used as an additional step in the pole attachment rate determination process in order to ensure long term stability in rates. For example, if the levelized cost base, was used in the 2005 attachment rate would have been $24.43, instead of $22.35, shown below:

	Item	Amount	Reference
A	Levelized Annual Indirect (Common) cost per pole	$102.80	Table 10, Column “G”
B	Common Cost Allocation Ratio	21.9%	Table 5, Row "I"
C	**Indirect cost per telecom attacher**	**$22.51**	= B x C
D	Direct cost per attacher	1.92	Table 5, Row "C"
E	**2005 Rate (based on levelized cost)**	**$24.43**	= B x C

That is, a constant rate $24.43 could have been applied for all years over the useful life of poles. In contrast, using current (net embedded) cost approach the rate varies from year to year as shown Table 11 below:

Table 11: Year to Year Pole Attachment Rate (Based on 2005 OEB Rate Model)

Year (N)	Common Cost per Pole (see Table 9 Column F)	Allocation Rate (Table 5, Row "I" above)	Indirect Cost Per Attacher	Direct Cost Per Attacher (Table 5, Row "I" above)	Rate Per Attacher
	A	B	D = A x B	E	F = D + E
1	$ 70.65	21.9%	$ 15.47	$ 1.92	$ 17.39
2	$ 121.73	21.9%	$ 26.66	$ 1.92	$ 28.58
3	$ 118.18	21.9%	$ 25.88	$ 1.92	$ 27.80
4	$ 114.62	21.9%	$ 25.10	$ 1.92	$ 27.02
5	$ 111.07	21.9%	$ 24.32	$ 1.92	$ 26.24
6	$ 107.52	21.9%	$ 23.55	$ 1.92	$ 25.47
7	$ 103.97	21.9%	$ 22.77	$ 1.92	$ 24.69
8	$ 100.41	21.9%	$ 21.99	$ 1.92	$ 23.91
9	$ 96.86	21.9%	$ 21.21	$ 1.92	$ 23.13
10	$ 93.31	21.9%	$ 20.43	$ 1.92	$ 22.35
11	$ 89.75	21.9%	$ 19.66	$ 1.92	$ 21.58
12	$ 86.20	21.9%	$ 18.88	$ 1.92	$ 20.80
13	$ 82.65	21.9%	$ 18.10	$ 1.92	$ 20.02
14	$ 79.10	21.9%	$ 17.32	$ 1.92	$ 19.24
15	$ 75.54	21.9%	$ 16.54	$ 1.92	$ 18.46
16	$ 71.99	21.9%	$ 15.77	$ 1.92	$ 17.69
17	$ 68.44	21.9%	$ 14.99	$ 1.92	$ 16.91
18	$ 64.89	21.9%	$ 14.21	$ 1.92	$ 16.13
19	$ 61.33	21.9%	$ 13.43	$ 1.92	$ 15.35
20	$ 57.78	21.9%	$ 12.65	$ 1.92	$ 14.57
21	$ 54.23	21.9%	$ 11.88	$ 1.92	$ 13.80
22	$ 50.67	21.9%	$ 11.10	$ 1.92	$ 13.02
23	$ 47.12	21.9%	$ 10.32	$ 1.92	$ 12.24
24	$ 43.57	21.9%	$ 9.54	$ 1.92	$ 11.46
25	$ 40.02	21.9%	$ 8.76	$ 1.92	$ 10.68
26	$ 18.96	21.9%	$ 4.15	$ 1.92	$ 6.07

The resulting year-to-year pole attachment rates based on the 2005 OEB Rate Model are depicted in Figure 4, below.

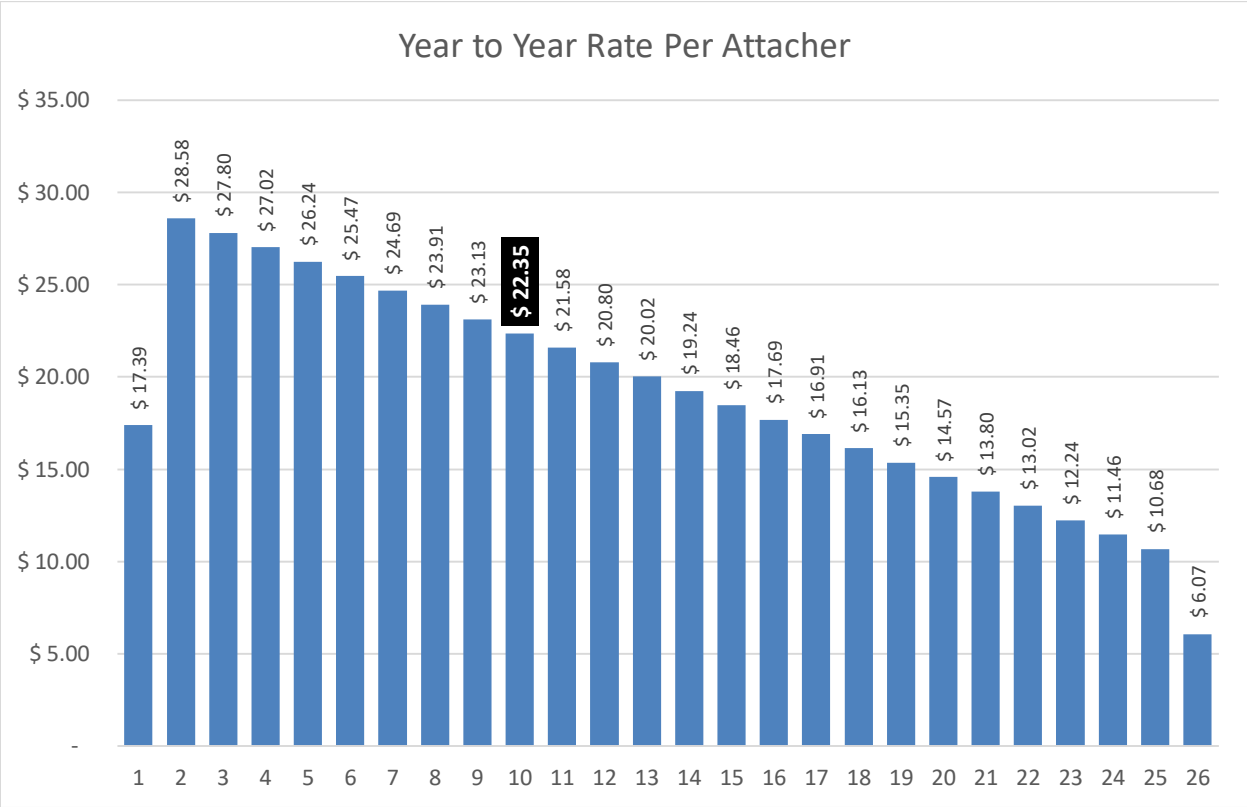


Figure 4: Year to Year Pole Attachment Rate (Based on 2005 OEB Rate Model)

The levelized cost approach may be used as a reference to avoid the possible rate variation - as shown in Table 11 and Figure 4 above. For example, based on levelized cost a constant (stable) rate of $24.43 could be maintained over the useful life of the pole. Using this rate as benchmark, the current OEB rate model could be modified to produce this rate. For instance, instead of using net embedded cost (gross book value less accumulated depreciation) for each year, net embedded cost may be estimated assuming on average the age of pole population is 75% of the total useful life[32] – some poles are newly installed, some are 10 years old, some have ended their useful life, and so forth. Accordingly, a constant rate using the current OEB Rate model may be developed. For example, Table 5 above may be revised as below:

[32] The 75% ratio may change depending on the applicable capital carrying cost rate.

Table 12: REVISED 2005 OEB Decision and Order – Cost Breakdown

	Price Component - Per Pole	$	Explanation
	DIRECT COST		
A	Administration Costs	$ 0.69	CRTC estimate 1999 $0.62, plus inflation
B	Loss in Productivity	$ 1.23	MEA estimate 1991 - $3.08, plus inflation, and divided between 2.5 pole attachers
C	Total Direct Costs	**$ 1.92**	A + B
	INDIRECT COST		
D	Net Embedded Cost per pole	**$583.31**	**= 75% x Embedded Cost $ 777.75 (Table 9, Column "A" above)**
E	Depreciation Expense	$ 31.11	Milton Hydro 1995 = $31.11
F	Pole Maintenance Expense	$ 7.61	Milton Hydro 1995 = $6.47, plus inflation
G	Capital Carrying Cost	$ 66.61	Pre-tax weighted average cost of capital 11.42% applied to net embedded cost per pole (D)
H	Total Indirect Costs per Pole	**$ 105.33**	E + F + G
I	Allocation Factor	21.9%	Allocation based on 2.5 attachers
J	Indirect Cost Allocated	$ 23.07	H x I
K	Annual Pole Rental Charge	**$ 24.99**	C + J

3 Wireline Pole Infrastructure in Ontario

In this section, key trends in pole infrastructure in the province over the last 10 years and the standard specifications for attachment rate-making are discussed.

3.1 Pole Population and Key Trends

The average age of poles and the number of new poles versus replacements are key parameters in determining the capital cost base of a pole. Some stakeholders have questioned the appropriate methodology for calculating the average age of poles and whether the number of pole replacements has in fact, increased in response to intensified third party use of poles. Analysis of historical trends provides a framework to examine these issues.

In response to Nordicity's data request, five LDCs (Toronto Hydro, Hydro One, Horizon, London Hydro, and Hydro Ottawa) provided their installed poles data from 2005 to 2015[33], which is summarized in Table 13 below.

[33] CHEC did not respond to Nordicity's data request for pole population. Toronto Hydro only provided pole population data, excluding attachments data as requested.

Table 13: LDCs' Total Installed Poles in Ontario

Year	Toronto Hydro	London Hydro	Ottawa Hydro	Hydro One	Horizon	Total (2)
2005	159,000	27,700	44,600	1,451,344	n/a	1,682,644
2006	190,816	27,860	46,761	1,463,344	n/a	1,728,781
2007	181,397	28,000	51,582	1,475,344	n/a	1,736,323
2008	142,300	28,000	49,201	1,487,344	52,332	1,759,177
2009	140,771	28,698	48,699	1,499,344	52,146	1,769,658
2010	139,842	29,424	48,574	1,511,344	52,146	1,781,330
2011	140,641	29,384	48,377	1,523,344	52,163	1,793,909
2012	135,986	28,345	48,298	1,535,344	52,031	1,800,004
2013	135,986	27,980	47,978	1,547,344	51,615	1,810,903
2014	135,986	27,680	47,825	1,559,522	51,418	1,822,431
2015	137,172	27,184	48,384	1,571,384	51,390	1,835,514
Average	149,082	28,205	48,207	1,511,364	51,905	1,774,607
CAGR(1)	**-1.47%**	**-0.19%**	**0.82%**	**0.80%**	**-0.26%**	**0.87%**

(1). CAGR: Compound Annual Growth Rate
(2). The "Total" represents the total of pole data submitted by LDCs as above, which approximately represent 97% of the installed LDC poles in the province of Ontario

Overall, total poles increased from 1,682,644 in 2005 to 1,835,514 in 2015, an increase of only 152,870 poles over 10 years, which is less than one percent (0.87%) from year to year. In two cases, the population decreased – Hydro One (-1.47%), and London Hydro (-0.19%). These trends imply that since the 2005 Decision, there has been no significant growth in the pole population which would have caused significant variation in the capital cost base of the poles. **Nordicity believes any material variation in the average installed cost per pole is mainly due to replacements rather than net growth in the poles infrastructure in the province**.

It is worth noting that advancements in technology, such as horizontal direction drilling (HDD), in the past 10 years have enabled more efficient and cost effective deployment of buried/conduit cable. For example, carriers are increasingly relying on HDD techniques in their new fibre-to-the-home (FTTH) projects.

Based on the 10-year (2005-2015) simple average pole population, 92.8% of the total LDC pole population is owned by just two LDCs: Hydro One (84.5%) and Toronto Hydro (8.3%), as shown in Figure 5 below[34]. It is worth noting that with the addition of the next three LDCs: Hydro Ottawa, Horizon and London Hydro, these five LDCs represent over 95% of the total pole population in the province.

[34] CHEC did not respond to the data request, therefore not included in the pole population distribution shown in Figure 5

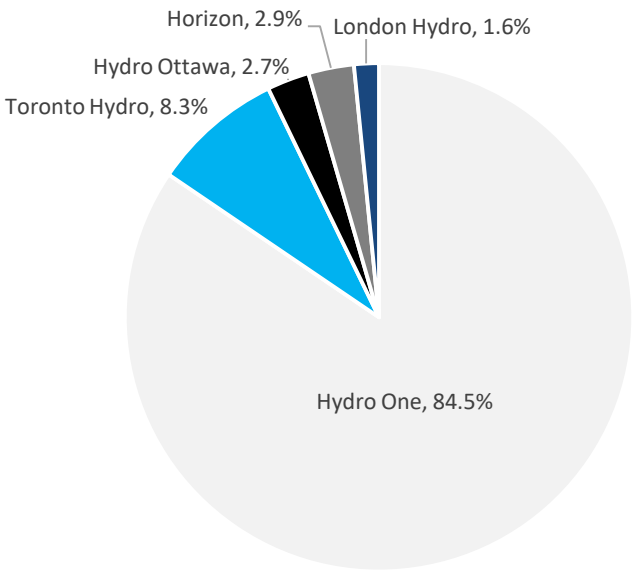
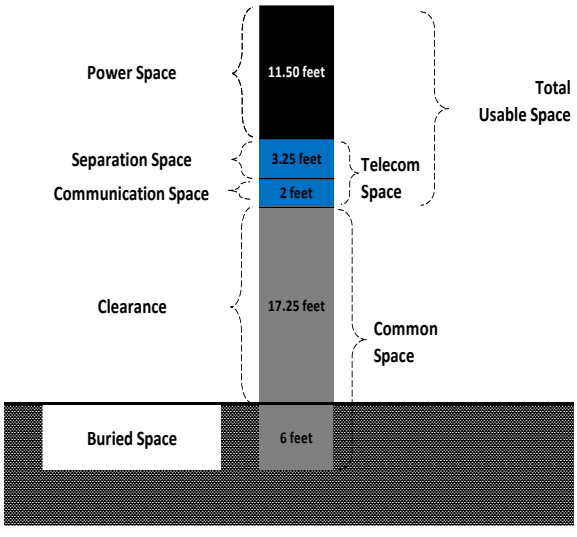


Figure 5: Average Pole Population by LDCs

3.2 Standard Pole Specification

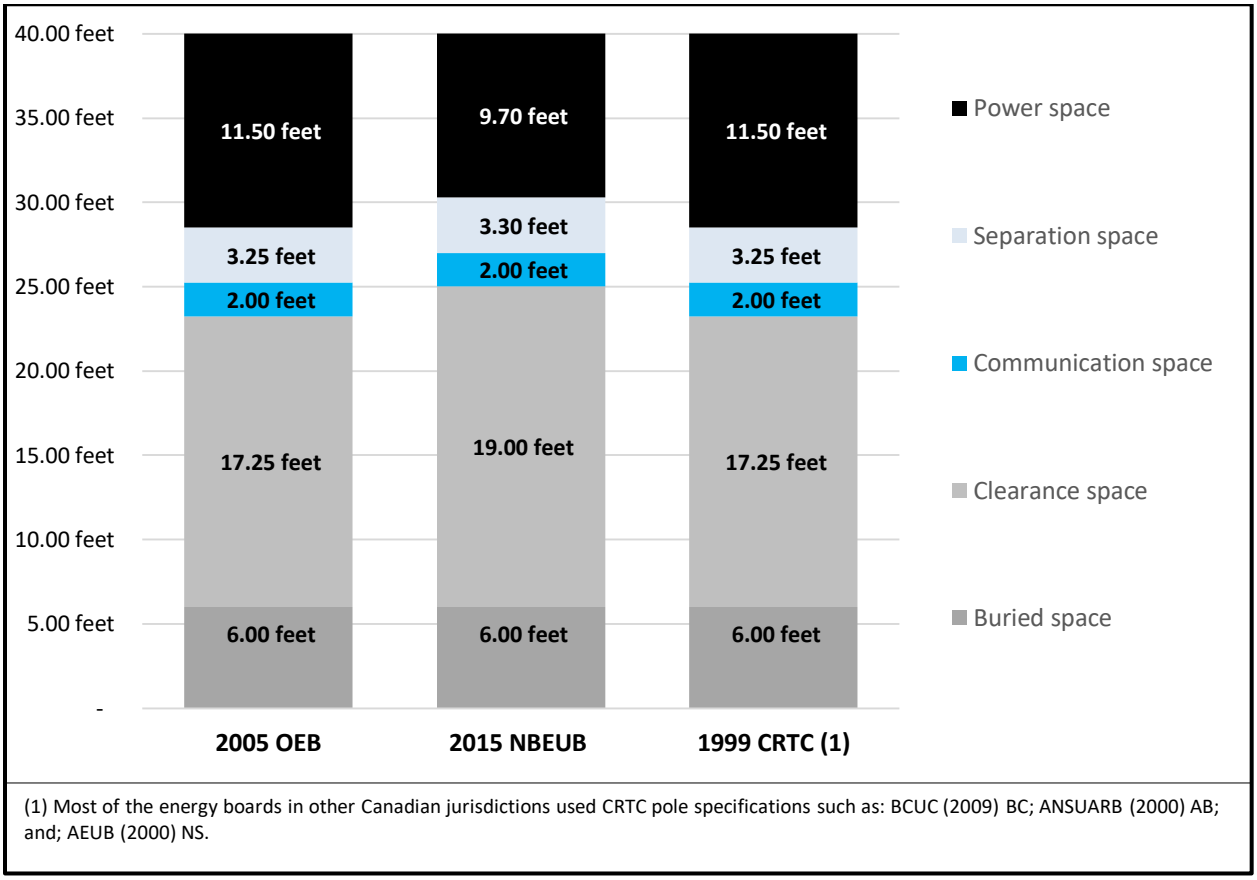
The 2005 OEB Decision was based on pole specifications, proposed by the Canadian Cable Television Association (CCTA), as shown in Figure 6 below:



	Feet
Power Space	**11.50**
Separation Space	3.25
Communication Space	2.00
Telecom Space	**5.25**
Total Usable Space	**16.75**
Clearance Space	17.25
Buried Space	6.00
Total Common Space	**23.25**
Total	**40.00**

Figure 6: Pole Specification used in 2005 OEB Rate Order

Other Canadian jurisdictions in their determinations also used an overall 40-foot pole height, with some minor variations in the different space areas, as shown in Figure 7 below:



(1) Most of the energy boards in other Canadian jurisdictions used CRTC pole specifications such as: BCUC (2009) BC; ANSUARB (2000) AB; and; AEUB (2000) NS.

Figure 7: Pole Specifications Used in Different Canadian Jurisdiction

During the consultation process, participating LDCs were requested to provide pole related data as a follow up to the 1st PAWG meeting. The purpose of this data request was to confirm whether the 40 feet pole size as shown in Figure 6 above fairly represents a standard pole in Ontario for rate making.

Table 14: Average Pole Specifications based on LDCs' Actual Data[35]

Pole Size (Feet)	Based on all Pole Classes						Joint Use Poles	
	Power Space (Feet)	Separation Space (Feet)	Communication Space (Feet)	Clearance Space (Feet)	Buried Space (Feet)	Total (Feet)	Total (Number)	%
30	3.86	2.87	1.90	14.91	4.95	28.50	61,047	8.8%
35	7.83	3.02	2.00	15.18	6.30	34.33	185,504	26.7%
40	11.77	3.22	2.00	14.56	7.17	38.73	192,239	27.7%
45	15.44	3.17	2.54	14.05	9.59	44.79	144,984	20.9%
50	20.96	3.33	2.00	13.99	8.77	49.06	46,437	6.7%
55	26.45	3.05	2.00	16.00	7.50	55.00	31,490	4.5%
60	30.64	3.08	2.00	16.28	8.00	60.00	18,725	2.7%
65	34.26	3.06	2.00	16.13	8.59	64.04	8,695	1.3%
70	38.79	3.08	2.00	17.13	9.00	70.00	3,086	0.4%
75	43.58	3.16	2.00	16.75	9.50	74.99	1,608	0.2%
80	47.50	3.23	2.00	17.25	10.00	79.98	451	0.1%
Other	n/a	n/a	n/a	n/a	n/a	n/a	3,089	0.4%
Total	13.08	3.12	2.10	14.76	7.42	40.49	693,815	100%
Sample (1)	11.39	3.14	2.15	14.64	7.53	38.85	522,727	75%
2005 OEB	11.50	3.25	2.00	17.25	6.00	40.00		

(1) Sample includes pole sizes of 35, 40, and 45 feet, which represent 75% of the total joint use poles shown above

According to Table 14 above, the average height of joint use poles is 40.49 feet, which is consistent with the 2005 OEB Decision. However, there are some differences in the space segments as noted below:

- Differences in separation space (3.25 vs. 3.12 feet), and communication space (2.00 vs. 2.1 feet) are minor;
- In case of power space, and buried space, actual averages are higher respectively by 1.6 feet (power space 11.5 vs. 113.08 feet), and 1.4 feet (buried space 6.00 vs. 7.42 feet); and,
- In the case of clearance space, there is a difference of 2.5 feet between the 2005 Order (17.25 feet) as compared to actual average (14.76 feet).

However, these differences are minimized if the calculation of the average is based on a 35, 40, and 45 feet (normal) size sample, which represents 75% of the above total pole population.

This analysis was presented to PAWG members in the second PAWG meeting on July 27, 2016. The participants agreed to maintain the pole specifications used in 2005 OEB Decision for the pole attachment rate calculation framework, as discussed in the next section.

[35] Includes pole data submitted by Hydro One, Hydro Ottawa, London Hydro, and Horizon. CHEC and Toronto Hydro did not respond to this data request.

4 Policy Attachment Rate Policy Framework

In the first PAWG meeting on May 20, 2016 Nordicity presented an overarching framework for the development of a pole attachment rate. The proposed framework is comprised of three key elements, as shown in Figure 8 below.

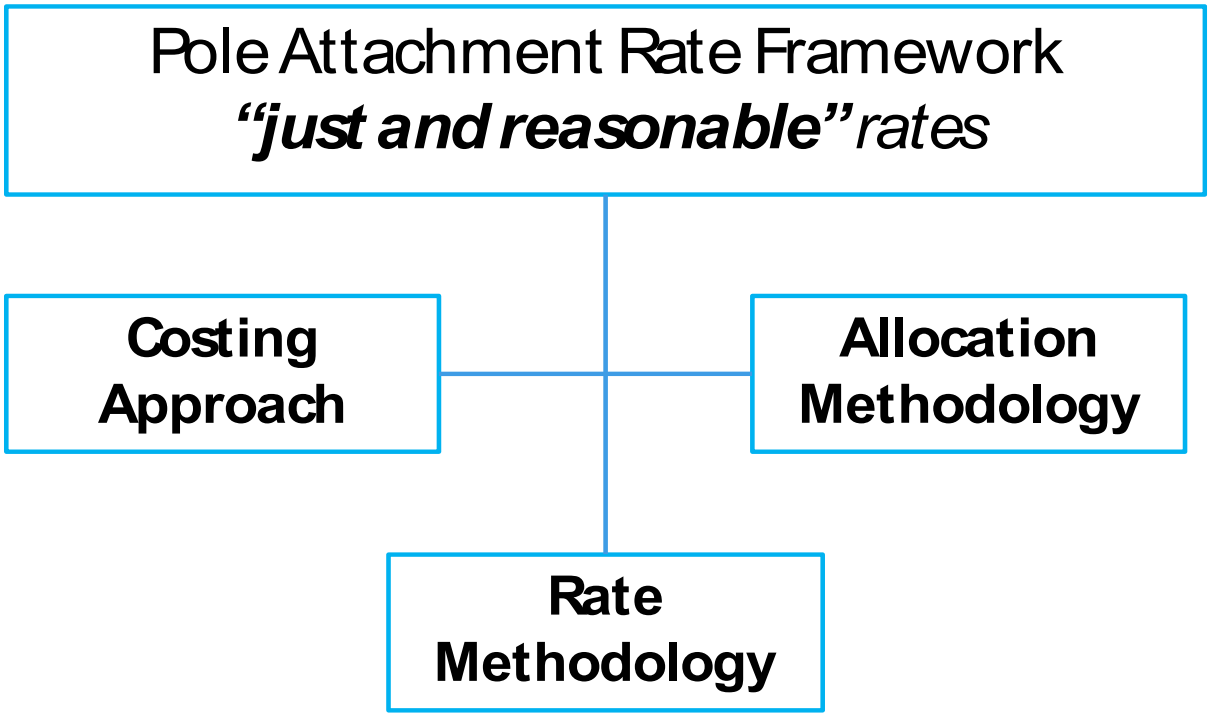


Figure 8: Key elements of pole attachment rate framework

It is worth noting that the above framework was used as a reference point for discussion in all the three subsequent three PAWG meetings. The three key elements of the rate framework are discussed in the following sections.

4.1 Costing Approach

The following three costing approaches may be considered for determining the common cost base for a pole attachment rate calculation:

- **Historical Cost**: Refers to the original or actual (book value) of the costs of poles operated by the LDC. Since the rate is determined for future years, this cost base may include budgeted estimates for the next two to three years. The budget estimates are normally based on historical cost trends and represent planned replacements of poles, as well as maintenance and repair expenditures.

- **Forward-looking/replacement cost:** Refers to the replacement cost of poles to service current and/or future volumes. The cost estimates may be based on a five to seven year forecast. This approach is useful if significant changes in cost structure and/or demand are anticipated in future.
- **Standard Cost (Benchmarking):** Refers to the cost of poles based on the industry's normal cost structure in comparable jurisdictions - excluding extraordinary costs such as disaster-recovery costs. This approach may be useful to determine a province-wide rate, assuming no major differences in the cost structure of poles operated by individual LDCs. This approach may also be useful in the following situations:

  (a) if reasonable cost estimates are not available for the LDCs operating in the province; and/or

  (b) actual costs across LDCs vary significantly due to differences in their respective accounting practice.

Table 6, above, indicates the costing approach used in different decisions in Canadian jurisdictions, which is primarily historical. It is pertinent to note that the trends in cost structure may lead different pole user groups to argue for a different costing approach. This issue has been noted by Tardiff in his paper *"Prices based on current or historical cost: How different are they?*" in the following word:[36]

> *"Parties advocating low rates favored replacement cost when equipment costs were expected to decrease, but original costs when such asset prices would be expected to increase"*

Tardiff further noted:

> *"……because the costs of acquiring, placing, and maintaining utility poles and conduit tend to increase over time because of their relatively low technology-intensity and relatively high labor-intensity, the use of historical cost pricing was widely believed to produce lower rates than would the use of current cost-based pricing"*[37]

In this context, it is important to note that historical cost would result in a significant understatement of rate in a scenario where:

i) The pole costs are significantly increasing due to inflationary factors such as increasing costs of material and labour, or new public safety and environment standards, regulations and by-laws; and,

ii) Major pole replacements are expected in the near future (next three to five years) due to aging of the pole infrastructure.

[36] Tardiff, J. T., "*Prices based on current or historical cost: How different are they?*", Journal of Regulatory Economics, Issue 47, 2015, p. 201
[37] Tardiff, J. T., "*Prices based on current or historical cost: How different are they?*", Journal of Regulatory Economics, Issue 47, 2015, p. 203

4.2 Allocation Methodology

After the cost base is ascertained, the next step in rate-making is to determine the appropriate approach to allocate costs associated with the common space of the pole (such as buried space and common space) between the two groups of attachers: telecom and power[38]. The following three approaches have been identified in the literature to allocate common costs of the pole:

1) **Proportionate**: This approach is based on the ratio of usable space (i.e. power space and communication space) used by the respective attacher groups. For illustration purposes, let's assume a total usable space of 10 feet which is comprised of 7 feet for power attachers and 3 feet for telecom attachers, and 30 feet of common space. Based on a proportionate allocation, then 9 feet [= (3÷10) x 30], or 30% of common cost is allocated to the telecom users. If there are two telecom attachers then 4.5 feet = 9 feet ÷ 2, or 15% is the ratio that will be used to allocated common cost to the individual telecom attacher. The NBEUB 2015 decision is a recent example of proportionate methodology, as shown in Table 15, below.

Table 15: **Illustration of Proportionate Use Methodology (2015 NBEUB Decision - NB Power)**

		Joint Pole Length (feet)		Attachers		Length Per Attacher (ft.)	Explanation
A	Power space	9.70	÷	1.00			A
B	Communication space	**2.00**	÷	**1.40**	=	1.43	B
C	Separation space	**3.30**	÷	**1.40**	=	2.30	D
D	**Total Usable Space**	**15.00**		**2.40**		**3.73**	**= A + B + C**
E	Clearance	19.00					E
F	Buried	6.00					F
G	**Total Common Space**	**25.00**					**= D + E + F**
H	**Total Pole Length**	**40.00**				**3.73**	**= D + G**
I	Allocation Rate					**25.2%**	= [(2+3.3) ÷ 15.0] ÷ 1.4
J	**Common Cost**	**$ 79.91**				**$ 20.15**	= $79.91 X 25.2%
K	**Direct Cost (Admin)**					**$ 0.62**	
L	**Total Rate**					**$ 20.77**	= J + K

In this regard, the NBEUB Decision noted:

> "*The proportionate sharing model, proposed by Rogers, recognizes the practical and economic*

[38] Separation space is generally considered as part of communication space since it is required (causal) to provide for communication space in conformance with the safety standards of the province. However, Rogers (a carrier) in the PAWG third meeting (November 24, 2016) raised the issue that the separation space should be equally divided if an equal sharing approach is used to allocate common cost.

disparities between NB Power, as pole owner, and third party attachers. Third party communications attachers do not have the rights of ownership of the pole. They are required to apply through an intermediary to gain attachment access. The evidence indicates that they are generally allocated the less desirable field side of the pole. Economic efficiency dictates that paying a reasonable rate on another party's joint-use pole network is preferred over building a stand-alone system. Further, the Board is not convinced, as Dr. Mitchell suggested, that all users or potential users of joint-use poles are established utilities with substantial revenues." Para [93]

The NBEUB in para [94] of its Decision made the following determination:

"The Board recognizes that all of the cost allocation methodologies reviewed above can be viewed as yielding fair rates. For the reasons outlined above, the Board prefers the proportionate sharing of common costs as the most appropriate methodology for the allocation of common costs between NB Power and third party attachers."

2) **Equal Sharing:** This approach allocates common costs of the pole equally between the two attacher groups (power and telecom). To illustrate this approach, the same example as above is used assuming a total usable space of 10 feet, which is comprised of 7 feet for power attachers and 3 feet for the telecom attachers, as well as 30 feet of common space. Using this example, the equal sharing approach may be applied in two ways, as follows:

   i) The first approach allocates the common space equally among all the combined number of attachers including power and telecom. That is, based on the example in 1) above, if there are three attachers (1 power + 2 telecom), each of the three attachers is allocated 10 feet (=30 feet ÷ 3), or 33% of the common space. The 2005 OEB Decision is based on this approach as illustrated in Table 16 below.

Table 16: Illustration of Equal Sharing Allocation Methodology (2005 OEB Order)

		Joint Pole Length (ft.)		Attachers		Length Per Attacher (ft.)	Explanation
A	Power space	11.50	÷	1.00			A
B	Communication space	**2.00**	÷	**2.50**	=	0.80	B
C	Separation space	**3.25**	÷	**2.50**	=	1.30	C
D	Total Usable Space	**16.75**		**3.50**		2.10	= A + B + C
E	Clearance	17.25					E
F	Buried	6.00					F
G	Total Common Space	23.25		3.50		6.64	= D + E + F
H	Total Pole Length	40.00				8.74	= D + G
I	Allocation Rate					**21.9%**	= 8.74 ÷ 40.0
J	Common Cost	**$ 93.31**				$ 20.43	= $93.21 X 21.9%
K	Direct Cost (Admin & LOP)					$ 1.92	
L	Total Rate					**$ 22.35**	= J + K

   ii) The second approach is a hybrid between "Equal Sharing" and "Proportionate Use" approaches, with 50% or 15 feet (= 30 ÷ 2) of the common space allocated equally to each of the two user groups (power and telecom). If there are two telecom attachers then 7.5 feet (= 15 feet ÷ 2), or 25% of the total common space is allocated to the individual telecom attacher. This application

of hybrid equal sharing is a novel approach proposed by Nordicity and has not been applied by any Canadian jurisdiction to the best of Nordicity's knowledge.

iii) Another variation of equal sharing methodology is the approach submitted by TransAlta in the 2000 Alberta Energy and Utilities decision (EUB Decision 2000-86 dated December 27, 2000). In this case, TransAlta submitted that the allocation methodology be based on a simplified hypothetical system where each utility constructs its own system without regard for existing facilities. TransAlta submitted that based on this approach each of the telephone and cable utilities accounted for 36% of the $51 total embedded cost per pole. The calculation of the 36% ratio was based on TransAlta's consideration of the following factors:

- TransAlta required longer poles than telephone or cable companies;
- TransAlta was prepared to bear a higher than average share of the costs;
- In areas where only TransAlta and one other party were present (telephone or cable), TransAlta accounted for 54% of the total cost and the other party accounted for 46% of the total cost; and
- In an area where TransAlta and two other parties were present (telephone and cable), TransAlta accounted for 38% of the cost while telephone and cable each accounted for 31% of the total cost.

The Alberta Energy and Utilities Board determined that shared-use poles are of a greater height and strength than single-use poles, and TransAlta's allocation of 36% of the $51 embedded cost per pole per year was reasonable. Since this allocation is based on a hypothetical scenario of three pole infrastructure systems (power, telephone, and cable), it lacks practicability and objectivity, particularly in jurisdictions such as Ontario where there are multiple electricity distribution utilities.

3) **Incremental:** This approach is based on the principle that the cost attributable to telecom attachers is the incremental annual cost per pole that is associated with the provision of additional space for telecom attachers on an LDC pole. For example, if a typical power-only (single attacher) pole height is 36 feet, and the LDC installs a 40-foot pole (instead of 36 feet) to accommodate telecom attachers, then under the incremental costing approach, the annual costs causal to the provision of the additional 4 feet is attributable to the telecom attachers. Although this approach has been discussed in different proceedings, it has not been implemented to date for pole attachment rates to the best of Nordicity's knowledge.

The major limitation associated with this approach is that the proponents (third party attachers) of this methodology overlook the issue of cross-subsidization. To illustrate the cross-subsidization issue Nordicity assumes the following hypothetical example:

- $80 is the cost of a dedicated pole of a telecom attacher
- $100 is the cost of dedicated pole of a power attacher (power poles require additional strength)
- $120 is the cost of a joint-use pole (power and telecom attachers) owned by an electric utility.

The proponents of the incremental costing approach would argue that telecom attacher should pay for the incremental cost of $20, which represents the cost of additional space to accommodate telecom attachers on an electric utility pole. However, the implication is that a telecom attacher using a joint-use pole avoids incurring a cost of $80, which only benefits their customers at the expense of electric utility customers. That is, it results in cross-subsidization of pole costs by electric utility customers.

In the 2000 Alberta Energy and Utilities Board decision (EUB Decision 2000-86 dated December 27, 2000), TELUS (telecom attacher) argued for incremental costing, which was opposed by TransAlta on the grounds that it can result in cross-subsidization. The Alberta Energy and Utility Board determined it reasonable that those customers (i.e. the telecommunications carriers and cable operators) that benefit from the use of TransAlta's distribution poles should pay an appropriate rate so that TransAlta's other customers do not incur or cross-subsidize this additional cost[39].

4.3 Rate Methodology

It is apparent from the preceding section (also see tables 15 and 16) that the number of attachers (also referred to as "users") is critical in the final rate outcome. The first issue in this regard is to determine whether a rate should be based on:

4) The number of attachers (users), or

5) The number of attachments

An attacher is referred to as an entity (firm) that is attached to an LDC pole. It is worth noting that the attachers can have more than one attachment. In addition, an attacher may also be hosting attachments of other entities, referred to as "overlashing. Overlashing, in certain cases is an effective way of efficiently accommodating additional attachments, particularly where space is limited.

In the second data request issued in June 2016, as part of the PAWG consultation process, LDCs (*Hydro One*, *Hydro Ottawa*, *Toronto Hydro*, *London Hydro*, *Horizon*, and *CHEC members*) were requested to provide data on the number of attachments. No response was received from the LDCs. According to Hydro One's response "*Hydro One will not be able to complete this tab* [attachment data request] *as Hydro One tracks permitted attachments on Hydro One owned poles using a data base that is not GIS related."*

Based on the responses received and feedback provided by LDCs during the second PAWG meeting on July 27th, 2016, it would appear at least for certain LDCs that current information systems do not have the capability to track and provide the number of attachments on an LDCs' poles. The magnitude of investment required to implement systems and processes to enable the tracking/counting of the number of attachments on their poles is yet to be determined.

[39] AEUB Decision 2000-86 (December 27, 2000), p. 20

Absent a count of the number of attachments, the alternative methodology is to continue with the status quo of using the number of attachers, which has been commonly used in pole attachment rate determinations. With the number of attachers, there are two approaches that can be used in the application of this methodology:

a) Presumptive Number of Attachers

This refers to the number of attachers assumed in the rate calculation in the absence of information required to determine the actual number of attachers for a certain service area. For example, US Federal Communications Commission (FCC) established rebuttable presumptive average numbers of attaching entities (attachers) for two categories, as below[40]:

- 3 attaching entities (attachers) for non-urbanized areas (less 50,000 population), representing *electric*, *telephone*, and *cable* attachers
- 5 attaching entities (attachers) for urbanized areas, representing *electric*, *telephone*, *cable*, *competitive telecommunications service providers,* and *governmental agencies*[41].

Taking a similar approach, the OEB in its 2005 Order determined the average number of telecom attachers to be 2.5, (instead of 2 which had been assumed in previous CRTC decisions): "*The OEB considers 2.5 attachers to be reasonable. Things have changed since the days of the CRTC decision. If anything, there will be more than 2.5 attachers in the future"* (OEB 2005 Order, p. 7).

b) Actual Number of Attachers.

An alternative approach is to determine the actual number of attachers. However, this depends on the availability of consistent, reliable and verifiable actual data across all LDCs in the province. It is worth noting the FCC's explanation regarding its rebuttable presumptive average number of attachers approach. The FCC explained that: "*As with all our presumptions, either party may rebut this presumption with a statistically valid survey or actual data*" (FCC 01-170, 2001, paragraph 70, p. 39).

Subsequently, after considering rebuttals the FCC acknowledged that a gap existed between its presumptive average 5 (urbanized) and 3 (non-urbanized) attachers and the average based on an actual count of attachers. Accordingly, the FCC in its November 24, 2015 Order (FCC 15-151) expanded its presumptive average attachers definition according to service area categories, instead of urbanized and non-urbanized[42]. The FCC's expanded presumptive attachers' averages by service areas currently include 5, 4, 3, and 2 attaching entities.

[40] See "CONSOLIDATED PARTIAL ORDER ON RECONSIDERATION" FCC 01-170, May 25 2001, paragraphs 69-72, p.39-40
[41] "The record supports a presumptive average number of five attachers in urbanized areas" (FCC 01-170, 2001, para 72, p.40)
[42] "Specifically, we add cost allocators for poles with 2 and 4 attaching entities to augment the current cost allocators that target poles with 3 and 5 attaching entities. We also provide that, for fractional attaching-entity averages, cost allocators are to

In its recent decisions, the OEB has relied on the actual attacher count evidence submitted by LDCs[43]. For example, in its February 2016 Hydro Ottawa decision (EB-2015-0141), the OEB determined that an average of 1.74 telecom attachers (excluding power) per pole submitted by Hydro Ottawa based on an actual count was appropriate. Previously, the New Brunswick Energy and Utilities Board (NBEUB) in its 2015 (matter no. 272) Decision accepted NB Power's calculation of 2.4 (including power) attachers. NBEUB in its decision noted that "This [2.4 attachers] represents the quotient of the total number on its poles, divided by the number of NB Power joint-use poles"

Based on the above three precedents (FCC, OEB, NBEUB), it can be reasonably argued that it is more appropriate to base the calculation on the total number of joint use poles with an actual number of attachers instead of a presumptive average of attachers - subject to satisfying the following criteria[44]:

- the actual average number of attachers estimate/calculation is based on reasonably reliable and verifiable data;
- the actual average number of attachers justly and reasonably represents the specific usage of individual attachers; and;
- the actual average number of attachers calculation is relatively consistent across all LDCs in the province.

In this context, LDCs were requested to provide attacher data, following the May 20, 2016 PAWG first meeting. London Hydro, Hydro Ottawa, and Horizon submitted the data in accordance with the specified format, which is summarized in Table 17 below.

be interpolated from the whole-number cost allocators." (FCC 15-151, 2015, paragraph 16, p. 8)

[43] The Board relied on its 2005 Order, that provided for that "Any LDC that believes that the province-wide rate is not appropriate can bring an application to have the rates modified based on its own costing" (p. 8).

[44] Some may further argue that the actual average number must meet the market test – that is the number must reasonably reflect the general business environment. For example, typically a joint use pole would include at least two attachers: power (LDC), and telco (ILEC). With presence of cablecos in certain geographies (e.g. urbanized areas), the joint-use pole is likely to have at least 3 three attachers in certain parts of the province. With the emergence of CLECs (competitive communication service providers), and the attachment of street lights in certain parts of the province, the actual attacher count may be 4 to 5.

Table 17: Average Attachers per Pole (excluding Hydro One)

Pole Size (Feet)	London Hydro				Hydro Ottawa				Horizon				Province (excl. Hydro One)			
	Poles		Total Attachers	Attachers per Pole	Poles		Attachers	Attachers per Pole	Poles		Attachers	Attachers per Pole	Poles		Attachers	Attachers per Pole
30	2,149	8%	2,822	1.31	1,472	3%	2,626	1.78	3,623	7%	9,414	2.60	7,244	6%	14,862	2.05
35	**4,937**	**18%**	**9,041**	**1.83**	**6,078**	**13%**	**12,412**	**2.04**	**12,931**	**26%**	**30,879**	**2.39**	**23,946**	**19%**	**52,332**	**2.19**
40	**4,836**	**18%**	**10,929**	**2.26**	**10,650**	**22%**	**22,867**	**2.15**	**11,500**	**23%**	**29,968**	**2.61**	**26,986**	**22%**	**63,764**	**2.36**
45	**5,831**	**21%**	**13,113**	**2.25**	**12,268**	**25%**	**26,811**	**2.19**	**11,513**	**23%**	**34,905**	**3.03**	**29,612**	**24%**	**74,829**	**2.53**
50	3,243	12%	9,775	3.01	5,168	11%	10,757	2.08	6,508	13%	21,336	3.28	14,919	12%	41,868	2.81
55	3,931	14%	11,318	2.88	3,619	8%	8,234	2.28	2,977	6%	10,466	3.52	10,527	8%	30,018	2.85
60	1,701	6%	2,603	1.53	4,098	8%	9,861	2.41	595	1%	1,895	3.18	6,394	5%	14,359	2.25
65	393	1%	681	1.73	1,271	3%	2,874	2.26	73	0%	257	3.52	1,737	1%	3,812	2.19
70	139	1%	216	1.55	373	1%	780	2.09	11	0%	35	3.18	523	0%	1,031	1.97
75	24	0%	40	1.67	132	0%	224	1.70	3	0%	6	2.00	159	0%	270	1.70
80	-	0%	-	n/a	33	0%	50	1.52	-	0%	-	n/a	33	0%	50	1.52
Other	-	0%	-	n/a	3,090	6%	3,375	1.09	-	0%	-	n/a	3,090	2%	3,375	1.09
Sample	**15,604**	**57%**	**33,083**	**2.12**	**28,996**	**60%**	**62,090**	**2.14**	**35,944**	**72%**	**95,752**	**2.66**	**80,544**	**64%**	**190,925**	**2.37**
Total	**27,184**	**100%**	**60,538**	**2.23**	**48,252**	**100%**	**100,871**	**2.09**	**49,734**	**100%**	**139,161**	**2.80**	**125,170**	**100%**	**300,570**	**2.40**

- Sample attachers per pole is based on weighted average of joint use pole sizes 35, 40, and 45 feet, which represent 75% of the total
- Total attachers per pole is based on weighted average of joint use poles of all sizes listed above.

According to Table 17 above, the average number of attachers per pole is estimated at 2.4, based on data provided by Hydro Ottawa (2.09), London Hydro (2.23), and Horizon (2.80). These are overall attacher averages including 1 for power space and 1.4 for telecom space, excluding Hydro One.

Toronto Hydro and CHEC did not submit the attachment data. Hydro One indicated that it does not track attachment data by pole size. However, based on the billing data, Hydro One provided a summary of its attachment data i.e. total number of attachments and poles. If Hydro One's summary of attachments is incorporated, the overall average attachment per pole reduces to 2.3, instead of 2.4 as shown in the Table 18, below.

Table 18: Average Attacher per Pole (including Hydro One)

		Hydro One		Other		Total	
Number of Poles							
A	Power only	1,001,477	64%	138,960	53%	1,140,437	62%
B	Joint Use	572,185	36%	125,170	47%	697,355	38%
C = B + C	Total	**1,573,662**	100%	**264,130**	100%	**1,837,792**	100%
Attachers							
D = C	Power	1,573,662	68%	264,130	60%	1,837,792	67%
E	Telecom + Other	733,753	32%	175,400	40%	909,153	33%
F = D + E	Total	**2,307,415**	100%	**439,530**	100%	**2,746,945**	100%
Average Attacher Per Pole							
G = E / B + 1	per Joint Use Poles	2.28		2.40		2.30	
H = F / C	per All Poles	1.47		1.66		1.49	

The analysis provided in Tables 17 and 18 above was presented at the PAWG's second July 27th, 2016 (2nd) and third November 24th, 2016 (3rd) meetings for feedback and comments. It is worth noting, as stated above, 1.3 average attacher (excluding power) shown in Table 18 above are based on poles data submitted by the four participating LDCs, including Hydro One, Hydro Ottawa, London Hydro, and Horizon

5 Determining Average Annual Common (Indirect) Cost per Pole

As shown in Figure 6 above, a pole is comprised of three main sections – common space, communication space, and power space. Power and communication spaces are referred to as usable space. The two broad categories of costs associated with these sections include:

a) Capital Cost: Refers to the capitalized cost of a pole, which includes items such as the initial installation cost of a pole, replacements, capitalized upgrades, and capitalized repairs, if any.

b) Expenses: Primarily refers to ongoing maintenance and repair of poles.

Nordicity understands that these costs are recorded in the following three Uniform System of Accounts (USoA) accounts as specified in the OEB 2012 Accounting Procedures Handbook (APH):

i) Account # 1830: Poles, Towers, and Fixtures (Capital Cost)

ii) Account # 5120: Maintenance of Poles, Towers and Fixtures

iii) Account # 5135: Overhead Distribution Lines and Feeders - Right of Way

Detailed descriptions of these accounts are provided in the OEB's APH and are reproduced in appendices A1, A2, and A3. According to the account descriptions, these accounts include items that are typically related to power lines – power fixtures. To determine the relevant costs for calculation of the pole attachment rate, power fixture-related costs need to be removed. In the second and third PAWG meetings the LDCs were asked if they maintained sub-accounts to track power fixture-related costs separately. Except for London Hydro, all other LDCs (Hydro Ottawa, Hydro One, Horizon) confirmed that they did not maintain sub accounts to separately track the pole-related costs of assets (common costs) from strictly power fixtures (power-only costs).

5.1 Average Embedded Cost per Pole

It is worth noting that in certain proceedings in the USA and Canada, the accounting cost of poles has been reduced by a factor of 15% to remove the cost of power-specific fixtures. For example, the FCC in its *Order of Reconsideration* determined, "*We also affirmed our adjustment to a utility's net pole investment of 15% for electric utilities and 5% for LECs to eliminate the investment in crossarms and other non-pole related items*" (FCC 01-170, para 32, p. 20-21). The NBEUB in its 2015 Decision noted a "*15% reduction had been agreed upon by the various stakeholders, as referred to in the 2008 Report, which was applied to NB Power's calculation of the average embedded cost*" (para 11, p.3).

The following excerpt from the Order of the Public Service Commission (Kentucky, USA), dated August 12, 1982, provides detailed historical context to the application of the 15% adjustment factor.

"South Central Bell used 78 percent of its gross pole accounts as a "bare pole factor" to exclude investment attributable to appurtenances, i.e., cross arms, guys, anchors, etc. CATV's testimony was that 85 percent of pole accounts was accepted industry standard for bare poles, which standard includes investment in anchors and guy wires and excludes all other appurtenances. General Telephone has also used 85 percent factor, but has testified that this factor excludes "cross arms, anchors and other fixtures," which appears inconsistent with the testimony of other parties.

"Therefore, for telephone utilities the Commission finds that 22 percent of the utility's pole account consists of appurtenances and should be excluded.

"For electric utilities, the cost of major appurtenances such as cross arms can be specifically identified in sub-accounts and excluded, but lesser appurtenances such as aerial cable clamps, pole top pins, and ground wires are not segregated in the basic pole accounts. Kentucky Power offered the only specific evidence on ground wire cost, for which it adds $12.21 to the pole accounts, and estimated that 8.7 per cent of the unsegregated pole accounts represents lesser appurtenances. It was acknowledged generally by CATV operators and the telephone utilities that an exclusion of 15 percent for pole appurtenances would be reasonable, but this percentage did not include the cost of anchors.

"Consistent with our finding that 22 percent of the utility's pole account is a reasonable exclusion for telephone utilities, and the ratio of the cost of anchors to the basis pole accounts should not vary significantly between telephone and electric utilities, the Commission finds that an adjustment of 15 percent and a deduction of $12.50 per ground will reasonably approximate the cost of an average base wooden electric utility pole." (Public Service Commission, Kentucky, USA, 1982, p.8-9)

To determine the gross capital cost (account 1830) attributable to the pole, there were two options:

a) Undertake a detailed analysis and audit of the account 1830 maintained by individual LDCs, or

b) Request LDCs to provide estimated breakdowns based on an analysis of sample data.

Option a) was considered to be time consuming, and not feasible given the specified duration and scope of this study. Accordingly, the participating LDCs were requested to provide an estimated breakdown of account 1830 into "Poles", "Power Fixtures", and "Other"[45]. Table 19, below provides a summary of the cost breakdown in account 1830 for the years 2005-2015.

The distribution of embedded cost per pole is separated into three sub-items - poles, power fixtures, and other - based on data submitted by Hydro One, Hydro Ottawa, and London Hydro. For the other two LDCs (Horizon and Toronto Hydro), the distribution was estimated based on the distribution ratios submitted by London Hydro[46] Since CHEC did not respond to the data request, it was not included in the averages shown in Table 19 below.

Table 19: Historical (Embedded) Cost per Pole (2005-2015) – Account 1830

Year	Installed Poles	Total General Submission	Distribution of Capital Cost - Act 1830		
			Poles	Power Fixtures	Other
2005	1,682,644	$ 1,182.70 100.0%	$ 1,010 85.4%	$ 170.93 14.5%	$ 1.94 0.2%
2006	1,728,781	$ 1,211.74 100.0%	$ 1,035 85.4%	$ 175.03 14.4%	$ 2.02 0.2%
2007	1,736,323	$ 1,271.95 100.0%	$ 1,086 85.4%	$ 183.63 14.4%	$ 2.15 0.2%
2008	1,759,177	$ 1,356.02 100.0%	$ 1,158 85.4%	$ 196.15 14.5%	$ 2.18 0.2%
2009	1,769,658	$ 1,425.86 100.0%	$ 1,217 85.3%	$ 207.32 14.5%	$ 1.97 0.1%
2010	1,781,330	$ 1,481.52 100.0%	$ 1,264 85.3%	$ 215.46 14.5%	$ 2.03 0.1%
2011	1,793,909	$ 1,568.97 100.0%	$ 1,339 85.3%	$ 228.15 14.5%	$ 2.16 0.1%
2012	1,800,004	$ 1,592.92 100.0%	$ 1,357 85.2%	$ 234.98 14.8%	$ 1.19 0.1%
2013	1,810,903	$ 1,715.97 100.0%	$ 1,462 85.2%	$ 252.95 14.7%	$ 1.34 0.1%
2014	1,822,431	$ 1,814.17 100.0%	$ 1,546 85.2%	$ 267.02 14.7%	$ 1.53 0.1%
2015	1,835,514	$ 1,890.97 100.0%	$ 1,611 85.2%	$ 277.87 14.7%	$ 1.73 0.1%
Average	**1,774,607**	**$ 1,501.16 100.0%**	**$ 1,280.28 85.3%**	**$ 219.04 14.6%**	**$ 1.84 0.1%**

According to Table 19 above, the overall cost per pole increased by 4.8% annually, from $1,182.70 (2005) to $1,890.97. The 10 year (2005-2015) simple average cost per pole is $1,501.16, including 85.3%

[45] Although the description of Account # 1830 in OEB's Accounting Procedures Handbook (APH) includes "Towers" LDCs confirmed that towers (if any) are separately recorded and any cost of towers is not included in their respective account 1830.
[46] The updated distribution ratios provided by London Hydro are same as those of Hydro One, which are 85% Poles, and 15% Power Fixtures

cost attributable to poles[47]. The 85.3% ratio is consistent with the 78% to 85% range used in the precedents cited above. However, according to the data submitted by the three LDCs, the ratio of cost attributable to poles varies somewhat, as listed below:

- Hydro Ottawa: 92%,
- Hydro One: 85%, and
- London Hydro: 85%.

The range of 92% to 85% may imply either inconsistency in accounting practices across LDCs or peculiar characteristics of individual LDCs' poles cost structure. Without an independent substantive assessment of LDCs' accounts it is not possible to clearly ascertain the cost attributable to poles in their Account 1830 and other related accounts, if any.

Based on the best available data Nordicity believes it is reasonable to presume an average embedded cost per pole of $1,280.28 for allocation between power and communication attachers, which is based on a 10-year trend and represents 85.3% of account 1830. Table 20 below provides a summary of Nordicity's proposed average embedded cost per pole.

Table 20: Estimated Average Embedded Cost per Pole

Embedded Cost per Pole (1830)	Total *10 Year Average (2005-15)*		Applicable to Poles (%)	Estimated Cost	
Pole	$ 1,280.28	85.3%	100.0%	$ 1,280.28	*100.0%*
Towers	-	-	-	-	-
Power Fixtures	$ 219.04	14.6%	-	-	-
Other	$ 1.84	0.1%	-	-	-
	$ 1,501.16	100.0%		**$ 1,280.28**	***100.0%***

5.2 Net Embedded Cost per Pole

Net embedded cost refers to the net book value of capital assets (poles):

Net Embedded Cost =	**[Gross Book Value of Poles or Account # 1830] – [Accumulated Depreciation of Poles)**

In terms of the OEB's current rate framework, net embedded cost is needed to determine the carrying (financing) cost of net investment in poles. According to the OEB Accounting Procedures Handbook, only five consolidated accumulated depreciation accounts exist for this group of assets, as listed below:

[47] Based on the 2005-2015 cost, the weighted average cost per pole is $1,506.49, which is similar to the simple average of $1,501.16, shown in Table 19 above.

Account #	Description
2105	Accumulated Depreciation of Electric Utility Plant - Property, Plant and Equipment
2120	Accumulated Amortization of Electric Utility Plant - Intangibles
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment
2160	Accumulated Depreciation of Other Utility Plant
2180	Accumulated Depreciation of Non Rate-Regulated Utility Property

It is apparent from the above list that no corresponding accumulated depreciation account is reported by LDCs for the account # 1830 in the OEB's RRR system: Poles, Towers, and Fixtures (Capital Cost). That is, accounting depreciation recorded for poles is embedded in account 2105 and it is not possible to segregate costs in this account in order to compute the net embedded cost of poles, unless the information is acquired through a distributor's rate application. During the consultation process, the LDCs confirmed that they do not maintain any sub-account(s) in their accounting systems to separately account for accumulated depreciation for poles. Based on this understanding, in the first data request, LDCs were requested to provide year-to-year estimates of embedded and net embedded costs per pole, as summarized in Table 21 below.

Table 21: LDCs Estimate of Embedded and Net Embedded Cost per Pole

Year	Average Cost Per Pole ($)											
	Toronto Hydro		London Hydro		Ottawa Hydro		Hydro One		Horizon		Average	
	Embedded	Net Embedded	Embedded	Net Embedded	Embedded	Net Embedded	Embedded	Net Embedded	Embedded	Net Embedded	Embedded	Net Embedded
2005	1,779	1,083	270	235	2,404	1,122	1,061	550	n/a	n/a	1,151	610
2006	1,530	893	308	263	2,439	1,133	1,116	599	n/a	n/a	1,185	641
2007	1,694	961	369	310	2,328	1,065	1,169	647	n/a	n/a	1,246	687
2008	2,253	1,236	443	369	2,494	1,085	1,231	702	1,206	745	1,335	752
2009	2,348	1,233	1,227	625	2,251	1,087	1,286	754	1,340	841	1,398	802
2010	2,455	1,245	1,208	600	1,092	1,092	1,351	815	1,446	921	1,431	856
2011	2,637	1,393	1,271	630	1,242	1,210	1,423	885	1,634	1,073	1,517	935
2012	2,816	1,483	1,354	699	1,399	1,331	1,490	951	1,222	1,164	1,577	1,003
2013	2,910	1,528	1,420	736	1,582	1,475	1,608	1,067	1,337	1,245	1,694	1,112
2014	1,511	1,463	1,505	792	1,792	1,641	1,750	1,210	1,450	1,322	1,721	1,237
2015	1,999	1,883	1,586	837	2,016	1,819	1,793	1,254	1,587	1,420	1,805	1,314
Average	**2,176**	**1,309**	**997**	**554**	**1,913**	**1,278**	**1,389**	**858**	**1,403**	**1,091**	**1,460**	**905**

As shown in Table 21 above, the 10-year average embedded cost per pole based on LDCs estimate is $1,460, which is only 2.7% lower than the $1,501 based on Account # 1830 (see Table 19 above). As also shown in Table 21 above, the 10-year average of net embedded cost per pole, according to LDCs' estimates is $905. This means, accumulated depreciation is estimated to be 38.01% of the poles infrastructure embedded cost [= 1 – ($905 ÷ $1,460)]. Based on this analysis, the net embedded cost of

poles is estimated below:

Embedded Cost per Pole (see Table 20)	**= $1,280.28**
Less: Accumulated Depreciation (38% x $1,280.28)	= $ 487.08
Net Embedded Cost	**= $ 793.20**

5.3 Annual Depreciation Cost of Pole

Based on the OEB's current rate model, depreciation is a major element of the annual common cost per pole. The current rate model is based on the straight-line depreciation method for a useful life of 25 years. Based on the data submitted by the five LDCs in response to the first data request, they all have used the straight-line method over the last 10 years (2010-2015). However, as shown in Table 22 below, all five LDCs changed their calculation of the useful life of poles and correspondingly the depreciation rate:

- In 2012 London Hydro changed the useful life from 25 years (4%) to 50 years (2%),
- Hydro Ottawa changed from 25 years (4%) to ~45 years (2.2%),
- Toronto Hydro uses a useful life of 44.44 years (2.25%),
- Horizon changed from 25 years (4%) to 45 years (2.22%), and
- In 2015 Hydro One changed from ~55 years (1.83%) to ~59 years (1.70%).

Table 22: Depreciation Method, Depreciation Rate and Useful Life of Poles used by LDCs

Year	Toronto Hydro			London Hydro			Ottawa Hydro			Hydro One			Horizon		
	Depreciation Method	Rate	Useful Life (Years)	Depreciation Method	Rate	Useful Life (Years)	Depreciation Method	Rate	Useful Life (Years)	Depreciation Method	Rate	Useful Life (Years)	Depreciation Method	Rate	Useful Life (Years)
2005	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2006	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2007	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2008	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2009	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2010	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2011	SL	2.25%	44.44	SL	4.00%	25.00	SL	4.00%	25.00	SL	1.83%	54.64	SL	4.00%	25.00
2012	SL	2.25%	44.44	SL	2.00%	50.00	SL	2.20%	45.45	SL	1.83%	54.64	SL	2.22%	45.00
2013	SL	2.25%	44.44	SL	2.00%	50.00	SL	2.20%	45.45	SL	1.83%	54.64	SL	2.22%	45.00
2014	SL	2.25%	44.44	SL	2.00%	50.00	SL	2.20%	45.45	SL	1.83%	54.64	SL	2.22%	45.00
2015	SL	2.25%	44.44	SL	2.00%	50.00	SL	2.20%	45.45	SL	1.70%	58.82	SL	2.22%	45.00

SL: Straight Line

The summary data provided in Table 22 above, was presented to the second PAWG meeting on July 27,

2016. After discussion, PAWG participants agreed to apply 40 years (2.5% annual straight line depreciation)[48] for rate calculation purposes. Based on this agreement, the annual average depreciation per pole is as follows:

Average Annual Depreciation per Pole	**= *Embedded Cost Per Pole* x *Annual Straight Line Depreciation***
	= $1,280.28 (see Table 19) x 2.5%
	= **$32.00**

5.4 Capital Carrying Cost (Cost of Capital)

Capital carrying represents the financing cost of net investment (net embedded cost) in poles. Capital carrying cost is also a major component of the average annual common cost per pole. The 2005 OEB Decision included a $54.59 capital carrying cost, which was based on 11.42% of the $478 net embedded cost. The 11.42% represented the pre-tax weighted average cost of capital, determined by the OEB for its 2005 Decision. In order to estimate the currently applicable cost of capital, LDCs were requested to provide their year-to-year cost of capital rates. Only four LDCs responded - Toronto Hydro, Ottawa Hydro, Hydro One, and Horizon - as summarized in the Table 23 below.

Table 23: LDCs Capital Carrying Cost - Cost of Capital[49]

Year	Toronto Hydro	Ottawa Hydro	Hydro One	Horizon	LDC Simple Average	LDC Weighted Average
2005	n/a	6.75%	n/a	n/a	6.75%	**6.75%**
2006	6.52%	6.75%	8.66%	n/a	7.31%	**8.37%**
2007	6.52%	6.75%	8.66%	n/a	7.31%	**8.38%**
2008	6.60%	6.55%	8.75%	7.02%	7.23%	**8.46%**
2009	6.34%	6.55%	8.75%	7.02%	7.17%	**8.44%**
2010	7.04%	6.55%	8.97%	7.02%	7.40%	**8.69%**
2011	6.94%	6.55%	8.49%	7.17%	7.29%	**8.27%**
2012	6.94%	6.95%	8.49%	7.17%	7.39%	**8.29%**
2013	6.94%	6.70%	8.49%	7.17%	7.33%	**8.29%**
2014	6.94%	7.00%	8.49%	7.17%	7.40%	**8.30%**
2015	6.17%	6.70%	7.87%	5.75%	6.62%	**7.65%**
Average	**6.70%**	**6.71%**	**8.56%**	**6.94%**	7.24%	**8.17%**

Table 23 was presented at the second PAWG meeting on July 27, 2016. According to Table 23, the overall (10 year – 4 LDCs combined) cost of capital is 7.24% (simple average), and 8.17% (weighted

[48] 2.5% depreciation rate = (1 ÷ 40 years useful life) x 100.
[49] The rates submitted by LDCs as shown in Table 23 are the after-tax cost of capital. However, for the purpose of pole the attachment rate calculation, before-tax cost of capital is used to allow for recovery of tax in overall revenue requirement calculation of the LDCs.

average)[50]. Nordicity believes the weighted average better represents the overall cost of capital. Accordingly, the capital carrying cost per pole is estimated below:

Capital Carrying Cost per Pole	= Net Embedded Cost Per Pole x Cost of Capital
	= $793.20 (see section 6.2) x 8.17%
	= **$ 64.80**

5.5 Average Annual Maintenance Cost of Poles

During the second PAWG meeting, the following two key accounts were identified regarding the maintenance cost of poles:

i) Account # 5120: Maintenance of Poles, Towers and Fixtures

ii) Account # 5135: Overhead Distribution Lines and Feeders - Right of Way

In terms of the APH description, these accounts also include items that are not strictly attributable to poles. During the PAWG consultation process, all LDCs confirmed that they did not maintain sub accounts for these accounts to track pole costs separately. Therefore, LDCs were requested to provide an estimated distribution of costs in the above two accounts for 2005-2015.

5.5.1 Annual Maintenance Cost per Pole - Account # 5120

Table 24 below provides a summary of the distribution of maintenance costs in account 5120.

Table 24: Annual Maintenance Cost Per Pole – Account 5120

Year	Installed Poles	Total General Submission		Distribution of Maintenance Cost - Act 5120					
				Poles		Power Fixtures		Other	
2005	1,682,644	35.11	100.0%	1.79	5.1%	33.32	94.9%	0.00	0.0%
2006	1,728,781	42.75	100.0%	2.16	5.1%	40.58	94.9%	0.00	0.0%
2007	1,736,323	11.58	100.0%	0.63	5.5%	10.94	94.5%	0.00	0.0%
2008	1,759,177	13.02	100.0%	0.87	6.7%	12.14	93.2%	0.01	0.1%
2009	1,769,658	12.73	100.0%	0.85	6.7%	11.87	93.3%	0.01	0.1%
2010	1,781,330	12.28	100.0%	0.91	7.4%	11.35	92.5%	0.01	0.1%
2011	1,793,909	16.06	100.0%	1.07	6.7%	14.98	93.3%	0.01	0.1%
2012	1,800,004	13.80	100.0%	1.02	7.4%	12.77	92.5%	0.01	0.1%
2013	1,810,903	14.50	100.0%	1.07	7.4%	13.42	92.5%	0.01	0.1%
2014	1,822,431	13.33	100.0%	0.90	6.7%	12.42	93.2%	0.01	0.1%
2015	1,835,514	11.67	100.0%	0.77	6.6%	10.89	93.4%	0.01	0.1%
Average	**1,774,607**	**13.22**	**100.0%**	**0.90**	**6.8%**	**12.31**	**93.1%**	**0.01**	**0.1%**

[50] Weight based on respective LDC's pole population for the year

The distribution of the annual maintenance cost per pole into three sub-items - poles, power fixtures, and other - is based on data submitted by only two LDCs, namely Hydro One and Hydro Ottawa. For the other three LDCs (London Hydro, Horizon and Toronto Hydro), the distribution was estimated based on distribution ratios submitted by Hydro One. CHEC (which accounts for less than 0.5% approximately of the total pole population) is not included since it did not respond to the data request.

As shown in Table 24 above, the average annual maintenance cost per pole in 2005 ($35.11) and 2006 ($42.75) appears to be abnormally high compared to the following years (2008-2015). As shown in Figure 9 below, the maintenance cost per pole exhibited some fluctuation from year-to-year, but mostly remained consistent, ranging between $11.58 (2007) and $16.06 (2011).

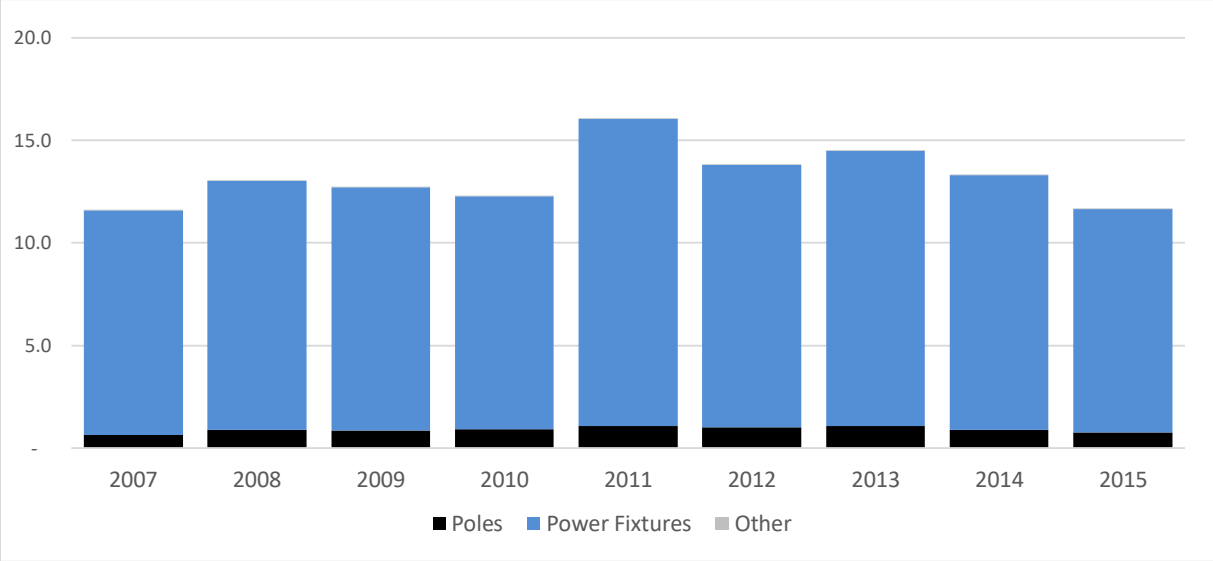


Figure 9: Average Maintenance Cost Per Pole (2007-2015) – Account 5120

As shown in Table 24 above, the eight year (2007-2015) simple average maintenance cost per pole is $13.22, of which 6.8% of the total cost is attributable to poles[51], as summarized Table 25 below.

Table 25: Break up of Annual Maintenance Cost per Pole

Maintenance cost per Pole (5120)	Total	
Poles	$ 0.90	*6.8%*
Towers	-	-
Power Fixtures	$ 12.31	*93.1%*
Other	$ 0.01	*0.1%*
Total	**$ 13.22**	***100.0%***

[51] Based on the 2008-2010 cost, the weighted average maintenance cost per pole is also $13.22, which is similar to the simple average, shown in Table 24 above.

According to the data submitted by the two LDCs, the ratio of cost attributable to poles varies significantly, as listed below:

- Hydro Ottawa: 92%, and
- Hydro One: 5%,

Given Hydro One poles constitute about ~85% of the total pole population, the overall ratio averages at 6.8%. However, the range of 92% to 5% may imply either inconsistency in accounting practices across LDCs or peculiar characteristics of individual LDCs' pole cost structure. Without an independent substantive assessment of LDCs' accounts it is not possible to clearly ascertain the cost attributable to poles in Account 5120 and other related accounts, if any. Based on the available data, Nordicity believes it is reasonable to presume that the allocation factor may range from a minimum of 5% (Hydro One) to a maximum 92% (Hydro Ottawa). Based on this range, the average maintenance cost per pole was estimated to be $6.41 - using a median average of 48.5% (=13.22 x 48.5%).[52]

5.5.2 Annual Repair and Right of Way Costs per Pole - Account # 5135

Table 26 below provides a summary of the LDCs' distribution of the right-of-way costs associated with overhead distribution (Labour, Truck and Other) lines and feeders in account 5135.

Table 26: Annual Repair and Right of Ways Cost per Pole - Account # 5135

Year	Installed Poles	Total General Submission		Distribution of Maintenance Cost - Act 5135 $							
				Labour		Material		Truck		Other	
2005	1,682,644	53.94	100.0%	43.94	81.5%	0.64	1.2%	8.22	15.2%	1.14	2.1%
2006	1,728,781	55.10	100.0%	44.90	81.5%	0.65	1.2%	8.39	15.2%	1.15	2.1%
2007	1,736,323	67.98	100.0%	55.40	81.5%	0.81	1.2%	10.36	15.2%	1.42	2.1%
2008	1,759,177	72.29	100.0%	58.94	81.5%	0.85	1.2%	11.01	15.2%	1.50	2.1%
2009	1,769,658	71.63	100.0%	55.89	78.0%	0.86	1.2%	11.34	15.8%	3.54	4.9%
2010	1,781,330	75.52	100.0%	60.40	80.0%	0.86	1.1%	12.84	17.0%	1.43	1.9%
2011	1,793,909	75.59	100.0%	62.21	82.3%	1.03	1.4%	11.32	15.0%	1.04	1.4%
2012	1,800,004	78.25	100.0%	64.33	82.2%	1.17	1.5%	11.62	14.8%	1.12	1.4%
2013	1,810,903	81.76	100.0%	68.39	83.6%	1.11	1.4%	11.13	13.6%	1.13	1.4%
2014	1,822,431	79.95	100.0%	65.16	81.5%	0.66	0.8%	12.53	15.7%	1.60	2.0%
2015	1,835,514	69.06	100.0%	57.17	82.8%	0.63	0.9%	10.16	14.7%	1.10	1.6%
Average	**1,774,607**	**71.01**		**57.88**	**81.5%**	**0.84**	**1.2%**	**10.81**	**15.2%**	**1.47**	**2.1%**

In the data request, LDCs were also asked to provide for each year the corresponding number of orders

[52] = [(5% + 92%) ÷ 2].

or jobs completed. This order volume information would have enabled further understanding of the year-to- year trends in terms of key cost elements: labour, material, truck, and other, and development of reasonable cost estimates attributable to poles and telecom wires. However, order volume data was not submitted by the LDCs. Only two LDCs (Hydro One and Ottawa Hydro) submitted the (average) cost distribution data as follows:

- Hydro One: Average cost per pole $54.11 including Labour (81.4%), Material (1.2%), Truck (15.2%), and Other 2.1%
- Hydro Ottawa: Average Cost per $62.64 including Labour (85%), and Truck (15%)

It appears that Hydro Ottawa included (assumed) “material” and “other” item costs, if any, as part of its labour cost associated with account 5120.

On this basis, both LDCs appear to have similar cost distribution – Labour versus Truck, however Hydro Ottawa’s average cost per pole is 16% higher ($62.64 vs. $54.11). Overall the cost per pole increased by a compounded annual growth rate (CAGR) of 2.5% (from $53.94 in 2005 to $69.06).

As shown in Figure 10 below, the right of way cost increased at a higher rate of 5.3% per year from 2005 to the peak year 2013 ($81.76), and then decreased by 8% in the remaining two years i.e. by 2.2% from 2013 to 2014, and by 13.6% from 2014 to 2015. Nordicity believes the 10-year cost per pole shown in Table 26 above presents a complete cost cycle reflecting peak, bottom and base cost years.

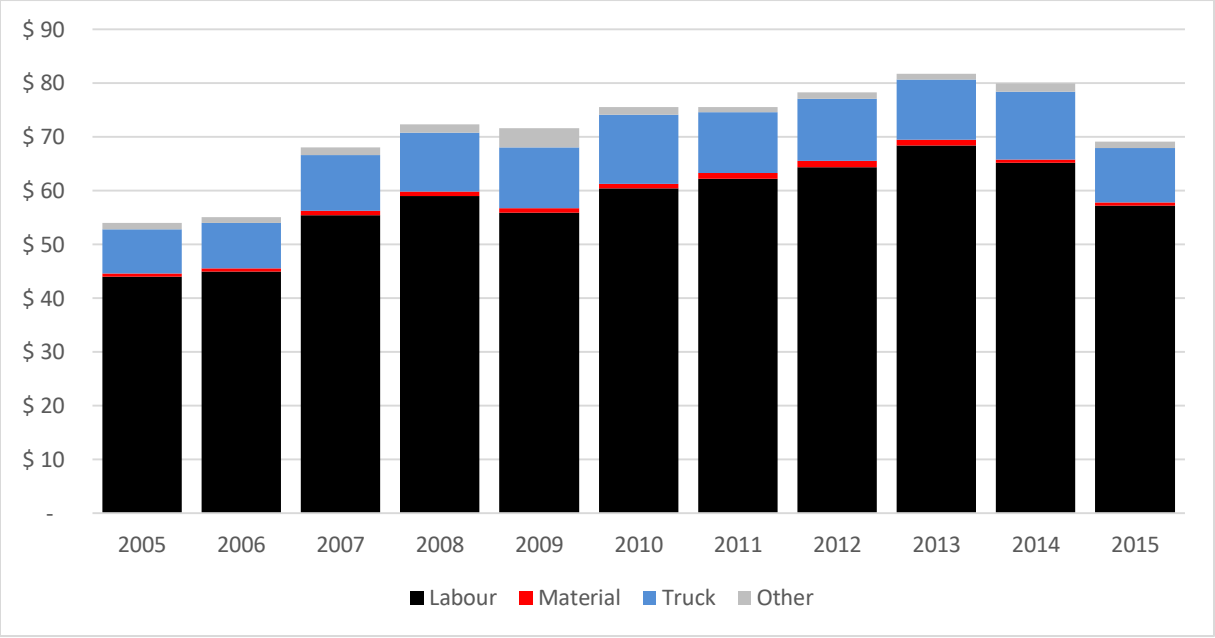


Figure 10: Annual Repair & Right of Way Cost per Pole

Without a detailed field study and examination of related operational data (truck roll/field dispatch orders), it is not possible to clearly ascertain the cost attributable to poles and telecom wires in account 5135. It is also worth noting that during the consultation meeting, telco’s argued that they undertake their own repair work when it directly concerns their customers. On this basis, it is reasonable to apply the 6.8% ratio (see Table 24 above) in order to allocate annual repair and right of way (account 5135)

cost to poles, thus calculated at $4.83 (= $71.01 x 6.8%).

It is important to note that inclusion of vegetation costs in terms of its definition and dollar estimate has been a major topic of discussion in recent pole attachment rate proceedings, such as 2015 NBEUB (NB Power, matter 272) and 2016 OEB (Ottawa Hydro, Hydro One). Based on the account description of 5135 as provided in the APH, Nordicity believes such vegetation costs are implicitly included in this account. Accordingly, this vegetation cost is fully accounted for in the cost per pole shown in Table 27 below. Based on the above, total maintenance cost including repair and right of way, attributable to poles is $11.24, as summarized in Table 27 below.

Table 27: Summary of Average Annual Maintenance Cost per Pole

		Total		Applicable to Poles (%)	Estimated Cost	
Maintenance cost per Pole (5120)	**Sub-total (A)**	**$13.22**	***100.0%***	**48.5%**	**$6.41**	***57.0%***
Repair & Right of Way (5135)	Labour	$57.88	*81.5%*	6.8%	$3.94	*35.0%*
	Material	$0.84	*1.2%*	6.8%	$0.06	*0.5%*
	Truck	$10.81	*15.2%*	6.8%	$0.74	*6.5%*
	Other	$ 1.47	*2.1%*	6.8%	$0.10	*0.9%*
	Sub-total (B)	**$71.01**	***100.0%***		**$4.83**	***43.0%***
Total: C = (A) + (B)		**$84.22**		→	**$11.24**	***100.0%***

6 Updated Annual Common (Indirect) Cost per Pole

Based on the cost inputs discussed in the preceding sections, the updated annual common cost per pole is $103.71, as compared to $93.31 determined in the 2005 Order. Table 28 provides a comparative summary of the updated total annual average common cost per pole.

Table 28: Update Annual Average Common Cost per Pole

Cost Components per Pole			2005 OEB	2017 NGL
Direct Cost	Administration Cost		$ 0.69	$ 2.85
	Loss in Productivity		$ 1.23	n.a
	Total Direct Cost		**$ 1.92**	**$ 2.85**
Indirect Direct (Common) Cost	Net Embedded Cost per pole	A	$ 478.00	$ 793.20
	Capital Carrying Cost Rate %	B	11.42%	8.17%
	Depreciation Expense	C	$ 31.11	$ 32.01
	Pole Maintenance Expense	D	$ 7.61	$ 11.24
	Capital Carrying Cost	E = A x B	$ 54.59	$ 64.81
	Utility Tax Cost	F	-	-
	Loss in Productivity	G	incl. above	incl. above
	Total Indirect (Common) Cost	K=C+D+E+F+G	**$ 93.31**	**$ 108.06**
Capital Cost Base	Embedded Cost per pole		$ 777.75	$ 1,280.28
	Accumulated Depreciation		$ 299.75	$ 487.08
	Percent Accumulated Depreciation		38.54%	38.05%

7 Determining Average Annual Direct Cost per Pole

In terms of the 2005 OEB Order, there are two cost items that are incurred by LDCs but are directly attributable to telecom space (third party) attachers. These cost items are:

- Administration Cost
- Productivity Loss

Table 29 below provides a comparative summary of direct costs per pole across jurisdictions.

Table 29: Comparative Summary of Direct Cost Pole from Past Decisions in Canadian Jurisdictions

Cost Components per Pole			2005 OEB	2016 OEB (Hydro Ottawa)	2016 NBEUB (NB Power)	1999 CRTC
Direct Cost	Administration Cost	A	$ 0.69	$ 2.28	$ 0.62	$ 0.62
	Productivity Loss	B	$ 1.23	$ 1.96	**	$ 3.15
	Total Direct Cost	C = A+B	**$ 1.92**	**$ 4.23**	**$ 0.62**	**$ 3.77**

** *NBP Power cost of loss in productivity is $5.43 which is included as a line item in Common (Indirect) Cost (NBEUB 2016, matter 272).*

7.1 Administration Costs

Administration costs are defined as net incremental costs incurred by LDCs for the placement of the cable companies' facilities (third party attachers) on LDC poles (CRTC 1999). That is, administration costs include functions such as issuance and management of permits, invoices and back office support activities. The annual administration cost generally has been lower than $1.00; for example, $0.62 in case of the NBEUB's 2016 Decision (matter no. 272) and CRTC (1999), and $0.69 in case of the 2005 OEB Decision. However, in case of 2016 Hydro Ottawa, the OEB determined an administration cost of $2.28, which is 3.3 times higher than that of 2005 OEB Decision.

In the first data request LDCs were requested to provide, on a yearly basis, administration costs attributable to third party attachers, for the years 2005-2015. Only Toronto Hydro responded to this request and it provided cost for only four years (2012-2015), as shown below:

	Toronto Hydro - Annual Administration Cost Per Pole				
Year	**2012**	**2013**	**2014**	**2015**	**Average**
Cost per pole	$ 6.19	$ 7.79	$ 9.25	$ 9.10	$ 8.08

According to the above table, Toronto Hydro's administration cost per pole increased by 47% in four years from $6.19 (2012) to $9.10 (2015). This significant increase in the administration cost of Toronto Hydro implies either major year-to-year changes in their cost structure or accounting practice. On this basis, it is not reasonable to rely solely on Toronto Hydro's administration costs for the updated rate model.

Nordicity believes detailed cost data analysis is required to develop an average rate that is directly attributable to hosting third party wires on LDC poles. Such analysis would necessarily include an examination of cost drivers such as annual volumes of permits processed, flow process (handling time per touch point), and fixed support and upgrade costs.

In the absence of such analysis, Nordicity believes it is reasonable - in the context of the current exercise - to estimate administration costs using the median (average) of the available minimum (lowest) and maximum (highest) amounts, adjusted to the 2015 price level using the consumer price index (CPI). For this purpose, Nordicity considers the minimum as $0.69 (2005 OEB Order), and the maximum as $6.19 (2012 Toronto Hydro, as above). Nordicity used Statistics Canada's Consumer Price Index (historical summary table for 1996-2015) of 107.0 for 2005, 121.7 for 2012, and 126.6 for 2015[53] to escalate the costs to 2015 dollars. On this basis, the administration cost is estimated to $3.63 per pole as shown below:

	Administration Cost Per Pole	
Minimum Base	$ 0.82	= $0.69 (2005 Order) x (126.6 ÷ 107)
Maximum Base	$ 6.44	= $6.19 (2012 Toronto Hydro) x (126.6 ÷ 121.7)
Median (Average)	**$ 3.63**	

7.2 Loss of Productivity

The loss of productivity refers to the incremental costs resulting from power utility crews having to work around cable companies' facilities (CRTC 1999, para 188). The OEB and the CRTC in their decisions included loss of productivity as a direct cost. However, NBEUB in its 2015 Decision included loss of productivity as common (indirect) cost.

Based on the discussion in the fourth PAWG meeting, Nordicity understands that LDCs do not separately track and maintain records of loss in productivity. This means the loss of productivity cost is subject to variation from LDC to LDC depending on accounting and business processes, and lacks verifiability. Nordicity also believes that such loss of productivity (e.g. cost of extra hours worked by LDC technicians) are implicitly captured in maintenance (account # 5120), and repair and right of way (account # 5135) accounts.

On this basis, Nordicity believes that proper inclusion of maintenance and repair cost attributable to poles, as discussed above, would also capture the cost associated with the loss of productivity. In other words, if loss of productivity is included in the rate as a separate line item, there are reasonable chances of duplication, and therefore it should not be considered as a separate item. Since loss of productivity has been extensively discussed in all of the past proceedings, there may be a need to show this cost as a separate item in the rate calculation. In that case, and to avoid double counting, there will be a need to

[53] 2002 is the base year (CPI = 100) as per Statistics Canada CPI summary table.

require LDCs to create a sub-account to separately track the costs associated with loss of productivity.

8 Pole Attachment Rate Model

As discussed above, the pole attachment rate model comprises three key elements as follows:

(a) annual cost per pole;

(b) ratio to allocate common (indirect) cost to the two types of attachers (power, and telecom); and

(c) average number of attachers.

The 2005 OEB Rate Model used an equal sharing approach to allocate common costs based on 3.5 as the presumptive number of attachers including 1 power, and 2.5 telecom.

Using the 2005 OEB Rate Model framework (presumptive attachers, and equal sharing), the allocation ratio attributable to a telecom attacher is calculated as follows:

2005 OEB Common Cost Allocation Methodology			
Pole Space Type	**Attacher Type**	**Calculation**	**Space Allocated per Telecom Attacher**
Common space	Power + Telecom	23.25 feet ÷ 3.5 attachers	6.64 feet
Telecom space	Telecom	5.25 feet ÷ 2.5 attachers	2.10 feet
Space allocated	Telecom	6.64 feet + 2.10 feet	**8.74 feet**
Allocation Ratio	Telecom	8.74 feet ÷ 40 feet	**21.85%**

It is worth noting that based on data submitted by LDCs in the process, the actual average number of attachers is 1.3 (see Table 18 above). If actual average number of attachers were used instead of the presumptive number of telecom attachers (2.5), the allocation ratio of 21.85% shown above would increase to 35.375%, as shown below:

2005 OEB Common Cost Allocation Methodology *(based on 1.3 actual number of telecom attachers shown in Table 18 above)*			
Pole Space Type	**Attacher Type**	**Calculation**	**Space Allocated per Telecom Attacher**
Common space	Power + Telecom	23.25 feet ÷ 2.3 attachers	10.11 feet
Telecom space	Telecom	5.25 feet ÷ 1.3 attachers	4.04 feet
Space allocated	Telecom	10.11 feet + 4.04 feet	**14.15 feet**
Allocation Ratio	Telecom	14.15 feet ÷ 40 feet	**35.375%**

The main argument used to support equal sharing is to avoid duplication of pole infrastructures, LDCs are mandated to add extra space on their joint use poles to accommodate telecom attachers. Otherwise telecom operators would be required to install poles. To meet Ontario safety standards, the telecom operators' poles require the same common space (23.25 feet) including clearance space (17.25 feet),

and buried space (6 feet). It is argued that since telecom operators avoid incurring this cost for common space, they should share it equally with LDCs, as they are attachers (users of LDCs' poles).

In this context of this argument Nordicity believes a more appropriate approach to applying an equal sharing methodology would be as follows:

Step 1: Equally divide the common space between the two types of attachers – power and telecom. In the current model, the LDC is counted as one attacher, whereas telecom attachers are counted as more than one (2.5 as per 2005 OEB Decision). Consequently, the current model allocates common space relatively more to telecom attachers than to the power attacher. As shown above, the total space allocated to a telecom attacher is 21.85%. This implies that total allocation of common space to all telecom attachers is more than 50%, i.e. 54.625% (= 21.85% x 2.5 telecom attachers). It is worth noting that the total allocation to telecom attacher could vary significantly, depending on the number of attachers used in the calculation. For example, if the actual number of average attachers 1.3, (instead of 2.5 presumptive attachers) were used then the total allocation to telecom attachers will in fact be less that 50% i.e. 45.99% (= 35.375% x 1.3 telecom attachers)

Step 2: Determine total pole space attributable to telecom attachers, which is:

= 5.25 feet (telecom space) + ½ of 23.25 feet (common space)

= 5.25 feet + 11.625 feet

= 16.875 feet

Step 3: Divide the total pole space of 16.875 feet (attributable to telecom attacher space calculated in step 2) among the telecom attachers. Based 2.5 telecom attachers used in the 2005 OEB rate model, pole space attributable to a telecom attacher is 6.75 feet (=16.875 feet ÷ 2.5 attachers), or 16.875% (6.75 feet ÷ 40 feet). Using this approach, the total space attributable to all telecom attachers is equal to 42.1875% (= 2.5 attachers x 16.875%), which Nordicity believes is reasonable given that the utilization (space, and volume and weight of attachments) of LDCs poles by telecom attachers is relatively less than that of the power attachers.

The second critical factor in the rate model is whether to use the presumptive or the actual number of attachers. The question of using number of attachments instead of attacher was also raised during the consultation process. To address this question, in the second data request LDCs were asked to provide attachment data. As pointed out in Section 5.3 above, no response was received from LDCs in this regard as LDCs only track attachers.

Given the cost impacts, Nordicity believes a feasibility study should be undertaken, after completion of this study, in order to examine the cost and benefits of developing a system to accurately track the number of attachments on a regular basis. To the best of Nordicity's knowledge there is no precedent of using the number of attachments instead of attachers; it is therefore reasonable to use the number of attachers in the rate model.

In its 2005 Decision, the OEB used the presumptive number of attachers. However, in subsequent decisions (e.g. 2016 Hydro Ottawa, 2015 Hydro One, and 2015 Toronto Hydro) the OEB applied the actual number of attachers in rate calculations. The CRTC in its 1999 Decision applied the presumptive number of attachers. However, later in Telecom Decisions CRTC 2010-900, and CRTC 2016-228 (TELUS) it

used the actual number of attachers[54]. The FCC (USA) established a rebuttable presumptive number of attachers at 2,3,4 and 5 according to service area categories, for example 5 for urban, and 2 for non-urban – for example see FCC 15-151. In its 2015 (FCC 15-151) Order FCC also noted:

"……..pole owners in fact often rebut the Commission's presumptions with much lower average numbers. For example, if the owner rebuts the urban presumption (5 attaching entities) with an actual count average of 2.6 attaching entities, the telecom rate can be as much as 70 percent higher…"(FCC 15-151, para 13, p.7-7).

The OEB determination of 2.5 telecom attachers in its 2005 Order was based on the assumption that the number of attachers in future will increase:

"The OEB considers 2.5 attachers to be reasonable. Things have changed since the days of the CRTC decision. If anything, there will be more than 2.5 attachers in the future" (2005 OEB Order, p. 7).

Based on the recent precedents and attacher data provided by LDCs in this consultation process it is apparent that the actual number of telecom attachers (1.3) is much less than the 2.5 presumptive number. Therefore, it is reasonable to use actual number of attachers in the rate model. Accordingly, the revised allocation ratio to attribute common (indirect) costs to telecom attachers, using the 2005 OEB framework, would be as follows:

Common Cost Allocation Ratio per Telecom Attacher (Based on actual average number of attachers)			
Pole Space Type	**Attacher Type**	**Calculation**	**Space Allocated per Telecom Attacher**
Common space	Power + Telecom	23.25 feet ÷ 2.3 attachers	10.1087 feet
Telecom space	Telecom	5.25 feet ÷ 1.3 attachers	4.0385 feet
Space allocated	Telecom	10.1087 feet + 4.0385 feet	**14.1472 feet**
Allocation Ratio	Telecom	14.1472 feet ÷ 40 feet	**35.368%**

Using the three-step alternative approach, described above, the allocation ratio will be as shown below:

Pole Space Type	**Calculation**	**Space Allocated**
Common space	A = 23.25 feet ÷ 2 (equal share)	11.625 feet
Add Telecom space	B	5.25 feet
Total Space Attributable to Telecom Attacher	C = A + B	**16.875 feet**
Space per telecom attacher	16.875 feet ÷ 1.3 attachers	**12.9808 feet**
Allocation Ratio per telecom attacher	12.9808 feet ÷ 40 feet	**32.4519%**

[54] CRTC refers to "*number of annual billing units"* instead of attachers

Based on updated cost inputs as shown above and actual number of attacher, the updated pole attachment rate per telecom attacher is calculated below:

Updated Pole Attachment Rate per Telecom Attacher			
Item	Explanation	2005 OEB Approach (Equal Sharing)	Hybrid Approach (Equal Sharing-Proportional)
Total Annual Common (Indirect) Cost	A	$ 108.06	$ 108.06
Equal Sharing Allocation Ratio per telecom attacher	B	35.368%	32.4519%
Annual Common (Indirect) cost per telecom attacher	C = A x B	$ 38.56	$ 35.07
Direct Annual Cost per telecom attacher	D	$ 3.63	$ 3.63
Annual Attachment rate per telecom attacher	**E = C + D**	**$42.19**	**$38.70**
Note: As discussed in Section 8.2 above, the above rates per attacher exclude loss of productivity, to avoid double counting			

9 Overlashing, and Associated Revenues

In the third PAWG meeting, telecom operators pointed out that LDCs receive $22.35 per overlasher they host on their attachments. LDCs confirmed the same. LDCs also confirmed that that the attacher data they provided was based on their invoicing data, and was therefore reflective of the overlashers. On this basis, Nordicity believes, this issue is not relevant for pole attachment rate model. It is worth noting that, this issue has not been raised any other Canadian jurisdiction, to the best of Nordicity's knowledge. In the USA, this issue has been addressed by the FCC below:

"We expect and encourage the overlashing and host attaching entities to negotiate a just and reasonable rate of compensation between them for the overlashing, which will represent some sharing of the usable and unusable space costs. Until our intervention is necessary to facilitate pole attachments for these parties, we will rely on all parties to act in good faith to develop their own just and reasonable compensation." (FCC 01-170, 2001, para 76)

We also believe that the inclusion of overlashing will increase the complexity of the rate calculation framework.

10 Proposed Rate Calculation Framework

As shown in Figure 8, a typical pole attachment rate framework that is "just and reasonable" will encompass the following key elements:

1) Costing approach to estimate cost base for input to the rate model
2) Allocation Methodology
3) Rate Methodology

All PAWG participants agreed on Nordicity's proposed conceptual framework, shown in Figure 8 above. However, in terms of the specific methodology to be used for the above three elements there were certain differences in the respective positions of the carrier, LDC, and rate payer groups, as expressed in the PAWG consultation process.

10.1 Costing Approach

To ascertain a "just and reasonable" average cost per pole two main questions need to be addressed:

- What is the basis of cost determination (cost base)?
- What key elements comprise the cost per pole (cost components)?

Cost Base: Section 5.1 identifies three main approaches to determine cost of poles including (a) historical cost, referred to as embedded cost, (b) forward looking or replacement cost, and (c) standard (benchmark) cost. These three approaches were presented in the first PAWG meeting. All PAWG members agreed to use historical (embedded) cost, as discussed in Section 6. The rate payers group in each of the four PAWG meetings, however, emphasized that the cost base should reflect the forward-looking view based on the LDCs' pole replacement plan over the next three to five years. As noted in Section 5.1 this position of rate payer group is based on the understanding that current embedded cost is likely to be understated given significant pole replacements envisaged by the LDCs, as per their filings (financial forecasts) submitted to the OEB. Nordicity believes the costing approach explained in Section 6 above is adequate for the following reasons:

i.) Expenditure estimates of planned replacements lack objectivity, reliability, and verifiability compared to incurred costs;

ii.) The cost of poles is not subject to factors, other than inflation, that may cause significant cost increases or decreases over time such as technological changes, techniques of installation and maintenance of poles, and so forth;

iii.) Regulatory precedents to date do not provide support to include forward-looking cost estimates in the pole attachment rate calculation;

iv.) The 10-year (2005-2015) actual data presented in Section 6 provide a reasonable long term view of the trends in the cost structure of poles in Ontario, and do not indicate any extraordinary variation in the year-over-year historical cost of poles.

v.) Based on historical trends an annual adjustment factor may be used to account for inflation and normal replacements.[55]

Cost Components: The cost analysis provided in Section 6 above was discussed in detail during the third

[55] According to Table 19 above, the overall cost per pole increased by 4.8% annually, from $1,182.70 (2005) to $1,890. 97 (2015). This rate may be used to adjust the pole attachment rate annually.

and fourth PAWG meetings. The PAWG members generally agreed that account description provided for in USoAs 1830, 5120 and 5135 reasonable the poles capital, maintenance and repair cost, provided power related items are excluded. Breakout sessions were held at the end of 3rd PAWG meeting to determine what items should be removed from these accounts, being power related items. Since sub-accounts are not maintained by LDCs it was agreed to apply a percentage factor to exclude power related items. Accordingly, based on the data provided by LDCs' percentage factor was determined as detailed in Section 6 above. However, LDCs argued there are certain other accounts that include items which should be included in the cost base to calculate pole attachment rate. For USoA 1835 for the cost of neutral that run across poles, and USoA 5020 for pole inspection cost. However, LDCs and carriers presented different views with respect to the causality of cost associated with neutrals. The carrier group argued that neutrals are strictly causal to power lines. The LDCs emphasised that neutrals are causal to both power and telecom attachments, and therefore the associated costs should be included in the common cost of pole. In support of the LDCs' position, a Kinetrics report previously submitted to OEB on this issue was also cited. To the best of Nordicity's knowledge no regulatory precedent exists to support the inclusion of cost of neutrals in the common cost of poles. On this basis, Nordicity does not recommend including the cost of neutrals in the common cost of poles.

10.2 Allocation Methodology and the Cross-subsidization Issue

As discussed in Section 5.4 above, the two most frequently applied methodologies to allocate common costs are (a) **equal sharing**, and (b) **proportionate use**. As shown in Table 6 above, the proportionate use methodology has been used in more jurisdictions (NBEUB, CRTC, NSURB) than that of equal sharing (OEB, AEUB). The proportionate use allocation rate is based on the ratio of usable space dedicated for the telecom attachers.

In Canada, the application of proportionate use originates from the CRTC's 99-13 Decision. In this decision, the CRTC approved the proportionate use methodology on the basis that the cable companies (third party attachers) do not have **the right of ownership of poles**. In para 222 of its Decision CRTC noted:

> *"The Commission is of the view that in determining the appropriate costs to be recovered from the cable companies, it is important to consider that they do not have the rights of ownership of the pole. Accordingly, the Commission considers that the fully distributed costing approach proposed by the MEA is not appropriate and that an allocation factor based on the percentage of usable space consumed is more reflective of a user's actual use and therefore is a more appropriate means of allocating costs."* (CRTC 99-13, para. 222)

In its 2002 decision, the Nova Scotia Utility and Review Board accepted CRTC's proportionate use approach:

> *"the Board finds the CRTC's approach to determining space allocation to be helpful."* (NSUARB-P-873, 2002 NSUARB 1, par. [58])

Most recently NBEUB-New Brunswick Energy and Utility Board (November 15, 2015, matter 272) approved the proportionate use methodology on the same basis – "the right of ownership of poles" argument. In para 93, NBEUB stated that the proportionate sharing model recognizes the practical and economic disparities between NB Power, as pole owner, and third party attachers; third party communications attachers do not have the rights of ownership of the pole.

In summary, "the right of ownership of poles" has been the main argument accepted by regulators (CRTC, NBEUB, NSURB) in support of the proportionate use allocation methodology.

It is pertinent to note that in para 94 of the Decision, the NBEUB also noted that both the cost allocation methodologies (equal sharing and proportionate use sharing) they reviewed during the proceeding above can be viewed as yielding fair rates.

In this Decision, the NBEUB also established the principle that the pole attachment rate should not cause the LDCs' other customers (rate payers) to cross-subsidize the cost of poles, stating:

"The Board considers it reasonable that those customers that benefit from the use of NB Power's distribution poles should pay an appropriate rate so that NB Power's other customers do not incur or cross-subsidize any additional cost of providing such a benefit." (NBEUB matter 272, para 89)

It appears that the issue of cross-subsidization between the two attacher groups (power and telecom) has been considered in the above-cited decisions in Canadian jurisdictions strictly within the framework of the economic efficiency principle. That is, it is economically efficient to share poles:

- If the incremental cost of joint-use poles is less than the standalone-cost of separate LDCs and Telecom poles (referred to as the "standalone-cost" test), and
- If no firm (attacher) subsidizes the incremental cost of joint-use poles (referred to as "incremental-cost" test)

We understand that the regulatory boards based their decisions, cited above, on the principle of economic efficiency and determined that a rate is deemed to be "subsidy-free" if it satisfies the "increment-cost" and "standalone-cost" tests. In other words, an economically efficient rate is deemed to be subsidy-free if it accounts for the cost that is higher than the incremental cost of a joint-use pole and lower that the standalone cost of a single-use pole. The underlying rationale is that since sharing of poles results in net cost savings[56], the welfare interest of rate payers is better served as long as the telecom attacher's rate is within the lower (greater than incremental cost – floor price) and upper (lower than standalone cost – ceiling price) levels. This implies that any rate within this range is deemed to be subsidy-free. In this sense, rates determined using both proportionate use and equal sharing have been deemed to be "subsidy-free".

We believe application of the economic efficiency principle in those cases is restrictive. That is, it

[56] Net cost savings represents standalone-cost of telecom only pole less the incremental cost; The example of incremental cost may include the cost equal to the cost of LDC joint-use pole less the cost of LDC power only (single-use).

provides the low and high boundaries of a range for efficient rates. However, without further examination and analysis, the conventional (simplistic) application of the economic efficiency principle does not address the overarching issues such as the equitable distribution of efficiency gains (net cost savings) between the two rate payer groups – electricity versus telecom. That is, once the subsidy-free price range is established, the next step is to determine the appropriate price point within that range. For this purpose, a proper (quantitative) analysis that is based on relevant data according to the given situation is required to determine the appropriate price point.

It is worth noting that Dr. Roger Ware, in his expert report (dated May 14, 2015) followed this approach to advance his line of argument only in theoretical terms in order to support the proportionate use methodology. Dr. Ware, stated:

"26. The proportionate use methodology occupies a middle ground between the two more extreme approaches of equal sharing and incremental cost. It is the only methodology that attempts to capture the different demands made by users on a common capital input, and reflects differences– legal or operational–in rights and advantages provided by pole ownership relative to tenancy. For both these reasons, proportionate use is the appropriate methodology for computing pole attachment rates for cable attachers in New Brunswick."[57]

However, Dr. Ware did not present any analysis based on real data to demonstrate that the proportionate use method is appropriate in the context of demand for pole attachments in New Brunswick.

Dr. Faulhaber, professor at the Business Policy Department, Wharton School, University of Pennsylvania, pointed to the limitations of a simplistic application of the incremental cost and standalone cost rule in the following words:

"Thirty years have passed since the publication of "Cross-subsidization: Pricing in Public Enterprises." The article rigorously defined cross-subsidization and is now a standard citation of regulators and scholars addressing the pricing of regulated multiproduct firms. The incremental cost test and the stand-alone cost test, however, have been misunderstood and misapplied"[58]

The observation by Professor Faulhaber suggests that the conventional application of the economic efficiency principle to allocate common costs on poles has certain limitations, as explained in terms of the following key questions below:

i) **What is the relevant incremental cost**?

For example, assume the standalone cost of a single-use (power only) LDC pole is $100, the standalone cost of a telecom only pole is $75, and cost of a LDC joint-use pole is $125. In order to

[57] Dr. Roger Ware, (May 4, 2015), Expert Report, NB Power 2015/16 General Rate Application, Matter No. 0272.
[58] Faulhaber, G. F. (2005). *Cross-Subsidy Analysis with More than Two Services*. Journal of Competition Law and Economics 1(3), 441-448.

conduct a subsidy analysis in this example, the alternative methods of calculation underlying the question: *What should be the proper measurement of incremental cost?* must first be resolved:

(a) $125 - $ 75 = $50, which is 40% of joint-use LDC pole cost of $125?, or

(b) $125 - $100 = $25, which is 20% of the joint-use LDC pole cost of $125?

In this regard, it is important to understand the distinction between "incremental cost" and "marginal cost". That is, these two terms sometime are used interchangeably in the literature. In simple terms, marginal cost refers to the additional cost to produce an additional unit of output. In incremental cost refers to the additional cost for the incremental capacity required to produce incremental output.

To illustrate the difference, assume an existing LDC pole is 35 feet in height and can only accommodate power attachers. To accommodate telecom attachers, an additional 5 feet of space is required on the pole, totalling to 40 feet in height.

If the existing 35 feet can be extended to 40 feet then marginal and incremental cost would be same. However, practically this is not possible – 5 feet cannot be added to the same pole and a pole with more height requires additional strength to meet the public safety standards. Such distinction between a single-use (power only) and joint-use poles is well established in regulatory decisions. That is to say, a joint-use pole is required to accommodate telecom attachers because additional space and pole strength (as per technical specifications) are needed. For example, according to the Alberta Energy and Utilities Board:

"The Board notes that shared use poles are of a greater height and strength than single-use poles." (EUB Decision 2000-86, p. 20).

It has also been argued that since the joint-use pole already exists (sunk cost), the incremental cost only represents (the marginal/variable) cost to attach an additional attacher to an existing pole. This presumption is not consistent with well-established "fully distributed cost" or "fully allocated cost[59]" pricing approach used by energy boards and telecom regulators, as also noted by Dr. Roger Ware in his expert report submitted to the 2015 NBEUB proceeding (matter no. 272):

"…..an example of a very standard approach in regulatory pricing, used and endorsed by regulatory agencies around the world, known as Fully Distributed Cost (FDC) pricing"[60]

[59] "Fully Allocated Cost is an accounting method to distribute all costs among a firm's various products and services; hence, the FAC may include costs not directly associated with a particular product or service." (http://regulationbodyofknowledge.org/glossary/f/fully-allocated-cost%20FAC/)

[60] Expert Report by Dr. Ware, NB Power 2015/16 General Rate Application, Matter No. 0272, para 20, p.20.

As noted above, in the 2001 Alberta Energy Board (200-96) proceeding, TransAlta submitted that the costs for shared-use poles it installs are significantly greater than for single-use poles, and provided the following capital cost estimate[61]:

Pole Description	Pole Class	Pole Height	Cost	Ratio
Shared-use	Class 4	40 ft.	$564	100.00%
Single-use	Class 5	35 ft.	$360	63.83%
Incremental Cost			**$204**	**36.17%**

Based on TransAlta's capital cost estimates, the incremental cost for a joint-use pole over those for single use pole is $204, which is 36% of its overall joint-use pole cost.[62]

This price differential corresponds with data from American Timber and Steel (**http://www.americantimberandsteel.com**) wherein the current price differential of a 40-foot versus a 35 foot bare pole (not installed/embedded cost) is US $161.45, which is 35.6% of the 40-foot. pole price as shown below:

Pole Description	Pole Class	Pole Height	Price (US $	Ratio
Class 4 SYP Unframed CCA Treated Pole 40	Class 4	40 ft.	$453.70	100.00%
Class 5 SYP Unframed CCA Treated Pole 35	Class 5	35 ft.	$292.25	64.42%
Incremental Cost			**$161.45**	**35.58%**

Source: American Timber and Steel @ **http://www.americantimberandsteel.com/poles-pilings-utility-poles-unframed-cca.html**

It is worth noting that New Brunswick Energy and Utility Board in its 2015 Decision determined the common cost allocation ratio of 35.33% attributable to telecom attachers (see Table 15 above), based on the following calculations: 5.3 feet. (telecom space) ÷ 15 foot total usable space. This ratio is slightly lower that the incremental cost ratio of 36% shown above.

This analysis implies that without a detailed examination of incremental cost there is a possibility that the proportionate use allocation may not satisfy the incremental cost test. For example, a typical telecom equipment such as digital switches can be upgraded to accommodate incremental subscribers (users) without replacing the entire equipment. Whereas, utility poles, generally installed on public land are subject to public safety standards and regulations. Therefore, a single-use (power only) pole cannot be simply upgraded or modified to provide for additional space for telecom attachers. Instead a single-use pole needs to be replaced with a pole that has adequate specifications for joint-use, according to applicable safety standards. In this sense, the appropriate basis to determine the incremental cost is to determine the difference between the cost of a single-use pole and cost of a joint-use pole.

[61] The cost estimates submitted by the TranAlta were accepted by the Board. See section 3.1. (p.17) of the Alberta Utility Board 2000 Decision (2000-86)
[62] = $204 ÷ $564 x 100 = 36.17%

ii) **Is the demand elasticity of attacher's service relevant?**

The service demand of the two rate payers group may be different – inelastic versus elastic, or the same - "inelastic" or "elastic". Under these different demand scenarios, determination of what is the more appropriate (efficient) cost allocation methodology – proportionate use or equal sharing, for optimum distribution of cost savings between both rate-payer groups will depend on the elasticity of demand for the particular service. For example, traditionally, electricity demand is inelastic, whereas the demand for broadband (internet) services has been viewed as inversely elastic. For example, FCC's allocation methodology is driven by its policy consideration of promoting competition and investment for broadband growth[63]. If broadband demand is elastic, then an allocation methodology such as proportionate use - which allocates a lesser cost to the telecom user, may be more appropriate in order to achieve such a policy objectives rather that the alternative equal sharing methodology[64].

However, if the demand for broadband is inelastic and the OEB is not subject to such a policy mandate, then proportionate use would require further examination and analysis, as discussed later in this section.

iii) **Are "subsidization of service" and "subsidization of rate-payers" the same?**

The analysis based on the conventional application of the economic efficiency principle only allows one to address the issue of subsidies between commodities (services). The underlying rationale is that the welfare of the rate payers of the service will be same or better off than before. In the words of Professor Faulhaber,

"Subsidy-free prices do no more than insure that the production and sale of each commodity makes all consumers at least as well off as they would otherwise be"[65].

This implies that this approach is restricted from considering whether the efficiency gains (cost savings) are optimally distributed among the individual rate payers in each group of rate payers – it does not address the question whether the efficiency gains are distributed equitably among all rate payers.

[63] See para 39 (p.19), "ORDER ON RECONSIDERATION", FCC 15-151 (November 2015)
[64] . In that case, the inverse elasticity rule would also provide support for proportionate use methodology. Drawn from the efficient commodity taxation principle, which is based on Ramsey pricing, the inverse elasticity rule suggests that if the demand for each good depends only on its own price so there are no cross-price effects, then consumer welfare may be maximized and required level of tax revenue (revenue requirement in our case) may be obtained by taxing goods relatively high that have low elasticities of demand.
[65] Gerald R. Faulhaber, G. R., The American Economic Review, Vol. 65, No. 5 (Dec., 1975), p. 967

To answer this question, the analysis needs to be extended to examine the impact of the efficiency gains on individual payers. If the impact is not equitable, it implies that the issue of "just and reasonable" distribution of efficiency gains among different group of rate payers – electricity and telecom may exist and this needs to be further investigated empirically.

In the above-cited Canadian decisions, which approved the proportionate use methodology, the issue of cross-subsidy as well as equitable distribution of efficiency gains between electricity and telecom rate payers does not appear to have been examined empirically.

For instance, if the "proportionate use" allocation methodology is used, instead of the two equal-sharing approaches discussed in Section 9, the common cost allocated (paid) by the telecom attacher would be 31.34% of the total $108.06, as shown below:

Power Space (*see line A in Table 16 above*)	**11.5 feet**	**68.66%**
Telecom Space, including separation space *(see Lines B and D in Table 16 above)*	5.25 feet	31.34%
Total Usable Space = Power + Telecom (*also see line D in Table 16 above)*	16.75 feet	100.00%

As noted above, the incremental cost may be up to 36% of the joint use pole cost. In that case, the allocation ratio based the proportionate-use methodology may not satisfy the incremental cost test. That is, given the actual average telecom attachers are 1.3 per pole, the allocation ratio per attacher, based on the proportionate use methodology, is 24.11% (= 31.34% ÷ 1.3). This means that according to proportionate use, the common cost attributable to telecom rate payers is $33.87 (= $108.06 x 24.11% x 1.3 attachers). The remaining $74.19 common cost (=$108.06 - $33.87) is then attributable to the LDCs' rate payers.

We believe the critical step missing in the analysis leading to the regulatory preference for the proportionate use methodology has been the understanding of the impact of the resulting allocated cost on individual electricity and telecom rate payers. Nordicity's analysis - presented in Appendix B, attempts to fill this gap. The analysis clearly demonstrates that the equal sharing methodology is most appropriate to allocate common cost between two types of attachers on joint-use poles.

11 Conclusion and Recommendations

Based on the above analysis, the pole attachment rate is $42.19 per attacher, using OEB's current equal sharing methodology to allocate indirect cost. This rate represents an increase of 88.8% from $22.35 determined in 2005 OEB Decision. This increase is due to the following two reasons:

- Increase in cost per pole including (a) 15.8% increase in the indirect cost per pole from $93.31 (2005) to $108.06, and (b) increase in direct (administration) cost from $0.69 (2005) to $3.63.
- Decrease in average telecom attachers per pole from 2.5 (2005) to the current average of 1.3.

If Nordicity's proposed equal sharing approach, (explained in Section 8), is used, then the updated pole attachment rate is $38.70 per telecom attacher, instead of $42.19.[66] These rates are based on the rate calculation framework illustrated in Section 4, which comprises three key elements:

- Costing approach (methodology)
- Cost Allocation methodology
- Rate Calculation Methodology

For the costing approach, all PAWG members agreed to use embedded (historical) cost. Accordingly, the updated indirect cost of $108.06 was calculated using pertinent USoAs for capital cost, maintenance and repair expense - annually submitted by LDCs to the OEB, for the period 2005-2015.

The main issue in using this approach is that USoAs also include costs strictly associated with the power assets installed on the poles. This issue would not exist if LDCs maintained sub-accounts for the main categories of the different cost elements included in the USoA. Since LDCs currently do not maintain such sub-accounts, a percentage adjustment factor was used to remove the power-related cost to arrive at a $108.06 indirect cost. For example, the adjustment factor of 14.7% to remove power related costs from the capital cost base (USoA 1830) was estimated, based on the data submitted by LDCs in response to the data request during the PAWG consultation process. This approach is supported by various regulatory precedents in the USA (e.g. FCC) and Canada (e.g. NBEUB).

This adjustment factor can have a significant impact on the rate, as evident during the PAWG consultation process and thus subject to major disagreements on interpretations of which items to include or remove from the cost base, depending on the interests of different types of attachers such as LDCs (pole owners) and carriers (third party attachers).

To avoid this situation on going forward basis, it is recommended that LDCs be required to set up appropriate sub-accounts and submit detailed accounts as part of their annual general submissions to the OEB. The implementation of sub-accounts system would allow to automatically updates to the cost input to the pole attachment rate model. As a result, major pole attachment-related regulatory hearings could be avoided in future. This would also ensure long term rate stability and predictability, critical to the effectiveness of a regulatory framework.

For the cost allocation methodology two methods were primarily considered in the PAWG consultation process: proportionate use and equal sharing. The carrier group argued for the proportionate use, and LDCs indicated their preference for equal sharing.

Both methodologies have been extensively discussed in several pole attachment rate proceedings in Canada over the past several years. It has been well established that both methodologies conform to the principle of economic efficiency and avoid any potential issue of cross-subsidization. That is, in theoretical terms, both methodologies satisfy the minimum incremental cost and maximum standalone

[66] $38.70 is also based on the same cost per pole of $108.06 and current average of 1.3 telecom attachers.

cost range of economic efficiency. However, the empirical evidence that is based on relevant data according to the specific case under consideration is sparse to support this view.

The second issue is that a wide range of possible rates can be set within such minimum and maximum economically efficient cost thresholds. Consequently, different types of attachers argue for the approach which will determine a rate that suits their best interest. Thus, carrier groups - interested in the lowest possible rate, argue for incremental cost (minimum possible), or proportionate use methodologies. Whereas, LDCs, seeking to recover the maximum possible cost from third party attachers, prefer equal sharing.

Because of these opposing interests there is a need to determine a rate that is optimum from the perspectives of both attacher groups. An optimal rate that is empirically proven would help avoid future rate proceedings due to issues related to the cost allocation methodology. The analysis presented in Section 10 demonstrates that the equal-sharing methodology produces an optimum rate from the perspective of both telecom and electricity rate payers. Therefore, the equal sharing methodology is recommended to allocate indirect costs in the determination of the pole attachment rate. Consideration of any other methodology would require a detailed assessment of costs such as incremental cost (minimum threshold) and standalone cost (maximum threshold) in the Ontario context.

For the rate calculation methodology, the main issue discussed during the PAWG consultation process was how to determine the number of attachers. In the 2005 OEB Decision, the presumptive number of attachers (2.5 telecom or 3.5 including power) was used to determine the pole attachment rate. However, in subsequent rate proceedings (2005 NBEUB), (2015-16 OEB), the evidence demonstrated that the actual number of telecom attachers are generally less than 2 attachers: 1.4 (2015 NBEUB – NB Power), 1.74 (2015 OEB – Hydro Ottawa), 1.30 (2015 OEB – Hydro One), and 1.61 (2014 OEB – Toronto Hydro). In the USA, although FCC follows the presumptive number of attachers approach but the evidence submitted by utilities in their rebuttals demonstrated a relatively very low number of attachers.

During the PAWG consultation process there was general agreement among the members to use an average based on the actual number of attachers. However, carrier group argued that such average should be based on joint use poles that excludes poles with Bell only attachments, given their agreement with Hydro One. That is, according to the carrier group, only poles that have third party (carrier) attachers should be counted in determining the average of telecom attachers. Intuitively, this approach would lead to number of telecom attachers per pole of 2 or more. Based on the data submitted by LDCs during the PAWG process, the overall average number of telecom attachers is 1.3. The average attacher approach carrier posited is not consistent with the cost per pole which is based on the overall pole population. If the carriers' proposed approach were to be retained, there would be a corresponding need to determine the cost per pole for the subpopulation of poles with third party attachments. Given the limitations of the group asset accounting system used by LDCs, it would not be practical to objectively determine cost per pole of third party poles only.

In light of the evidence considered above, it is recommended that the OEB use the number of 1.3 average attachers per pole which is based on overall pole data submitted by LDCs in the PAWG process. To ensure transparency and reliability of attachers' data, it is also recommended that the LDCs be required to enhance the attacher tracking system - linked to the invoicing system, and to include the attachers' data as part of their annual general submission to the OEB. The recommended process will allow automatic updates to the pole attachment rate, and will help avoid future rate proceedings on this issue.

Another important question raised was whether there should be a single pole attachment rate for the entire province or it should vary according to geographic location. During the PAWG consultation process, participants were particularly requested to provide their position on this issue. Generally, the participants agreed on a single province-wide rate on the basis that it would be simple to administer. However, the carrier group stated its preference for an LDC-specific rate. Based on the data submitted by LDCs during the PAWG consultation process, it was not possible to determine the cost per pole according to different geographic locations, such as rural versus urban, and to identify cost differences. The examination of data submitted by LDCs also did not reveal major systemic cost differences. On this basis, a single province-wide rebuttable rate is recommended. That is, LDCs may be allowed to apply to vary the rate if they believe that the provincial rate does not represent their cost structure, which they would demonstrate through submission of a detailed cost study.

Finally, an effective framework is required to implement updates to the rate on going-forward basis. As noted in this report, the major factor that can cause major year-to-year fluctuations in the rate is the number of pole replacements vis-à-vis declining net book value (net embedded cost) balance due to depreciation expense. This issue may be addressed through a levelised approach – as proposed in Section 2 above. The other factors include inflation, higher cost (due to increase in labour rate), and productivity improvement (due to operational efficiencies). These factors can be accounted for if the rate model is periodically updated (every three to five years), using LDCs' annual USoA general submissions along with attacher data as described above.

Appendix A: List of Issues Submitted by the Carrier Group

Framework	Costing Approach	Allocation Methodology	Rate Methodology
• Rate Framework Approach and Inputs • Nature and quantum of the joint use pole-sharing arrangement that exists between the hydro company and the local telephone company • Whether there should be a province-wide rate or a company-specific rate • Relationship between pole attachment rates and electricity rates to consumers • Time period and process for pole rate review • Future Proofing	• Historical versus Forecasted Costs • How power-specific assets on the pole should be treated to ensure that they are not recovered through the pole attachment rate • How special circumstances and events should be treated (ice storms, fires, large pole replacement programs)	• Direct and Indirect Costs • Cost Allocation / Accounting Principles/ Cost Sharing Model • How the common costs of a pole should be allocated among the various users of the pole • Appropriate space on a pole that should be allocated to each of the different attachers	• Third Party Attachers / Overlashing / Access (Shared Access) • Number and types of all possible attachers, including actual and potential, third party power and wireless service providers • Joint use poles that are not used by communications attachers

Appendix B: Why the Equal Sharing Allocation Methodology is Appropriate for Ontario

For this purpose of this analysis, Nordicity considers the typical telecom rate payer is an Internet (broadband) user, given broadband penetration is the key driver of telecom infrastructure deployment.

We believe it is reasonable to assume that 100% of households are electricity users (rate payers). Internet penetration in Canada is estimated to be 88.5% in 2016[67]. To understand how the proportionate use cost allocation impacts the two types of rate payers viz. electricity and telecom, observe the following example:

(A) Assume a LDC joint use pole serves 100 electricity rate payers and 88.5 telecom rate payers in the province.

(B) The cost per joint-use LDC pole is $108.06, as shown in Table 28 above.

(C) If the incremental cost of joint-use pole is 36% of joint-use pole, as shown above, the cost per single-use (power only) then may be estimated as $108.06 ÷ 1.36 = $79.46

(D) In the 2015 New Brunswick Energy Board (matter 272) hearing, Dr. Roger Ware, expert for Rogers Communication Inc. advanced the argument that the proportionate use methodology takes into account the differences in demand generated by different users of the pole, i.e. electricity attachers versus telecom attachers. In his testimony, Dr. Ware stated:

"*The proportionate use methodology is an example of fully distributed cost pricing in which users pay a price that reflects the differential demands that they make on a common capital input, namely the buried and clearance 10 sections of the pole*" (Dr. Ware, Hearing Day 9 Transcript, p. 1376, lines 7-11)[68]

On the basis of this argument, it may be assumed that since electricity attachers place relatively much heavier demand (weight and space) than telecom attachers, the stand-alone cost of a telecom-only pole would be less. For the purpose of this analysis, the cost of an LDC standalone pole is assumed to cost 25% more than the telecom standalone pole. Based on this assumption, the standalone telecom cost per pole may be estimated at $63.56 = $79.46 (C) ÷ 1.25

Based on the above cost estimates, if both rate payers were to pay their respective standalone pole costs, the total cost to the rate payers would be $143.02 = $79.46 + $63.56. There is clear economic efficiency if a joint-use pole is used given the cost to all rate payers will be reduced to $108.06 from $143.02 - a net saving of $34.96 (24.4%).

The question however, is how this economic efficiency shown above is shared by individual rate payers in the two groups. To understand this, the pole cost per rate payer if both groups were to pay for their respective standalone-cost is examined first. In that case, as shown below, the telecom rate payer will pay $0.72, and the electricity rate payer will pay $0.79, resulting in a combined average of $0.76.

[67] See http://www.internetlivestats.com/internet-users/canada/
[68] http://www.nbeub.ca/opt/M/browserecord.php?-action=browse&-recid=457

		Total	Electricity	Telecom
A	Number of rate payers per pole assumed	188.50	100.00	88.50
B	Single Use (Standalone) Cost Per Pole	$143.02	$79.46	$63.56
C	Pole cost per rate payer (B ÷ A)	$ 0.76	$ 0.79	$ 0.72

If a joint-use pole is used, the combined average cost per rate payer will be reduced to $0.57 (=$108.06 ÷ 188.5), from $0.76, a net saving (economic efficiency) of $0.19.

The next step is to determine the optimal distribution of these savings between the two groups of rate payers. That is, the savings should be distributed equally, on the principle of equity and fairness. If common costs are allocated using the proportionate use methodology, the telecom rate payers receive 85% of the savings, as shown below:

		Total	Electricity	Telecom
A	Allocation Ratio (Proportionate Use)	100.00%	68.66%	31.34%
B	Allocated Cost ($108.06 x A)	$108.06	$74.19	$33.87
C	Single Use (Standalone) Cost Per Pole	$143.02	$79.46	$63.56
D	Net Savings (C - B)	**$34.96**	**$5.26**	**$29.70**
E	Share of Net Savings	100%	15%	85%

Based on the proportionate use methodology, since there are savings for both rate payer groups: $5.26 (15%) for electricity rate payers, and $29.70 (85%) for telecom rate payers, both are better off than they otherwise would be under any other solution. However, on a cost per rate payer basis, the savings for electricity rate payers are relatively very small. As shown below, the cost per electricity rate payer decreased only by 6.6% (from $0.79 to $0.74), whereas in case of telecom attachers the cost per rate payer decreases to almost half, 46.7%, from $0.72 to $0.38. That is, based on the proportionate use methodology, the efficiency gain for telecom rate payers is 7 times more than for electricity rate payers.

		Total	Electricity	Telecom
A	**Number of rate payers per pole assumed**	**188.50**	**100.00**	**88.50**
B	Allocated Cost (Proportionate Use)	$108.06	$74.19	$33.87
C	**Pole cost per rate payer (B ÷ A)**	**$ 0.57**	**$ 0.74**	**$ 0.38**
D	Pole cost per rate payer (as shown above)	$ 0.76	$ 0.79	$ 0.72
E	Net Savings (D - C)	$ 0.19	$ 0.05	$ 0.34
F	Net Savings % (E ÷ D)	24.4%	6.6%	46.7%

If the economic efficiency gains are not distributed equitably among the impacted individual rate payers, then the resulting rates cannot be claimed to be "*just and reasonable*" from the perspective of the rate payers' groups.[69]. Nordicity believes such problem could be avoided if the allocation ratio of common

[69] See for example, Faulhaber, G. R. (2005), , Faulhaber, G. R. , and Levinson, S.B. (1981),

cost is such that it results in the same or equitable pole cost per rate payer. The analysis shown above demonstrates that the allocation ratio based on the proportionate use methodology does not address this problem.

As illustrated in Figure 11 below, the potential problem of inequitable distribution of efficiency gains among rate payers can be avoided if the overall allocation of common cost between telecom and power attachers is 47% and 53% (=100% - 47%), respectively.

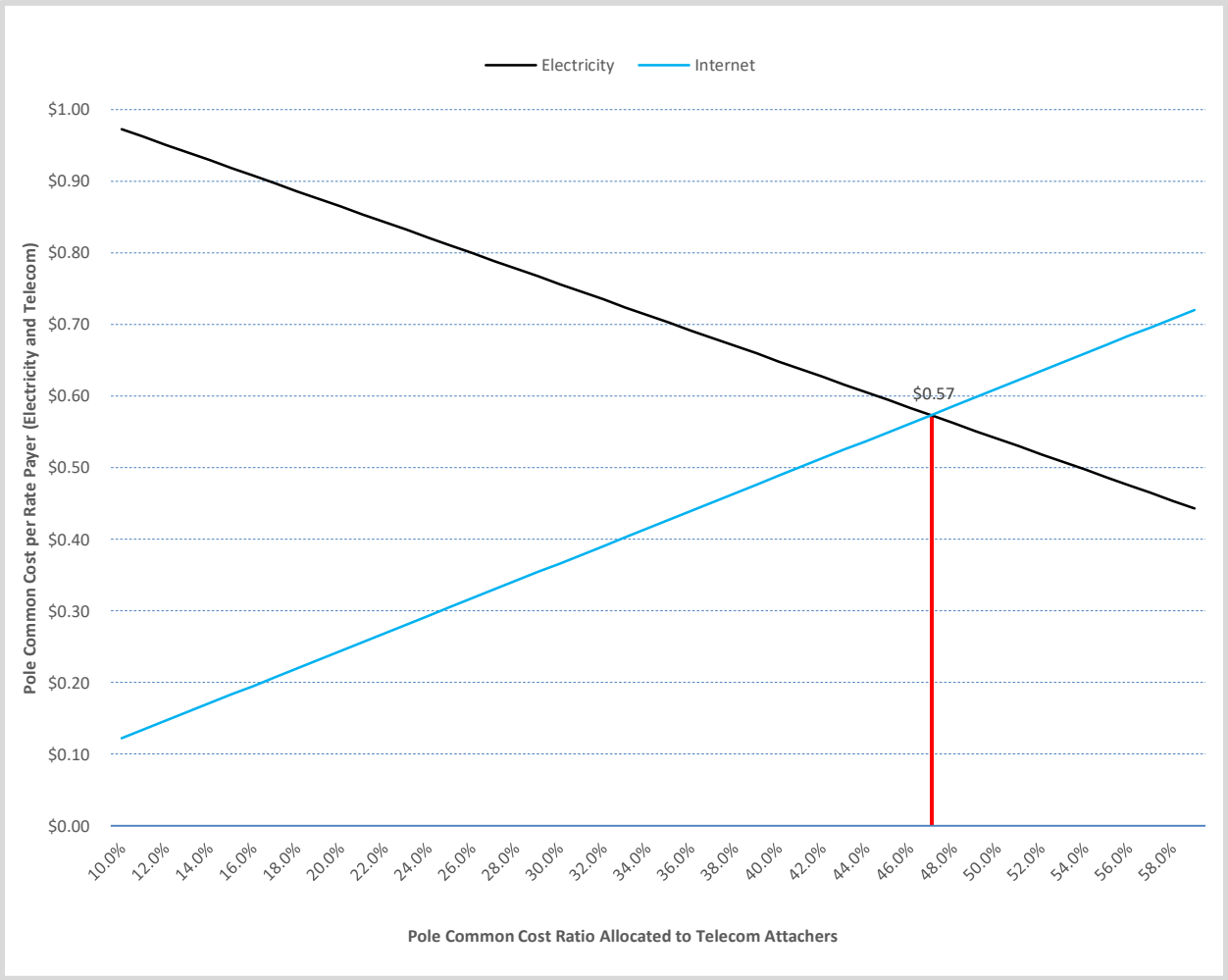


Figure 11: Common Cost per Pole - Allocated to Rate Payers (Electricity vs. Telecom)

As shown in section 9 above[70], based on OEB's current equal sharing methodology, the total allocation ratio to telecom rate payers is 45.99% (=35.368% x 1.3 attachers). Using Nordicity's proposed alternative approach of equal sharing, the total allocation ratio to the telecom rate payer is 42.19% (= 32.4519% x 1.3. attachers). In comparison, based on proportionate use, the total allocation ratio to telecom rate payers is 31.34%. In light of the 47% ratio that ensures equitable distribution of efficiency gains among rate payers, the OEB's current equal sharing method (45.99%) provides the desired outcome[71]. However, if the average number of attachers increases, the current OEB allocation methodology may result in exceeding the 47% threshold, which may result in inequitable distribution of efficiency in favour of electricity rate payers relative to telecom rate payers. Such a situation can be prevented if Nordicity's proposed three-step, equal-sharing methodology is used.

The proportionate use approach primarily originated from telecommunications regulators, such as the FCC in USA. The FCC's arguments in support of proportionate use have mainly been focused on its policy mandate (*the Telecommunications Act*, USA) to promote investment and competition in broadband and make it affordable for its citizens. For example, the FCC in its 2011 (FCC 11-50) *"Report and Order and Order on Reconsideration*", stated:

"The Order is designed to promote competition and increase the availability of robust, affordable telecommunications and advanced services to consumers throughout the nation" (para 1, FCC 11-50).

In its more recent 2015 Decision, "Order on Reconsideration" (FCC 15-151), the FCC reiterated its policy objective regarding pole attachment rates in the following words:

"By keeping pole attachment rates unified and low, we further our overarching goal to accelerate deployment of broadband by removing barriers to infrastructure investment and promoting competition." (para 4, FCC 15-151).

It may be noted that CRTC 99-13 relied on the "pole ownership" argument instead of the above noted FCC argument to accelerate broadband deployment and promote competition. However, during the PAWG meetings, carriers expressed their concern regarding Bell Canada's reciprocity arrangement with LDCs to use each other poles at no cost. For example, during the fourth PAWG meeting on January 31, 2017, Mr. Michael Piaskoski (Rogers Communications Inc.) commented as follows:

> *"….Let's imagine a world where Hydro One and Bell cooperate on building poles and let each other use the poles without charging each other. This works in a situation with no competition.*

[70] Section 8 Table entitled 'Updated Pole Attachment Rate per Telecom Attacher'

[71] For example, common cost of $108.06 allocated to telecom rate payer will be equal to $108.06 x 45.99% = $49.70, which is $0.56 per telecom rate payer (=49.76 ÷ 88.5 internet users). The remaining $58.36 (= $108.06 - $49.70), will be allocated to electricity rate payers, which is $0.58 per electricity rate payer, higher by a negligible difference of $0.02 than that of telecom rate payer

"Then other players come along and they need access too. My argument is that Bell has made a capital contribution to all the poles that Hydro One has access to. You can't treat Bell as a rate paying attacher because it has already paid for the pole by building all the other poles. Hydro One has already recovered let's say 40% of those poles from Bell. The balance is what it needs to recover from the other Carriers."
(January 31, 2017 Fourth PAWG Meeting Minutes)

We believe the empirical evidence does not suggest that Bell's arrangement with LDCs provides it any competitive advantage. For example, cablecos and other carriers (excluding Bell – Incumbent TSP), have larger share of Internet subscribers as shown in figure 12, below.

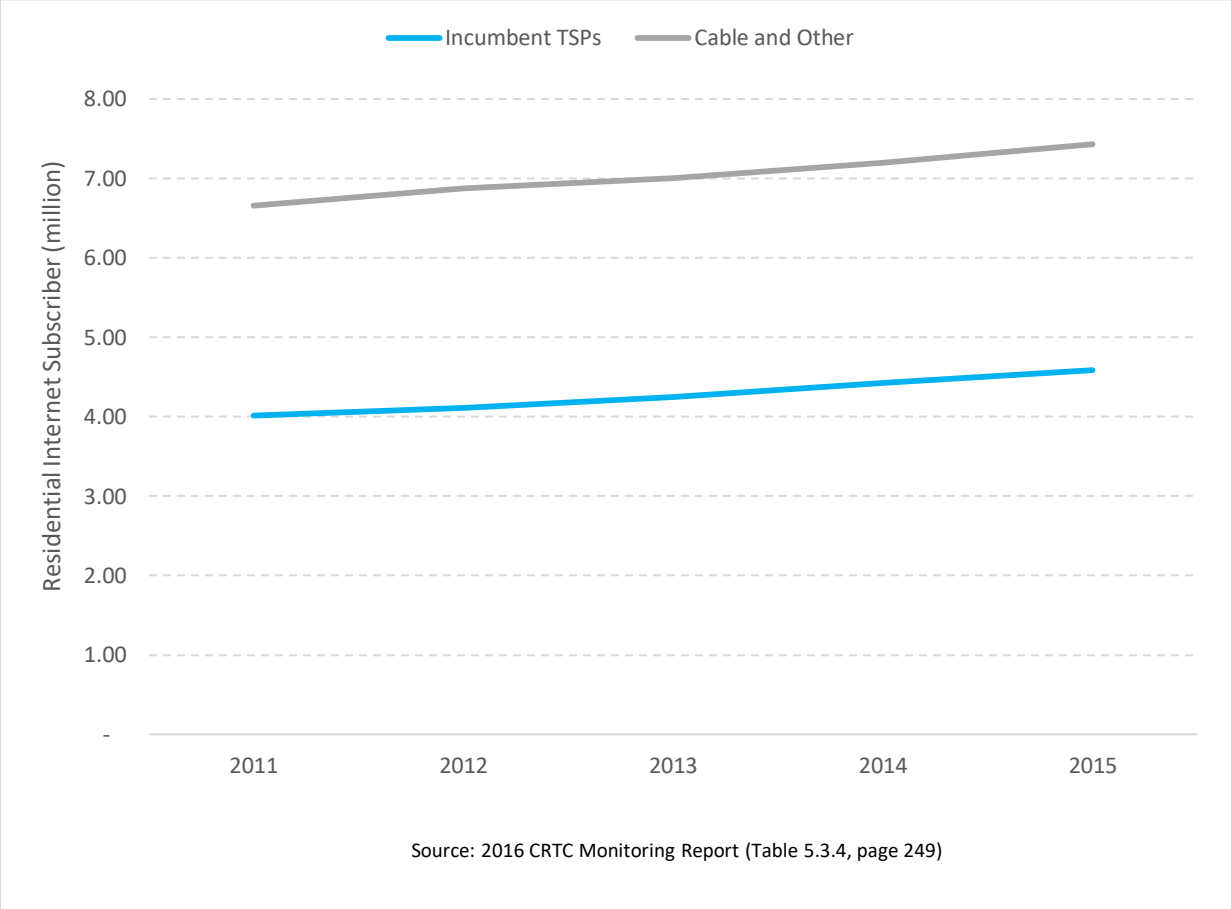


Figure 12: Share of Residential Internet Service Subscribers, by type of service provider

The proponents of the proportionate use methodology also rely on the Ramsey pricing principle, discussed in the Review of Network Economics, Vol. 9 [2010], Issue 3:

"*When fixed, costs must be recovered, as in the case of a utility pole, prices must be set above marginal costs, and the challenge for the regulator is to ensure that those mark-ups reduce welfare to the least degree possible. It is well known that the best (most socially efficient) linear prices, which recover costs, are the inverse-elasticity based prices known as Ramsey prices*".[72]:

"*When fixed, costs must be recovered, as in the case of a utility pole, prices must be set above marginal costs, and the challenge for the regulator is to ensure that those mark-ups reduce welfare to the least degree possible. It is well known that the best (most socially efficient) linear prices, which recover costs, are the inverse-elasticity based prices known as Ramsey prices*".

That is to say, electricity prices are deemed to be price-inelastic, which means the demand for electricity does not decrease or increase due to an increase or decrease in electricity prices. Whereas, broadband services have typically been viewed as price (inverse) elastic. That is, this view suggests that higher prices will result in low demand for broadband, and vice versa. Therefore, to encourage broadband penetration, telecoms prices should be lowered by encouraging competition and reducing investment barriers to entry. In this context, increasing pole attachment rates may be considered as increasing relative cost of broadband service in a competitive market, thus undermining competition.

However, in the Canadian context, the empirical evidence does not lend support to this view giver the current socio-economic trends, where broadband is increasingly becoming a necessity in every-day life. For example, as shown in Figure 13 below, Internet prices significantly increased by over 40% in the period 2011-2015. Furthermore, cable and other carriers could maintain relatively higher prices than that of incumbent TSPs (such as Bell Canada). Despite these price increases, demand for Internet service also increased as shown in Figure 12 above. These trends clearly suggest that the demand for broadband cannot be viewed to be elastic. Some recent empirical studies also provide support that broadband

[72] *"….When fixed, costs must be recovered, as in the case of a utility pole, prices must be set above marginal costs, and the challenge for the regulator is to ensure that those mark-ups reduce welfare to the least degree possible. It is well known that the best (most socially efficient) linear prices, which recover costs, are the inverse-elasticity based prices known as Ramsey prices" …… Establishing feasible rates for a mixed-use facility like utility poles ordinarily requires that the fixed costs of constructing the facility be recovered from users of that facility. However, this cost recovery requires that rates deviate from the first-best marginal cost rate. It is arguably the task of the regulator to divide those fixed costs among users of the facility in a way that recovers them, yet ideally maximizes welfare. Ramsey pricing, a form of elasticity-based price setting, achieves this goal by assigning the shares of fixed costs to users of the facility to reflect their elasticities of demand for the facility's services. The Ramsey, inverse-elasticity rule is, in fact, the optimal uniform price mechanism for doing this (Brown and Sibley, 1986, Ch. 3; Mitchell and Vogelsang, 1991, Ch. 4). The goal of this approach, though, is efficiency, not uniformity—indeed, a Ramsey pricing approach often requires different users of a pole attachment to pay a substantially different share of the fixed costs of that facility while consuming essentially identical services. Still, from the public interest perspective, Ramsey prices are highly desirable.*
……the evidence presented above suggests that the allocation of the costs of unusable space between electric utilities and the communications industry needs to be re-examined. The demand for electricity remains highly inelastic today, while the demand for broadband and triple-play communications services is relatively elastic. An efficient Ramsey pricing approach to pole attachment rates supports lowering the allocation of the cost of unusable space collectively paid by the broadband network operators, and commensurately increasing the allocation of these costs to electric utility companies. Prior to setting a specific rate, however, further analysis is warranted, particularly if policymakers wish to change significantly attachment rates across industries." Review of Network Economics, Vol. 9 [2010], Issue 3.

demand, particularly in OECD countries, is in elastic range[73]. Therefore, although it is beyond the scope of the OEB mandate in the light of the 2003 Supreme Court decision, the argument of competition and cost of broadband services versus its demand does not appear to be relevant given emerging socio-economic trends.

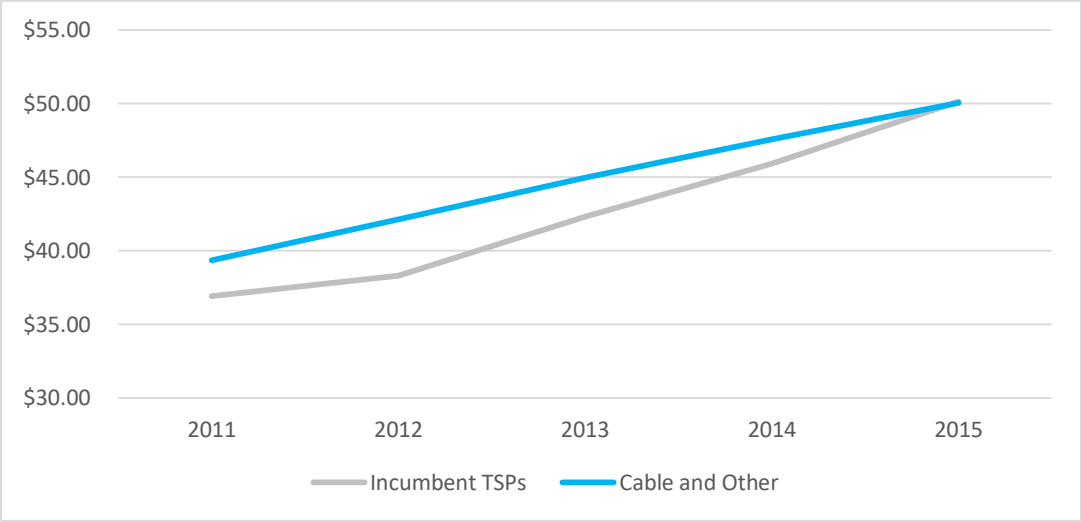


Figure 13: Comparative Prices of Residential Internet Service, by type of service provider

[73] For example, see (A) Cadman, R.,& Dineen, C.(2008). *Price and income elasticity of demand for broadband subscriptions: A cross-sectional model of OECD countries*. London: SPC Network, (B) Galperin, H., and Ruzzier, C., "*Price elasticity of demand for broadband: Evidence from Latin America and the Caribbean*", Telecommunications Policy, 2013, vol. 37, issue 6, 429-438., and (C) Haucap, J., Heimeshoff, U., and Lange. M.R.J., "*The impact of tariff diversity on broadband penetration—An empirical analysis Original Research Article*", Telecommunications Policy, 40(8), August 2016, pp 743-754.

Glossary

APH:	OEB's Accounting Procedures Handbook
CATV:	Community Access Television
CCTA:	Canadian Cable Television Association
CHEC:	Cornerstone Hydro Electric Concepts Inc. (an association of 15 LDCs in Ontario)
CPI:	Consumer Price Index
CRTC:	Canadian Radio-television and Telecommunications Commission
EDA:	Electricity Distribution Association
FCC:	Federal Communications Commission (USA)
ILEC:	Incumbent Local Exchange Carrier
LDC:	Local Electricity Distribution Company
MEA:	Municipal Electric Association (Ontario)
NB:	New Brunswick
NBEUB:	New Brunswick Energy and Utility Board
NBP:	New Brunswick Power
NSURB	Nova Scotia Utility and Review Board
OEB:	Ontario Energy Board
OEBA	The Ontario Energy Board Act
PAWG:	Pole Attachment Working Group
RFP:	Request for Proposal
RRR:	Reporting and Record-keeping Requirements
TSP:	Telecom Service Provider
USoA	Uniform System of Accounts

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November 29, 2018

Report of the Ontario Energy Board

Energy Retailer Services Charges

EB-2015-0304

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4

T 416-481-1967 1-888-632-6273
F 416-440-7656 **OEB.ca**

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EXECUTIVE SUMMARY

This Report sets out the conclusions of the Ontario Energy Board (OEB) following the OEB's review of energy retailer service charges for electricity and natural gas distributors.

The OEB has determined that, due to the operational differences that exist between the electricity and natural gas sectors, it is not appropriate to establish standardized energy RSCs[1] that would apply equally to both electricity and natural gas distributors. The OEB has also determined that the service charges for natural gas distributors will not be adjusted given that the current charges continue to closely track costs. However, adjustments to the electricity RSCs are warranted to ensure that revenues are more closely aligned with the costs of providing services to electricity retailers. The OEB continues to be of the view that default electricity RSCs remain appropriate.

Energy retailer service charges refer to the charges that recover the cost of services provided by electricity and natural gas distributors to electricity retailers and natural gas marketers (collectively referred to as energy retailers) or to customers, related to the supply of competitive electricity or natural gas. Energy retailers offer consumers retail contracts with varied terms or offerings such as the opportunity to buy their energy at a fixed price for the term of the contract. Examples of services provided by electricity and natural gas distributors are the establishment of service agreements, billing and other transactional activities.

Retail service charges (RSCs) for electricity distributors were established by the OEB in 2002 with the opening of the competitive electricity market. At the time, the OEB reviewed practices in other jurisdictions and developed a set of default values for electricity distributors to charge for retail services with the understanding that the actual costs for providing these services may differ across distributors. These default values for electricity RSCs have not been reviewed since they were established. Natural gas distributors also have service charges but they are distributor-specific. These service charges have not been reviewed in the recent past, either. As a result, the OEB decided to proceed with a review of energy retailer service charges for both sectors.

The scope of the review also included an examination of the methodology to reset the energy RSCs and mechanisms for keeping these charges up to date. The review also examined the establishment of a new service charge for electricity and natural gas

[1] When the service charges for electricity and natural gas distributors are collectively referred to in this Report, they will be referred to as "energy retailer service charges" or "energy RSCs". Electricity RSCs refer to service charges for electricity distributors only.

distributors to recover the transactional costs of sending a “notice of switch” letter to low volume customers who signed a contract with an electricity retailer or gas marketer. The OEB established a working group to assist with the energy RSCs review.

A Draft Report of the OEB (Draft Report) was issued for comment on July 19, 2018. The OEB received nine letters of comment from interested stakeholders including electricity distributors, natural gas distributors, and energy retailers.

Through this review, it has become apparent that the current electricity RSCs, which were established approximately 16 years ago and have not been updated since then, do not recover the costs associated with providing services to electricity retailers. Currently, revenues collected from energy retailers cover about less than half the costs incurred to provide service. This under-recovery of costs means that ratepayers are cross-subsidizing energy retailers. While concerns were raised about the level of adjustment to the electricity RSCs proposed in the Draft Report, the OEB notes that energy retailers have benefited for several years from lower electricity RSCs given there have been no changes to them since they were established. The adjustment is an appropriate step in addressing the current cross-subsidization that exists, and is therefore in the public interest. The OEB will therefore proceed to adjust the electricity RSCs, except for the one-time Retail Service Agreement Charge.

The OEB intends to implement the updated electricity RSCs on May 1, 2019. The electricity RSCs will subsequently be adjusted annually commencing on January 1, 2020 based on the OEB’s inflation factor. Natural gas distributor RSCs will also be adjusted annually commencing on January 1, 2020 based on the OEB’s inflation factor. The OEB will not require any adjustments to the Agent Billing and Collection charges of Enbridge Gas Distribution Inc. (Enbridge Gas) as they are structured as a non-utility service.

The OEB will establish a new one-time energy retailer service charge for both electricity and natural gas distributors of $2.00 to recover the incremental cost of sending a notice of switch letter to low volume customers who sign a contract with an energy retailer. The new service charge will apply only to letters that are sent by standard hard copy mail. The new charge will be adjusted annually similar to all other energy RSCs commencing on January 1, 2020. After considering the comments on the Draft Report from electricity distributors, natural gas distributors, and energy retailers, the OEB believes that setting the notice of switch charge at $2.00 remains appropriate. However, the OEB will allow electricity and natural gas distributors the option to opt out of applying the charge to energy retailers.

The OEB will proceed with the elimination of the Retail Service Cost Variance Accounts (RCVAs) as outlined in the Draft Report. The OEB will, however, allow electricity

distributors who are still using the RCVAs to continue doing so until rebasing in light of concerns raised by electricity distributors on the potential financial disadvantage the immediate elimination may cause electricity distributors that are still using the RCVAs. At market opening, there was uncertainty about the cost of the settlement process with electricity retailers. This settlement process has now been an integral part of the operations of electricity distributors for more than 16 years. At rebasing, the balances will be disposed of and the RCVAs will be eliminated. Electricity distributors with a longer deferral period prior to rebasing can ask for disposition of the RCVAs prior to rebasing if the amounts in the RCVA are significant, however, the RCVAs will remain open until rebasing. The OEB does not see merit in electricity distributors continuing to track these variances beyond rebasing.

The increase in the electricity RSCs in the midst of an incentive rate-setting term will result in revenues earned being greater than amounts previously approved in an electricity distributor's distribution rates. As outlined in the Draft Report, a new variance account will be established for electricity distributors. However, this new variance account will now only apply to electricity distributors who no longer use the RCVAs. The new variance account will be disposed of and eliminated in an electricity distributor's future rate application.

The updated electricity RSCs are shown in the table below.

Table ES 1: Current and New Electricity Retail Service Charges

Electricity RSCs	Unit	Current Charges	New Charges
Retailer Service Agreement	per agreement (one-time)	$100.00	**No Change**
Monthly Fixed Charge	per retailer (monthly)	$20.00	**$40.00**
Monthly Variable Charge	per retail customer (monthly)	$0.50	**$1.00**
Distributor Consolidated Billing Charge	per retail customer (monthly)	$0.30	**$0.60**
Retailer Consolidated Billing Credit	per retail customer (monthly)	$(0.30)	**$(0.60)**
Service Transaction - Request fee	per request	$0.25	**$0.50**
Service Transaction - Process fee	per request	$0.50	**$1.00**
Information Standard Delivery Charge	per request, after 2 free requests	$2.00	**$4.00**

1. INTRODUCTION

On November 5, 2015, the OEB issued a letter announcing that it was initiating a comprehensive policy review of miscellaneous rates and charges applied by electricity distributors for specific services they provide.

These charges generate service revenues that result in lower base distribution rates. Without these revenues, the cost of providing these services would be recovered from all electricity and natural gas customers through distribution rates.

The OEB noted that it would commence the review of miscellaneous rates and charges in phases, beginning with the review of wireline pole attachment charges. On May 31, 2017, the OEB issued a letter announcing that the next phase in its review of miscellaneous rate and charges would be the review of energy RSCs for both the electricity and natural gas sectors. The OEB also announced that the review would examine the establishment of a new service charge for electricity and natural gas distributors to recover the transactional cost of sending a notice of switch letter to low volume customers who have signed a contract with an electricity retailer or natural gas marketer (collectively referred to as energy retailers).

The notice of switch letter was a new requirement implemented following the OEB's review in December 2016 of a broader package of measures to protect consumers in respect of energy retail contracts.[2] The OEB amended the Retail Settlement Code and the Gas Distribution Access Rule to require electricity and natural gas distributors to send a written notice to any low volume consumer who has signed a contract with an energy retailer, confirming that the consumer has been switched to contracted supply. This requirement came into effect on July 1, 2017. In the context of that consultation which included the development of the July 1st requirement, the OEB indicated that it is appropriate for electricity and natural gas distributors to recover the transactional cost of sending a notice of switch letter. The OEB also indicated that the policy review of miscellaneous rates and charges would include the examination of the notice of switch letter.

The letter issued on May 31, 2017 invited stakeholders from the sector to express their interest in participating in a working group as part of the consultation process. The OEB selected participants to be part of a working group led by OEB staff that represented electricity distributors, natural gas distributors, and energy retailers.

[2] Giving Effect to the OEB's Report on the Effectiveness of the Energy Consumer Protection Act, 2010 (EB-2015-0268); Retail Settlement Code section 10.5.4A; Gas Distribution Access Rule section 4.3.10.

On July 19, 2018, the OEB issued its Draft Report for stakeholder comments. The Draft Report was the culmination of the efforts of the OEB and the members of the working group.

A. Background

Electricity RSCs refer to the services provided by electricity distributors to electricity retailers or customers related to the supply of competitive electricity. Default electricity RSCs were established in 2002 when the competitive electricity market was first opened and have never been updated. To establish these charges, the OEB reviewed practices in other jurisdictions and developed a set of default values for electricity distributors with the understanding that the actual costs for providing these services will vary across electricity distributors. These charges are set out in each electricity distributor's Tariff of Rates and Charges. Natural gas distributors levy similar charges for distributor-consolidated billing, contract administration, and bad debt related costs.

Electricity RSCs are grouped into the following three categories: 1) Establishing Service Agreements, 2) Billing and 3) Service Transaction Requests. The current OEB default electricity RSCs are shown in Table 1 below.

Table 1: Current Electricity Retail Service Charges

Category	RSCs	Unit	Charges	Description
1. Establishing Service Agreements	Retailer Service Agreement	per agreement (one-time)	$100.00	Intended to cover costs related to the service agreement between an electricity distributor and electricity retailer.
	Monthly Fixed Charge	per retailer (monthly)	$20.00	
	Monthly Variable Charge	per retail customer (monthly)	$0.50	
2. Billing	Distributor Consolidated Billing Charge	per retail customer (monthly)	$0.30	Intended to recover the incremental costs for an electricity distributor to provide distributor-consolidated billing. A credit is paid to electricity retailers that choose retailer-consolidated billing.
	Retailer Consolidated Billing Credit	per retail customer (monthly)	$(0.30)	
3. Service Transaction Requests	Service Transaction - Request fee	per request	$0.25	Intended to recover the incremental costs of labour, internal information system maintenance costs, and delivery costs.
	Service Transaction - Process fee	per request	$0.50	
	Information Standard Delivery Charge	per request, after 2 free requests	$2.00	

For natural gas distributors, there are no default charges. The charges are distributor-specific. The service charges for Enbridge Gas and Union Gas Limited (Union Gas) are shown in Table 2 below.

Table 2: Current Natural Gas Energy Retailer Service Charges

Category	Energy RSCs	Unit	Enbridge Gas Charges	Union Gas Charges	Description
1. Program Administration	Direct Purchase Admin Charge	Fixed Monthly Charge - per contract	$75	$75	Intended to recover the costs incurred for administrative activities related to gas supply arrangements transacted between the direct purchase contract holder and gas marketer.
		Account Monthly Charge - per account (monthly)	$0.21	$0.19	
2. Billing	Distributor Consolidated Billing Charge	Per retail customer (monthly)	$1.30 per Rate 1 Account $2.00 per Rate 6 & 9 Accounts $5.00 per Rate 100+ Accounts	$0.57	For Enbridge Gas, these charges are not part of the regulated rate setting process. For Union Gas, these charges are intended to recover the costs incurred to allow gas marketers the ability to charge their customers commodity and transportation on the gas bill. Includes an allocation of commodity related bad debt.
3. Miscellaneous Transaction Requests	Invoice Vendor Adjustment Charge	Per transaction	$0.30	$1.09	For Enbridge Gas, these charges are not part of the regulated rate setting process. For Union Gas, the charges are intended to recover the costs incurred to allow gas marketers the option to apply an adjustment on the gas bill.

2. THE CONSULTATION PROCESS

The OEB received expressions of interest from 10 parties to participate in the working group and selected all 10 parties. OEB staff led the working group. The working group was comprised of the following members:

Table 3: Working Group Composition

Electricity Distributors	Member
Guelph Hydro Electric Systems Inc.	Krista Perry
Hydro One Networks Inc.	Danny Relich
Hydro Ottawa Limited	April Barrie
London Hydro Inc.	Martin Benum
Veridian Connections Inc.	Kyle Brown
Natural Gas Distributors	**Member**
Enbridge Gas Distribution Inc.	Rob DiMaria
Union Gas Limited	Tom Byng
Energy Retailers[3]	**Member**
Ag Energy Co-operative Ltd.	Katie Morrow
Just Energy Ontario L.P.	Frances Murray
Summitt Energy Management Inc.	Jeff Donnelly

The OEB held four working group meetings between September and November 2017. At the first working group meeting, OEB staff presented a draft list of topics. Following input received from the working group, OEB staff finalized the list of topics. The final list of topics is included in Appendix A.

At the conclusion of the working group meetings, OEB staff provided an opportunity for working group members to provide written comments on each of the topics. Working group meeting materials and written comments are posted on the OEB's Review of Miscellaneous Rates and Charges webpage.

[3] The three energy retailers who were members of the working group are each licensed by the OEB to retail electricity and market gas and are active in both sectors.

3. THE OEB'S APPROACH

On July 19, 2018, the OEB issued a Draft Report for stakeholder comment. The Report is the culmination of the efforts of the OEB and members of the working group comprised of OEB staff, electricity distributors, natural gas distributors, and energy retailers.

The OEB received nine letters of comment from stakeholders. Letters of comment were received from electricity distributors including the Coalition of Large Distributors[4] (CLD), Electricity Distributors Association (EDA), London Hydro Inc. (London Hydro), and Whitby Hydro Electric Corporation (Whitby Hydro); natural gas distributors (Enbridge Gas, Kitchener Utilities, and Union Gas); and the energy retailers Ag Energy Co-operative Ltd. (Ag Energy) and Just Energy Ontario L.P. (Just Energy).

The comments are posted on the OEB's Review of Miscellaneous Rates and Charges webpage.

This section summarizes the OEB's final approach in each of the following areas:

- Guiding principles
- Province wide versus distributor specific service charges
- Costing methodology and cost elements
- Adjustment mechanism
- Electricity distributor Retail Service Cost Variance Accounts

A. Guiding Principles

Description

The working group members generally agreed that energy RSCs should be guided by the following principles to reasonably reflect the cost of providing service:

- Cost Causality: The service charges should reflect the user pay principle.
- Fairness: The approach should strike a balance between cost causality and simplicity.
- Simplicity: The methodology to re-calibrate the charges should be proportional to materiality. An onerous process is therefore not warranted.

[4] The CLD consists of the following electricity distributors: Alectra Utilities Corporation, Hydro One Networks Inc., Hydro Ottawa Limited, Toronto Hydro-Electric System Limited, and Veridian Connections Inc.

- Flexibility: The methodology should be simple to administer and be adaptable to changing market conditions.
- Minimized Regulatory Burden: The regulatory burden should be reflective of materiality. The revenues associated with the charges should also be easy to forecast.

Stakeholder Comments on the Draft Report

All stakeholders who commented agreed with the guiding principles. One stakeholder indicated that the OEB's principled approach can serve as a framework to guide the ongoing evolution and assessment of electricity RSCs. Another supported the guiding principles established but indicated that including fixed costs in the cost methodology does not reflect the guiding principle of fairness.

The OEB's Approach

The OEB accepts the guiding principles identified by the working group and adopts them for purposes of the updates to energy RSCs. By ensuring that energy RSCs are set at a level that is reflective of cost and by updating these charges periodically, cross-subsidization by ratepayers will be minimized. At the same time, the methodology to reset the charges and keep them up to date should be simple, flexible and not impose an undue regulatory burden on electricity and natural gas distributors. The OEB believes it is appropriate to include both fixed and variable costs as they are reflective of the overall costs incurred to provide service. This is discussed in further detail in Section 3C of this Report.

B. Province-Wide vs. Distributor Specific Service Charges

Description

A "one size fits all" approach was viewed by the working group to be more appropriate for the electricity sector than for the natural gas sector. This is because electricity distributors deliver similar services to retailers and similar costs are incurred. Enbridge Gas and Union Gas did not agree with standardizing the charges across the energy sector, noting that some direct purchase services offered by natural gas distributors were fundamentally different than those offered by electricity distributors. They opined that this would be counter to the principle of cost causality. Natural gas distributors also noted that the current service charges continue to closely track costs incurred to provide the services. It was however noted that there is commonality in terms of the costs related to issuing notice of switch letters between natural gas and electricity distributors.

Working group energy retailers said that it would be administratively burdensome to have different charges applied by each electricity distributor.

Working group members discussed whether the charges for the notice of switch letter could be the same for electricity and natural gas distributors. There was general agreement from all working group members that the charge should be the same for both electricity and natural gas distributors given that the nature of costs incurred are similar.

Stakeholder Comments on the Draft Report

There were no objections to the OEB's approach to maintain default province-wide electricity RSCs, while maintaining the status quo of distributor-specific charges for natural gas distributors. As well, there were no objections to the approach of establishing a single notice of switch letter charge for both electricity and natural gas distributors.

The OEB's Approach

The OEB will not establish distributor-specific charges for each electricity distributor. The OEB is of the view that this would be administratively burdensome for both electricity distributors and electricity retailers, therefore, default charges continue to be appropriate. As is currently the case, electricity distributors will continue to have the ability to apply for a distributor-specific rate at the time of rebasing.

Given that there are operational differences that exist between the electricity and natural gas sectors, the OEB is of the view that standardization of energy retailer service charges between electricity and natural gas distributors is not warranted. For example, because natural gas distributors have a gas supply procurement function, the nature of the services provided to energy retailers are different than the electricity sector.

The OEB is also of the view that default values for natural gas distributors are not necessary, nor are they required to be updated at this time. This review determined that the charges for natural gas distributors continue to closely track costs and are reviewed, and updated if required, by the natural gas distributors at rebasing.

The OEB will establish a single default charge for electricity and natural gas distributors for the notice of switch letter given that the nature of the services and types of costs incurred are similar between electricity and natural gas distributors.

C. Costing Methodology and Cost Elements

Description

The working group discussed an appropriate costing methodology, the types of costs incurred to provide these services and whether those costs are fixed, variable or semi-variable.

A fully allocated costing methodology was the approach preferred by electricity and natural gas distributors. Most energy retailers suggested that only variable costs be borne by energy retailers. Energy retailers commented that the level of the energy RSCs should allow the retail market in Ontario to be sustained, and that any increase to the energy RSCs should not effectively eliminate the retail market.

Table 3 below shows a summary of the costs identified by Hydro One, which were indicative of the types of costs incurred by the majority of working group members. A more detailed cost matrix can be found in Appendix B.

Table 4: Cost Matrix – Hydro One Networks Inc.

	Fixed	Variable	Semi-Variable
Customer Service Organization		X	
IT Application	X		
Application Support		X	
Finance	X		
Collections – Write off		X	

For both electricity and natural gas distributors, fixed costs identified by the working group distributor members included labour for IT testing and billing personnel that perform the settlement and invoicing of transactions. Variable costs included call center costs and application support. Variable costs were driven by the number of retail customers or the number of transactions. Differences between electricity and natural gas distributors' cost elements were also identified. For instance, natural gas distributors include the costs of commodity related bad debt and system costs in their charges while electricity distributors do not.

Working group electricity distributors submitted data on total costs incurred for providing services to energy retailers. Electricity distributors were also asked to provide an estimate of bad debt attributable to the commodity portion of the bill. Total costs were classified into fixed and variable costs, using the Hydro One cost matrix. While there was general consensus on which cost element was fixed, variable or semi-variable, the

level of costs incurred for each of those categories varied significantly across distributors.

Stakeholder Comments on the Draft Report

One retailer disagreed with the inclusion of fixed costs and the use of a fully-allocated costing methodology, noting that the inclusion of fixed costs, which would be incurred by electricity distributors regardless, would not reflect the guiding principle of fairness.

The OEB's Approach

The OEB continues to be of the view that a fully allocated costing methodology is appropriate as it reflects cost causality and value to customers, and would minimize cross-subsidization between ratepayers and energy retailers. Using the approach suggested by one retailer would still result in an increase to the existing electricity RSCs of approximately 90%. This is because the majority of costs identified by the working group electricity distributors are variable.

The OEB agrees that the cost elements identified by the working group distributor members are reasonable. However, for electricity distributors, the OEB believes that the electricity RSCs should also incorporate commodity related bad debt as the risk of default on payment can be directly linked with the service provided to electricity retailers. Section 4A provides further information on this cost element. Section 4A also describes the OEB's final approach with respect to the updated electricity RSCs.

D. Adjustment Mechanism

Description

Working group electricity distributors agreed with an annual adjustment to the charges to keep them up to date and generally supported using the annual adjustment factor applied in the OEB's incentive regulation mechanism (i.e., inflation minus a productivity factor). Natural gas distributors indicated that there was no need to change the current approach used for setting rates, as charges are reviewed at rebasing. The working group also discussed the OEB's approach to adjust the pole attachment charge for electricity distributors. At the time, the OEB had not issued its final report but there was consensus that the same adjustment mechanism to be determined in the pole attachment charge consultation should apply to electricity RSCs. There was support from one working group energy retailer for an annual adjustment mechanism. Another energy retailer said that creating an adjustment mechanism could be cumbersome and suggested that the OEB consider a global review using standard cost allocations for all distributors.

Stakeholder Comments on the Draft Report

Electricity distributors generally supported an annual inflation adjustment to the electricity RSCs. One energy retailer indicated that it also supported the annual inflation adjustment but not the immediate increase of the electricity RSCs as the starting point.

Of the two natural gas distributors who filed comments, only Enbridge Gas asked for a slightly different approach given that some of its energy RSCs are structured as non-utility services and agreements. Enbridge Gas therefore requested that its Agent Billing and Collection charges[5] be excluded from the annual inflation adjustment.

The OEB's Approach

The OEB will implement an annual adjustment based on the OEB's inflation factor commencing on January 1, 2020. The OEB will use the same approach that will be used to implement the adjustment factor for the OEB's pole attachment charge. The OEB is of the view that an annual adjustment similar to the final policy for the OEB's pole attachment charge which is based on inflation (with no offset for productivity) should apply in order to ensure that the charges are kept up to date over time. The OEB is also of the view that this annual adjustment should apply to both natural gas and electricity distributors. The OEB notes that with the implementation of an annual adjustment to the energy RSCs to account for inflation, the differences between revenues and actual costs should be minimized over time.

The annual adjustment for the natural gas distributors' service charges will be accommodated within the new rate-setting framework for Enbridge Gas and Union Gas.[6] The OEB will however exclude Enbridge Gas' Agent Billing and Collection charges given that they are structured as a non-utility service.

Further details on how the annual adjustment will be implemented are provided in Section 5.

[5] Enbridge Gas' Agent Billing and Collection charges are identified in Table 2 of this Report (Category 2 and Category 3).

[6] EB-2017-0306/EB-2017-0307.

E. Electricity Distributor Retail Service Cost Variance Accounts

Description

RCVAs are used to record the difference in revenues and direct incremental costs incurred to provide services to energy retailers. Given the potential for an annual adjustment mechanism to keep the electricity RSCs current, the working group discussed whether this mechanism would negate the need for electricity distributors to continue to use the RCVAs.

Working group members were generally of the view that if the charges were kept updated through an annual adjustment mechanism, the need for the RCVAs would be diminished. However, some members of the working group were of the view that the RCVAs should be kept in place until such time that the electricity RSCs are re-calibrated, as electricity distributors would not have an opportunity to adjust the electricity RSCs prior to rebasing.

The Draft Report proposed the elimination of the RCVAs and the establishment of a new variance account for all electricity distributors. The purpose of the new variance account is to capture the incremental revenues that are a result of the increase in the electricity RSCs in the midst of an incentive rate-setting term, resulting in revenues earned being greater than amounts previously approved in an electricity distributor's distribution rates. The balance in the new variance account would be refunded to ratepayers in a future rate application, and the new account subsequently closed.

Stakeholder Comments on the Draft Report

Electricity distributors did not support the immediate elimination of the RCVAs. Some electricity distributors were not opposed to their eventual elimination but indicated that an immediate elimination could financially disadvantage some electricity distributors.

One stakeholder did not support the elimination of the RCVAs for all electricity distributors. It was opined that the elimination of the RCVAs should be at the discretion of each electricity distributor. This party also did not support the establishment of a new variance account. It was instead suggested that the OEB redesign the existing RCVAs to track both incremental costs and revenues.

Another party recommended that the existing RCVAs be maintained to track the incremental revenues in place of a new variance account. Electricity distributors that no longer use the current RCVAs would be required to use the new variance account.

Some parties also raised difficulties with having to track revenues by rate class as proposed by the Draft Report. It was noted that some electricity distributors may have difficulty tracking revenues by rate class because the revenue transactions relate to

electricity retailers rather than retailer customers. It was suggested that incremental revenue could be allocated in the same manner as existing RCVAs, or that incremental revenue could be allocated based on forecasted retail customers.

The OEB's Approach

The comments received confirmed that electricity distributors use two different accounting methods with respect to revenues and costs associated with the provision of retail services. For electricity distributors who currently use the RCVAs, the deficiency or surplus is recorded in the RCVAs, and is eventually collected from or refunded to ratepayers. For those electricity distributors that do not use the RCVA's, the difference between forecast costs and revenues is embedded into their revenue requirement. The two methods are shown in the illustrative example in Table 5 below.

Table 5: Accounting Methods - No RCVAs vs Using RCVAs

METHOD 1 **Electricity Distributors who no longer use the RCVAs**	**METHOD 2** **Electricity Distributors who currently use the RCVAs**
Base Distribution Rates: - OM&A includes $1,000 - Other Revenue Offsets include $800	Base Distribution Rates: - OM&A excludes $1,000 - Other Revenue Offsets exclude $800
Revenue Requirement: Includes $200 in deficiency from retail service costs/revenues	Revenue Requirement: Unaffected by retail service costs/revenues.
Accounting Method: No RCVAs accounting entries required.	Accounting Method: RCVAs used to collect/return $200 difference in cost/revenue.

Note: The illustrative example in this table assumes the following: 1) forecasted costs associated with retail services are $1,000 and 2) forecasted revenue from electricity RSCs is $800.

As indicated in the Draft Report, there are two electricity distributors[7] who have recently been granted OEB approval to no longer use the RCVAs and there are also many electricity distributors who no longer track the revenues and costs for retail services in the RCVAs.

Given the concerns raised by electricity distributors regarding the immediate elimination of the RCVAs, the OEB has determined that an immediate elimination of the RCVAs for

[7] Toronto Hydro-Electric System Limited (EB-2014-0116) and Hydro Ottawa Limited (EB-2015-0004).

all electricity distributors is not warranted. The OEB continues to believe that, for those electricity distributors that are currently using the RCVAs, the elimination of the RCVAs is appropriate but will allow for this to occur at rebasing along with final disposition of the balances in the RCVAs. Electricity distributors with a longer deferral period prior to rebasing can ask for disposition of the RCVAs prior to rebasing if the amounts in the RCVA are significant, however, the RCVAs will remain open until rebasing. The OEB does not see merit in electricity distributors continuing to track these variances any further past rebasing. Following rebasing, those distributors are expected to include in their revenue requirement the difference between forecast costs and revenues associated with retail services. Electricity distributors still using the RCVAs shall continue to track the balances in accordance with the guidance set out in the OEB's *Accounting Procedures Handbook for Electricity Distributors*.

The RCVAs were established at market opening when electricity distributors first began to settle with electricity retailers. At that time, there was uncertainty about the cost of the settlement process and the RCVAs tracked the costs and revenues to enable an evaluation of the appropriateness of the approved rates at a later date.[8] Settlement with electricity retailers has now been an integral part of the operations of electricity distributors for more than 16 years. The OEB considers that activities relating to the settlement with electricity retailers are now part of ordinary business for distributors and therefore the OEB does not see merit in a regular true-up of these costs.

The OEB will proceed with the establishment of the new variance account. The new variance account will capture incremental revenues, but only for those electricity distributors that no longer use the RCVAs.

The balance in this new account will be disposed of at the electricity distributor's next rebasing application and the variance account will then be closed. Electricity distributors that are in the midst of lengthy deferral periods, have the option of applying for disposition of the account in an incentive rate-setting application if the balance is significant. In this instance, the account will remain open to continue to track amounts until rebasing.

The new variance account will track incremental revenue only, as commodity related bad debt is already included in the distributors' base rates. For administrative ease, the incremental revenue will be allocated on the same basis as the RCVAs (i.e., based on number of customers) as opposed to a direct assignment.

[8] *Accounting Procedures Handbook for Electricity Distributors*, Article 490.

4. NEW ELECTRICITY RETAIL SERVICE CHARGES

This section discusses the OEB's approach for updating electricity RSCs. As previously mentioned, there will be no updates to the current energy retailer service charges for natural gas distributors as they continue to closely track costs. The new service charge for the notice of switch letter will, however, be applicable for both electricity and natural gas distributors.

A. Updates to Current Electricity Retail Service Charges

Description

Working group distributors submitted data on total costs incurred for providing services to energy retailers. Electricity distributors were asked to provide costs from 2016 as it represented the most recent year for which actual year-end data was available. In addition, electricity distributors were asked to provide an approximation of the total annual bad debt for electricity retailer customers for the commodity portion of the bill only. Two of the electricity distributor working group members (London Hydro and Hydro One) provided data on commodity related bad debt, while the others were unable to do so. Total costs were classified into fixed and variable costs, using the cost matrix provided by Hydro One.

As part of the working group discussions, electricity distributors generally agreed that the revenues generated from the electricity RSCs should be doubled. Working group energy retailers did not specifically address the quantum of the increase of the charges in their written comments following the conclusion of the working group meetings, but indicated that any adjustment to the existing electricity RSCs should be substantiated and that a further breakdown of costs from more than the five working group electricity distributors should be provided.

Stakeholder Comments on the Draft Report

Electricity distributors generally agreed that adjusting the electricity RSCs to ensure that the revenues are more closely aligned to the costs is a good initial step to address the current under-recovery that exists, but indicated that the OEB should review the electricity RSCs on a more frequent basis going forward.

One retailer disagreed with the level of adjustment to the electricity RSCs because it is well above an increase to account for inflation since 2002. A 40% increase was recommended instead, or if the OEB was to proceed with the adjustment being proposed, a five year phase-in may be more appropriate. It was noted that an immediate increase in the electricity RSCs would add tens of thousands of dollars to

operating costs. Another retailer did not specifically address the proposed adjustment of the electricity RSCs, but indicated its disagreement with the use of a fully allocated costing methodology which includes the recovery of fixed costs.

The OEB's Approach

The OEB continues to be of the view that adjusting the electricity RSCs to address the under-recovery and to eliminate the cross-subsidization that currently exists in a timely fashion is appropriate. Currently, revenues collected from retailers cover about less than half the costs incurred to provide service. The updated electricity RSCs will apply to all electricity distributors.[9]

As discussed in Section 2C, the approach suggested by one retailer would still result in an increase to the existing electricity RSCs of approximately 90% because the majority of costs identified by the electricity distributors in the working group are variable. The OEB does not see merit in phasing in the level of the electricity RSCs given there have been no changes since 2002 resulting in a large cross-subsidization built up over time. The OEB is of the view that it is not in the public interest to continue that cross subsidization, even at declining levels over the next five years, as suggested by a retailer.

Based on the data provided by working group electricity distributors, a total under-recovery of approximately $1.6 million was identified for the last full year for which this data was available (2016). This under-recovery represents approximately 60% of the total costs incurred to provide services to electricity retailers and includes estimated commodity related bad debt for two of the five working group electricity distributors (London Hydro and Hydro One).[10] A breakdown of expenses and revenue by working group electricity distributor is provided in Appendix C.

The OEB agrees with the electricity distributor working group members that it is an appropriate time to adjust the electricity RSCs to ensure that revenues recovered from retailers are more closely aligned with the costs of providing service. While doubling the electricity RSCs does not fully eliminate the total revenue deficiency identified by electricity working group members, the OEB is of the view that this level is appropriate. With respect to the data used by the OEB, the OEB is of the view that the sample size is

[9] Hydro Ottawa's electricity RSCs have been adjusted by an inflationary rate since 2016. The updated electricity RSCs will also apply to Hydro Ottawa.

[10] The other three working group electricity distributors were unable to provide this data.

sufficient as the five electricity distributors collectively serve approximately 40% of customers in Ontario.

While the OEB intended, to the extent possible, that the new electricity RSCs reflect the nature of the costs (fixed vs. variable) incurred to provide service, analysis of the data provided by electricity distributors revealed wide variability in the level of fixed and variable costs. As a result, the OEB used a top-down approach in determining electricity RSCs, excluding the Retailer Service Agreement charge, to be consistent with the approximate level of the overall cost under-recovery. The Retailer Service Agreement charge is a one-time charge incurred when an electricity retailer establishes a service agreement with an electricity distributor. Most working group members were of the view that the current level is reflective of costs incurred to provide that service.

Altogether, the OEB is of the view that the new electricity RSCs reasonably reflect the principles established by the working group. The OEB will implement the updated electricity RSCs in 2019. The electricity RSCs will be adjusted for inflation annually commencing on January 1, 2020. The updated electricity RSCs for implementation are shown in Table 6 below.

Table 6: Current and New Electricity Retail Service Charges

Category	RSCs	Unit	Current Charges	New Charges	Description
1. Establishing Service Agreements	Retailer Service Agreement	per agreement (one-time)	$100.00	**No Change**	Intended to cover costs related to the service agreement between an electricity distributor and electricity retailer
	Monthly Fixed Charge	per retailer (monthly)	$20.00	**$40.00**	
	Monthly Variable Charge	per retail customer (monthly)	$0.50	**$1.00**	
2. Billing	Distributor Consolidated Billing Charge	per retail customer (monthly)	$0.30	**$0.60**	Intended to recover the incremental costs for an electricity distributor to provide distributor-consolidated billing. A credit is paid to electricity retailers that choose retailer-consolidated billing.
	Retailer Consolidated Billing Credit	per retail customer (monthly)	$(0.30)	**$(0.60)**	
3. Service Transaction Requests	Service Transaction - Request fee	per request	$0.25	**$0.50**	Intended to recover the incremental costs of labour, internal information system maintenance costs, and delivery costs.
	Service Transaction - Process fee	per request	$0.50	**$1.00**	
	Information Standard Delivery Charge	per request, after 2 free requests	$2.00	**$4.00**	

B. Notice of Switch Letter Service Charge

Description

The data submitted by electricity distributors working group members showed that the costs to issue the notice of switch letter ranged between $1.00 and $3.00. For the two natural gas distributors, the costs were $1.17 and $1.67 respectively. Electricity and natural gas distributors indicated that they incur costs for postage, paper, envelope, printing, and call handling for the notice of switch letters. The average cost for all working group distributor members is $1.91 per notice of switch letter. The OEB understands that the working group members are sending letters by standard mail for

the most part, although the Retail Settlement Code does allow for other means to send the letter such as by email.

One working group energy retailer indicated that it was sending a letter similar to the OEB's notice of switch letter prior to it being mandated as of July 1, 2017, and its cost per letter was $1.07, excluding labour, which is less than the estimated costs of some members of the working group.

Stakeholder Comments on the Draft Report

Electricity distributors generally supported the establishment of a new service charge of $2.00, but indicated that the service charge should be optional. Electricity distributors indicated that that costs to implement the new charge might exceed the $2.00 charge per letter.

Just Energy suggested that the OEB consider a charge of less than $2.00 given the lower costs of the two natural gas distributors compared to the working group electricity distributors. Just Energy also questioned whether the OEB considered allowing the energy retailers to send the notice of switch letter directly to customers to achieve lower costs.

The OEB's Approach

The OEB will establish a new notice of switch letter service charge for both electricity and natural gas distributors of $2.00, which is the rounded average to the closest dollar of the costs provided by working group distributors. The OEB acknowledges that this charge is higher than the costs identified by one energy retailer, but notes that the $1.07 figure is exclusive of labour costs and therefore would not include call handling costs. Based on the principle of cost causality, the OEB is of the view that including call handling costs is appropriate. The new service charge will apply to letters sent by standard mail only given that the costs provided by working group distributors are generally related to sending the letters by standard mail. The OEB has also determined that the adjustment factor discussed in Section 3D will apply to the new service charge. The new service charge will be implemented in 2019.

Some comments suggested that electricity and natural gas distributors should have the option to apply the new charge to an energy retailer when issuing a notice of switch letter. The OEB agrees that electricity and natural gas distributors should have the option to opt out of charging energy retailers the new $2.00 service charge when mailing the Notice of Switch Letter, if the costs (e.g., system changes) outweigh the benefits. The opt out only applies to the application of the $2.00 charge and does not negate the requirement under the Retail Settlement Code and the Gas Distribution Access Rule requiring electricity and natural gas distributors to send a written notice to

any low volume consumer who has signed a contract with an energy retailer. The OEB believes that this change in approach will especially benefit electricity distributors with low energy retailer customer numbers and who typically send fewer letters in comparison to larger electricity distributors who have a greater proportion of energy retailer customers.

Electricity and natural gas distributors that choose to opt out of applying the $2.00 charge will be required to file a one-time letter with the OEB to indicate their intention to opt out 60 days after the issuance of any final rate order that follows this consultation. The OEB expects that electricity and natural gas distributors that have opted out will notify the OEB when filing an incentive rate-setting or cost based application should they decide to commence applying the charge.

5. IMPLEMENTATION

The OEB will implement the updated electricity RSCs in 2019. The OEB is issuing a draft rate and accounting order for stakeholder comment. The draft order contemplates an effective date of May 1, 2019. The new service charge for the notice of switch letter will also come into effect on this same date.

The annual inflationary adjustment mechanism for the energy retailer service charges for electricity and natural gas distributors will take effect on January 1, 2020. For electricity distributors, the OEB will use the same process that it will follow to implement the annual adjustment for the pole attachment charge. To that end, the OEB will update the generic charges annually and not rely on utilities bringing forth proposals in their annual rate applications.

As indicated in the Draft Report, the OEB will issue a generic order every December to adjust all miscellaneous service charges that are subject to an inflationary adjustment to be effective January 1st of each year. The OEB acknowledges the comments from one stakeholder that confirmation of the annual inflation factor prior to November 1st would facilitate accurate rates and implementation for electricity distributors. The OEB will determine the exact date of the inflationary adjustment order on a year by year basis. Natural gas distributors will update their charges on a distributor-specific basis as part of their annual rates applications.

The OEB also acknowledges that in order to facilitate changes to customer information systems and Electronic Business Transactions (EBT) standards (which will require internal and external resources and testing), implementation should occur at minimum three months after issuance of this Report. The OEB confirms that the application of the new charges will be prospective. As discussed in Section 4B, electricity and natural gas distributors will be allowed to opt out of charging for the notice of switch letter if the costs outweigh the benefits. For the new notice of switch letter charge, electricity and natural gas distributors who do not opt out of sending it will be able to use a currently unused charge type (that should be re-named), negating the need to incur additional costs of having to add a new charge in the EBT system.

APPENDIX A

WORKING GROUP TOPICS LIST

	Topic
1.	The overarching guiding principles that the OEB should consider.
2.	The type of costs that should be included as part of the overarching costing methodology for distributor-consolidated billing, service transaction requests, service agreements, and notice of switch letters.
3.	Whether a fully allocated costing methodology is appropriate for existing energy retailer service charges and if not, the other approaches that the OEB should consider.
4.	Whether a consistent application of energy retailer service charges should be followed or whether distributor specific charges should apply.
5.	Whether a mechanism should be considered by the OEB in order to keep energy retailer service charges up to date.
6.	Whether Retail Service Cost Variance Accounts (which are used to record the difference between charges levied on customers and retailers and the direct incremental costs for the provision of retailer services) should be eliminated and the implications of doing so.
7.	Whether there are approaches or lessons learned for charges from the natural gas distributors to natural gas marketers that could be considered for electricity and vice versa.
8.	The factors that the OEB should consider with respect to the implementation of any changes made to the current energy retailer service charges.

APPENDIX B

HYDRO ONE COST MATRIX

	Fixed	Variable	Semi-Variable
Customer Service Organization			
Retailer emails/communication/Account analysis/Offline settlements/Summary Billing/Net Metering		X	
Call Centre - Retailer specific call handling		X	
(Settlements) Process Retailer Enrolled Complex Billed Accounts		X	
IT Application			
Internal Application Costs (system maintenance/upgrades)	X		
spi/ERTH	X		
Application Support			
Retailer Issues, EBT Exceptions and Tickets		X	
Integration (iHUB and PI) monthly support		X	
Finance			
Invoice Settlement Total (IST) Payable/Receivable Reconciliation	X		
Invoice Bill Ready (IBR) Payable/Receivable Analysis	X		
Reporting & Analysis	X		
Collections - Write off			
Total Retailer Charges Written Off		X	

APPENDIX C

ELECTRICITY DISTRIBUTOR RETAIL SERVICES EXPENSES AND REVENUES

Electricity Distributor	Total Expenses A	Total Revenue B	Total Under-Recovery C = A - B
Guelph Hydro	$ 91,000	$ 22,753	$ 68,247
Hydro One	$ 1,539,000[1]	$ 619,658	$ 919,342
Hydro Ottawa	$ 559,086	$ 177,364	$ 381,722
London Hydro	$ 182,801[2]	$ 73,161	$ 109,640
Veridian Connections	$ 221,838	$ 83,821	$ 138,017
Total	**$ 2,593,725**	**$ 976,757**	**$ 1,616,968**

Notes:
[1] Includes an estimate of commodity related bad debt of $78,000.
[2] Includes an estimate of commodity related bad debt of $47,784.



Public Opinion Research

2017 National Public Attitudes Survey

Canadian Electricity Association
275 Slater Street, Suite 1500
Ottawa, Ontario K1P 5H9

Canadian Electricity Association | Association canadienne de l'électricité

November 2017

STRICTLY PRIVILEGED AND CONFIDENTIAL

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Key Findings

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All in all, a good year for Canada's electricity sector

1. **Improvements on all key satisfaction measures.** CSI scores have improved and electricity prices are increasingly deemed reasonable. Satisfaction with electricity companies has improved, as has satisfaction with provincial government management of the sector.

2. **Putting customers first continues to drive overall satisfaction.** While there has been improvement on some key customer-focused attributes, there is room for further gains in this area. The public wants to be consulted, and electricity companies may have a lot to gain by keeping customers informed about planned and ongoing customer engagement initiatives.

3. **Keep the doors of communication open.** Communication is second only to customer service when it comes to driving satisfaction.

4. **Provincial results vary from national trend.** Most provinces are showing more stable results than the national trend would suggest. Last year's negative results were driven disproportionately by a negative trend in Ontario. This year's improvements are driven disproportionately by Ontario, although several smaller provinces with integrated utilities also registered significant improvement.

5. **Did the weather help?** We note that in two key areas of improvement – impact on household finances and reliability – weather can have an impact. Lower demand for air conditioning may have helped the bill impact question in some provinces. Similarly, fewer weather-related outages could be a source of the decline in reported outages. Both reliability and pocketbook impact have significant impact on overall reputation. We may want to explore how we can bring weather into the trend analysis.

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Key Metrics - General

Distributor Reputation

- Overall satisfaction has increased 6 points from 56% in 2016 to 62% in 2017. With only one exception, satisfaction on tracked attributes has also improved over the past 12 months.
- Satisfaction has increased on four of the five attributes that were included in the 2016 survey.
- There are three attributes on which fewer than half are satisfied.

Reliability & Power Quality

- The proportion reporting 2 more outages over the past 12 months has dropped from 54% to 45%, along with a corresponding increase from 16% to 26% in the proportion who didn't recall any outages.
- Despite experiencing fewer outages, satisfaction on attributes* related to reliability is not improving
- Fewer than half (40%) are satisfied that their distributor is considering their needs when planning an outage

Communications

- Most (53%) are satisfied with the overall communication from their distributor. At 39%, net satisfaction has returned to the higher levels reported in 2015.
- While many don't know how satisfied they are with specific forms of communication, and many others have a neutral opinion, distributor websites and bill inserts receive the highest levels of satisfaction (37% and 36% net satisfaction, respectively).

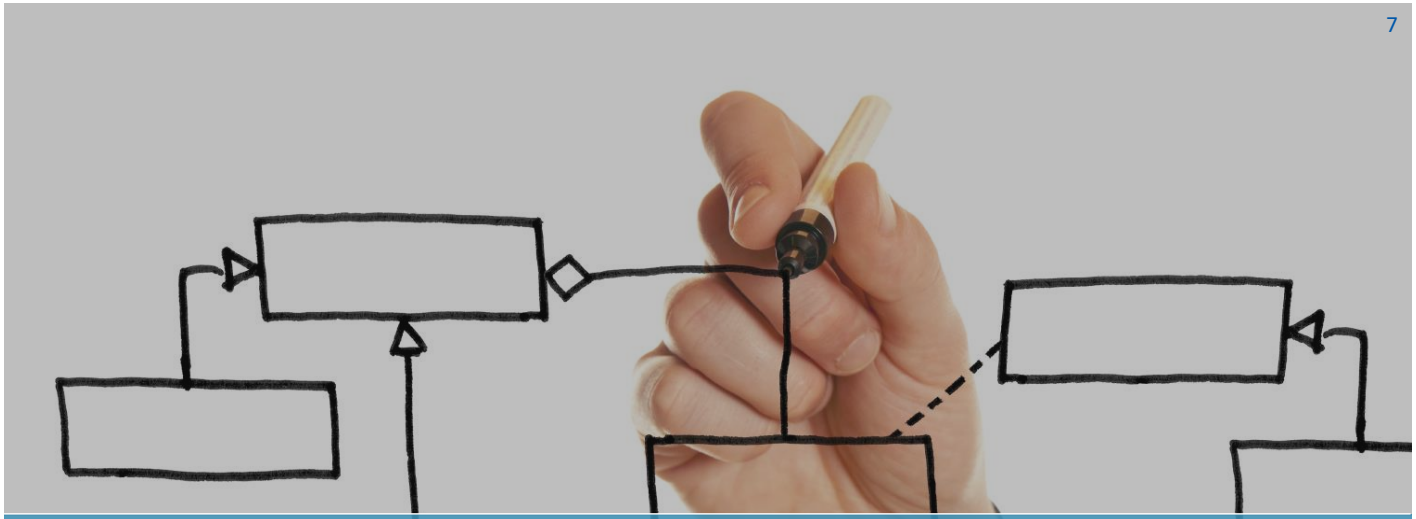
Key Metrics – Price, Billing and Payment

Price

- An increase of 4 points over 2016, 45% say the price they pay for electricity in their province is reasonable.
- Net agreement that 'my electricity bill has a major impact on my finances and requires I do without other important priorities' is down from 20% in 2016 to only 7% this year.
- There has been a six point increase in the net agreement that 'thinking of all regular household bills, I receive good value for the price I pay for electricity', from -4% to 2%.

Billing & Payment

- There has been a significant increase on satisfaction with accuracy (net satisfaction up from 52% to 64%) and bills that are easy to read and understand (up from 53% to 64%).
- Net satisfaction is strong for convenient options for receiving (71%) and paying (67%) bills.
- Half (49%) report that they still receive a paper bill in the mail.



Methodology & Demographics

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Online Survey Methodology



The findings presented in this report are based on an Innovative Research Group (**INNOVATIVE**) online survey conducted between October 4th and October 23rd, 2017 among **9,368** Canadian adults (18yrs or older).

The survey instrument was designed by INNOVATIVE, with input and direction from CEA members, and made available to respondents in either French or English.

The survey sample was weighted by age, gender and region using Statistics Canada Census data to reflect the actual demographic composition of the Canadian adult population. Upon request, additional oversamples were conducted among the general population in a number of CEA member distribution service territories to provide greater confidence in the data at a sub-regional level of analysis. Oversampled regions were weighted down to a representative national sample size of **n=5,400**.*

Online survey respondents were recruited from a wide variety of sources to reflect the age, gender, and regional characteristics of the country as a whole. INNOVATIVE provided each survey respondent with a unique URL (hyperlink) to the online survey via an email invitation to ensure that only invited respondents are able to complete the survey. Unique URLs were disabled after survey completion to ensure that invited respondents could only complete their individual survey once.

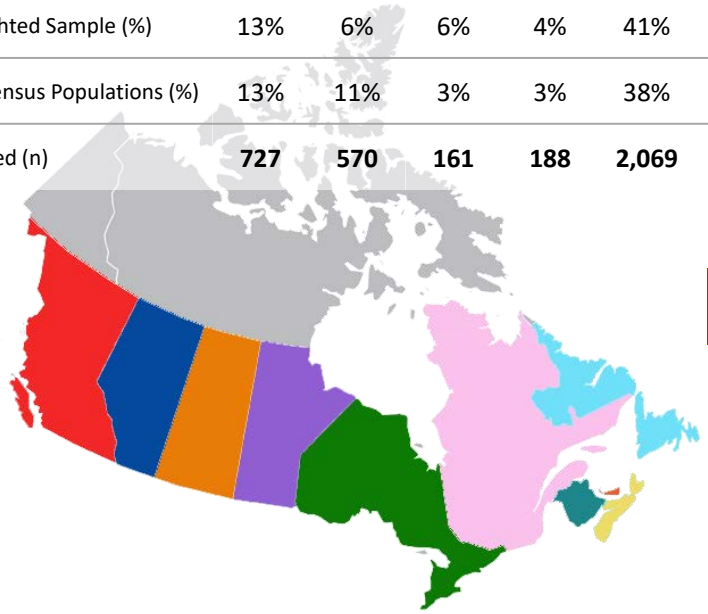
Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

* The survey sample has been weighted by the population, age and gender distributions within 32 graphical sub-regions across Canada, using the latest available Census data. This weighting convention ensures that the survey data is representative at both the national- and provincial-levels of analysis.

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Sample Design

	BC	AB	SK	MB	ON	QC	NB	PE	NS	NL	Total
Unweighted Sample (n)	**1,216**	**573**	**541**	**510**	**3,732**	**1,339**	**570**	**101**	**581**	**204**	**9,368**
Unweighted Sample (%)	13%	6%	6%	4%	41%	15%	6%	1%	6%	1%	100%
2016 Census Populations (%)	13%	11%	3%	3%	38%	24%	2%	0%	3%	2%	100%
Weighted (n)	**727**	**570**	**161**	**188**	**2,069**	**1,294**	**124**	**23**	**153**	**87**	**5,400**



n=5,400
National Weighted Sample

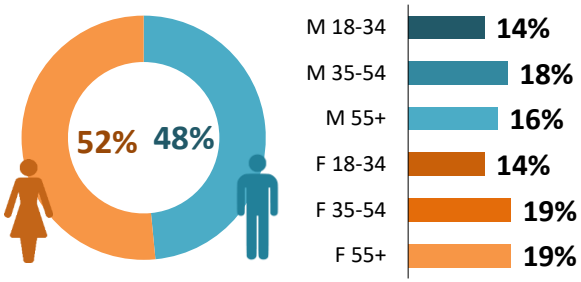
Note: The sample has been weighted by the population, age and gender distributions within 32 graphical sub-regions across Canada, using the latest available Census data. This weighting convention was used to ensure representative data at both the national- and provincial-levels of analysis.

Oversampled regions were weighted *down* (as opposed to *up*) – *from a unrepresentative national sample size of n=9,368 to a representative national sample size of n=5,400* – to ensure that respondent input from any region was not artificially inflated.

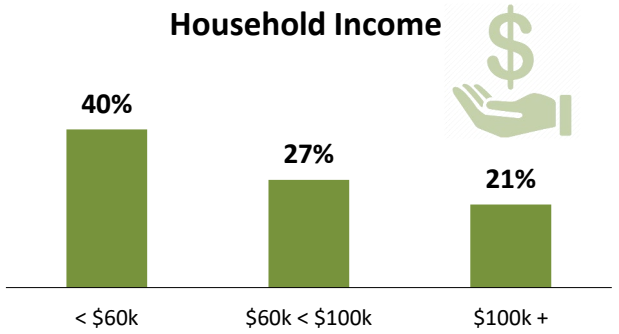
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Demographics: Respondent profile

Gender and Age

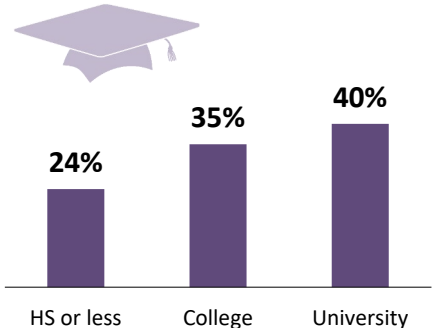


Household Income



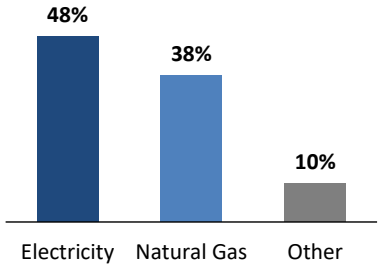
13% Prefer not to say

Education



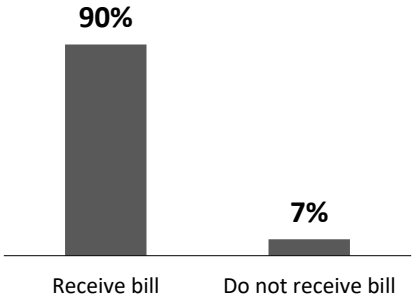
2% Prefer not to say

Primary Home Heating Source



3% Don't know

Billing



3% Don't know

Survey Design: Question Tracking

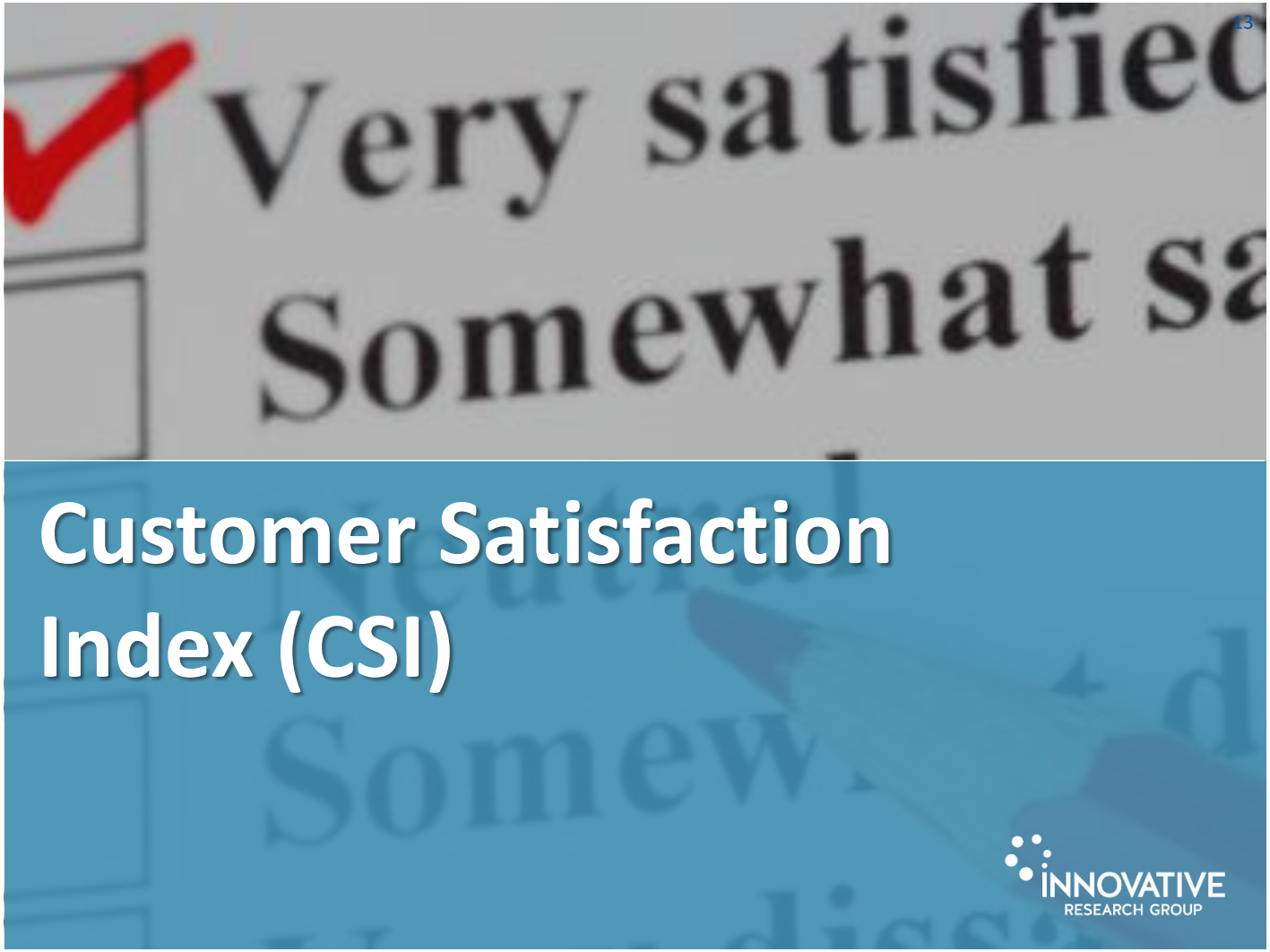
A significant change to the 2017 survey – compared to the 2014-16 versions – is that all questions pertain to ***distributors*** only. The table below indicates which questions have been tracked from previous waves of the NPAS survey.

Survey Section	Tracking	New
Satisfaction (with Distributor)		
Overall satisfaction	X	
Caring about its customers	X	
Taking care of any problems the first time you contact them	X	
Operating in an environmentally responsible manner	X	
Protecting public safety	X	
Providing energy conservation and efficiency programs and information *(Previous wording: Encouraging consumers to make more efficient use of electricity)*	X	
Being a good corporate citizen through initiatives such as contributing to community sponsorship programs *(Previous wording: Contributing back to the community through initiatives such as community sponsorship programs)*	X	
Providing online services		X
Being trustworthy		X
Being transparent		X
Consulting with customers before making decisions that impact them		X
Reliability and Power Quality		
In the past 12 months, how many power outages do you recall experiencing at home? (slight wording change)	X	
Did [INSERT COMPANY NAME] proactively communicate with you regarding the outage? | Effectiveness of communication		X
Providing reliable electricity service, as judged by the number of outages you experience *(Previous wording: Providing reliable electricity service, with a minimal number of outages)*	X	
Providing timely and accurate information regarding outages *(Previous wording: Letting you know when power will be restored in the event of an outage)*	X	
The amount of time it takes to restore power when power outages occur *(Previous wording: Speed of power restoration when an outage occurs)*	X	
Considering your needs when planning an outage		X
The quality of power delivered to you taking into consideration voltage fluctuations, that can result in flickering or dimming of lights		X

…. Continued on following slide

Survey Design: Question Tracking (cont'd)

Survey Section	Tracking	New
Billing and Payment		
Providing accurate bills	X	
Providing bills that are easy to understand	X	
Providing convenient options to receive my bill		X
Providing convenient options to pay my bill		X
Price		
Overall, do you think that the price for electricity in your province is reasonable or unreasonable?	X	
My electricity bill has major impact on my finances and requires I do without other important priorities.	X	
Thinking of all regular household bills, I receive good value for the price I pay for electricity.	X	
Communications		
Overall satisfaction	X	
Satisfaction with: Phone/In-person | Website | Social media | Outage notifications | Bill inserts | Advertising | Written inquiries		X
Do you feel you require more or less information about how your electricity supplier and the provincial electricity system operate?	X	
Customer Journey		
How would you prefer to pay bills? | What is your preferred method of bill payment?	X	
Ranking preferences for receiving updates on the status of power restoration		X
General Attitudes		
Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?	X	
Perception of increasing price of electricity to invest in province's electric system	X	
Do you think helping customers with energy conservation and management is important?		X
Would you be prepared to pay slightly more for renewable power?		X
Satisfaction with provincial government management of electricity system	X	
In Closing		
How does your customer experience with [INSERT COMPANY NAME] compare to that of other service providers you use (telephone, cable, TV/internet, natural gas, your bank)?	X	


Very satisfied
Somewhat sa
Customer Satisfaction Index (CSI)
INNOVATIVE
RESEARCH GROUP

Customer Satisfaction Index

The **Customer Satisfaction Index** (CSI) is a number that summarizes consumers' overall satisfaction with their electricity company using an analysis of each brand attribute tested.

In 2014, INNOVATIVE updated the methodology used to construct the CSI. This year's study follows this updated methodology, but – due to the survey redesign – focuses on a combined national score.

CSI Calculation Steps:

1. A ***factor analysis*** finds the true underlying dimensions of consumer satisfaction that explain the pattern of responses on the larger set of brand attributes.
    - Factor analysis allows us to find which attributes mean similar things to the public. The use of factor analysis allows us to determine which attributes should be grouped together in order to conduct meaningful analysis.)
    - We tested **20 brand attributes** for all electricity companies in the analysis. While each of these attributes seems distinct in important ways to people who are close to the industry, many of these items seem similar to members of the general public. We found that **7 underlying *factors*** explain most of the variance in the larger set of attributes.
2. We use a ***Shapley Value*** regression analysis to determine the relative contribution of each *factor* to overall satisfaction.
    - Shapley Values are a calculation of how much of the variance in overall satisfaction each individual factor explains, after statistically accounting for the fact that some of the factors are correlated with one another.
3. Take an average of the mean score on each of the *factors* weighted by their *Shapley Values* to determine the overall **CSI scores**.
4. *In keeping with the revised survey and analysis plan, the CSI is now being calculated as a single measure for all electricity companies included in the research*

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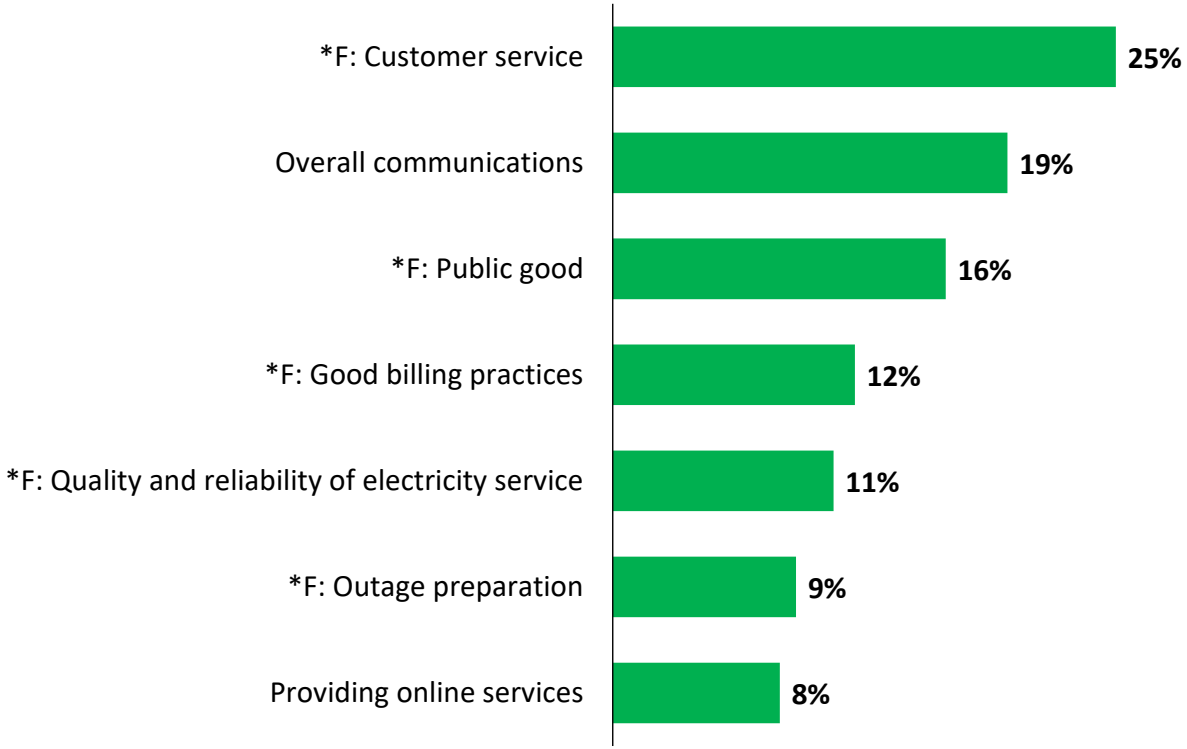
Factor Analysis: Utility attributes that group together from the perspective of the public

Utility Attributes	Customer Service	Billing Practices	Quality/ Reliability	Public Good	Outage Preparation
Consulting with customers before making decisions	X				
Being transparent	X				
Caring about its customers	X				
Being trustworthy	X				
Taking care of problems first time you contact them	X				
Being a good corporate citizen				X	
Operating in an environmentally responsible manner				X	
Protecting public safety				X	
Providing energy conservation and efficiency programs				X	
Providing convenient options to pay my bill		X			
Providing convenient options to receive my bill		X			
Providing bills that are easy to read and understand		X			
Providing accurate bills		X			
The quality of power delivered to you			X		
Providing reliable electricity service			X		
The amount of time it takes to restore power			X		
Considering your needs when planning an outage					X
Providing timely and accurate information re: outages					X

Standalone Attributes	Communication	Online services
Overall Communication	X	
Providing Online Services		X

2017 Key Drivers of "Electricity Company" Satisfaction

Relative contribution of each factor (*F) to overall satisfaction according to Shapley Value regressions

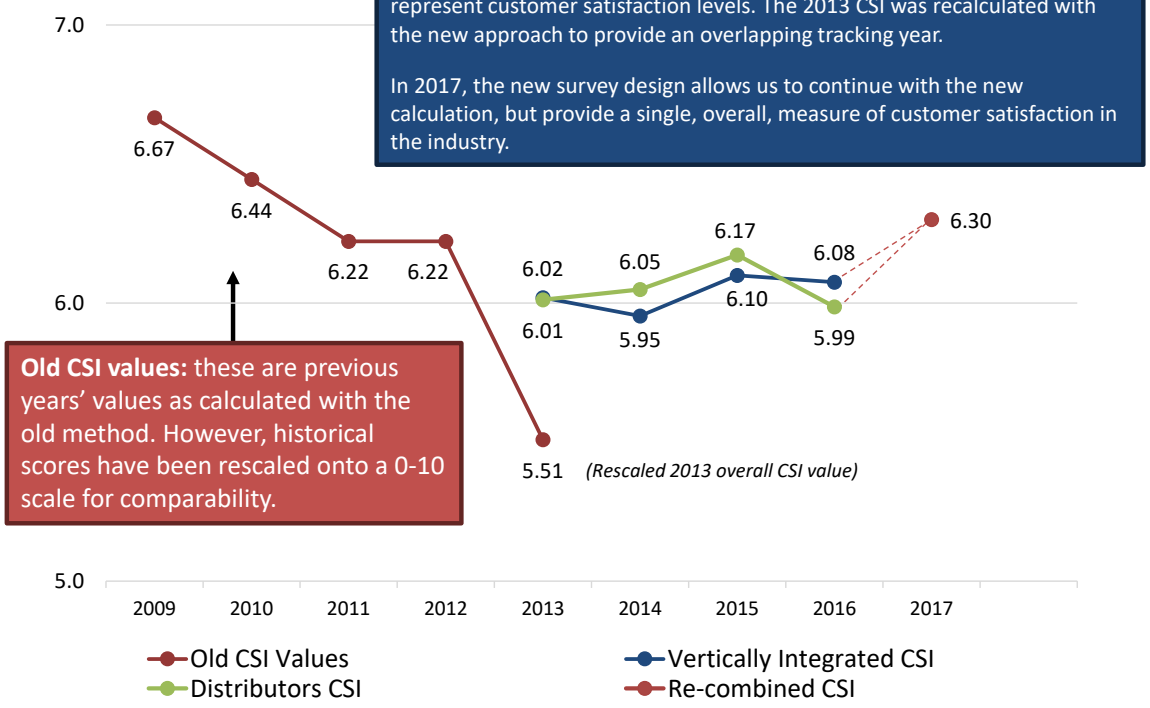


2017 R^2: 55%

Index Tracking: CSI scores at highest level in 5 years

CSI values: starting in 2014 CSI is calculated using a new approach to better represent customer satisfaction levels. The 2013 CSI was recalculated with the new approach to provide an overlapping tracking year.

In 2017, the new survey design allows us to continue with the new calculation, but provide a single, overall, measure of customer satisfaction in the industry.



Old CSI values: these are previous years' values as calculated with the old method. However, historical scores have been rescaled onto a 0-10 scale for comparability.

Note: previously the CSI had been calculated on a 1-10 scale; in keeping with the move to a 0-10 scale for this year's survey, previous year's CSI scores have been rescaled 0-10. For example the 2013 score of 5.51 on a 0-10 scaled that is reported here corresponds to last year's reported score of 5.9 on a 1-10 scale.

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Action Analysis

What does the data tell us about what to do next?

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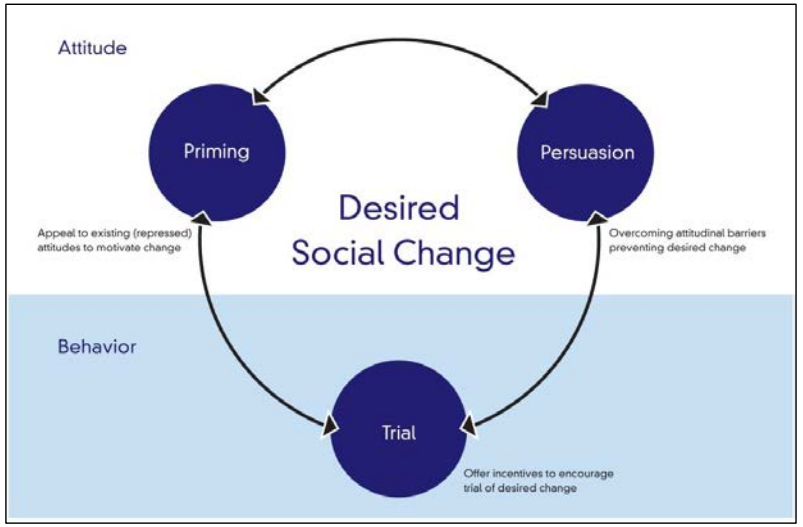
Changing Public Perceptions: Social Marketing

The concept of social marketing is all about getting people to change their behaviour. Getting a flu shot. Taking precautions when investing. Saving for retirement. Using less electricity. Accepting price increases. **Simply stated, but not simply achieved.**

There are three primary options for opinion change:

- **Persuasion** – Teaching people something they didn't know in order to increase their likelihood of doing or believing the desired belief or action.
- **Priming** – Reminding people of something they already know in order to increase their likelihood of doing or believing the desired belief or action.
- **Trial** – Getting people to do the desired behaviour so it becomes a habit.

On-going research will provide electricity companies with a framework to assess their target audience to identify the key opinion anchors for priming, the best new information for persuasion, and the most appealing offers for trial.



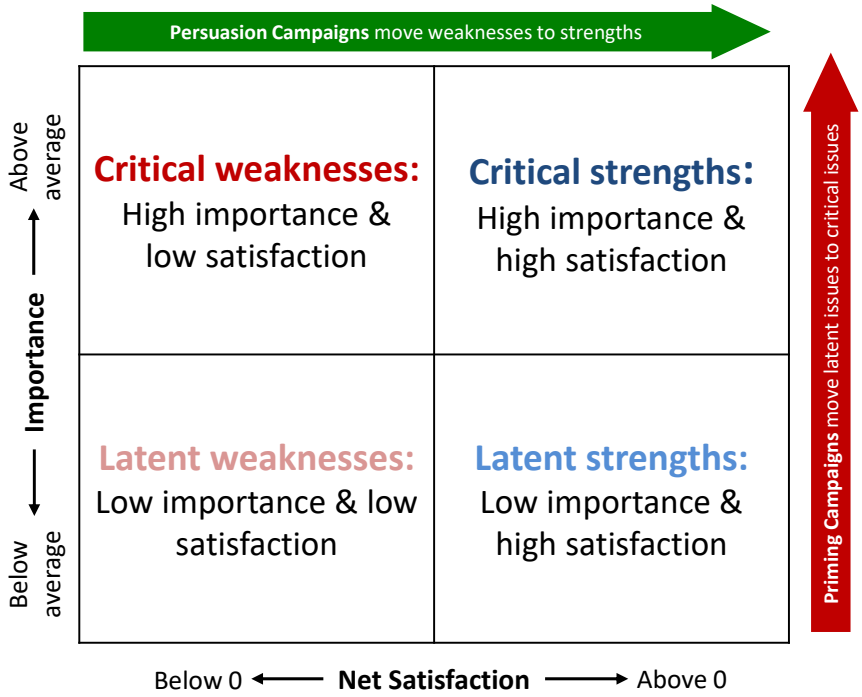
In terms of behaviour, **trial** is best since a change of behaviour is the goal. Trial works best if it is run in parallel with a supportive campaign to change attitudes that conflict with the behaviour.

Persuasion is the next best since persuasion results in permanent behaviour change.

Priming is the often the least effective for long term change since once the campaign is over, the priming effect quickly fades. But if priming is sustained long enough to establish new habits, the change can be permanent.

Comparing Importance and Satisfaction

Once we understand what factors underlie each brand, we can examine how levels of overall satisfaction on each factor compare to their level of importance. The satisfaction scores shown below are net satisfaction while the level of importance is calculated using a *Shapley Value* regression as detailed in the previous section.

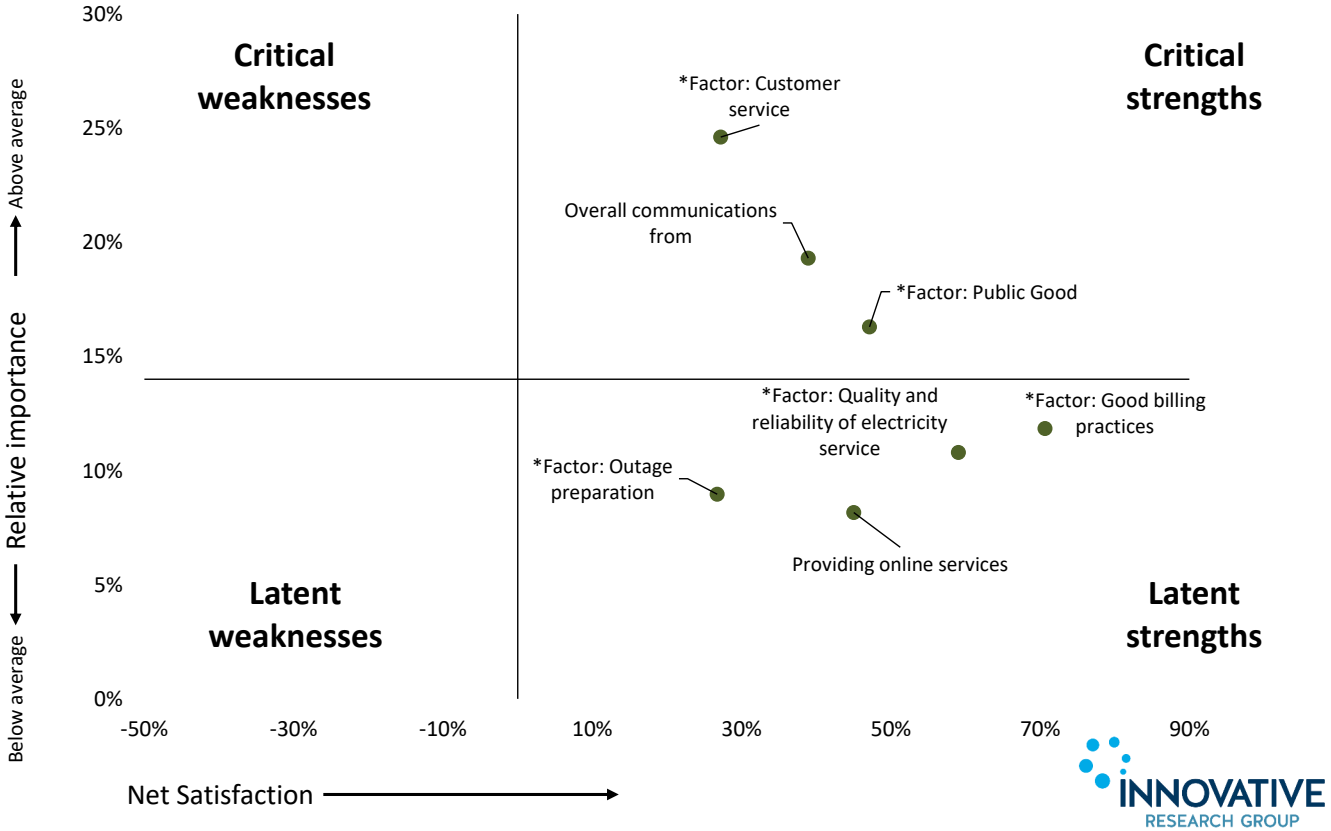


Improving the importance of an issue is best approached through *Priming*. This means moving it away from being a *latent strength* and towards being a *critical strength*. Priming by raising the salience of an issue in usually executed through advertising and the media, but only lasts as long as the issues remains in the public eye.

Increasing the levels of satisfaction with an issue is *Persuasion*. This means moving an issue from a weakness to a strength. Once people are persuaded that an organization is doing well on a particular attribute that opinion is likely to stick. However, persuasion campaigns are often long fought and expensive.

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Distribution: *Importance vs. Satisfaction*





Distributor Reputation

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Summary: Distributor Reputation

In this section, survey participants were asked about overall satisfaction and satisfaction with specific attributes of their distribution company.

Overall satisfaction has increased 6 points from 56% in 2016 to 62% in 2017. With only one exception, satisfaction on tracked attributes has also improved over the past 12 months.

Net satisfaction has improved on the following attributes:

- Taking care of any problems the first time you contact them (from 36% to 38%)
- Operating in an environmentally responsible manner (from 32% to 37%)
- Being a good corporate citizen through initiatives such as contributing to community sponsorship programs* (from 19% to 29%)
- Caring about its customers (from 18% to 26%)

Despite some improvements over last year, there are still attributes on which fewer than half are satisfied:

- Caring about its customers (48% satisfied)
- Being a good corporate citizen through initiatives such as contributing to community sponsorship programs* (42% satisfied)
- Being transparent (40% satisfied)
- Consulting with customers before making decisions that impact them (34% satisfied)

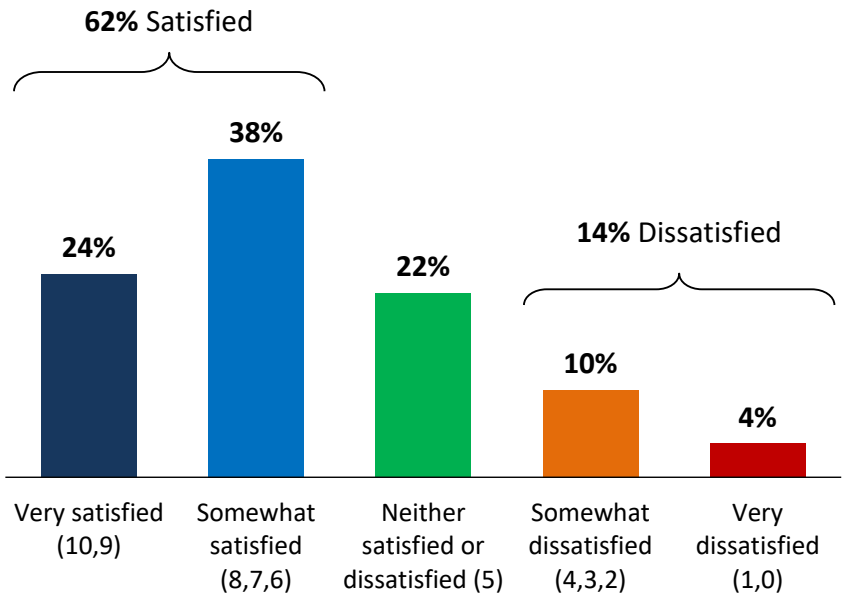
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* Wording changed from *"Contributing back to the community through initiatives such as community sponsorship"*

Satisfaction: Approximately 3-in-5 respondents are satisfied with their electricity company

Q In general, how satisfied are you with [ELECTRICITY COMPANY]]? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

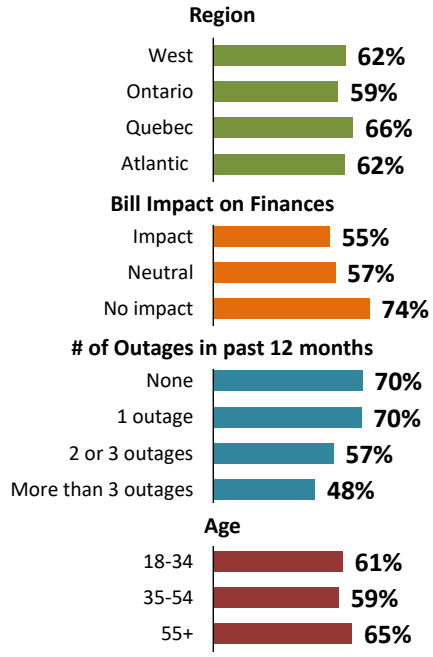
[asked of all respondents; n=5,400]



Note: 'Don't know' (2%) not shown

2017 Segmentation

*Those who say **"satisfied"** with their electricity company*



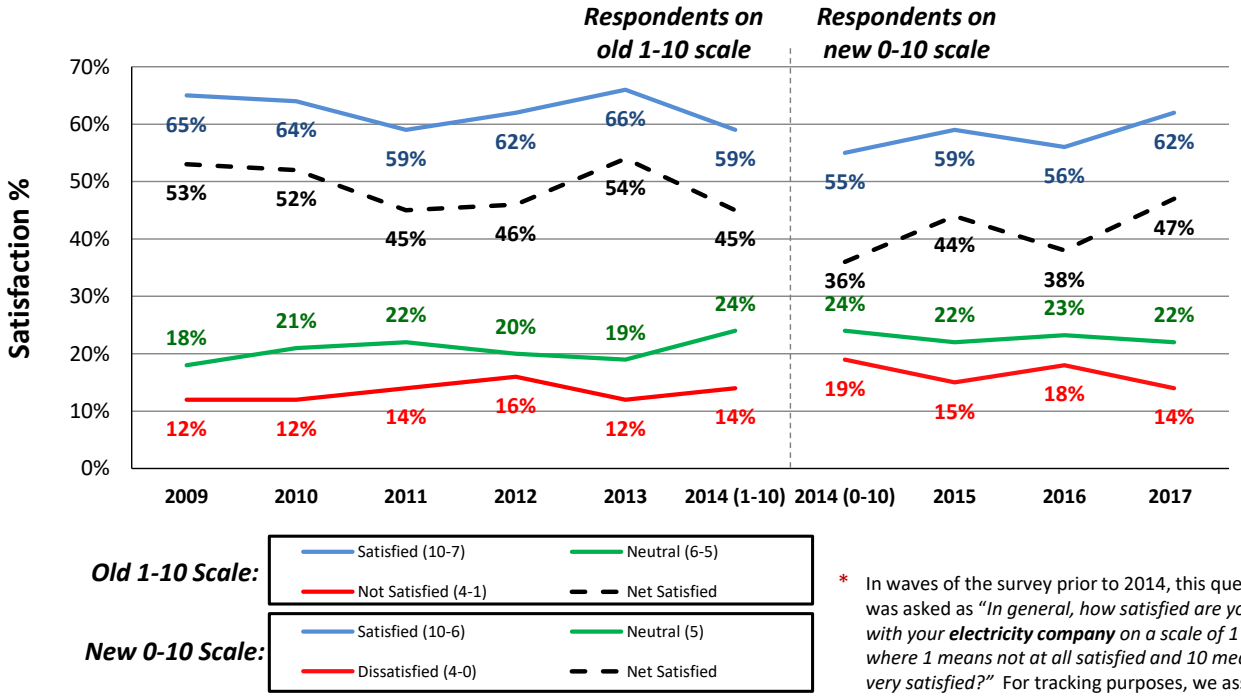
OVERALL SATISFACTION

Overall Satisfaction:

Net satisfaction is up 9 points since last year

Q Generally, how satisfied are you with [ELECTRICITY COMPANY]]? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; 2017, n=5,400; 2014 split sample: n=1,588]

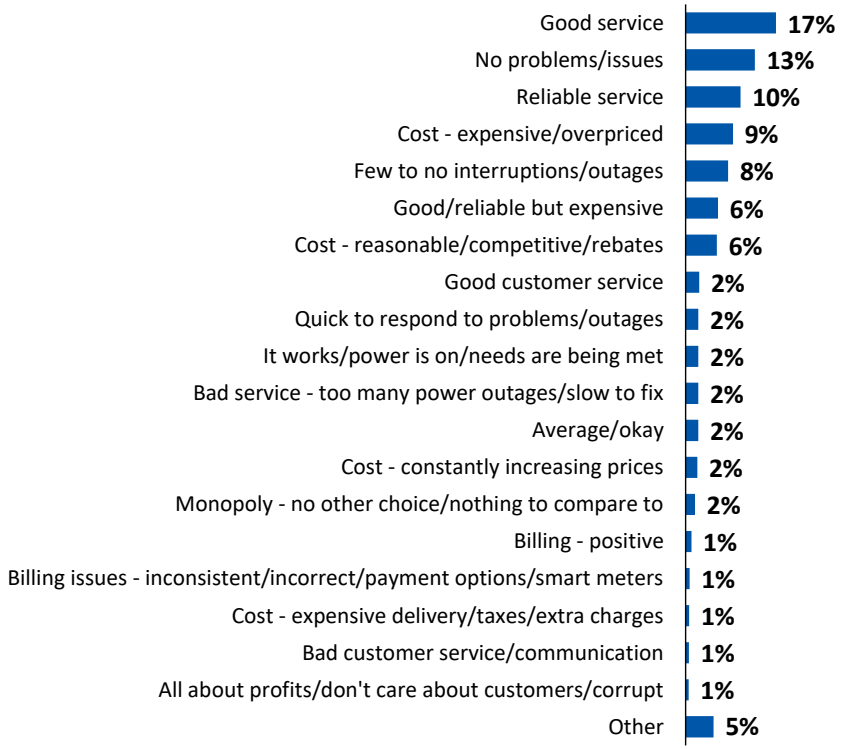


* In waves of the survey prior to 2014, this questions was asked as "*In general, how satisfied are you with your **electricity company** on a scale of 1 to 10, where 1 means not at all satisfied and 10 means very satisfied?"* For tracking purposes, we assume that "**electricity company**" mean "**company that provides distribution services**". In the 2014 survey two scales were used to rate satisfaction, 1-10 and 0-10.

Why Satisfied?

Over 1-in-4 (27%) cite good or reliable service as top reason

Q Tell us why you feel this way [OPEN ENDED]
[asked of those who are satisfied with their distributor; n=3,338]

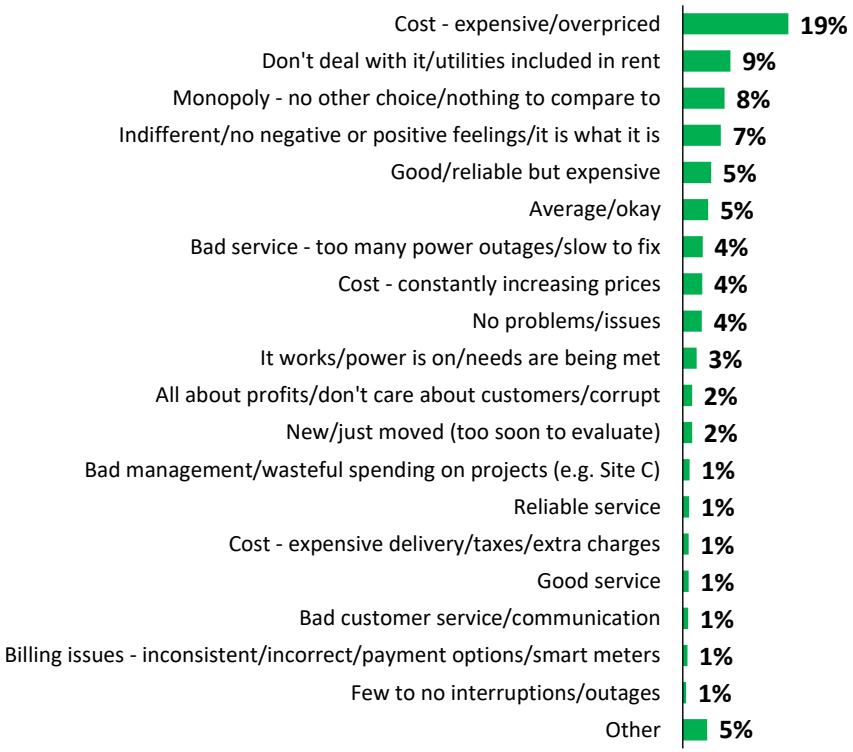


Note: “No reason”/”Don't know”/”Refused” not shown.

Why Neutral? Cost is key reason for ambivalent

Q Tell us why you feel this way [OPEN ENDED]

[asked of those who have a neutral opinion of their distributor; n=1,284]



Note: “No reason”/”Don't know”/”Refused” not shown.

Why Not Satisfied?: Cost (by far) most important reason for dissatisfied group

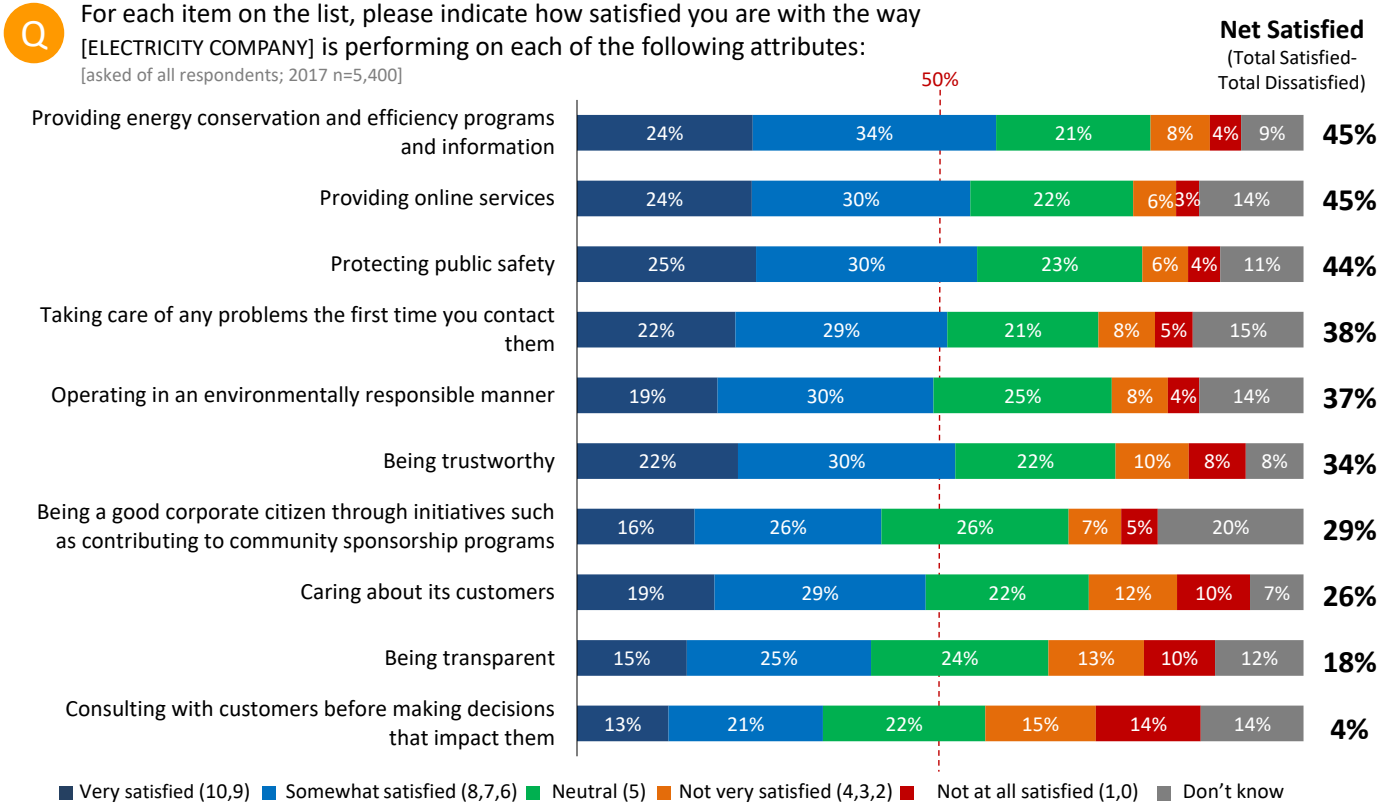
Q Tell us why you feel this way [OPEN ENDED]
[asked of those who are dissatisfied with their distributor; n=778]



Note: “No reason”/”Don't know”/”Refused” not shown.

All Attributes: Satisfaction highest with *CDM*, *online services*, and *public safety*. Least satisfied with *consultation*

Q For each item on the list, please indicate how satisfied you are with the way [ELECTRICITY COMPANY] is performing on each of the following attributes:
[asked of all respondents; 2017 n=5,400]

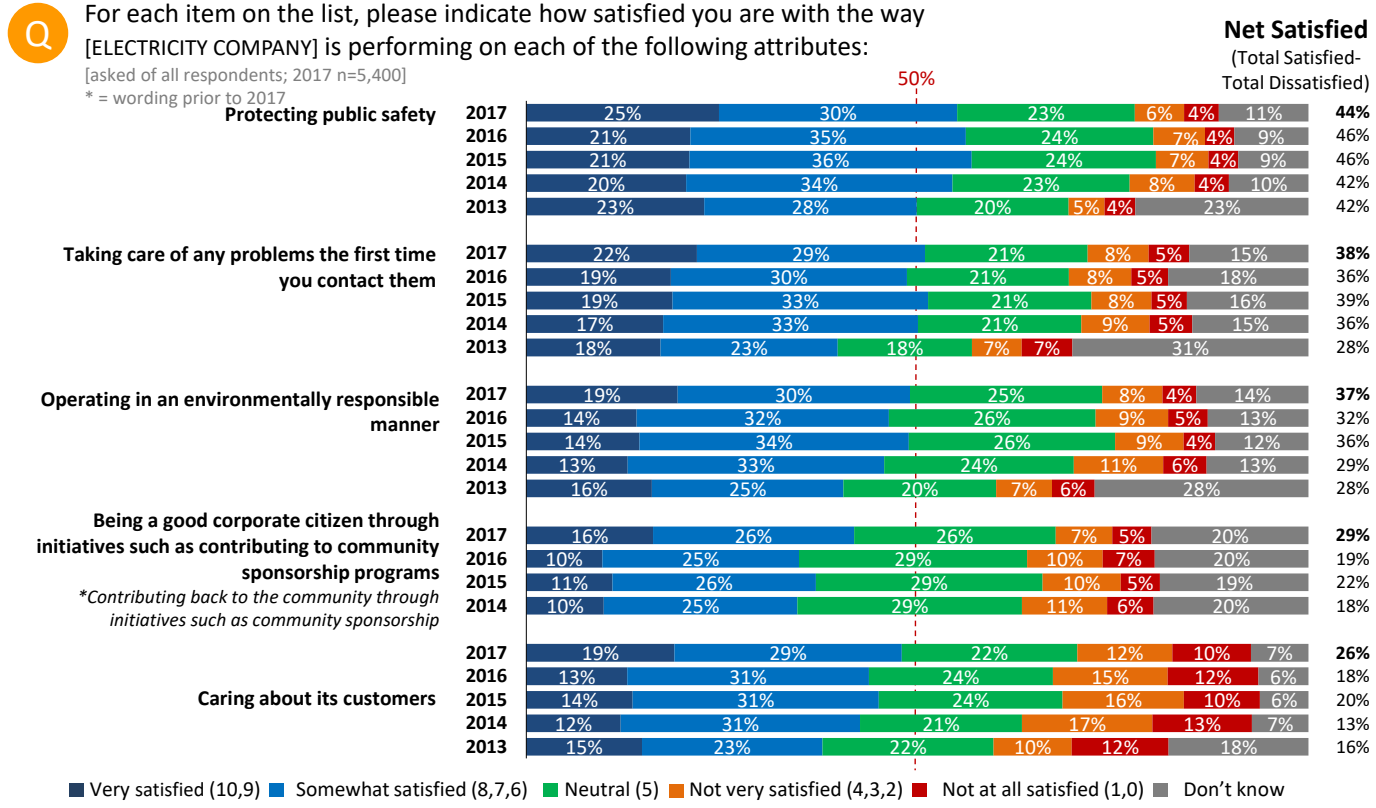


OVERALL SATISFACTION

Tracking Attributes: Satisfaction up from 2016 on *corporate citizenship, caring about customers & enviro responsibility*

Q For each item on the list, please indicate how satisfied you are with the way [ELECTRICITY COMPANY] is performing on each of the following attributes:

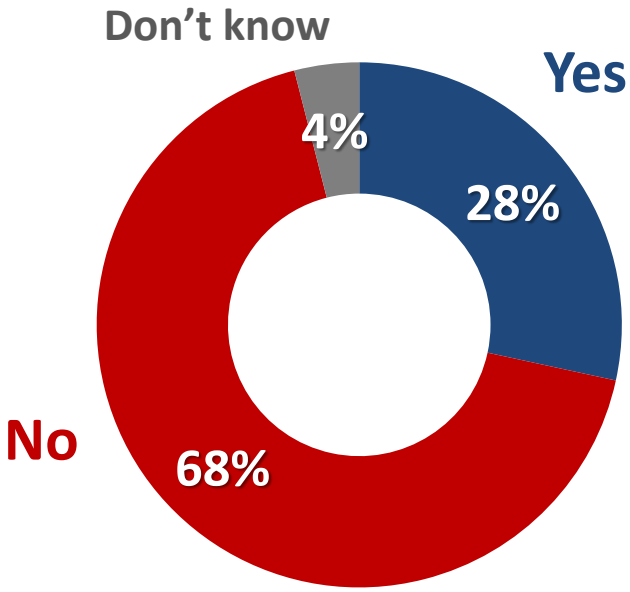
[asked of all respondents; 2017 n=5,400]
* = wording prior to 2017



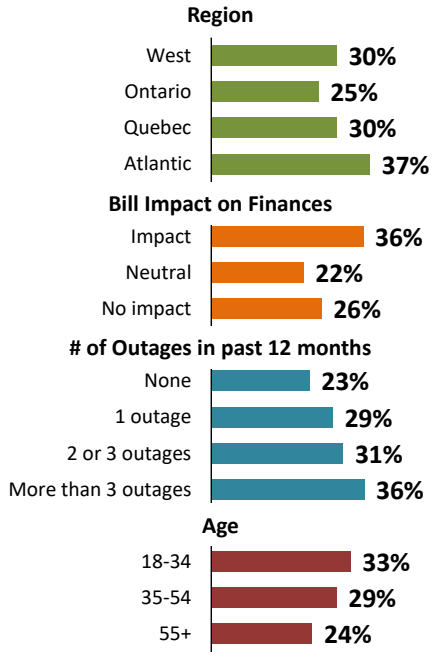
OVERALL SATISFACTION

Interaction: Fewer than three-in-ten have had an interaction with their distributor in the past year

Q Have you had an interaction with [COMPANY NAME] in the last 12 months? *Please select Yes or No.*
[asked of all respondents; n=5,400]



2017 Segmentation
*Those who **have had an interaction** with their electricity distributor*



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Alberta Satisfaction

INNOVATIVE RESEARCH GROUP

Methodology: Alberta Satisfaction Only



The findings presented ***in this section of the report only*** are based on an Innovative Research Group (**INNOVATIVE**) online survey conducted between November 10th and November 15th, 2017 among **307** adults (18yrs or older) living in Alberta.

The survey instrument was designed by INNOVATIVE, with input and direction from CEA members.

The survey sample was weighted by age, gender and region using 2016 Statistics Canada Census data to reflect the actual demographic composition of the Albertan adult population. The final weighted sample size is 200.

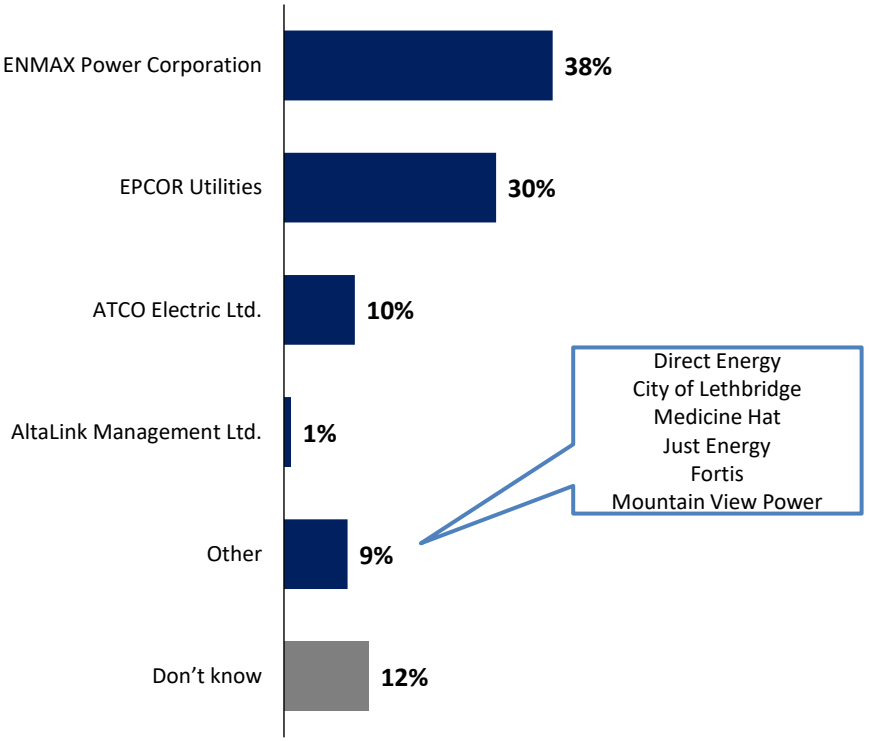
Online survey respondents were recruited a variety of sources. INNOVATIVE provided each survey respondent with a unique URL (hyperlink) to the online survey via an email invitation to ensure that only invited respondents are able to complete the survey. Unique URLs were disabled after survey completion to ensure that invited respondents could only complete their individual survey once.

Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

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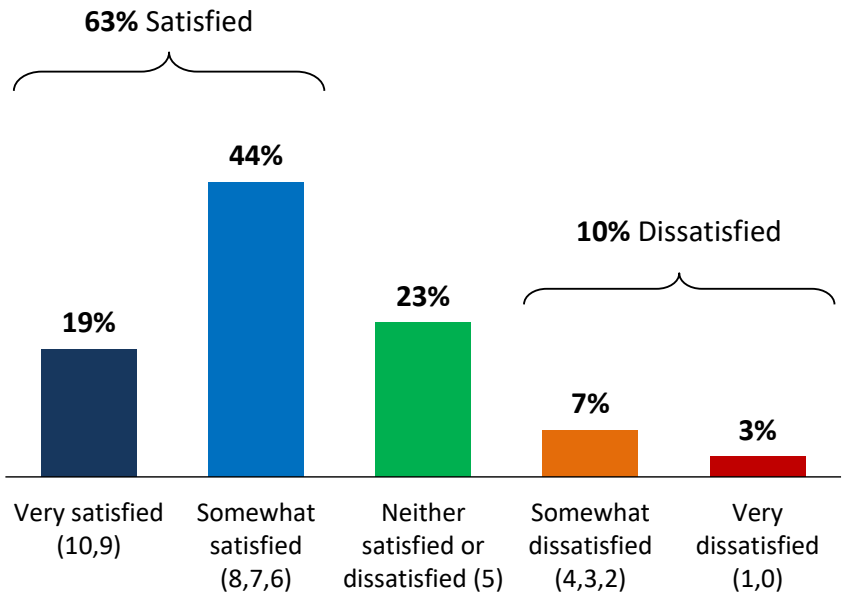
Transmission Company: Most identify ENMAX or EPCOR as their transmission company

Q Which transmission company is PRIMARILY responsible for delivering your electricity?
[asked of all respondents; n=200]



Satisfaction with Transmission Company: Almost two-thirds (63%) are satisfied with their transmission company

Q In general, how satisfied are you with [TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=200]



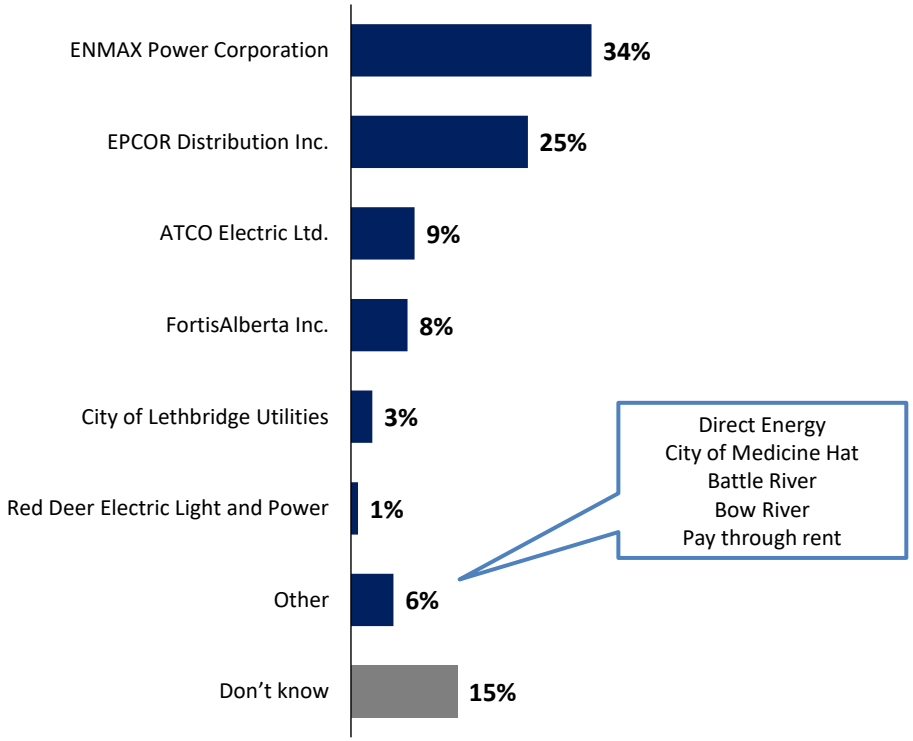
Note: 'Don't know' (4%) not shown

OVERALL SATISFACTION

INNOVATIVE RESEARCH GROUP

Distribution Company: Most identify ENMAX or EPCOR as their distribution company

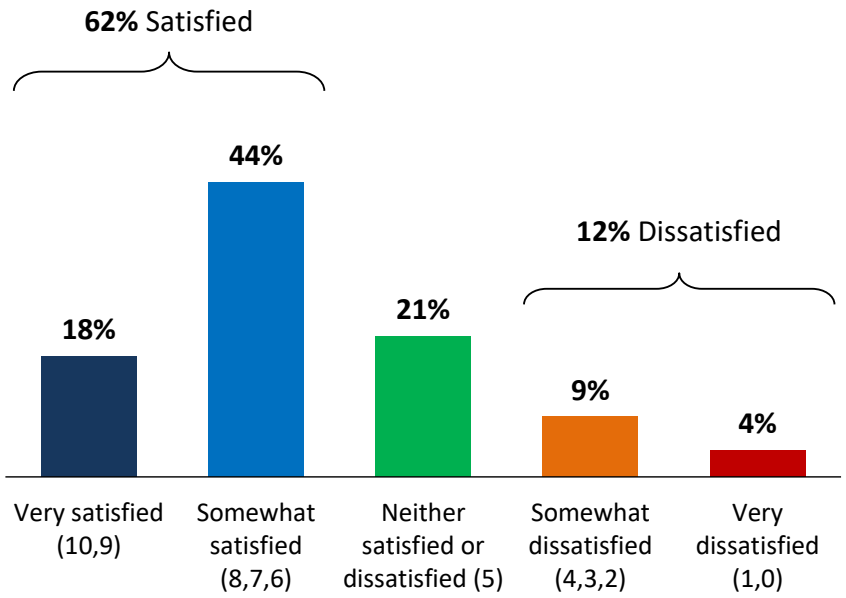
Q Which distribution company delivers your electricity?
[asked of all respondents; n=200]



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Satisfaction with Distribution Company: More than six-in-ten (62%) are satisfied with their distribution company

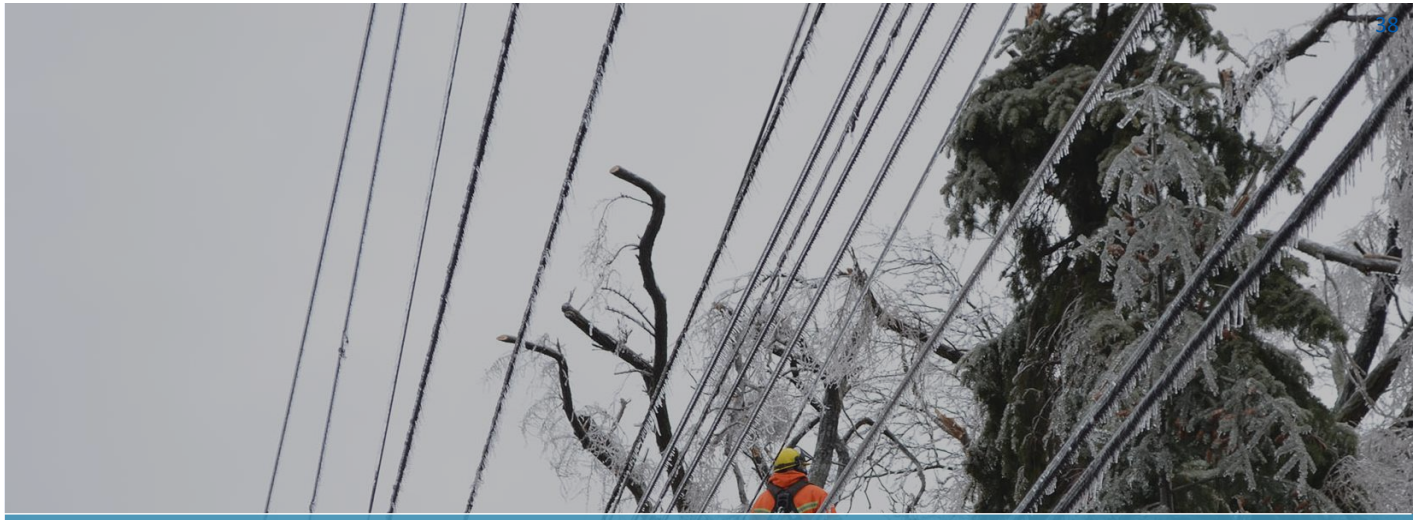
Q In general, how satisfied are you with [DISTRIBUTION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=200]



Note: 'Don't know' (4%) not shown

OVERALL SATISFACTION

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Reliability & Power Quality

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Summary: Reliability and Power Quality

- The proportion reporting 2 more outages over the past 12 months has dropped from 54% to 45%, along with a corresponding increase from 16% to 26% in the proportion who didn't recall any outages.
- One in five (19%) who experienced an outage report their distributor proactively communicated with them about the outage, and 74% of this group said the proactive communication was effective in helping them manage through the power interruption.
- Despite experiencing fewer outages, satisfaction on attributes* related to reliability is not improving:
    - Providing reliable electricity service, as judged by the number of outages you experience (net satisfaction down from 60% to 56%)
    - The amount of time in takes to restore power when outages occur (largely unchanged: 49% vs 48% net satisfaction)
    - Providing timely and accurate information regarding outages (largely unchanged: 27% vs 26% net satisfaction)
- Fewer than half (40%) are satisfied that their distributor is considering their needs when planning an outage.

* See corresponding chart for wording changes in each attribute

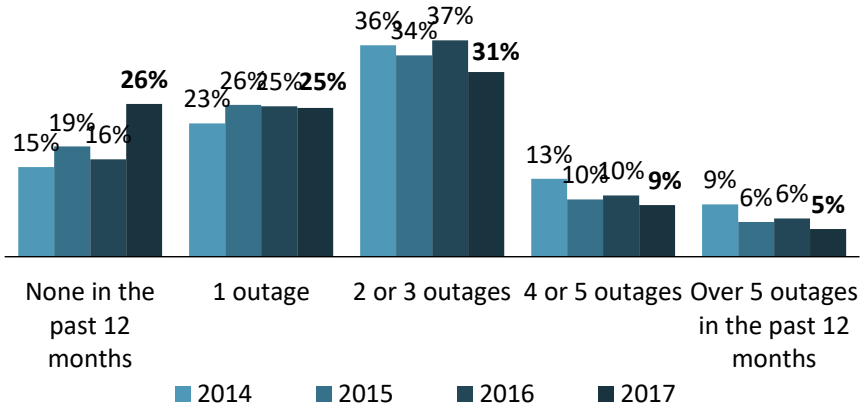
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Power Outages: For the first time since tracking began, fewer than half report having had 2 or more outages in the past year

Q In the past 12 months, how many power outages do you recall experiencing at home?

[asked of all respondents; 2017 n=5,400]

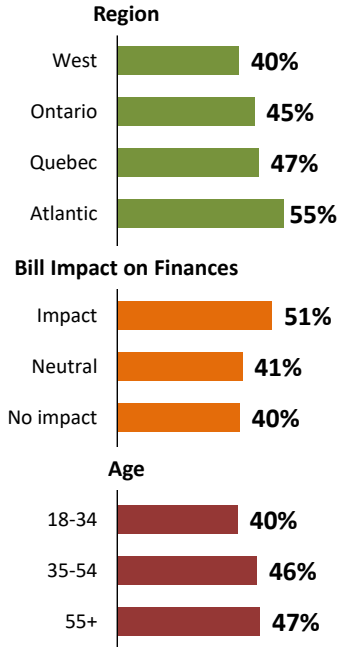
Respondents who have experienced 2 or more outages over the past 12 months:
2014: 58%
2015: 50%
2016: 54%
2017: 45%



Note: 'Don't know' (4%) not shown

2017 Segmentation

Those who say they have experienced ***"two or more outages"***

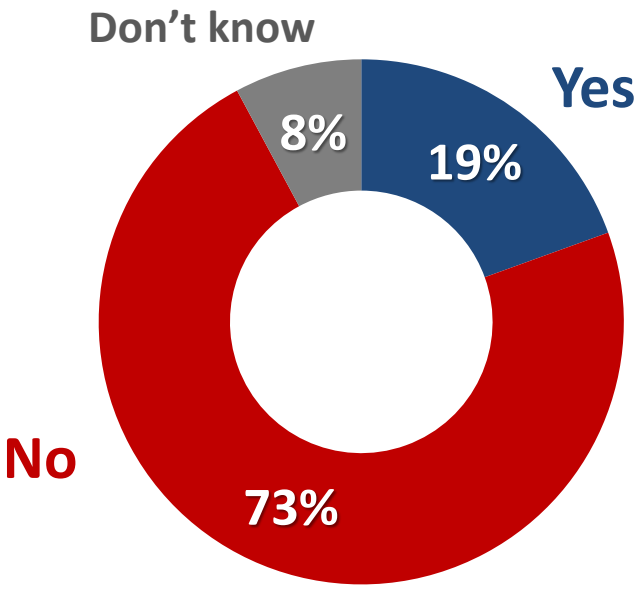


INNOVATIVE RESEARCH GROUP

Proactive Communication: Most respondents were not proactively communicated with regarding outages

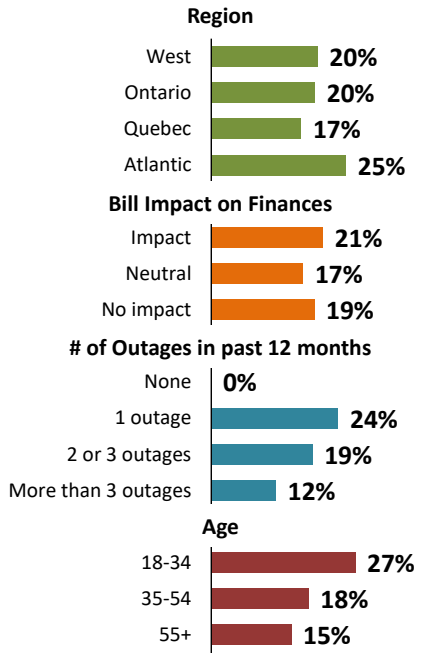
Q Did [INSERT COMPANY NAME] proactively communicate with you regarding the outage?

[asked of respondents who have experienced an outage; n=3,773]



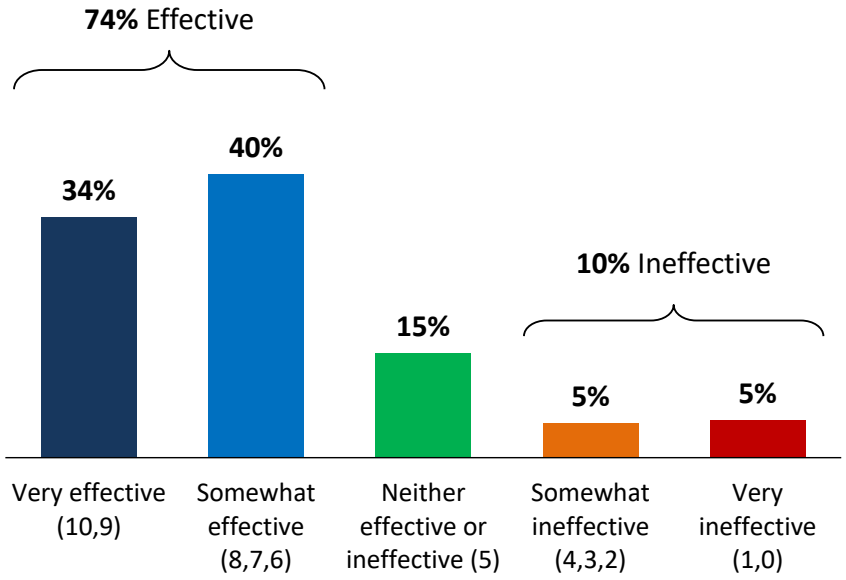
2017 Segmentation

*Those who **received proactive communication** regarding outage*



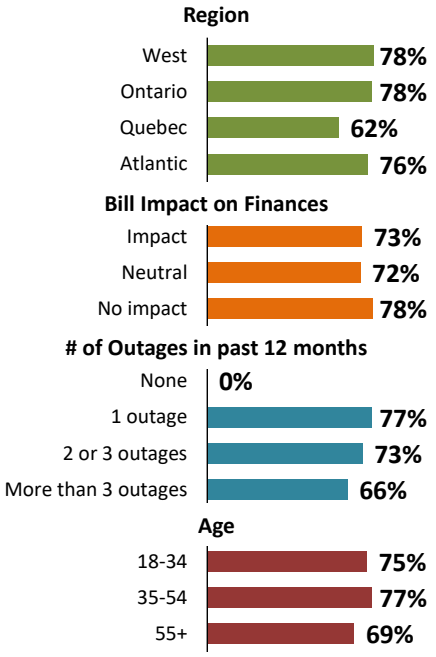
Assessment of Communication: Those who did receive proactive communication found it effective in helping them manage

Q Was the communication effective in helping you manage through the power interruption?
Please use the scale from 0 to 10, where 0 means very ineffective and 10 means very effective.
[asked of respondents who received proactive communication; n=735]



Note: 'Don't know' not shown

2017 Segmentation
*Those who say the communication was **"effective"***

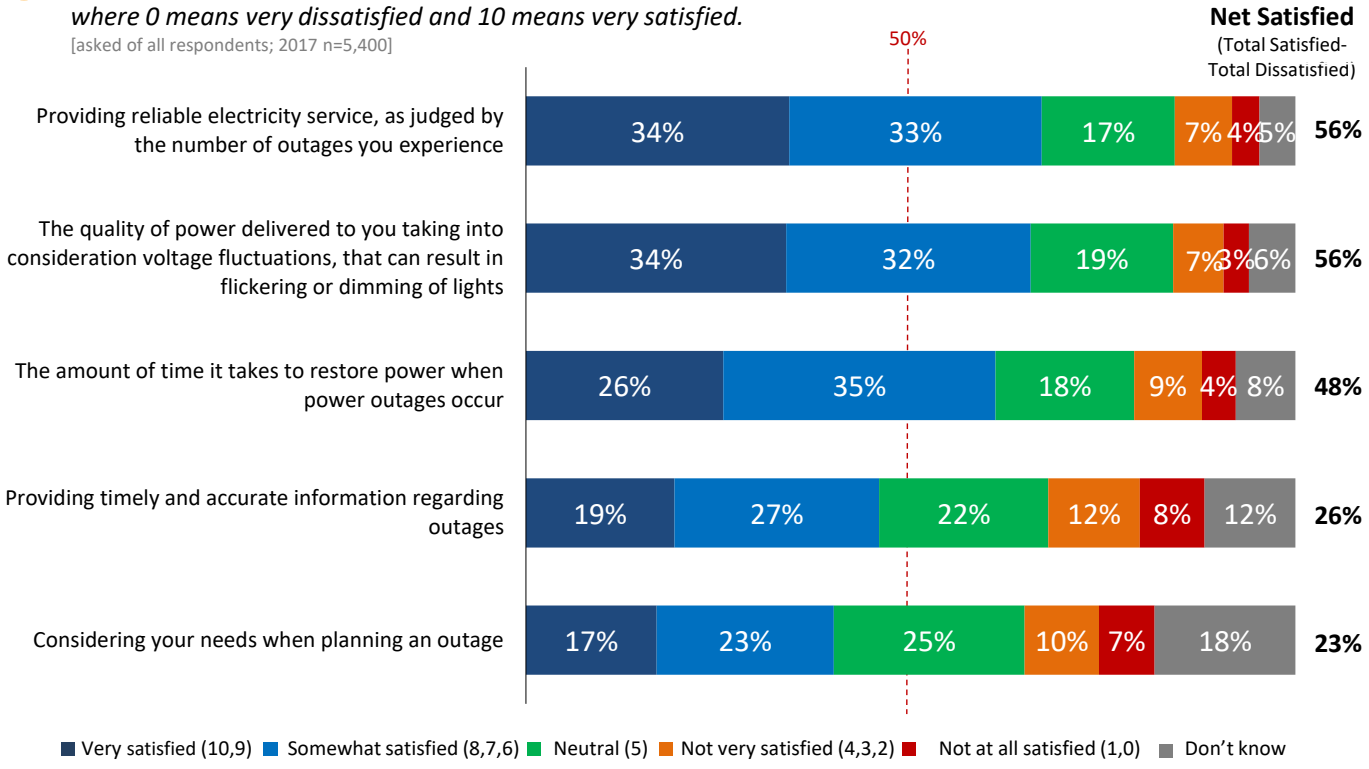


INNOVATIVE RESEARCH GROUP

All Attributes: Approximately 2-in-3 respondents are satisfied with the reliability of electricity & quality of power

Q Please indicate how satisfied you are with the way that [INSERT COMPANY NAME] is performing on each of the following attributes related to your electrical service: *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

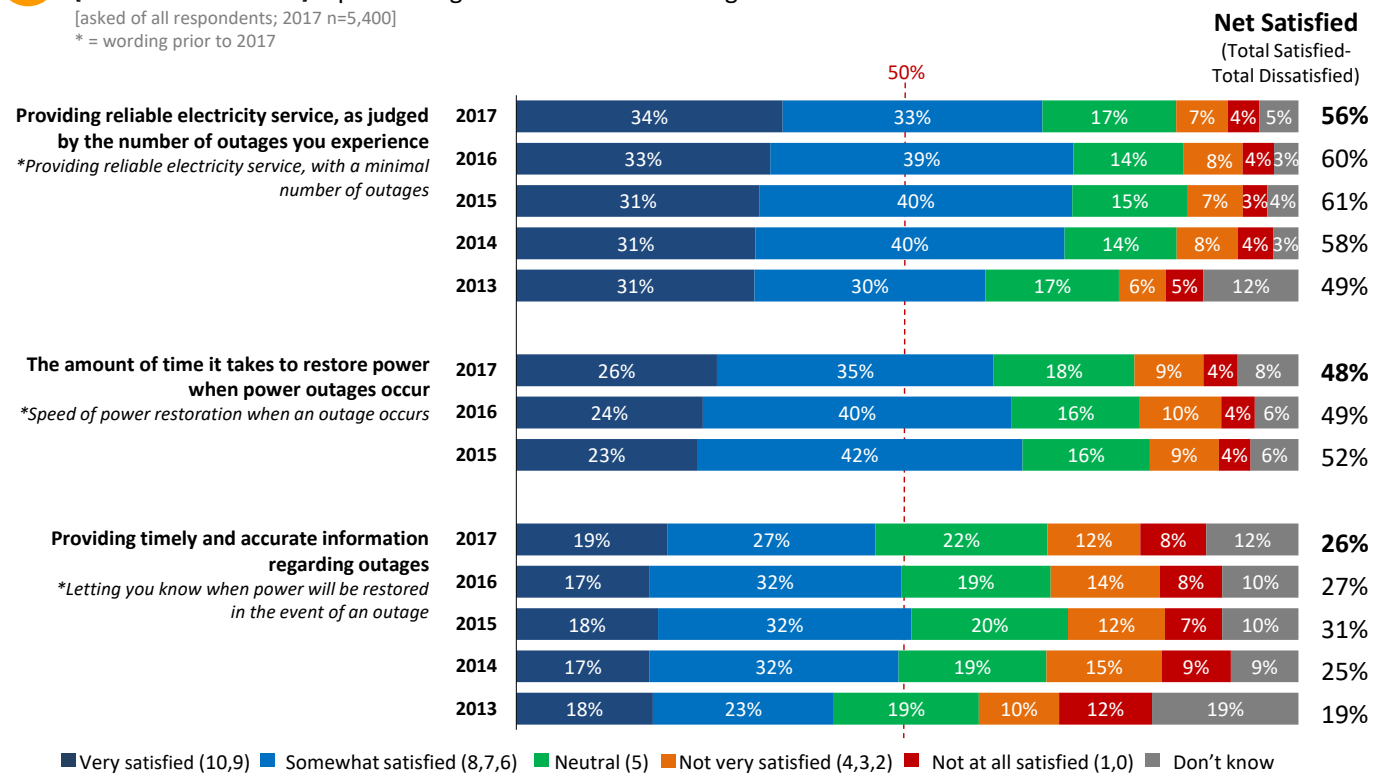
[asked of all respondents; 2017 n=5,400]

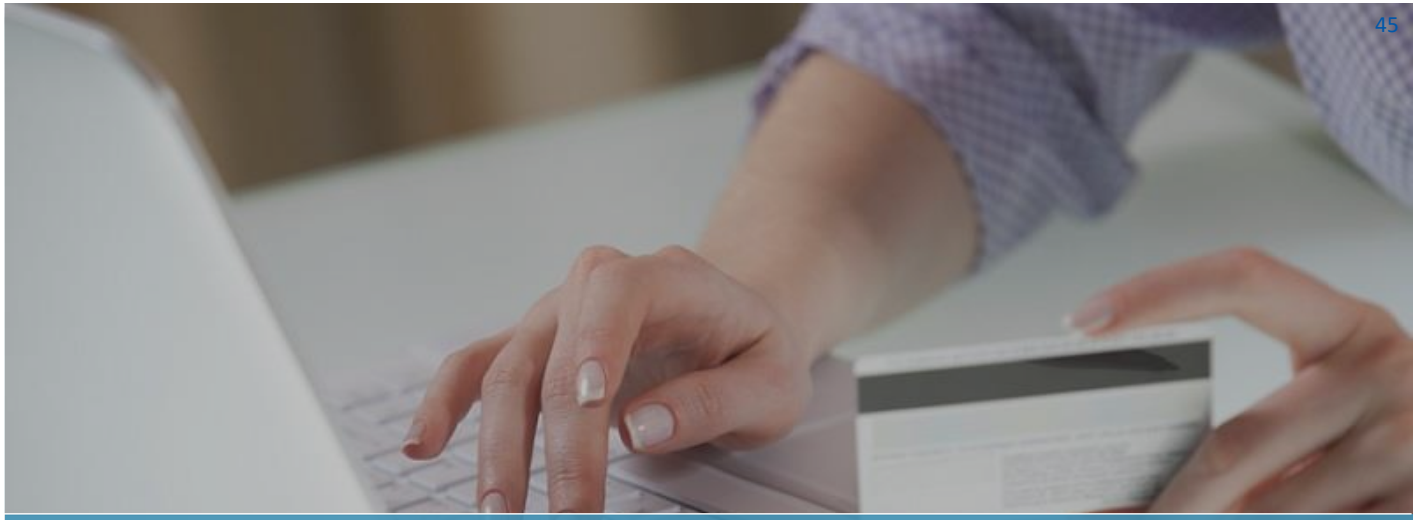


Tracking Attributes: Satisfaction down slightly or fairly steady since 2016 (note wording changes)

Q For each item on the list, please indicate how satisfied you are with the way [ELECTRICITY COMPANY] is performing on each of the following attributes:

[asked of all respondents; 2017 n=5,400]
* = wording prior to 2017





Billing & Payment

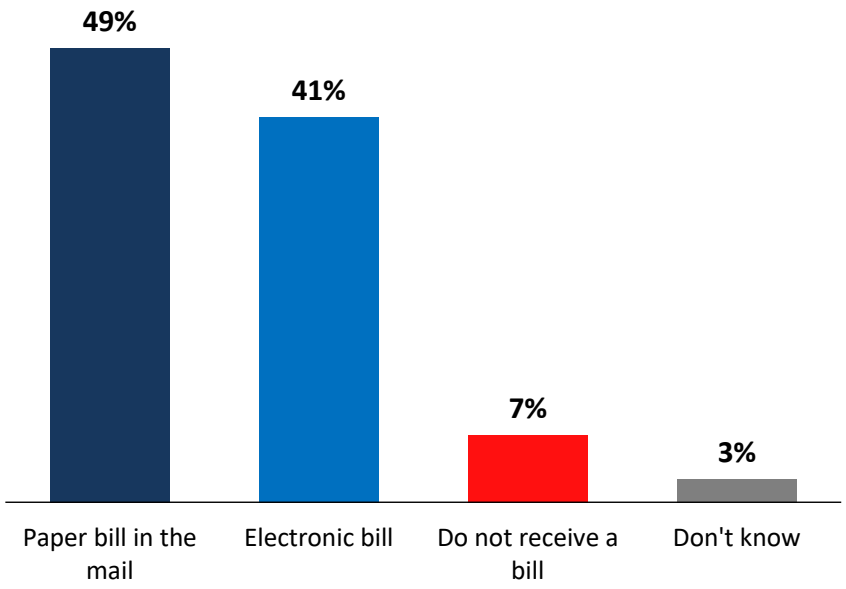
INNOVATIVE RESEARCH GROUP

Summary: Billing and Payment

- Half (49%) report that they still receive a paper bill in the mail.
- There has been a significant increase on satisfaction with accuracy (net satisfaction up from 52% to 64%) and bills that are easy to read and understand (up from 53% to 64%).
- Net satisfaction is strong for convenient options for receiving (71%) and paying (67%) bills.

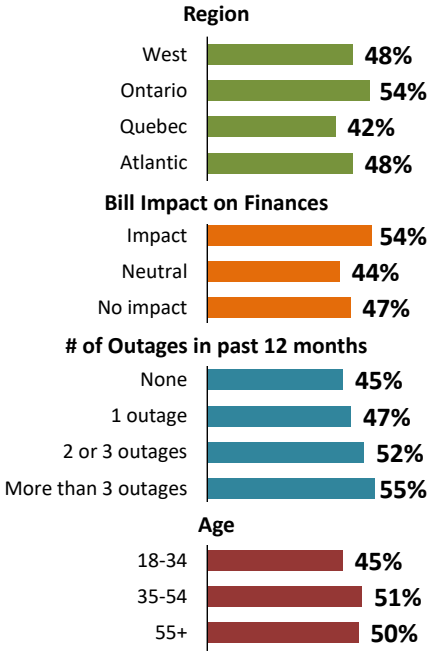
Format of Electricity Bill: Approximately half (49%) of respondents receive a paper bill

Q In what format do you receive your electricity bill?
[asked of all respondents; n=5,400]



2017 Segmentation

*Those who say they receive a "**paper bill in the mail**"*

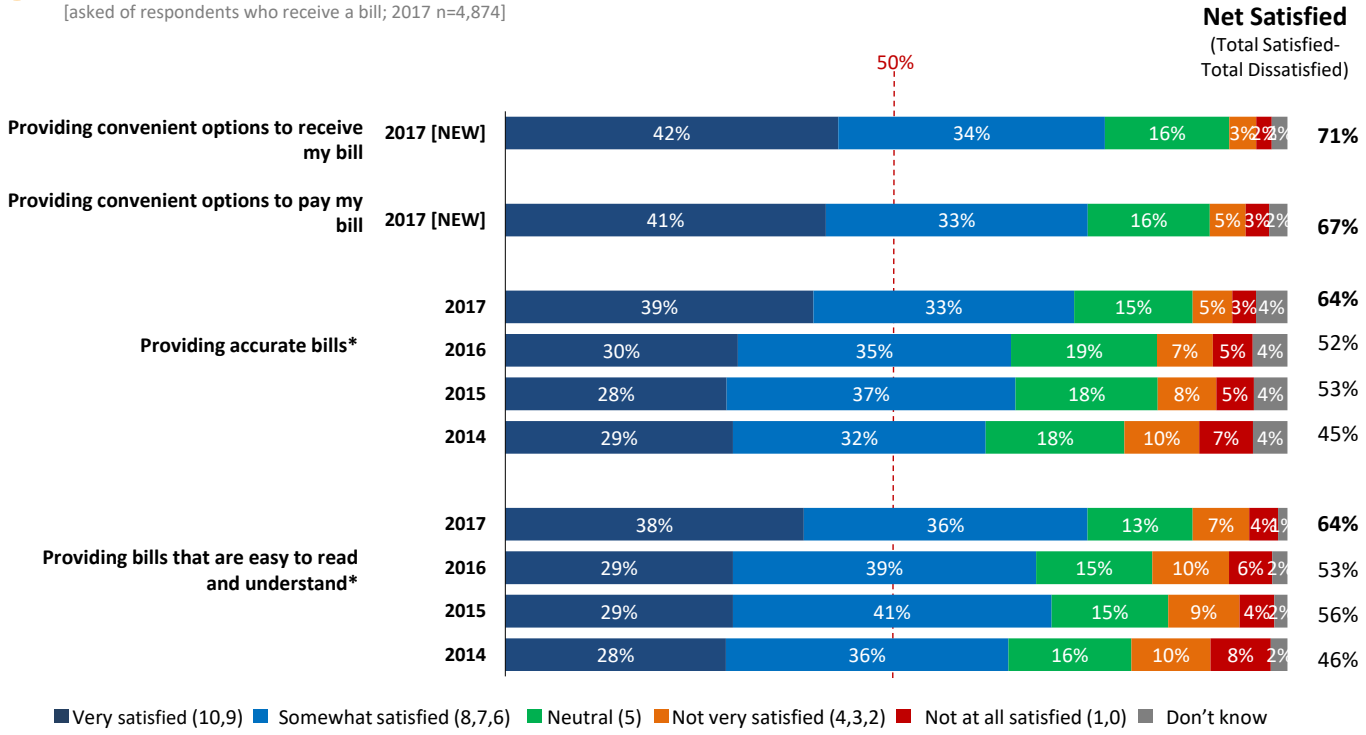


INNOVATIVE RESEARCH GROUP

Tracking Billing & Payment Attributes: Bills are perceived as convenient, accurate and easy to understand

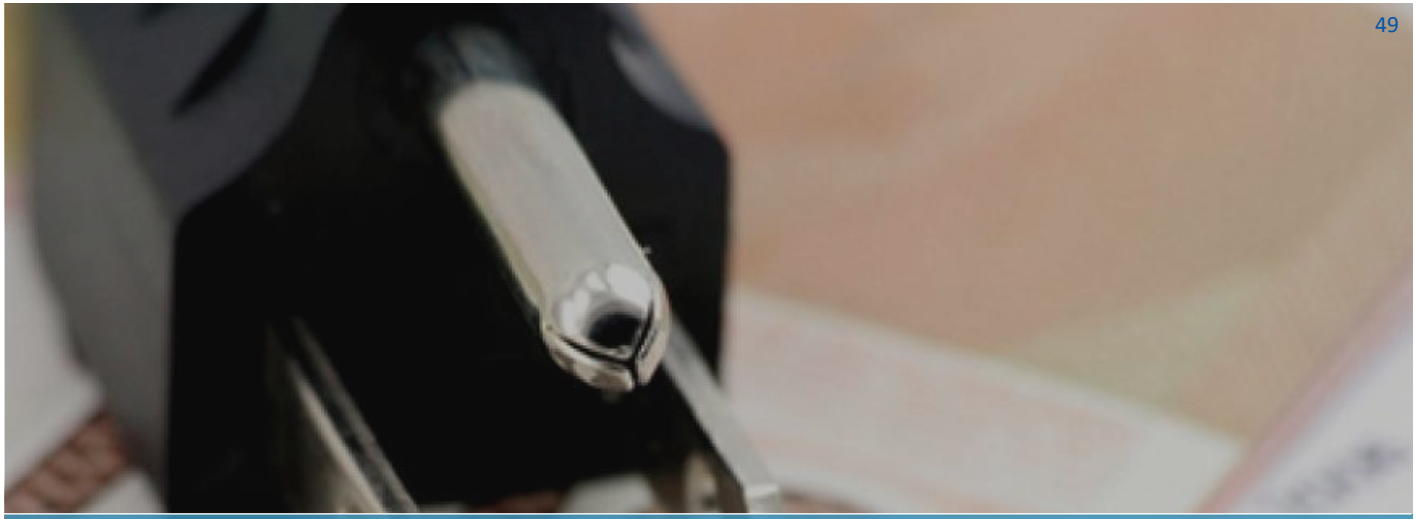
Q For each item on the list, please indicate how satisfied you are with the way [ELECTRICITY COMPANY] is performing on each of the following attributes related to your electricity bills:

[asked of respondents who receive a bill; 2017 n=4,874]



BILLING & PAYMENT

*Tracking from 2013 not included due to differences in how billing question was asked.



Price

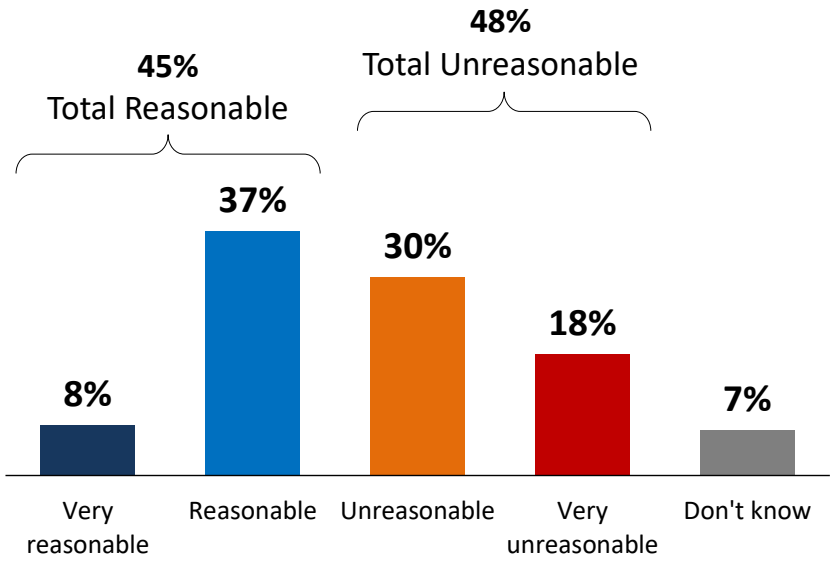
INNOVATIVE RESEARCH GROUP

Summary: Price

- An increase of 4 points over 2016, 45% say the price they pay for electricity in their province is reasonable. However, for the fourth year in a row, “net reasonable” remains in the negative at -4%.
- A cooler Canadian summer (as well as a decrease in hydro bills in Ontario) is reflected in the reported impact of electricity bills. Net agreement that *‘my electricity bill has a major impact on my finances and requires I do without other important priorities’* is down from 20% in 2016 to only 7% this year.
- Along a similar vein, there has been a six point increase in the net agreement that *‘thinking of all regular household bills, I receive good value for the price I pay for electricity’*, from -4% to 2%.

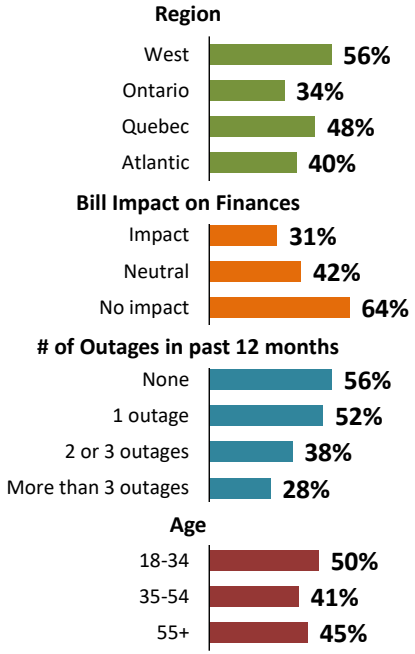
Attitudes on Price: "Unreasonable" barely edges out "reasonable" when it comes to the price of electricity

Q Overall, do you think that the price for electricity in your province is reasonable or unreasonable?
[asked of all respondents; n=5,400]



2017 Segmentation

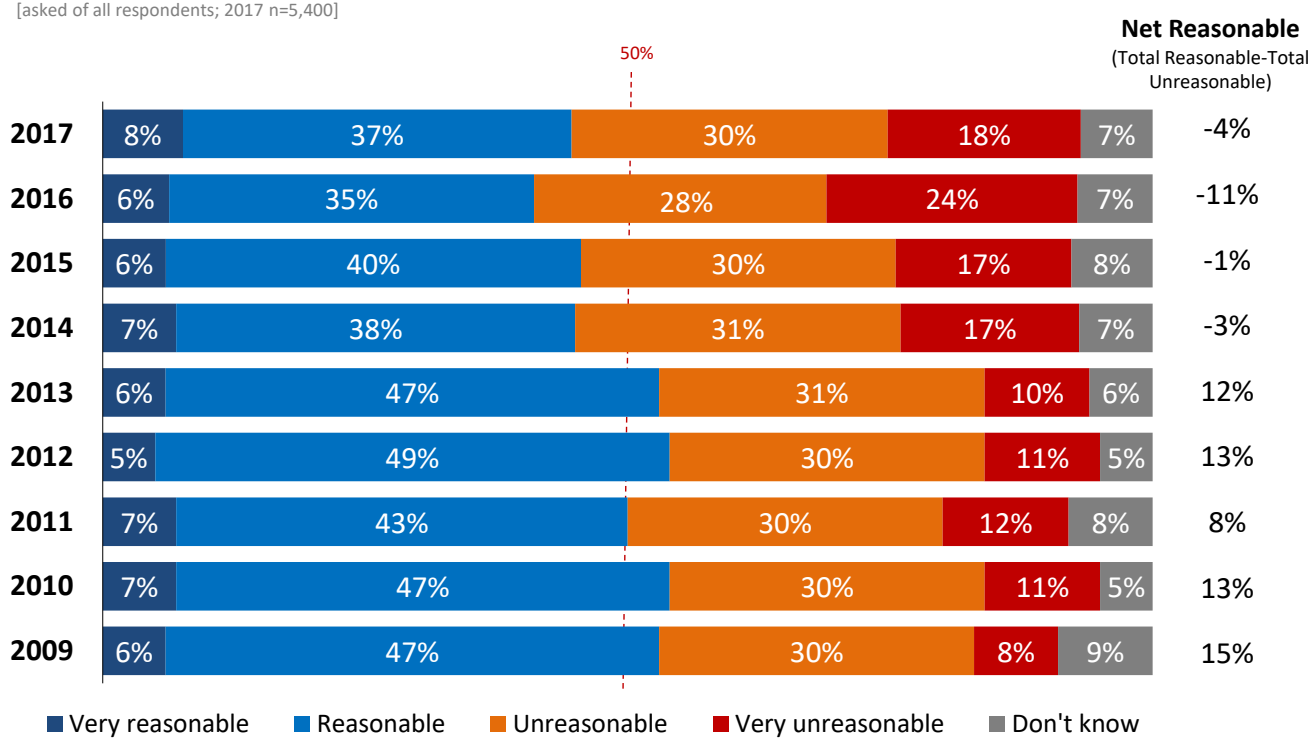
*Those who say the price of electricity is **"reasonable"***



PRICE $

Reasonable Price: Net reasonability of electricity prices returns to 2014 level

Q Overall, do you think that the price for electricity in your province is reasonable or unreasonable?
[asked of all respondents; 2017 n=5,400]

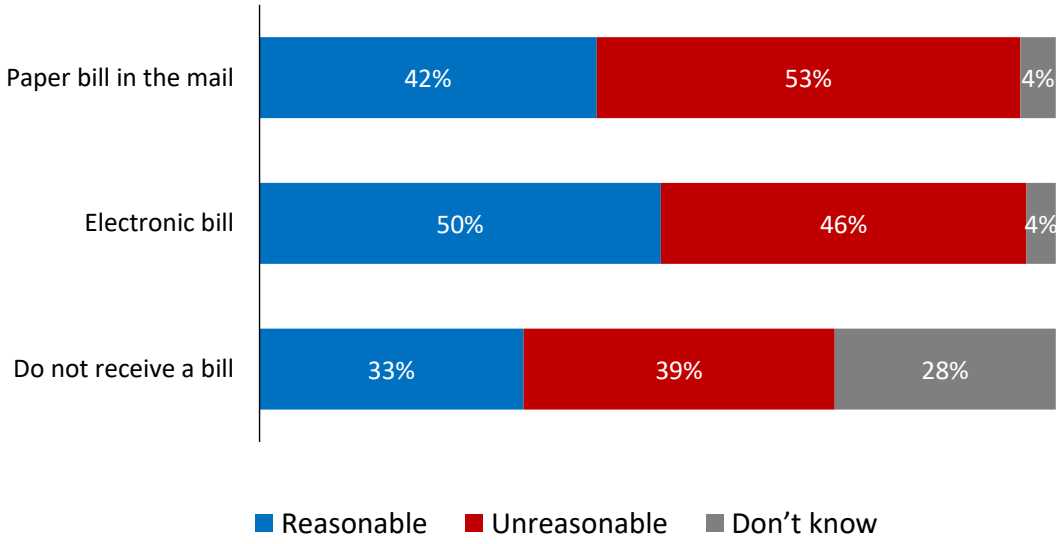


PRICE $

Reasonable price: Those who receive an electronic bill are most likely to say the price of electricity is reasonable

Q Overall, do you think that the price for electricity in your province is very reasonable, reasonable, unreasonable, or very unreasonable? BY Type of bill

[asked of all respondents; 2017 n=5,400]

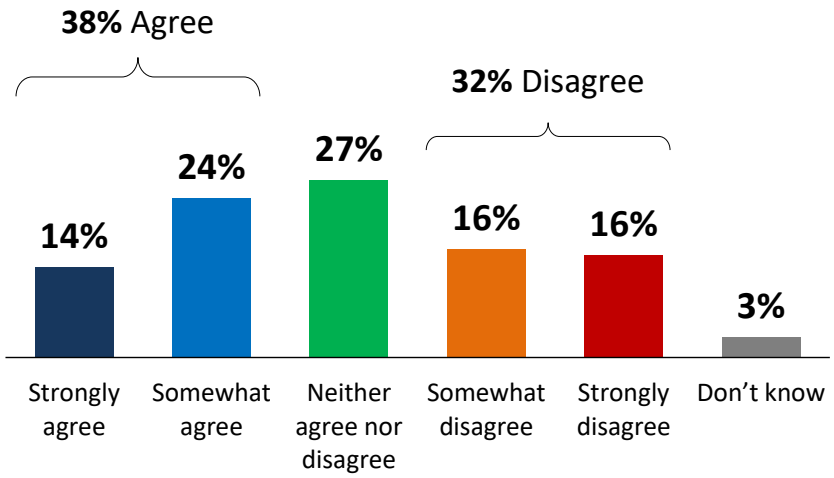


PRICE $

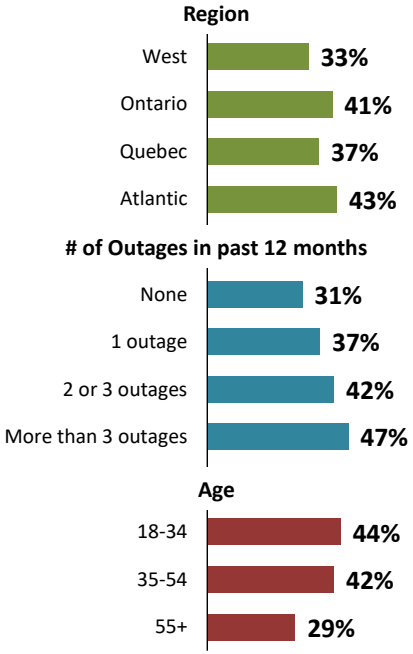
INNOVATIVE RESEARCH GROUP

Financial Impact: 38% of respondents say bill has major impact; those who experience 'more than 3 outages' appear most effected

Q Do you agree or disagree with the following statements?
My electricity bill has major impact on my finances and requires I do without other important priorities.
[asked of all respondents; n=5,400]



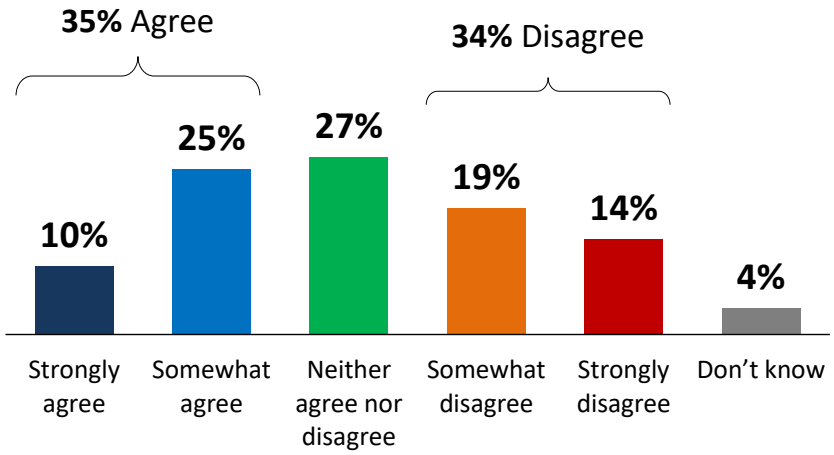
2017 Segmentation
*Those who say **"agree"***



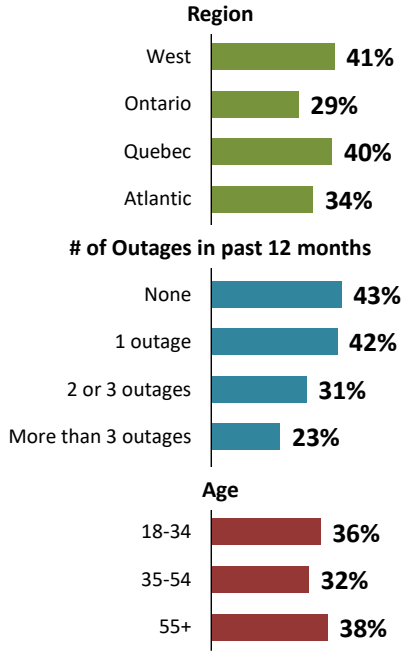
PRICE $

Value for Money: Almost even division on whether or not respondents are getting value for money on their electricity

Q Do you agree or disagree with the following statements?
Thinking of all regular household bills, I receive good value for the price I pay for electricity.
[asked of all respondents; n=5,400]



2017 Segmentation
*Those who say **"agree"***

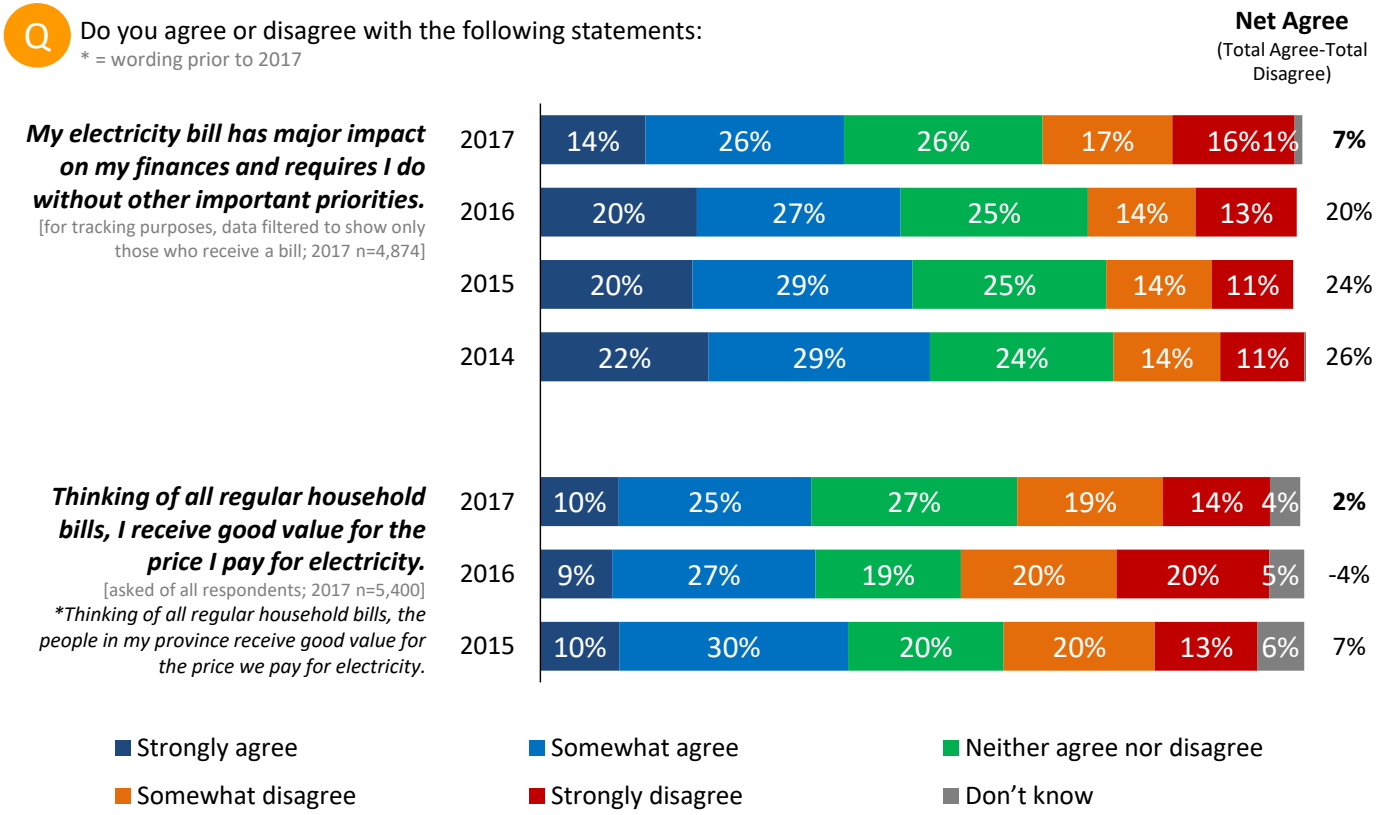


PRICE $

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Tracking Financial Impact: Significant reduction in reported impact of electricity bills; slight gain on perceived value

Q Do you agree or disagree with the following statements:
* = wording prior to 2017



PRICE $

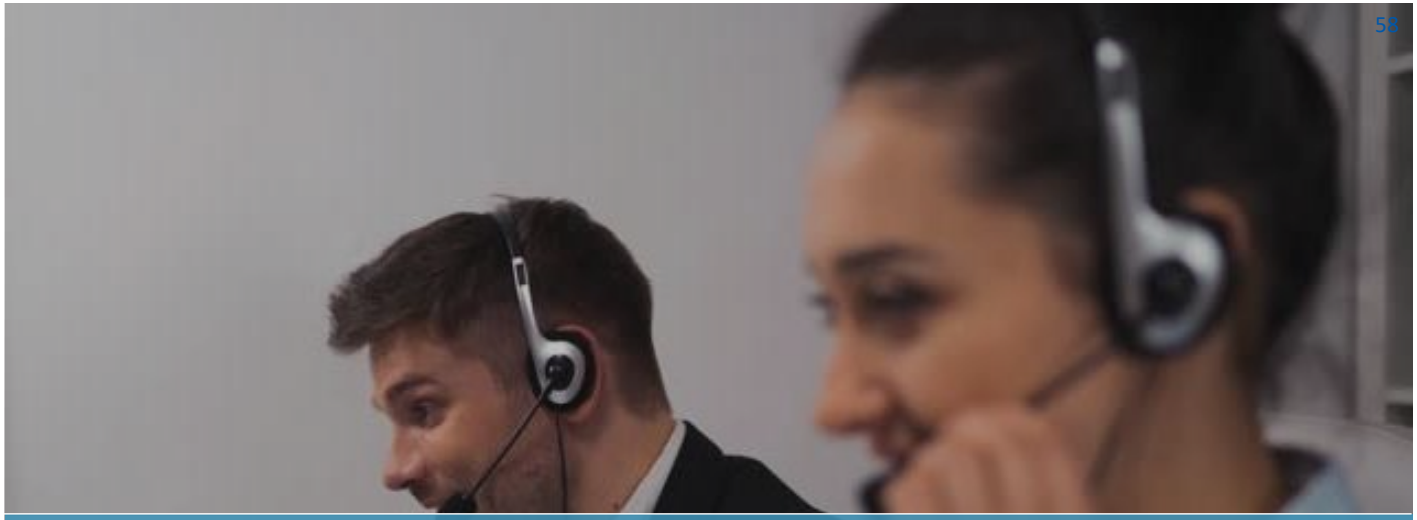
Those whose electricity bills are impacting their finances are much more likely to say prices are unreasonable

Q Overall, do you think that the price for electricity in your province is very reasonable, reasonable, unreasonable, or very unreasonable?
[asked of all respondents; n=5,400]

Do you agree or disagree with the following statement:
My electricity bill has a major impact on my finances and requires I do without some other important priorities.

	Strongly agree	Somewhat agree	Neither	Somewhat disagree	Strongly disagree	Overall
Very reasonable	10%	6%	4%	5%	18%	8%
Reasonable	12%	30%	40%	54%	51%	37%
Unreasonable	25%	41%	33%	28%	16%	30%
Very unreasonable	51%	20%	12%	9%	10%	18%

Values are column percentages **Note:** 'Don't know' not shown



Communications

INNOVATIVE RESEARCH GROUP

Summary: Communications

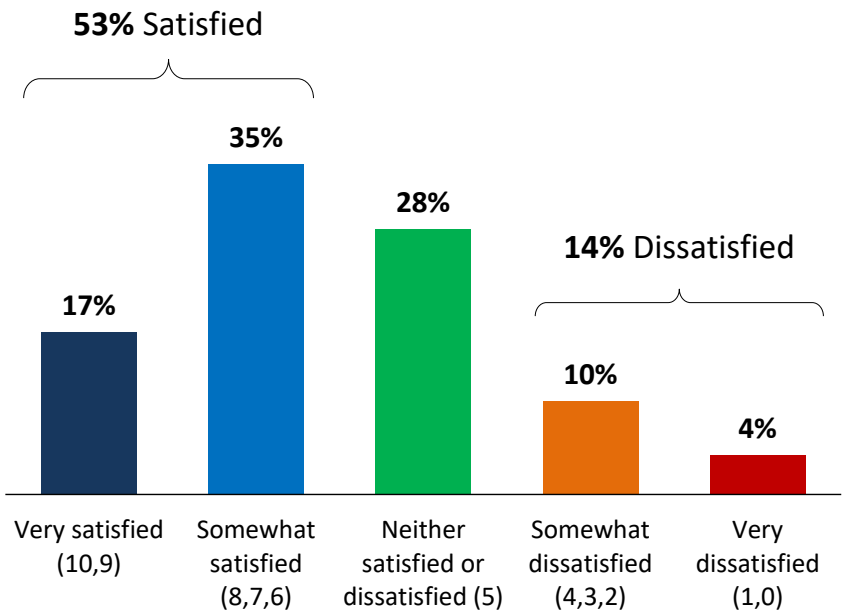
- Most (53%) are satisfied with the overall communication from their distributor. At 39%, net satisfaction has returned to the higher levels reported in 2015.
- While many don't know how satisfied they are with specific forms of communication, and many others have a neutral opinion, distributor websites and bill inserts receive the highest levels of satisfaction (37% and 36% net satisfaction, respectively).
- Net satisfaction is significantly lower for written inquiries (16%), social media (16%) and outage notification (15%).

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Overall Communications: More than half (53%) are satisfied; highest among those who've experienced less than two outages

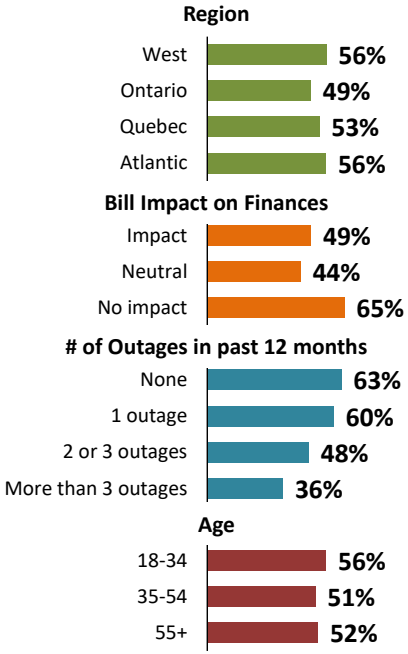
Q Please indicate how satisfied you are with overall communications from [INSERT COMPANY NAME]. *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied*

[asked of all respondents; n=5,400]



2017 Segmentation

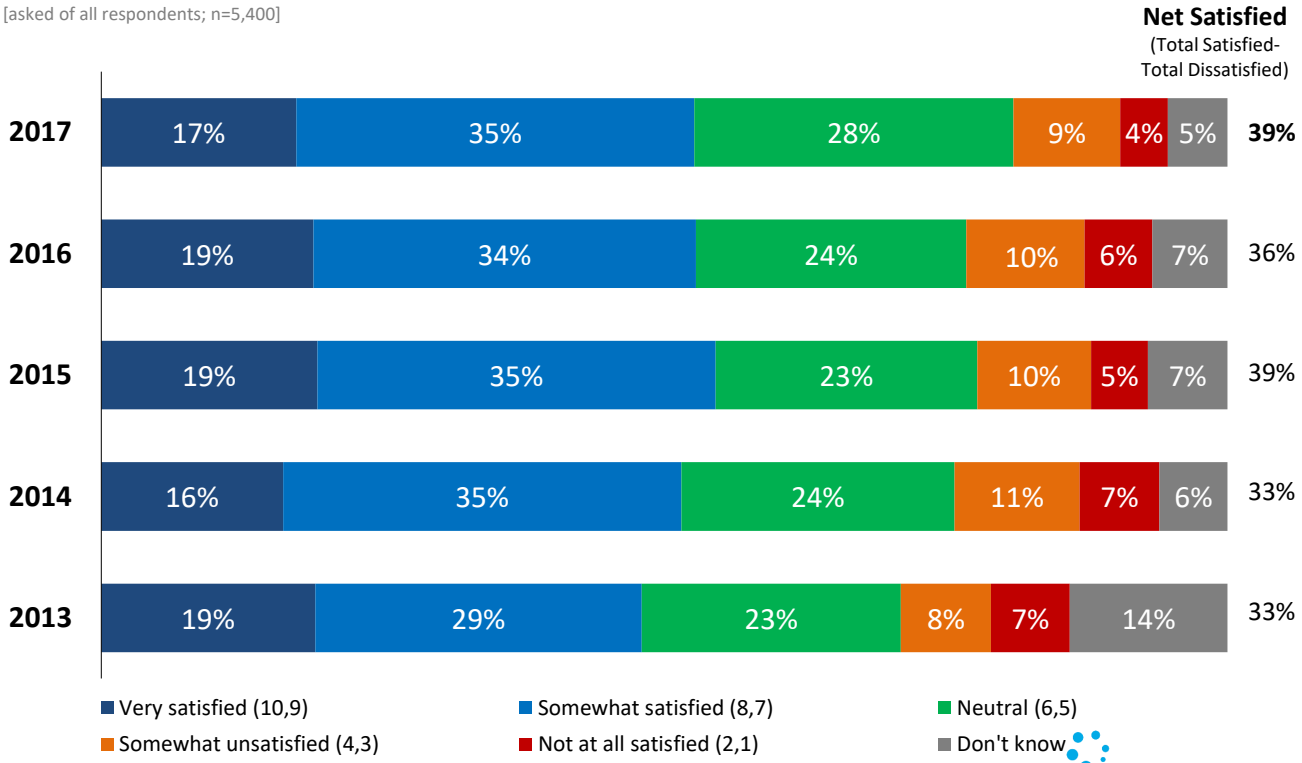
*Those who say they are **"satisfied"** with overall communications*



COMMUNICATIONS

Tracking Overall Communications: Net satisfaction is up marginally, along with an increase in neutral opinion

Q Please indicate how satisfied you are with overall communications from [INSERT COMPANY NAME].
Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied
[asked of all respondents; n=5,400]

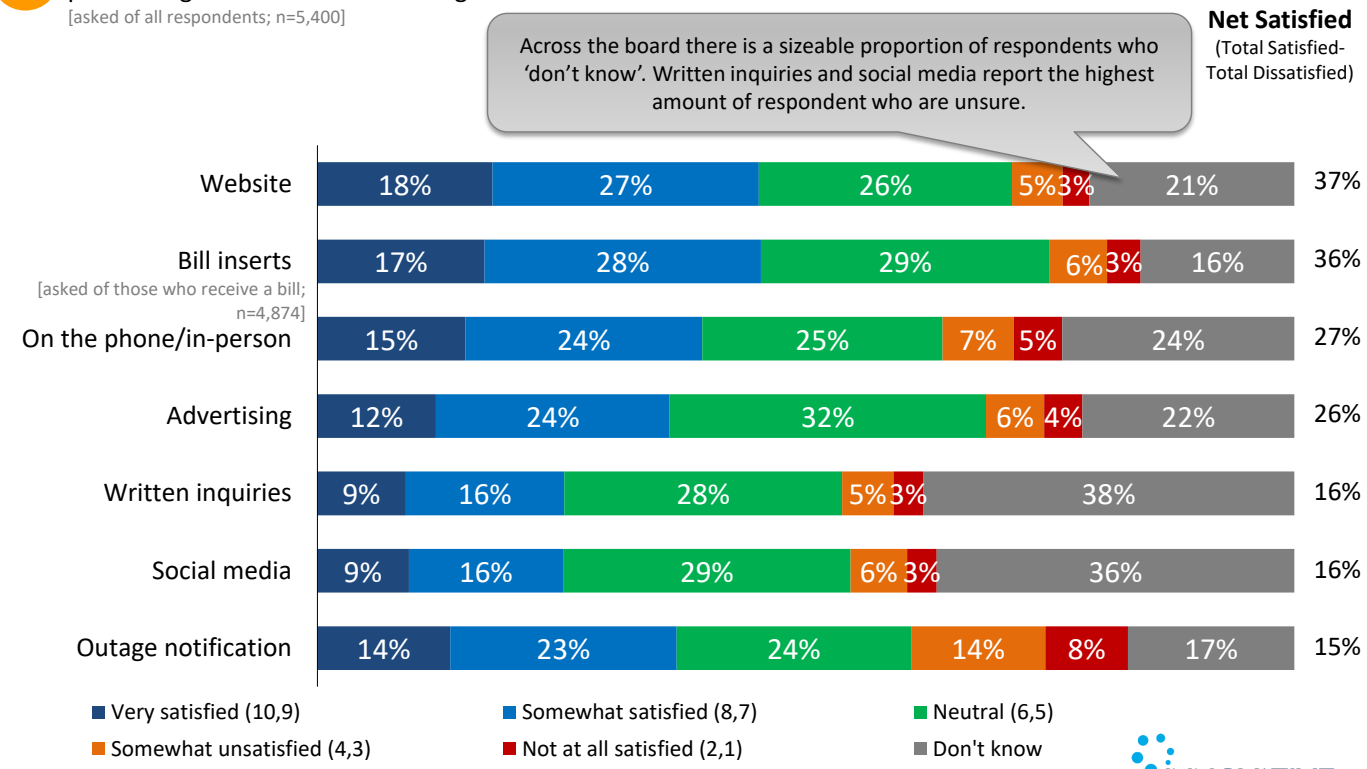


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Forms of Communication: Overall respondents are most satisfied with website & bill inserts, but many are uncertain

Q Please indicate how satisfied you are with the way [INSERT COMPANY NAME] is performing on each of the following forms of communication:
[asked of all respondents; n=5,400]

Across the board there is a sizeable proportion of respondents who 'don't know'. Written inquiries and social media report the highest amount of respondent who are unsure.



COMMUNICATIONS

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Customer Journey

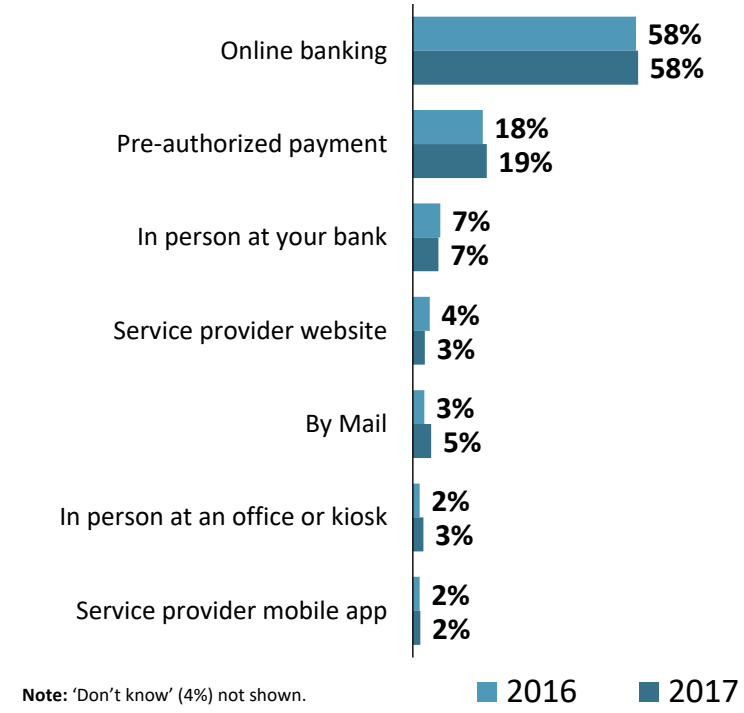
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Summary: Customer Journey

- Consistent with 2016, a majority (58%) indicate that online banking is how they prefer to pay their bills, and most (54%) prefer to pay via a bank account transfer.
- Three-in-ten (30%) choose text notification from their utility as their first choice for receiving updates on the status of power restoration. Speaking with a live operator is significantly less popular with 17% saying this is their first choice.

Bill Preference: Most (58%) prefer to pay bills via online banking; 1-in-5 (19%) prefer pre-authorized payment

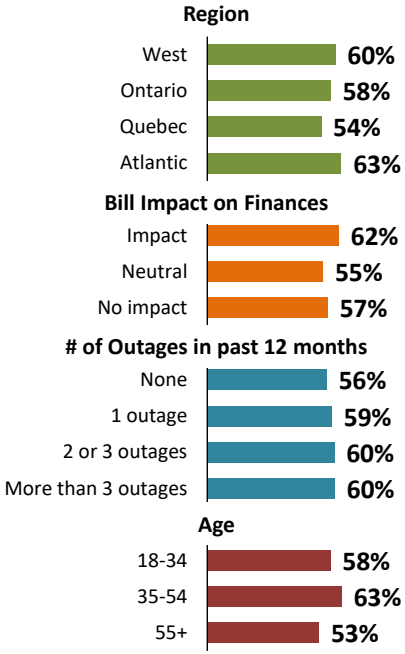
Q How do you prefer to pay your bills?
[asked of all respondents; 2017 n=5,400]



Note: 'Don't know' (4%) not shown.

2017 Segmentation

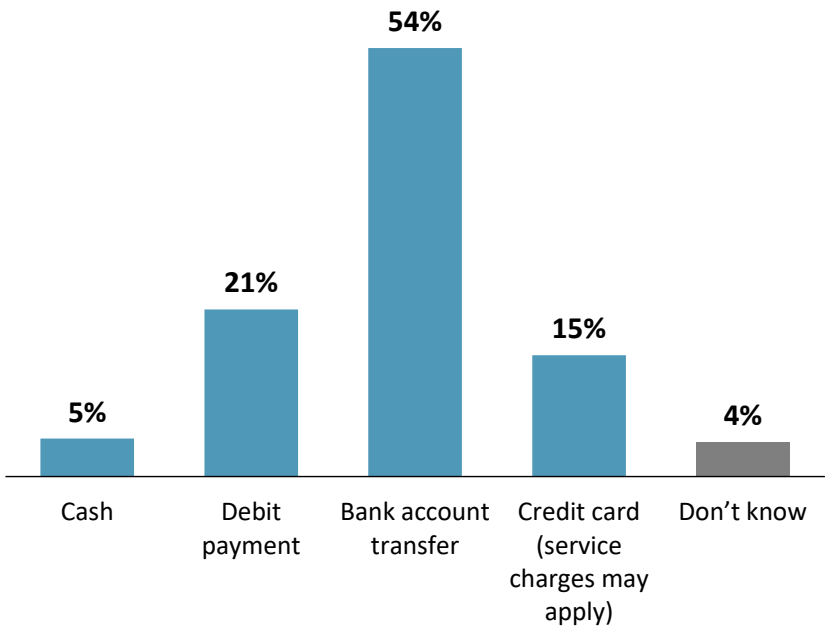
*Those who say they prefer **"online banking"***



INNOVATIVE RESEARCH GROUP

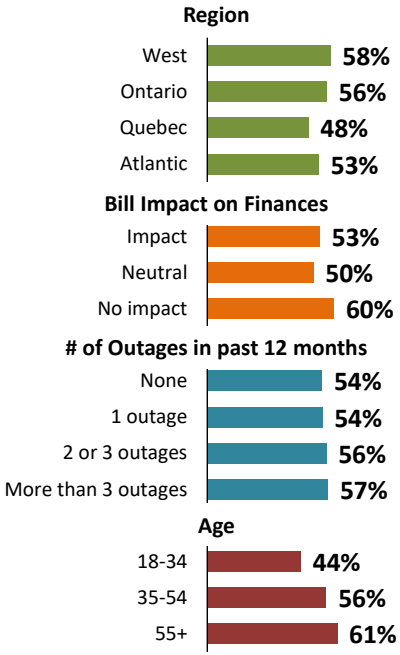
Payment Preference: More than half (54%) prefer a bank account transfer; even higher among those aged 55+

Q What is your preferred method of bill payment?
[asked of all respondents; n=5,400]



2017 Segmentation

*Those who say they prefer **"bank account transfer"***

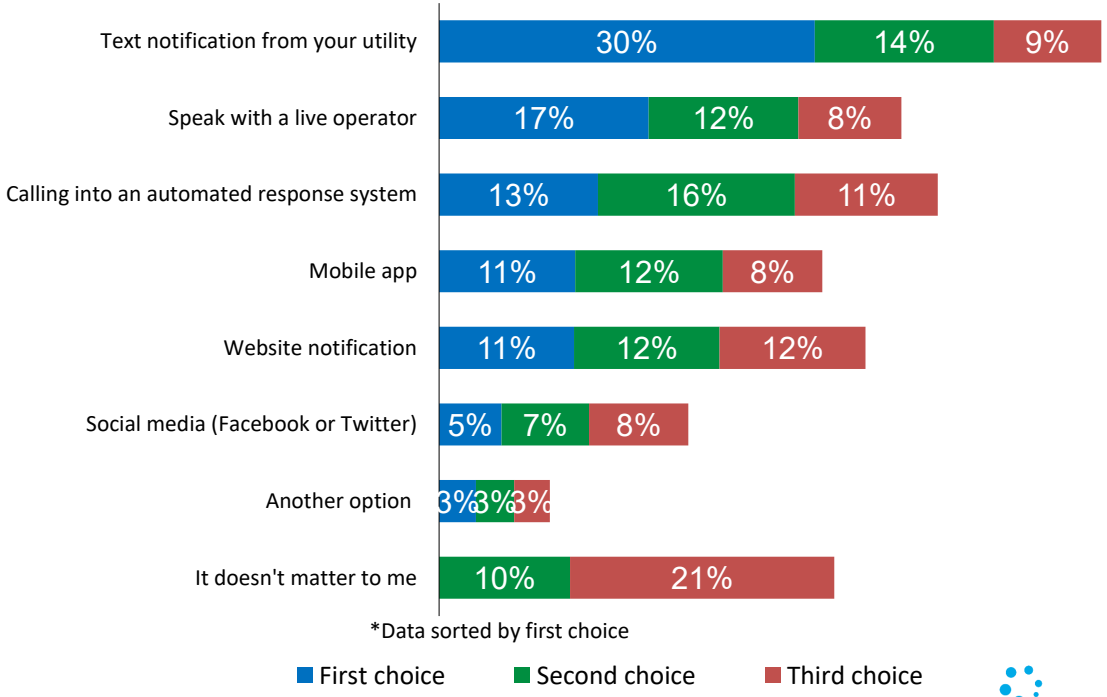


CUSTOMER JOURNEY

Forms of Communication: Text notification, speaking with a live operator, and an automated response system are top choices

Q Please indicate which of the following methods would be your first choice for receiving updates on the status of power restoration. And, which would be your second choice for receiving updates on the status of power restoration? And, which would be your third choice for receiving updates on the status of power restoration?

[asked of all respondents; n=5,400; all percentages are based on all respondents]



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General Attitudes

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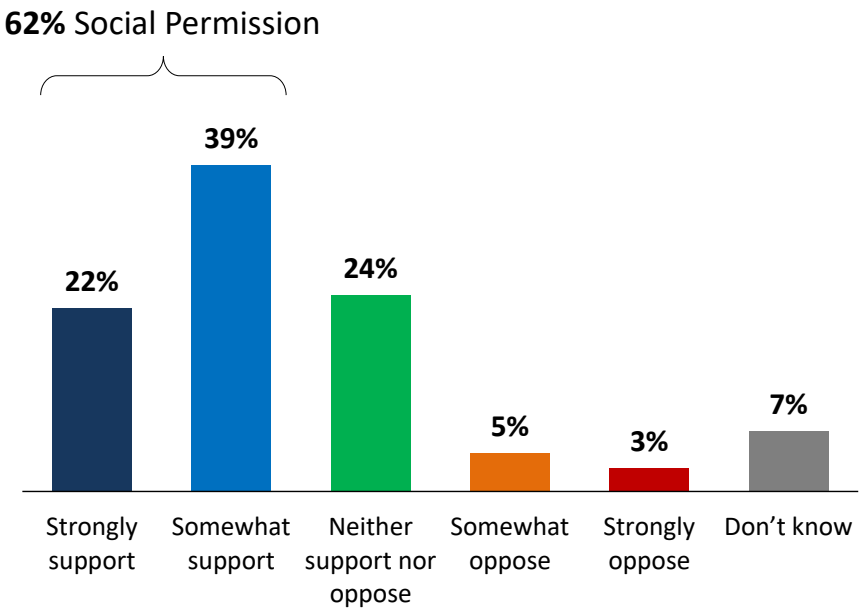
Summary: General Attitudes

- 62% support investment, replacement and/or expansion of electricity infrastructure in their province to improve reliability and safety and to keep up with growth and innovation. This represents a 10 point increase in social permission over previous years. (It should be noted that there was a change in question wording which mentioned the benefits of investing in the system).
- Opposition (47%) edges out social permission (43%) for increasing the price of electricity in order to invest in the provincial system. However, there has been a 3 point increase in social permission since 2016.
- More than three quarters (78%) feel it is important to help customers with energy conservation and management.
- Most (54%) are *not* prepared to pay more for renewables.
- A plurality (39%) are *dissatisfied* with the provincial government's management of the system, and net satisfaction has decreased from -19% to -9% over the past year.
- Just over half (52%) say their experience with their electricity distributor is similar to other companies, such as telephone, cable TV, etc.)

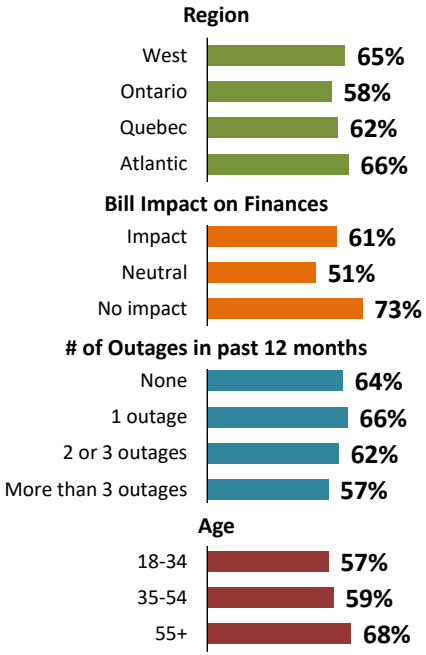
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Infrastructure Investment: Approximately 3-in-5 (62%) respondents support infrastructure investment

Q Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?
[asked of all respondents; n=5,400]



2017 Segmentation
*Those who say "**support**"*



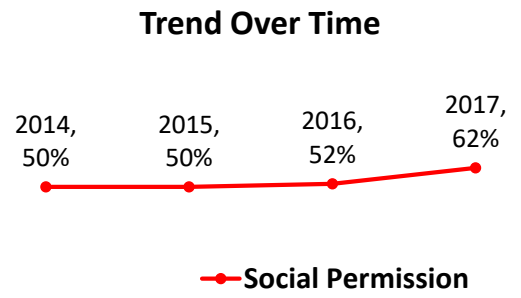
INNOVATIVE RESEARCH GROUP

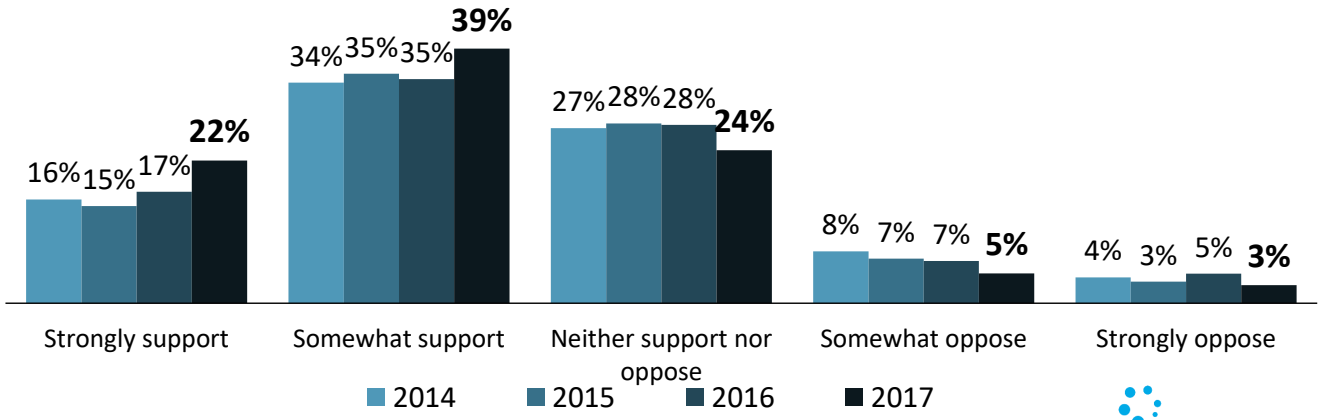
Tracking Infrastructure Investment: 'Social permission' is up 10 points since 2016

Q Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?

(2014-2016: Given everything you have read, seen or heard ... Do you support or oppose investment in and expansion of the generation, transmission and distribution of electrical power in your province?)

[asked of all respondents; n=5,400]

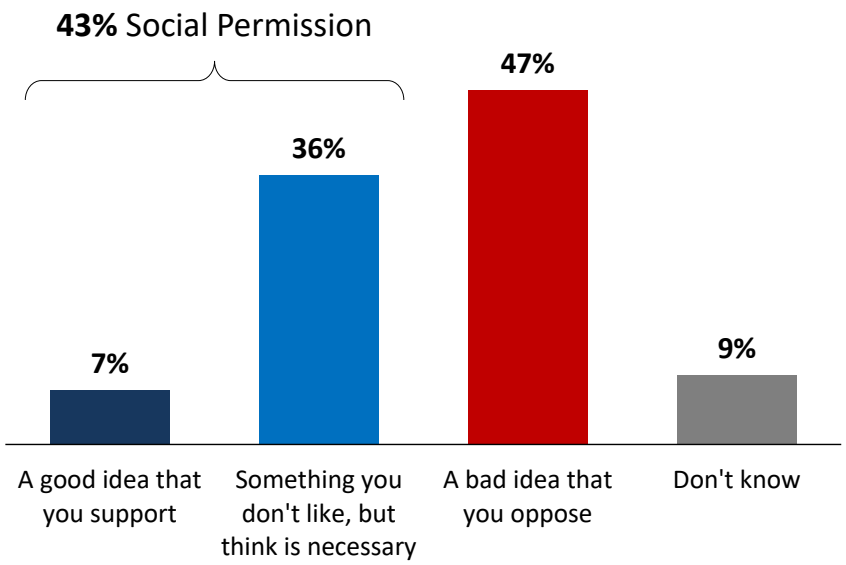




Permission on Price: 43% give 'social permission' for increasing prices to invest in the provincial system

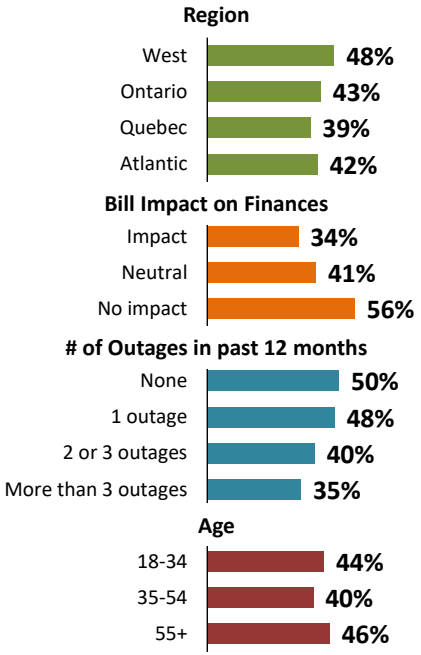
Q Do you think increasing the price of electricity to invest in our province's electric system is…

[asked of all respondents; 2017 n=5,400]



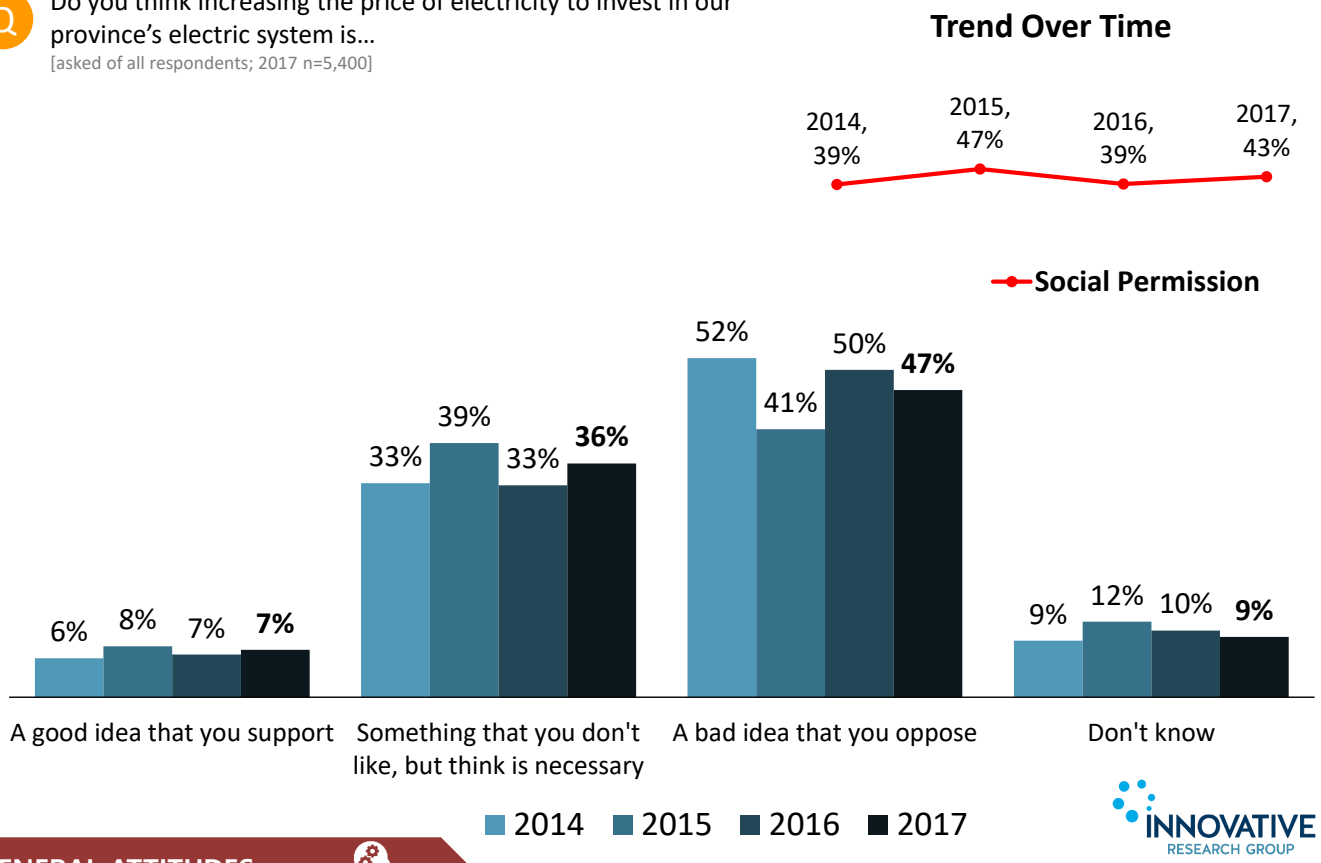
2017 Segmentation

*Those who say **"good idea/ necessary"***



Tracking Permission on Price: 'Social permission' is up slightly from 2016

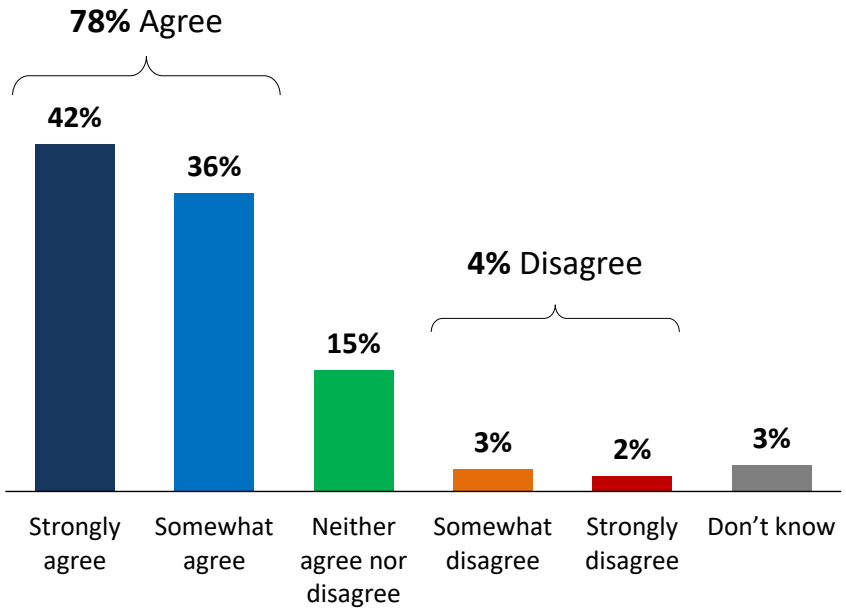
Q Do you think increasing the price of electricity to invest in our province's electric system is…
[asked of all respondents; 2017 n=5,400]



Energy Conservation: A majority think helping customers with energy conservation management is important

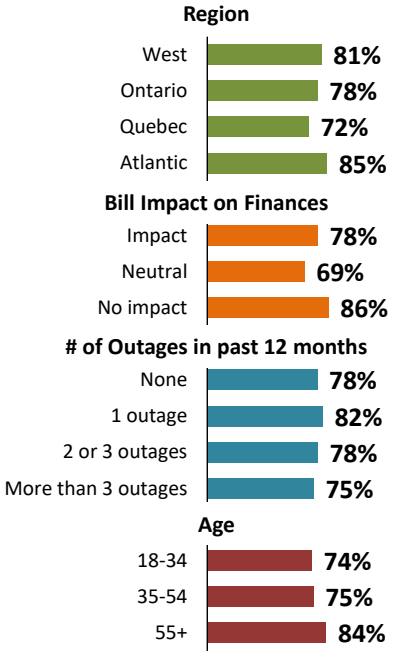
Q Do you think helping customers with energy conservation and management is important?

[asked of all respondents; n=5,400]



2017 Segmentation

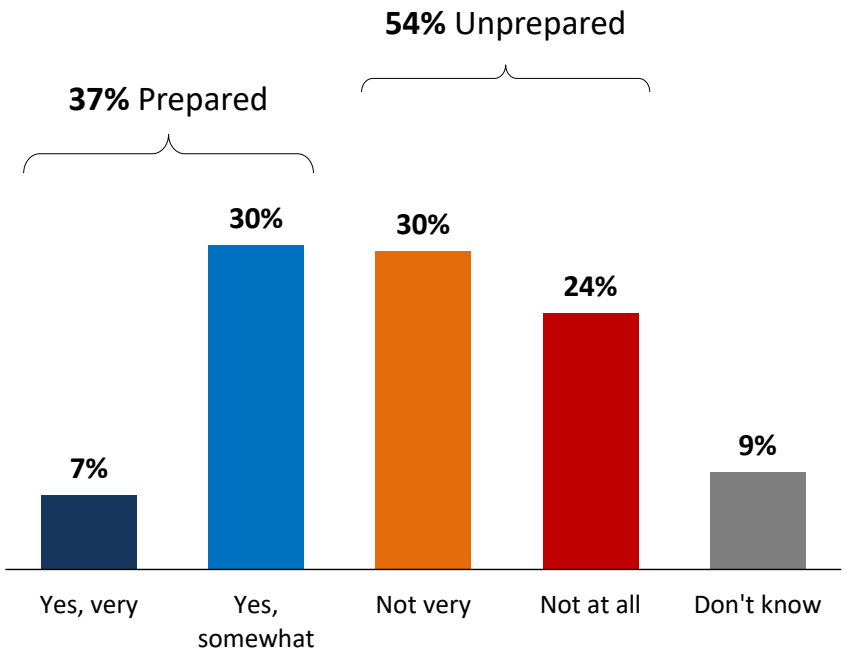
*Those who say **"agree"***



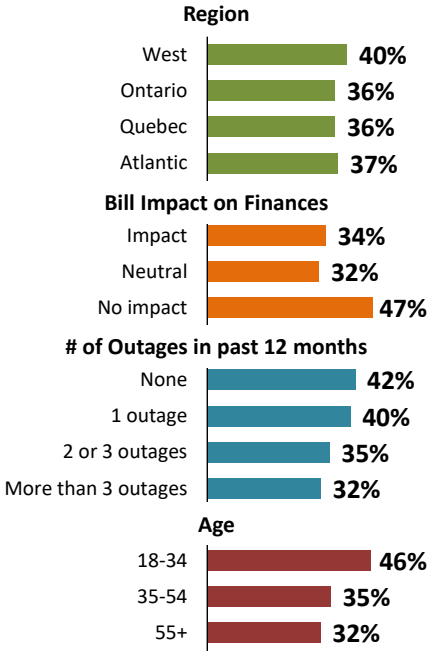
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Paying for Renewables: More than half are not prepared to pay more for renewable energy; youngest are more prepared than others

Q Would you be prepared to pay slightly more for renewable power?
[asked of all respondents; n=5,400]



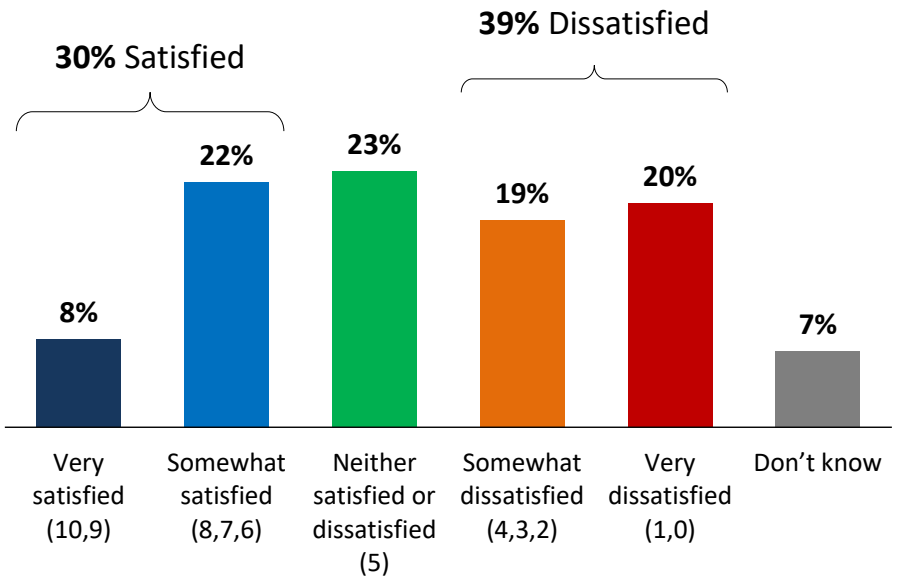
2017 Segmentation
*Those who say **"prepared"***



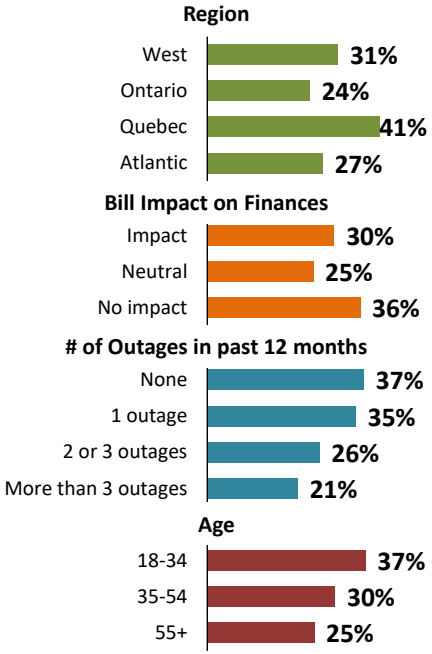
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Provincial Gov't: 3-in-10 (30%) are satisfied with the performance of the provincial gov't on electricity system; highest among ages 18-34

Q How satisfied are you with the job your provincial government is doing to manage the electricity system? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*
[asked of all respondents; n=5,400]



2017 Segmentation
*Those who say **"satisfied"***

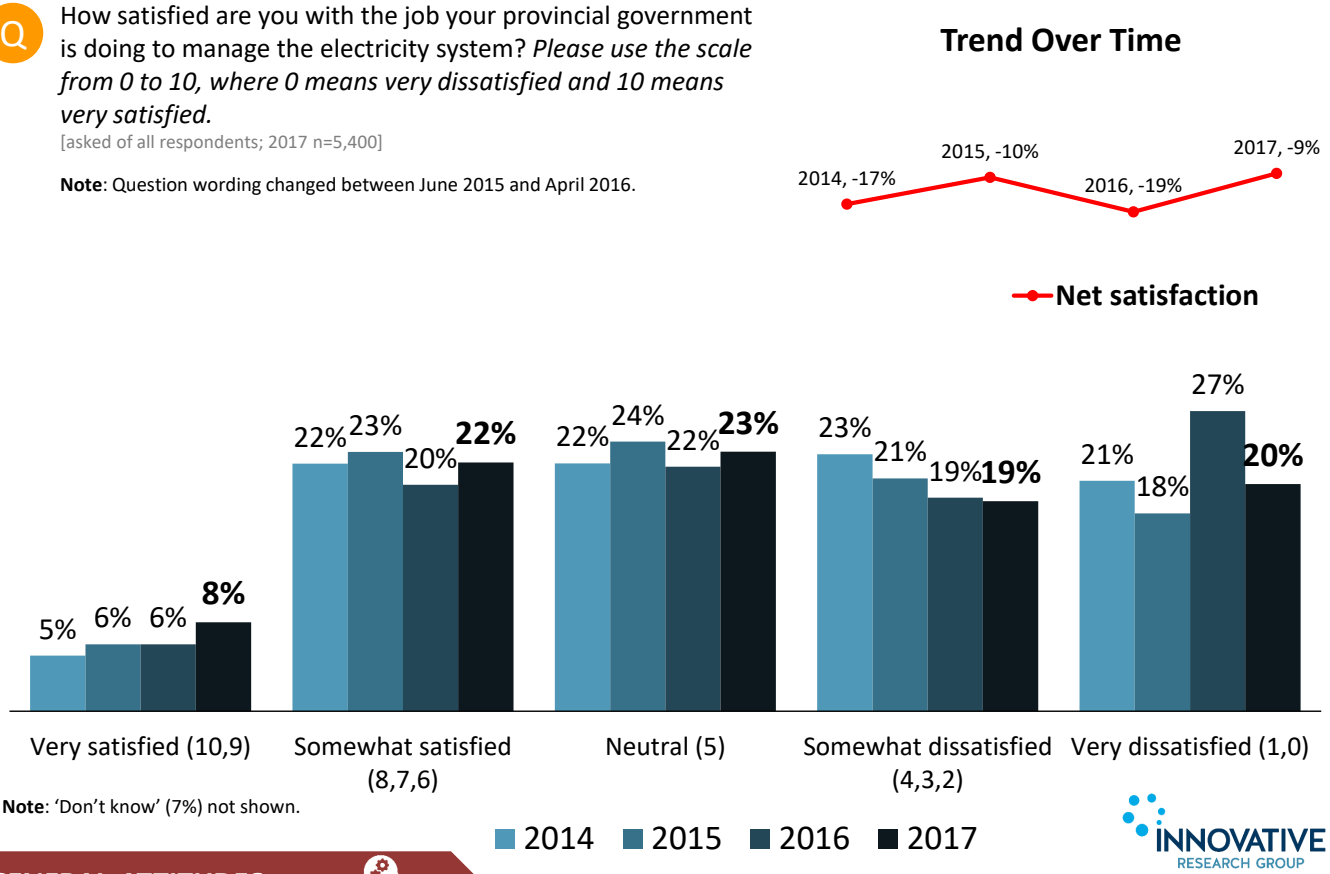


Tracking Provincial Gov't: Net satisfaction up 10 points since 2016; 'very dissatisfied' down 7 points

Q How satisfied are you with the job your provincial government is doing to manage the electricity system? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; 2017 n=5,400]

Note: Question wording changed between June 2015 and April 2016.

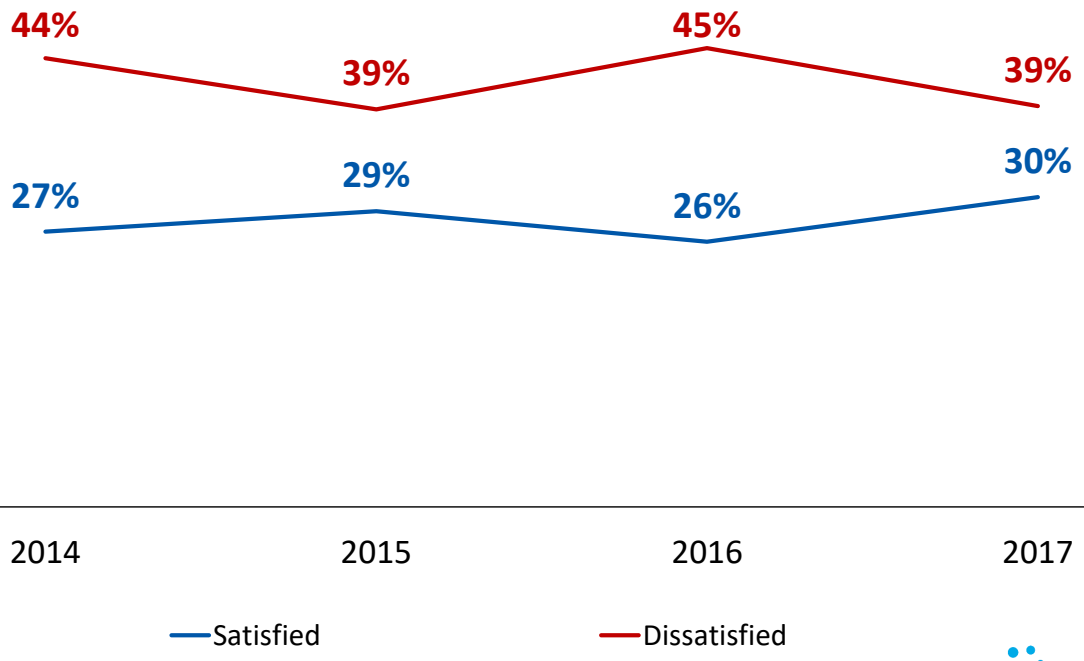


Note: 'Don't know' (7%) not shown.

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Tracking Provincial Gov't: Satisfaction up 4 points year-over-year; dissatisfaction down 6 points

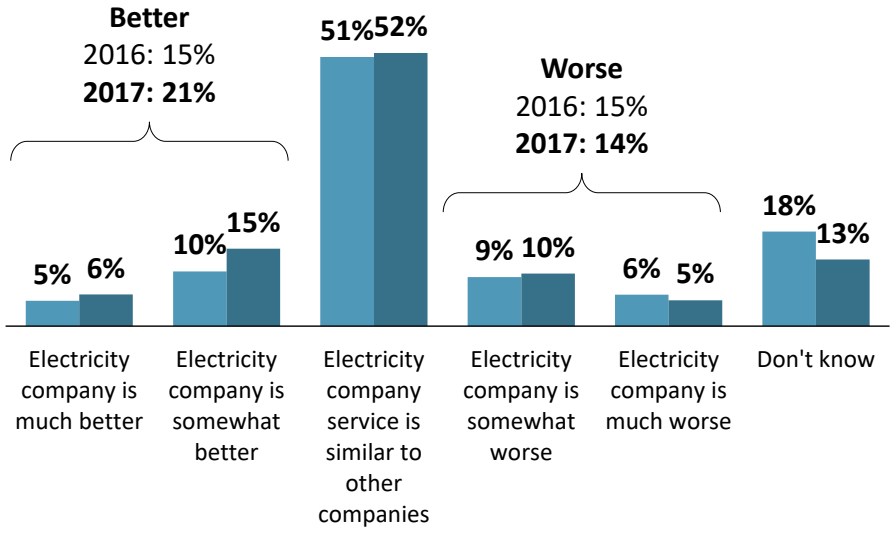
Q How satisfied are you with the job your provincial government is doing to manage the electricity system?
Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=5,400]



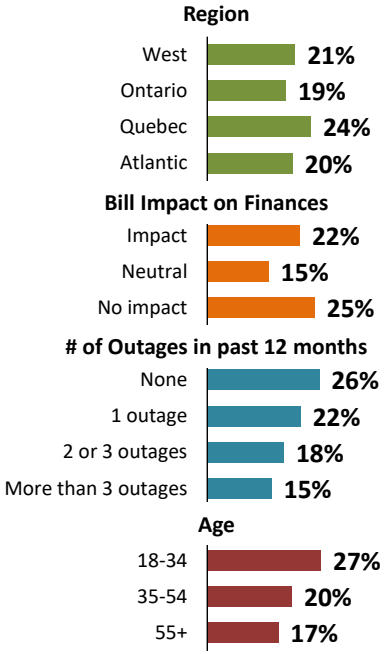
Note: 'Don't know' (2014:7%; 2015:8%; 2016:6%; 2017:7%) not shown

Comparing customer experience: 1-in-5 (21%) say their experience is better than other service providers; up 6 pts from 2016

Q How does your customer experience with [INSERT COMPANY NAME] compare to that of other service providers you use (telephone, cable, TV/internet, natural gas, your bank)?
[asked of all respondents; 2017 n=5,400]



2017 Segmentation
*Those who say **"better"***



Regression Analysis

What drives satisfaction?

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Using Regression Analysis

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain the key question we are interested in and see which of these is the most important. Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).

Satisfaction Regression Analysis ▸▸

- In this study what aspects of respondents' demographics and public opinion drive their overall satisfaction with their electricity company?
- We use the factors that fed into the CSI but also add respondents' demographics, attitudes, and experiences to the model to see what matters most when everything else is held constant
- When respondents were asked about their overall satisfaction they were asked *specifically* about the company that they are a customer of by name.

Attitudes and Brand Attributes factored ▸▸

- In addition to the factor analysis of company attributes previously described, key attitudes about the electricity system, price, and the environment were again factored to reduce overlap in the regression models.
- The following slides describes the result of this analysis.

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Attitudinal Factor Analysis

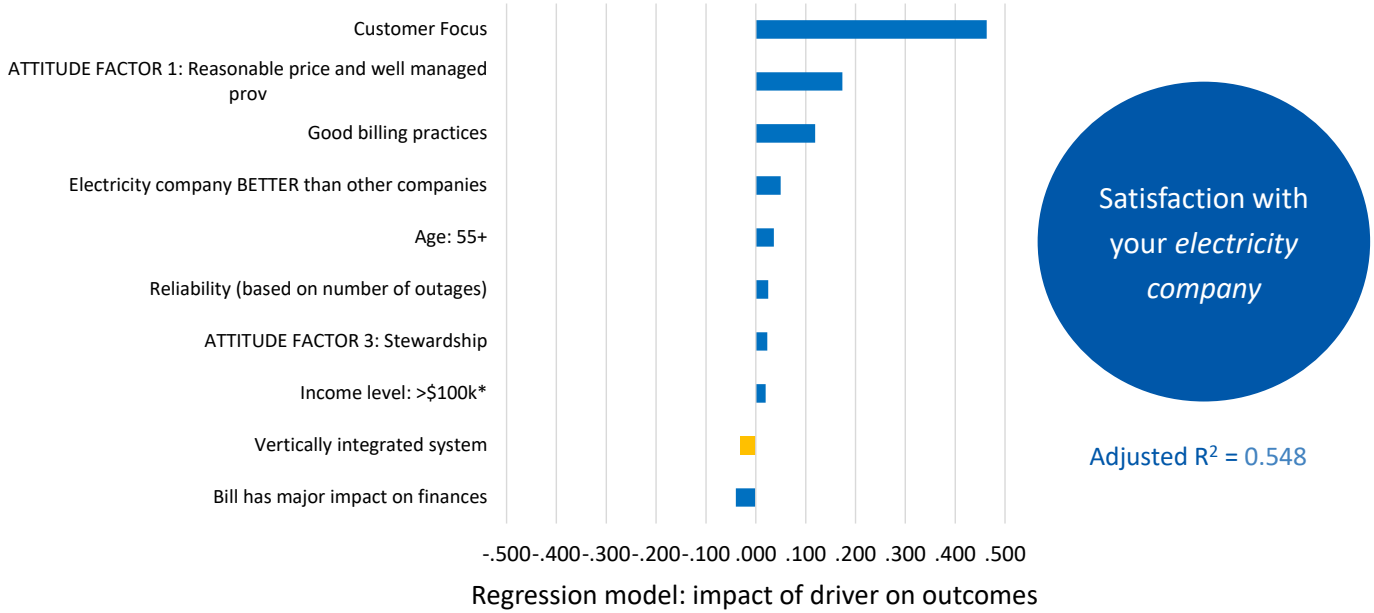
General Attitudes	Reasonable price and well managed province	Prince insensitive, green	Stewardship	Standalone
Overall: Price is reasonable/unreasonable	X			
I receive good value for the price I pay for electricity.	X			
Satisfied with the job the provincial government is doing to manage the electricity system.	X			
Increasing the price of electricity to invest in the province's electric system is a good idea.		X		
I would be prepared to pay slightly more for renewable power.		X		
Helping customers with energy conservation and management is important.			X	
I support investment, replacement and/or expansion of electricity infrastructure to improve reliability and safety…			X	
My electricity bill has a major impact on my finances and requires I do without other important priorities.				X

Brand Attribute Factors: Secondary Factor Analysis to Reduce Overlap Among Original Factors in Regression Analysis

Factors	Customer Focus	Billing Practices	Quality/ Reliability
Consulting with customers before making decisions	X		
Being transparent	X		
Caring about its customers	X		
Being trustworthy	X		
Taking care of problems first time you contact them	X		
Being a good corporate citizen	X		
Operating in an environmentally responsible manner	X		
Protecting public safety	X		
Providing energy conservation and efficiency programs	X		
Overall Communication	X		
Providing Online Services	X		
Providing convenient options to pay my bill		X	
Providing convenient options to receive my bill		X	
Providing bills that are easy to read and understand		X	
Providing accurate bills		X	
The quality of power delivered to you			X
Providing reliable electricity service			X
The amount of time it takes to restore power			X
Considering your needs when planning an outage			X
Providing timely and accurate information re: outages			X

Regression Analysis

Customer Focus is, by far, the largest driver of satisfaction. Respondents vertically integrated systems tend to be less satisfied overall. Likewise, struggling to pay electricity bills makes one less satisfied.



Note: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.
* Indicates statistical significance at 90% level.

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Building Understanding.

Personalized research to connect you and your audiences.

For more information, please contact:

Greg Lyle
President
416-642-6429
glyle@innovativeresearch.ca

Jason Lockhart
Vice President
416-642-7177
jlockhart@innovativeresearch.ca

Susan Oakes
Vice President
416-642-6340
soakes@innovativeresearch.ca

Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto ON | M5E 1A7
www.innovativeresearch.ca
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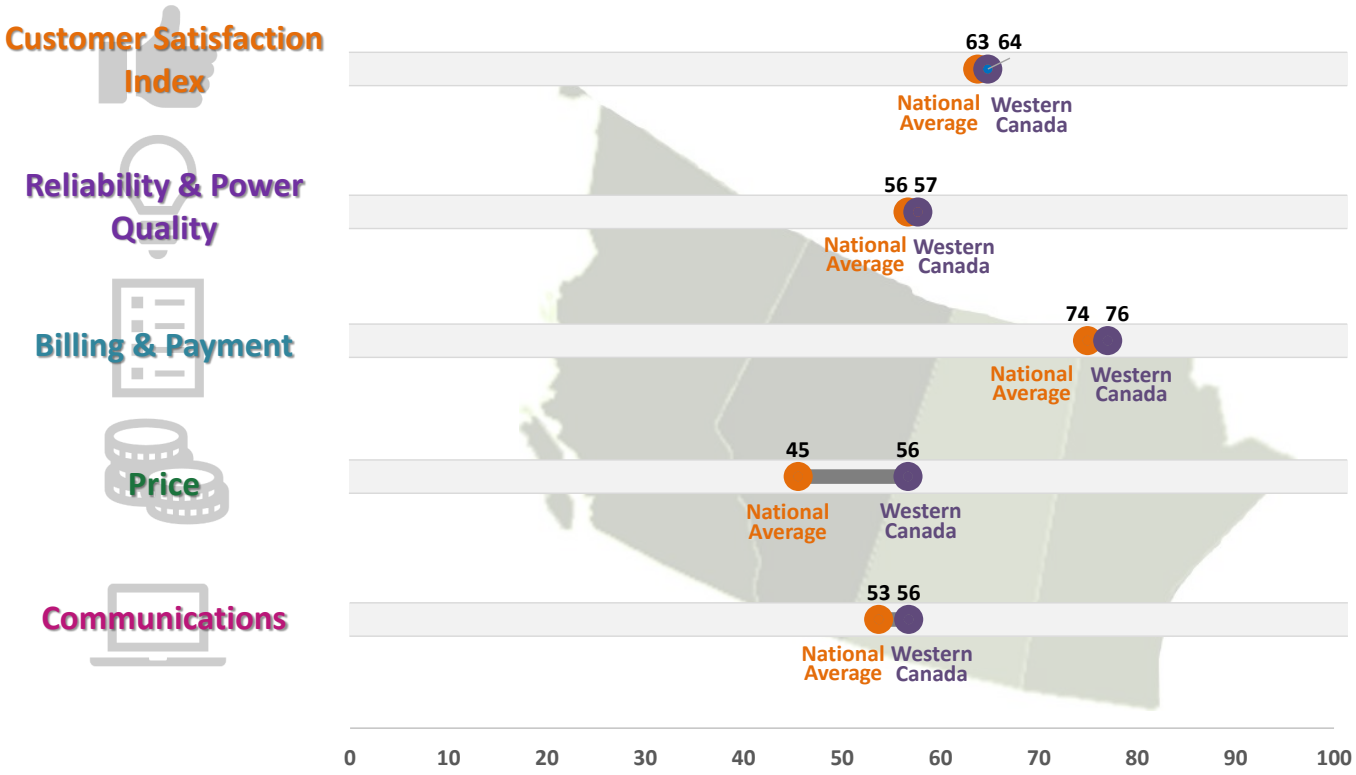
Appendices

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Regional Summaries

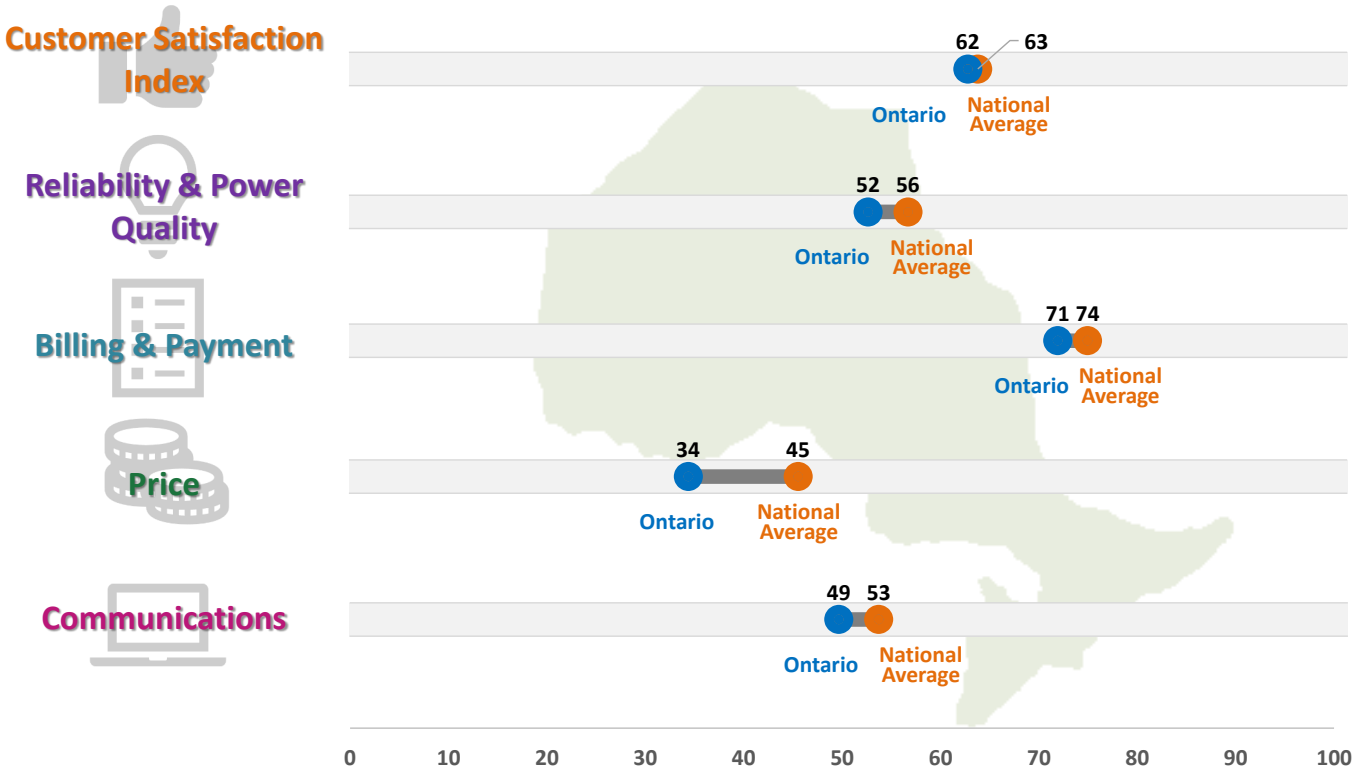
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How is Western Canada different from the national average?[88]



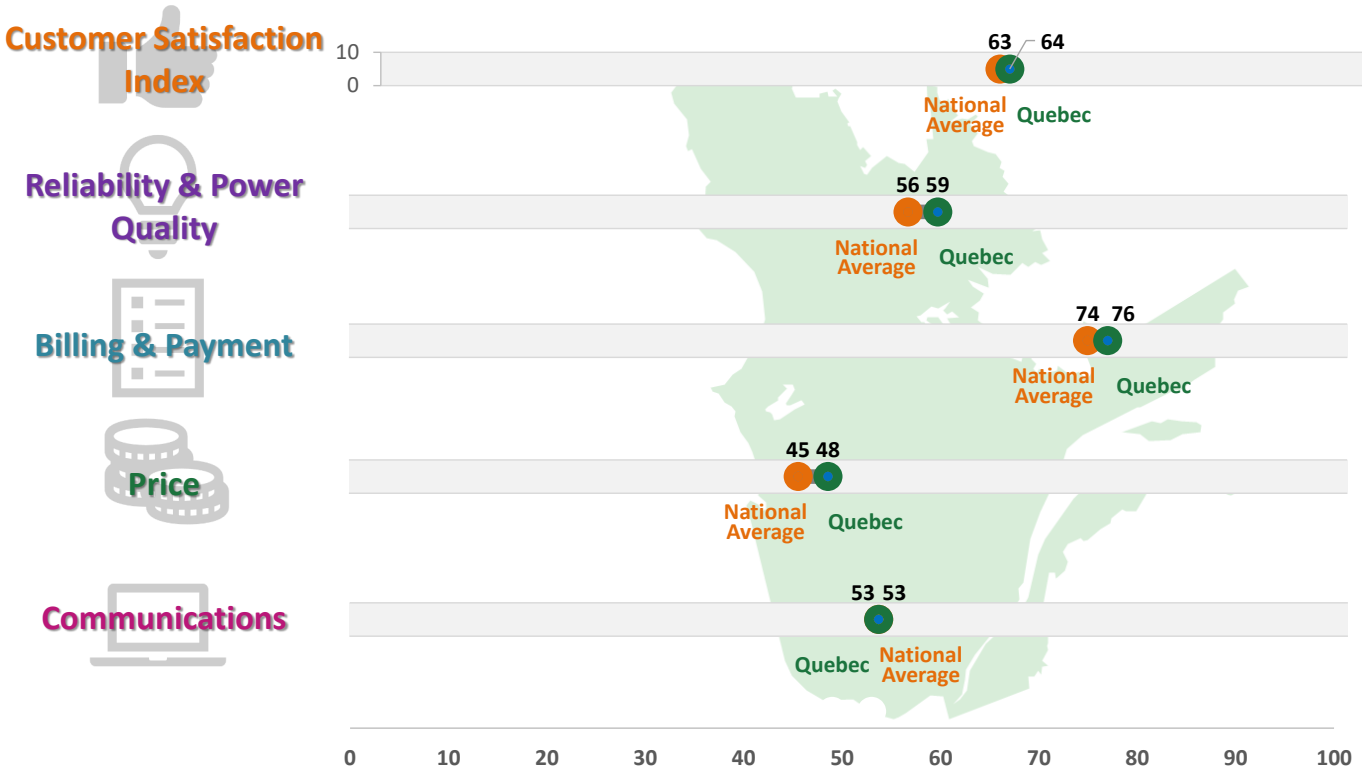
Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures. *"Reliability & Power Quality"* and *"Billing & Payment"* represent an index of all measures of satisfaction within that section.

How is Ontario different from the national average?



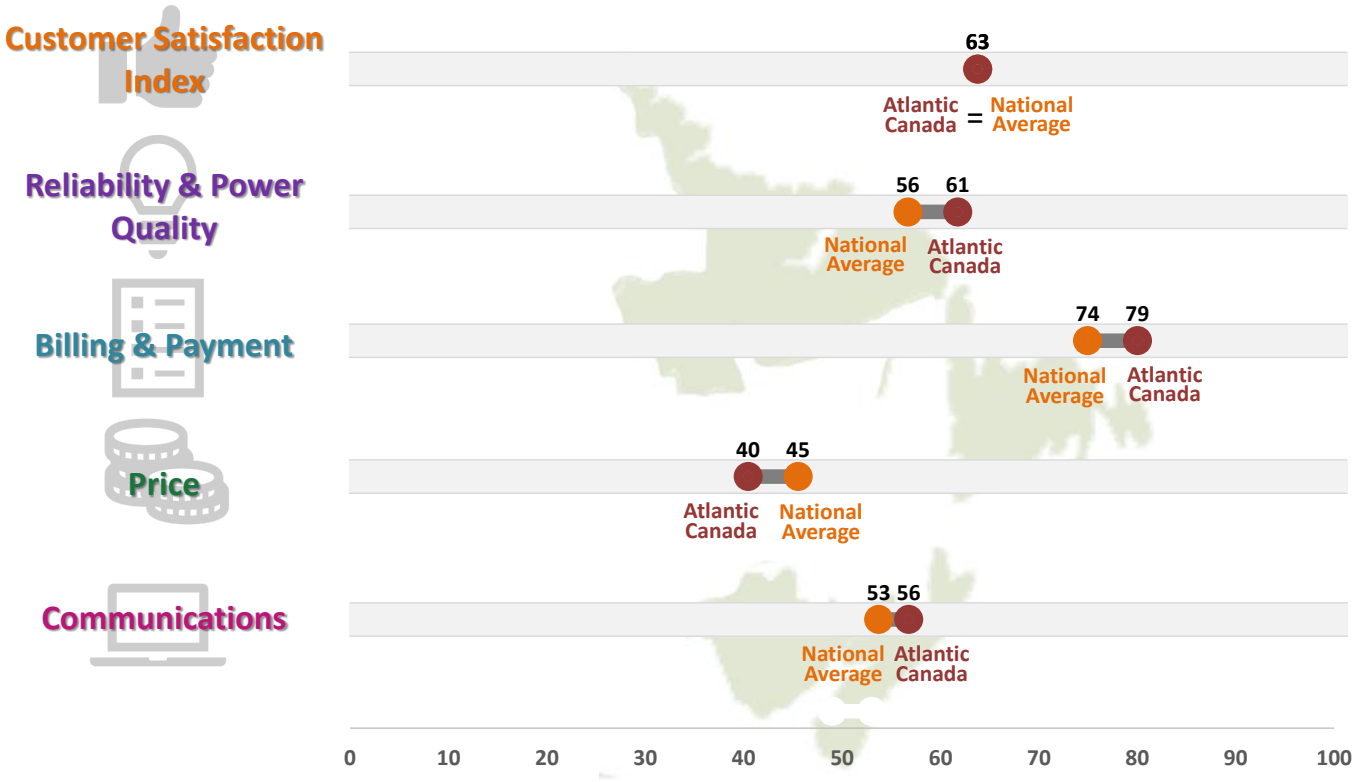
Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures. *"Reliability & Power Quality"* and *"Billing & Payment"* represent an index of all measures of satisfaction within that section.

How is Quebec different from the national average?



Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures. *"Reliability & Power Quality"* and *"Billing & Payment"* represent an index of all measures of satisfaction within that section.

How is Atlantic Canada different from the national average?



Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures. *"Reliability & Power Quality"* and *"Billing & Payment"* represent an index of all measures of satisfaction within that section.

Environmental Controls

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Environmental Controls:

It is important to distinguish between what is within, and what is outside an electricity company's influence or control when it comes to drivers of customer satisfaction.

Perceptions of electric companies often tend to move with general perceptions of provincial government management in the sector rather than in response to the local utility. In addition, perceptions of utilities are also strongly correlated with financial circumstances. In tough times perception and preference can change because customers are struggling with bills, not because of anything the company has, or has not, done

Control questions help distributors distinguish between utility driven preferences and externally driven preferences. INNOVATIVE uses two questions to help capture external phenomena:

1. **Government Performance:** *How satisfied are you with the job your provincial government is doing to manage the electricity system?*
2. **Personal Financial Hardship**: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

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Summary: Change within Controls

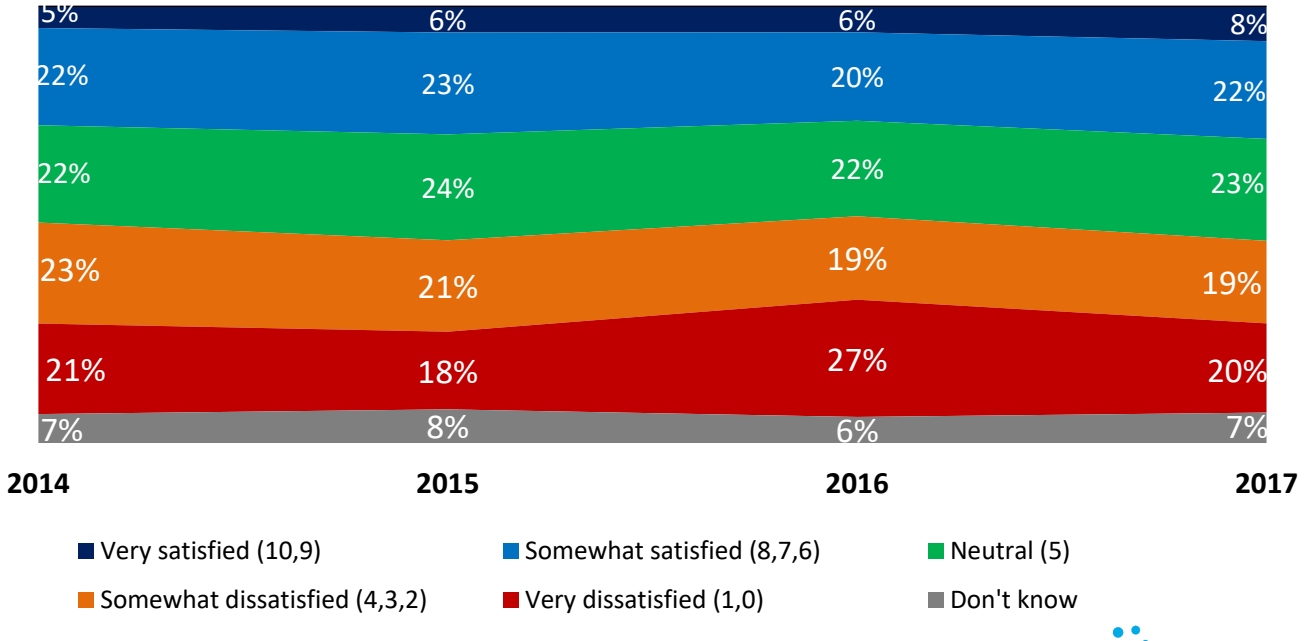
- Both government approval and the impact of electricity bills on personal circumstances have improved this year.
- However, electricity utilities have improved their reputation beyond those general trends.
- Among the customers most angry with the government and most financially distressed, utilities are receiving some of their best reputation scores in the past four years.
- This suggests there are specific experiences related to utility performance that are leaving customers more satisfied with their utilities.

Tracking Provincial Gov't: Satisfaction remains fairly steady, while dissatisfaction tends to fluctuate more

Q How satisfied are you with the job your provincial government is doing to manage the electricity system? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; 2017 n=5,400]

Note: Question wording changed between June 2015 and April 2016.



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There has been a significant increase in *satisfaction* with electricity company, regardless of satisfaction with gov't

% Satisfied with Electricity Company

Satisfaction with provincial gov't management of electricity system	2014	2015	2016	2017
Very satisfied (10,9)	86%	90%	86%	91%
Somewhat satisfied (8,7,6)	84%	85%	85%	87%
Neutral (5)	47%	51%	51%	56%
Somewhat dissatisfied (4,3,2)	51%	53%	54%	56%
Very dissatisfied (1,0)	32%	35%	36%	42%

% Dissatisfied with Electricity Company

Satisfaction with provincial gov't management of electricity system	2014	2015	2016	2017
Very satisfied (10,9)	8%	5%	8%	4%
Somewhat satisfied (8,7,6)	5%	5%	6%	5%
Neutral (5)	9%	9%	10%	9%
Somewhat dissatisfied (4,3,2)	25%	22%	20%	19%
Very dissatisfied (1,0)	42%	36%	36%	32%

Significantly different from previous year at 95% confidence level

Significantly different from previous year at 90% confidence level

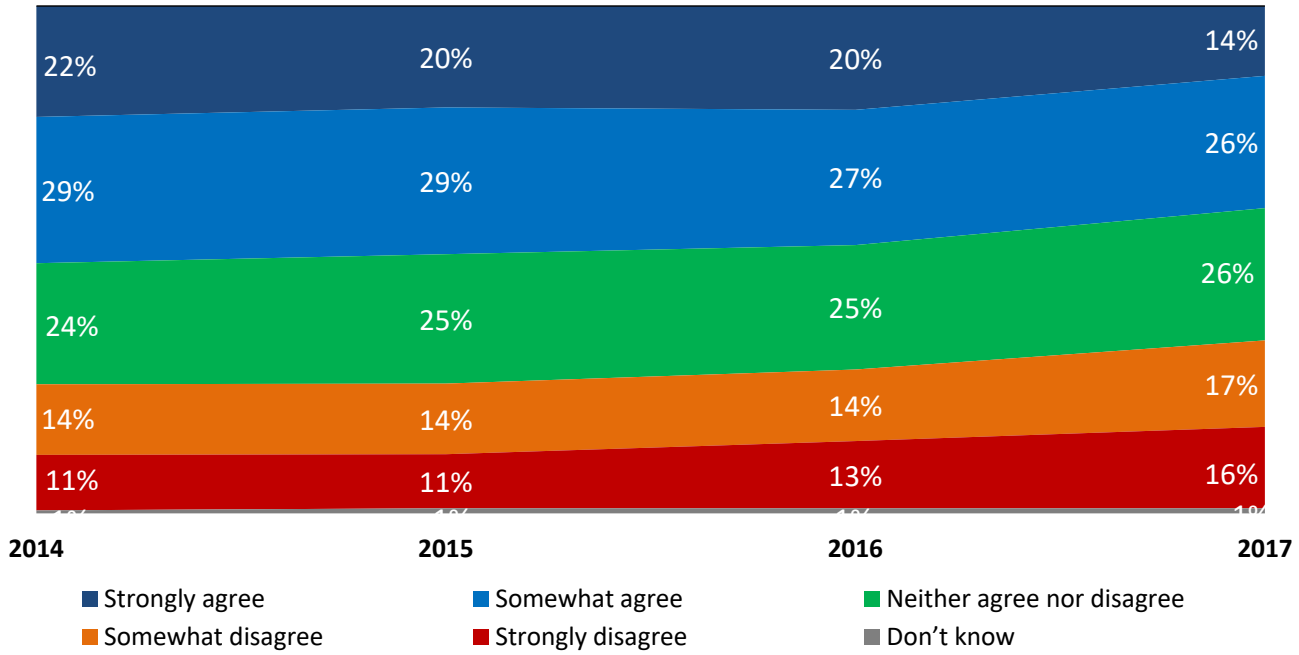
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Tracking Financial Impact: Decline in "agree" over time, with a corresponding increase in "disagree"; neutral fairly steady

Q Do you agree or disagree with the following statement:

My electricity bill has major impact on my finances and requires I do without other important priorities.

[for tracking purposes, data filtered to show only those who receive a bill; 2017 n=4,874]



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In addition to fewer struggling with their bill, those who *are* struggling are also more satisfied than last year

% Satisfied with Electricity Company

Electricity bill has major impact on finances	2014	2015	2016	2017
Strongly agree	37%	43%	35%	43%
Somewhat agree	55%	58%	56%	61%
Neither agree nor disagree	56%	63%	62%	59%
Somewhat disagree	71%	74%	72%	73%
Strongly disagree	73%	79%	78%	75%

% Dissatisfied with Electricity Company

Electricity bill has major impact on finances	2014	2015	2016	2017
Strongly agree	40%	33%	42%	38%
Somewhat agree	19%	17%	19%	16%
Neither agree nor disagree	14%	10%	10%	11%
Somewhat disagree	12%	10%	10%	8%
Strongly disagree	9%	8%	7%	9%

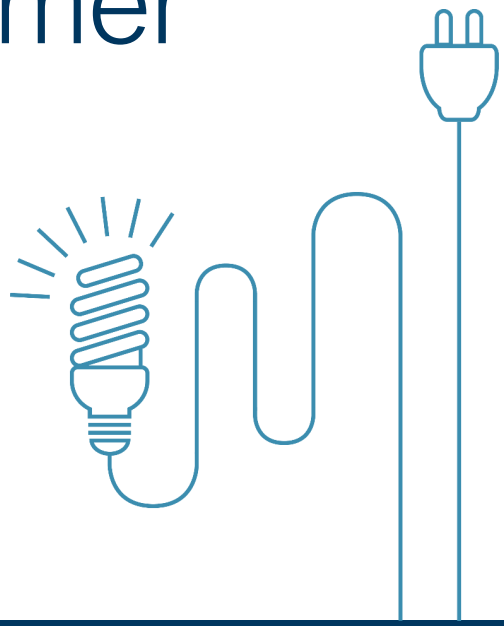
Significantly different from previous year at 95% confidence level

Significantly different from previous year at 90% confidence level

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National Electricity Customer Satisfaction Report



Canadian Electricity Association | Association canadienne de l'électricité

January 10 2019 Presentation

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Methodology & Demographics

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Research Overview

The Canadian Electricity Association (CEA) commissioned Innovative Research Group Inc. (INNOVATIVE) to conduct the CEA's 2018 Annual National Customer* Satisfaction Survey. The focus of this survey is public attitudes towards the electricity companies that serve them.

In 2018, the survey re-introduced Net Promoter Score (NPS) for distributors and key satisfaction metrics for transmitters. The exact structure of the survey in each province reflects the unique circumstances of that province (see slide 12 for summary of provincial regimes).

Key company-specific (distributor) topics include:

- Overall satisfaction
- Performance attributes
- Customer experience (*planned outages, billing, and other customer contact*)
- Net Promoter Score

** Almost all respondents receive a bill from an electricity distributor and therefore they have a direct customer relationship with a utility. However, it should be noted that approximately 10% of respondents say they do not receive a bill directly from an electricity distributor.*

Other topics include:

- Key satisfaction metrics for transmitters
- The price of electricity
- Interest in conservation programs
- New technology
- Environmental controls (underlying factors – outside a utility's control – that may impact perceptions of electricity companies)

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Survey Methodology



The CEA's 2018 Annual National Public Attitudes Survey is an online survey conducted by Innovative Research Group (**INNOVATIVE**). Data collection occurred between October 4th and October 29th, 2018 among 7,192 Canadian adults (18yrs or older).

The survey instrument was designed by INNOVATIVE, with input and direction from CEA members, and made available to respondents in either French or English.

The survey sample was weighted by age, gender and region using 2016 Statistics Canada Census data to reflect the actual demographic composition of the Canadian adult population. Upon CEA member request, additional oversamples were included in a number of distribution service territories or provinces to provide greater confidence in the data at a sub-regional level of analysis. In the final data, the oversampled regions were weighted down to a representative national sample size of n=1,600.* Tracking results are drawn from previous CEA National Surveys from 2013** to 2017.

Survey respondents were recruited from a wide variety of sources to reflect the age, gender, and regional characteristics of the country as a whole. Because this is an online survey, and not a random probability sample, the results cannot be generalized across all Canadians, and we cannot apply a margin of error. INNOVATIVE provided each survey respondent with a unique URL (hyperlink) to the online survey via an email invitation to ensure that only invited respondents were able to complete the survey. Unique URLs were disabled upon survey completion to ensure that invited respondents could only complete their individual survey once.

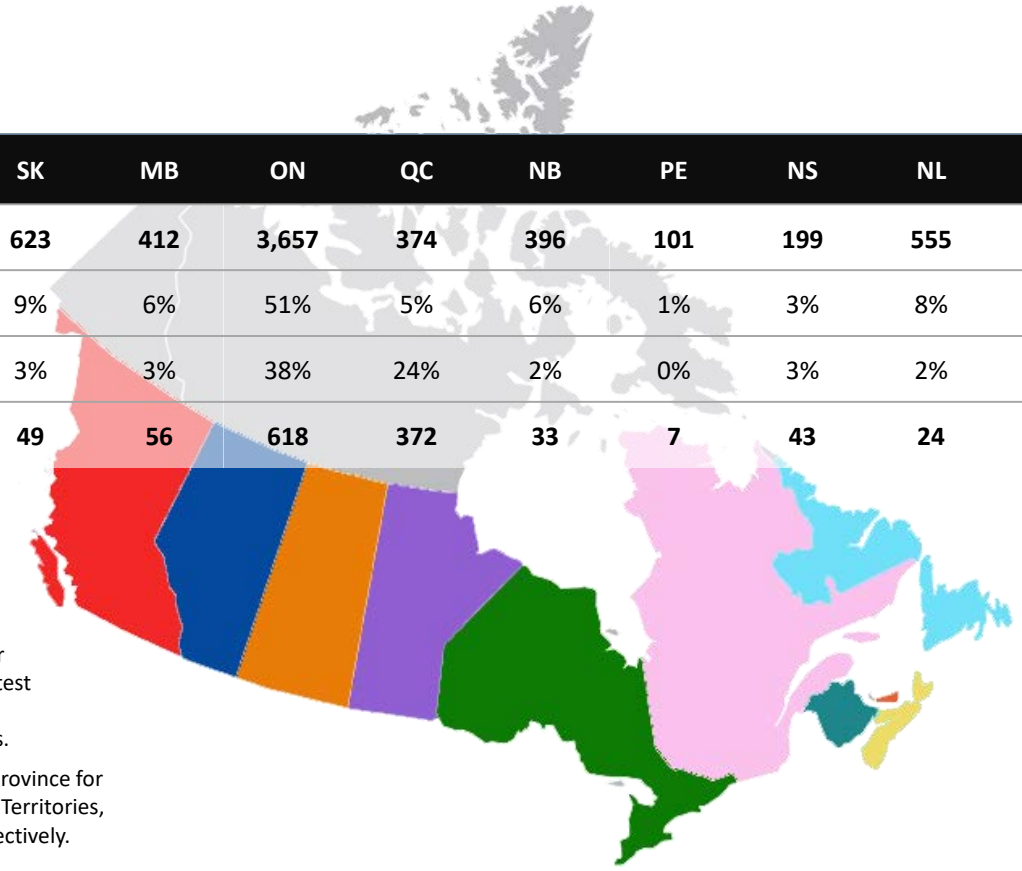
Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

**** NOTE ON WEIGHTING:** The survey data has been weighted by the population, age and gender distributions within 30 graphical sub-regions across Canada, using 2016 Census data. This weighting convention ensures that the survey data is representative at both the national- and provincial-levels of analysis.*

***** NOTE ON TRACKING:** Reliable tracking from years prior to 2014 is limited to questions that were not impacted by the transition from 1-10 to 0-10 response scales in 2014. Where reliable tracking is available, in some instances it dates back as far as 2009.*

Sample Design

	BC	AB	SK	MB	ON	QC	NB	PE	NS	NL	Total
Unweighted Sample (n)	**465**	**410**	**623**	**412**	**3,657**	**374**	**396**	**101**	**199**	**555**	**7,192**
Unweighted Sample (%)	6%	6%	9%	6%	51%	5%	6%	1%	3%	8%	100%
2016 Census Population (%)	13%	11%	3%	3%	38%	24%	2%	0%	3%	2%	100%
Weighted (n)	**214**	**185**	**49**	**56**	**618**	**372**	**33**	**7**	**43**	**24**	**1,600**



n=1,600
National Weighted Sample

NOTE: The sample has been weighted by the population, age and gender distributions within 30 graphical sub-regions across Canada, using the latest available Census data. This weighting convention was used to ensure representative data at both the national- and provincial-levels of analysis.

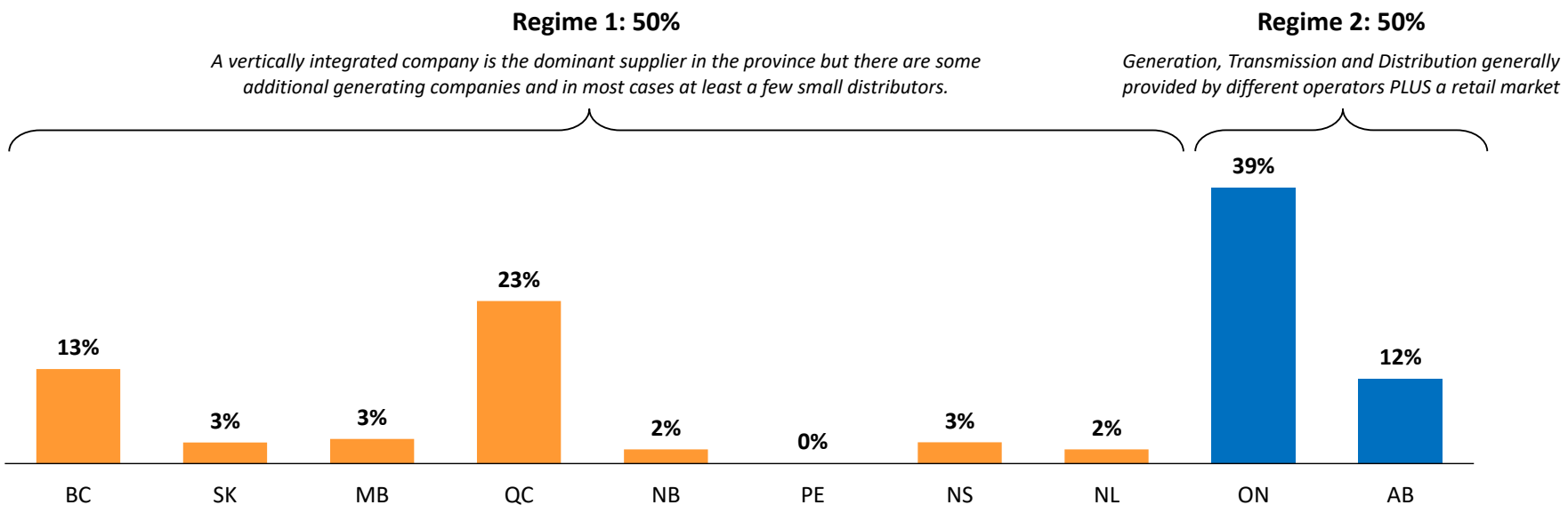
Respondents from the territories are grouped with those in the nearby province for weighting purposes and regional analysis. Those from Yukon, Northwest Territories, and Nunavut are grouped together with BC, Alberta, and Manitoba respectively.

Oversampled regions were weighted *down* (as opposed to *up*) – *from an unrepresentative national sample size of n=7,192 to a representative national sample size of n=1,600* – to ensure that respondent input from any region was not artificially inflated.

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Region & Regime

The survey design applies to all respondents regardless of the provincial electricity system – whether customers predominantly receive their electricity services from a vertically integrated company (Regime 1) or from different operators of transmission and distribution (Regime 2).



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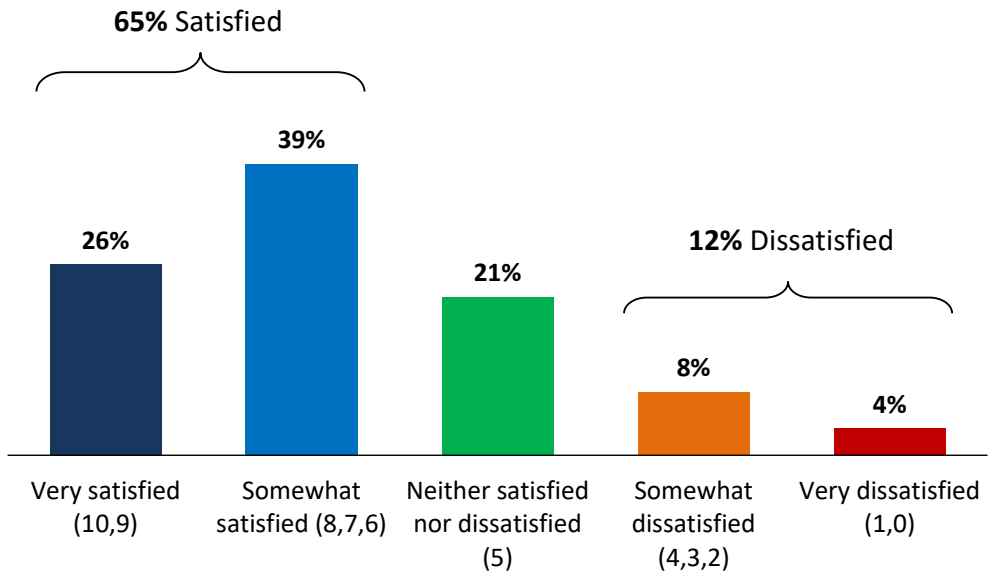
General Satisfaction

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General Satisfaction: Two-thirds (65%) are generally satisfied with their electricity company; higher in Quebec and those not impacted by bills or outages

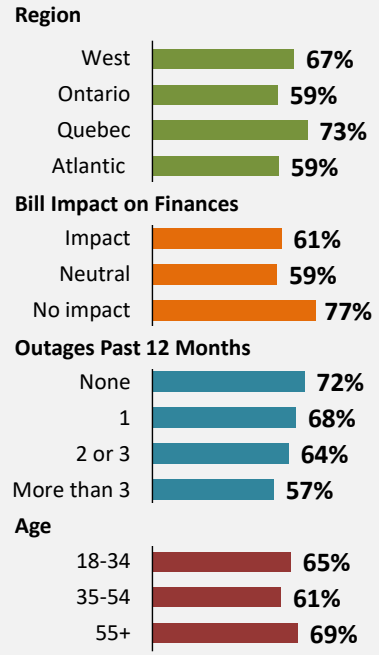
Q The following questions are about the local distribution system, the part of the system that brings electricity from nearby substations to your home and local businesses. In general, how satisfied are you with [COMPANY]? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; n=1,600]



Segmentation

*Those who are **"satisfied"** with their electricity company*

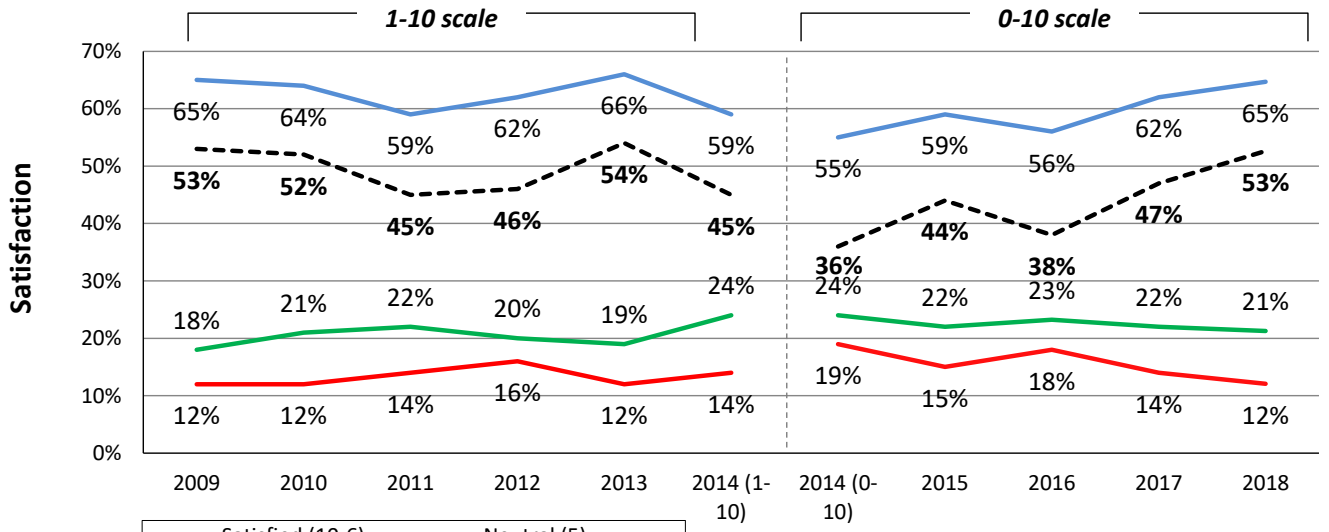


NOTE: 'Don't know' (2%) not shown.

General Satisfaction: Net satisfaction is up 6 points since over 2017, due to a marginal increase in satisfaction along with a marginal decrease in *dis*satisfaction

Q The following questions are about the local distribution system, the part of the system that brings electricity from nearby substations to your home and local businesses. In general, how satisfied are you with [COMPANY]? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; n=1,600]



* Prior to the 2014 survey, this question was asked as "*In general, how satisfied are you with your **electricity company** on a scale of 1 to 10, where 1 means not at all satisfied and 10 means very satisfied?*" For tracking purposes, we assume that "**electricity company**" means "**company that provides distribution services**". In the 2014 survey two scales were used to rate satisfaction, as we transitioned from a 1-10 to a 0-10 scale.

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Assessing the Role of the Broader Environment on Satisfaction

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Environmental Controls: *Uncontrollable External Factors*

It is important to distinguish between what is within, and what is outside of an electrical utility's influence or control when it comes to drivers of satisfaction.

Perceptions of electricity companies often tend to move with general perceptions of ***provincial government performance in the sector*** rather than in response to the utility itself.

In addition, perceptions of utilities are strongly correlated with **financial circumstances**. In tough times, perception and preference can change because customers are struggling with their bills, not because of anything the company has – or as not – done.

Control questions help distributors distinguish between two factors that impact public perception:

a) utility-driven programs; and

b) uncontrollable external factors.

In this survey, we include two environmental control questions to help capture external phenomena:



Government Performance: *How satisfied are you with the job your provincial government is doing to manage the electricity system?*



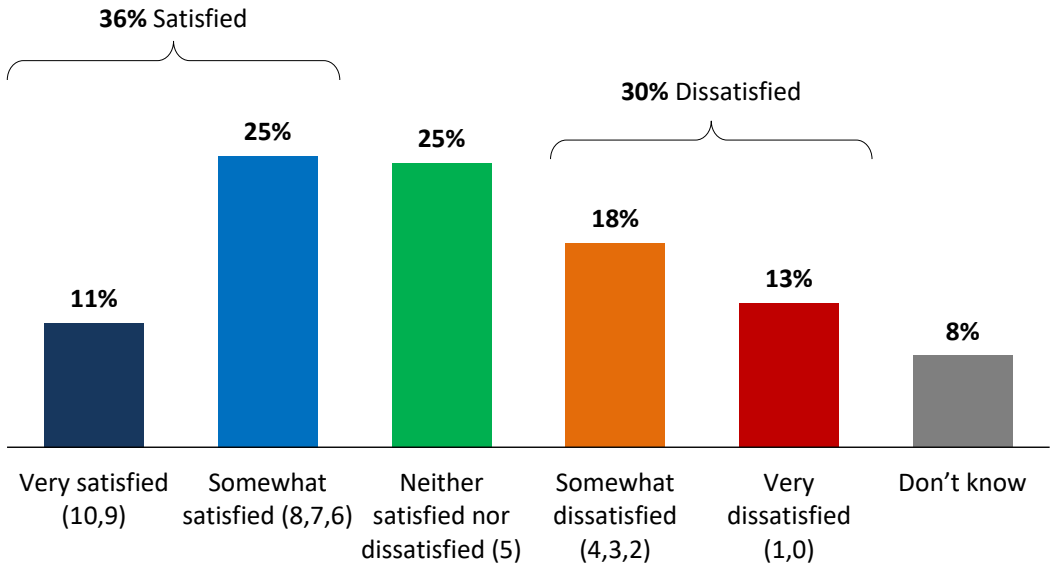
Financial Circumstances: *The cost of my electricity bill has major impact on my finances and requires I do without some other important priorities.*

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Provincial Gov't: Over one-third (36%) are satisfied with provincial government performance on electricity system; highest among ages 18-34 and Quebecois

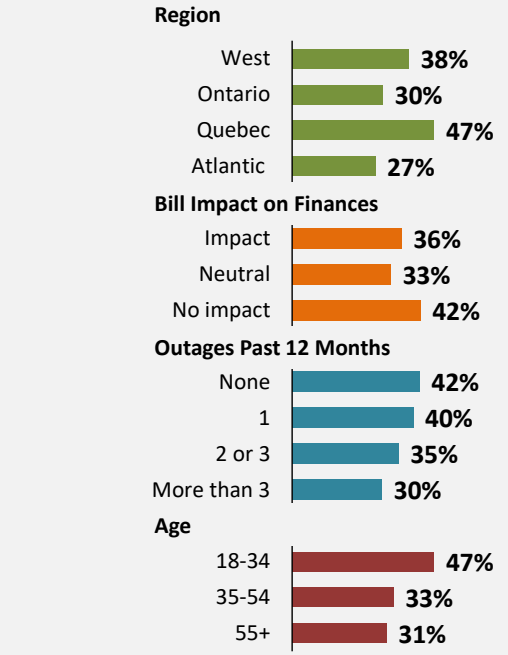
Q How satisfied are you with the job your provincial government is doing to manage the electricity system? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents; n=1,600]



Segmentation

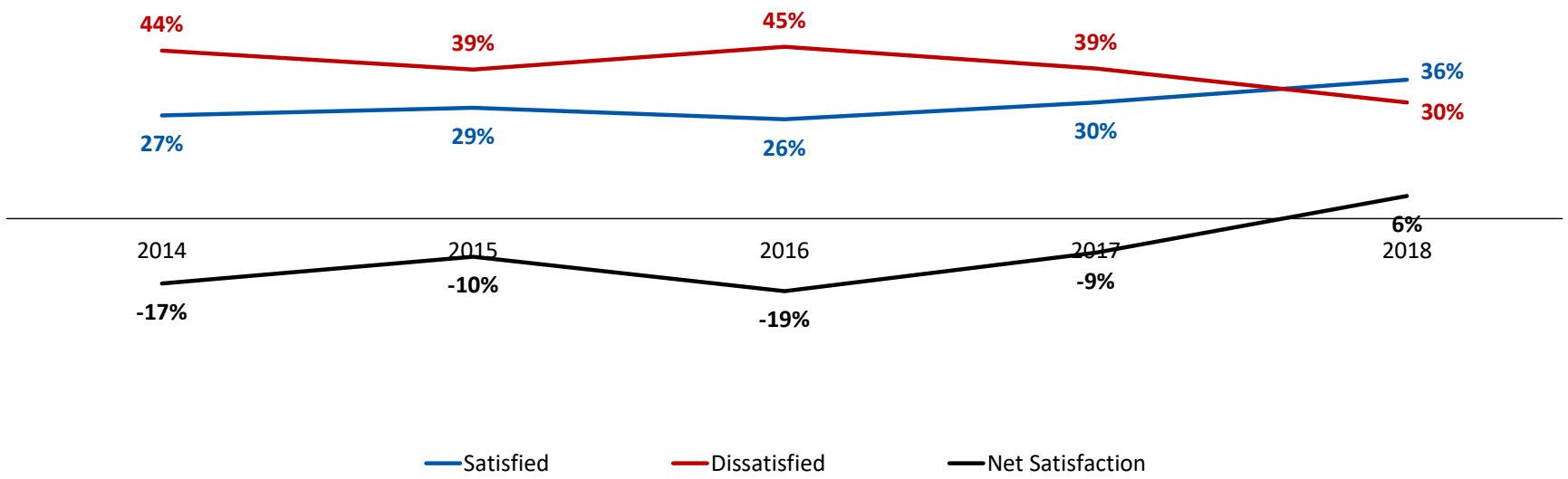
*Those who are **"satisfied"***



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Gov't Performance (Tracking): Satisfaction up 6 pts over 2017; dissatisfaction down 9 pts. Net satisfaction positive for first time since tracking began

Q How satisfied are you with the job your provincial government is doing to manage the electricity system? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=1,600]

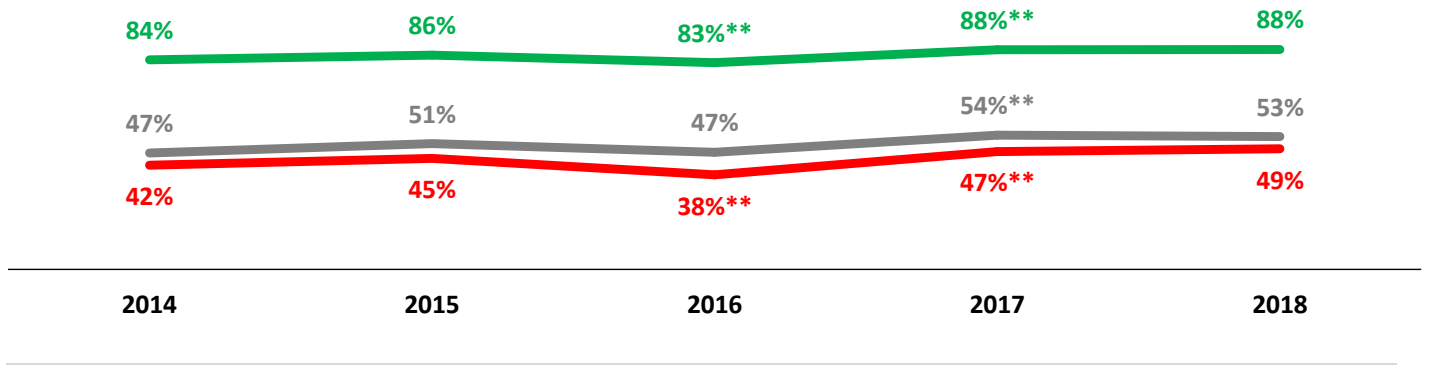


NOTE: 'Don't know' (8%) not shown.

Government Performance: Utilities sustaining positive views among growing numbers who are happy with gov't; gaining among those unhappy with gov't

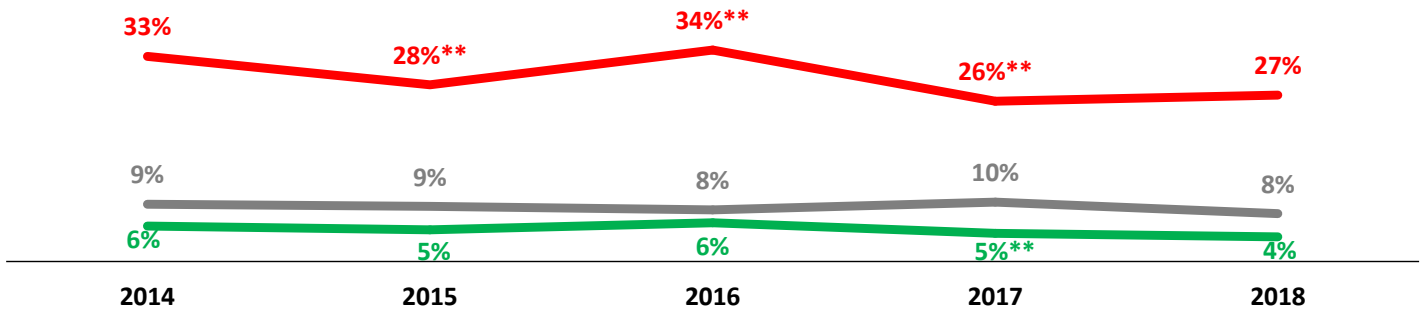


% Satisfied with Electricity Company





% Dissatisfied with Electricity Company



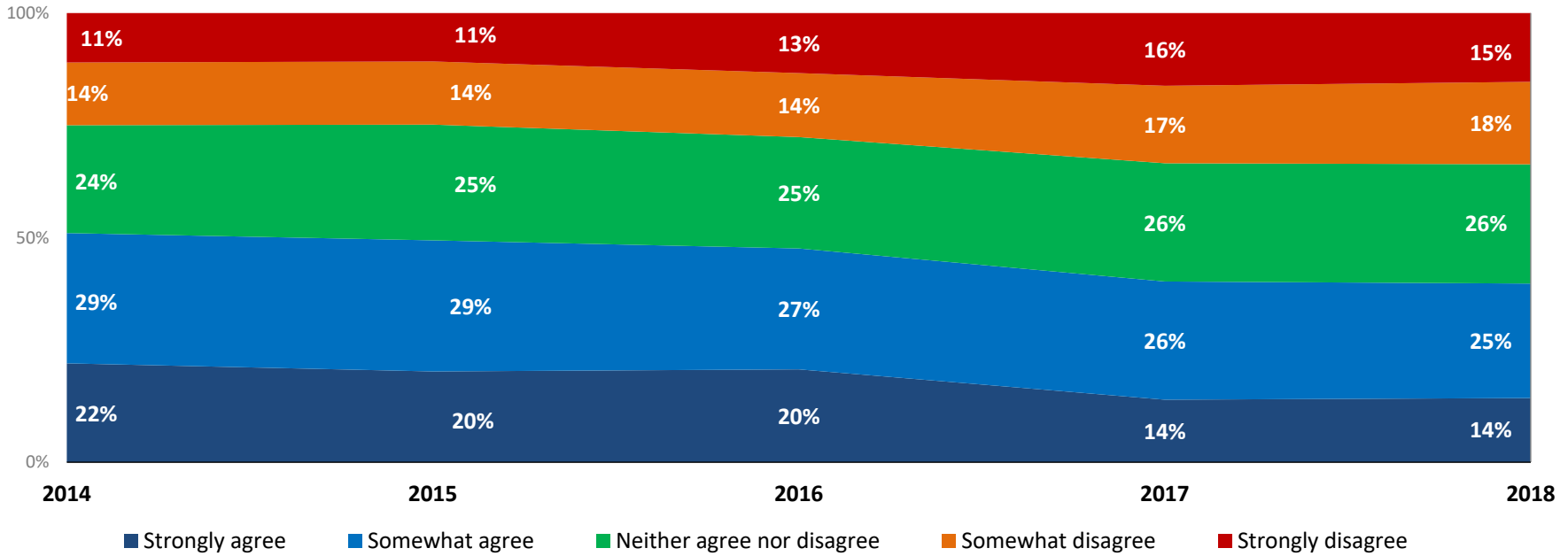
* Significantly different from the year prior at 90% confidence level
** Significantly different from the year prior at 95% confidence level

Financial Circumstances (Tracking): Perception of bill impact has not changed in the past year

Q Do you agree or disagree with the following statement:

My electricity bill has major impact on my finances and requires I do without other important priorities.

[for tracking purposes, data filtered to show only those who receive a bill; n=1,452]



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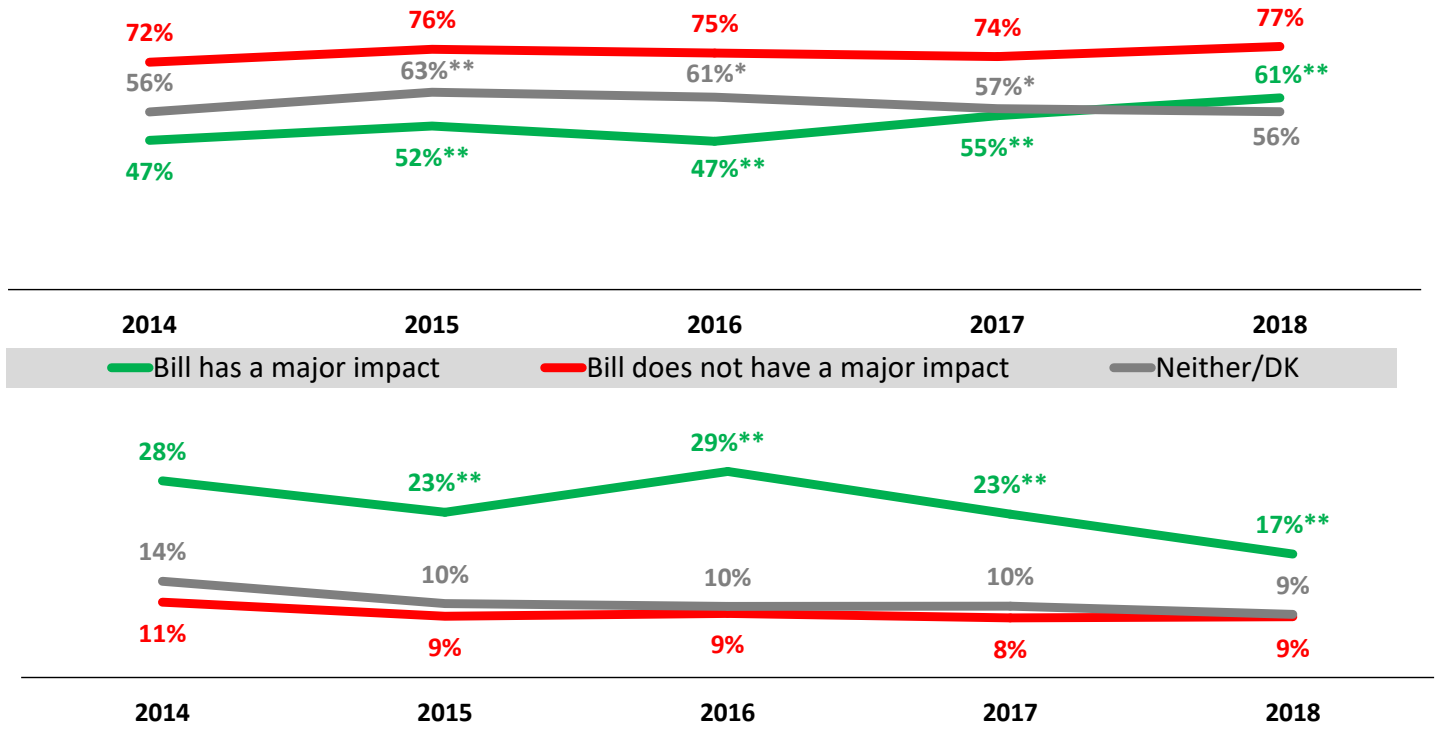
Financial Circumstances: People struggling to pay their bills significantly more satisfied with their utility



% Satisfied with Electricity Company



% Dissatisfied with Electricity Company



* Significantly different from the year prior at 90% confidence level
** Significantly different from the year prior at 95% confidence level

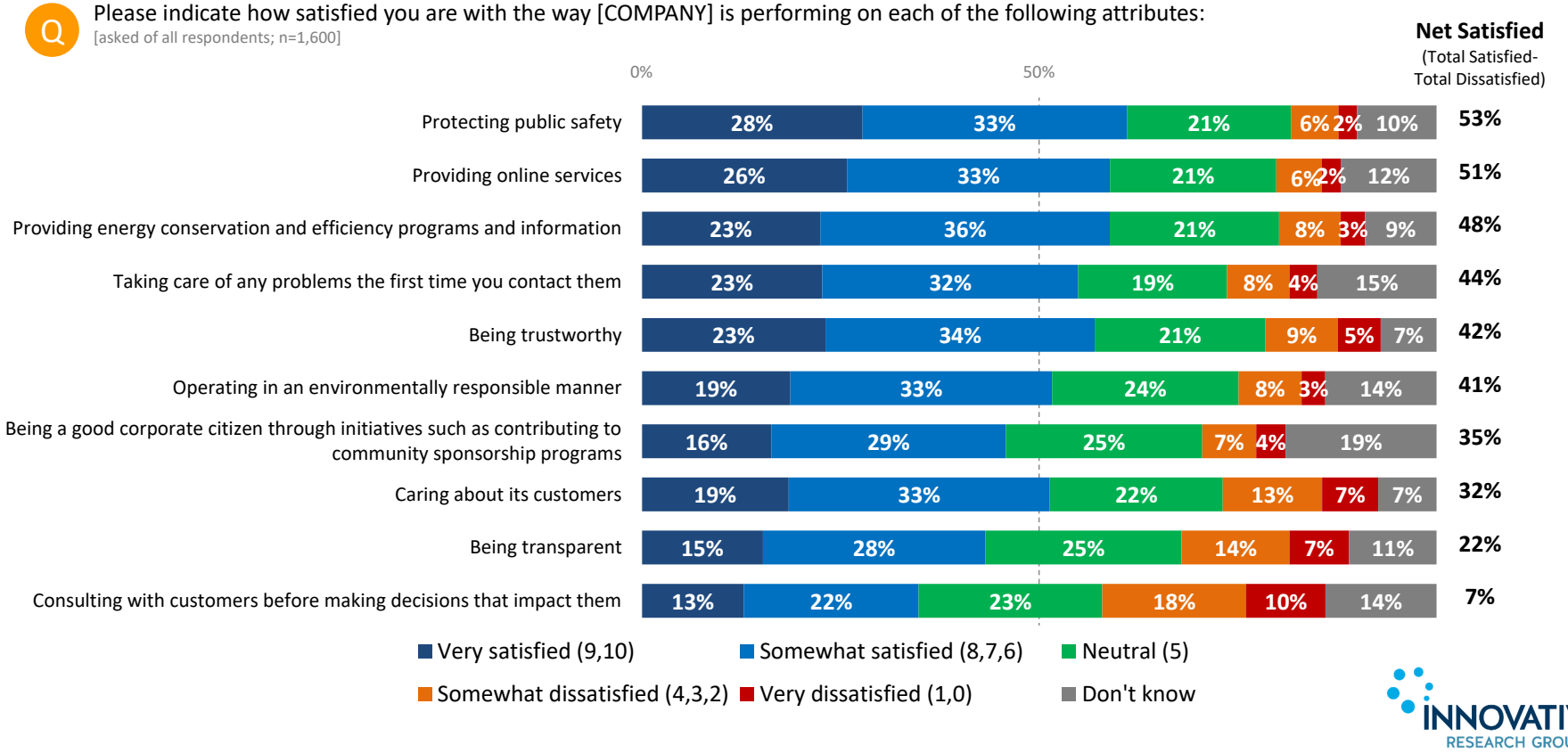
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Diving Deeper into Reputation

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Brand Attributes: Satisfaction highest with public safety, provision of online services, and CDM. Transparency and customer consultation are vulnerabilities.

Q Please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes:
[asked of all respondents; n=1,600]

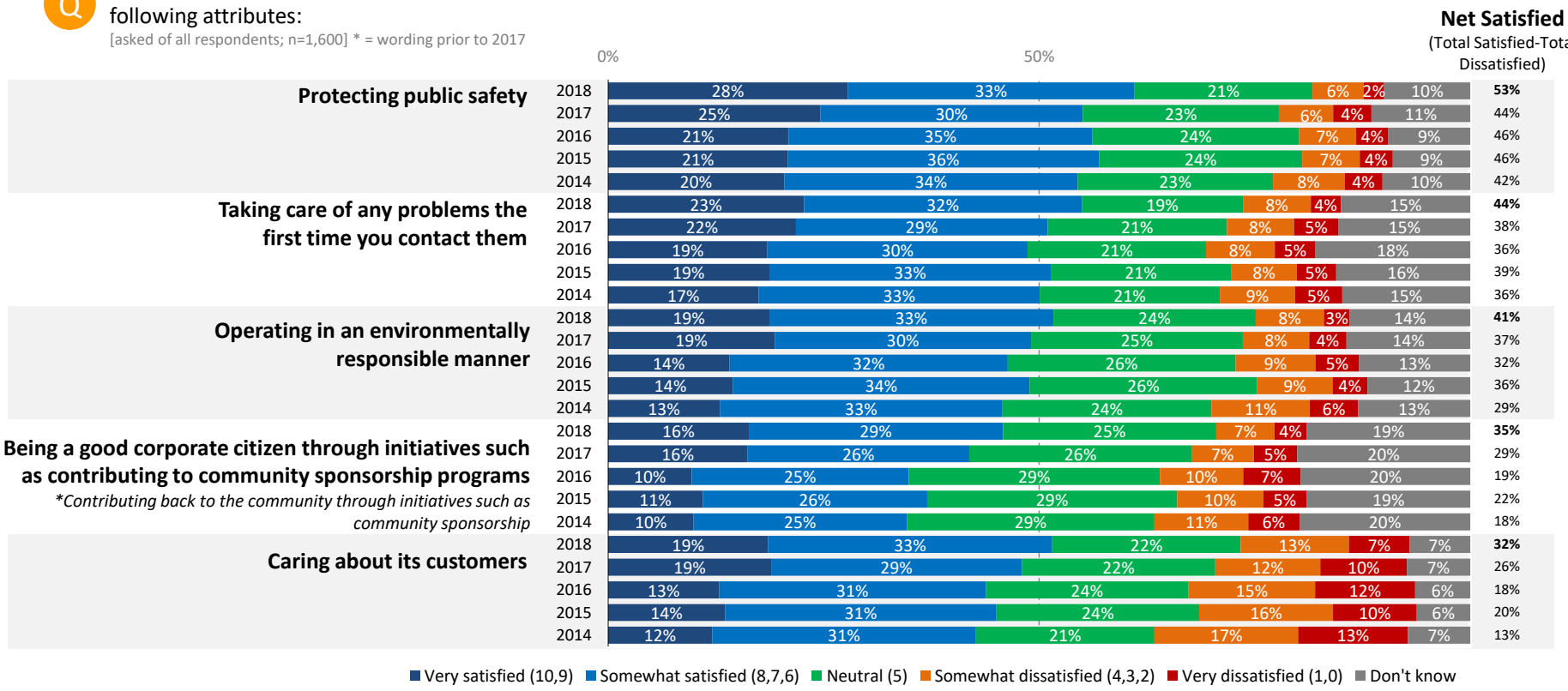


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Brand Attributes (Tracking): Satisfaction has increased on all brand attributes that have been tracked for five years

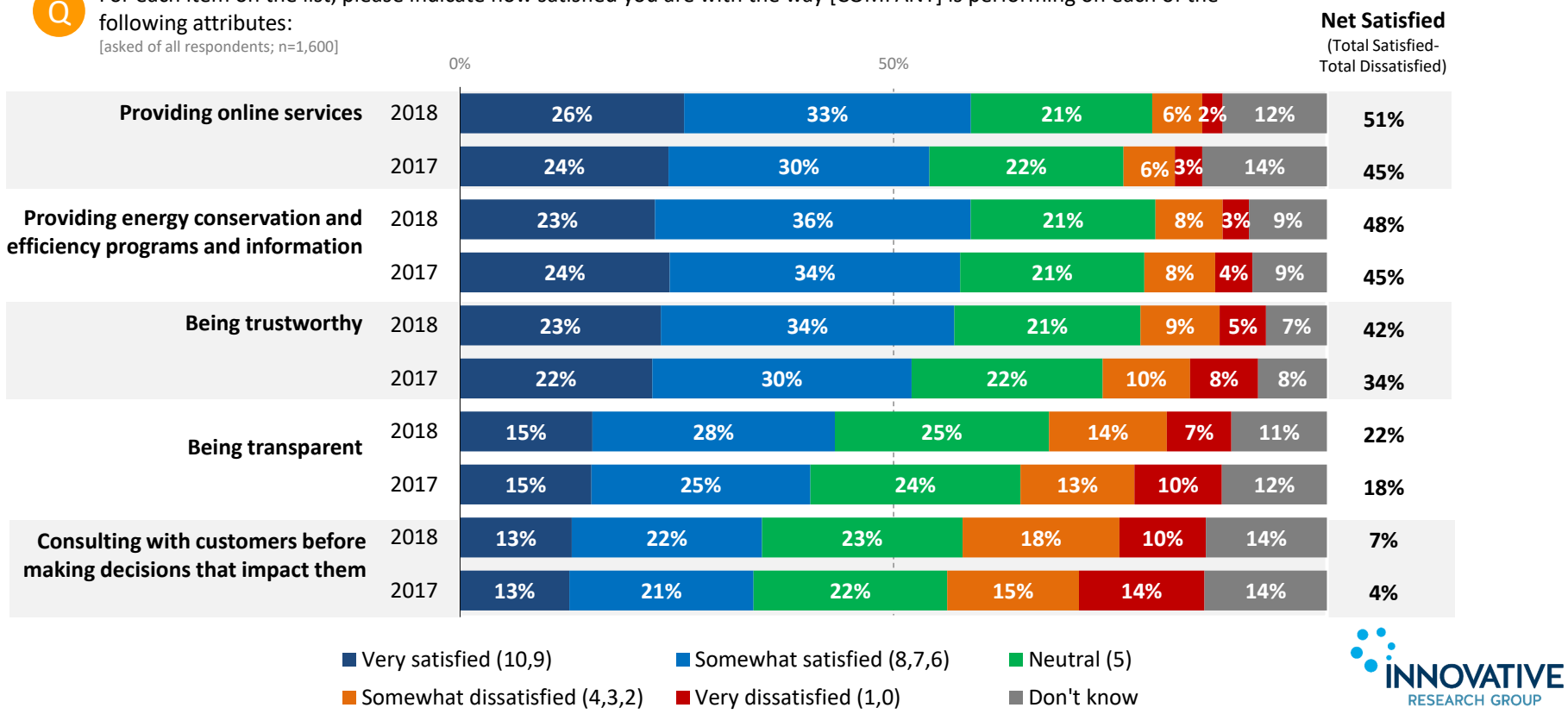
Q For each item on the list, please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes:

[asked of all respondents; n=1,600] * = wording prior to 2017



Brand Attributes (Tracking): Satisfaction increases on all brand attributes that were introduced in 2017

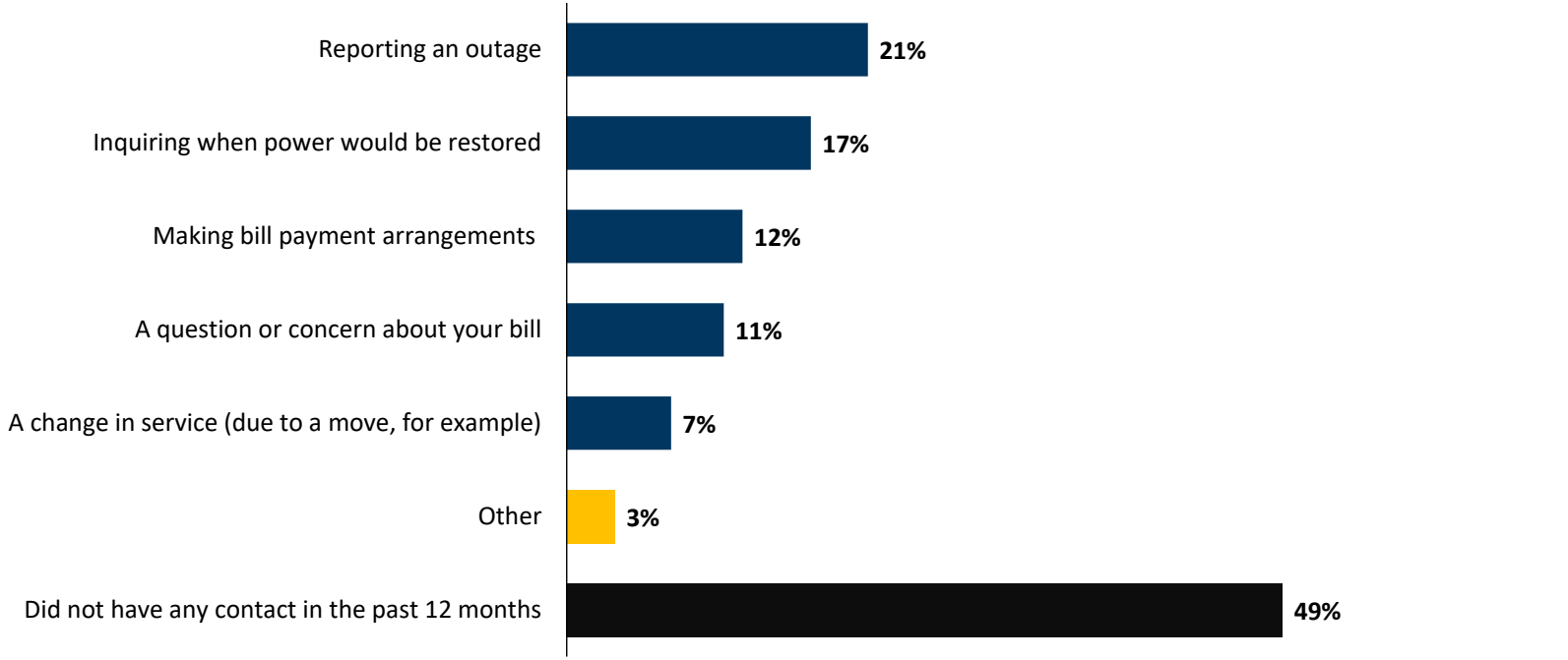
Q For each item on the list, please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes:
[asked of all respondents; n=1,600]



INNOVATIVE RESEARCH GROUP

Distributor Contact: Half (49%) haven't contacted their distributor in the past year. Outage reporting and power restoration inquiries most common

Q In the past 12 months, which (if any) of the following issues have you contacted [COMPANY] about? *Select all that apply.*
[asked of all respondents; n=1,600]



NOTES: 'Don't know' (3%) not shown.
Chart total is greater than 100% as multiple mentions were accepted

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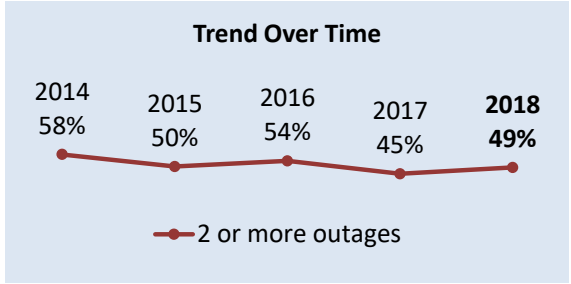


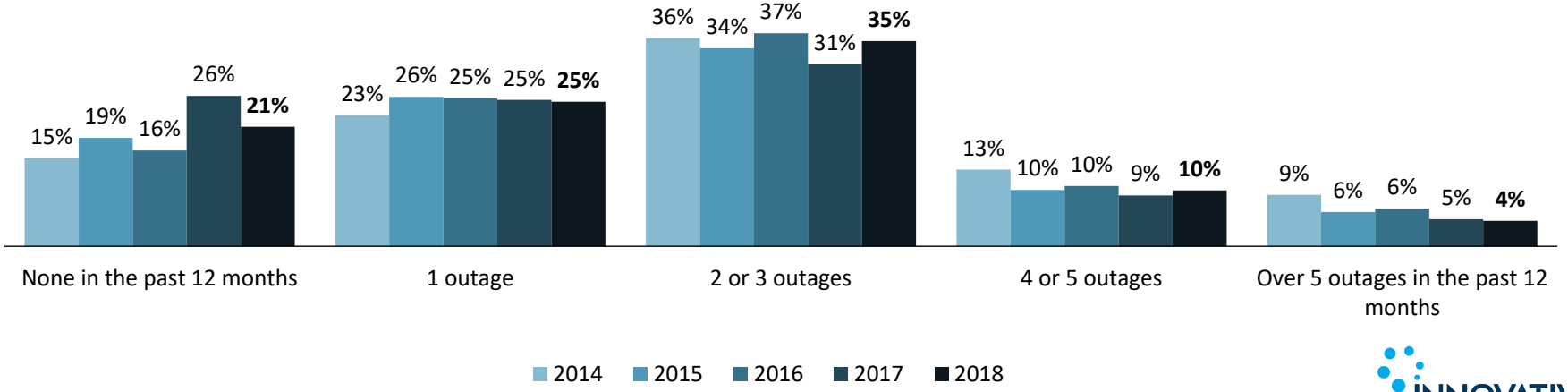
Reliability & Power Quality

INNOVATIVE RESEARCH GROUP

Power Outages: About half (49%) report experiencing at least two outages in the past year; up 4 points over 2017. Only 14% have had more than 3 outages.

Q In the past 12 months, how many power outages do you recall experiencing at home?
[asked of all respondents; n=1,600]



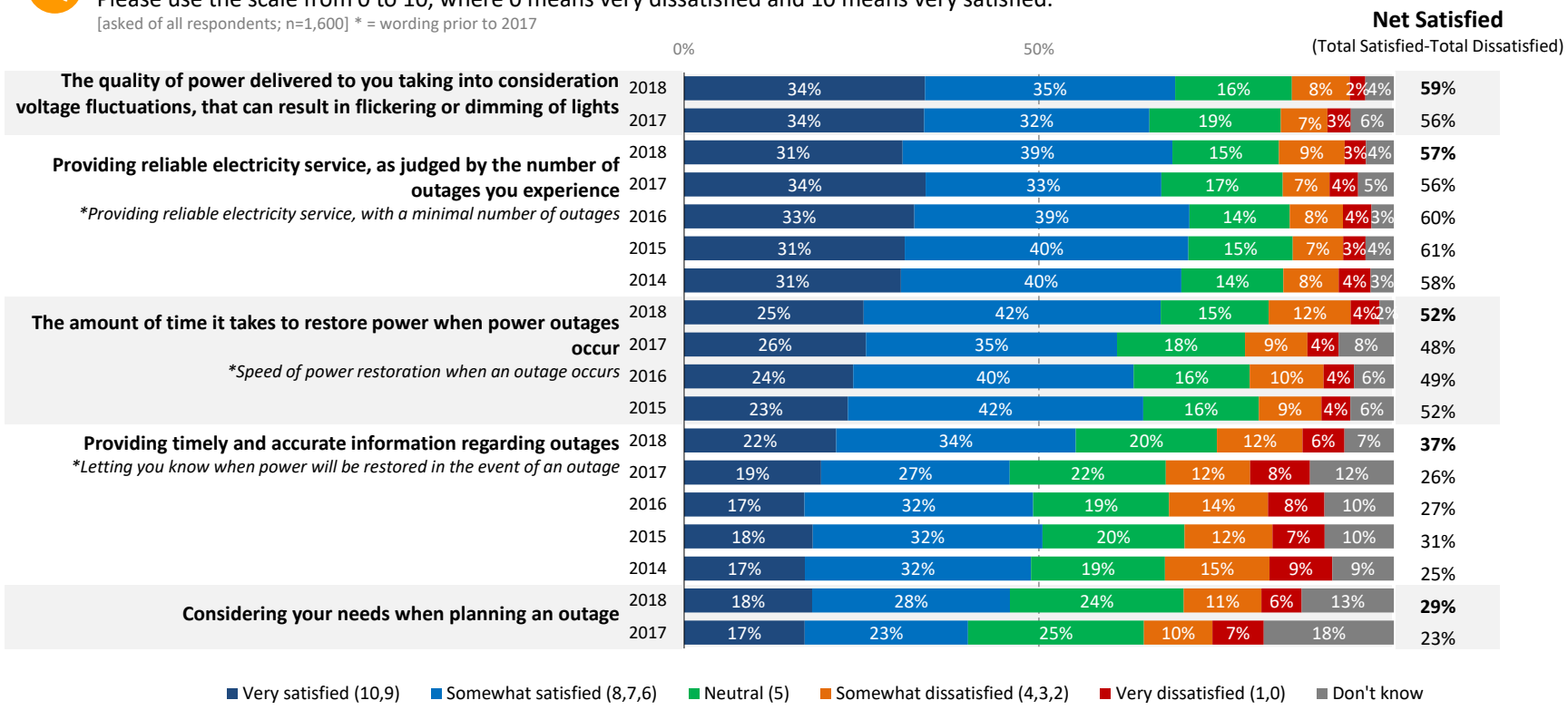


NOTE: 'Don't know' (5%) not shown.

Reliability & Quality Attributes (Tracking): Strongest gains (11pts) on provision of timely and accurate outage information; marginal gains on other attributes

Q Please indicate how satisfied you are with the way that [COMPANY] is performing on each of the following attributes related to your electrical service: Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents; n=1,600] * = wording prior to 2017



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Planned Outages

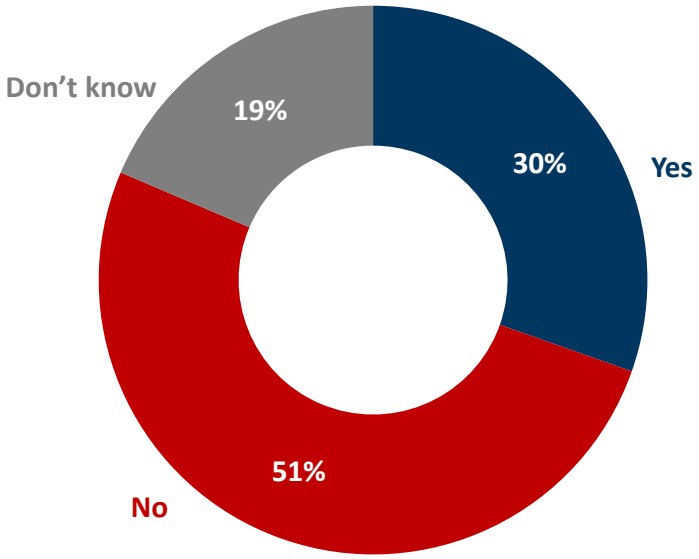
(New in 2018)



Planned Outages: 3-in-10 (30%) recall being impacted by planned outages in the past two years; higher in Quebec

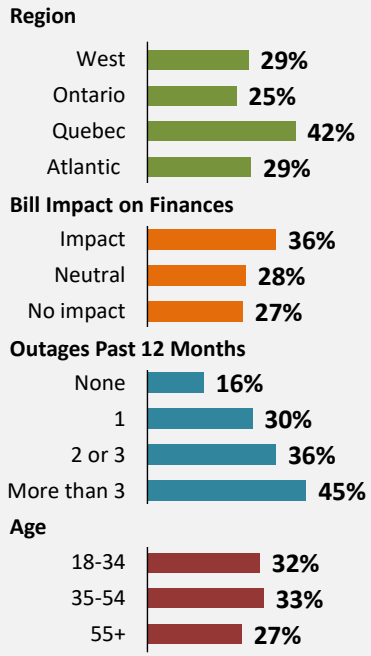
Q From time to time, your local utility has to turn off the power to repair or replace equipment. This work is generally planned in advance and these outages are called planned outages. Over the past 2 years, have you been impacted by any planned outages?

[asked of all respondents; n=1,600]



Segmentation

*Those who say **"yes"***

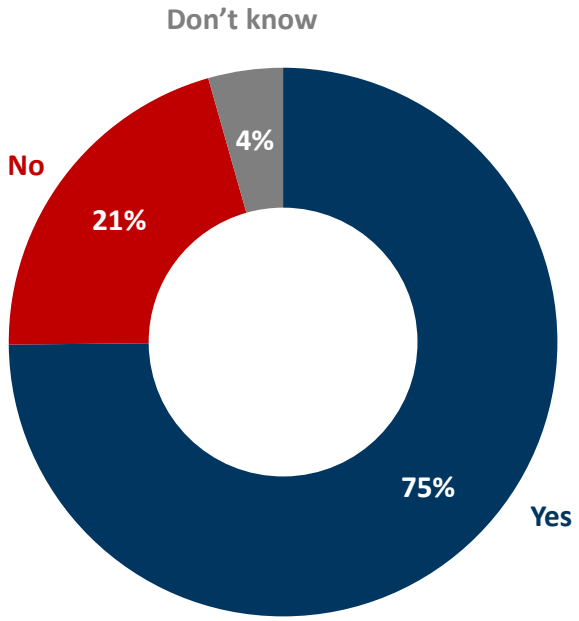


INNOVATIVE RESEARCH GROUP

Proactive Communication: Three-quarters (75%) recall proactive communication from their distributor about the most recent planned outage they experienced

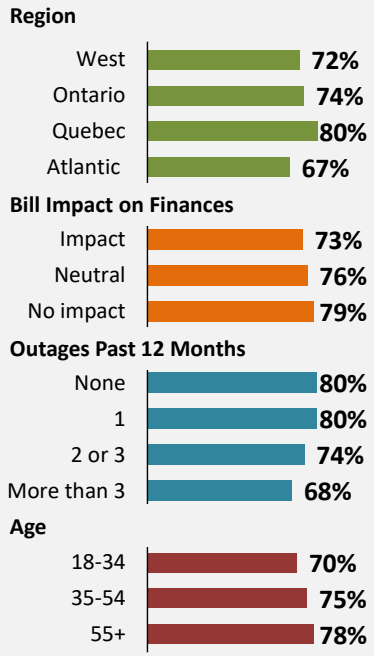
Q Did [COMPANY] proactively communicate with you about the most recent planned power outage that you experienced?

[asked of respondents who have been impacted by planned outages within the past 2 years; n=486]



Segmentation

*Those who say **"yes"***

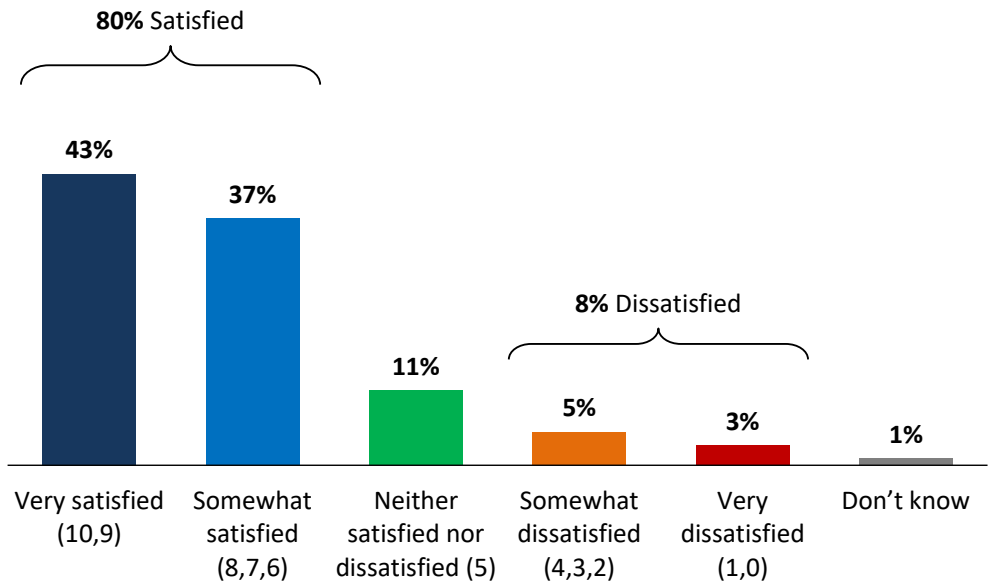


INNOVATIVE RESEARCH GROUP

Satisfaction with Planned Outage Communication: 4-in-5 (80%) are satisfied with the way their distributor communicated; higher among 18-34-year-olds

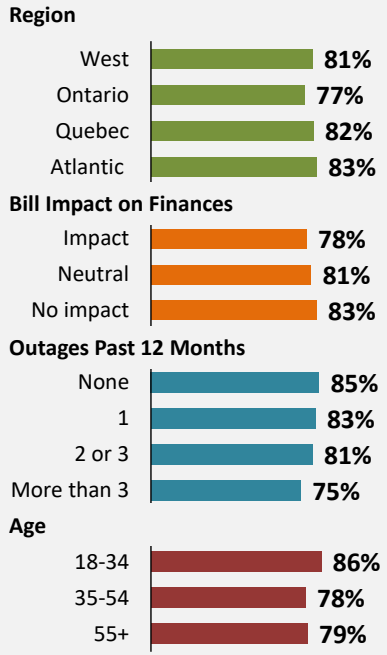
Q How satisfied are you with the way the company communicated with you about that planned outage? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of respondents who can recall being contacted by distributor during the most recent planned outage; n=364]



Segmentation

*Those who are **"satisfied"** with outage communication*



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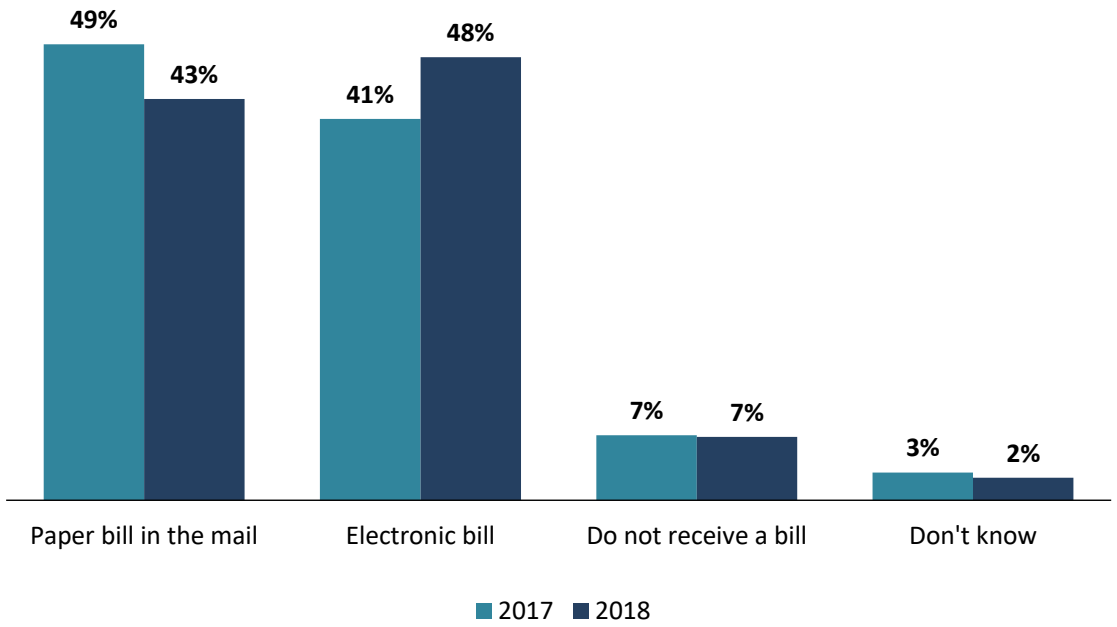
Billing & Payment



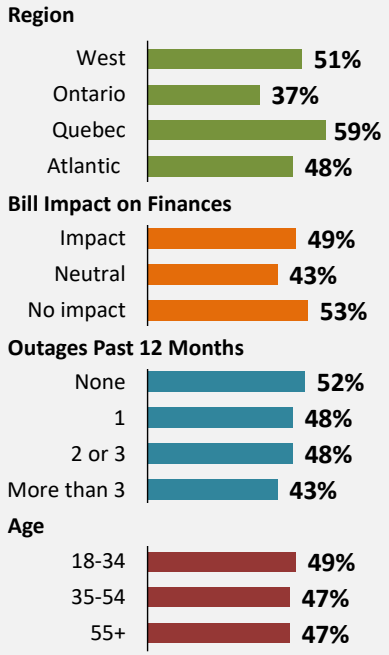
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Format of Electricity Bill: Over the past year, electronic bills have surpassed paper bills, especially in Quebec

Q In what format do you receive your electricity bill?
[asked of all respondents; n=1,600]



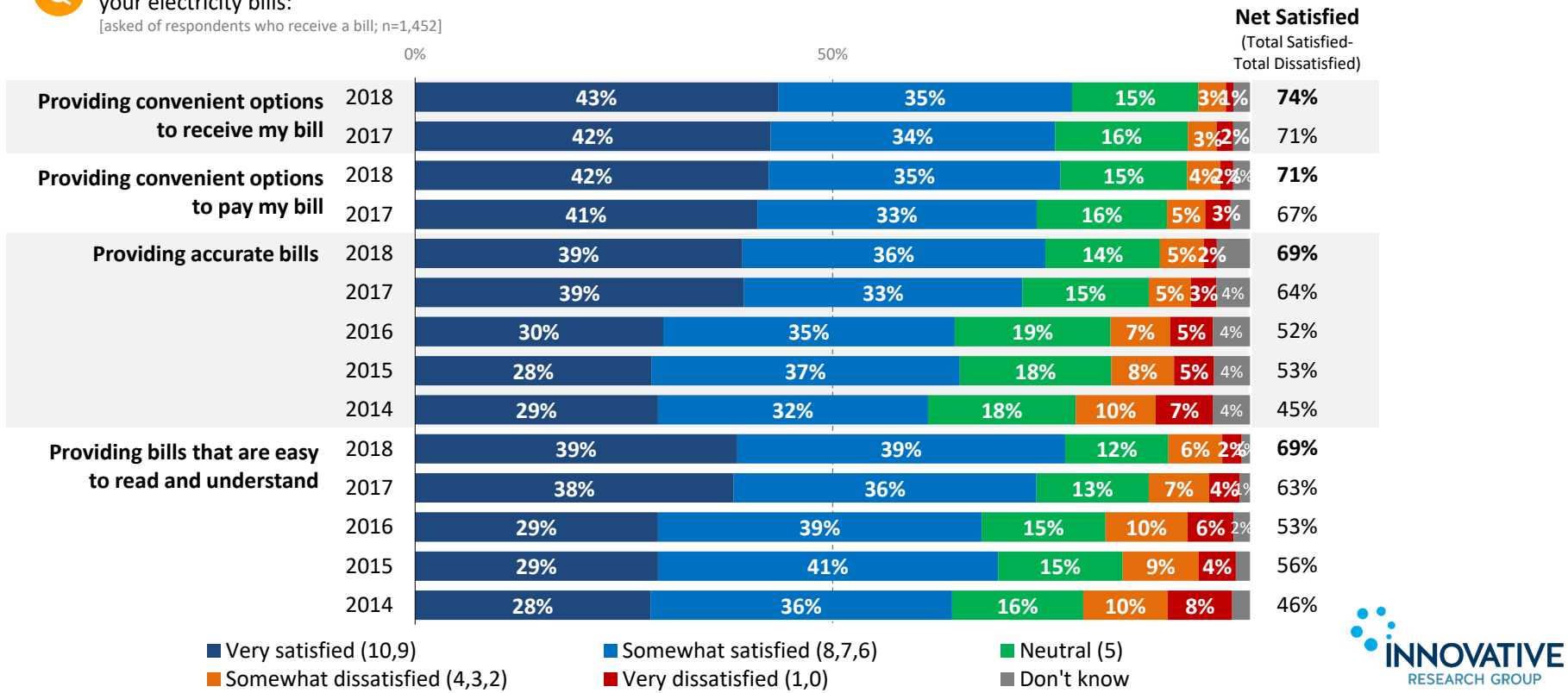
Segmentation
*Those who get an **electronic bill***



REMINDER: These results are from an online survey. As such, the proportion of customers who receive a paper bill may be under-represented

Billing & Payment Attributes (Tracking): Marginal gains on all billing/payment attributes. Convenience edges out accuracy & ease of understanding.

Q For each item on the list, please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes related to your electricity bills:
[asked of respondents who receive a bill; n=1,452]



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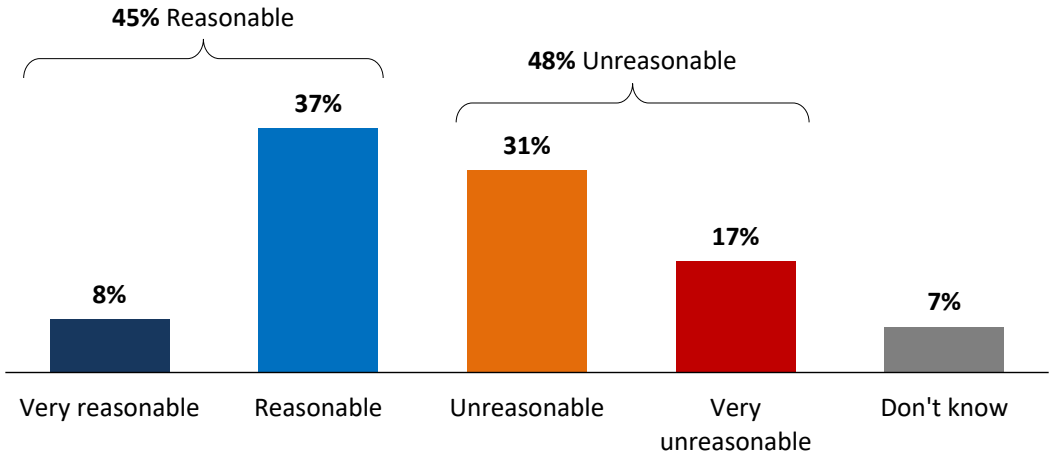
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Price

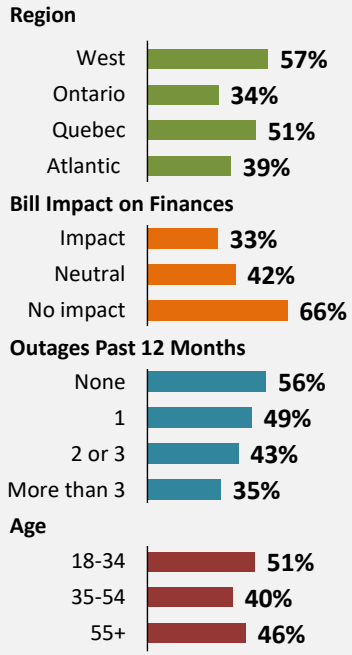
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Reasonable Price?: Unreasonable marginally higher than reasonable, and twice as high in intensity. Positive response to price deceases as impact of bill increases.

Q Overall, do you think that the price for electricity in your province is reasonable or unreasonable?
[asked of all respondents; n=1,600]



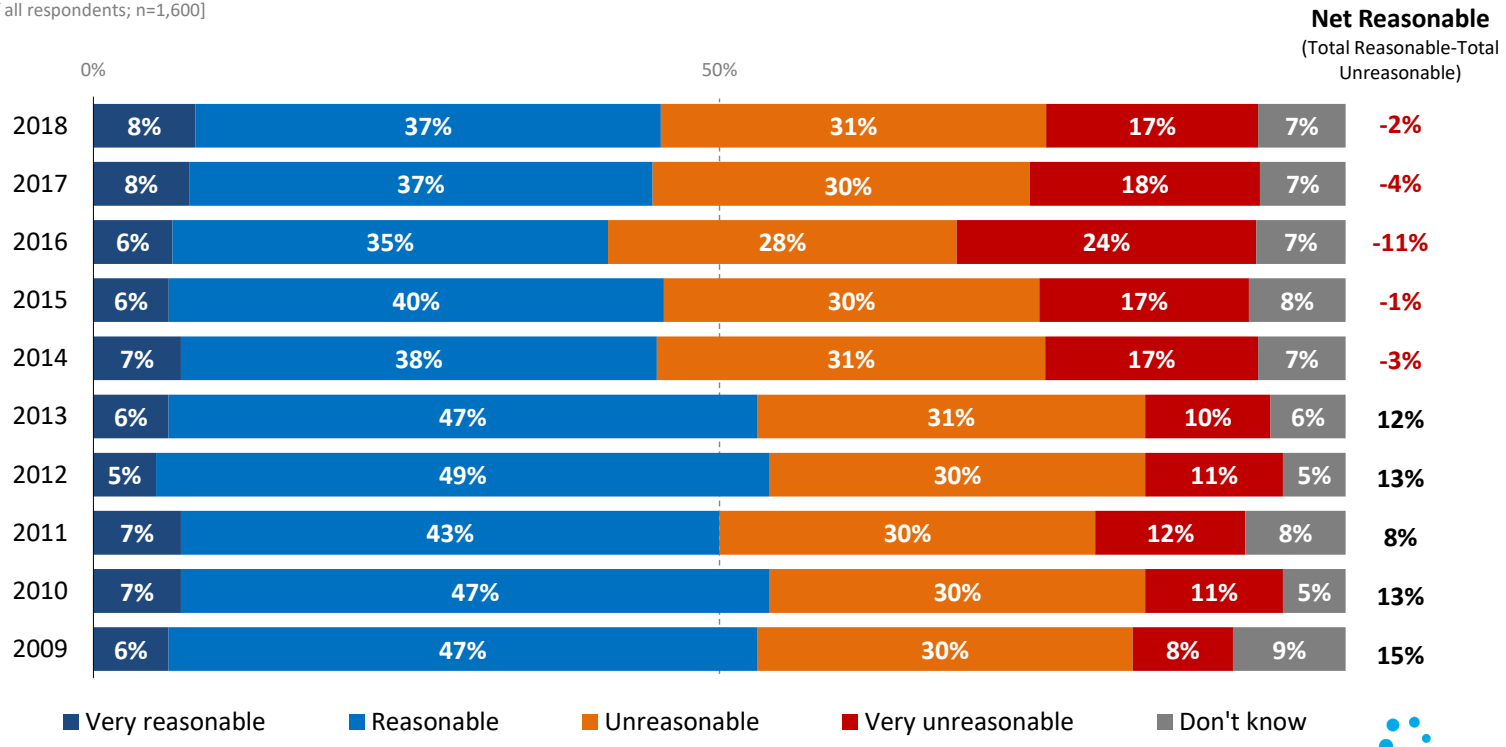
Segmentation
*Those who say **"reasonable"***



INNOVATIVE RESEARCH GROUP

Reasonable Price (Tracking): Net reasonability of electricity prices stable year over year, maintains recovery from all-time low in 2016

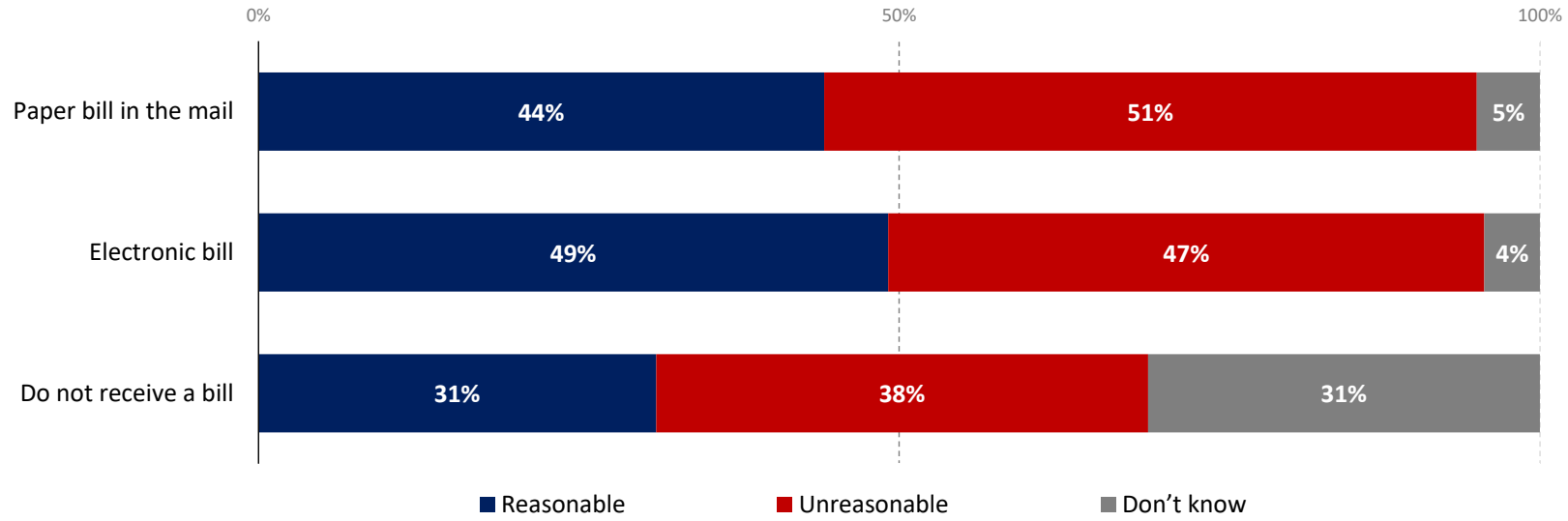
Q Overall, do you think that the price for electricity in your province is reasonable or unreasonable?
[asked of all respondents; n=1,600]



INNOVATIVE RESEARCH GROUP

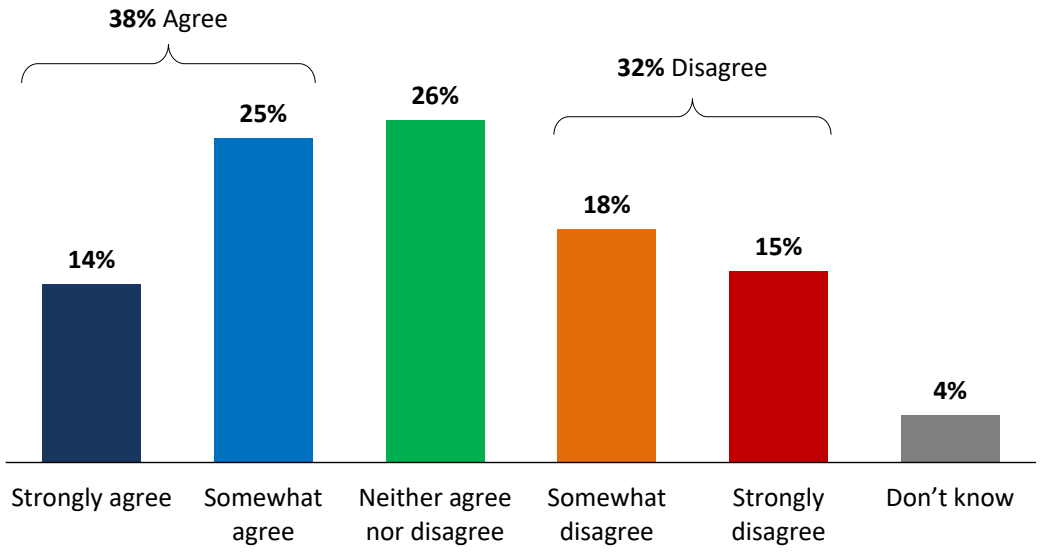
Price Assessment by Bill Format: Those who receive an electronic bill are marginally more likely to say price is reasonable than those with a paper bill

Q Overall, do you think that the price for electricity in your province is very reasonable, reasonable, unreasonable, or very unreasonable?
BY
Bill format
[asked of all respondents; n=1,600]

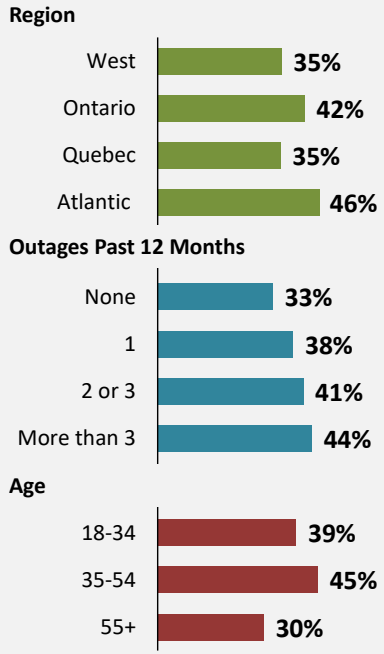


Financial Impact: 2-in-5 (38%) say their electricity bill has major financial impact; perceived impact increases with number of outages experienced

Q Do you agree or disagree with the following statements?
My electricity bill has major impact on my finances and requires I do without other important priorities.
[asked of all respondents; n=1,600]



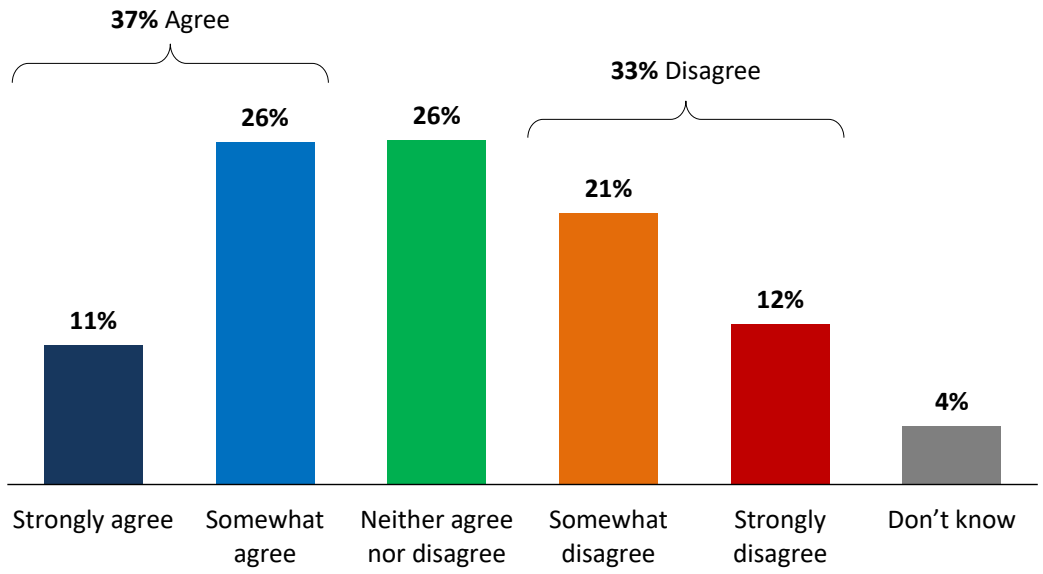
Segmentation
*Those who **"agree"***



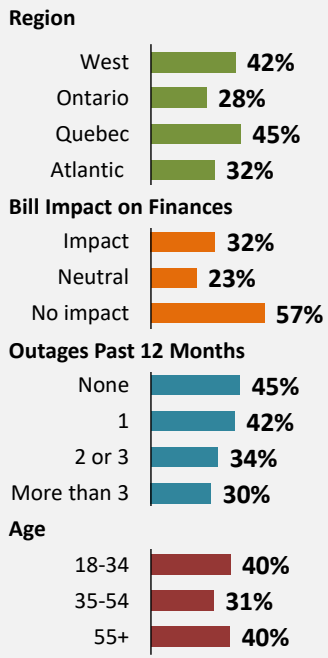
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Value for Money: Almost even division on whether or not respondents are getting value for money on their electricity; Ontarians least likely to agree

Q Do you agree or disagree with the following statements?
Thinking of all regular household bills, I receive good value for the price I pay for electricity.
[asked of all respondents; n=1,600]



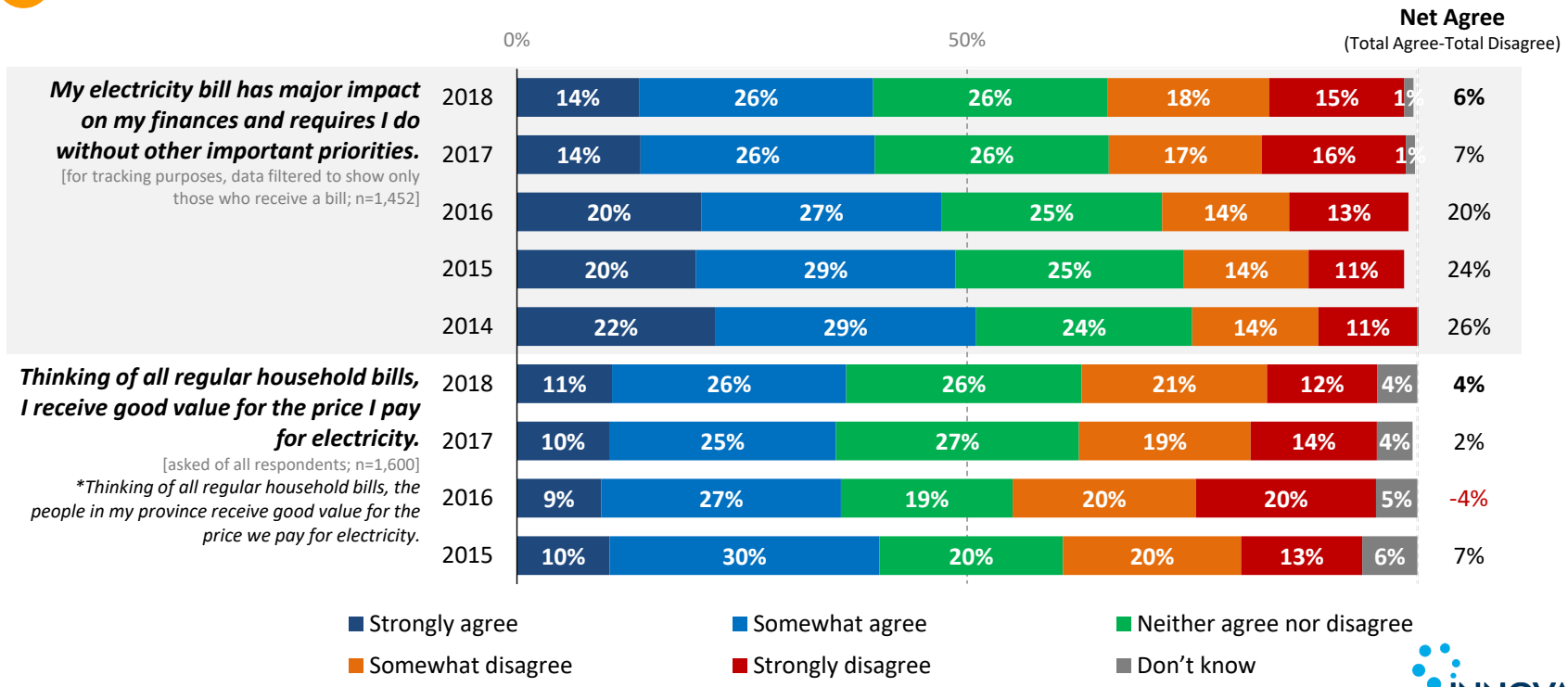
Segmentation
*Those who **"agree"***



INNOVATIVE RESEARCH GROUP

Financial Impact (Tracking): 2017's sharp reduction on bill impact has been maintained in 2018; virtually no change on value for money

Q Do you agree or disagree with the following statements:
[respondent base for each statement shown below]



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Perception of Price by Bill Impact: The extent to which electricity bills impact finances greatly influences opinion of price

Q Overall, do you think that the price for electricity in your province is very reasonable, reasonable, unreasonable, or very unreasonable?
BY
My electricity bill has a major impact on my finances and requires I do without some other important priorities.
[asked of all respondents; n=1,600]

Do you agree or disagree with the following statement:
My electricity bill has a major impact on my finances and requires I do without some other important priorities.

	Strongly agree	Somewhat agree	Neither	Somewhat disagree	Strongly disagree	Overall
Very reasonable	16%	4%	3%	5%	22%	8%
Reasonable	11%	33%	38%	54%	52%	37%
Unreasonable	24%	40%	39%	28%	15%	31%
Very unreasonable	46%	21%	11%	9%	6%	17%
Net Reasonable	**-43%**	**-24%**	**-9%**	**22%**	**53%**	**-3%**

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NOTE: 'Don't know' not shown

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Communications

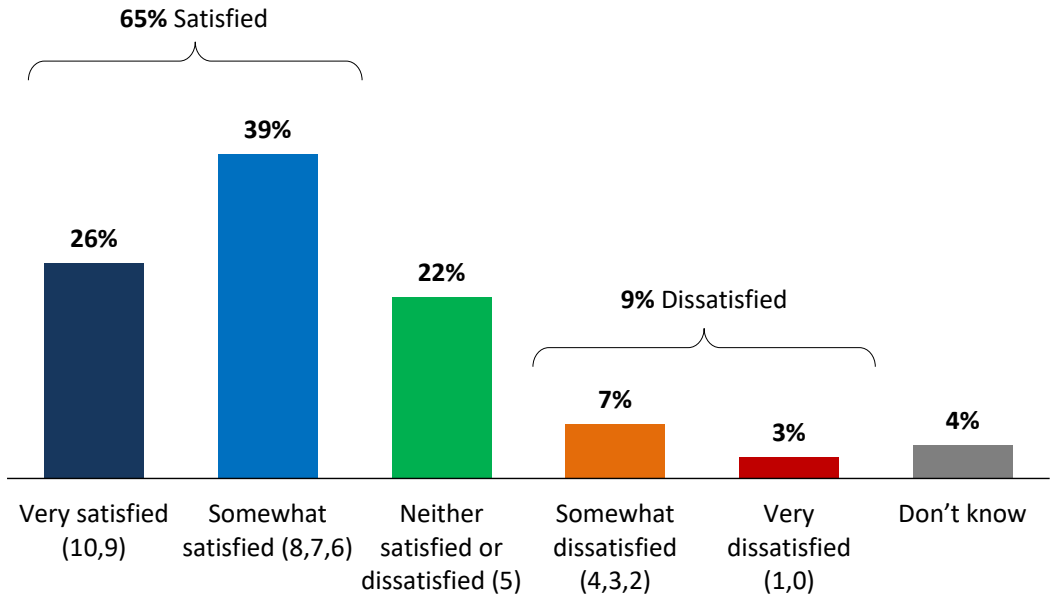


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Overall Communications: Two-thirds (65%) are satisfied with overall communications, particularly those whose bill doesn't cause financial strain

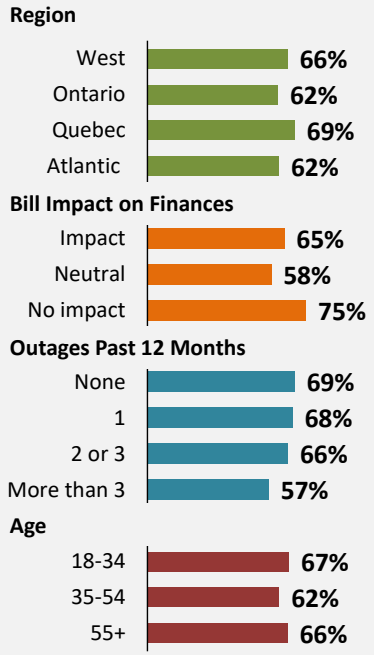
Q Please indicate how satisfied you are with overall communications from [COMPANY]. *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; n=1,600]



Segmentation

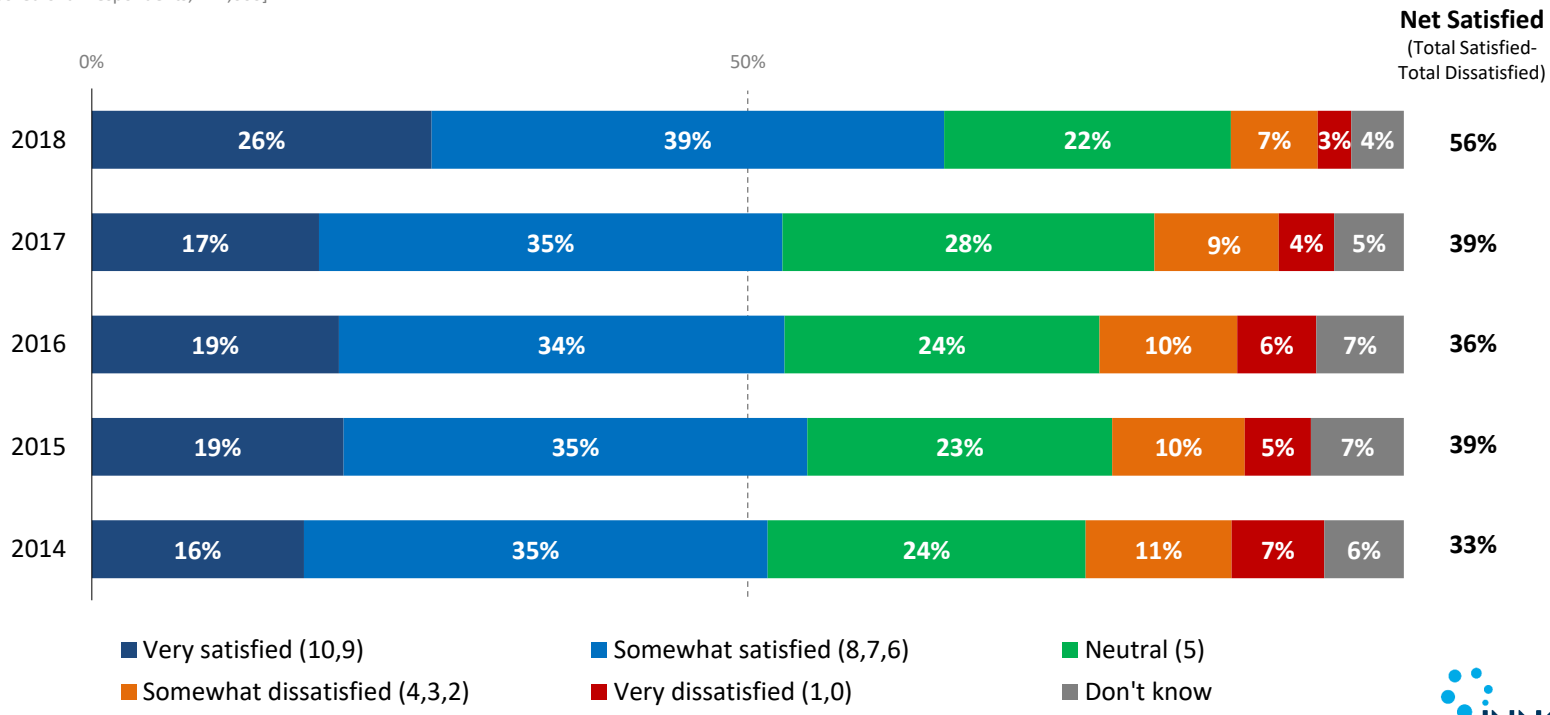
*Those who are **"satisfied"** with overall communications*



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Overall Communications (Tracking): Strong gains on satisfaction with communications; highest level of intense satisfaction (26%) since tracking began

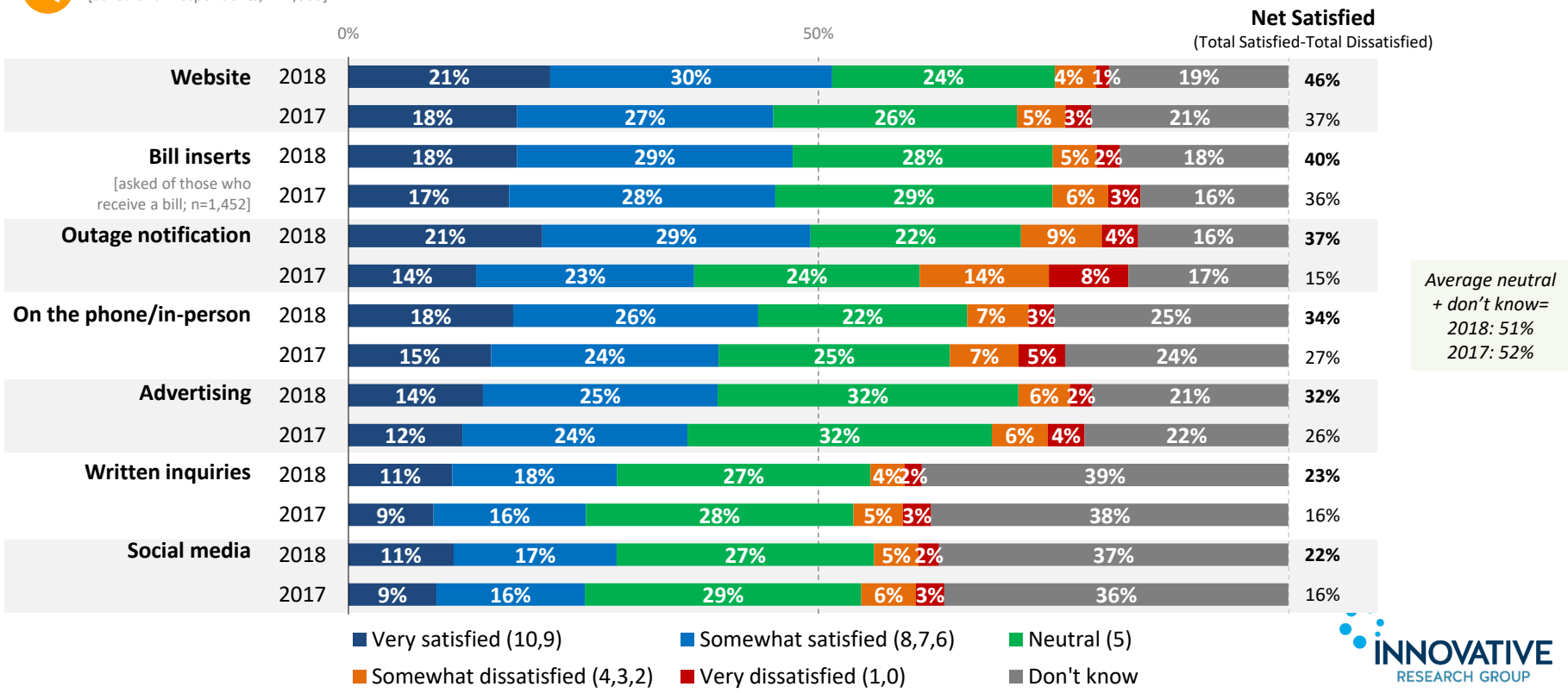
Q Please indicate how satisfied you are with overall communications from [COMPANY].
Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=1,600]



INNOVATIVE RESEARCH GROUP

Forms of Communication: Gains in satisfaction across all forms of communication; biggest gains for outage notification and website

Q Please indicate how satisfied you are with the way [COMPANY] is performing on each of the following forms of communication:
[asked of all respondents; n=1,600]

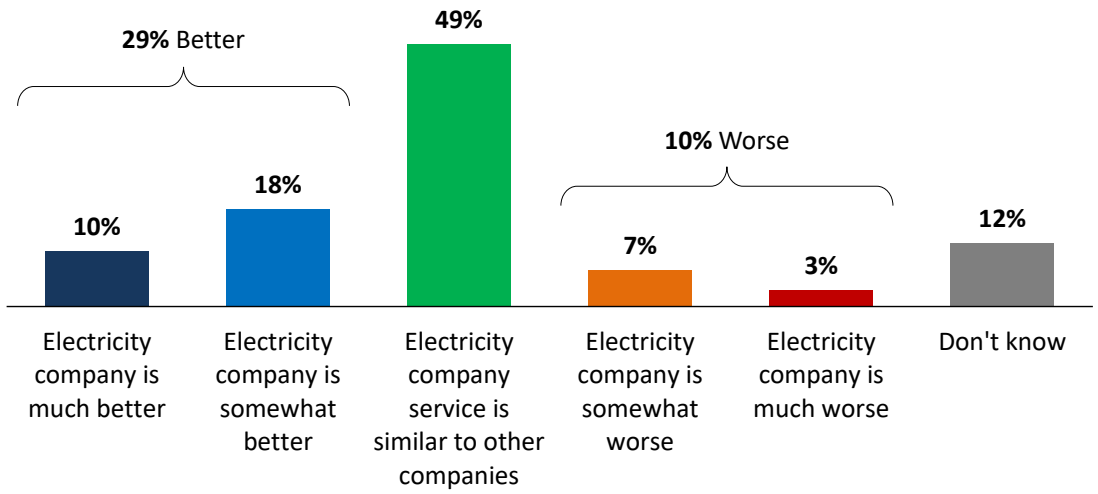


Average neutral + don't know=
2018: 51%
2017: 52%

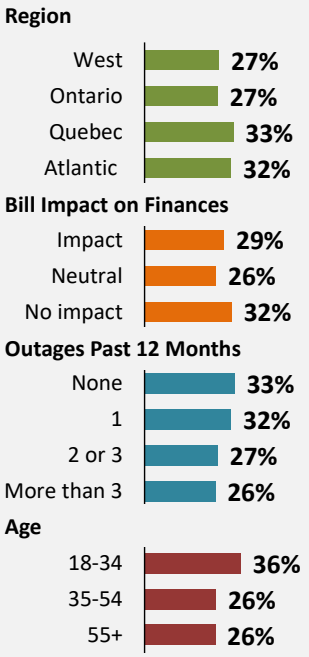
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Comparing Customer Experience: Respondents 3x more likely to say distributor experience is better (29%) rather than worse (10%) than other service providers

Q How does your customer experience with [COMPANY] compare to that of other service providers you use (telephone, cable, TV/internet, natural gas, your bank)?
[asked of all respondents; n=1,600]



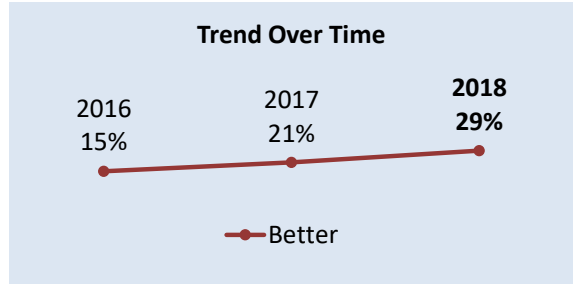
Segmentation
*Those who say **"better"***

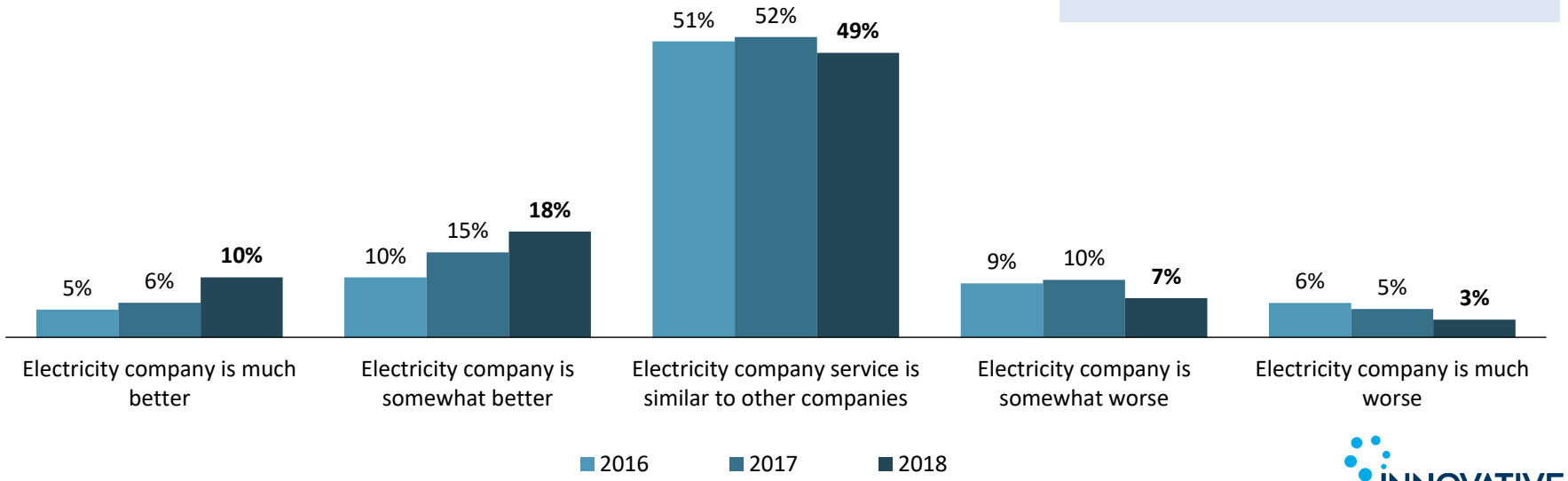


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Comparing Customer Experience (Tracking): "Better" (29%) has doubled over the past two years (15% in 2016)

Q How does your customer experience with [COMPANY] compare to that of other service providers you use (telephone, cable, TV/internet, natural gas, your bank)?
[asked of all respondents; n=1,600]





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Net Promoter Score (NPS)

(This metric was last asked on the 2016 survey)

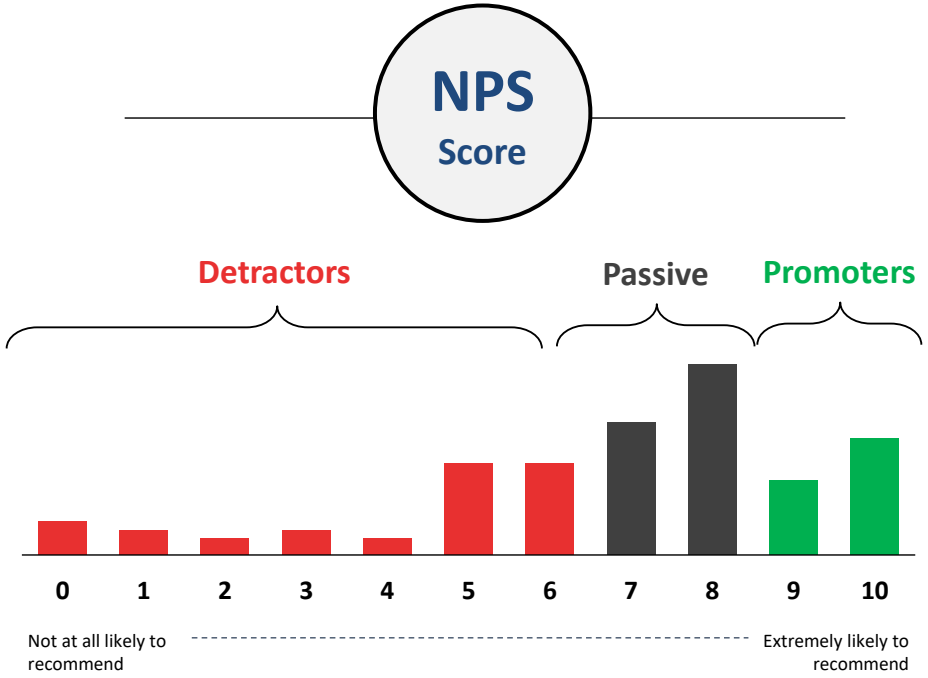
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Endorsement: *Calculating "Net Promoter Scores" (NPS)*

A *Net Promoter Score* (NPS) is based on the fundamental perspective that every organization's clientele can be divided into three categories: Promoters, Passives, and Detractors.

By asking one simple question — *If you had a choice between several possible providers of electricity, how likely would you be to recommend [COMPANY] to your friends, family and others as the preferred electricity distributor?* — you can track these groups and get a clear measure of the customer's experience with your organization. Customers respond on a 0-to-10 point rating scale and are categorized as follows:

- **Promoters** (score 9-10) are loyal enthusiasts who would refer others to your organization if they had that option. These customers are an important source of strength for the brand. An estimated 80-90% of positive word-of-mouth come from *Promoters*.
- **Passives** (score 7-8) are satisfied but unenthusiastic customers who would be vulnerable to offerings from competitors, given the option of a choice.
- **Detractors** (score 0-6) are unhappy customers who can damage your brand and impede growth through negative word-of-mouth. Detractors are responsible for an estimated 80-90% of all the negative word-of-mouth. Furthermore, this group of customers complain more frequently, thereby consuming service resources at a much higher rate than other customers.



NOTE: 'Don't know' removed from calculation

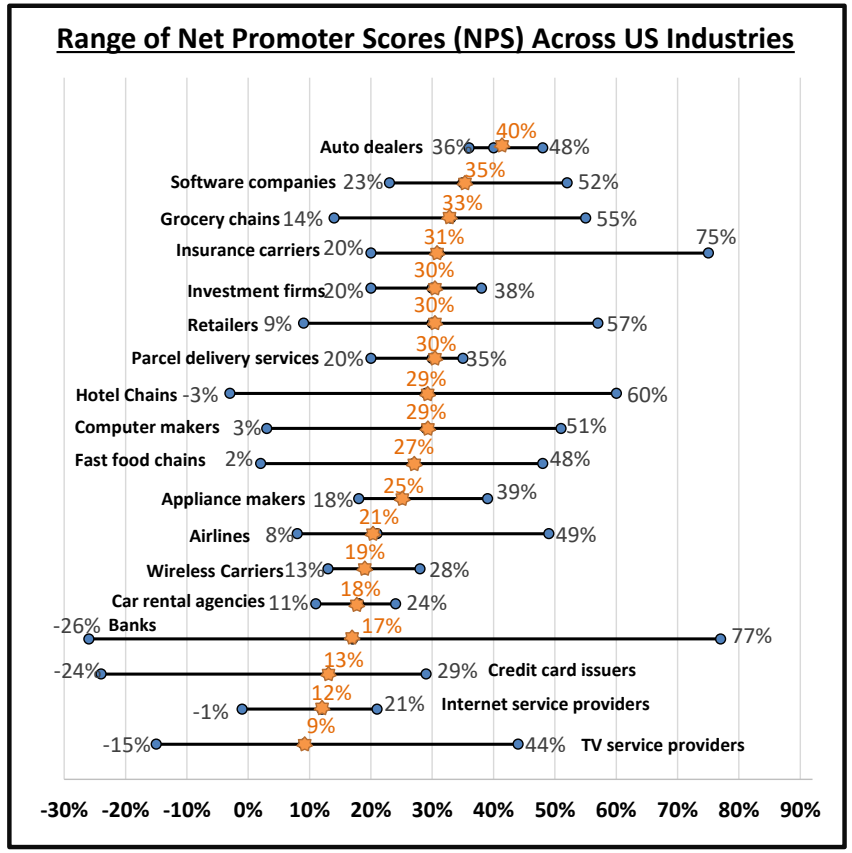
Comparing NPS Across Industries (US Data)

The Net Promoter Score (NPS) was created in the 90's to evaluate the growth potential of companies that operate in competitive markets. Typically, organizations with scores higher than their competitors tend to grow faster.

Because almost all CEA members operate primarily in regulated monopoly markets, NPS should only be considered a "rough proxy" for customer satisfaction.

To put NPS in context, this chart shows the average NPS for several industries in the U.S. This data was taken from a 2012 study surveying 5,000 U.S. consumers evaluating multiple companies that compete in various industries.

As the chart shows, it is not uncommon for organizations in various sectors to have a negative NPS.



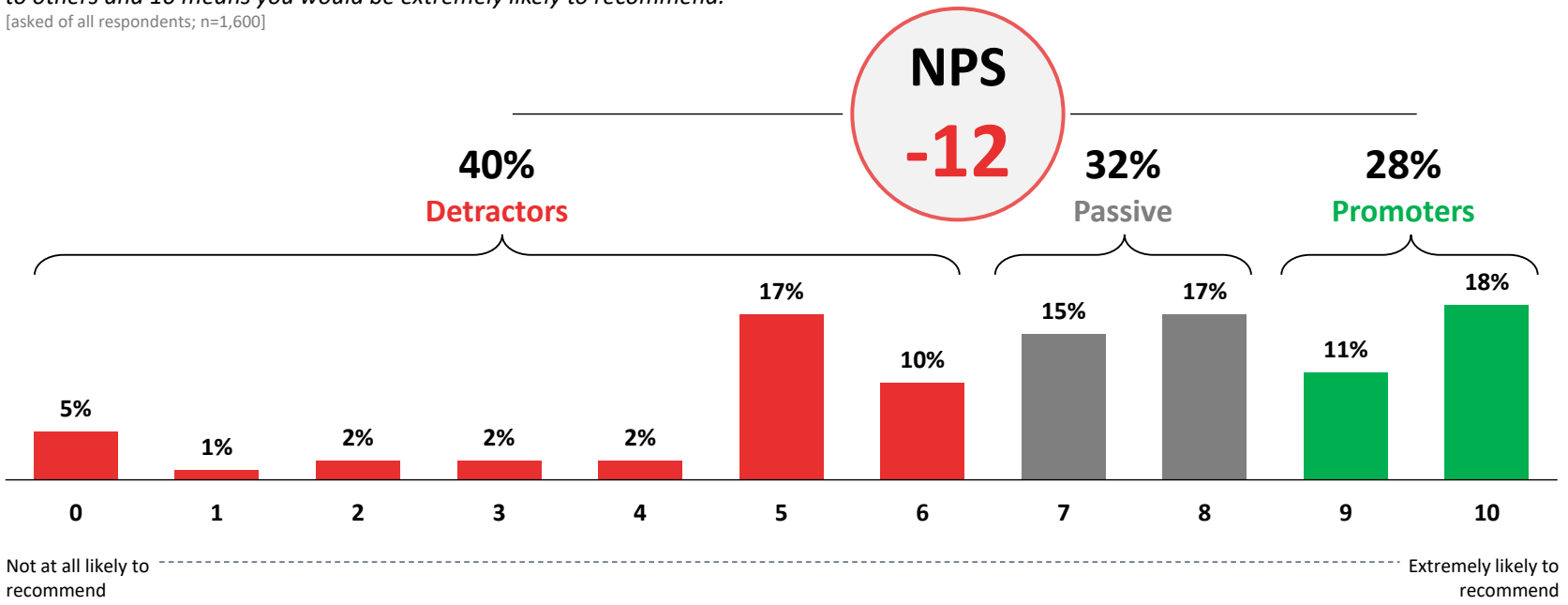
Source: Temkin Group Q3 2012 Survey

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Net Promoter Score: Negative NPS overall. One-in-three are *"Passive"*

Q If you had a choice between several possible providers of electricity, how likely would you be to recommend [COMPANY] to your friends, family and others as the preferred electricity distributor? *Please use a scale from 0 to 10, where 0 means you would not be at all likely to recommend [COMPANY] to others and 10 means you would be extremely likely to recommend.*

[asked of all respondents; n=1,600]

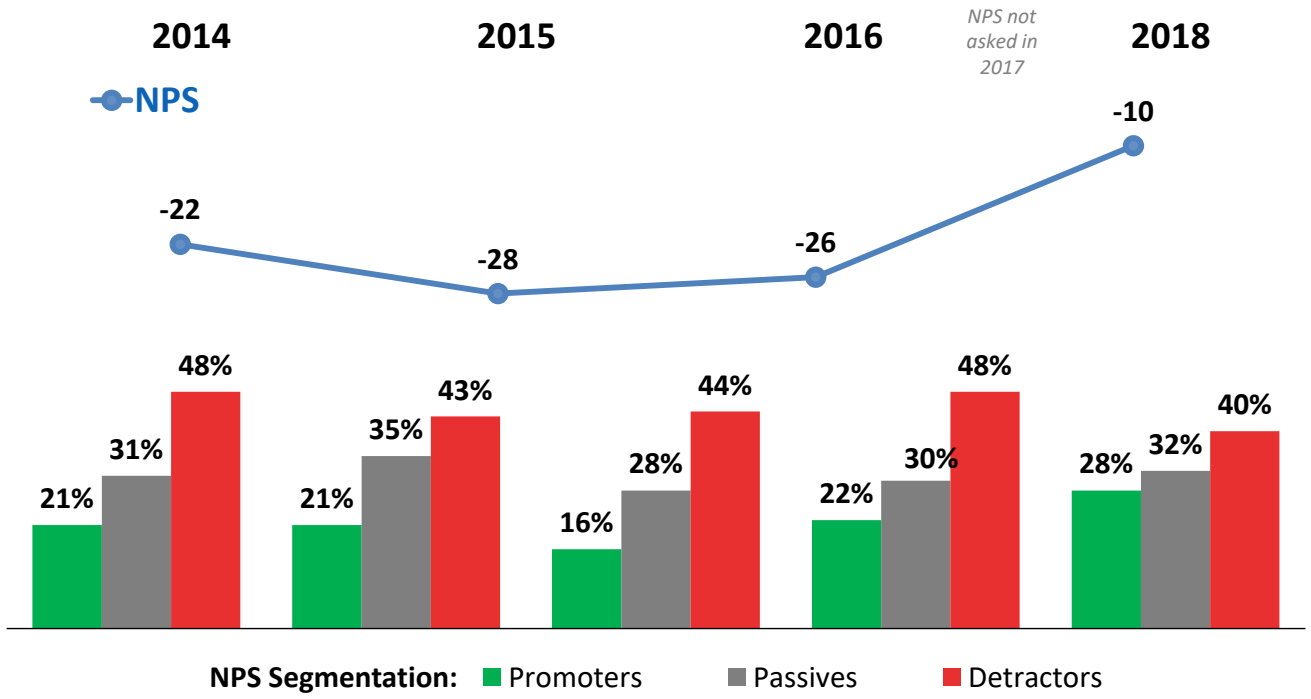


NOTE: 'Don't know' (10%) removed from calculation

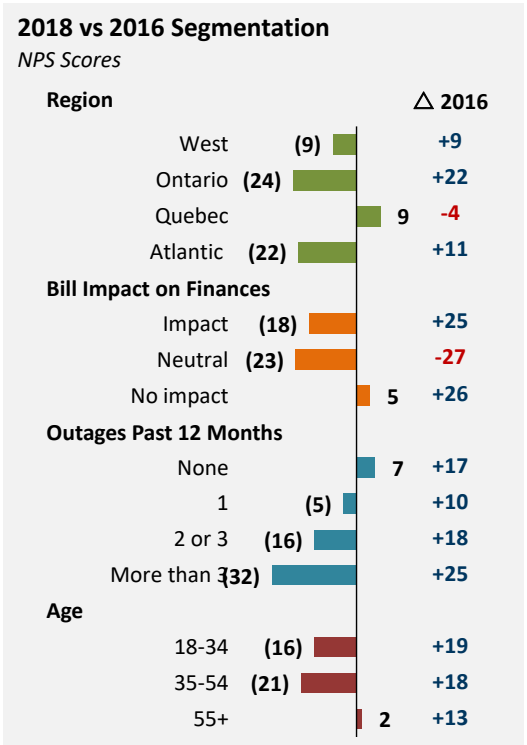
NPS Tracking: NPS reaches highest point since tracking began in 2014. Gains across all segments except in QC and among those who are neutral on bill impact

Q If you had a choice between several possible providers of electricity, how likely would you be to recommend [DISTRIBUTION COMPANY] to your friends, family, and others as the preferred electricity distributor? *Please use a scale from 0 to 10, where 0 means you would not be at all likely to recommend [COMPANY] to others and 10 means you would be extremely likely to recommend.*

[asked of all respondents; n=1,600]



NOTE: 'Don't know' (10%) removed from calculation



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Customer Satisfaction Index (CSI)

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Customer Satisfaction Index (CSI)

The **Customer Satisfaction Index (CSI)** is a number that summarizes respondents' overall satisfaction with their electricity distributor using an analysis of each brand attribute tested.

In 2014, INNOVATIVE updated the methodology used to construct the CSI. In 2017, the calculation methodology was updated again to reflect the survey redesign that occurred that year. This year's study follows the 2017 method.

Calculating CSI:

1. A ***factor analysis*** finds the true underlying dimensions of customer satisfaction that explain the pattern of responses on the larger set of brand attributes.
    - Factor analysis allows us to find which attributes mean similar things to the public. The use of factor analysis allows us to determine which attributes should be grouped together in order to conduct meaningful analysis.
    - We tested **20 brand attributes** for all electricity companies in the analysis. While each of these attributes seems distinct in important ways to people who are close to the industry, many of these items seem similar to members of the general public. We found that **5 underlying *factors,*** along with 3 additional (standalone) attributes explain most of the variance in the larger set of attributes.
2. We use a ***Shapley Values*** regression analysis to determine the relative contribution of each *factor* to overall satisfaction.
    - *Shapley Values* are a calculation of how much of the variance in overall satisfaction can be explained by each individual factor, after statistically accounting for the fact that some of the factors are correlated with one another.
3. We then take an average of the mean score on each of the *factors,* weighted by their *Shapley Values* to determine the overall **CSI scores**.
4. *In keeping with the revised survey and analysis plan, the CSI is now being calculated as a single measure for all electricity companies included in the research.*

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Factor Analysis (General Satisfaction): *Based on their responses, which attributes mean similar things to the public?*

Customer Focus

- Consulting with customers before making decisions
- Being transparent
- Caring about its customers
- Being trustworthy

Quality & Reliability

- Providing reliable electricity service
- The amount of time it takes to restore power
- The quality of power delivered to you

Billing Practices

- Providing convenient options to pay my bill
- Providing convenient options to receive my bill
- Providing bills that are easy to read and understand
- Providing accurate bills

Public Good

- Operating in an environmentally responsible manner
- Providing energy conservation and efficiency programs
- Protecting public safety
- Being a good corporate citizen

Outage Preparation

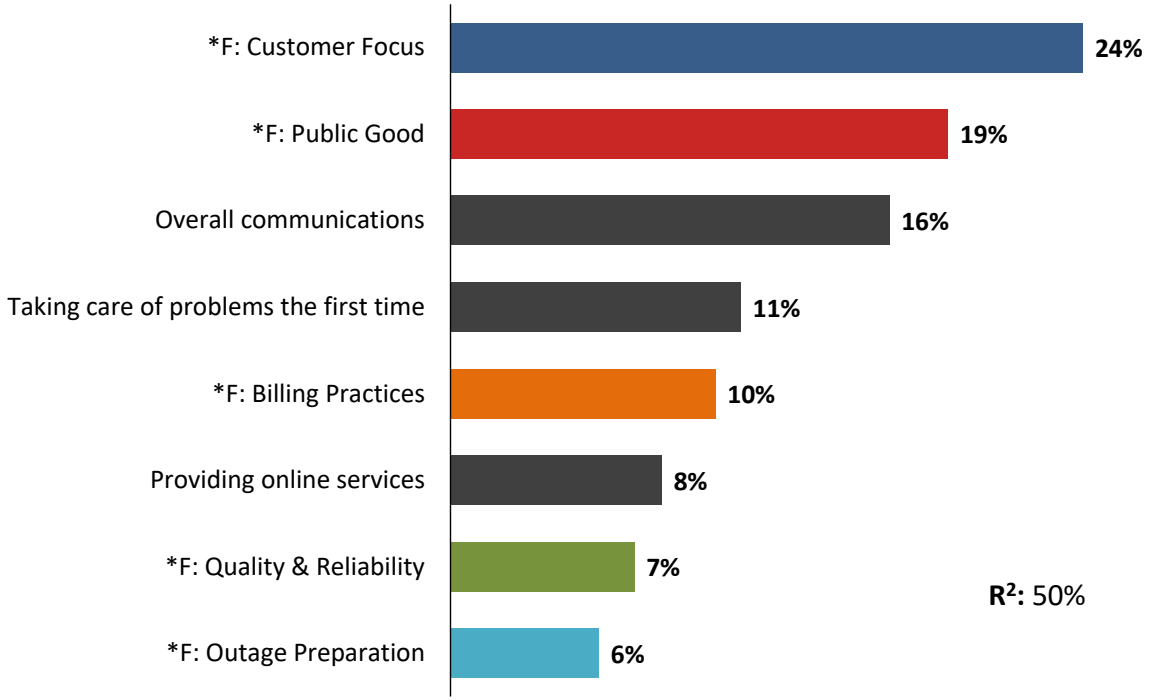
- Providing timely and accurate information re: outages
- Considering your needs when planning an outage

Standalones

- Taking care of problems the first time you contact them
- Overall communication
- Providing online services

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Shapley Values Regression: *Relative contribution of each factor to the Customer Satisfaction Index (CSI) according to Shapely Values regression*



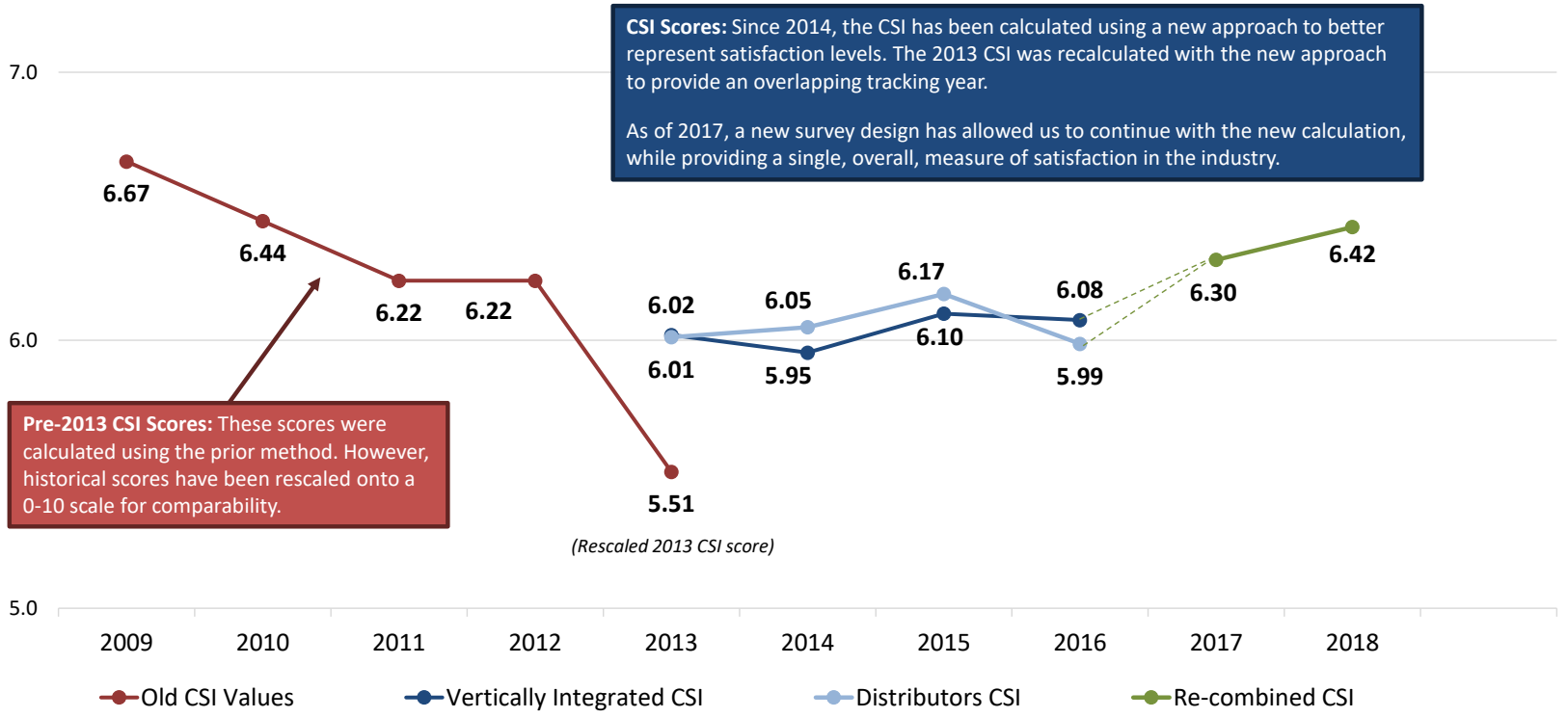
The percentage for each factor/metric shows the contribution of each to the amount of variance being explained by the model (in this case, 50%).

These values are used to create the CSI score.

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*F – Denotes what has been identified as a "factor", where multiple attributes are viewed similarly to respondents. All others are standalone attributes

CSI Tracking: CSI continues to improve, now reaching its highest level in eight years



NOTE: Previously the CSI had been calculated on a 1-10 scale; in keeping with the move to a 0-10 scale for this year's survey, previous year's CSI scores have been rescaled 0-10. For example the 2013 score of 5.51 on a 0-10 scaled that is reported here corresponds to last year's reported score of 5.9 on a 1-10 scale.

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Action Analysis

What does the data tell us about what to do next?

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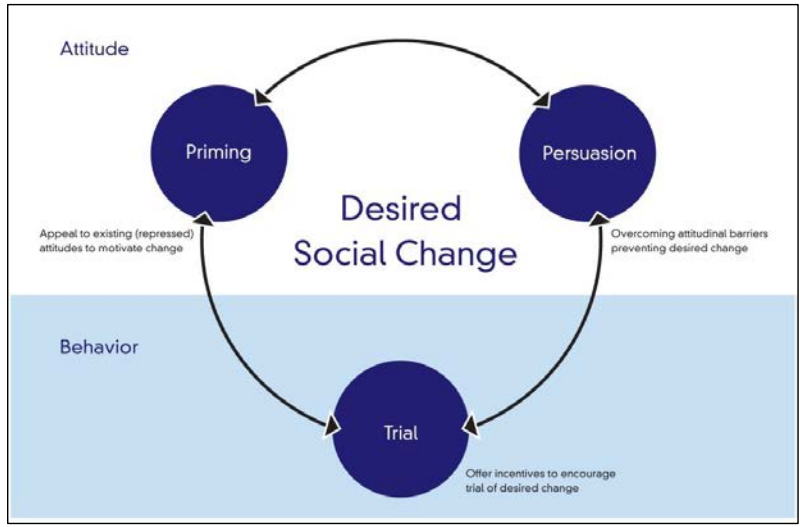
Changing Public Perception: *Social Marketing*

The concept of social marketing is all about getting people to change their behaviour. Getting a flu shot. Taking precautions when investing. Saving for retirement. Using less electricity. Accepting price increases. **Simply stated, but not simply achieved.**

There are three primary options for opinion change:

- **Persuasion** – Teaching people something they didn't know in order to increase their likelihood of doing the desired action or believing the desired belief.
- **Priming** – Reminding people of something they already know in order to increase their likelihood of doing the desired action or believing the desired belief.
- **Trial** – Getting people to do the desired behaviour so it becomes a habit.

On-going research will provide electricity companies with a framework to assess their target audience to identify the key opinion anchors for priming, the best new information for persuasion, and the most appealing offers for trial.



In terms of behaviour, **trial** is best since a change of behaviour is the goal. Trial works best if it is run in parallel with a supportive campaign to change attitudes that conflict with the behaviour.

Persuasion is the next best since persuasion results in permanent behaviour change.

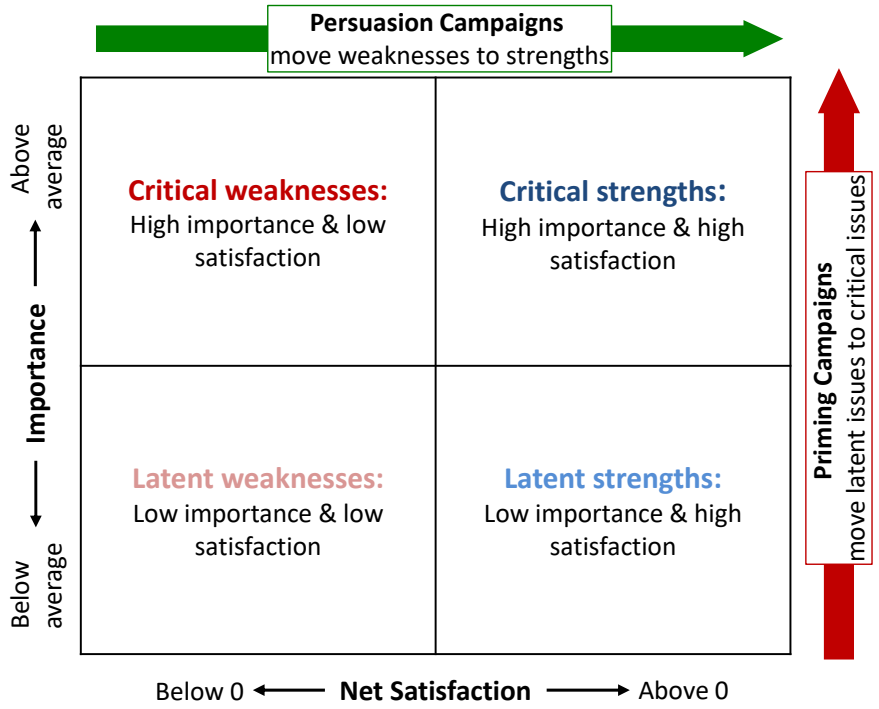
Priming is often the least effective for long term change since once the campaign is over, the priming effect quickly fades. But if priming is sustained long enough to establish new habits, the change can be permanent.

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Combining Importance & Satisfaction: *Priming and Persuasion*

Once we understand what factors underlie each brand, we can examine how levels of overall satisfaction on each factor compare to their level of importance. The satisfaction scores shown below are net satisfaction while the level of importance is calculated using a *Shapley Values* regression as detailed in the previous section.

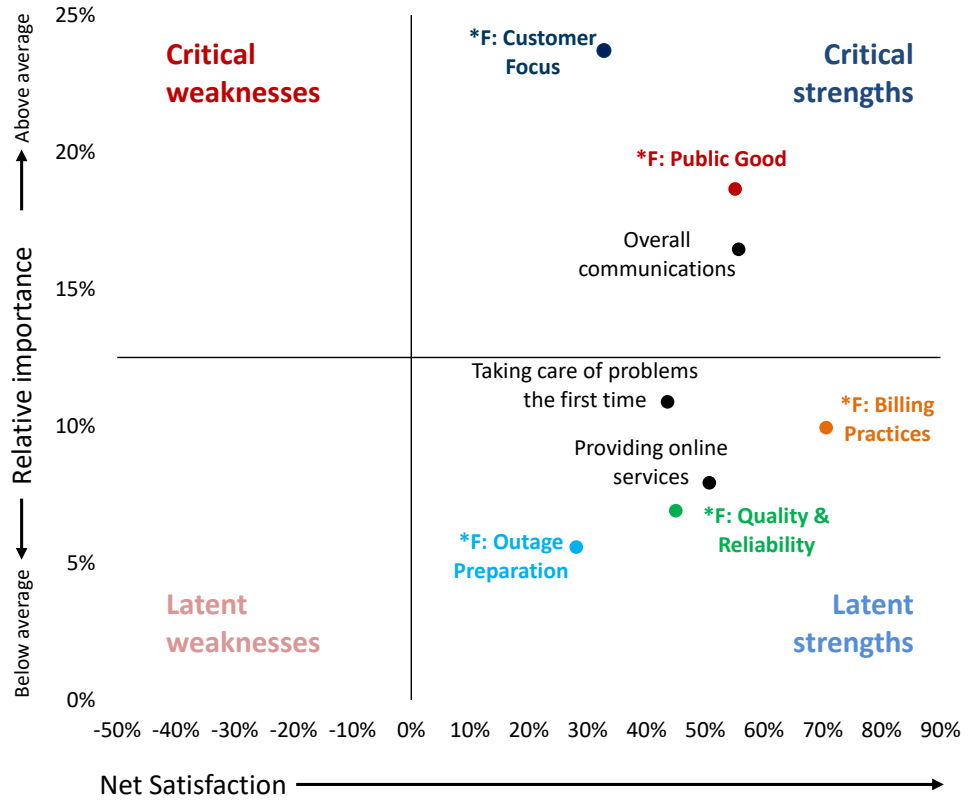


Improving the importance of an attribute is best approached through *Priming*. This means moving it away from being a *latent strength* towards being a *critical strength*. Priming by raising the salience of an attribute is usually executed through advertising and the media.

Increasing the levels of satisfaction with a brand is *Persuasion*. This means moving an attribute from a weakness to a strength. Once people are persuaded that an organization is doing well on a particular attribute, that opinion is likely to stick. However, persuasion campaigns are often long fought and expensive.

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Action Analysis: While there are no current weaknesses, there is room for improvement on latent strengths; particularly problem resolution and billing



*F – Denotes what has been identified as a "factor", as described on the right

Customer Focus
- Consulting with customers before making decisions
- Being transparent
- Caring about its customers
- Being trustworthy

Public Good
- Operating in an environmentally responsible manner
- Providing energy conservation and efficiency programs
- Protecting public safety
- Being a good corporate citizen

Quality & Reliability
- Providing reliable electricity service
- The amount of time it takes to restore power
- The quality of power delivered to you

Billing Practices
- Providing convenient options to pay my bill
- Providing convenient options to receive my bill
- Providing bills that are easy to read and understand
- Providing accurate bills

Outage Preparation
- Providing timely and accurate information re: outages
- Considering your needs when planning an outage

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Regression Analysis

What drives general satisfaction and NPS?

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Using Regression Analysis

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain the key question we are interested in and see which of these is the most important. Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).

Satisfaction Regression Analysis ▸▸

- In this study what aspects of respondents' demographics and public opinion drive their overall satisfaction with their electricity company?
- We use the factors that fed into the CSI but also add respondents' demographics, attitudes, and experiences to the model to see what matters most when everything else is held constant
- When respondents were asked about their overall satisfaction they were asked *specifically* about the company that they are a customer of by name.

Attitudes and Brand Attributes factored ▸▸

- In addition to the factor analysis of company attributes previously described, key attitudes about the electricity system, price, and the environment were again factored to reduce overlap in the regression models.
- The following slides describes the result of this analysis.

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Regression Analysis: *The Full Model*

Customer Focus

- Consulting with customers before making decisions
- Being transparent
- Caring about its customers
- Being trustworthy

Public Good

- Operating in an environmentally responsible manner
- Providing energy conservation and efficiency programs
- Protecting public safety
- Being a good corporate citizen

Quality & Reliability

- Providing reliable electricity service
- The amount of time it takes to restore power
- The quality of power delivered to you
- Providing timely and accurate information re: outages
- Considering your needs when planning an outage

This ***Quality & Reliability*** factor includes the variables from the ***Outage Preparation*** factor from the previous analysis.

Billing Practices

- Providing convenient options to pay my bill
- Providing convenient options to receive my bill
- Providing bills that are easy to read and understand
- Providing accurate bills

Outage Communication

- Recall experiencing a planned outage P12M
- Communications during planned outage were proactive
- Satisfaction with planned outage communication

Standalones

- Taking care of problems the first time you contact them
- Overall communication
- Providing online services
- Number of power outages experienced in the last 12 months
- Price reasonable for electricity in province
- Good value for money

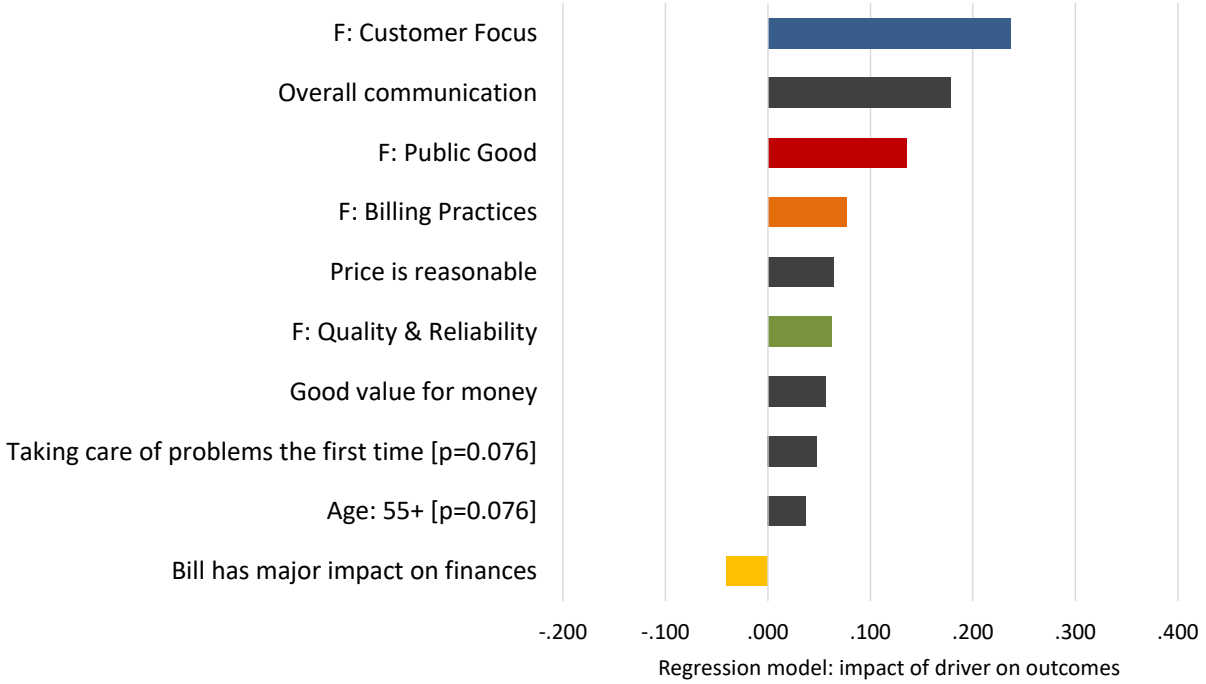
Controls

- Province
- Basic demos (age, gender, education, income)
- Primary heat source
- Electricity company better than other companies
- Bill has major impact on finances
- Satisfaction with provincial government's management of electricity system

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Regression Analysis: *General Satisfaction*

Customer Focus is, by far, the largest driver of satisfaction, followed by overall communication from the distributor. Struggling to pay electricity bills has a small negative effect. *Public Good* is the third most influential driver.



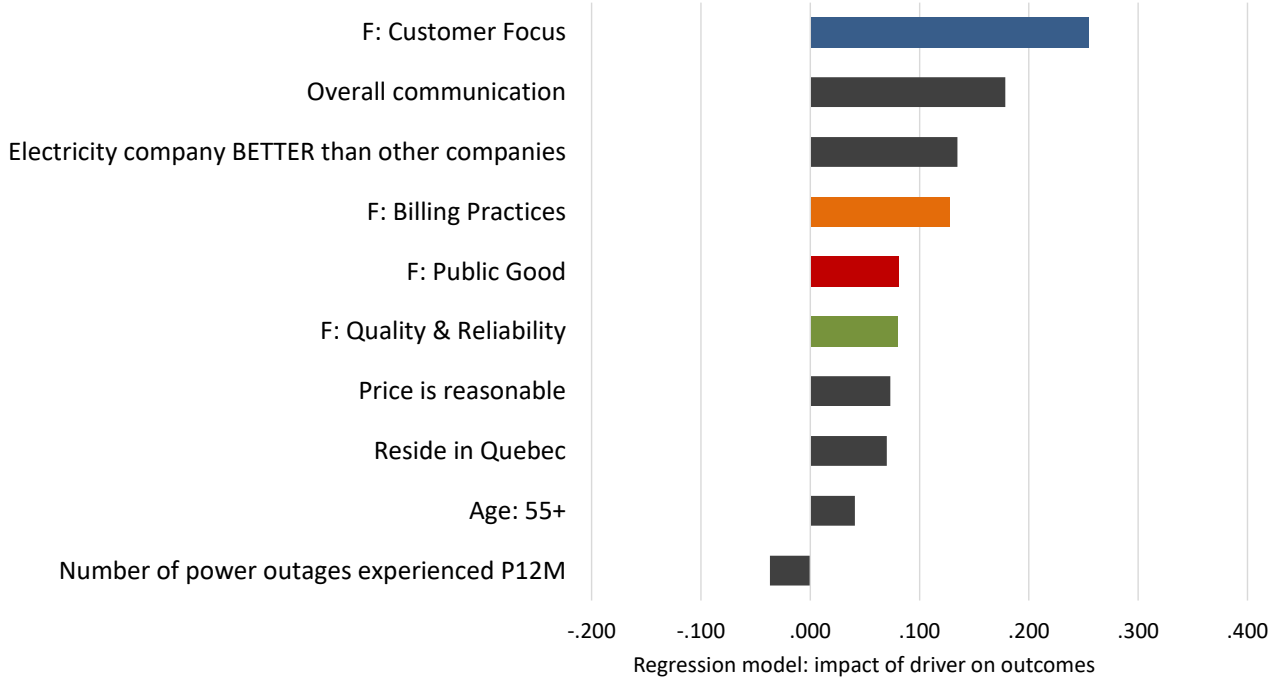
Satisfaction with your *electricity company*

Adjusted R^2 = 0.524

NOTE: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

Regression Analysis: *Net Promoter Score (NPS)*

The strongest drivers of NPS are similar to those for general satisfaction: *Customer Focus*, followed by overall communications. However, *Billing Practices* have more of an influence on NPS than on overall satisfaction. Feeling one's distributor provides better service than other suppliers is also a strong driver of NPS.



NPS for your *electricity company*

Adjusted $R^2 = 0.604$

NOTE: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

Summary: *Regression Analysis*

- The strongest driver of both general satisfaction and NPS is *Customer Focus*. It comes down to the intangible relationship with the utility as a brand: consulting customers, transparency, demonstrating care and trustworthiness.

Brand (intangible)

- Interactions with the utility are second tier drivers: communication, billing convenience, accuracy and comprehension, quality of service and perception of price.

Tangible interactions

- How a utility operates is also a strong driver of both metrics. Customers want utilities to protect the environment and public safety, help with conservation, and be a good corporate citizen.

Public Good

- *Quality & Reliability* also drives satisfaction and NPS. Not only the attributes of quality and reliability, but also the experience – the number of outages experienced has a negative impact on NPS.

Quality & Reliability

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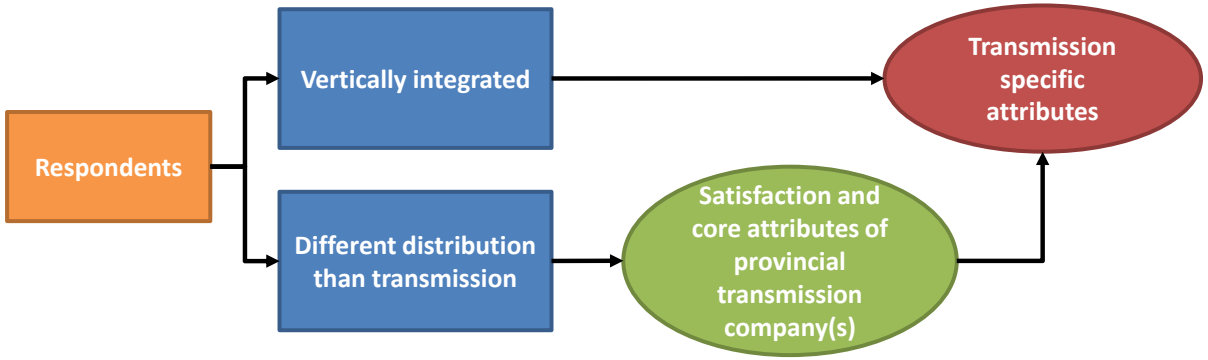
Transmission

(This series of questions was last asked in 2016)

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Transmission: Which respondents answered which questions?

- The satisfaction and attribute ranking questions asked in this section are related to a respondent's provincial transmission company, either independent transmission companies or the transmission operations of vertically integrated companies.
- In most cases, for vertically integrated companies, respondents were only asked to rate the company on its transmission specific attributes in this section (as core attribute questions were asked earlier, in the distribution section).
- Respondents who have different transmission and distribution companies were asked all of the questions in this section.



For most vertically integrated companies – where the customer's distributor is also responsible for transmission – the respondent was shown the following preamble before rating the two core transmission attributes:

> *"The following questions are about the transmission system, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed."*

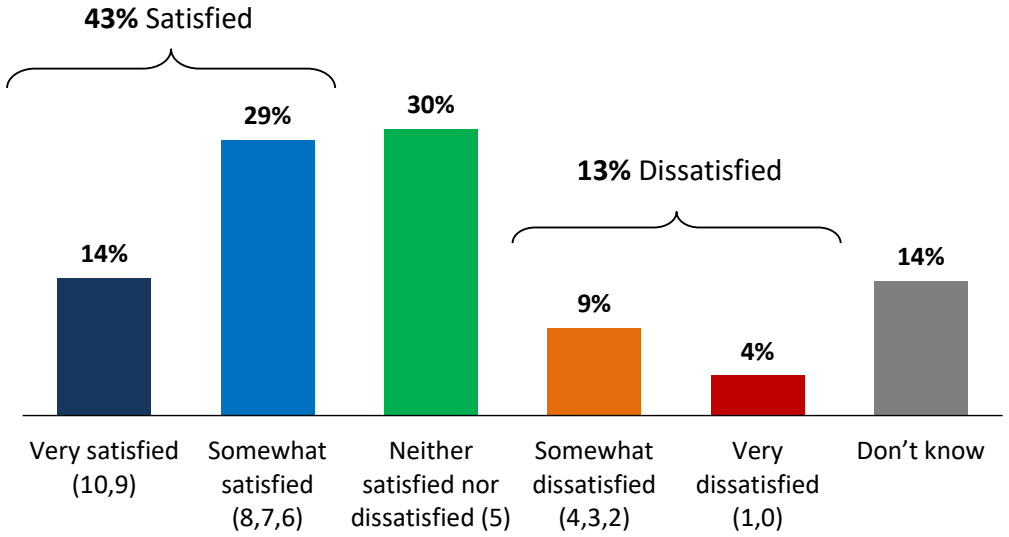
Summary: *Transmission Reputation*

The CEA survey last asked about transmission companies in 2016. Re-introducing some of those questions in 2018 allows us to see if there have been any shifts in opinion over the past two years.

- A plurality (43%) say they are satisfied with their provincial transmission company. Three-in-ten (30%) have a neutral opinion and another 14% “don’t know”.
- There has been a nine point increase in satisfaction since 2016 (from 34% to 43%), evenly divided between *very* satisfied and *somewhat* satisfied.
- Net satisfaction with transmission reliability is up from 55% in 2016 to 61% in 2018.
- Net satisfaction with maintaining the transmission system in an environmentally responsible manner has increased from 42% to 52% over the course of two years.

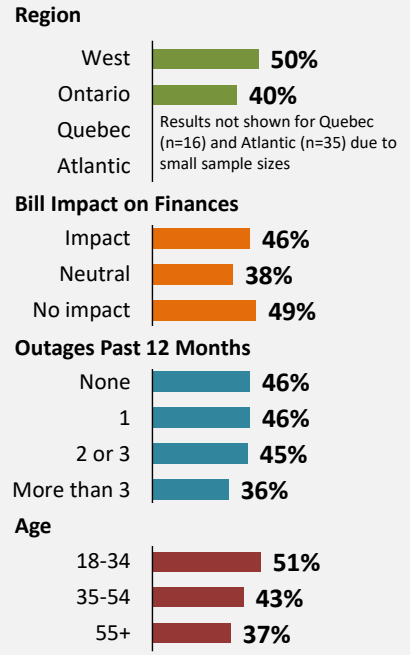
Satisfaction with Transmission (ALL): A plurality (43%) are satisfied with their transmission company; an equal number are neutral (30%) or "don't know" (14%)

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with [PROVINCIAL TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents who have different distribution and transmission companies; n=760]



Segmentation

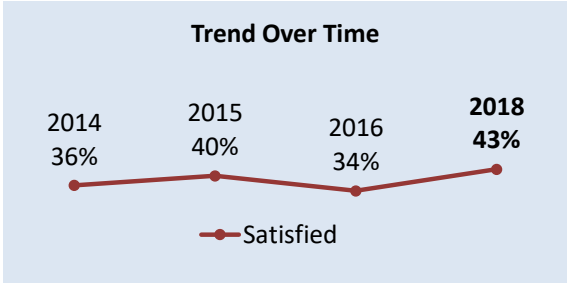
*Those who are **"satisfied"** with their transmission company*

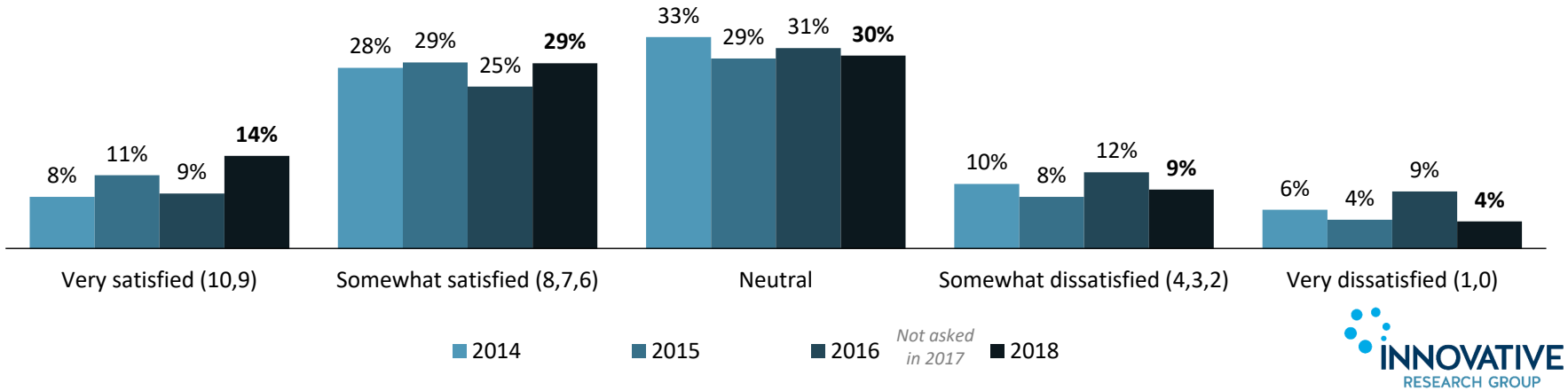


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Satisfaction with Transmission (ALL): Satisfaction up 9 points from 2016 to highest point since tracking began; 5pt gain on intense satisfaction

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with [PROVINCIAL TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents who have different distribution and transmission companies; 2018; n=760]

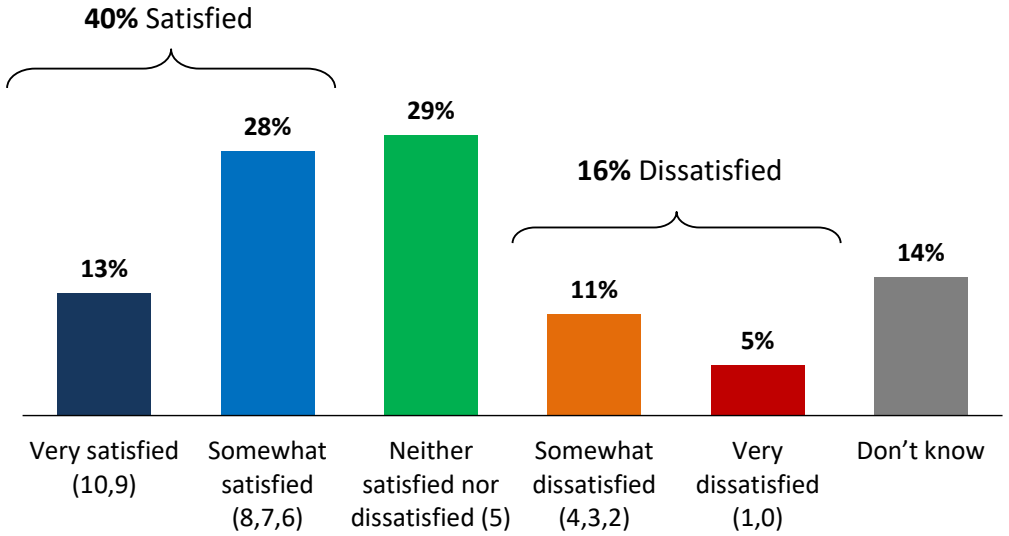




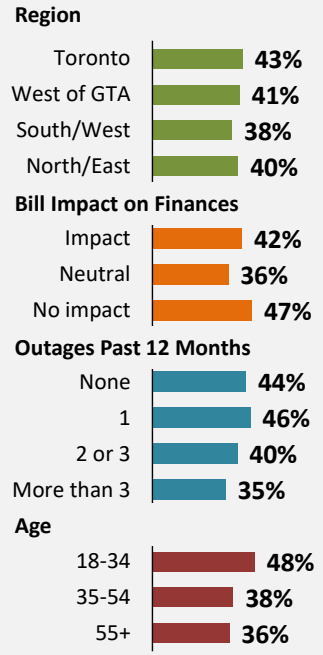
NOTE: 'Don't know' (14% in 2018) not shown.

Satisfaction with Transmission (Ontario): 4-in-10 are satisfied with Hydro One; satisfaction decreases with number of outages in the past 12 months

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with Hydro One? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents from Ontario; n=3,500*]



Segmentation
*Those who are **"satisfied"** with Hydro One*

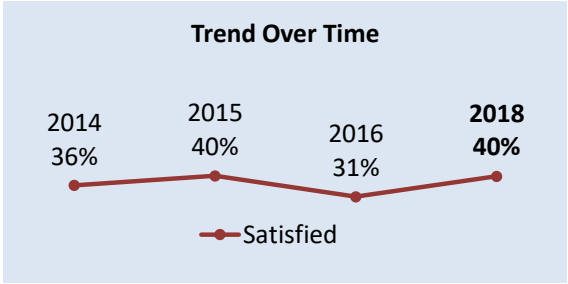


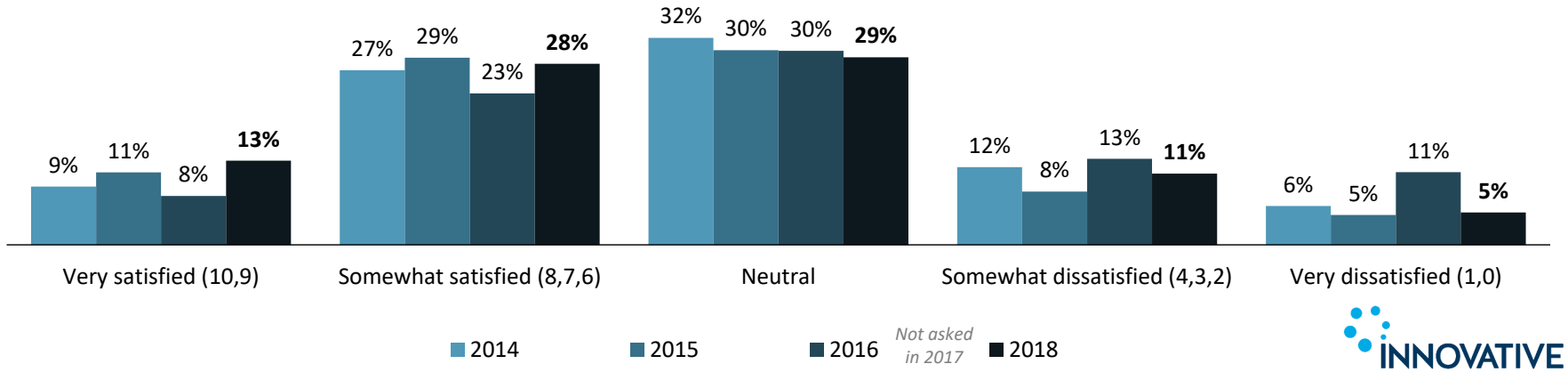
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** For this analysis, we applied provincial weights to the Ontario-only data to increase the sample size and, therefore, accuracy of the results.*

Satisfaction with Transmission (Ontario): Satisfaction returns to high point (40%) set in 2015

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with [PROVINCIAL TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents who have different distribution and transmission companies in Ontario; 2018 n=3,500]



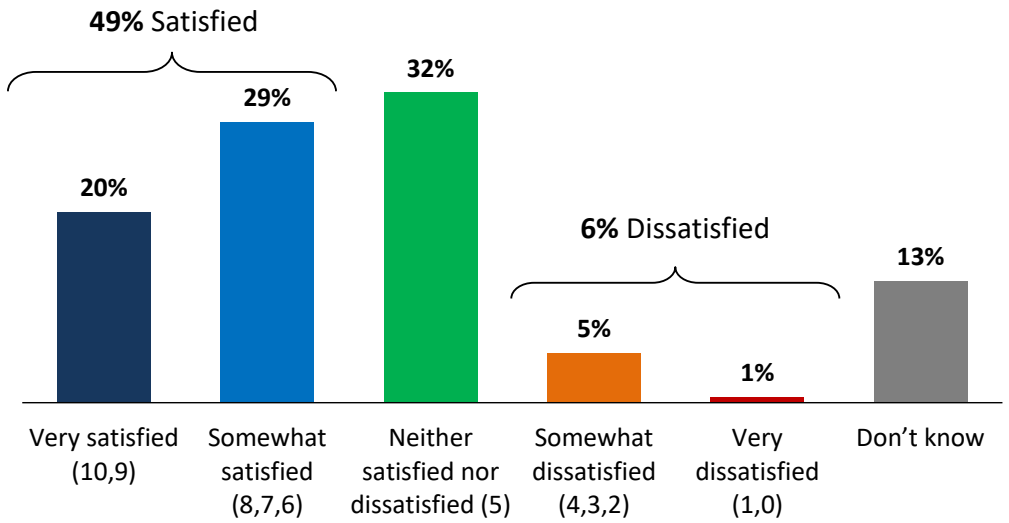


NOTE: 'Don't know' (14% in 2018) not shown.

Satisfaction with Transmission (Alberta): Half (49%) of Albertans are satisfied with transmission; higher among youngest respondents

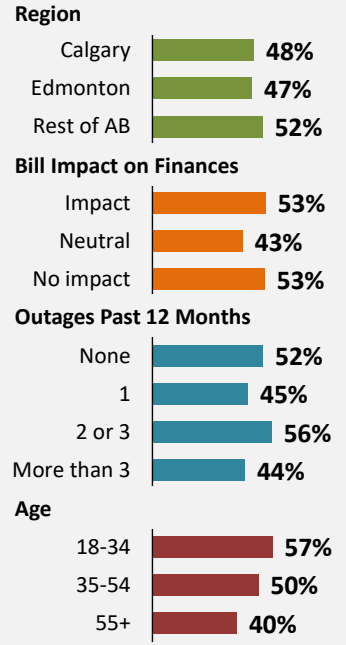
Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with the transmission companies that operate in Alberta? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents from Alberta; n=400*]



Segmentation

*Those who are **"satisfied"** with their transmission company*

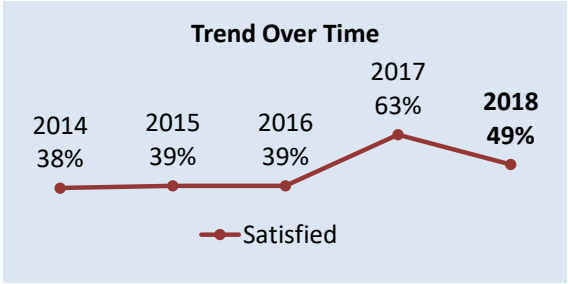


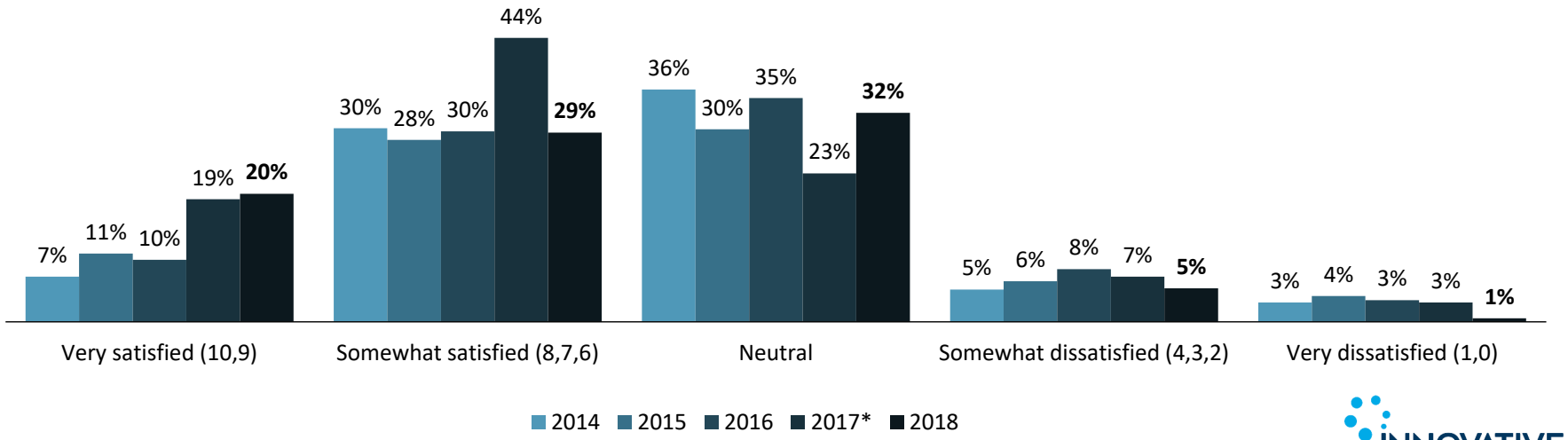
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** For this analysis, we applied provincial weights to the Alberta-only data to increase the sample size and, therefore, accuracy of the results.*

Satisfaction with Transmission (Alberta): Satisfaction down 14pts in the past year, with a shift from "somewhat satisfied" to a neutral opinion

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with [PROVINCIAL TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents who have different distribution and transmission companies in Alberta; 2018 n=400]





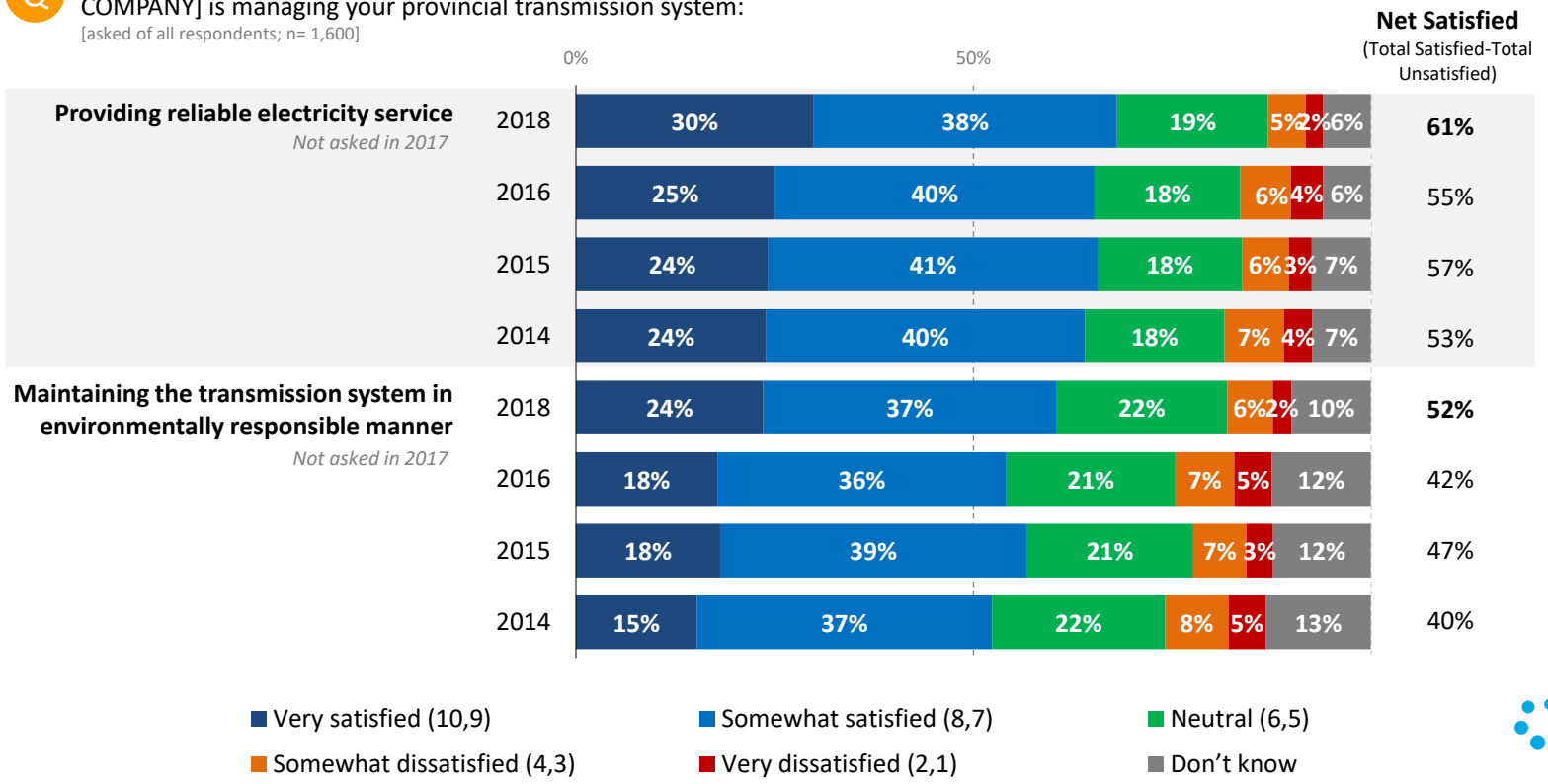
NOTE: 'Don't know' (13% in 2018) not shown.

* In 2017, satisfaction with transmission company was asked in Alberta only on a separate online omnibus, not as part of the annual CEA survey.

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Transmission Performance (ALL): Reliability and environmental responsibility have both improved since 2016, reaching the highest levels since tracking began

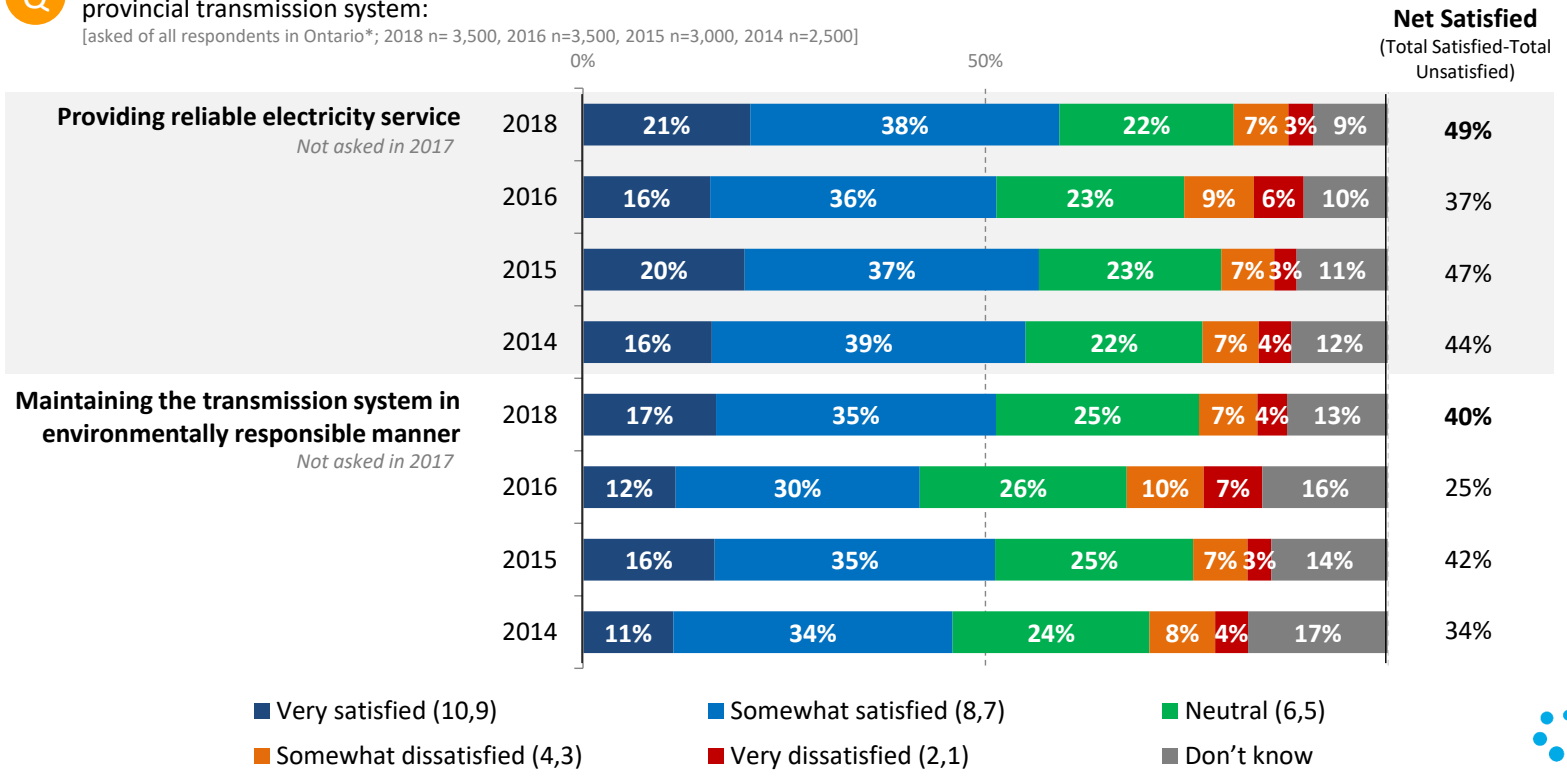
Q For each of the following items, please indicate how satisfied you are with the way [PROVINCIAL TRANSMISSION COMPANY] is managing your provincial transmission system:
[asked of all respondents; n= 1,600]



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Transmission Performance (Ontario): Satisfaction with reliability reaches an all-time high, and environmental responsibility returns to 2015 levels

Q For each of the following items, please indicate how satisfied you are with the way Hydro One is managing your provincial transmission system:
[asked of all respondents in Ontario*; 2018 n= 3,500, 2016 n=3,500, 2015 n=3,000, 2014 n=2,500]



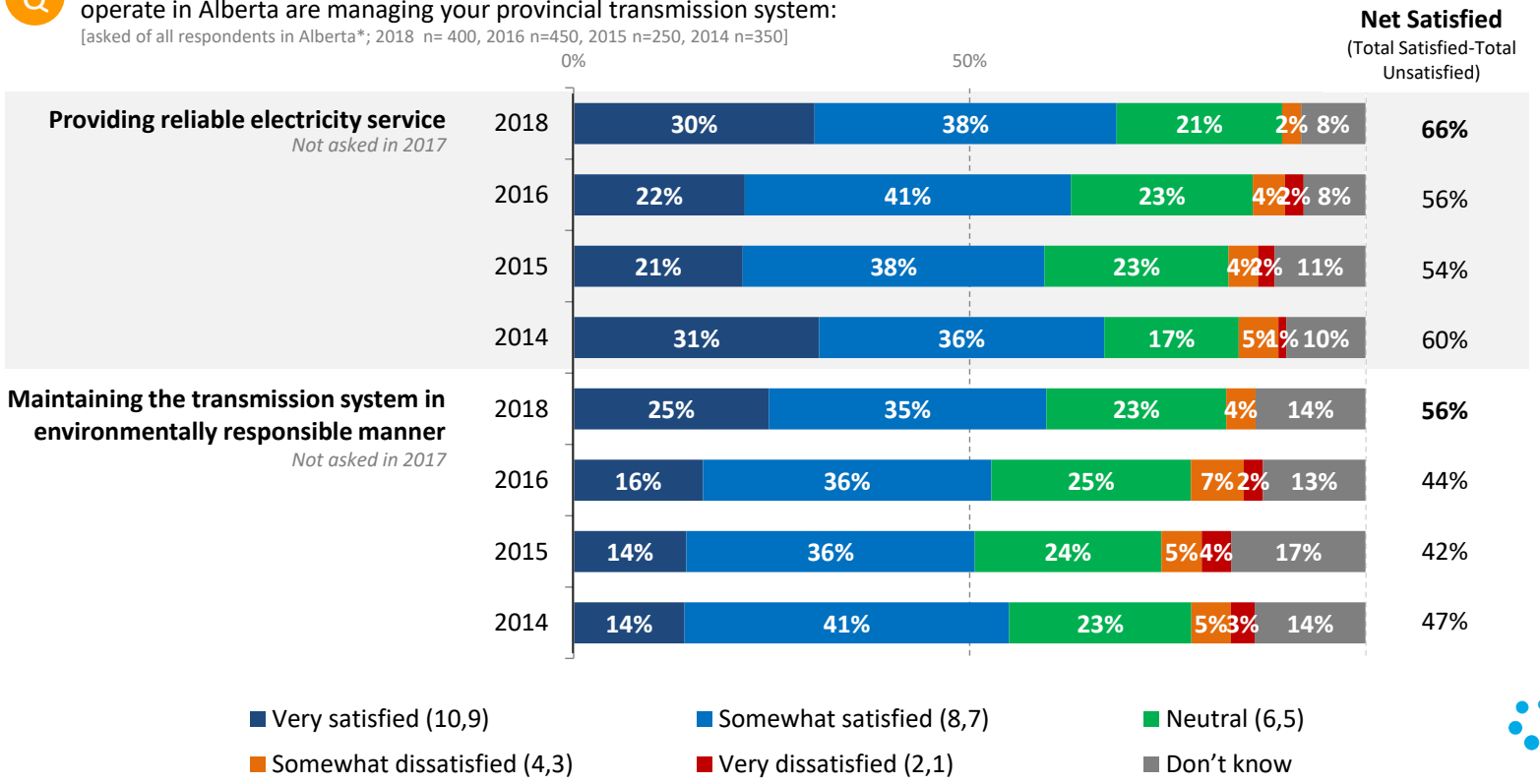
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** For this analysis, we applied provincial weights to the Ontario-only data to increase the sample size and, therefore, accuracy of the results.*

Transmission Performance (Alberta): Highest satisfaction on both attributes since tracking began, with gains in intensity

Q For each of the following items, please indicate how satisfied you are with the way the transmission companies that operate in Alberta are managing your provincial transmission system:

[asked of all respondents in Alberta*; 2018 n= 400, 2016 n=450, 2015 n=250, 2014 n=350]



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** For this analysis, we applied provincial weights to the Alberta-only data to increase the sample size and, therefore, accuracy of the results.*

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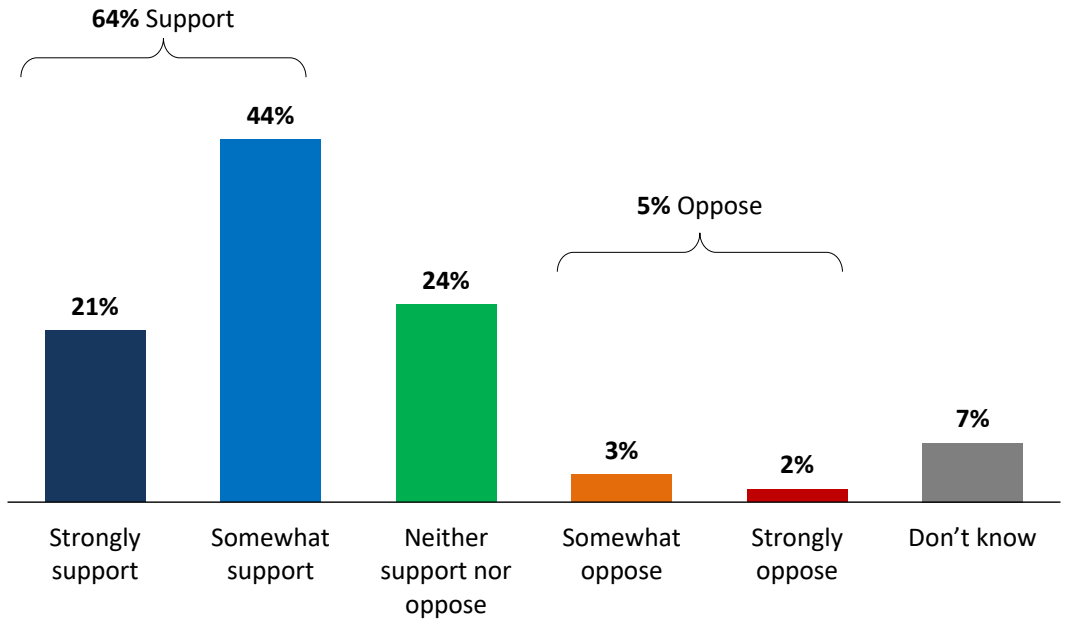
General Attitudes

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Infrastructure Investment: Nearly two-thirds (64%) support investing in system infrastructure; highest among those not impacted by their electricity bill

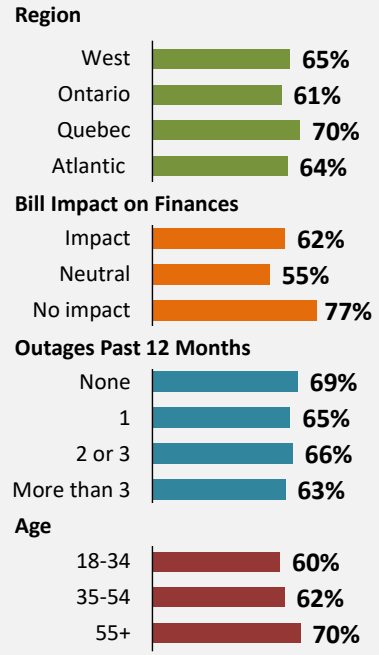
Q Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?

[asked of all respondents; n=1,600]



Segmentation

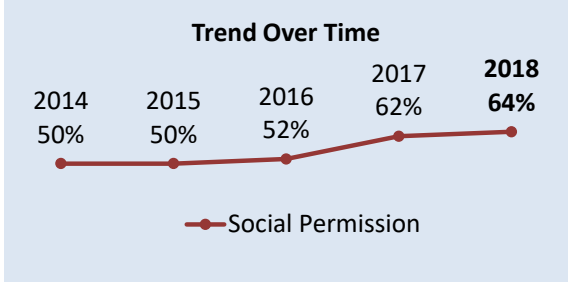
*Those who **"support"***

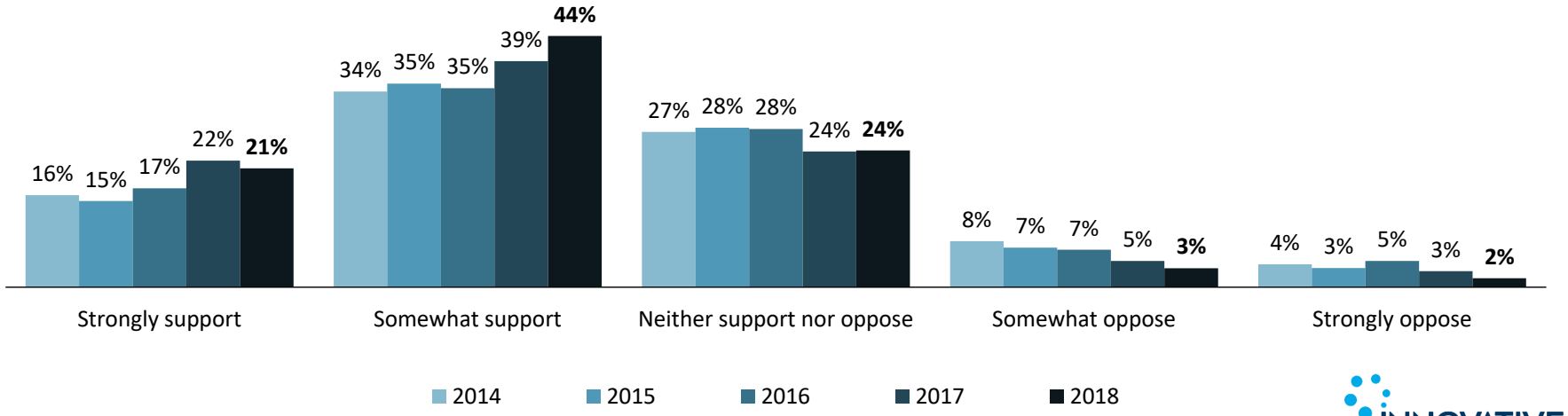


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Infrastructure Investment (Tracking): 'Social permission' continues on an upward trend with a 5 point gain in moderate support

Q Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?
(2014-2016: Given everything you have read, seen or heard ...
Do you support or oppose investment in and expansion of the generation, transmission and distribution of electrical power in your province?)
[asked of all respondents; n=1,600]

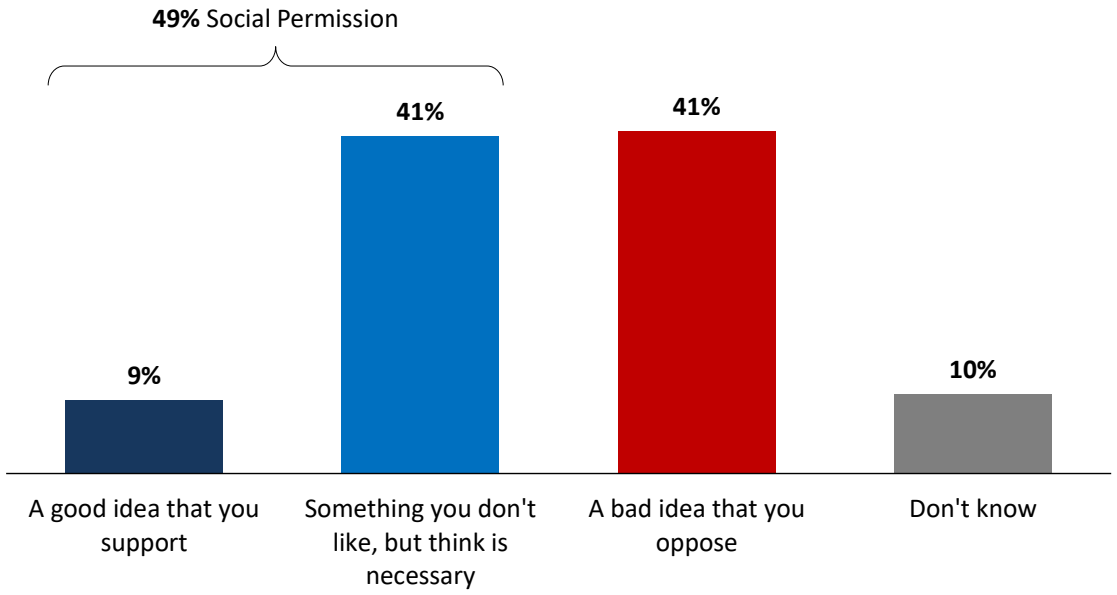




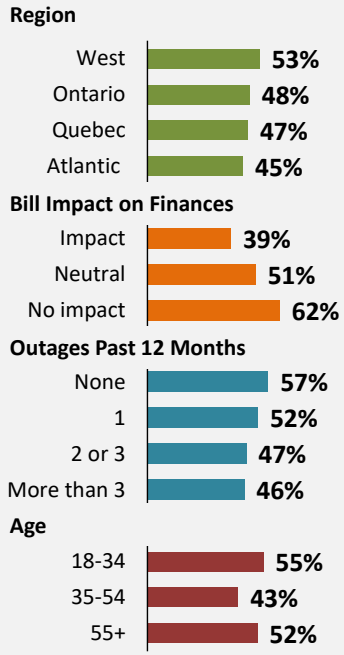
NOTE: 'Don't know' (7%) not shown.

Permission on Price Increase: Half (49%) give 'social permission' for increasing prices to invest in the provincial system

Q Do you think increasing the price of electricity to invest in our province's electric system is…
[asked of all respondents; n=1,600]



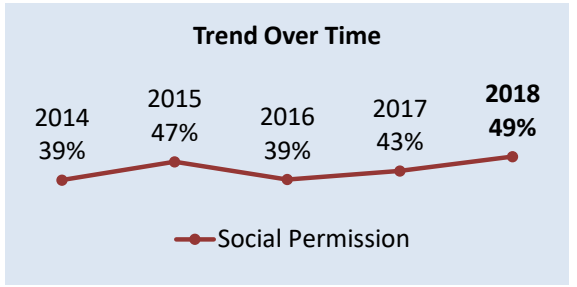
Segmentation
*Those who say **"good idea/necessary"***

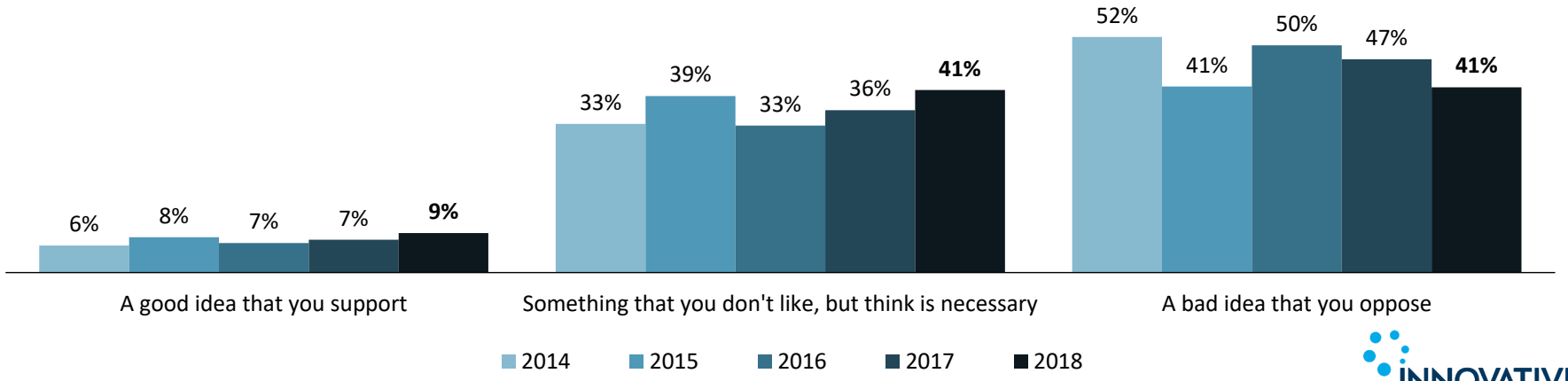


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Social Permission on Price (Tracking): 'Social permission' for increasing price to pay for system investment is up 6 points from 2017

Q Do you think increasing the price of electricity to invest in our province's electric system is…
[asked of all respondents; n=1,600]





NOTE: 'Don't know' (10% in 2018) not shown.

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Conservation

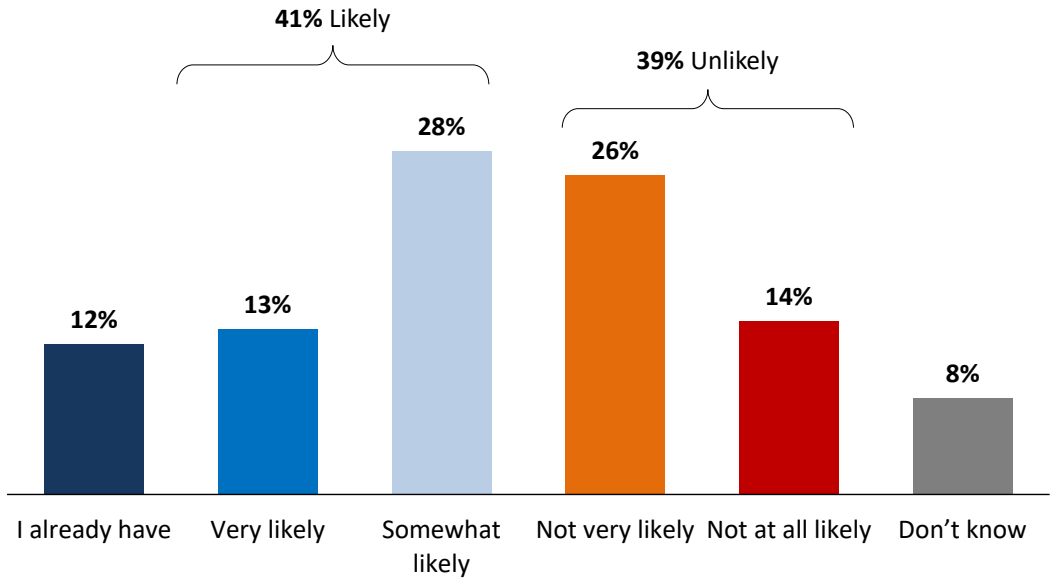
(New in 2018)



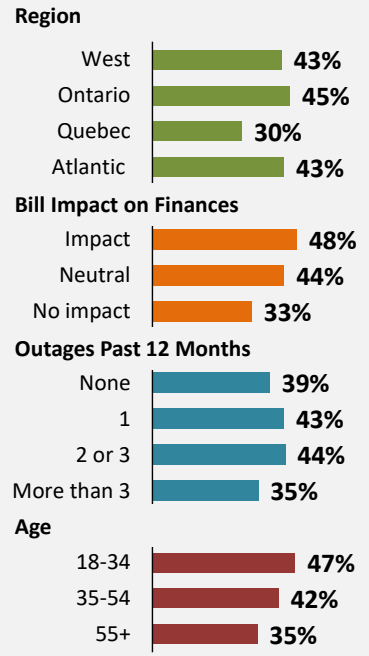
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Seeking Conservation Info: Most already have (12%) or say they are likely (41%) to seek CDM information from their distributor; lower in Quebec

Q How likely are you to seek out information from your electricity company so you can do more to conserve electricity?
[asked of all respondents; n=1,600]



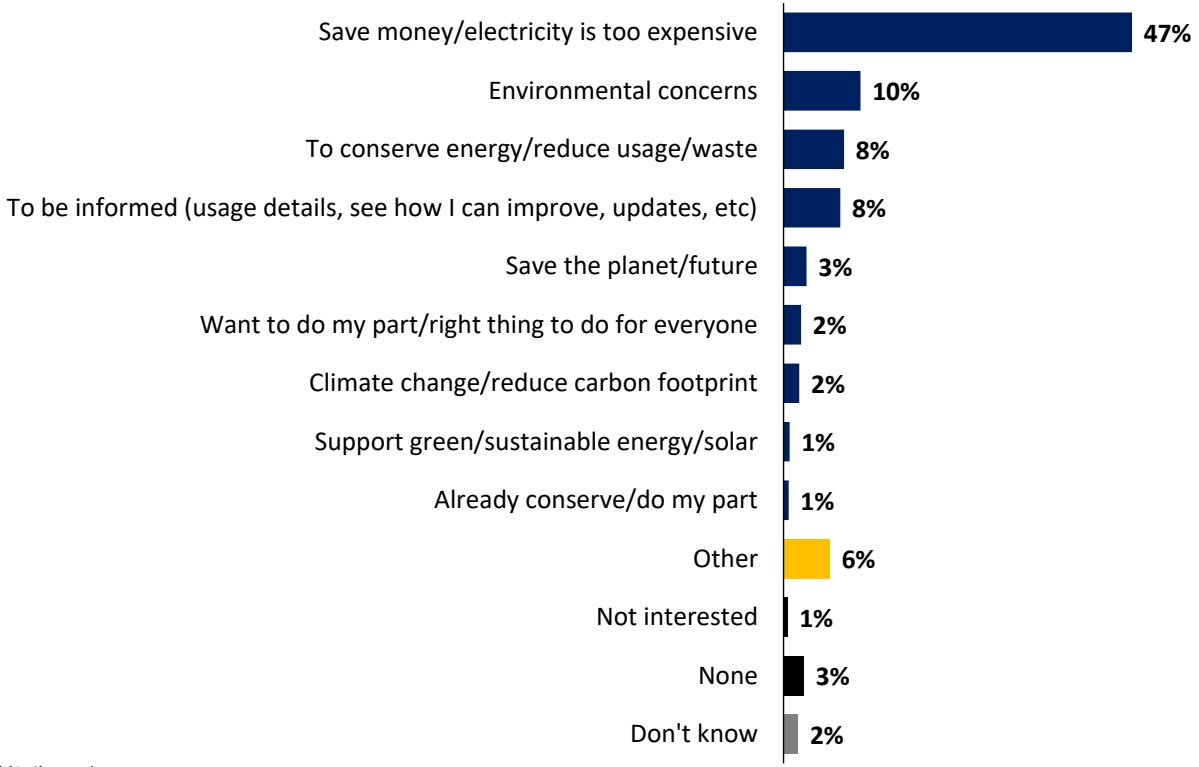
Segmentation
*Those who say **"likely"***



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Reasons for Interest in Conservation: Almost half (47%) of those likely to seek information say saving money is the main reason for their interest in conservation

Q Why are you interested in information on electricity conservation?
[asked of respondents who already have, or who are likely to seek out information; n=845]

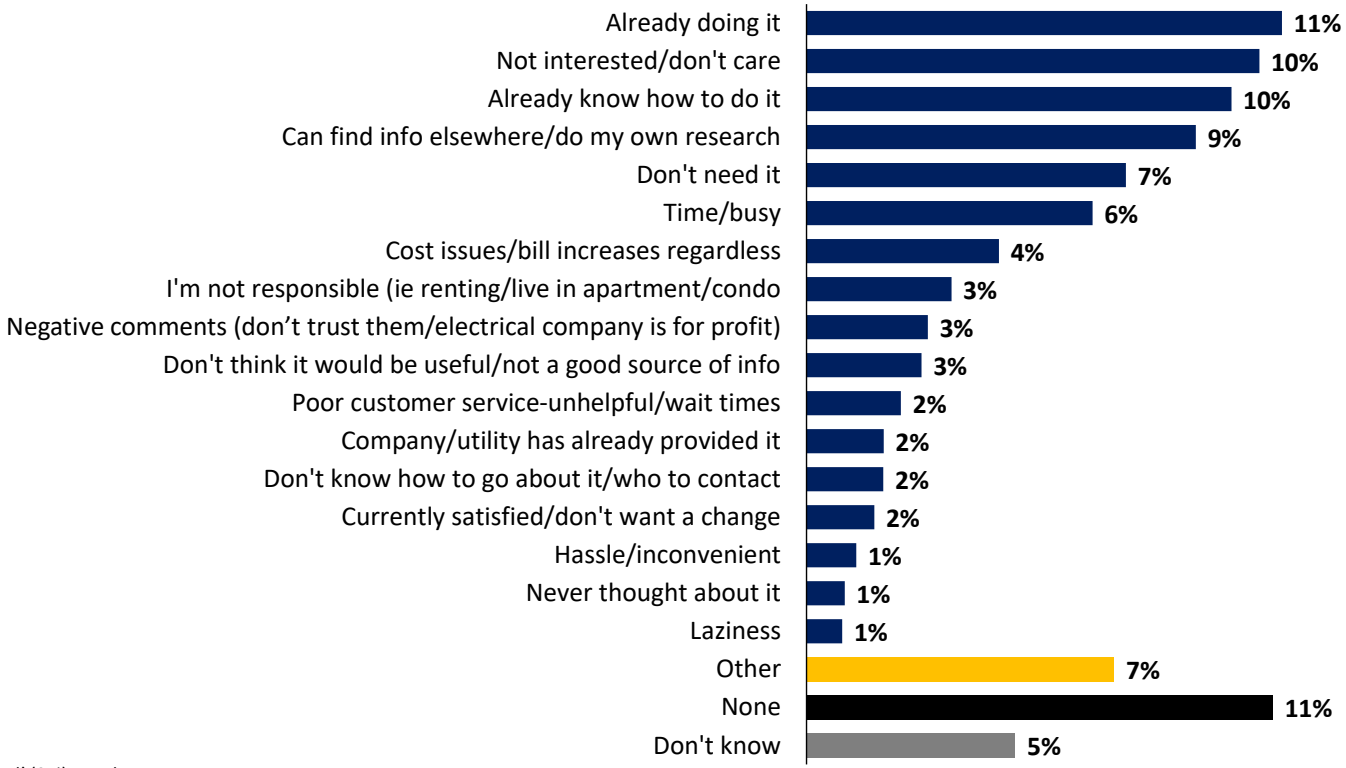


NOTE: 'Refused' (3%) not shown.

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Reasons For Not Seeking Conservation Info: Already doing what they can, lack of interest, and already informed are the top reasons for not seeking CDM info

Q What would hold you back from seeking that type of information?
[asked of respondents who are not likely to seek out information; n=631]

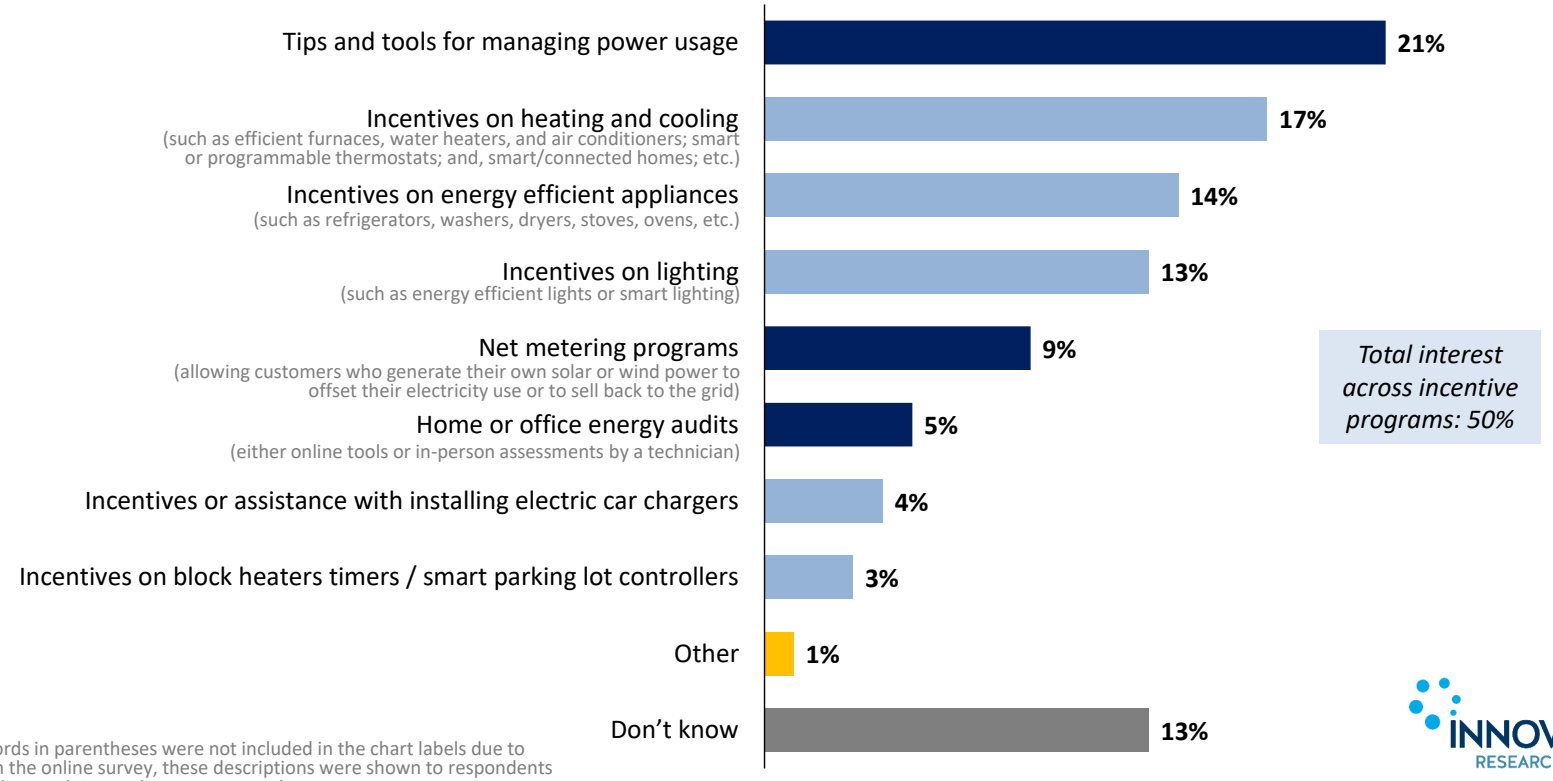


NOTE: 'Refused' (2%) not shown.

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Conservation Programs: As a standalone, tools and tips for managing power usage is of most interest, but half are interested in various the incentives

Q Which of the following energy conservation programs are you most interested in?
[asked of those who are at least "not very likely" to seek out information; n=1,254]



(The descriptive words in parentheses were not included in the chart labels due to space restriction. In the online survey, these descriptions were shown to respondents in the same font colour and size as the summary tag.)

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Technology

(New in 2018)

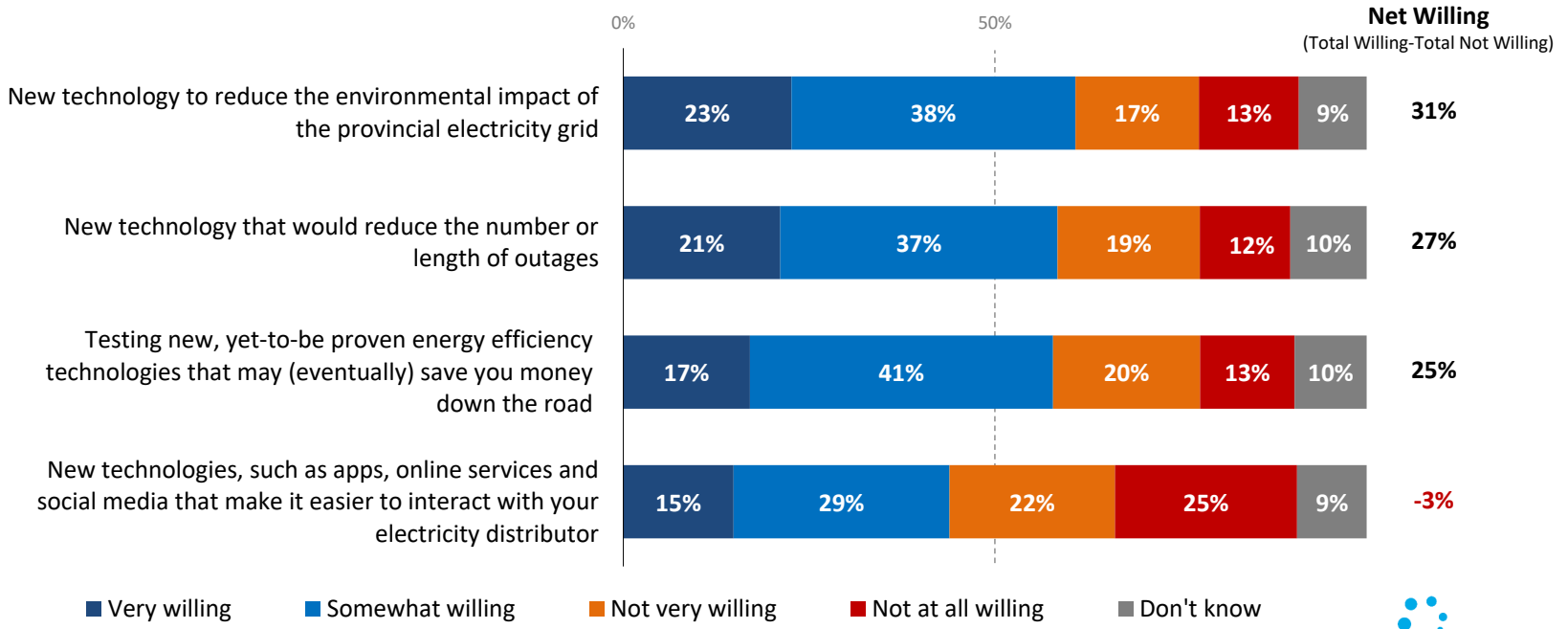


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Paying for Tech Innovation: Most willing to pay if there is a tangible benefit – to the environment, duration and number of outages, or the pocketbook

Q Sometimes new technology can save money in electricity systems. Other times it can add costs. Now we would like to ask you about some ways that that electricity companies can improve services to you that would add some costs to your bills. Please indicate how willing you would be to pay more for the following technological innovations from [COMPANY].

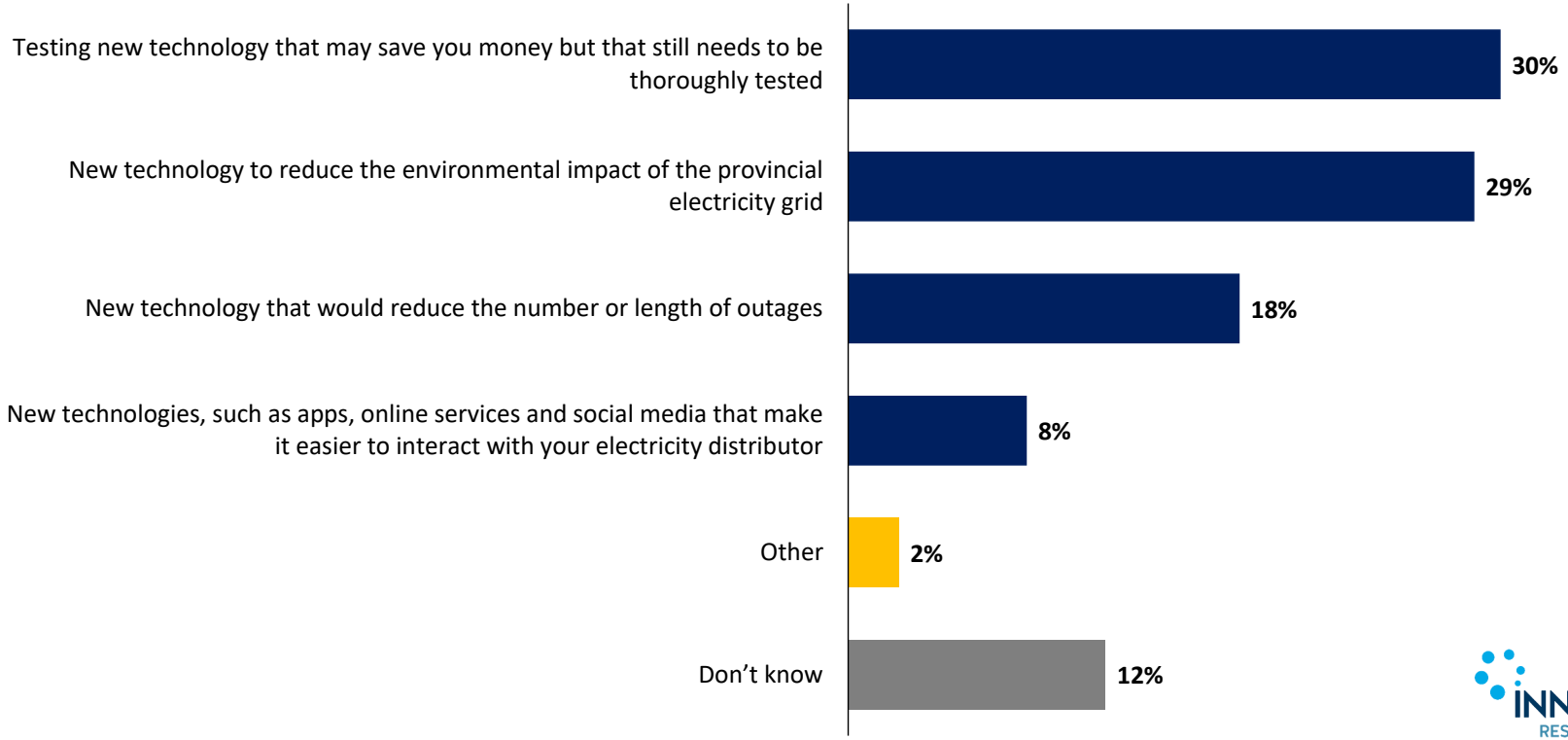
[asked of all respondents; n=1,600]



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Technological Priorities: When asked to prioritize, respondents show a clear preference for saving money and the environment over outage reduction

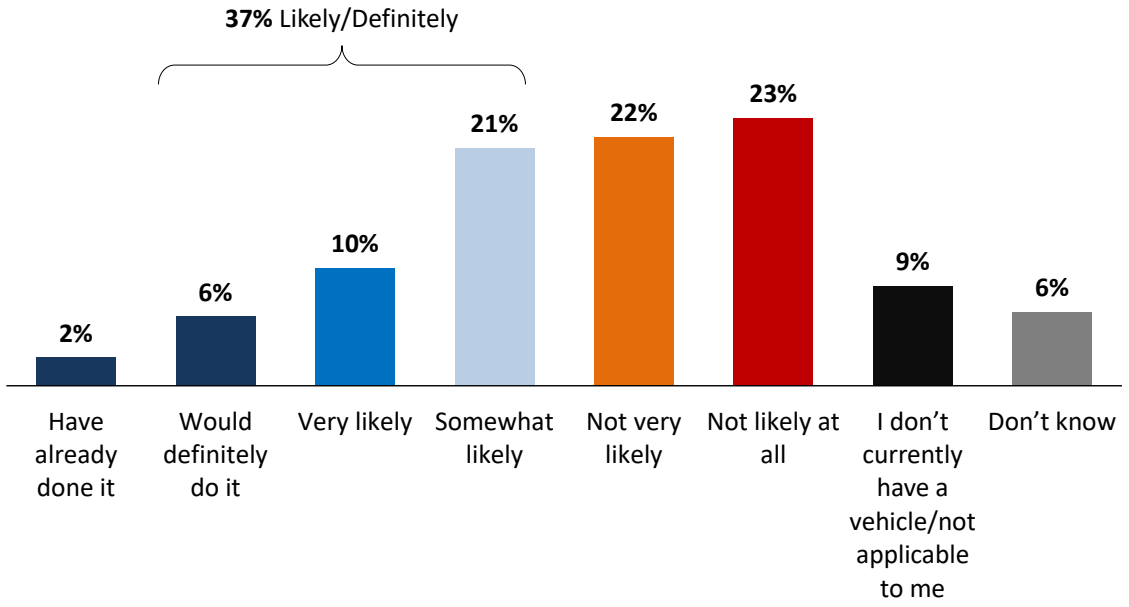
Q When it comes to developing new technology, which of the following do you feel should be the main priority for your electricity distributor?
[asked of all respondents; n=1,600]



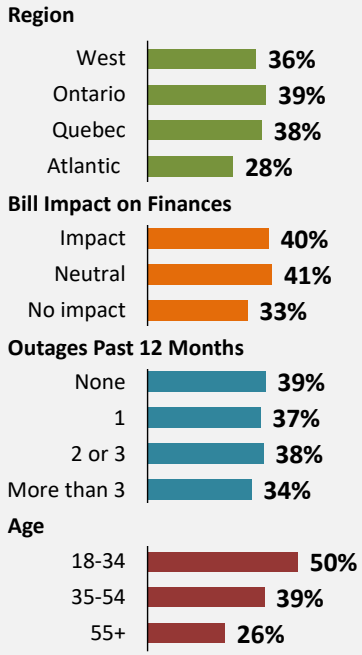
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Buying Electric Vehicles: Almost 2-in-5 (37%) are at least somewhat likely to purchase an EV; likelihood decreases significantly with age

Q How likely would you say you are to buy an electric car when it's time to replace your current vehicle?
[asked of all respondents; n=1,600]



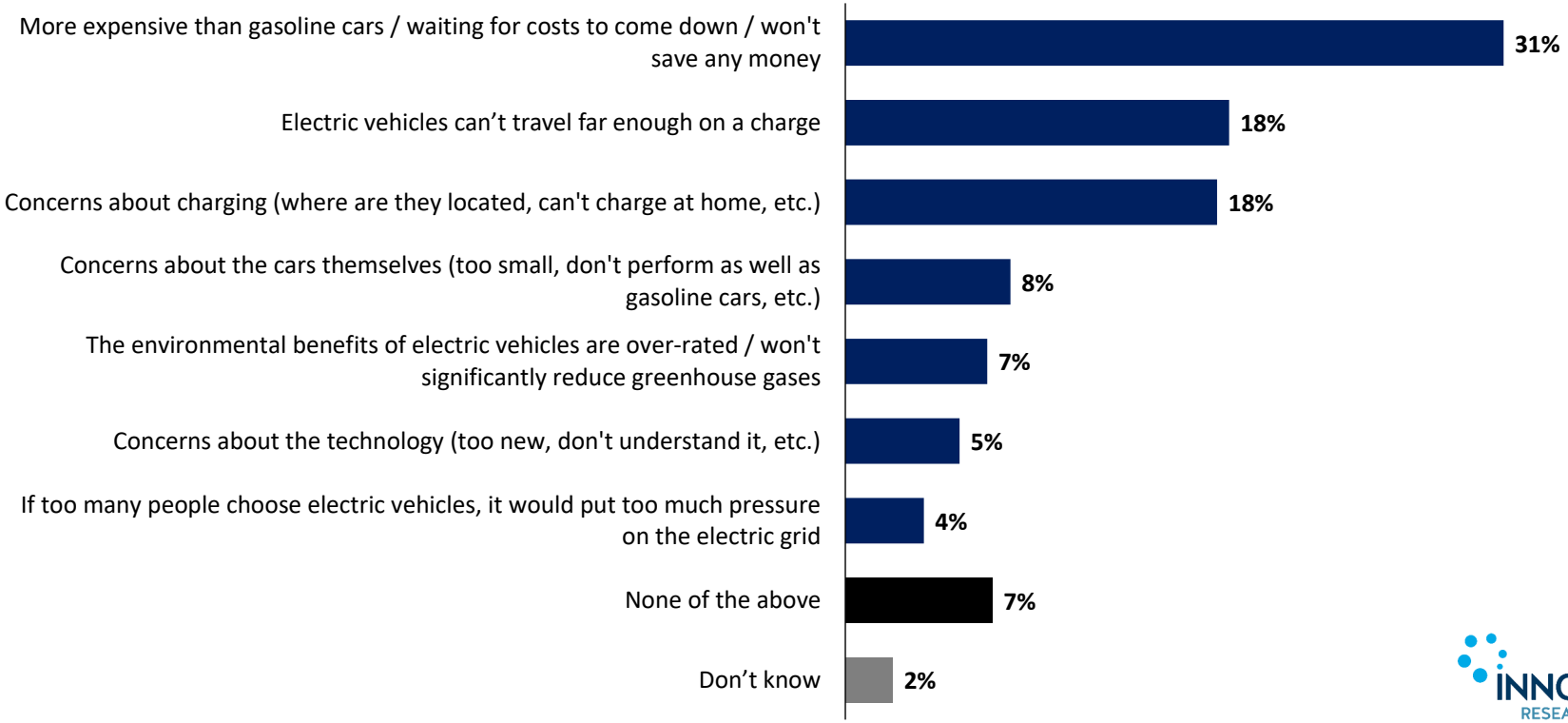
Segmentation
*Those who say **"likely/definitely"***



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Reasons Against Purchasing an EV: Cost is the largest barrier to purchasing an electric car, followed by range and concerns about charging

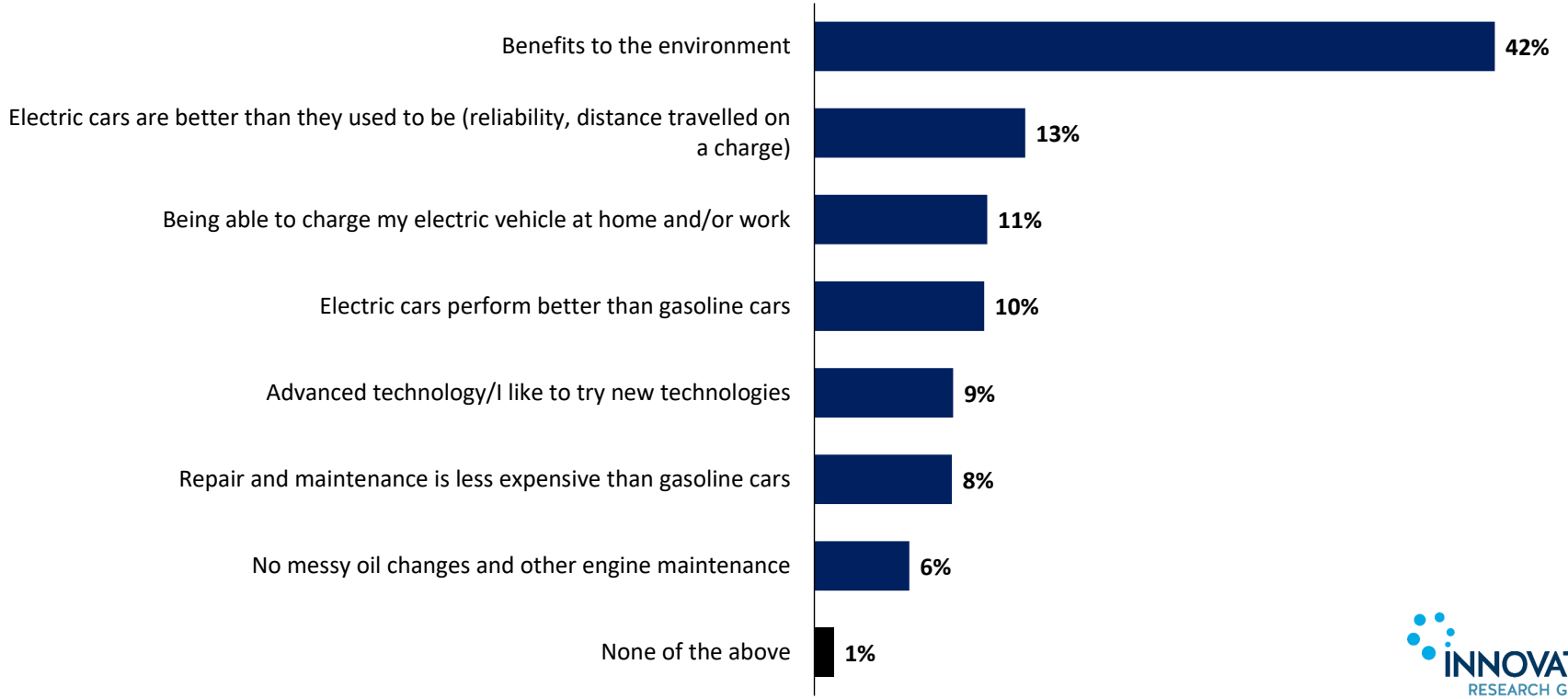
Q Which of the following best describes why you might not purchase an electric car? [RESPONSES CHOSEN FROM LIST]
[asked of respondents who are either likely or not likely to purchase an electric car; n=1,220]



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Why Purchased/Plan to Purchase an EV: A plurality cite environmental benefit as the reason they have purchased or plan to purchase an EV; savings not a priority

Q Which of the following best describes why you have purchased or plan on purchasing an electric car? [RESPONSES CHOSEN FROM LIST]
[asked of respondents who have purchased or plan on purchasing an electric car; n=136]



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Summary

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Another good year for Canada's electricity sector

1. **Continued improvements on all satisfaction measures.** CSI scores have improved – despite a marginal increase in the number of outage experiences – and perceptions on price hold steady. NPS has risen dramatically over the past two years and is now at its highest point since tracking began. Analysis shows that these increases are due both to an improving political and economic environment as well as utility actions.

2. **The relationship between the customer and the utility continues to drive overall satisfaction.** If you were to stop someone on the sidewalk and ask them what is most important to them when it comes to electricity, they would probably mention cost and reliability. However, regression analysis shows us that respect and consideration is even more important in explaining how customers feel about their utilities.

3. **Keep the doors of communication open.** Again this year, overall communication is second only to customer service for driving both satisfaction and NPS.

4. **Conservation matters.** While they won't be breaking down the doors of their distributor to get information, most are interested in learning more about conserving energy. Providing conservation and efficiency programs is part of *"Public Good"* which is a second-tier driver of satisfaction and NPS, so even if customers don't act on it, they still want to know conservation programs are there.

5. **Do customers want to pay for innovation?** If passion equals action, then no, not really. On average, one-in-five say they are "very willing" to pay for technological innovation. Innovations that will save the environment or their pocketbook are the most appealing.



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Greg Lyle
President
416-642-6429
glyle@innovativeresearch.ca

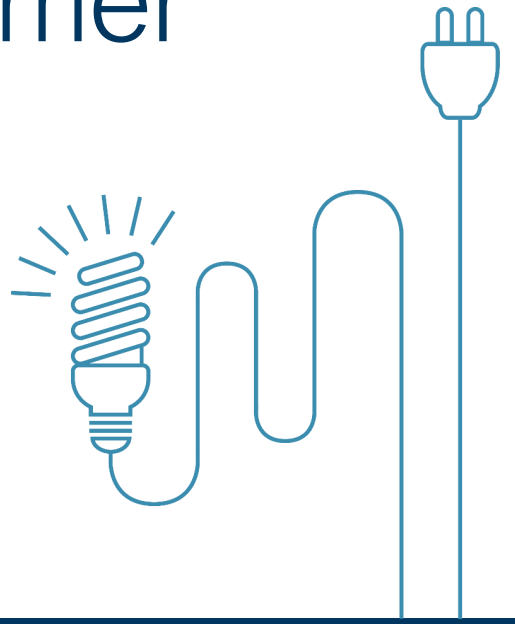
Susan Oakes
Vice President
416-642-6341
soakes@innovativeresearch.ca

Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto ON | M5E 1A7
www.innovativeresearch.ca

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INNOVATIVE RESEARCH GROUP

National Electricity Customer Satisfaction Report



Canadian Electricity Association | Association canadienne de l'électricité

December 2019

:: REVIEW DRAFT ::

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Key Findings

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For the second year running, another good year for Canada's electricity sector

1. **Steady on all satisfaction measures.** CSI scores have reached the highest point since the new scale was introduced in 2013. Overall, there are no latent or critical weaknesses – only latent strengths poised for growth. NPS continues to improve, reaching a new all-time high. Analysis shows that these increases are due both to an improving political and economic environment as well as utility actions.

2. ***Customer Focus*** **drives overall satisfaction and NPS.** It's not just about keeping the lights on, and it's not just about cost. It's about consulting with the customer, being transparent, caring and trustworthy.

3. **Keep the doors of communication open.** Again this year, overall communication is a secondary driver for both satisfaction and NPS.

4. **Adoption may be slow, but innovation is important.** Customers want their distributor to help with find ways to reduce consumption, and they don't want them to be passive players in developing new innovations. Financial savings are what customers really want out of new innovations.

5. **Enhanced customer contact is nice to have, but not a need to have.** Most feel their distributor already has their current contact information. While there are no stand-out barriers to providing contact information, and customers are interested in the types of information that may be shared, it's not enough to motivate those who have not yet shared their contact details.



Update on Core Benchmarks

Distributor Satisfaction

- General satisfaction is mostly steady year to year (66% vs. 65% in 2018), with an 11-point increase since the new scale was introduced in 2014 (55%).
- Net satisfaction has held steady on most metrics, with a marginal gain on transparency and a sizeable gain on consulting customers.

Reliability & Power Quality

- Nearly half (47%) have experienced two or more outages in 2019, a marginal decrease of two points since last year.
- Net satisfaction is strong on all five reliability and quality metrics: strongest on quality (60% net satisfied), weakest on 'considering your needs when planning an outage' (30%), which has not moved since 2018.

Planned Outages

- 30% recall being impacted by a planned outage in the past two years, with no change on this measure since last year.
- 73% report that their electricity company reached out to them proactively before the planned outage, with no significant shift since 2018 (75%).
- Of those who were contacted, 82% feel satisfied with the communication.

Billing & Payment

- A plurality (47%) report they receive their bill electronically, while 43% say they receive a paper bill in the mail. This is unchanged since 2018, a year when e-billing grew eight points and shifted the balance from paper to online.
- A strong majority are net satisfied with all four billing and payment metrics, with no major changes since 2018.

Communications

- 65% are satisfied with the communication from their distributor, stable year-to-year. After double-digit gains from 2017 (39%) to 2018 (56%) net satisfaction is steady at 57%.
- Respondents are three times more likely to say the customer experience with their electricity company is better (29%) than worse (9%), compared to other types of service providers.

Transmission

- A plurality (45%) are satisfied with their transmission company, while just 10% say they are dissatisfied.
- Satisfaction in Ontario (44%) has improved four points since last year (40%), while satisfaction in Alberta (44%) has dipped five points and is down nearly 20 points from a high of 63% in 2017.

Update on Core Benchmarks (cont'd) & Summary of New* Issues

Price

- 48% feel the price they pay for electricity is reasonable and 44% say the opposite.
- For the first time since 2013, feeling on price is net positive (4%) with a marginal shift in negative intensity away from 'very unreasonable' (17% in 2018 to 14% in 2019).
- A plurality (37%) struggle to pay their electricity bill, agreeing that it has a major impact on their finances with 1-in-3 (33%) who disagree.
- A plurality (38%) agree with the statement "thinking of all regular household bills, I receive good value for money" with 3-in-10 (31%) who disagree.

Innovation*

- 54% prefer that their distributor actively help them find ways to reduce electricity consumption, while 38% just want the lights to turn on.
- 55% feel electrical utilities should invest in new technologies, while 32% say they should wait until they've been proven elsewhere
- A third (33%) of respondents feel that their distributor should both help them reduce consumption and hold off on investing. Less than 2-in-10 (17%) think their distributor should help them reduce consumption and also invest in new technologies.
- 42% feel investments should focus on financial savings through increased efficiency. Just 12% felt companies should focus on increasing reliability.
- In our innovation index created based on acquisition of or interest in the six types of new innovation, only 7% were early adopters.

Customer Contact*

- 78% say their distributor has their contact information on file.
- 34% would be willing to share their current contact information with their distributor, while 3-in-10 (31%) would not be willing to do so.
- When asked why they haven't shared their contact info with their distributor, top reasons included "they haven't asked for it" (21%), "there's no reason to share it with them" (16%), and "privacy concerns" (15%).
- A majority of respondents were interested in each of the seven motivators tested (although they did not increase likelihood of sharing contact info):
- A strong plurality (48%) of respondents say email is their preferred method for updating contact info.

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Methodology & Demographics

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Research Overview

The Canadian Electricity Association (CEA) commissioned Innovative Research Group Inc. (INNOVATIVE) to conduct the CEA's 2019 Annual National Customer* Satisfaction Survey. The focus of this survey is public attitudes towards the electricity companies that serve them.

In 2019, the survey re-introduced Net Promoter Score (NPS) for distributors and key satisfaction metrics for transmitters. The exact structure of the survey in each province reflects the unique circumstances of that province (see slide 12 for summary of provincial regimes).

Key company-specific (distributor) topics include:

- Overall satisfaction
- Performance metrics
- Customer experience (*planned outages, billing, and other customer contact*)
- Net Promoter Score

** Almost all respondents receive a bill from an electricity distributor and therefore they have a direct customer relationship with a utility. However, it should be noted that approximately 10% of respondents say they do not receive a bill directly from an electricity distributor.*

Other topics include:

- Key satisfaction metrics for transmitters
- The price of electricity
- Consumer interest in new innovations
- Connecting with consumers for enhanced communication
- Environmental controls (underlying factors – outside a utility's control – that may impact perceptions of electricity companies)

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Survey Methodology



The CEA's 2019 Annual National Public Attitudes Survey is an online survey conducted by Innovative Research Group (**INNOVATIVE**). Data collection occurred between October 10th and November 5th, 2019 among 6,471 Canadian adults (18yrs or older).

The survey instrument was designed by INNOVATIVE, with input and direction from CEA members, and made available to respondents in either French or English.

The survey sample was weighted by age, gender and region using 2016 Statistics Canada Census data to reflect the actual demographic composition of the Canadian adult population. Upon CEA member request, additional oversamples were included in a number of distribution service territories or provinces to provide greater confidence in the data at a sub-regional level of analysis. In the final data, the oversampled regions were weighted down to a representative national sample size of n=1,600.* Tracking results are drawn from previous CEA National Surveys from 2013** to 2018.

Survey respondents were recruited from a wide variety of sources to reflect the age, gender, and regional characteristics of the country as a whole. Because this is an online survey, and not a random probability sample, the results cannot be generalized across all Canadians, and we cannot apply a margin of error. INNOVATIVE provided each survey respondent with a unique URL (hyperlink) to the online survey via an email invitation to ensure that only invited respondents were able to complete the survey. Unique URLs were disabled upon survey completion to ensure that invited respondents could only complete their individual survey once.

Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

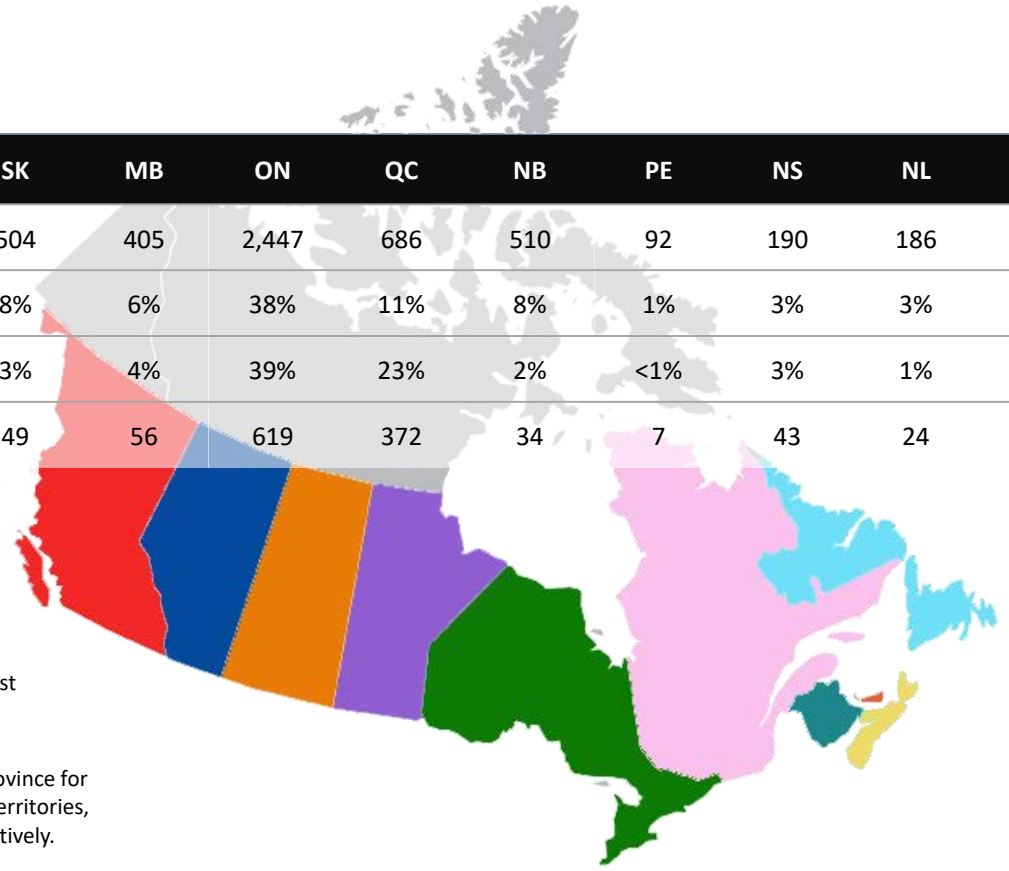
**** NOTE ON WEIGHTING:** The survey data has been weighted by the population, age and gender distributions within 30 graphical sub-regions across Canada, using 2016 Census data. This weighting convention ensures that the survey data is representative at both the national and provincial levels of analysis.*

***** NOTE ON TRACKING:** Reliable tracking from years prior to 2014 is limited to questions that were not impacted by the transition from 1-10 to 0-10 response scales in 2014. Where reliable tracking is available, in some instances it dates back as far as 2009.*

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Sample Design

	BC	AB	SK	MB	ON	QC	NB	PE	NS	NL	Total
Unweighted Sample (n)	1,101	350	504	405	2,447	686	510	92	190	186	**6,471**
Unweighted Sample (%)	17%	5%	8%	6%	38%	11%	8%	1%	3%	3%	100%
2016 Census Population (%)	13%	11%	3%	4%	39%	23%	2%	<1%	3%	1%	100%
Weighted (n)	214	183	49	56	619	372	34	7	43	24	**1,600**



n=1,600
National Weighted Sample

NOTE: The sample has been weighted by the population, age and gender distributions within 30 graphical sub-regions across Canada, using the latest available Census data. This weighting convention was used to ensure representative data at both the national- and provincial-levels of analysis.

Respondents from the territories are grouped with those in the nearby province for weighting purposes and regional analysis. Those from Yukon, Northwest Territories, and Nunavut are grouped together with BC, Alberta, and Manitoba respectively.

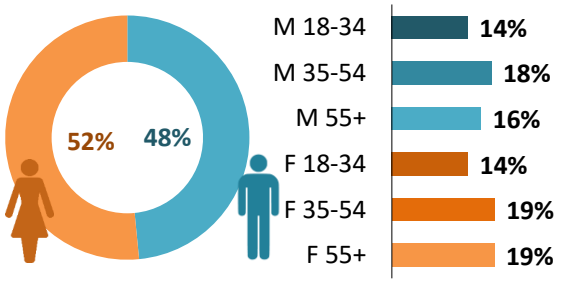
Oversampled regions were weighted *down* (as opposed to *up*) – *from an unrepresentative national sample size of n=6,471 to a representative national sample size of n=1,600* – to ensure that respondent input from any region was not artificially inflated.

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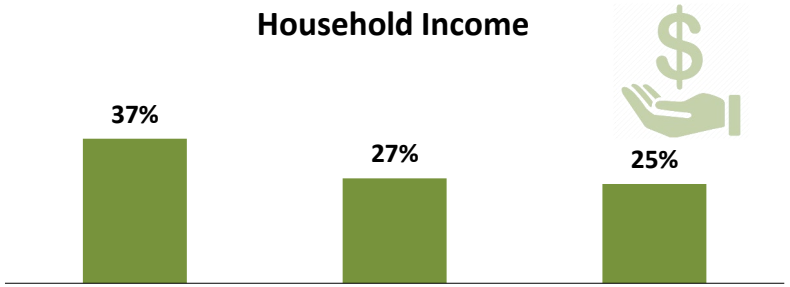
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Demographics: *Respondent Profile*

Gender and Age

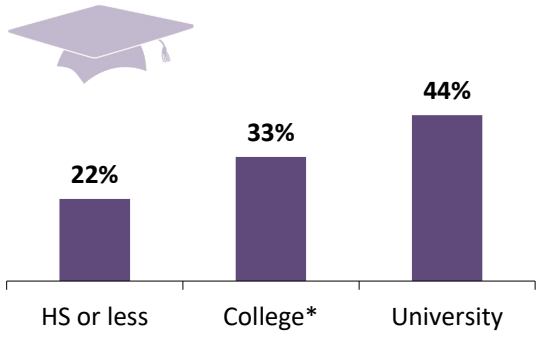


Household Income



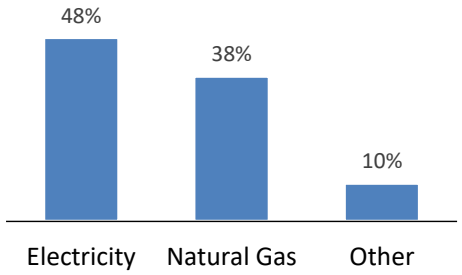
12% Prefer not to say

Education



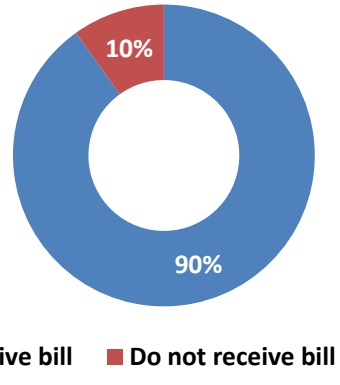
* Includes Diploma and Apprenticeship
2% Prefer not to say

Primary Home Heating Source



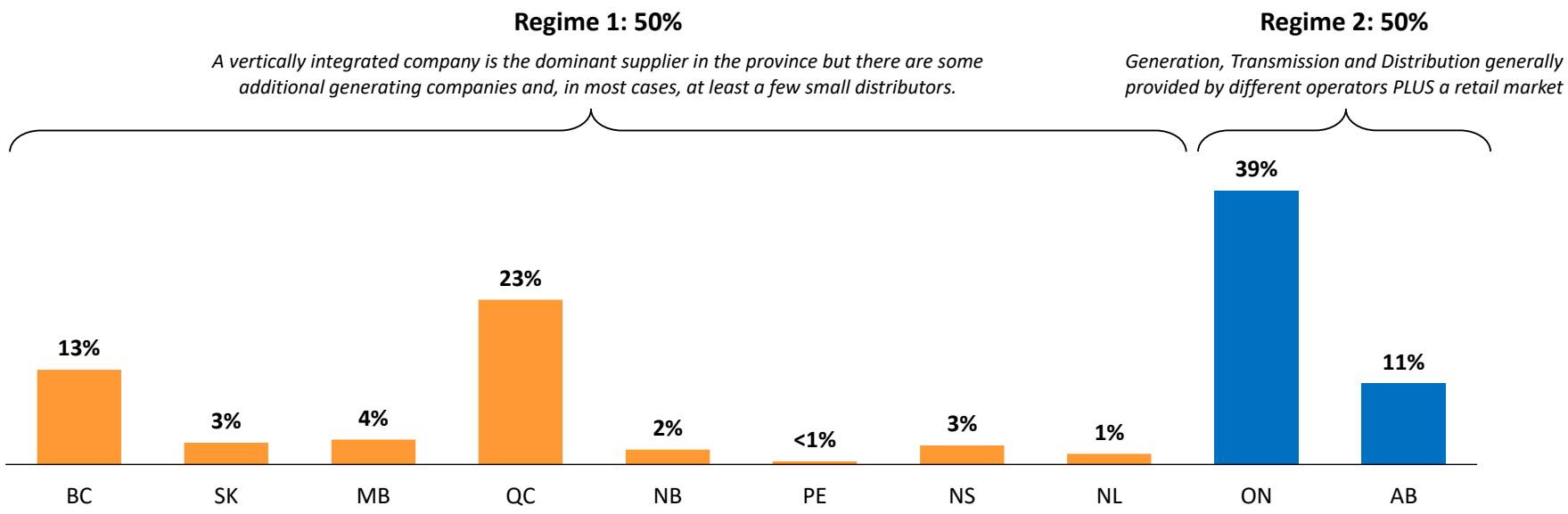
4% Don't know

Billing



Region & Regime

The survey design applies to all respondents regardless of the provincial electricity system – whether customers predominantly receive their electricity services from a vertically integrated company (Regime 1) or from different operators of transmission and distribution (Regime 2).



Survey Design: *Questionnaire Tracking*

At the beginning of the survey, respondents are asked which company they get their electricity bill from. All survey questions prior to the Transmission questions relate back to this company. The company name is inserted into the actual question several times to remind respondents to base their responses on that company.

Survey Section	2019	2018	2017	2016
Overall Satisfaction (Distributor)				
Familiarity with provincial electricity system	X	X		X
In general, how satisfied are you with [COMPANY]	X	X	X	X
Caring about its customers	X	X	X	X
Taking care of any problems the first time you contact them	X	X	X	X
Providing online services	X	X	X	
Operating in an environmentally responsible manner	X	X	X	X
Protecting public safety	X	X	X	X
Being trustworthy	X	X	X	
Being transparent	X	X	X	
Providing energy conservation and efficiency programs and information	X	X	X	
Being a good corporate citizen through initiatives such as contributing to community sponsorship programs	X	X	X	X
Consulting with customers before making decisions that impact them	X	X	X	
Reasons for contacting [COMPANY] in the past 12 months	X	X	X	X
Reliability and Power Quality				
In the past 12 months, how many power outages do you recall experiencing at home?	X	X	X	X
Providing reliable electricity service, as judged by the number of outages you experience	X	X	X	X
Providing timely and accurate information regarding outages	X	X	X	X
The amount of time it takes to restore power when power outages occur	X	X	X	X
Considering your needs when planning an outage	X	X	X	
The quality of power delivered to you taking into consideration voltage fluctuations, that can result in flickering or dimming of lights	X	X	X	
Planned Outages				
Over the past two years, have you been impacted by any planned outages?	X	X		
Did [COMPANY] proactively communicate with you about the most recent planned power outage that you experienced?	X	X		
Satisfaction with the way the company communication about planned outage	X	X		

NOTE: A red X indicates where question wording was slightly different in prior years

Survey Design: *Questionnaire Tracking (cont'd)*

Survey Section	2019	2018	2017	2016
Billing and Payment				
Format of bill	X	X	X	
Providing accurate bills	X	X	X	
Providing bills that are easy to understand	X	X	X	
Providing convenient options to receive my bill	X	X	X	
Providing convenient options to pay my bill	X	X	X	
Communications				
Overall satisfaction	X	X	X	
Satisfaction with: Phone/In-person | Website | Social media | Outage notifications | Bill inserts | Advertising | Written inquiries	X	X	X	
Customer experience with [COMPANY] compared to that of other service providers	X	X	X	X
Net Promoter Score (NPS)				
Likelihood to recommend [COMPANY]	X	X		X
Transmission				
General satisfaction with [TRANSMISSION COMPANY]	X	X		X
Providing reliable electricity service	X	X		X
Maintaining the electricity transmission system in a responsible manner	X	X		X
Price				
Overall, do you think that the price for electricity in your province is reasonable or unreasonable?	X	X	X	X
My electricity bill has major impact on my finances and requires I do without other important priorities.	X	X	X	X
Thinking of all regular household bills, I receive good value for the price I pay for electricity.	X	X	X	X
Innovation				
Utility as active partner vs just wanting the lights to go on	X			
Utilities should invest in new technology vs waiting for it to be proven elsewhere	X			
Priority for investing in new technology	X			
Interest in specific innovations	X			
Enhanced Customer Communication				
Likelihood to provide contact information	X			
Barriers and drivers for providing contact information	X			
General Attitudes				
Support for investment, replacement and/or expansion of electricity infrastructure to improve reliability and safety, and keep up with growth and innovation	X	X	X	X
Perception of increasing price of electricity to invest in electric system	X	X	X	X
Satisfaction with provincial government management of electricity system	X	X	X	X

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A Note on Environmental Controls

What are environmental controls?

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Environmental Controls: *Uncontrollable External Factors*

It is important to distinguish between what is within, and what is outside an electrical utility's influence or control when it comes to drivers of satisfaction.

Perceptions of electricity companies often tend to move with general perceptions of ***provincial government performance in the sector*** rather than in response to the utility itself.

In addition, perceptions of utilities are strongly correlated with **financial circumstances**. In tough times, perception and preference can change because customers are struggling with their bills, not because of anything the company has – or as not – done.

Control questions help distributors distinguish between two factors that impact public perception:

a) utility-driven programs; and

b) uncontrollable external factors.

In this survey, we include two environmental control questions to help capture external phenomena:



Government Performance: *How satisfied are you with the job your provincial government is doing to manage the electricity system?*



Financial Circumstances: *The cost of my electricity bill has major impact on my finances and requires I do without some other important priorities.*

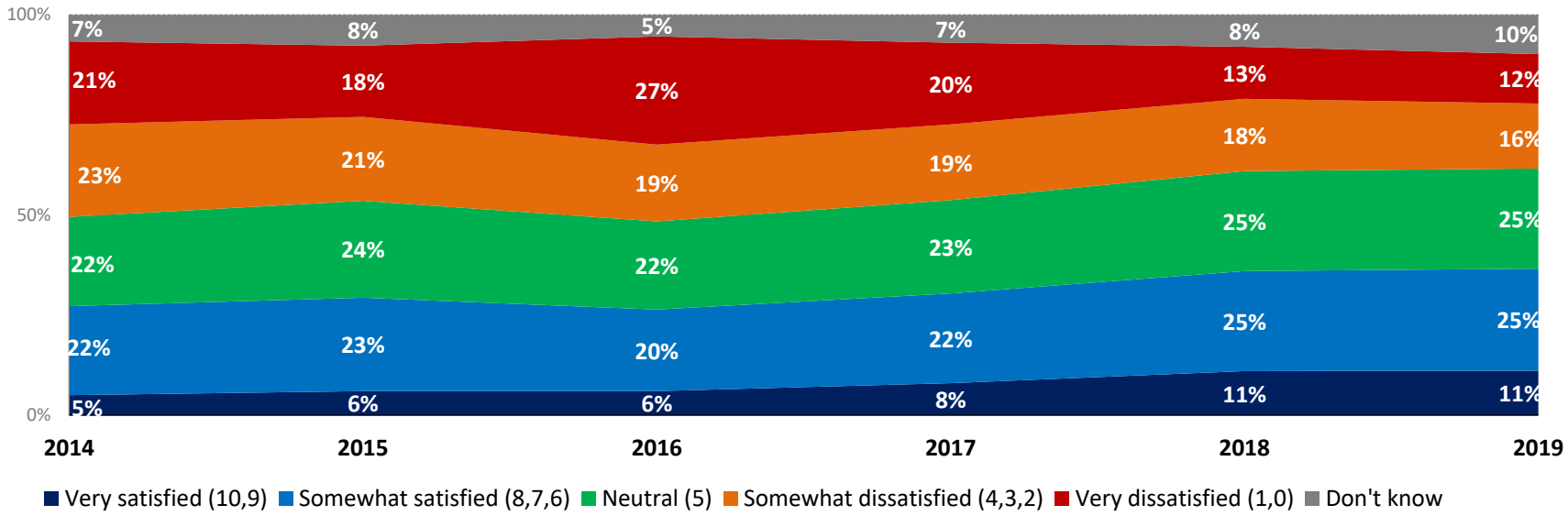
There is a more in-depth analysis of these environmental controls in the appendix

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Gov't Performance (Tracking): Net satisfaction has improved two years running, now at highest point (+8) since tracking began

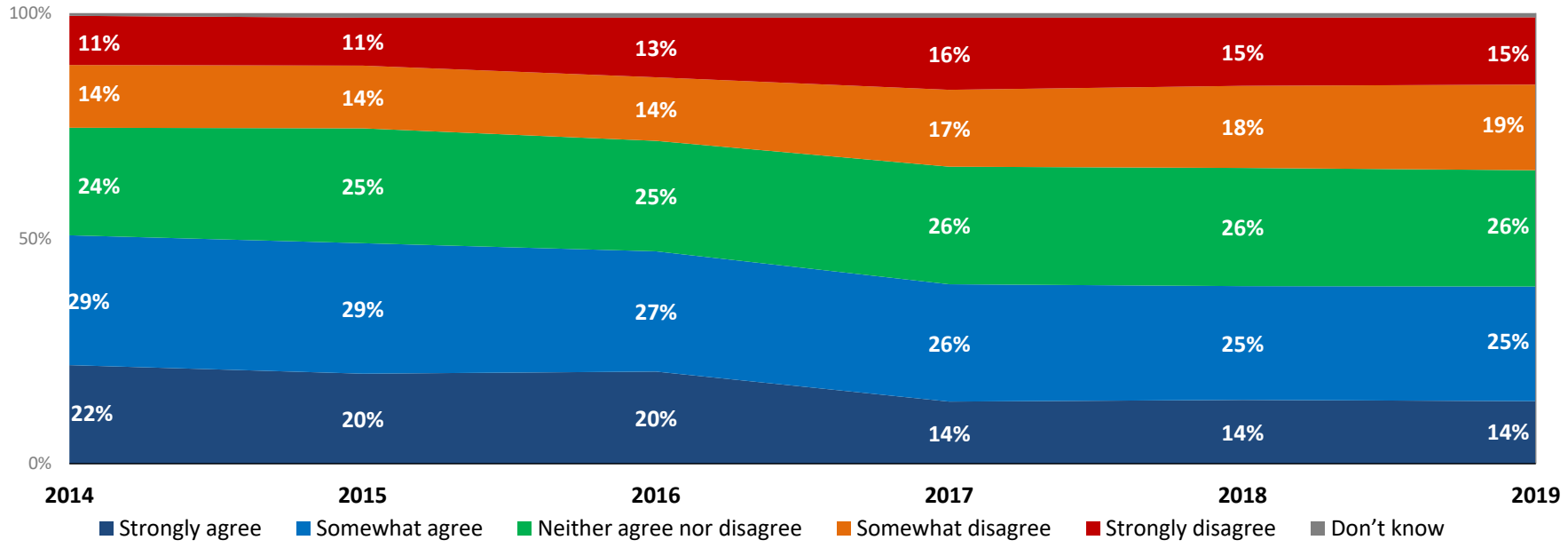
Q How satisfied are you with the job your provincial government is doing to manage the electricity system? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents; n=1,600]



Financial Circumstances (Tracking): Plurality (39%) struggle to pay electricity bills, no change year-to-year

Q Do you agree or disagree with the following statement:
My electricity bill has major impact on my finances and requires I do without other important priorities.
[for tracking purposes, data filtered to show only those who receive a bill; n=1,441]



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Customer Satisfaction Index (CSI)

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Customer Satisfaction Index (CSI)

The **Customer Satisfaction Index (CSI)** is a number that summarizes respondents' overall satisfaction with their electricity distributor using an analysis of each performance metric tested.

In 2014, INNOVATIVE updated the methodology used to construct the CSI. In 2017, the calculation methodology was updated again to reflect the survey redesign that occurred that year. As in 2018, this year's study follows the 2017 method.

Calculating CSI:

1. A ***factor analysis*** finds the true underlying dimensions of customer satisfaction that explain the pattern of responses on the larger set of brand metrics.
    - Factor analysis allows us to find which metrics mean similar things to the public. The use of factor analysis allows us to determine which metrics should be grouped together in order to conduct meaningful analysis.
    - We tested **20 performance metrics** for all electricity companies in the analysis. While each of these metrics seems distinct in important ways to people who are close to the industry, many of these items seem similar to members of the general public. We found that **5 underlying *factors,*** along with 3 additional (standalone) metrics explain most of the variance in the larger set of metrics.
2. We use a ***Shapley Values*** regression analysis to determine the relative contribution of each *factor* to overall satisfaction.
    - *Shapley Values* are a calculation of how much of the variance in overall satisfaction can be explained by each individual factor, after statistically accounting for the fact that some of the factors are correlated with one another.
3. We then take an average of the mean score on each of the *factors,* weighted by their *Shapley Values* to determine the overall **CSI scores**.
4. *In keeping with the revised survey and analysis plan, the CSI is now being calculated as a single measure for all electricity companies included in the research.*

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Factor Analysis (General Satisfaction): *Based on their responses, which metrics mean similar things to the public?*

Customer Focus

- Consulting with customers before making decisions
- Being transparent
- Caring about its customers
- Being trustworthy
- Being a good corporate citizen

Quality & Reliability

- Providing reliable electricity service
- The amount of time it takes to restore power
- The quality of power delivered to you

Billing Practices

- Providing convenient options to pay my bill
- Providing convenient options to receive my bill
- Providing bills that are easy to read and understand
- Providing accurate bills

Public Good

- Operating in an environmentally responsible manner
- Providing energy conservation and efficiency programs
- Protecting public safety

Outage Preparation

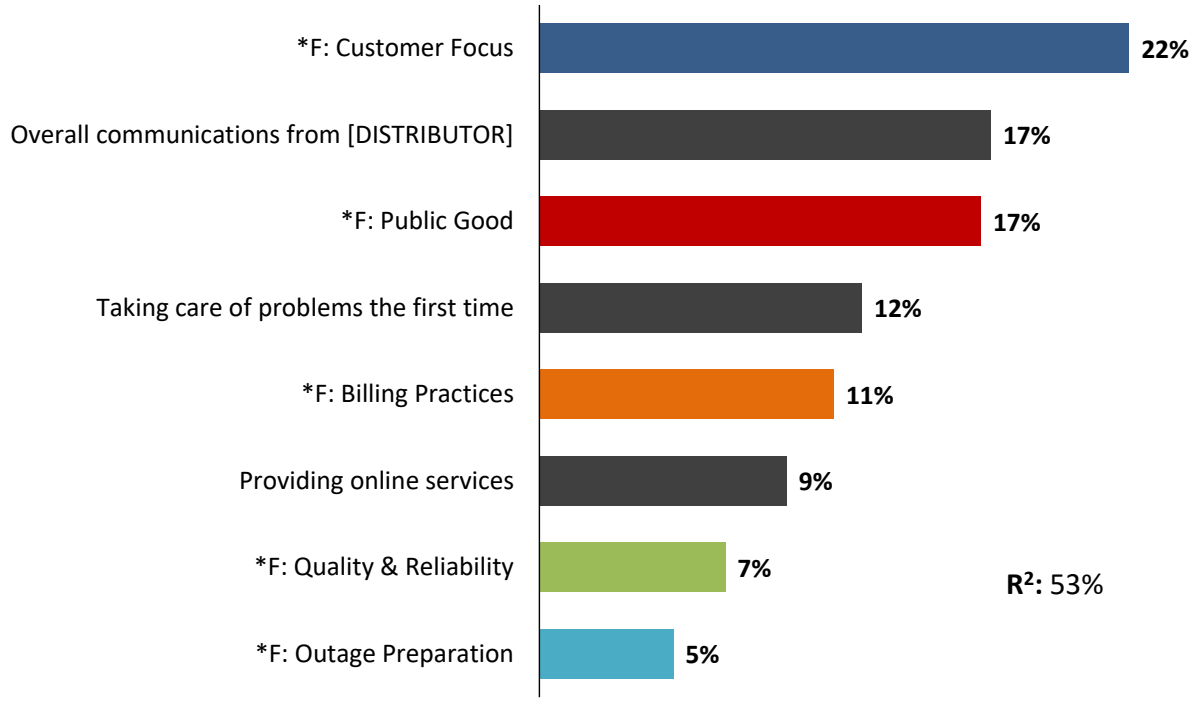
- Providing timely and accurate information re: outages
- Considering your needs when planning an outage

Standalones

- Taking care of problems the first time you contact them
- Overall communication
- Providing online services

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Shapley Values Regression: *Relative contribution of each factor to the Customer Satisfaction Index (CSI) according to Shapely Values regression*

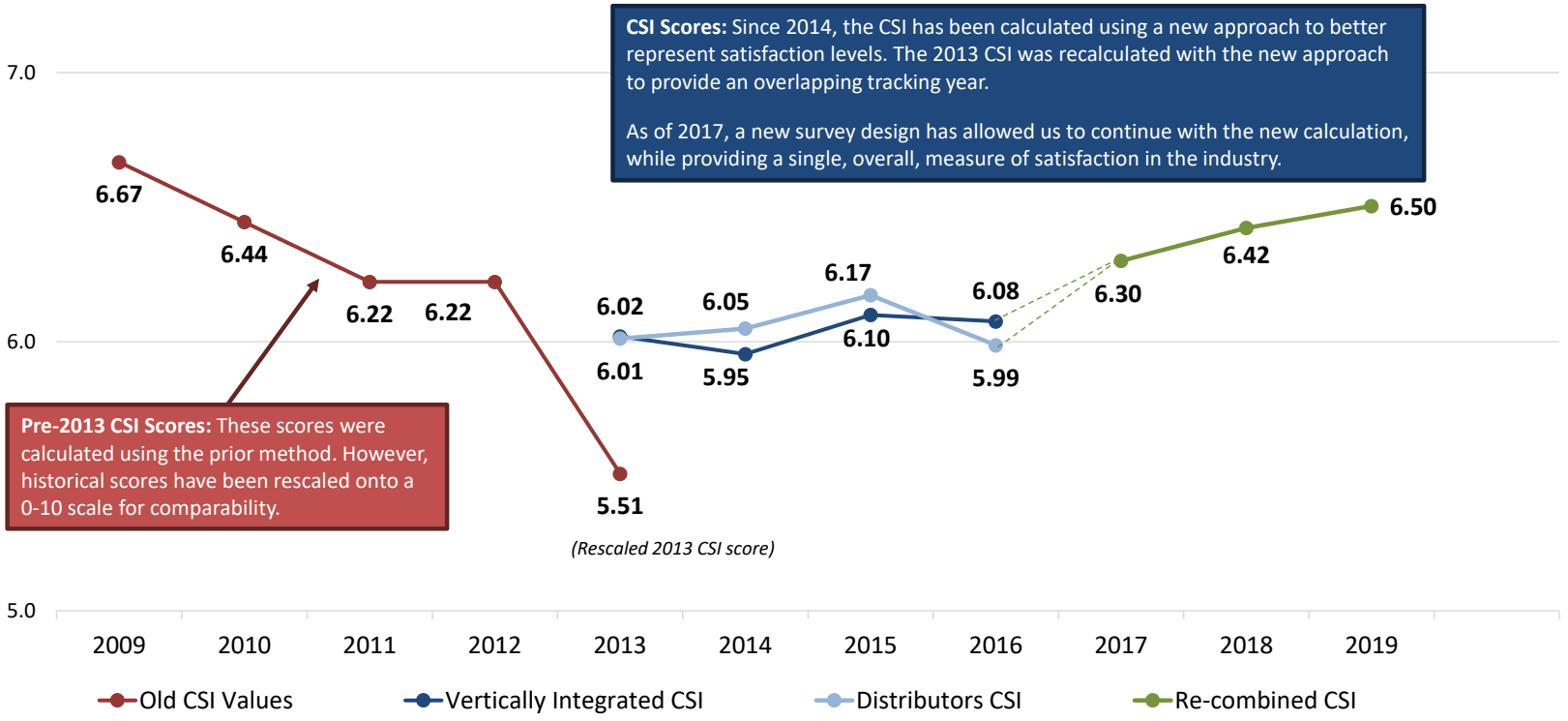


The percentage for each factor/metric shows the contribution of each to the amount of variance being explained by the model (in this case, 53%).

These values are used to create the CSI score.

*F – Denotes what has been identified as a "factor", where multiple metrics are viewed similarly to respondents. All others are standalone metrics

CSI Tracking: CSI improves again, now at highest level in nine years



NOTE: Previously the CSI had been calculated on a 1-10 scale; in keeping with the move to a 0-10 scale for this year's survey, previous year's CSI scores have been rescaled 0-10. For example the 2013 score of 5.51 on a 0-10 scaled that is reported here corresponds to last year's reported score of 5.9 on a 1-10 scale.

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Action Analysis

What does the data tell us about what to do next?

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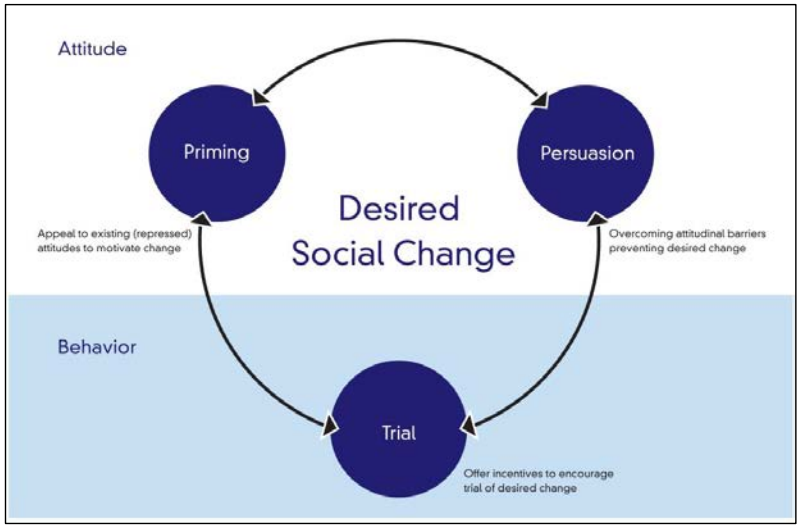
Changing Public Perception: *Social Marketing*

The concept of social marketing is all about getting people to change their behaviour. Getting a flu shot. Taking precautions when investing. Saving for retirement. Using less electricity. Accepting price increases. **Simply stated, but not simply achieved.**

There are three primary options for opinion change:

- **Persuasion** – Teaching people something they didn't know in order to increase their likelihood of doing the desired action or believing the desired belief.
- **Priming** – Reminding people of something they already know in order to increase their likelihood of doing the desired action or believing the desired belief.
- **Trial** – Getting people to do the desired behaviour so it becomes a habit.

On-going research will provide electricity companies with a framework to assess their target audience to identify the key opinion anchors for priming, the best new information for persuasion, and the most appealing offers for trial.



In terms of behaviour, **trial** is best since a change of behaviour is the goal. Trial works best if it is run in parallel with a supportive campaign to change attitudes that conflict with the behaviour.

Persuasion is the next best since persuasion results in permanent behaviour change.

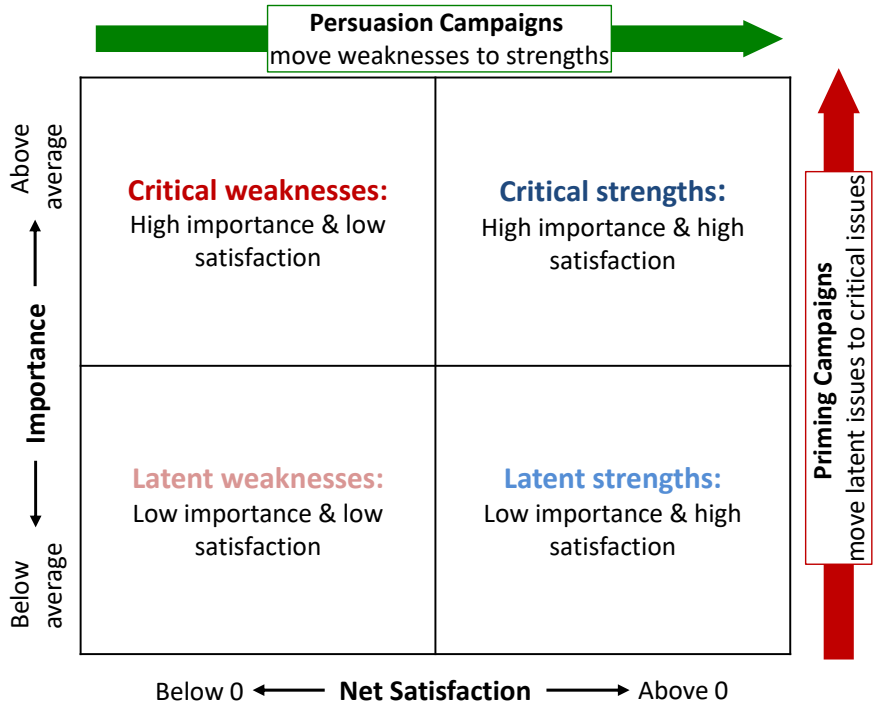
Priming is often the least effective for long term change since once the campaign is over, the priming effect quickly fades. But if priming is sustained long enough to establish new habits, the change can be permanent.

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Combining Importance & Satisfaction: *Priming and Persuasion*

Once we understand what factors underlie each brand, we can examine how levels of overall satisfaction on each factor compare to their level of importance. The satisfaction scores shown below are net satisfaction while the level of importance is calculated using a *Shapley Values* regression as detailed in the previous section.



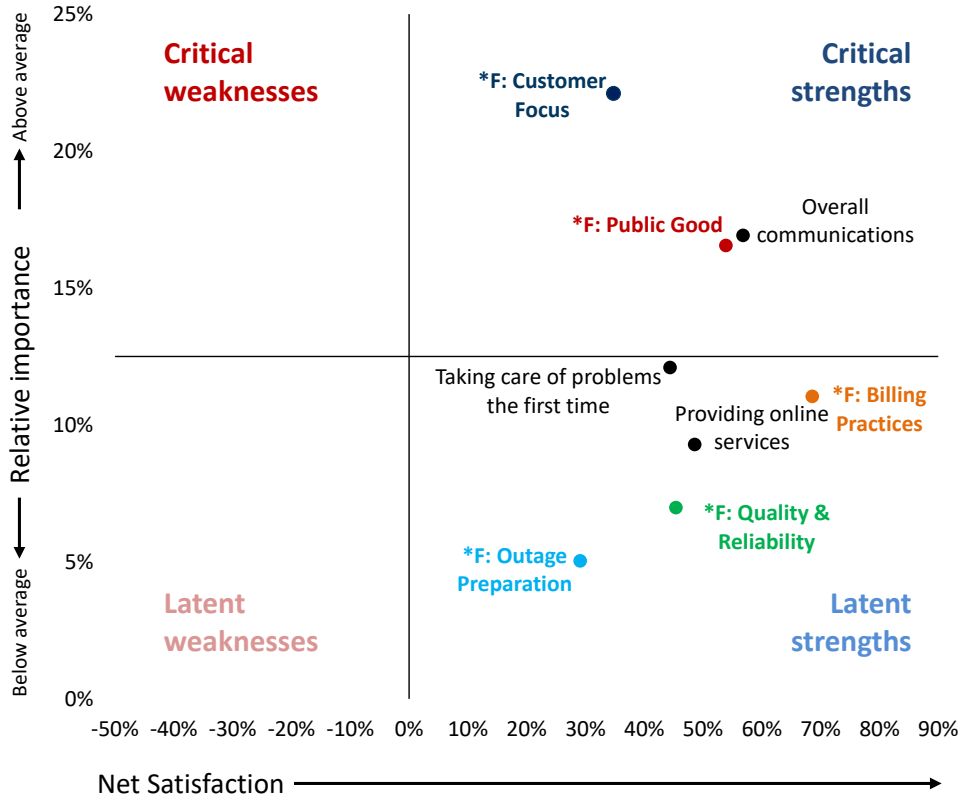
Improving the importance of a metric is best approached through *Priming*. This means moving it away from being a *latent strength* towards being a *critical strength*. Priming by raising the salience of a metric is usually executed through advertising and the media.

Increasing the levels of satisfaction with a brand is *Persuasion*. This means moving a metric from a weakness to a strength. Once people are persuaded that an organization is doing well on a particular metric, that opinion is likely to stick. However, persuasion campaigns are often long fought and expensive.

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Action Analysis: Overall, all key brand measures are viewed positively. Customer focus, Public good, and overall communications are critical strengths



*F – Denotes what has been identified as a "factor", as described on the right

Customer Focus
- Consulting with customers before making decisions
- Being transparent
- Caring about its customers
- Being trustworthy
- Being a good corporate citizen

Public Good
- Operating in an environmentally responsible manner
- Providing energy conservation and efficiency programs
- Protecting public safety

Quality & Reliability
- Providing reliable electricity service
- The amount of time it takes to restore power
- The quality of power delivered to you

Billing Practices
- Providing convenient options to pay my bill
- Providing convenient options to receive my bill
- Providing bills that are easy to read and understand
- Providing accurate bills

Outage Preparation
- Providing timely and accurate information re: outages
- Considering your needs when planning an outage

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System Familiarity

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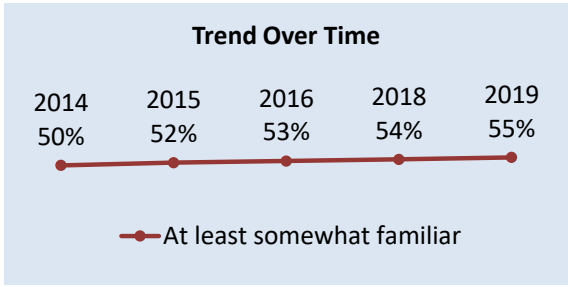
Familiarity with System – Regime 1: Majority (55%) are familiar with the system (outside of Alberta and Ontario); up five points since 2014

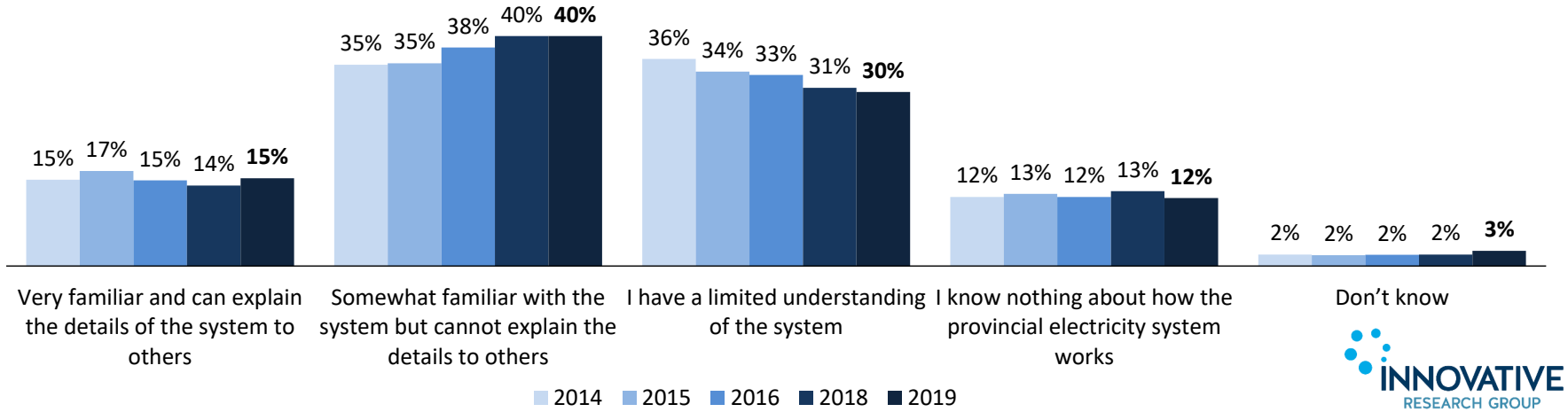
Q As you may know, [PROVINCE]'s electricity system has three key components: generation, transmission, and distribution:

- Power generation converts water from dams, coal, natural gas, wind and other resources into electricity;
- The transmission system use large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed; and
- The distribution system use smaller wires to carry electricity from substations to homes and businesses within local communities.

In general, how familiar are you with the way [PROVINCE]'s electricity system works?

[asked of all respondents outside of Alberta and Ontario; n=798]





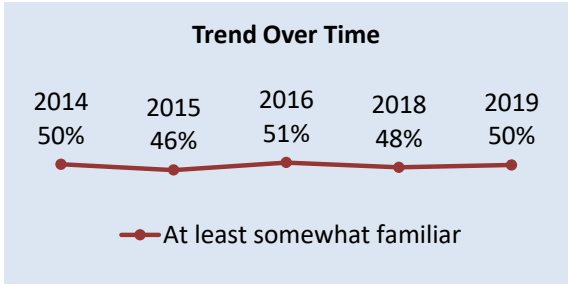
Familiarity with System – Regime 2: In Alberta and Ontario, half (50%) are familiar with the system; no change since 2014

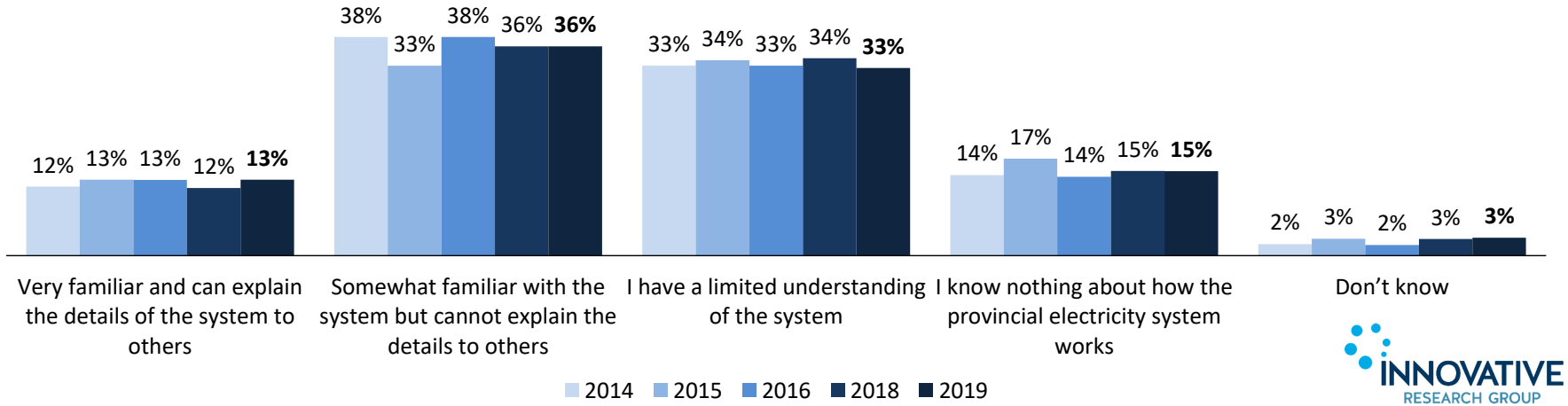
Q As you may know, [PROVINCE]'s electricity system has four key components: generation, transmission, distribution and retail market:

- Generating companies convert water from dams, coal, natural gas, wind and other resources into electricity;
- Transmission companies use large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed;
- Distribution companies use smaller wires to carry electricity to homes and businesses; and
- Electricity retailers buy electricity from generators and sell it directly to customers through contracts.

In general, how familiar are you with the way [PROVINCE]'s electricity system works?

[asked of all respondents in Alberta and Ontario; n=802]





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General Satisfaction

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Summary: *General Satisfaction*

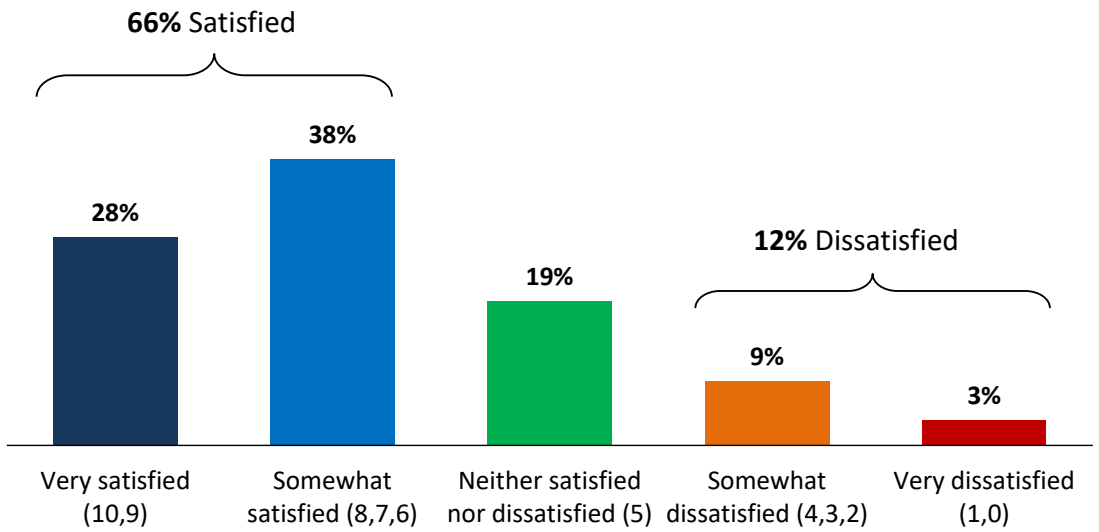
- General satisfaction is mostly steady year to year (66% vs. 65% in 2018), with an 11-point increase since the new scale was introduced in 2014 (55%).
- Respondents are net satisfied on all metrics, particularly when it comes to protecting public safety and providing online services. After strong gains on all performance metrics last year, net satisfaction has held mostly steady on eight metrics:
    - Protecting public safety (53%, no change);
    - Taking care of any problems the first time (44%, no change);
    - Operating in an environmentally responsible manner (42%, up one point);
    - Being a good corporate citizen through community initiatives (33%, down two points);
    - Caring about its customers (33%, up one point);
    - Providing online services (49%, down two points);
    - Providing energy conservation and efficiency programs (46%, down two points);
    - And being trustworthy (41%, down 1 point).
- On the remaining two metrics, those that ranked lowest in net satisfaction, there was a marginal gain on being transparent (25%, up three points) and a sizeable increase in satisfaction on consulting with customers (14%, up seven points).

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General Satisfaction: 2-in-3 (66%) are satisfied with their electricity company; highest in Quebec (73%) and among older respondents (72%)

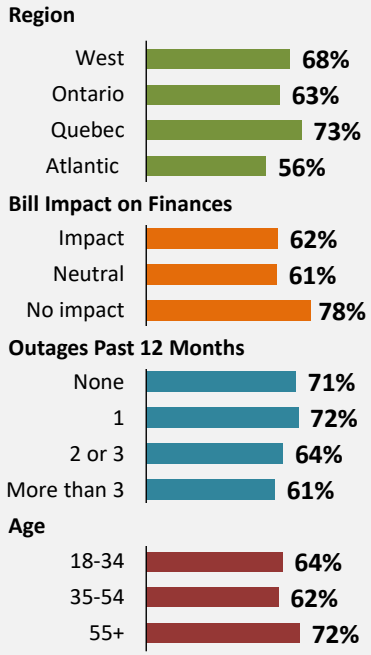
Q The following questions are about the local distribution system, the part of the system that brings electricity from nearby substations to your home and local businesses. In general, how satisfied are you with [COMPANY]? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; n=1,600]



Segmentation

*Those who are **"satisfied"** with their electricity company*

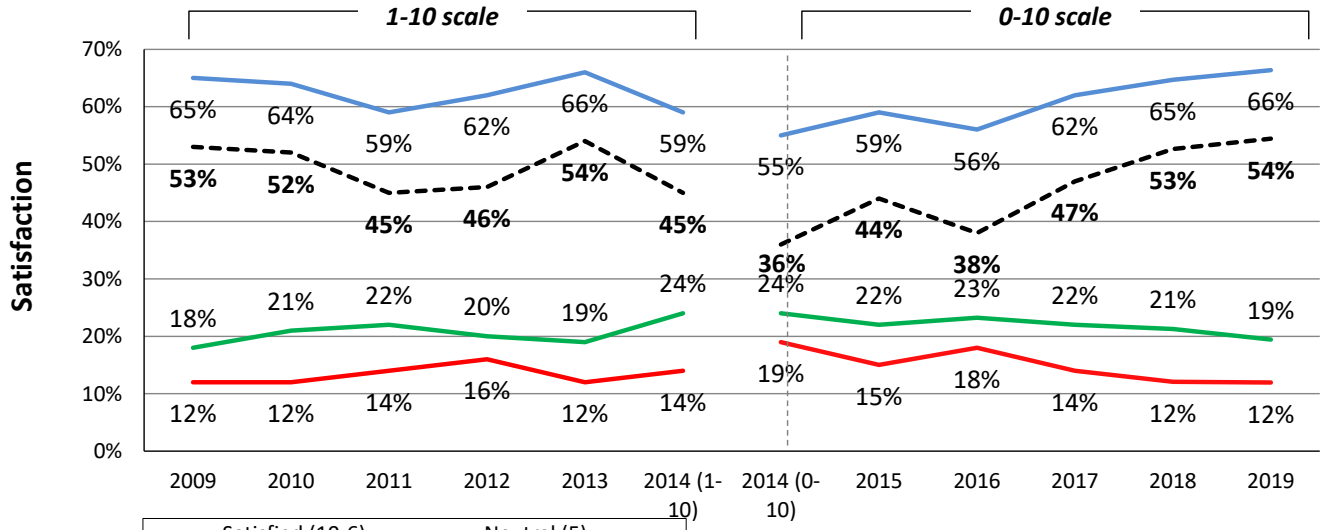


NOTE: 'Don't know' (2%) not shown.

General Satisfaction: Since the new (0-10) scale was introduced in 2014, net satisfaction has improved nearly 20 points

Q The following questions are about the local distribution system, the part of the system that brings electricity from nearby substations to your home and local businesses. In general, how satisfied are you with [COMPANY]? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

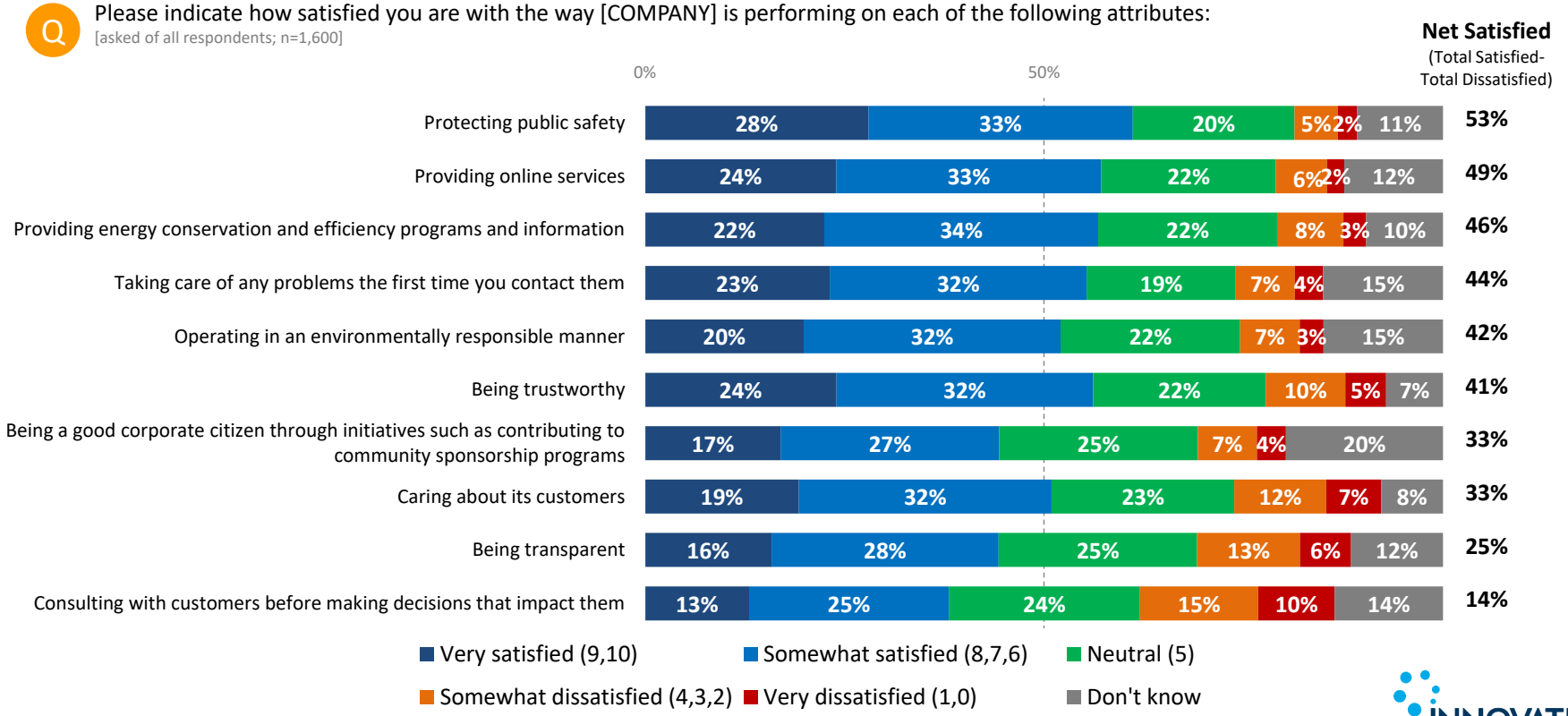
[asked of all respondents; n=1,600]



* Prior to the 2014 survey, this question was asked as "*In general, how satisfied are you with your **electricity company** on a scale of 1 to 10, where 1 means not at all satisfied and 10 means very satisfied?*" For tracking purposes, we assume that "**electricity company**" means "**company that provides distribution services**". In the 2014 survey two scales were used to rate satisfaction, as we transitioned from a 1-10 to a 0-10 scale.

Performance Metrics: Respondents most satisfied with their distributors' on protecting public safety, online services, and conservation/efficiency information

Q Please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes:
[asked of all respondents; n=1,600]

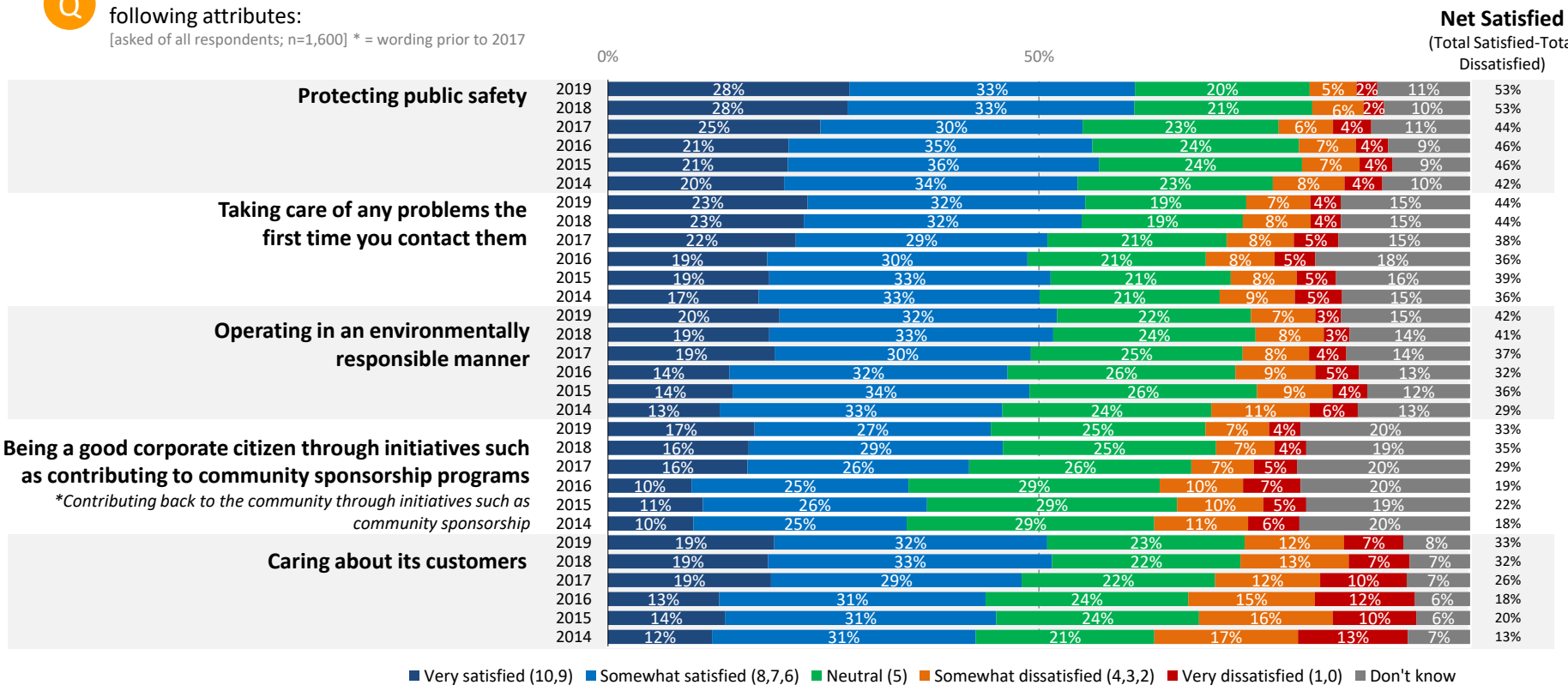


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Performance Metrics (Tracking): Net satisfaction on performance metrics tracked since 2014 are consistent year-to-year

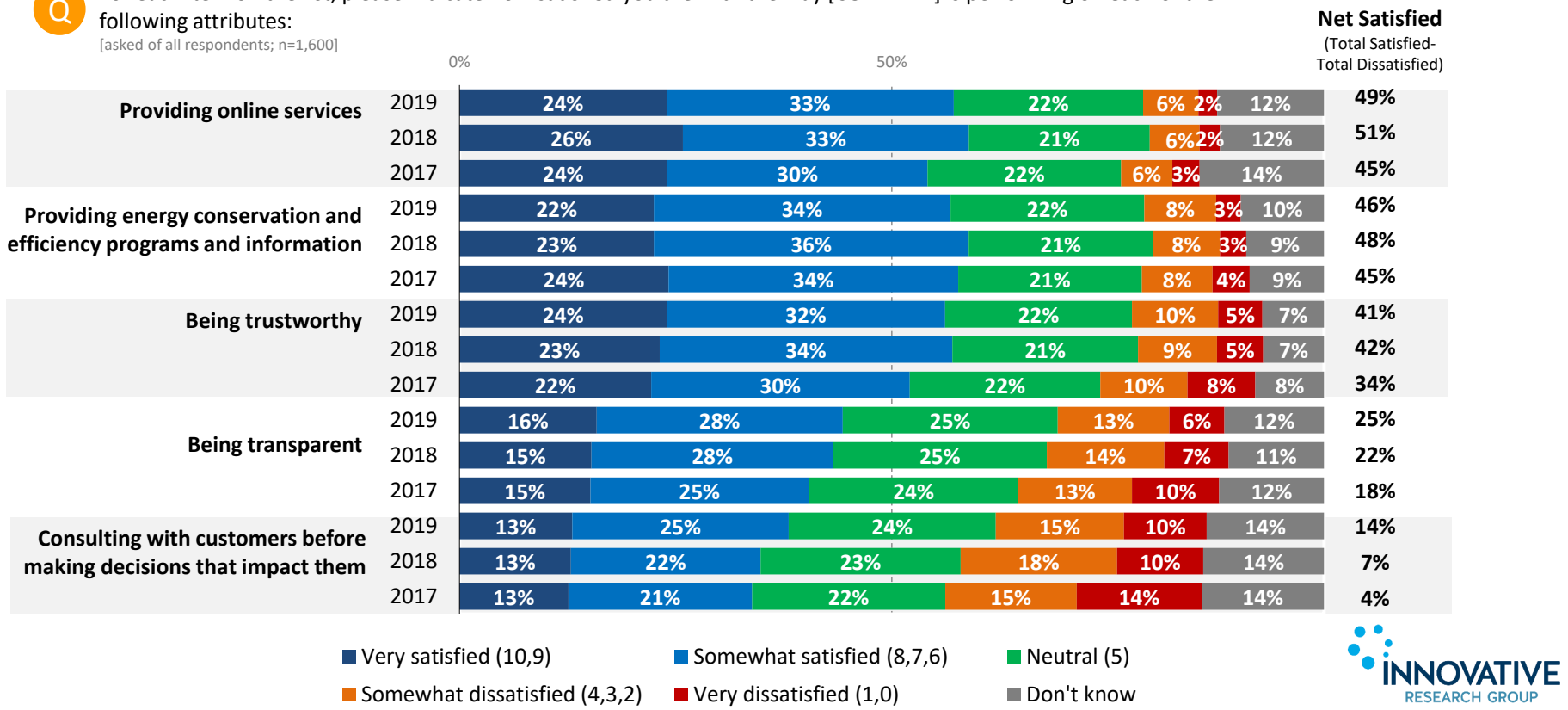
Q For each item on the list, please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes:

[asked of all respondents; n=1,600] * = wording prior to 2017



Performance Metrics (Tracking): No major changes on most "new" metrics; 7 point net increase since last year on 'consulting with customers before making decisions'

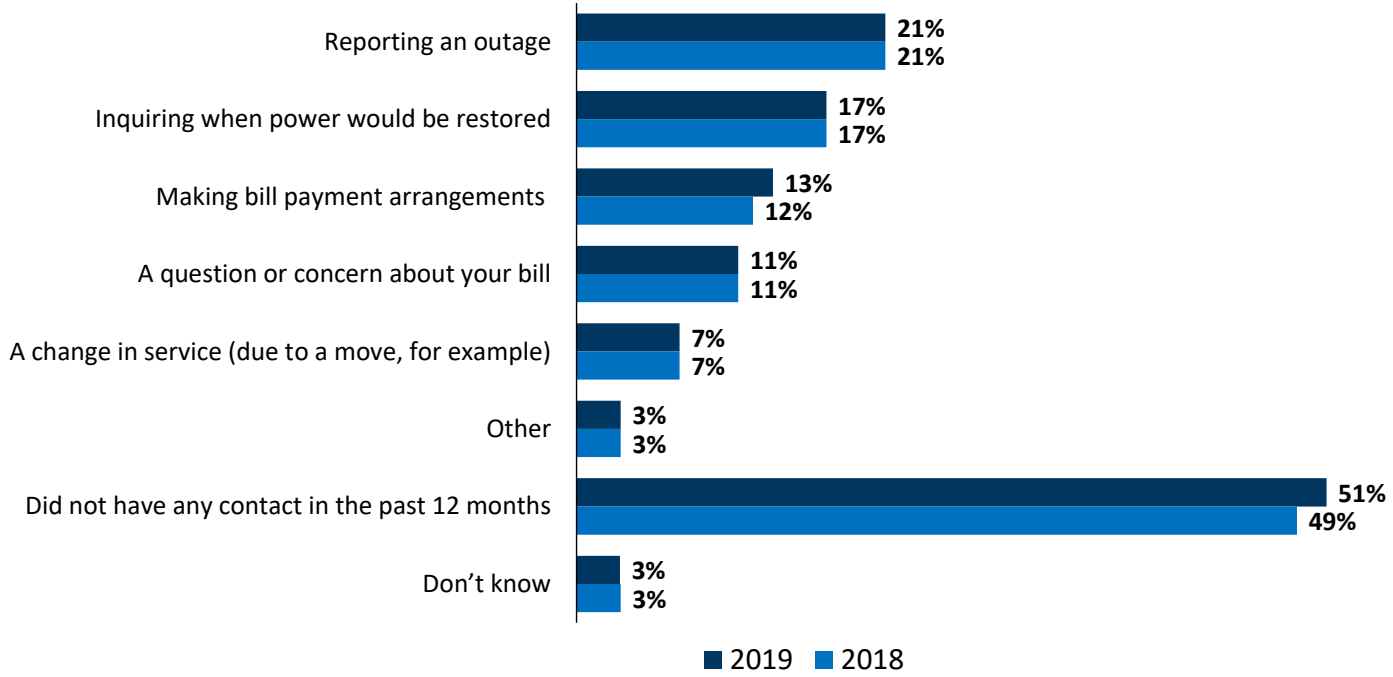
Q For each item on the list, please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes:
[asked of all respondents; n=1,600]



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Distributor Contact: As in 2018, a majority (51%) did not have any contact in past year, 1-in-5 (21%) reported an outage

Q In the past 12 months, which (if any) of the following issues have you contacted [COMPANY] about? *Select all that apply.*
[asked of all respondents; n=1,600]



NOTES: Chart total is greater than 100% as multiple mentions were accepted

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Reliability & Power Quality

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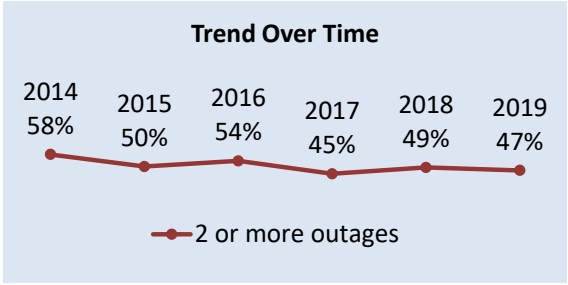
Summary: *Reliability & Power Quality*

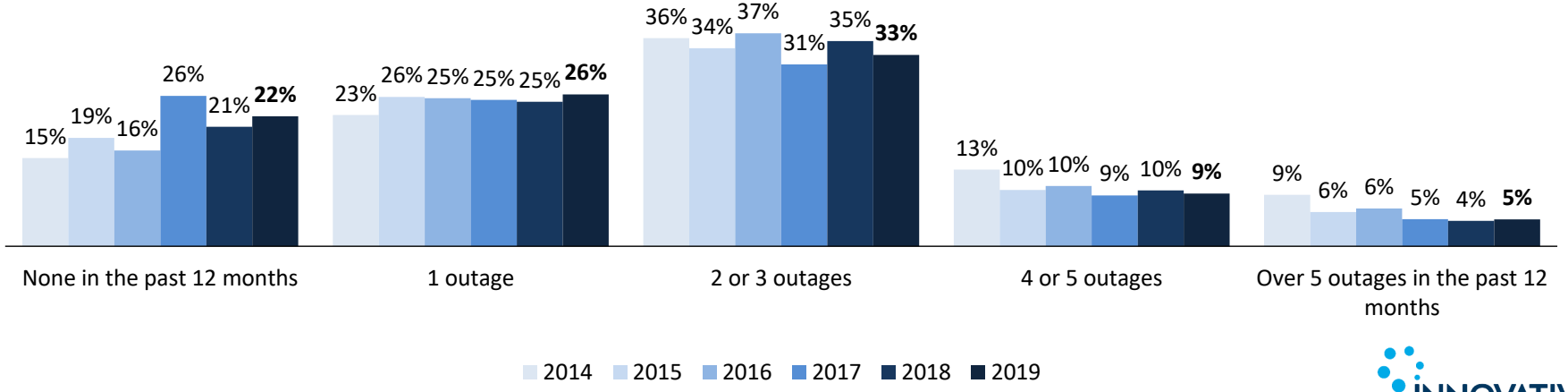
- Nearly half (47%) have experienced two or more outages in 2019, a marginal decrease of two points since last year.
- Of the five reliability and quality metrics, with no major shifts year-to-year, net satisfaction is strong when it comes to:
    - Quality of power (60%);
    - Reliable service (59%);
    - Time to restore power (54%);
    - And providing timely and accurate information (39%).
- This follows a strong 2018 year where improvements were made across all reliability and power quality metrics.
- The lowest performing metric, ‘considering your needs when planning an outage’ (30%), also has not moved since 2018.

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Power Outages: Nearly half (47%) have experienced two or more outages in the past year; down 11 points since 2014

Q In the past 12 months, how many power outages do you recall experiencing at home?
[asked of all respondents; n=1,600]

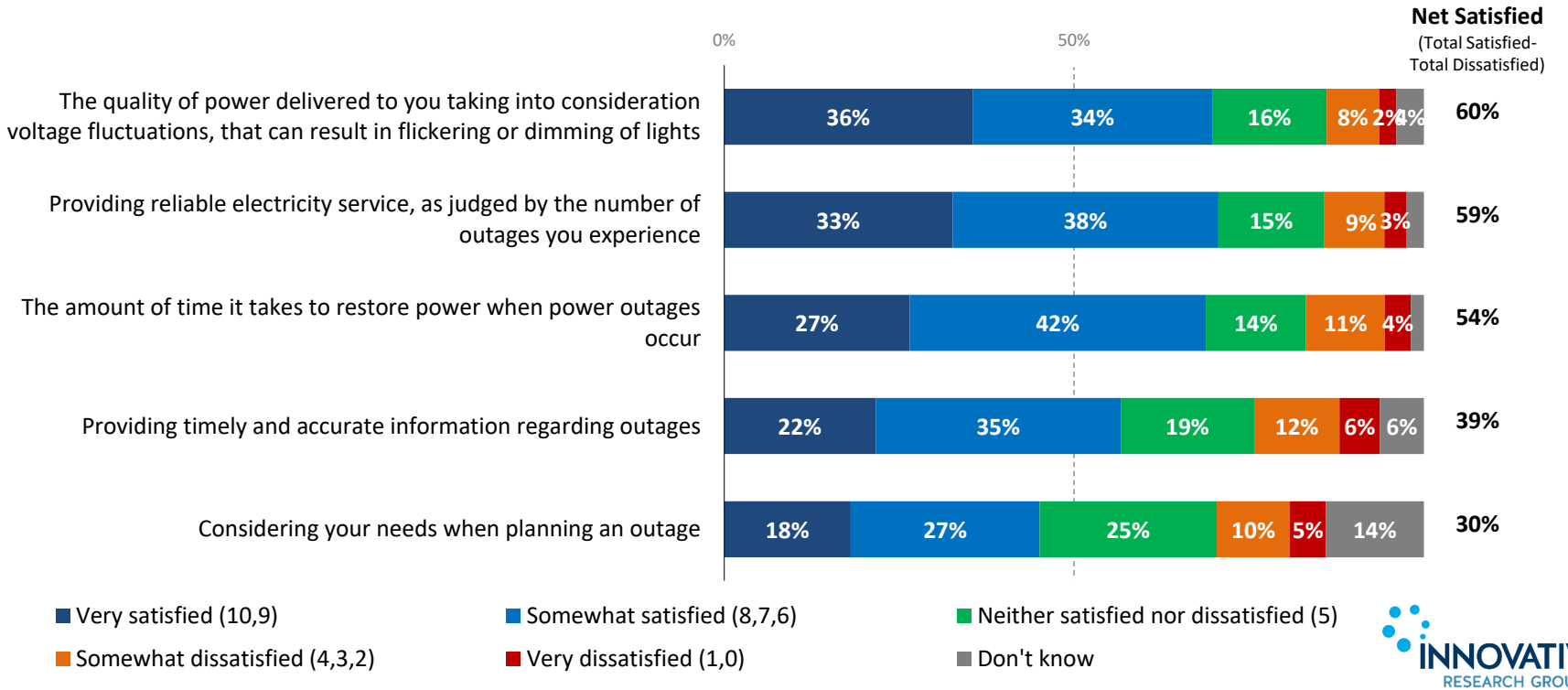




NOTE: 'Don't know' (5% in 2019) not shown.

Reliability & Quality Metrics: Strong majority are satisfied with the quality of power delivered, the reliability of service, and the amount of time to restore power

Q Please indicate how satisfied you are with the way that [COMPANY] is performing on each of the following attributes related to your electrical service:
Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=1,600]

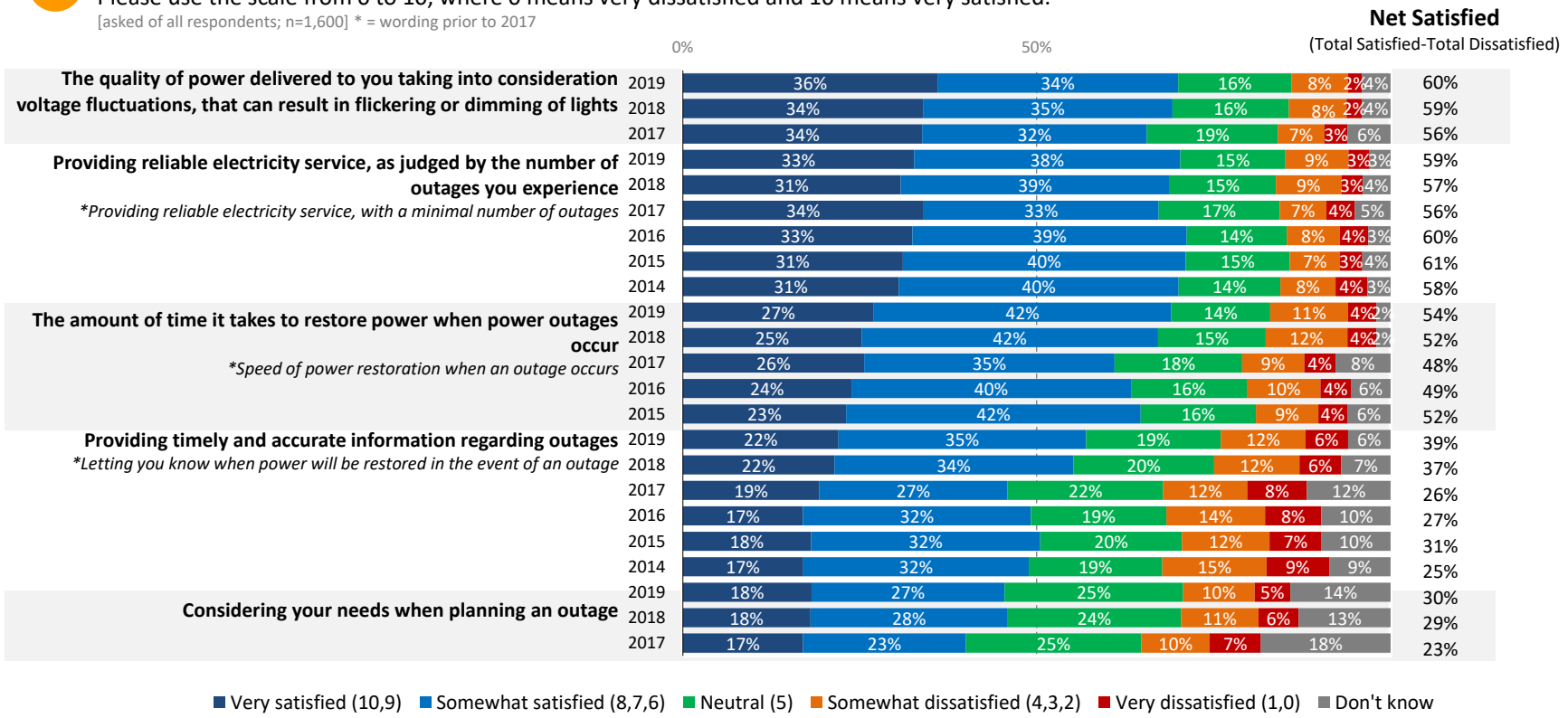


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Reliability & Quality Metrics (Tracking): No major shifts on reliability metrics year-to-year; most still feel their company provides quality & reliability

Q Please indicate how satisfied you are with the way that [COMPANY] is performing on each of the following attributes related to your electrical service: Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents; n=1,600] * = wording prior to 2017



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Planned Outages



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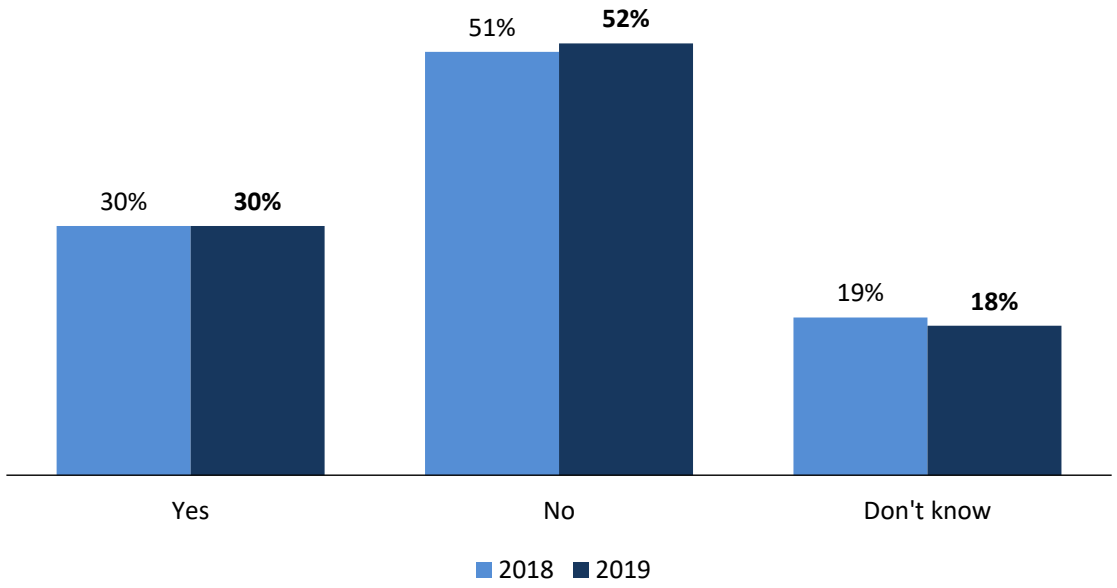
Summary: *Planned Outages*

- Three-in-ten (30%) recall being impacted by a planned outage in the past two years, with no change on this measure since this series of questions was introduced last year.
    - Those in Quebec (36%) and Atlantic Canada (33%), those most financially impacted (37%), and those experiencing frequent outages (3+: 48%) are most likely to recall being impacted by planned outages.
- 3-in-4 (73%) report that their electricity company reached out to them proactively before the planned outage, with no significant shift since 2018 (75%).
    - Older respondents (77%), those who did not experience any outages in the past 12 months (84%), and those who are not impacted by their electricity bill (79%) were the most likely to report early contact regarding planned outages.
- Of those who were contacted, more than 8-in-10 (82%, up two points since 2018) feel satisfied with the planned outage communication from their electricity company.

Planned Outages: 1-in-3 (30%) have been impacted by planned outages; those with repeated outages and who have financial struggles are most impacted

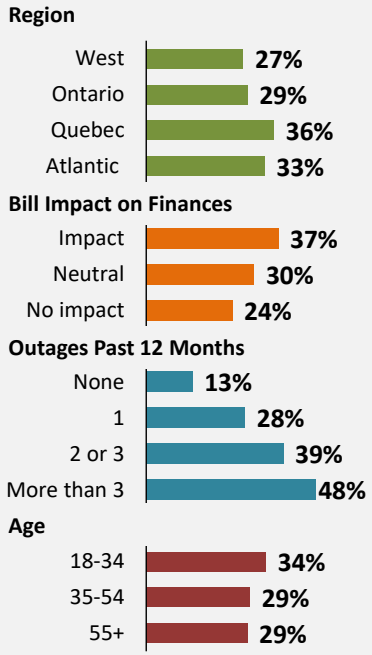
Q From time to time, your local utility has to turn off the power to repair or replace equipment. This work is generally planned in advance and these outages are called planned outages. Over the past 2 years, have you been impacted by any planned outages?

[asked of all respondents; n=1,600]



Segmentation

*Those who say **"yes"***

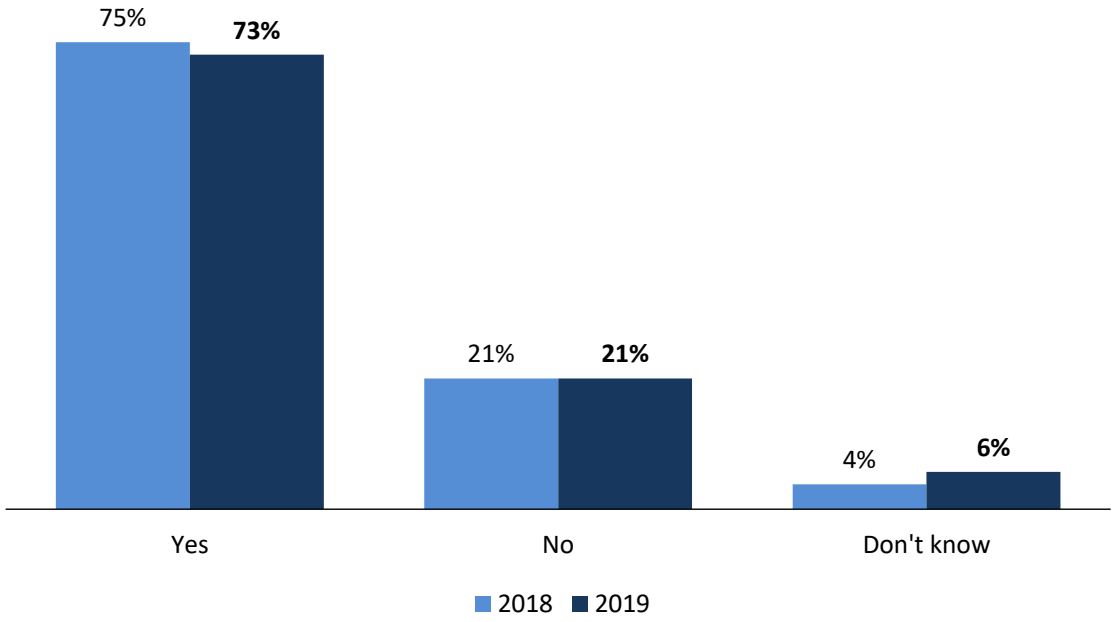


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Proactive Communication: 3-in-4 (73%) report that their electricity company reached out to them proactively about their most recent planned outage

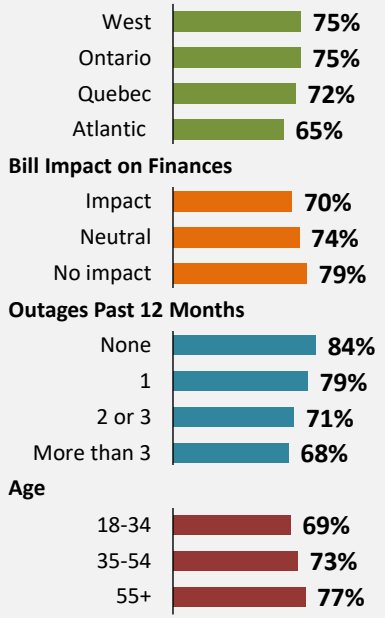
Q Did [COMPANY] proactively communicate with you about the most recent planned power outage that you experienced?

[asked of respondents who have been impacted by planned outages within the past 2 years; n=484]



Segmentation

*Those who say **"yes"***

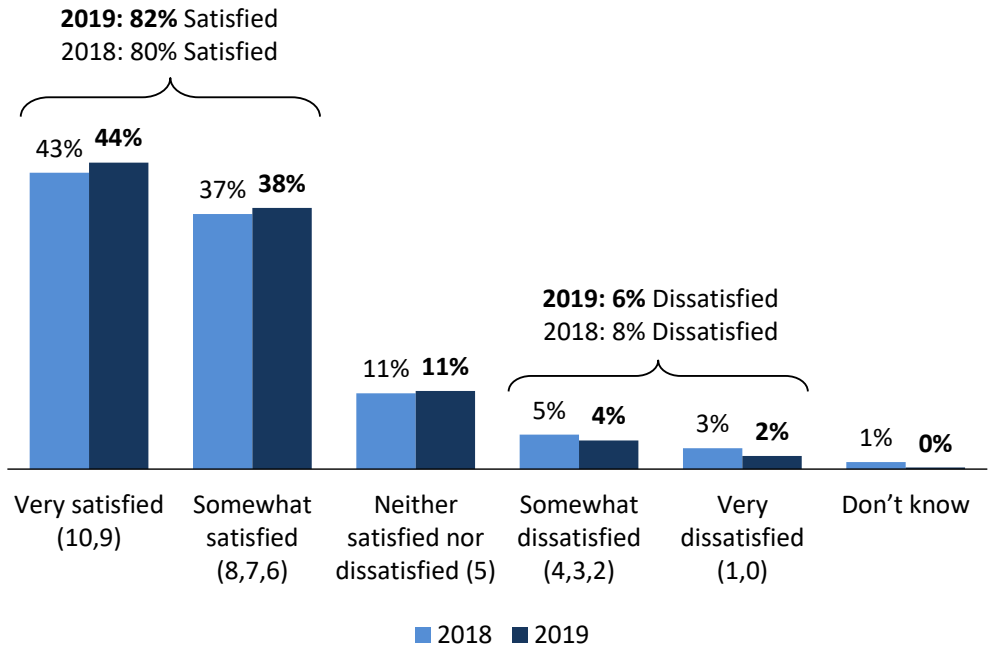


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Satisfaction with Planned Outage Communication: More than 8-in-10 (82%) are satisfied with planned outage communication; just 6% say they are dissatisfied

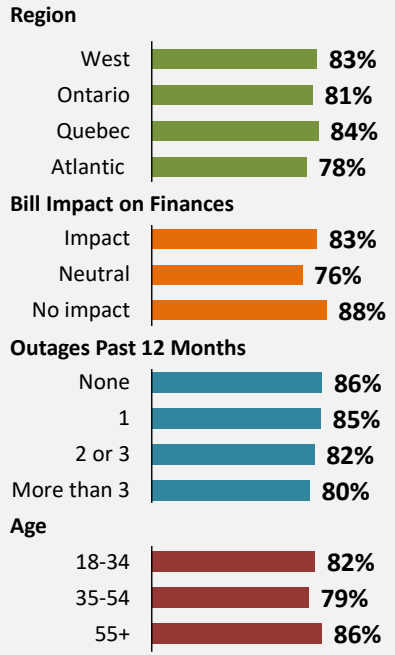
Q How satisfied are you with the way the company communicated with you about that planned outage? *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of respondents who can recall being contacted by distributor during the most recent planned outage; n=355]



Segmentation

*Those who are **"satisfied"** with outage communication*



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Billing & Payment



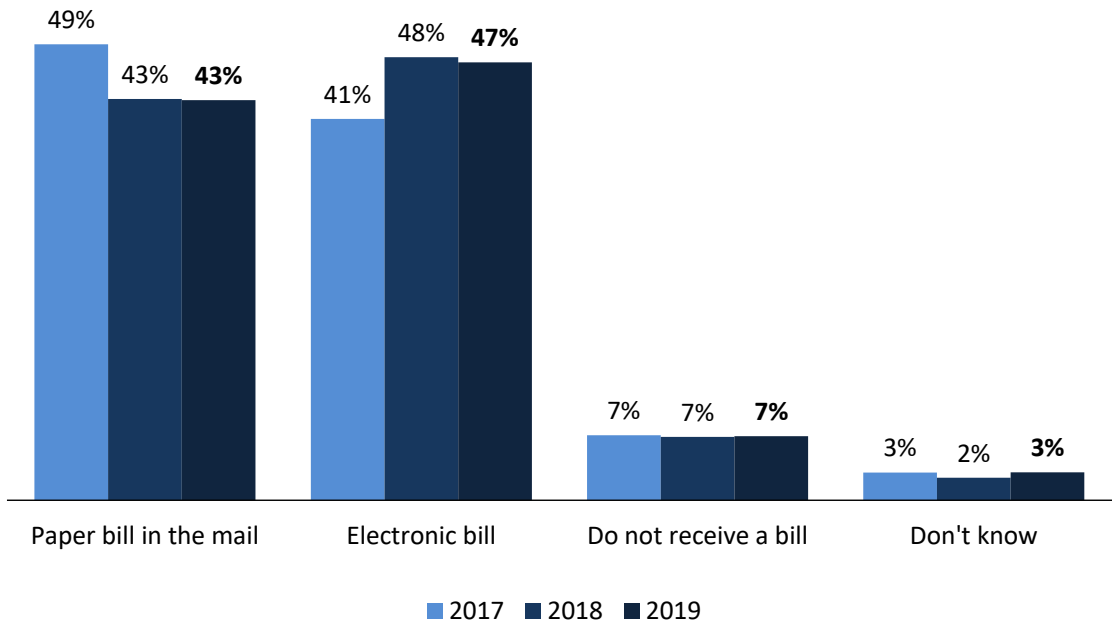
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Summary: *Billing and Payment*

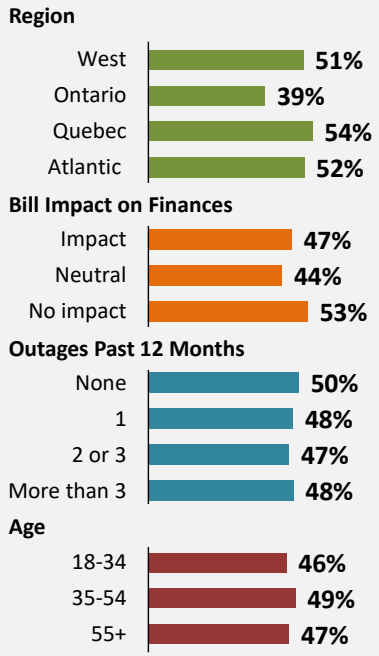
- A plurality (47%) report they receive their bill electronically, while 43% say they receive a paper bill in the mail. This is unchanged since 2018, a year when e-billing grew eight points and shifted the balance from paper to online.
- E-billing is most common in Quebec (54%) and among those who are not financially impacted by their electricity bills (53%).
- A strong majority are net satisfied with all four billing and payment metrics, with no major changes since 2018:
    - Convenient options to receive bills (74%, no change);
    - Convenient options to pay bills (71%, no change);
    - Providing accurate bills (68%, down one point);
    - And providing bills that are easy to read and understand (67%, down two points).

Format of Electricity Bill: In a reversal since 2017, now a plurality receive their bill online (47%) versus mail (43%); Ontario lags behind other regions on e-bills

Q In what format do you receive your electricity bill?
[asked of all respondents; n=1,600]



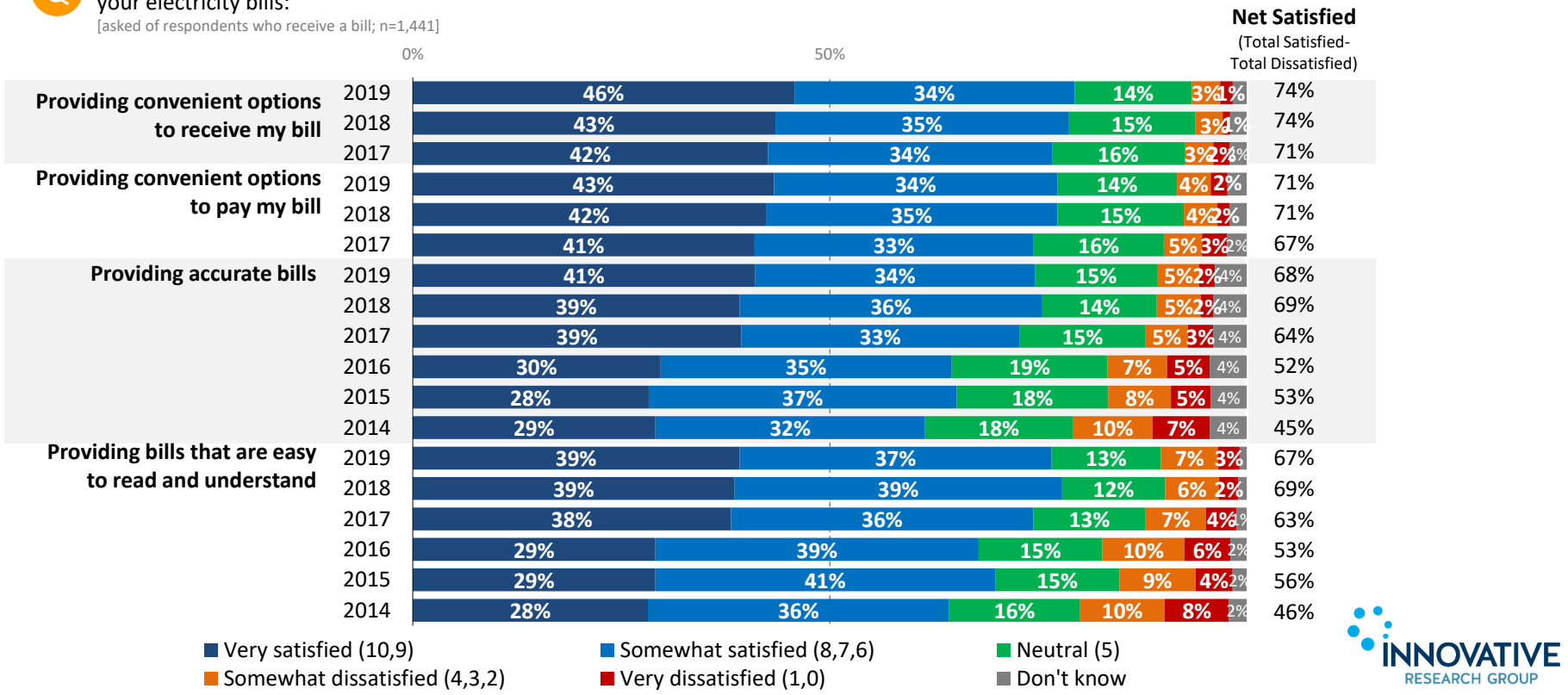
Segmentation
*Those who get an **electronic bill***



REMINDER: These results are from an online survey. As such, the proportion of customers who receive a paper bill may be under-represented

Billing & Payment Metrics (Tracking): Majority are satisfied with convenience, accuracy, and ease of understanding; no significant changes since 2018

Q For each item on the list, please indicate how satisfied you are with the way [COMPANY] is performing on each of the following attributes related to your electricity bills:
[asked of respondents who receive a bill; n=1,441]



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Communications



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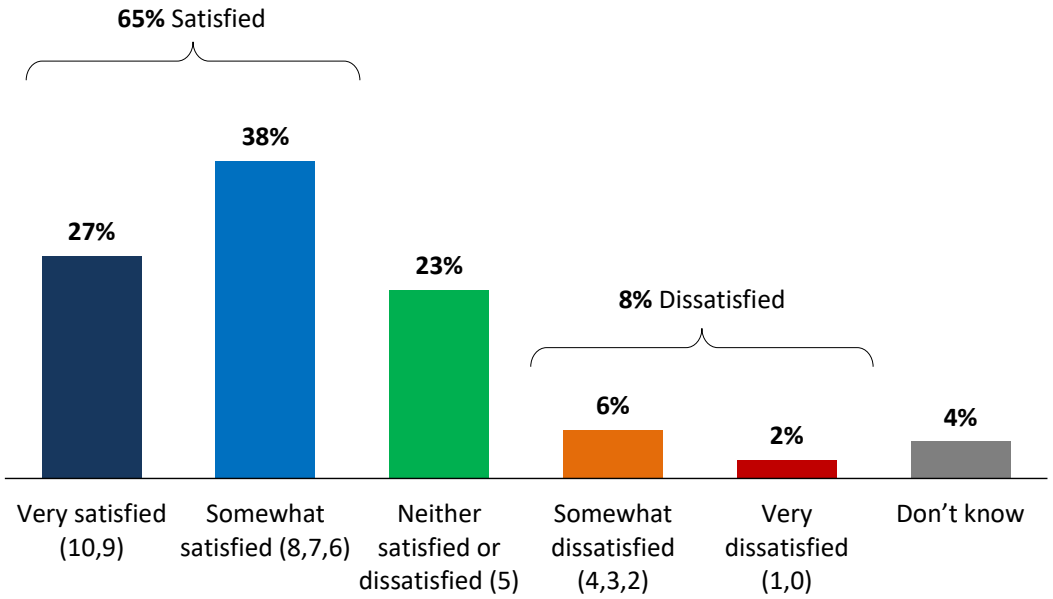
Summary: *Communications*

- 2-in-3 (65%) respondents are satisfied with the communication from their distributor, stable year-to-year. After double-digit gains from 2017 (39%) to 2018 (56%) net satisfaction is steady at 57%.
- On specific forms of communication, websites are the only form of communication where a majority (52%) of customers are satisfied, with bill inserts (48% among those who receive a bill) and outage notifications (48%) close behind.
    - For all seven measures of specific communications, there have been no major shifts year-to-year on net satisfaction.
- Respondents are three times more likely to say the customer experience with their electricity company is better (29%) than worse (9%), compared to other types of providers, such as a telephone and cable companies.
    - Distributor customer experience (better: 29%) has improved by 14 points since 2016 (15%), with no shift since last year (2018: 29%).

Overall Communications: 2-in-3 (65%) are satisfied with overall communications from their distributor; highest satisfaction for those with no bill impact

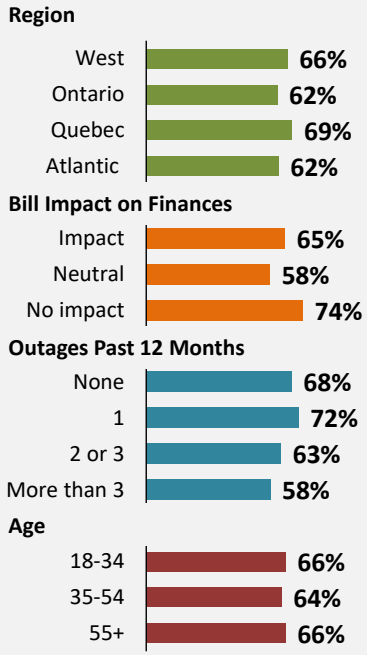
Q Please indicate how satisfied you are with overall communications from [COMPANY]. *Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.*

[asked of all respondents; n=1,600]



Segmentation

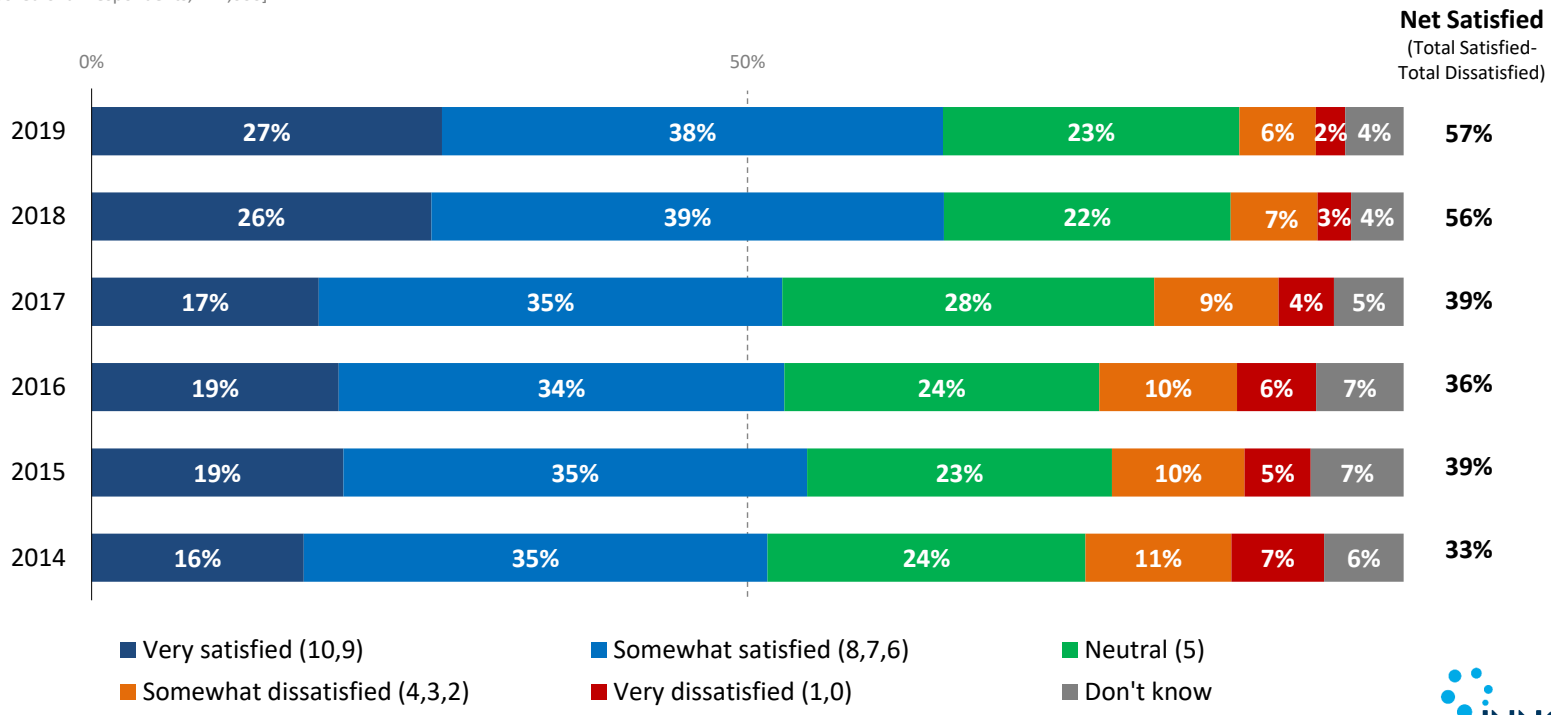
*Those who are **"satisfied"** with overall communications*



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Overall Communications (Tracking): Two-in-three (65%) are satisfied with overall communications; steady year-to-year

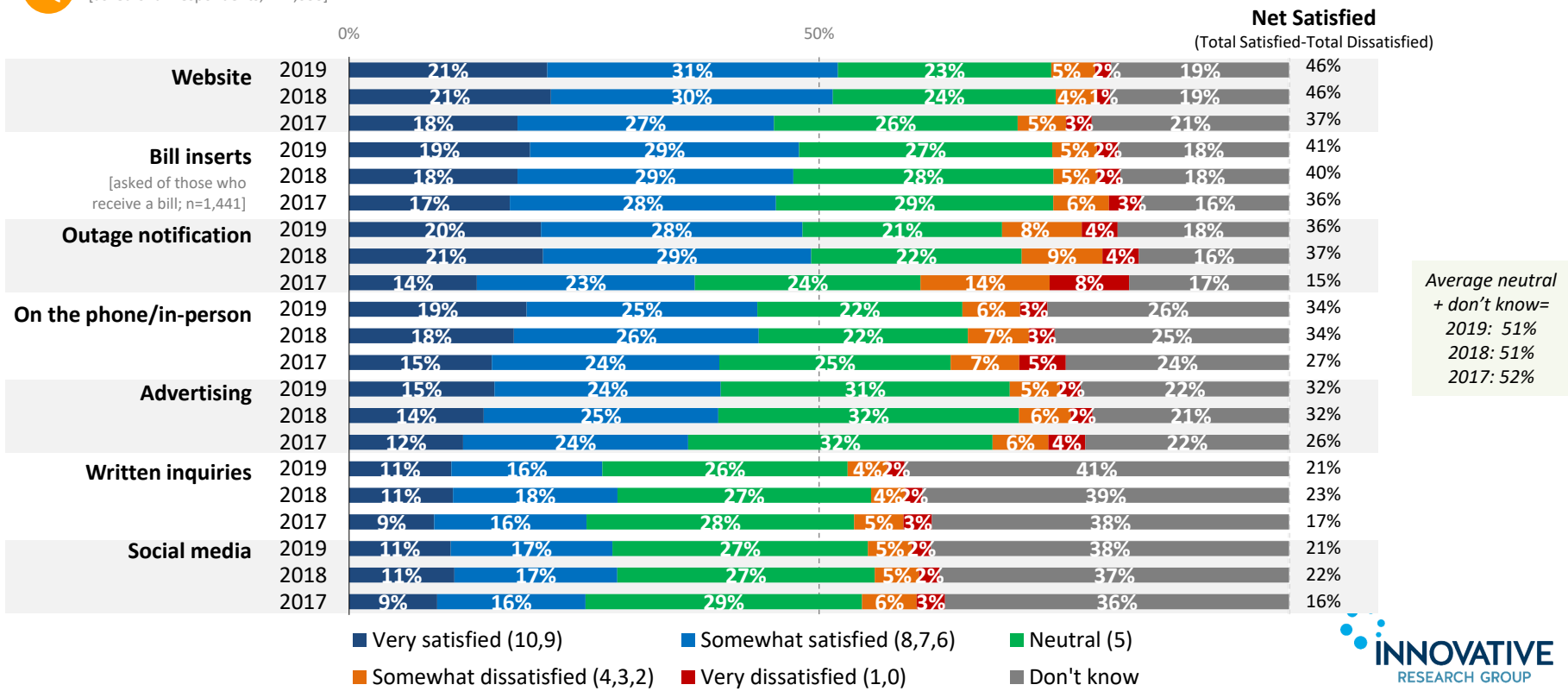
Q Please indicate how satisfied you are with overall communications from [COMPANY].
Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=1,600]



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Forms of Communication (Tracking): Majority are satisfied with website communication; lowest satisfaction on written inquiries and social media

Q Please indicate how satisfied you are with the way [COMPANY] is performing on each of the following forms of communication:
[asked of all respondents; n=1,600]

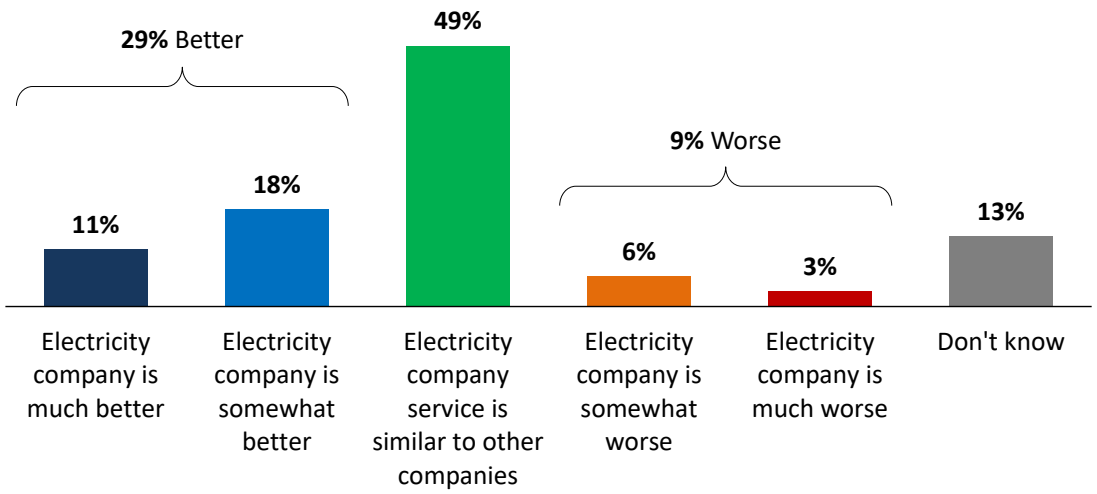


Average neutral + don't know=
2019: 51%
2018: 51%
2017: 52%

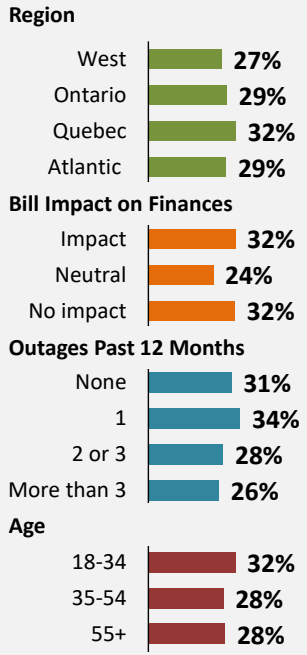
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Comparing Customer Experience: 3-in-10 (29%) feel their distributor provides a better customer experience than other service providers; half (49%) say 'similar'

Q How does your customer experience with [COMPANY] compare to that of other service providers you use (telephone, cable, TV/internet, natural gas, your bank)?
[asked of all respondents; n=1,600]



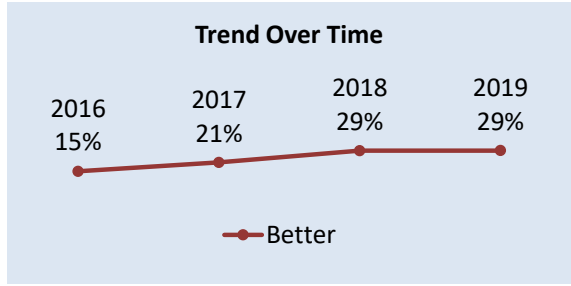
Segmentation
*Those who say **"better"***

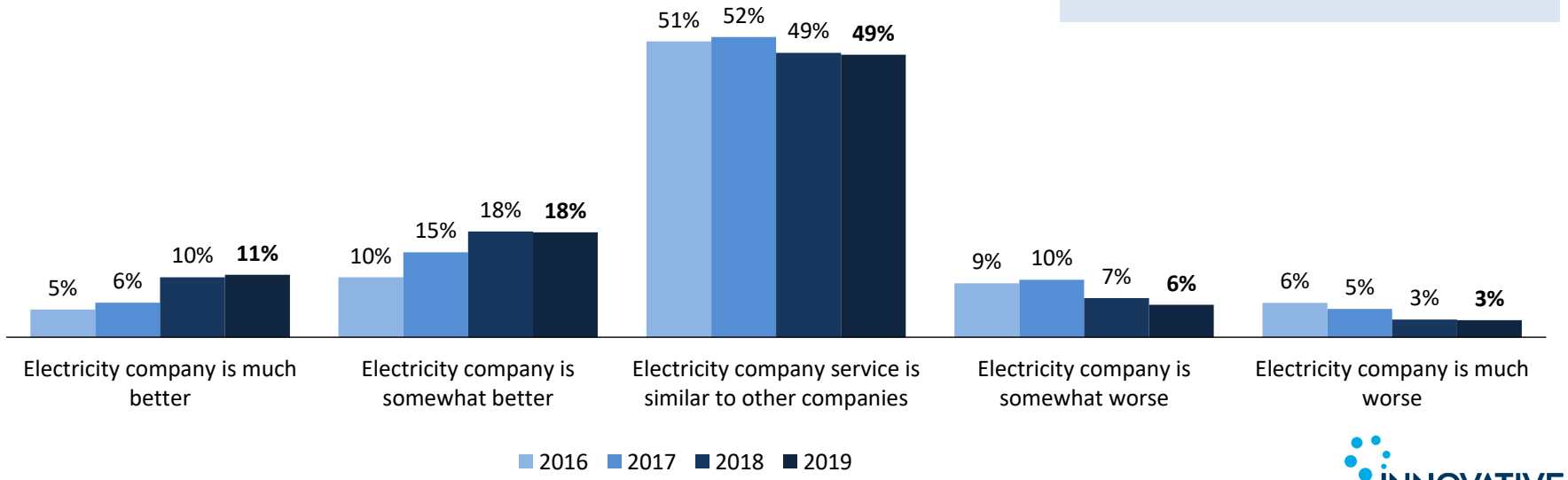


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Comparing Customer Experience (Tracking): Distributor customer experience has improved double digits since 2016, but no change year-to-year

Q How does your customer experience with [COMPANY] compare to that of other service providers you use (telephone, cable, TV/internet, natural gas, your bank)?
[asked of all respondents; n=1,600]





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Net Promoter Score (NPS)

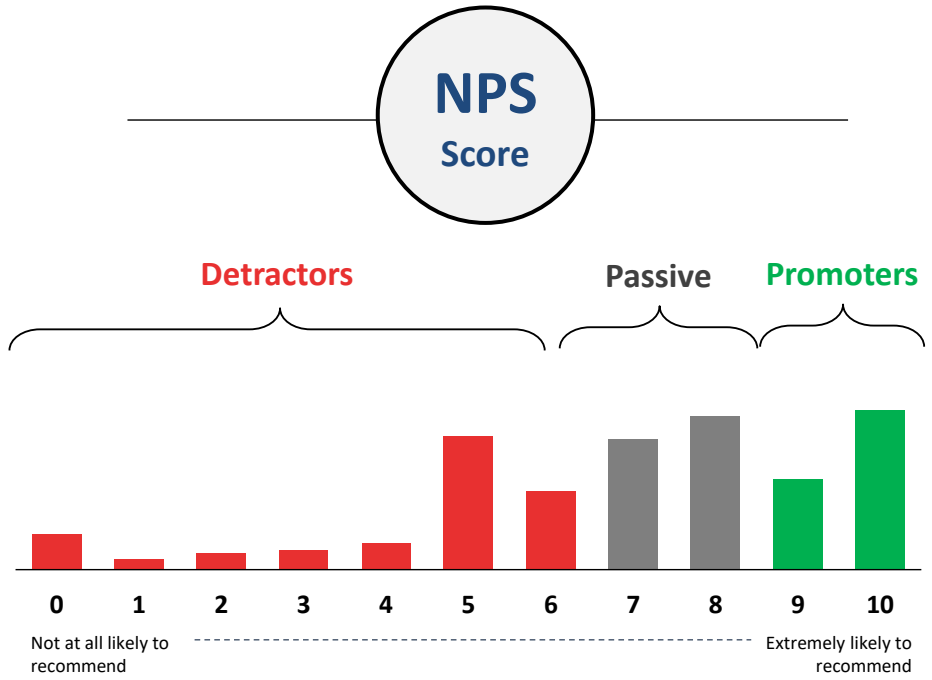
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Endorsement: *Calculating "Net Promoter Scores" (NPS)*

A *Net Promoter Score* (NPS) is based on the fundamental perspective that every organization's clientele can be divided into three categories: Promoters, Passives, and Detractors.

By asking one simple question — *If you had a choice between several possible providers of electricity, how likely would you be to recommend [COMPANY] to your friends, family and others as the preferred electricity distributor?* — you can track these groups and get a clear measure of the customer's experience with your organization. Customers respond on a 0-to-10 point rating scale and are categorized as follows:

- **Promoters** (score 9-10) are loyal enthusiasts who would refer others to your organization if they had that option. These customers are an important source of strength for the brand. An estimated 80-90% of positive word-of-mouth come from *Promoters*.
- **Passives** (score 7-8) are satisfied but unenthusiastic customers who would be vulnerable to offerings from competitors, given the option of a choice.
- **Detractors** (score 0-6) are unhappy customers who can damage your brand and impede growth through negative word-of-mouth. Detractors are responsible for an estimated 80-90% of all the negative word-of-mouth. Furthermore, this group of customers complain more frequently, thereby consuming service resources at a much higher rate than other customers.



NOTE: 'Don't know' removed from calculation

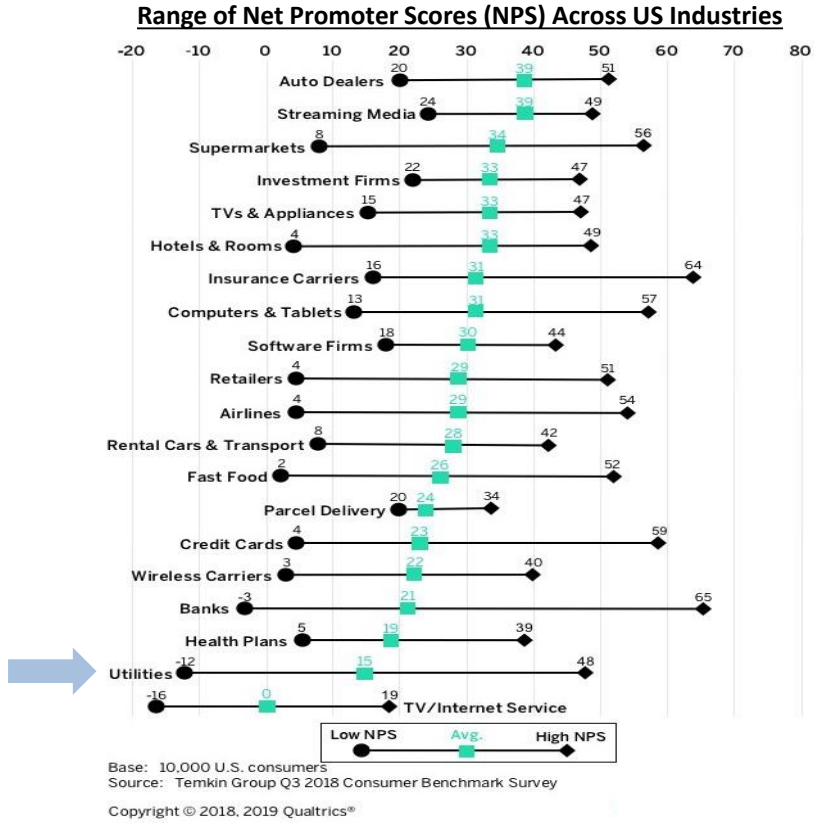
Comparing NPS Across Industries (US Data)

The Net Promoter Score (NPS) was created in the 90's to evaluate the growth potential of companies that operate in competitive markets. Typically, organizations with scores higher than their competitors tend to grow faster.

Because almost all CEA members operate primarily in regulated monopoly markets, NPS should only be considered a "rough proxy" for customer satisfaction.

To put NPS in context, this chart shows the average NPS for several industries in the U.S. This data was taken from a 2018 study surveying 5,000 U.S. consumers evaluating multiple companies that compete in various industries.

As the chart shows, it is not uncommon for organizations in various sectors to have a negative NPS, and utilities tend to have lower NPSs than other industries.

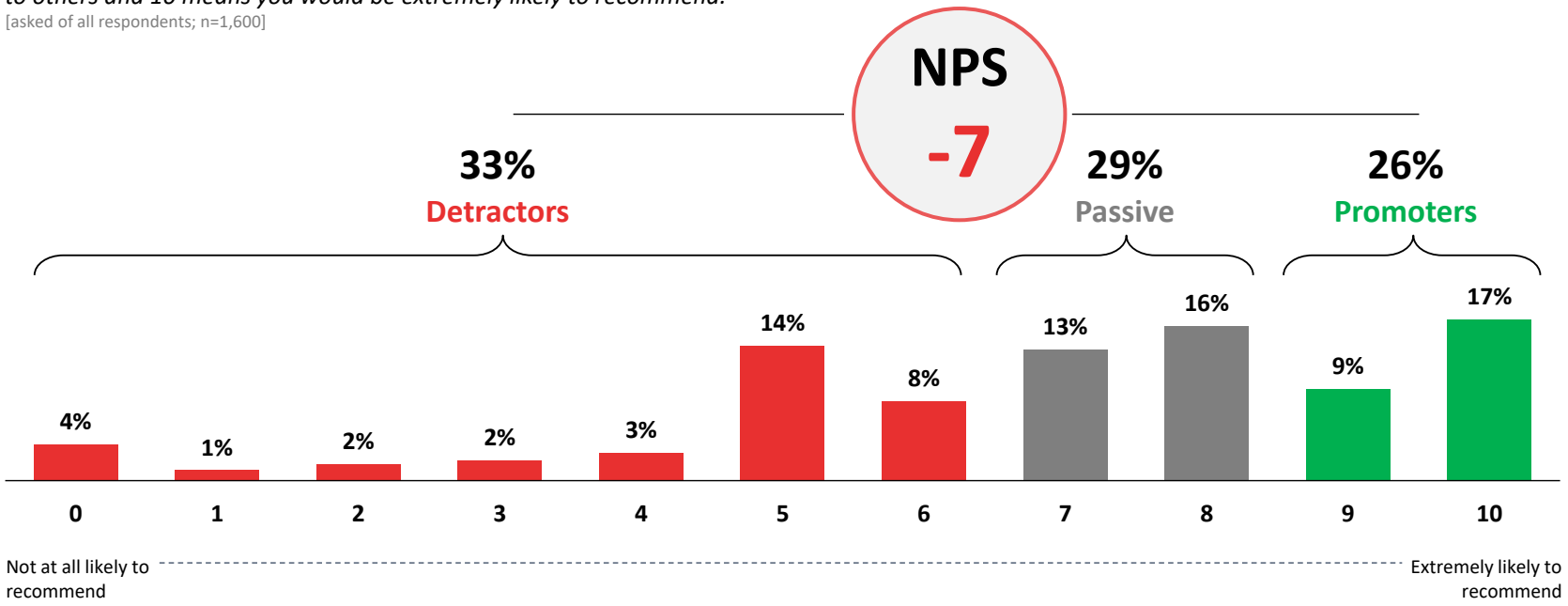


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Net Promoter Score: 1-in-4 (26%) likely to personally recommend their electricity company

Q If you had a choice between several possible providers of electricity, how likely would you be to recommend [COMPANY] to your friends, family and others as the preferred electricity distributor? *Please use a scale from 0 to 10, where 0 means you would not be at all likely to recommend [COMPANY] to others and 10 means you would be extremely likely to recommend.*

[asked of all respondents; n=1,600]

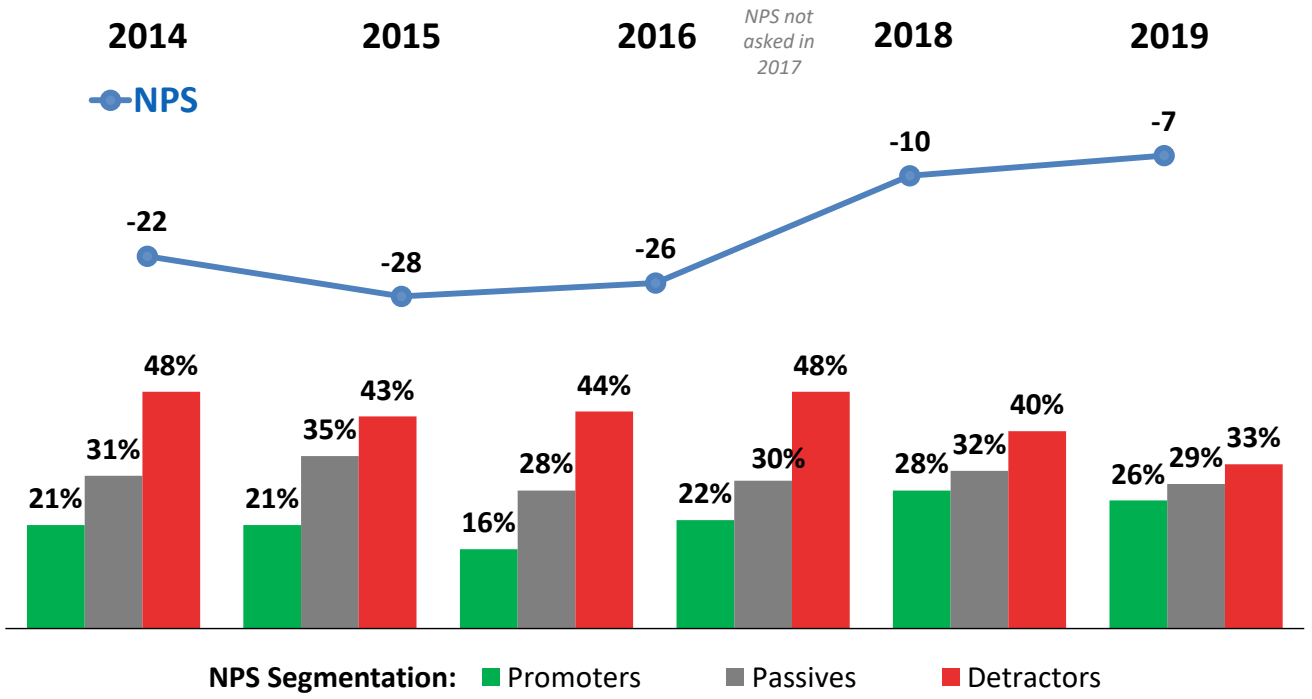


NOTE: 'Don't know' (11%) removed from calculation

NPS Tracking: NPS score has improved to highest levels since tracking began, biggest gains in Ontario (+12)

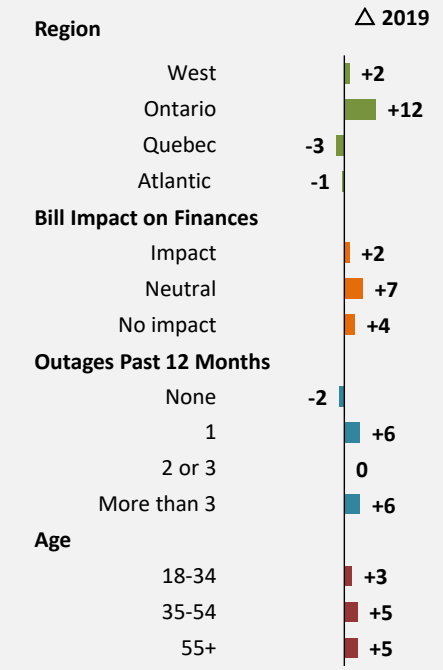
Q If you had a choice between several possible providers of electricity, how likely would you be to recommend [DISTRIBUTION COMPANY] to your friends, family, and others as the preferred electricity distributor? *Please use a scale from 0 to 10, where 0 means you would not be at all likely to recommend [COMPANY] to others and 10 means you would be extremely likely to recommend.*

[asked of all respondents; n=1,600]



2019 vs 2018 Segmentation

NPS Scores



NOTE: 'Don't know' (11% in 2019) removed from calculation

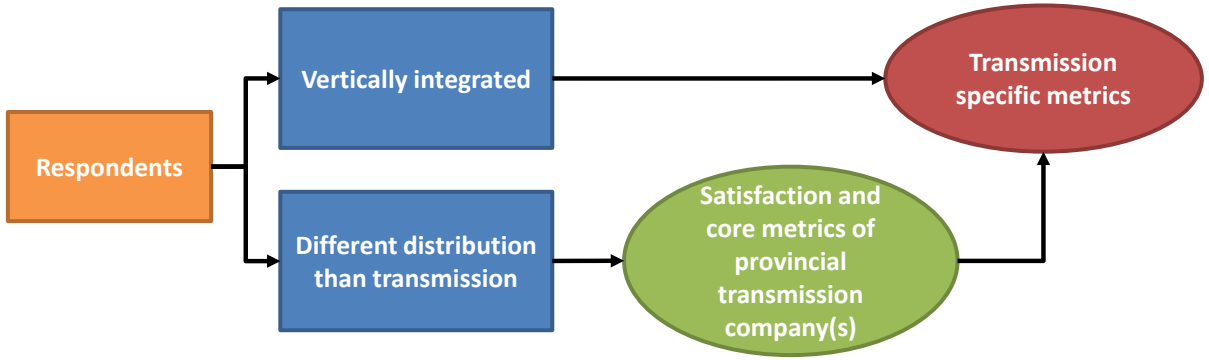
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Transmission

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Transmission: *Which respondents answered which questions?*

- The satisfaction and metric ranking questions asked in this section are related to a respondent's provincial transmission company, either independent transmission companies or the transmission operations of vertically integrated companies.
- In most cases, for vertically integrated companies, respondents were only asked to rate the company on its transmission specific metrics in this section (as core metric questions were asked earlier, in the distribution section).
- Respondents who have different transmission and distribution companies were asked all of the questions in this section.



For most vertically integrated companies – where the customer's distributor is also responsible for transmission – the respondent was shown the following preamble before rating the two core transmission metrics:

> *"The following questions are about the transmission system, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed."*

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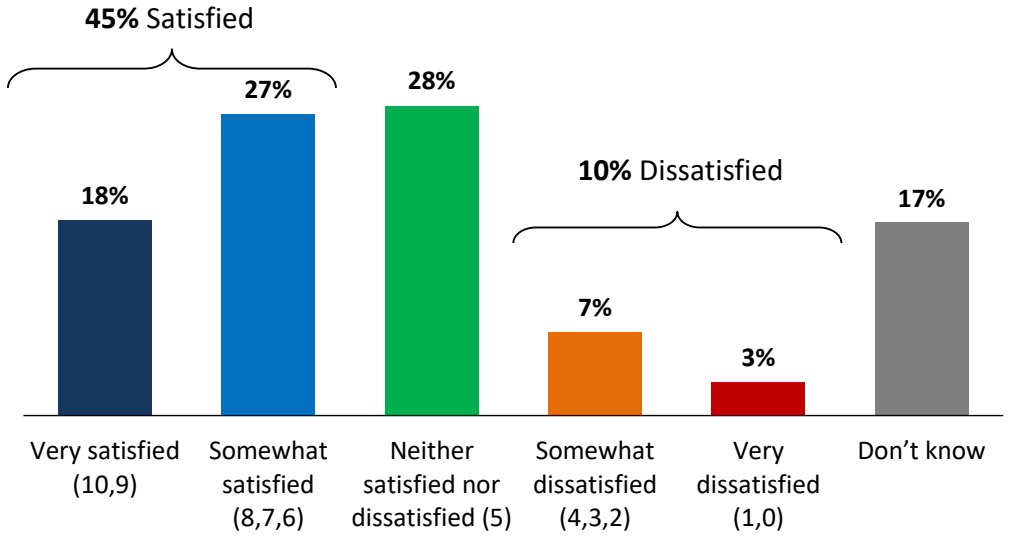
Summary: *Transmission Reputation*

- A plurality (45%) are satisfied with their transmission company, while just 10% say they are dissatisfied.
    - Those with 0-1 outages (49%) are much more satisfied than those with frequent ones (More than 3 outages: 39%).
    - There has been no major shift in satisfaction since 2018 (43%). Satisfaction has improved nine points since tracking began in 2014 (36%).
    - Regionally, satisfaction in Ontario (44%) has improved four points since last year (40%), while satisfaction in Alberta (44%) has dipped five points and is down nearly 20 points from a high of 63% in 2017.
- A strong majority are satisfied on the two key transmission metrics, ‘providing reliable electricity service’ (net: 64%) and ‘maintaining the transmission system in an environmentally responsible manner’ (net: 55%), with marginal gains (+3 for each) since 2018.
    - By province, Ontario has made significantly gains on both reliability (net: 49% in 2018 vs. 57% in 2019) and maintaining the system responsibly (net: 40% in 2018, 48% in 2019). Alberta holds steady on these measures year-to-year.

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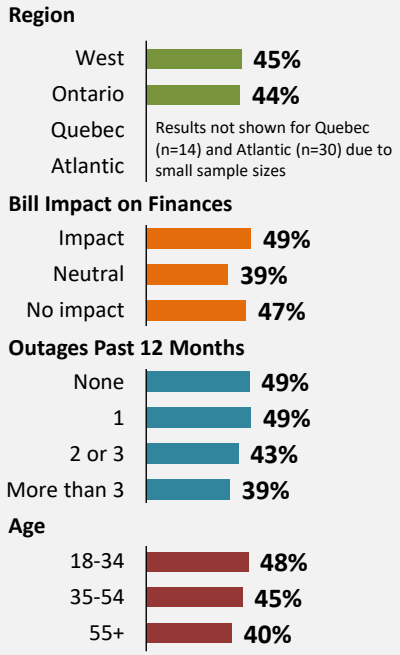
Satisfaction with Transmission (ALL): Nearly half (45%) are satisfied with their transmission company, with just 10% dissatisfied

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with [PROVINCIAL TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents who have different distribution and transmission companies; n=753]



Segmentation

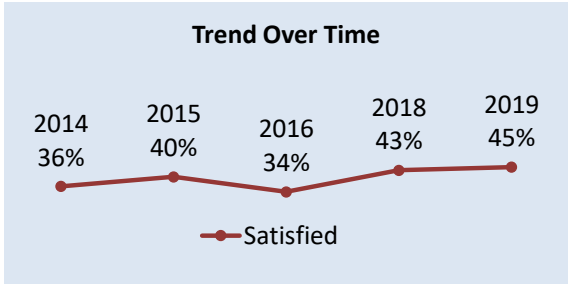
*Those who are **"satisfied"** with their transmission company*

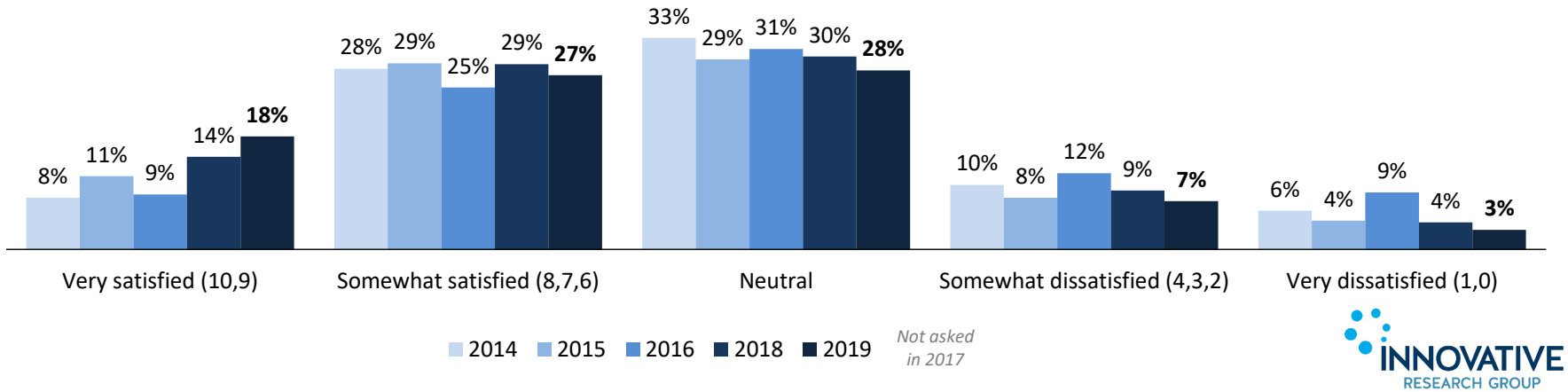


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Satisfaction with Transmission (ALL): In 2019, satisfaction at highest levels since tracking began; up nine points since 2014

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with [PROVINCIAL TRANSMISSION COMPANY]? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents who have different distribution and transmission companies; 2019; n=753]

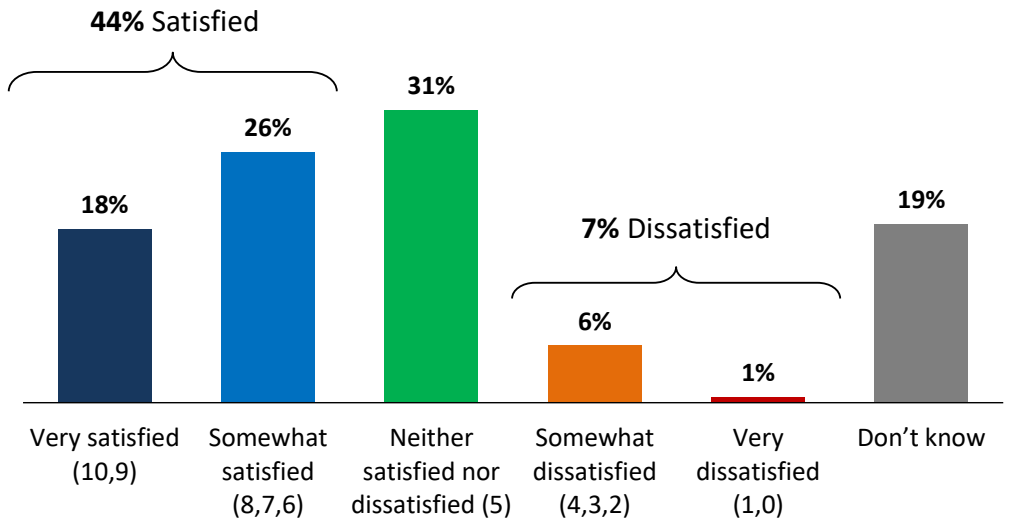




NOTE: 'Don't know' (10% in 2019) not shown.

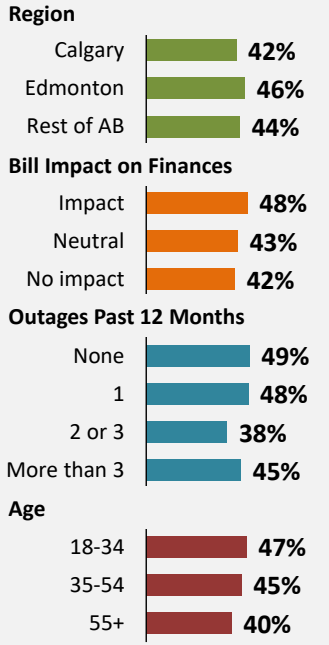
Satisfaction with Transmission (Alberta): Nearly half (44%) of Albertans say they are satisfied with their transmission company; only 7% are dissatisfied

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with the transmission companies that operate in Alberta? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents in Alberta; n=400*]



Segmentation

*Those who are **"satisfied"** with their transmission company*



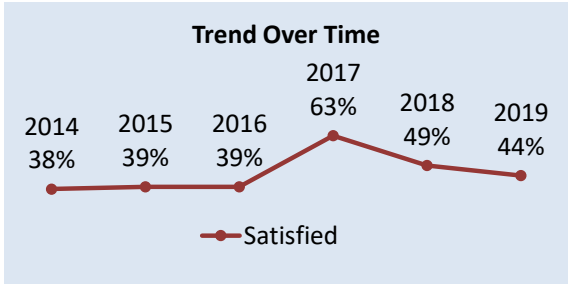
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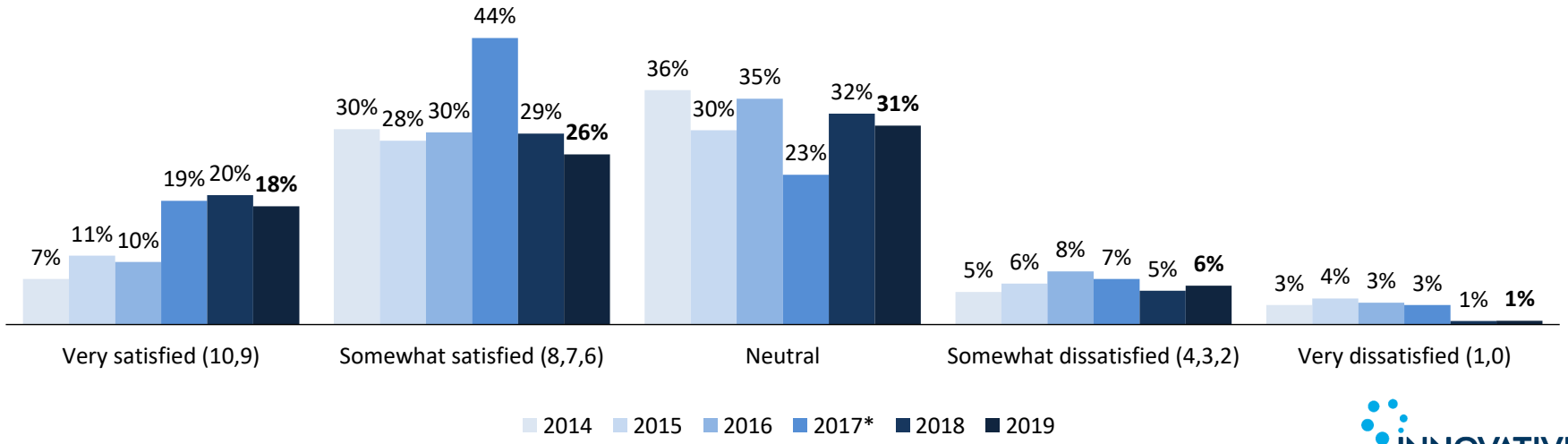
** For this analysis, we applied provincial weights to the Alberta-only data to increase the sample size and, therefore, accuracy of the results.*

Satisfaction with Transmission (Alberta): Satisfaction continues on downward trend since high point in 2017

Q The following questions are about the company or companies that operate your provincial transmission system – that is, the part of the system that uses large wires to connect the electricity produced at generating stations to transmission substations in the communities where it is needed.
Generally, how satisfied are you with the transmission companies that operate in Alberta? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents in Alberta; 2019 n=400]





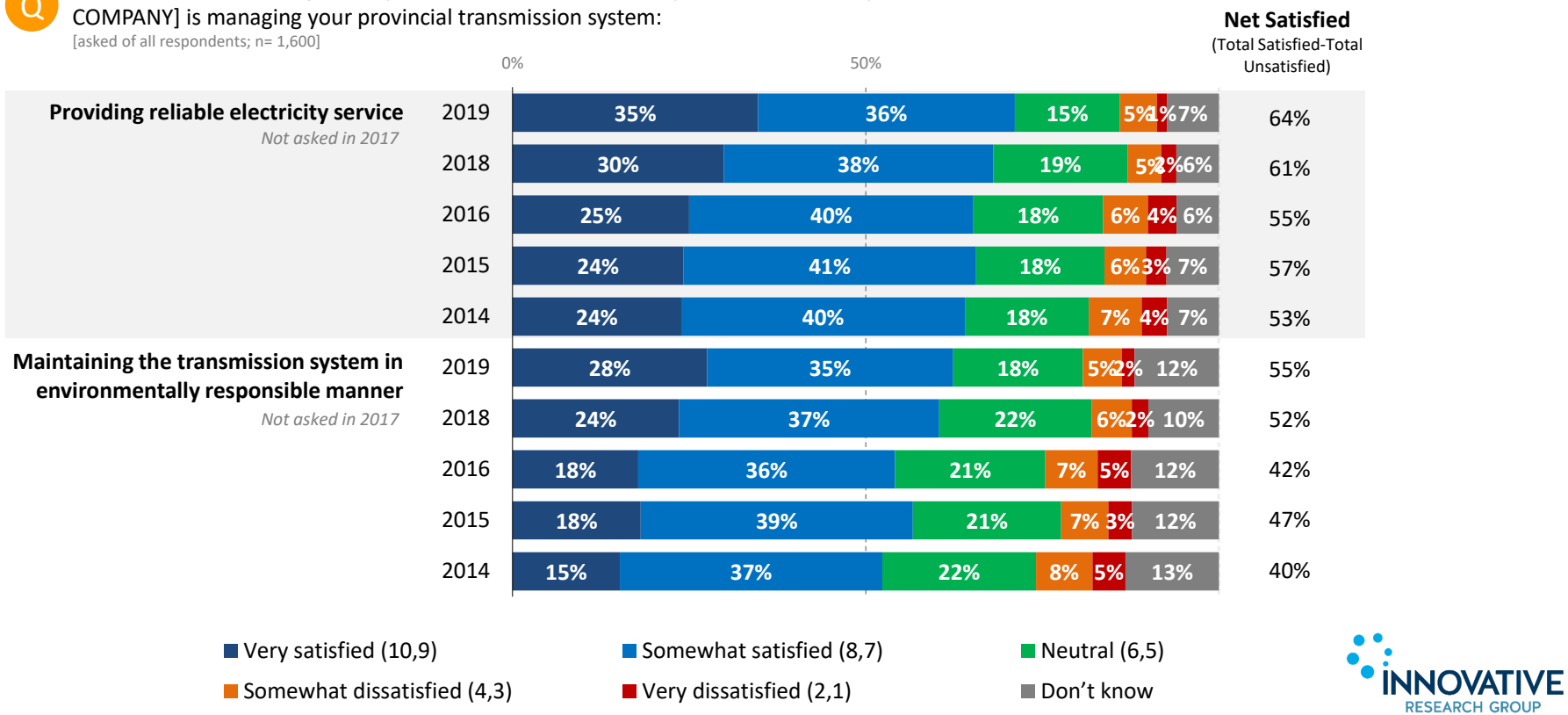
NOTE: 'Don't know' (19% in 2019) not shown.

* In 2017, satisfaction with transmission company was asked in Alberta only on a separate online omnibus, not as part of the annual CEA survey.

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Transmission Performance (ALL): Majority are satisfied with reliability and maintenance; net satisfaction on both has improved marginally year-to-year

Q For each of the following items, please indicate how satisfied you are with the way [PROVINCIAL TRANSMISSION COMPANY] is managing your provincial transmission system:
[asked of all respondents; n= 1,600]

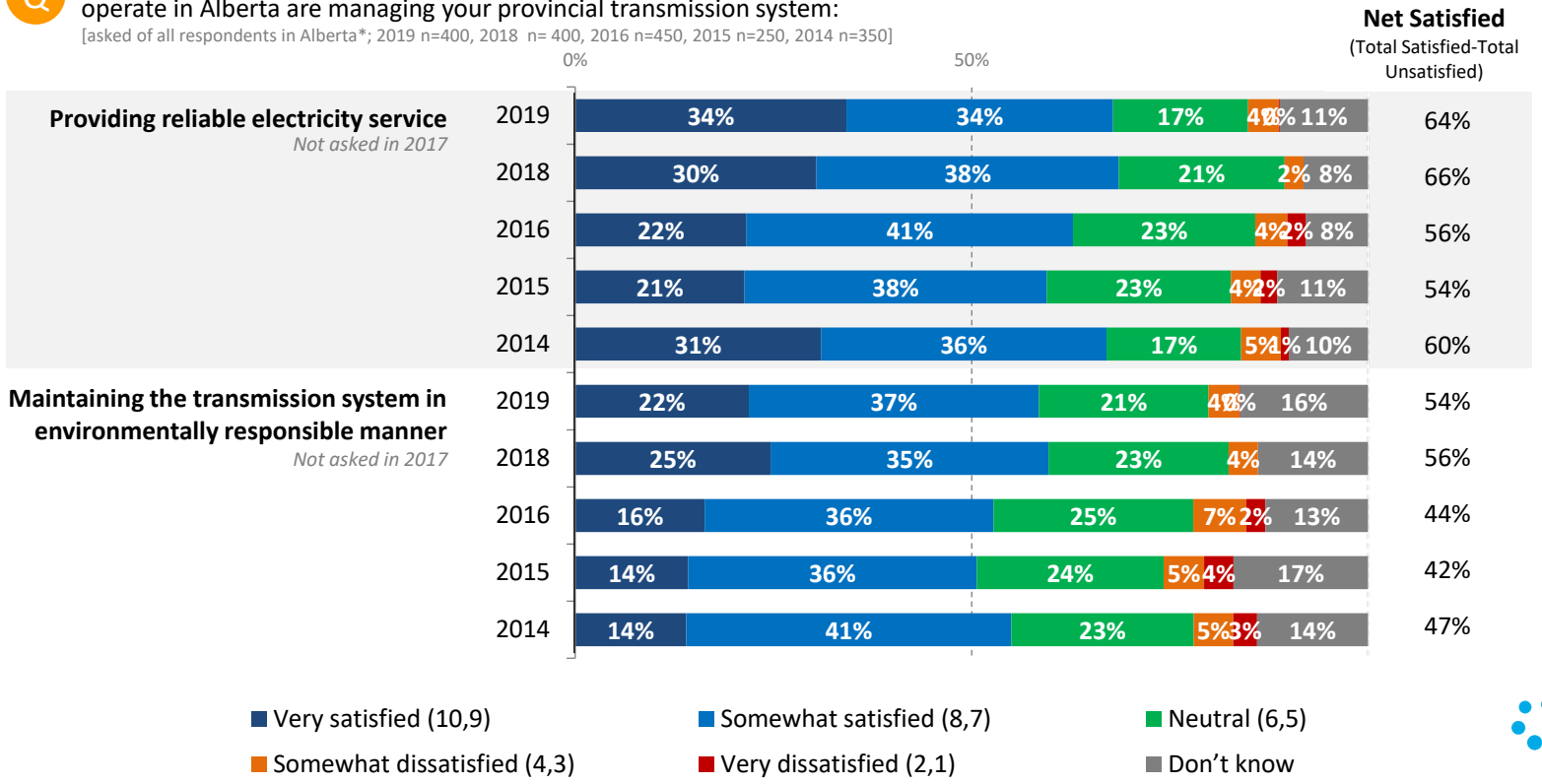


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Transmission Performance (Alberta): Satisfaction on reliability and maintenance mostly steady year-to-year

Q For each of the following items, please indicate how satisfied you are with the way the transmission companies that operate in Alberta are managing your provincial transmission system:

[asked of all respondents in Alberta*; 2019 n=400, 2018 n= 400, 2016 n=450, 2015 n=250, 2014 n=350]



** For this analysis, we applied provincial weights to the Alberta-only data to increase the sample size and, therefore, accuracy of the results.*

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Price

INNOVATIVE RESEARCH GROUP

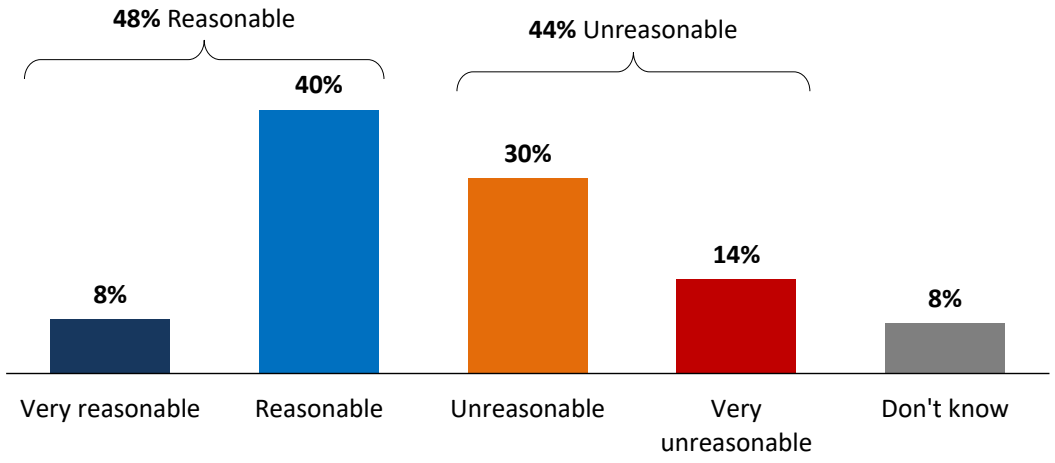
Summary: *Price*

- Respondents are fairly evenly divided on whether they pay a reasonable price for electricity, with 48% who feel it is reasonable and 44% who say the opposite.
    - Those in the West (56%) or Quebec (52%), those who do not feel impacted financially by their electricity bill (66%), and those who experience fewer (0 or 1) outages (56% and 54%, respectively) are most likely to feel the price they pay for electricity is reasonable.
    - For the first time since 2013, feeling on price is net positive (4%) with a marginal shift in negative intensity away from 'very unreasonable' (17% in 2018 to 14% in 2019).
    - Respondents who use e-billing (54%) are much more likely to see the price of their electricity bill as reasonable, compared to those who receive it in the mail (46%) or those who say they do not receive a bill (35%).
- A plurality (37%) struggle to pay their electricity bill, agreeing that it has a major impact on their finances with 1-in-3 (33%) who disagree.
    - Agreement is highest in Atlantic Canada (46%), among those who experience frequent outages (2+ outages: 41-43%) and among millennials (46%).
- A plurality (38%) agree with the statement "thinking of all regular household bills, I receive good value for money" with 3-in-10 (31%) who disagree.
    - A majority (56%) of those unimpacted financially by their bill say they get good value for money, while just 1-in-3 (33%) of those most impacted say the same.
    - Net agreement on value for money is at its highest levels since 2015 (7%), increasing three points year-to-year.

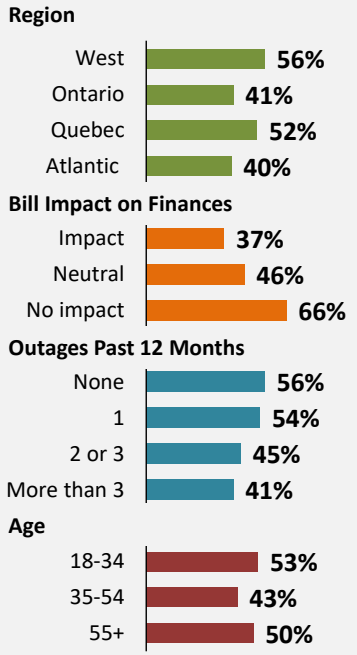
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Reasonable Price?: Slim plurality think the price of electricity is reasonable; majority in West (56%) and those who don't struggle with bills (66%)

Q Overall, do you think that the price for electricity in your province is reasonable or unreasonable?
[asked of all respondents; n=1,600]



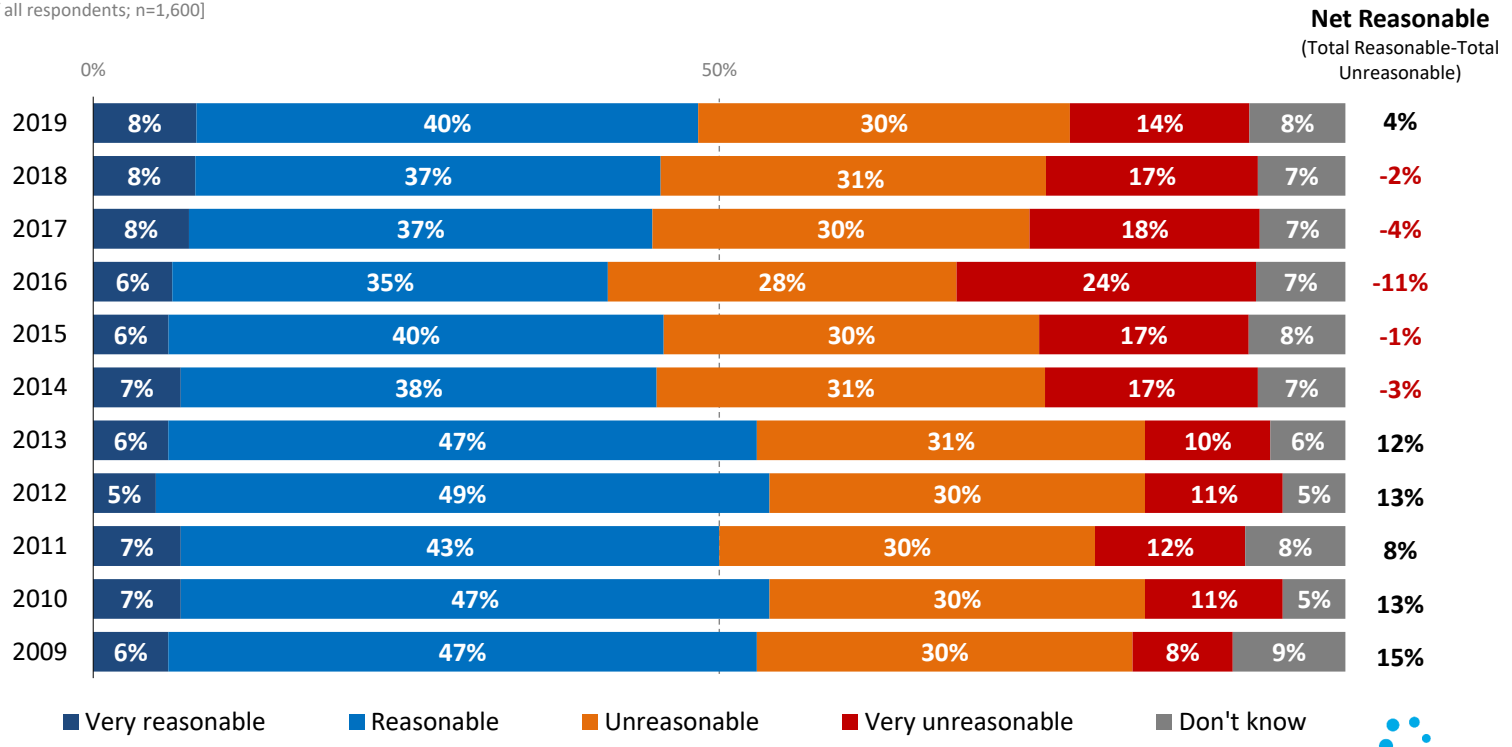
Segmentation
*Those who say **"reasonable"***



INNOVATIVE RESEARCH GROUP

Reasonable Price (Tracking): Feeling on price now net positive (+4%), highest score on price measure since 2013

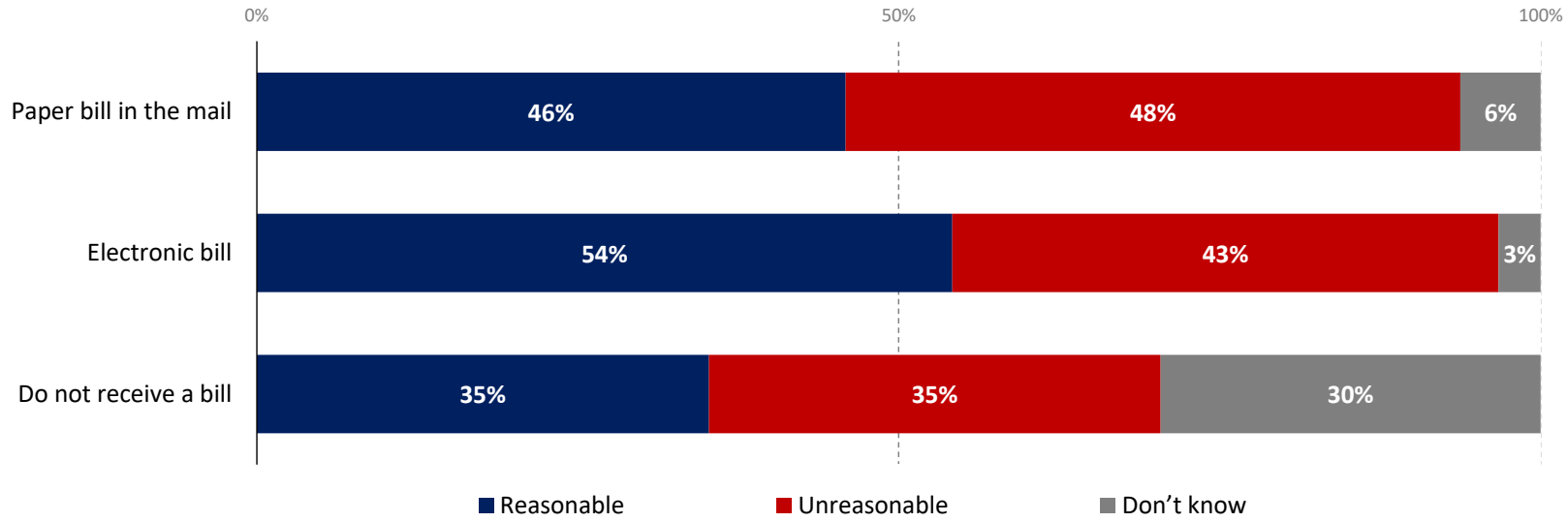
Q Overall, do you think that the price for electricity in your province is reasonable or unreasonable?
[asked of all respondents; n=1,600]



INNOVATIVE RESEARCH GROUP

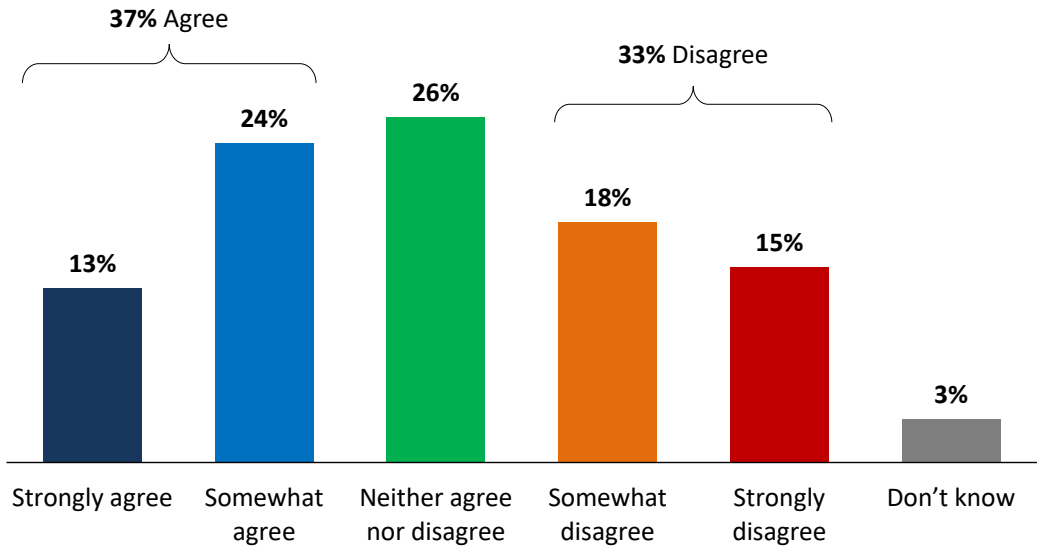
Price Assessment by Bill Format: Respondents on e-billing more likely to view the price of electricity as reasonable

Q Overall, do you think that the price for electricity in your province is very reasonable, reasonable, unreasonable, or very unreasonable?
BY
Bill format
[asked of all respondents; n=1,600]

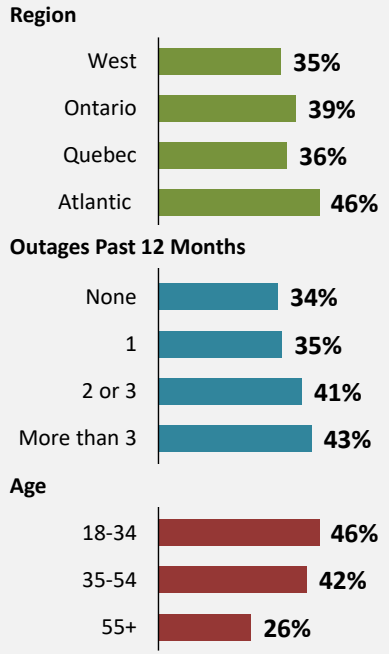


Financial Impact: Less than 4-in-10 (37%) struggle to pay their electricity bill, younger respondents and those in Atlantic region most likely to struggle

Q Do you agree or disagree with the following statements?
My electricity bill has major impact on my finances and requires I do without other important priorities.
[asked of all respondents; n=1,600]



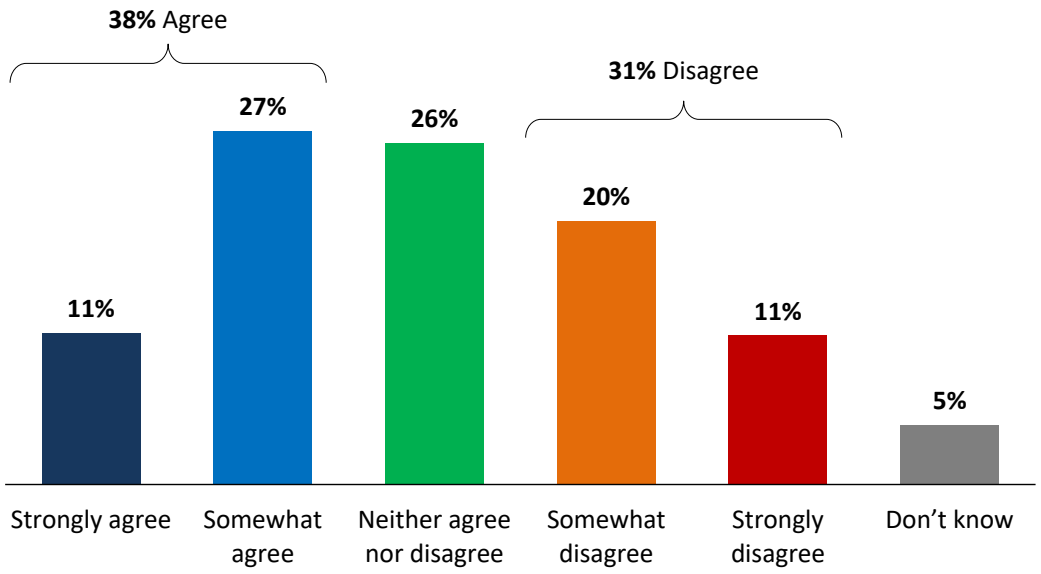
Segmentation
*Those who **"agree"***



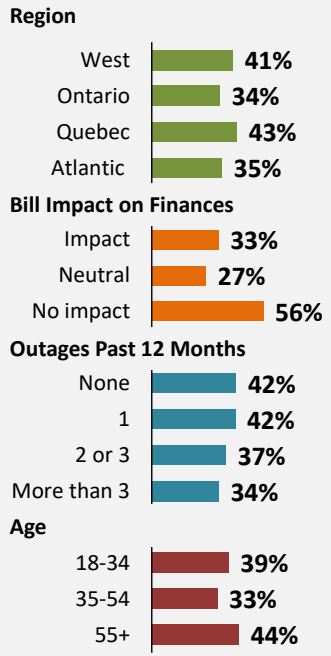
INNOVATIVE RESEARCH GROUP

Value for Money: About 4-in-10 (38%) think they are getting good value for money on their electricity bill; higher in Western Canada and Quebec

Q Do you agree or disagree with the following statements?
Thinking of all regular household bills, I receive good value for the price I pay for electricity.
[asked of all respondents; n=1,600]



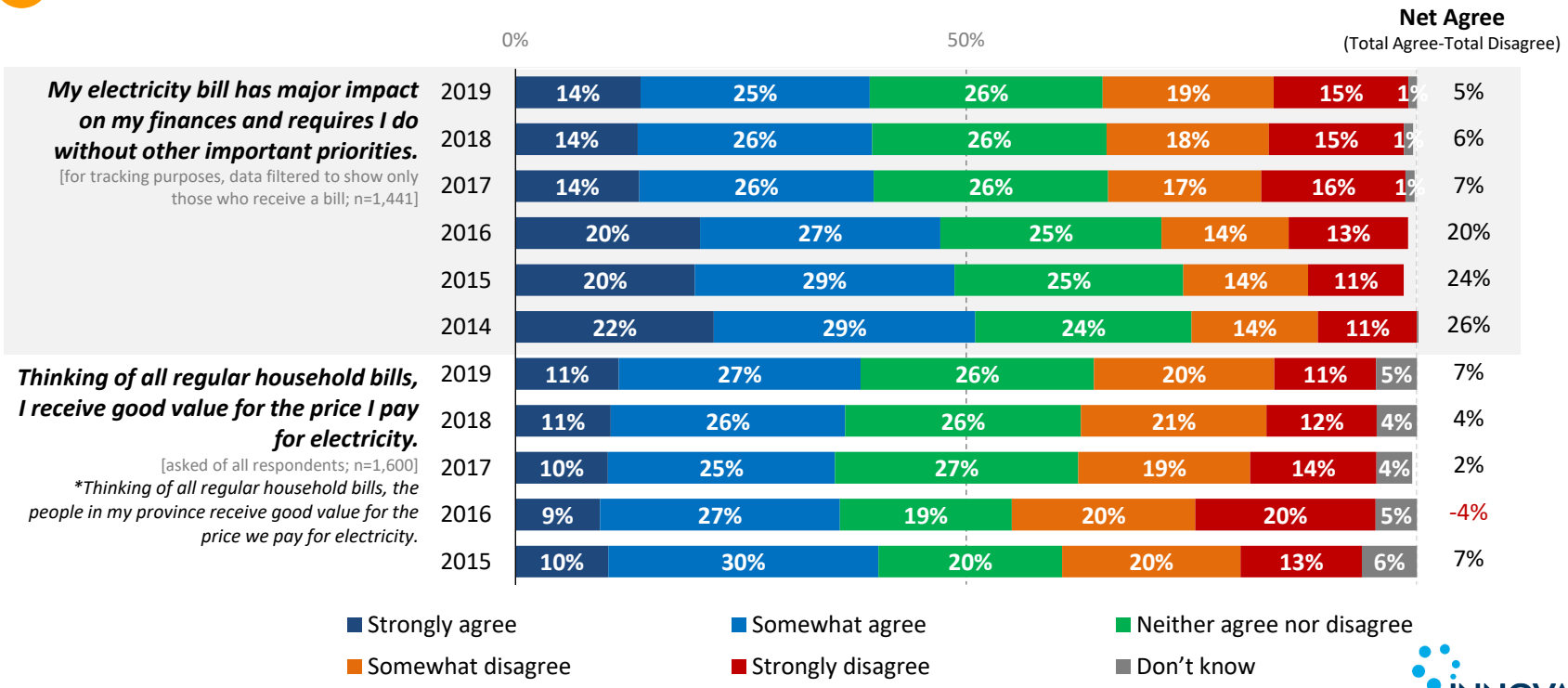
Segmentation
*Those who **"agree"***



INNOVATIVE RESEARCH GROUP

Financial Impact (Tracking): Net agreement on value-for-money (+7) up three points; now at highest levels since 2015; 'impact' continues to trend downward

Q Do you agree or disagree with the following statements:
[respondent base for each statement shown below]



INNOVATIVE RESEARCH GROUP

Perception of Price by Bill Impact: Those who feel most strongly they are impacted by their electricity bill are most likely to find it unreasonable

Q Overall, do you think that the price for electricity in your province is very reasonable, reasonable, unreasonable, or very unreasonable?
BY
My electricity bill has a major impact on my finances and requires I do without some other important priorities.
[asked of all respondents; n=1,600]

Do you agree or disagree with the following statement:
My electricity bill has a major impact on my finances and requires I do without some other important priorities.

	Strongly agree	Somewhat agree	Neither	Somewhat disagree	Strongly disagree	Overall
Very reasonable	17%	4%	4%	4%	21%	8%
Reasonable	17%	34%	42%	56%	52%	40%
Unreasonable	23%	41%	34%	28%	15%	30%
Very unreasonable	42%	17%	9%	6%	7%	14%
Net Reasonable	-31%	-20%	3%	27%	51%	4%

INNOVATIVE RESEARCH GROUP

NOTE: 'Don't know' not shown

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Innovation

(This series of questions was added in 2019)

INNOVATIVE RESEARCH GROUP

Summary: *Innovation*

This year, a new series of questions on technological innovations was added to the survey.

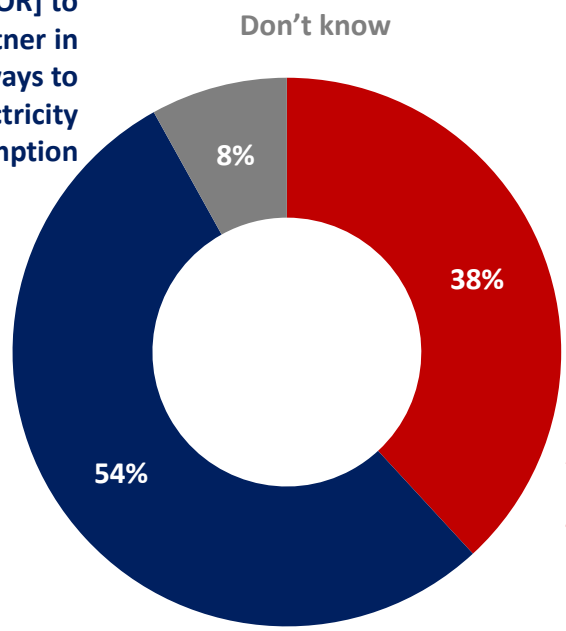
- A majority (54%) of respondents prefer that their distributor actively help them find ways to reduce electricity consumption. Less than 4-in-10 (38%) preferred the alternative statement: "as long as my lights and appliances turn on when I flick the switches, I am getting everything I need from [their distributor]".
    - Those most financially impacted (61%) and those in Atlantic Canada (60%) and Quebec (58%) are most likely to expect their distributor to help them reduce electricity consumption.
- When asked whether electrical utilities should invest in new technologies or wait until they've been proven elsewhere, a majority (55%) chose the former. Just 1-in-3 (32%) say that utilities "should wait until new technologies have been proven elsewhere".
    - Those who do not struggle to pay their electricity bill (64%) are much more likely to say electricity companies should invest in new technologies.
- In our innovation segmentation, a third (33%) of respondents feel that their distributor should both help them reduce consumption *and* hold off on investing. Less than 2-in-10 (17%) think their distributor should help them reduce consumption and also invest in new technologies.
- When asked what distributors' top investment goal in new technology should be, a plurality (42%) of respondents felt they should focus on financial savings through increased efficiency. Another 3-in-10 (30%) felt reducing impact on the environment was a priority, and just 12% felt companies should focus on increasing reliability.
- Turning to specific new innovations, few respondents reported owning any or actively looking to acquire them. The most active interest was on remote technologies, either thermostats (21%) or remotely controlled lights (14%).
- In our innovation index created based on acquisition of or interest in the six types of new innovation, only 7% were early adopters: those who have taken active steps to acquire most of the six innovations tested. Another 26% have adopted at least some of them or are interested in acquiring them.

INNOVATIVE RESEARCH GROUP

Partner vs Provider: Majority (54%) prefer their distributor to work actively to help them find ways to reduce consumption

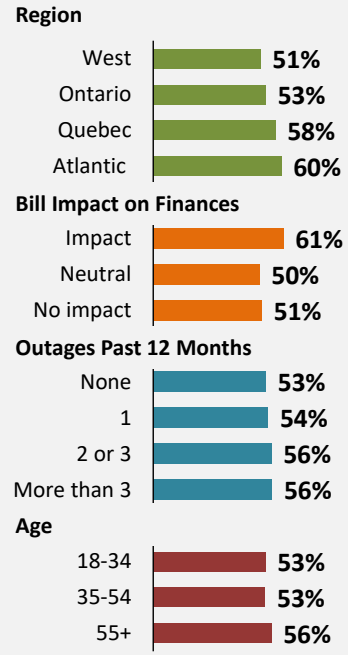
Q Which of the following statements best reflects your point of view?
[asked of all respondents; n=1,600]

I expect [DISTRIBUTOR] to be an active partner in helping me find ways to reduce my electricity consumption



As long as my lights and appliances turn on when I flick the switches, I am getting everything I need from [DISTRIBUTOR]

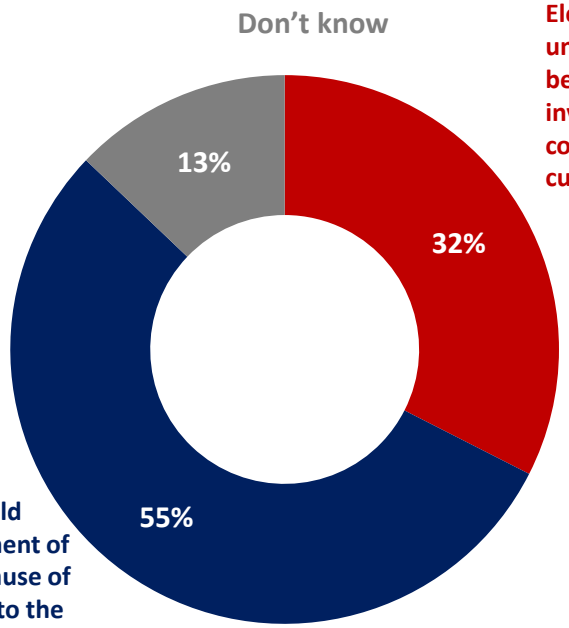
Segmentation
*Those who say **"active partner"***



INNOVATIVE RESEARCH GROUP

Invest vs Wait: Over half (55%) say utilities should invest in the development of new technologies for potential benefits

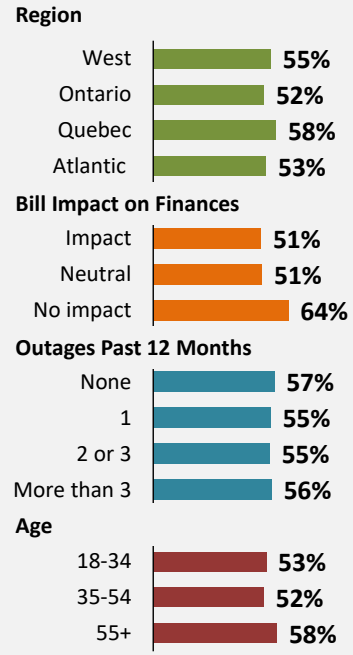
Q Which of the following statements best reflects your point of view?
[asked of all respondents; n=1,600]



Electrical utilities should wait until new technologies have been proven elsewhere before investing in them to keep costs from being passed on to customers

Electrical utilities should invest in the development of new technologies because of the potential benefits to the environment, reliability and efficiency

Segmentation
*Those who say **"should invest"***



INNOVATIVE RESEARCH GROUP

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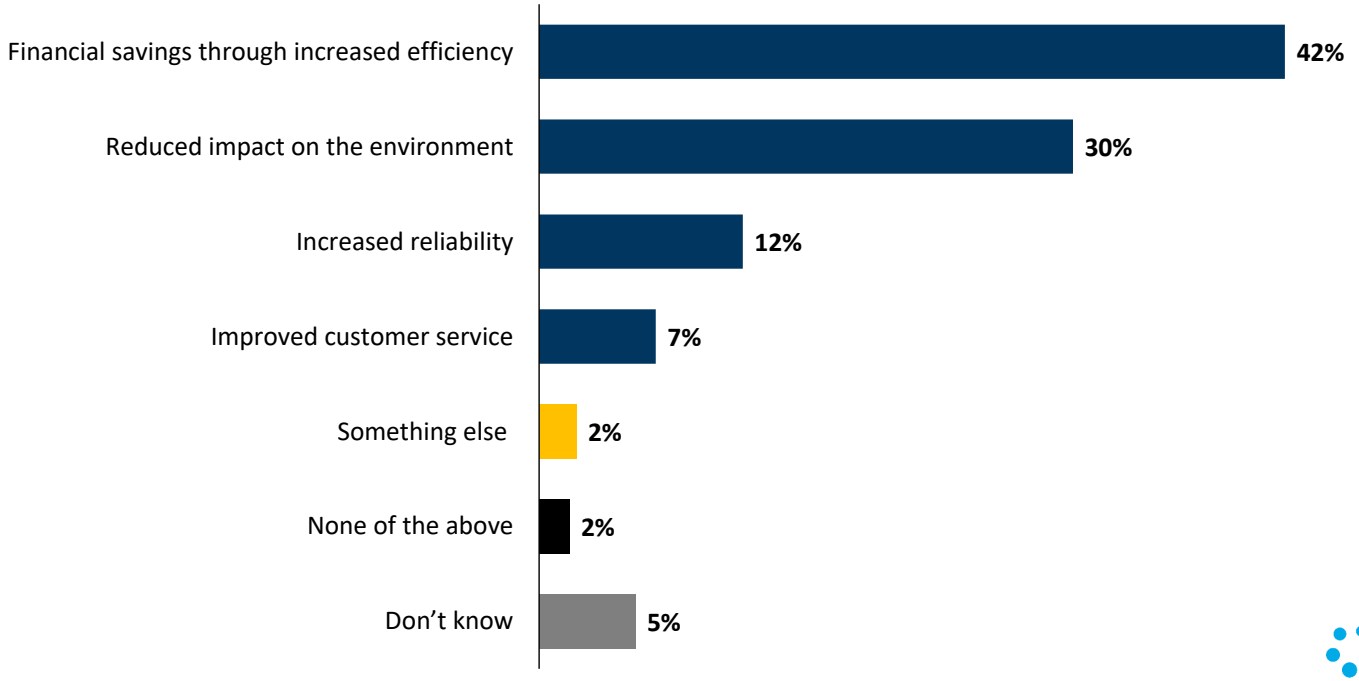
Partner / Investor: Whether or not they want their distributor to be an active partner in reducing consumption, consumers want utilities to invest in technology

	As long as my lights and appliances turn on when I flick the switches, I am getting everything I need from [DISTRIBUTOR]	I expect [DISTRIBUTOR] to be an active partner in helping me find ways to reduce my electricity consumption	Don't know
Electrical utilities should wait until new technologies have been proven elsewhere before investing in them to keep costs from being passed on to customers	37%	30%	19%
Electrical utilities should invest in the development of new technologies because of the potential benefits to the environment, reliability and efficiency	51%	63%	24%
Don't know	12%	7%	57%
TOTAL	**100%**	**100%**	**100%**

INNOVATIVE RESEARCH GROUP

Innovation Priorities: Plurality (42%) think the top priority should be to save money through efficiencies

Q If a utility is going to invest in new technology, which of the following goals do you think should be their TOP priority
[asked of all respondents; n=1,600]

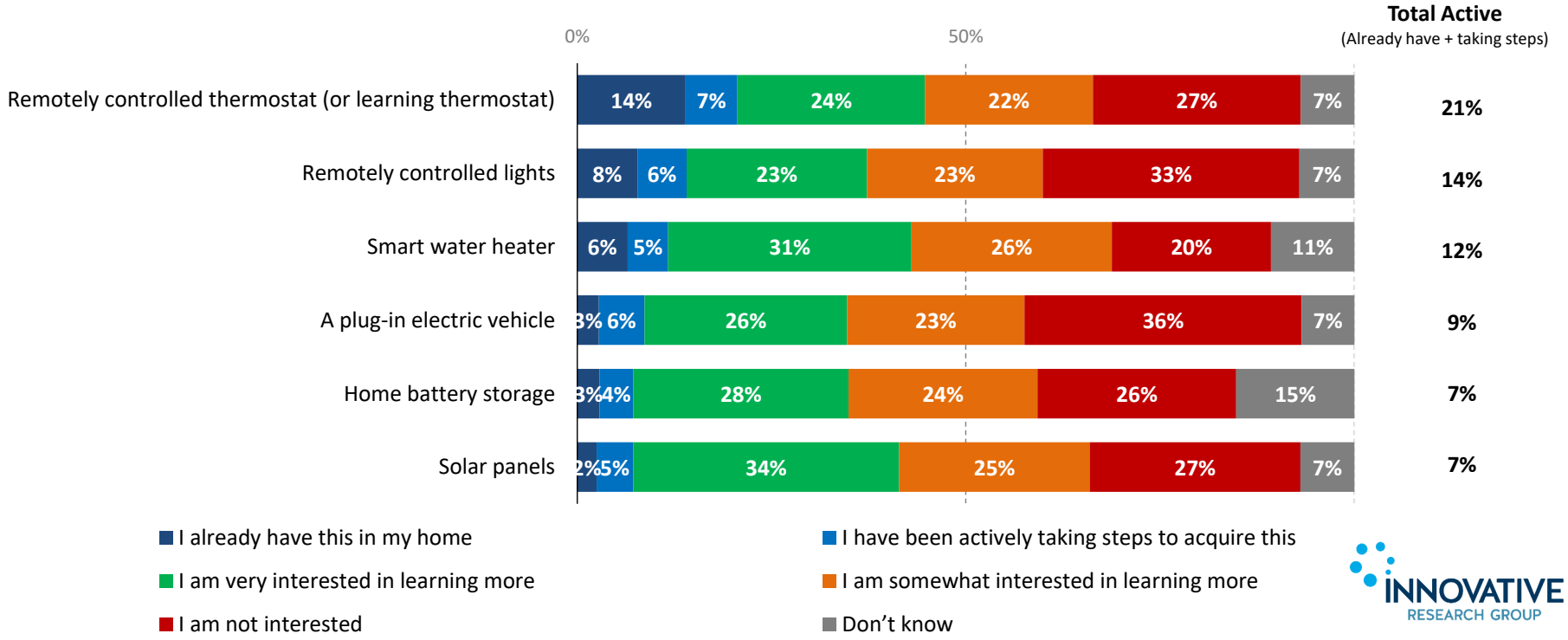


INNOVATIVE RESEARCH GROUP

Interest in Innovation: Most common active innovations are learning thermostats (21%), remote-controlled lights (14%), and smart water heaters (12%)

Q There are many new technologies that are currently already available or that are being developed. You may already have some of these innovations in your home, or there may be some that you are interested in learning more about. Please review the list below, and indicate which you currently have, which you are interested in, and which are not of interest to you.

[asked of all respondents; n=1,600]

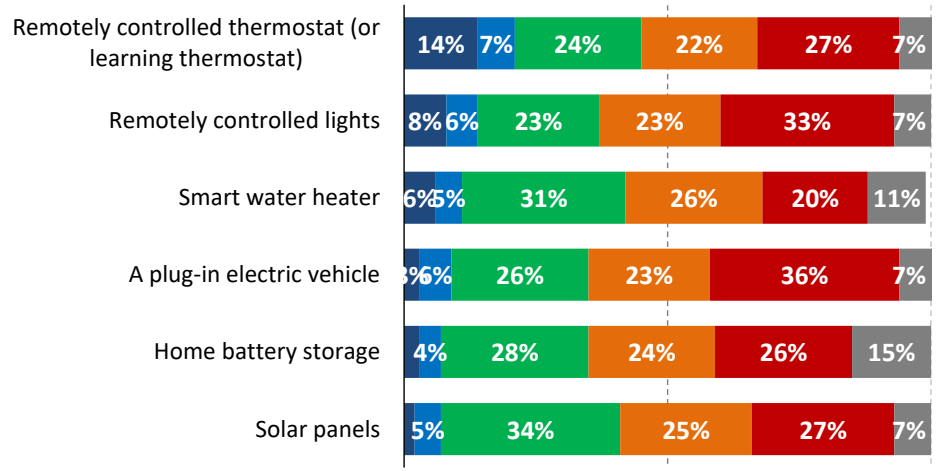


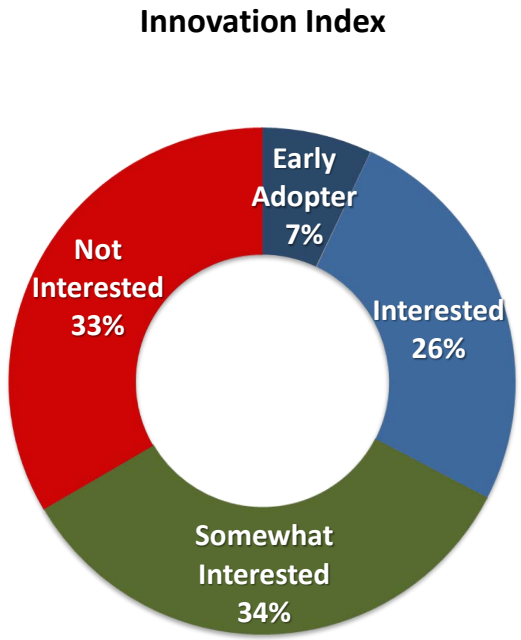
INNOVATIVE RESEARCH GROUP

Innovation and Innovation Index: Only 7% have taken active steps to acquire most new technologies, another 26% have adopted at least some or are interested

Q There are many new technologies that are currently already available or that are being developed. You may already have some of these innovations in your home, or there may be some that you are interested in learning more about. Please review the list below, and indicate which you currently have, which you are interested in, and which are not of interest to you.

[asked of all respondents; n=1,600]





The "Innovation Index" was created by giving respondents a score from 0 to 10 based on how actively they pursue various innovations.

INNOVATIVE RESEARCH GROUP

Innovation Ownership by Innovation Index: Across the board, *Early Adopters* are far ahead of other segments on having new technology in their homes

Q There are many new technologies that are currently already available or that are being developed. You may already have some of these innovations in your home, or there may be some that you are interested in learning more about. Please review the list below, and indicate which you currently have, which you are interested in, and which are not of interest to you. BY Innovation Index

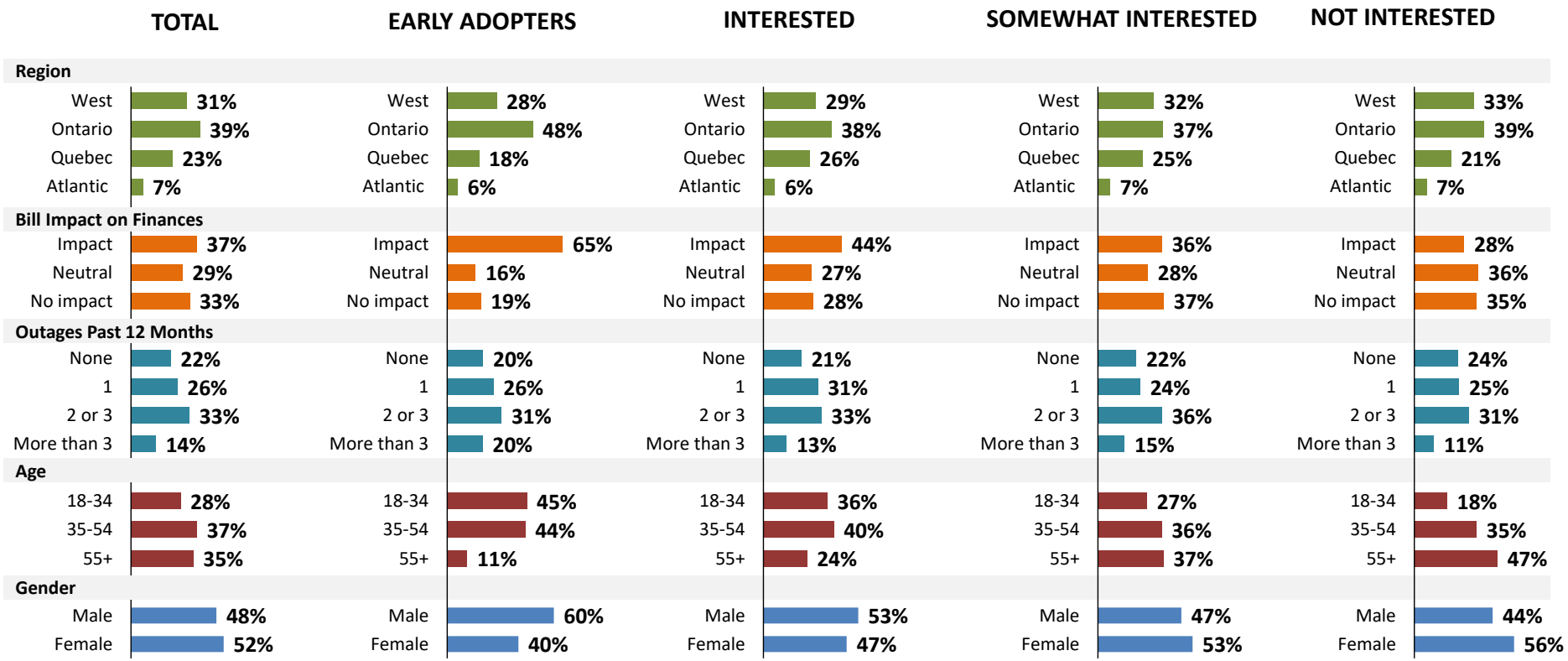
[asked of all respondents; n=1,600]

Innovations included in survey	Early Adopter	Interested	Somewhat Interested	Not Interested
	% "already have this in my home"			
Remotely controlled thermostat (or learning thermostat)	52%	21%	13%	2%
Remotely controlled lights	40%	12%	4%	1%
Smart water heater	32%	8%	5%	1%
Plug-in electric vehicle	26%	3%	1%	0%
Home battery storage	26%	3%	1%	0%
Solar panels	20%	3%	1%	0%

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Innovation Index Profiles: *Early Adopters* are more prevalent in Ontario, tend to be younger, male and more impacted by their electricity bill



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Customer Contact

(This series of questions was added in 2019)

INNOVATIVE RESEARCH GROUP

Summary: *Customer Contact*

A new series on enhanced customer contact was added to the 2019 survey:

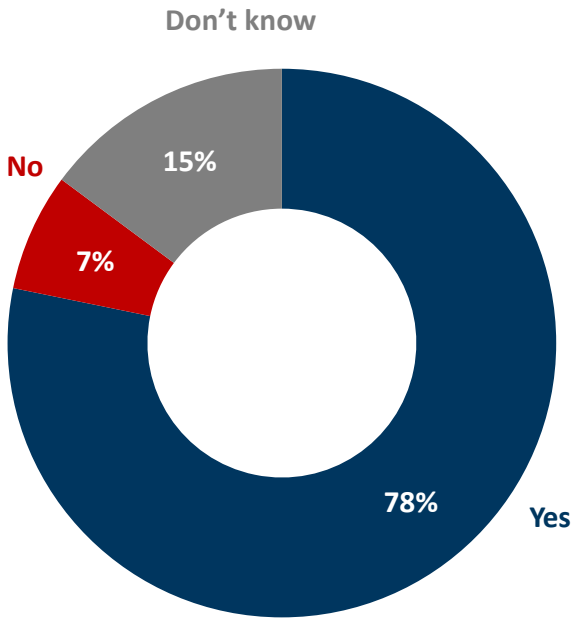
- Almost 8-in-10 (78%) say their distributor has their contact information on file, with the lowest incidence among millennials (70%) and Ontario residents (73%).
- A slight plurality (34%) would be willing to share their current contact information with their distributor, while 3-in-10 (31%) would not be willing to do so.
    - Those unimpacted by their bills financially are the most willing to provide their contact info (49%).
- When asked why they haven't shared their contact info with their distributor, top reasons included "they haven't asked for it" (21%), "there's no reason to share it with them" (16%), and "privacy concerns" (15%).
- A majority of respondents were interested in each of the seven motivators tested (although they did not increase likelihood of sharing contact info):
    - Advanced notice of planned outages (Net interested: 78%);
    - Updates regarding outage restoration (73%);
    - Notifications regarding extreme weather events (61%);
    - Emergency preparedness (60%);
    - Conservation tips (55%);
    - Electrical safety (53%);
    - And electronic billing/e-billing (net: 45%).
- A strong plurality (48%) of respondents say email is their preferred method for updating contact info.

INNOVATIVE RESEARCH GROUP

Contact Information: Almost 8-in-10 (78%) think their distributor has their contact information on file

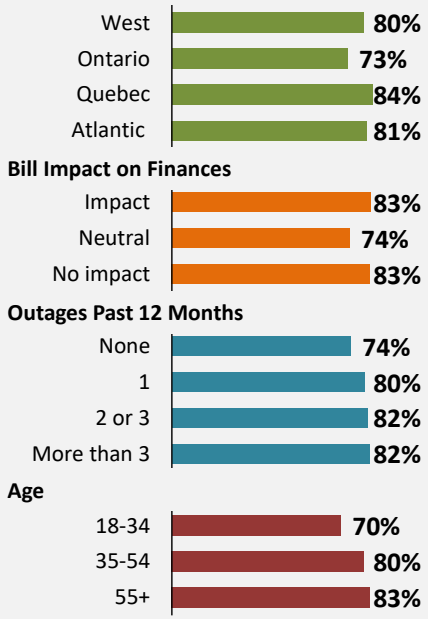
Q As far as you know, does [DISTRIBUTOR] have your current phone number and/or email address on file?

[asked of all respondents; n=1,600]



Segmentation

*Those who say **"yes"***

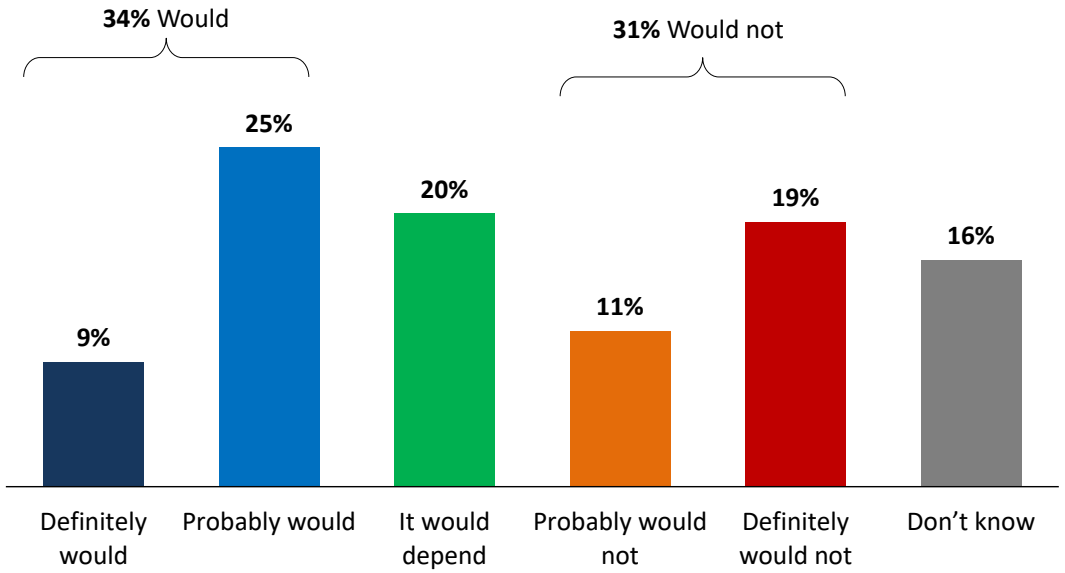


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Providing Contact Info: 1-in-3 (34%) would provide their contact info; those not impacted by their bill (49%) most likely to provide it

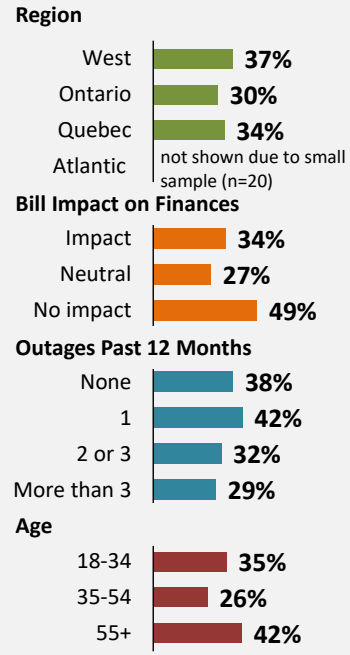
Q How likely would you be to share your current cellphone number and/or email address with [DISTRIBUTOR] so that they could easily contact you?

[asked of those whose distributor does not have current contact info; n=349]



Segmentation

*Those who **"would"***

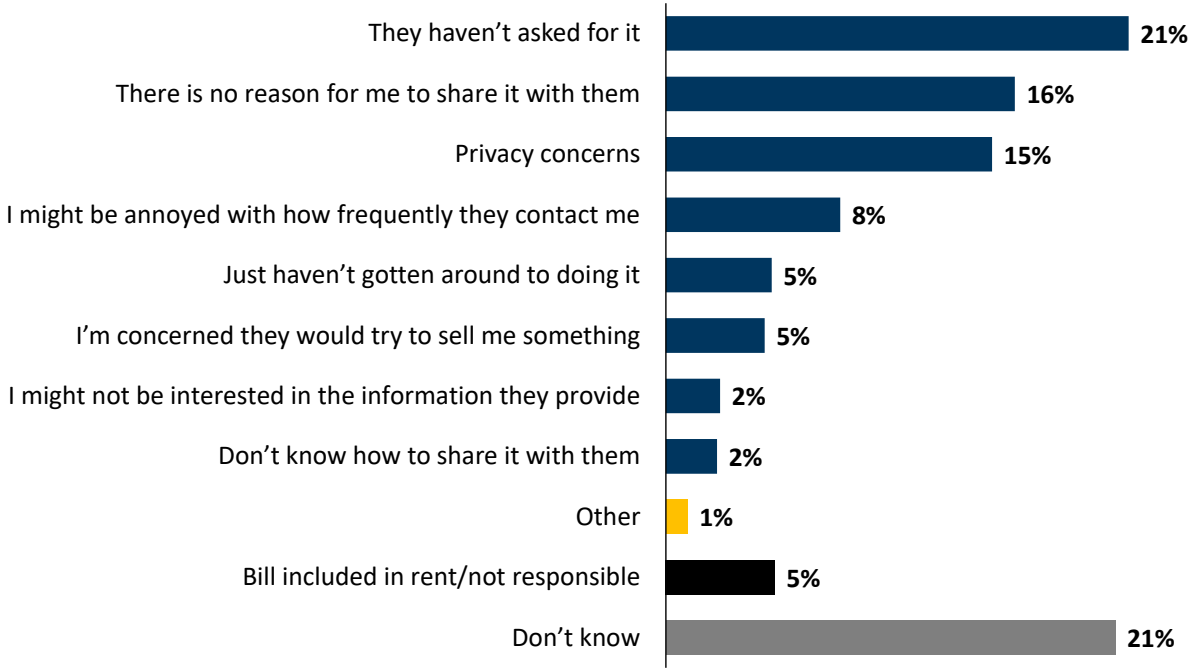


INNOVATIVE RESEARCH GROUP

Barriers: When asked why they haven't shared their contact information, top reason cited is distributor hasn't asked for it yet (21%)

Q There are many reasons why people may not have shared their contact information with [DISTRIBUTOR]. From the following list, which best describes why you have not shared your contact information?

[asked of those whose distributor does not have current contact info; n=349]

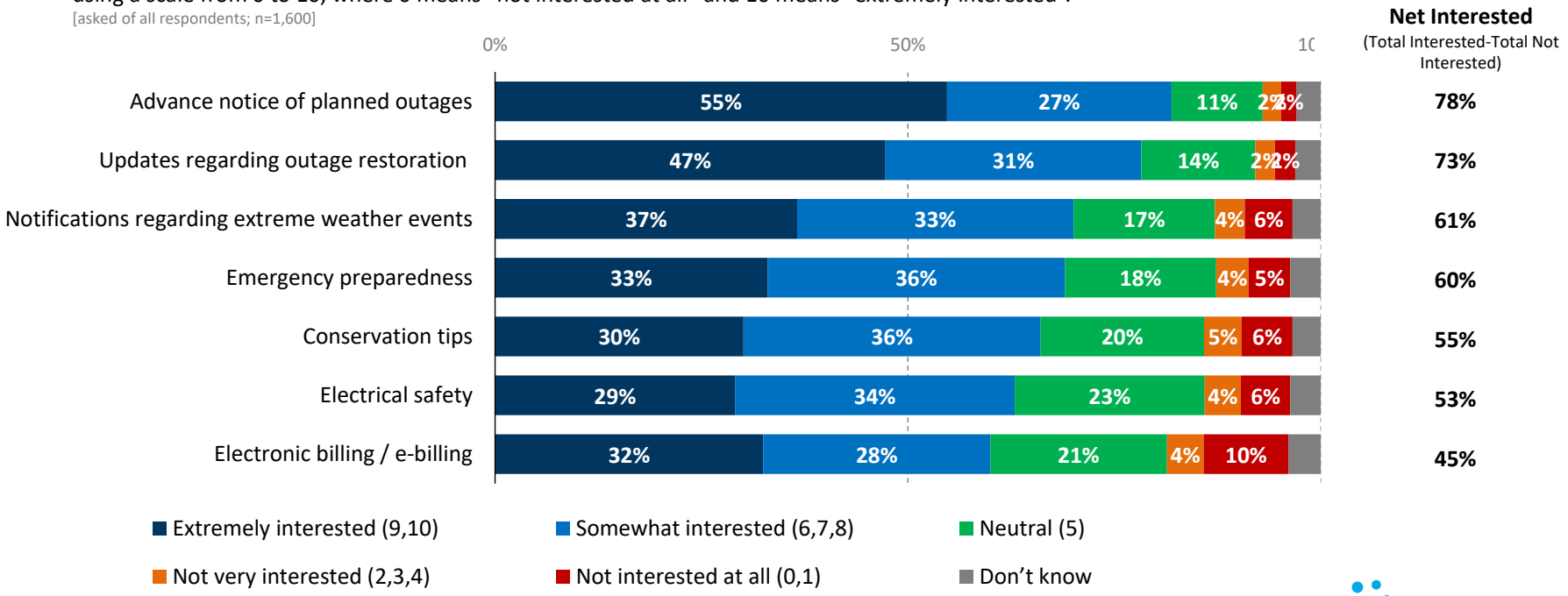


INNOVATIVE RESEARCH GROUP

Motivators: A majority (55%) would be “extremely interested” in advanced notices of outages; least interest shown for e-billing

Q There are different types of information and services that [DISTRIBUTOR] could provide if they were able to contact their customers either via text or email. For each of the items list below, please indicate how interested you would be in receiving that information from [DISTRIBUTOR]. Please answer using a scale from 0 to 10, where 0 means “not interested at all” and 10 means “extremely interested”.

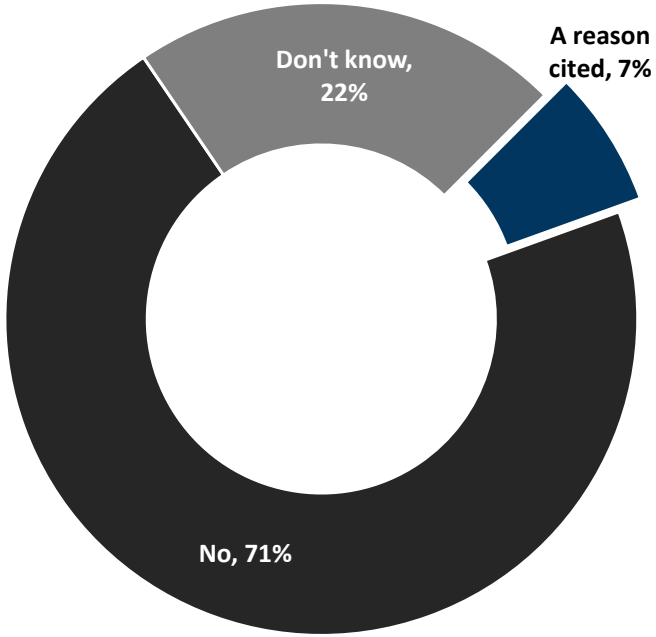
[asked of all respondents; n=1,600]



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Other Motivators: Only 7% cited a reason, others either say nothing (71%) or don't know (22%)

Q Aside from the list above, is there anything else that would motivate you to share your current contact information with [DISTRIBUTOR]?
[asked of all respondents; n=1,600]



Key Verbatims of those who cited a reason:

Reduce rates / bills are too expensive:
- *"If there was a price benefit - a reduction in the high prices"*
- *"Cheaper bills, too expensive for pensioners"*
- *"I wish they could do away with time of day rates. As a senior, I am at home during the day so am directly impacted"*

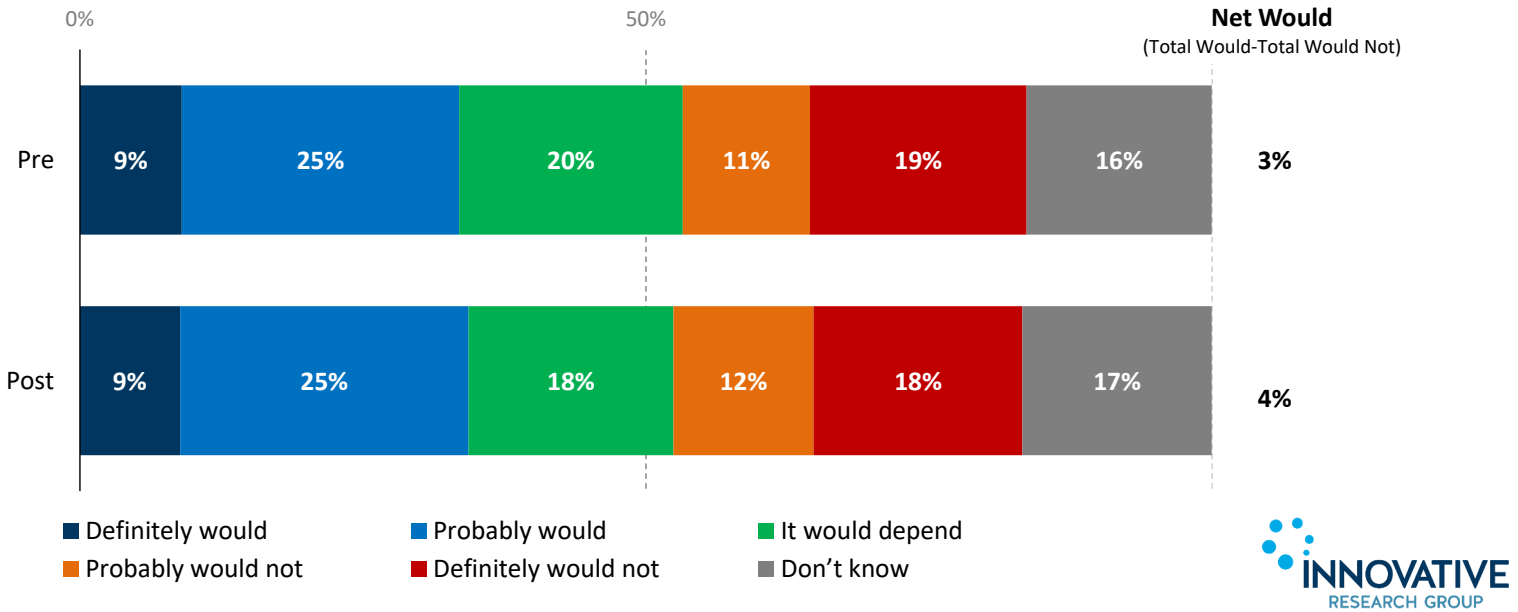
Discounts / contests / deals / promotions:
- *"Contests and giveaways for energy efficient products"*
- *"Customer contests, where our ideas or something, could be shared with them, and draw for several customers who do so (a credit on account). As well, a reward for giving input via surveys....and they should consider some focus groups at varied places in the province, especially outside the 2 big centers"*
- *"Extreme low rates for charging EV cars. Midnight to 6am. 2 cents per kWh. It encourages people to buy EV"*

Corporate transparency / open communication with customers:
- *"Be OPEN with communicating with your Customers. We can work together and facilitate "Scheduled Power Outages" for Maintenance and Infrastructure Upgrades. Just be honest…"*
- *"Corporate transparency and put the customers ahead of shareholders"*
- *"Explain why our delivery service charges are so high. I used $10 of electricity in Sept. and was charged $40 for delivery. Conservation only goes so far when you cannot control charges others pass along to the customer"*

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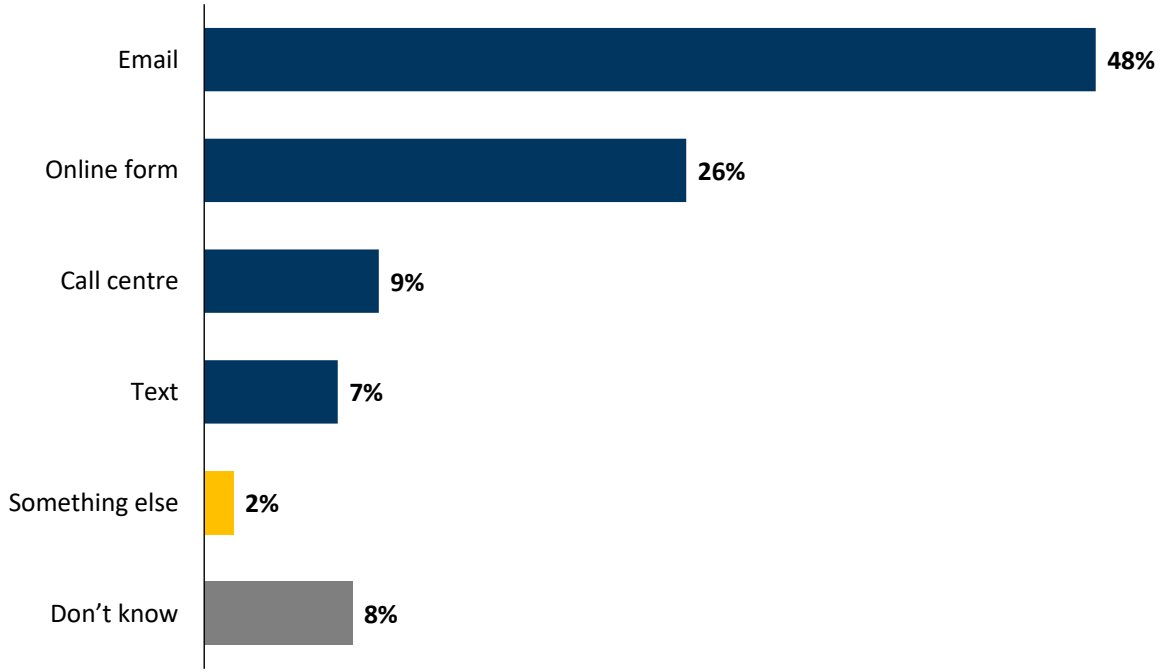
Providing Contact Info (Post): No change in pre-post numbers as a result of sharing types of information that might be shared

Q How likely would you be to share your current cellphone number and/or email address with [DISTRIBUTOR] so that they could easily contact you?
AND
Now that we have talked about some of the information [DISTRIBUTOR] could share with you, how likely would you be to share your current cellphone number and/or email address with [DISTRIBUTOR] so that they could easily contact you?
[asked of those whose distributor does not have current contact info; n=349]



Preferred Method: Nearly half (48%) would prefer email contact, 1-in-4 (26%) choose an online form for updating their information

Q Which of the following would be your preferred method for updating your contact information?
[asked of all respondents; n=1,600]



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Social Permission

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Summary: *Social Permission*

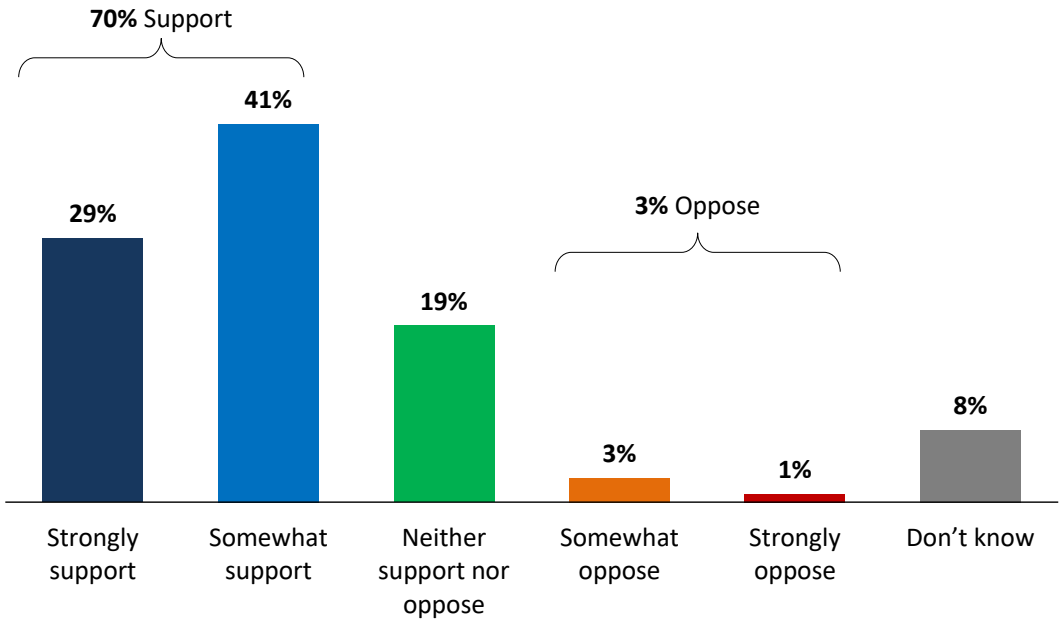
- 7-in-10 (70%) support infrastructure investment, and replacement, an increase of six points year-to-year and a 20-point gain since tracking began in 2014 (50%). Support is greatest among those not under financial strain (83%) and those 55 and older (76%).
- Half (50%) would provide social permission for a price increase, unchanged year-to-year (2018: 49%). 1-in-10 (9%) say a price increase is a good idea while 4-in-10 (40%) say they don't like it but think it's a necessary change. Another 4-in-10 (40%) think it's a bad idea and oppose the price increase.
    - Social permission has increased 11 points since tracking began in 2014 (39%).
    - Permission for an increase is 16 points higher than the national average among those who strongly support investment, replacement, and expansion of infrastructure (66% among 'strongly support' vs. 50% overall).
- A plurality (37%) are satisfied with the provincial government's stewardship of the electricity system and 3-in-10 (29%) are dissatisfied.
    - Satisfaction with the provincial government is highest among millennials (44%) , residents of Quebec (47%), and those experiencing minimal outages (0-1 outages: 41%).
    - Net satisfaction is mostly stable year to year (8% vs. 6% in 2018). For two years in a row, respondents are net satisfied with provincial government's management of the system.

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Infrastructure Investment: 7-in-10 (70%) support electricity infrastructure investment and replacement; highest support among financially comfortable

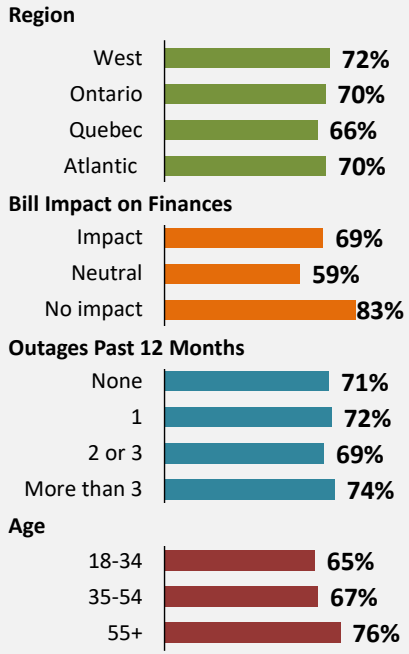
Q Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?

[asked of all respondents; n=1,600]



Segmentation

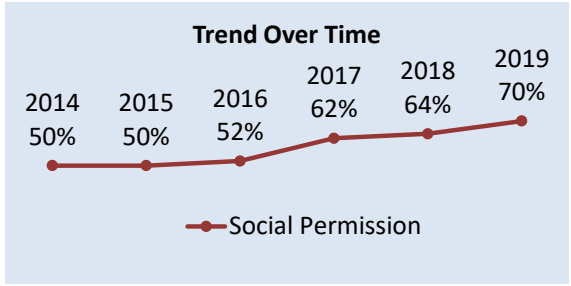
*Those who **"support"***

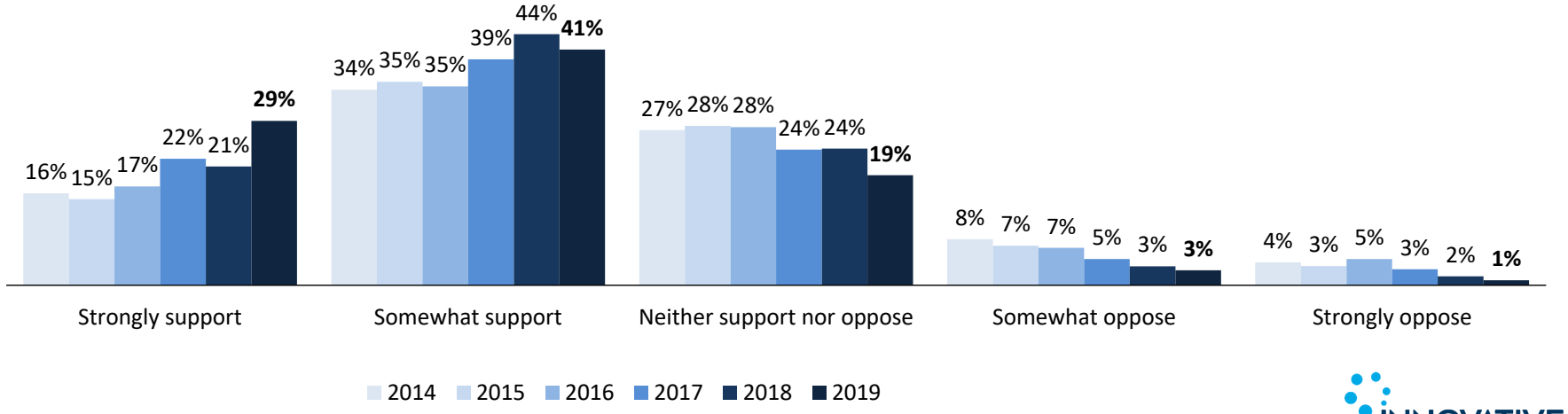


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Infrastructure Investment (Tracking): Support for investment continues to grow, now at 70% (a 20-point gain since tracking began in 2014)

Q Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?
(2014-2016: Given everything you have read, seen or heard ...
Do you support or oppose investment in and expansion of the generation, transmission and distribution of electrical power in your province?)
[asked of all respondents; n=1,600]

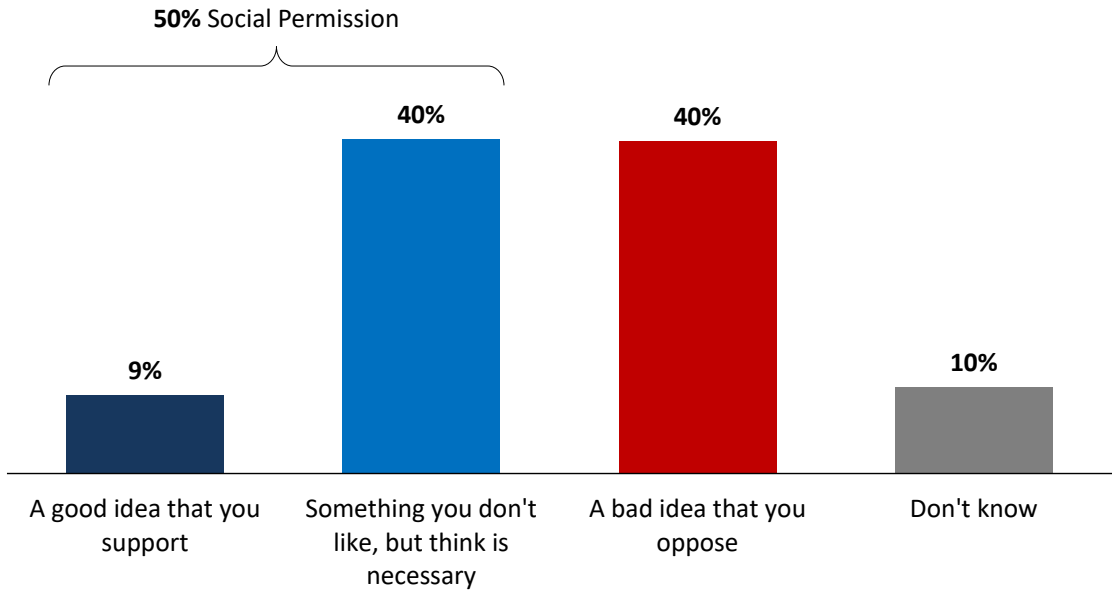




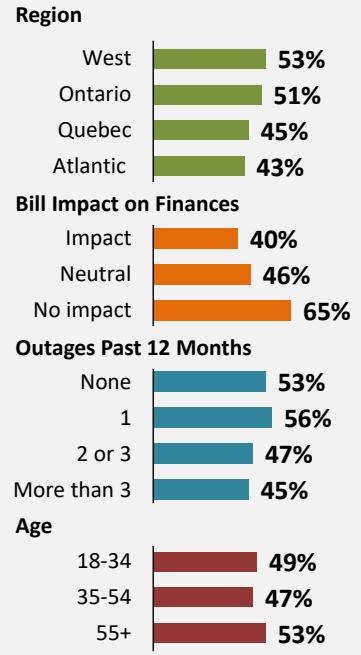
NOTE: 'Don't know' (8% in 2019) not shown.

Permission on Price Increase: Majority (50%) give permission for electricity price increase; highest support (65%) among financially comfortable

Q Do you think increasing the price of electricity to invest in our province's electric system is…
[asked of all respondents; n=1,600]



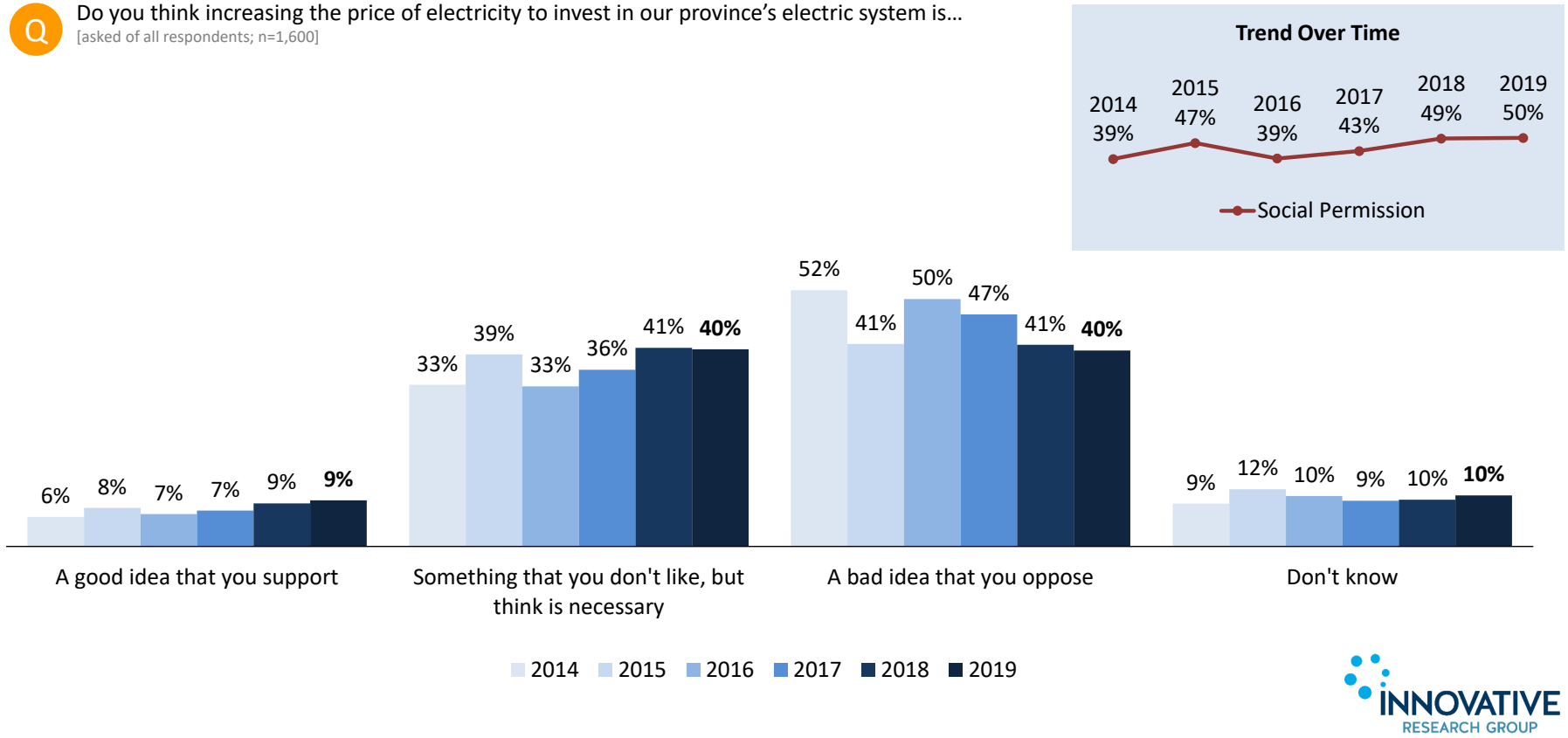
Segmentation
*Those who say **"good idea/necessary"***



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Social Permission on Price (Tracking): Majority (50%) now support a price increase; at highest levels since tracking began in 2014 (39%)

Q Do you think increasing the price of electricity to invest in our province's electric system is…
[asked of all respondents; n=1,600]



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Social Permission by Support for Infrastructure Investment: 2-in-3 (66%) who strongly support investment would allow a price increase

Q Do you think increasing the price of electricity to invest in our province's electric system is…
BY
Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?
[asked of all respondents; n=1,600]

Do you support or oppose investment, replacement and/or expansion of electricity infrastructure in your province to improve reliability and safety of our system and keep up with growth and innovation?

	Strongly support	Somewhat support	Neither	Somewhat oppose	Strongly oppose	Overall
A good idea that you support	16%	9%	5%	6%	6%	9%
Something you don't like, but think it is necessary	50%	44%	32%	23%	6%	40%
A bad idea that you oppose	30%	41%	50%	63%	85%	40%
Social Permission	66%	53%	37%	29%	12%	50%

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NOTE: 'Don't know' not shown.

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Regression Analysis

What drives general satisfaction and NPS?

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Using Regression Analysis

What is Regression Analysis?

Regressions are another means of determining importance.

- A regression allows us to take all the questions that may explain the key question we are interested in and see which of these is the most important. Regressions do this by holding all the likely suspects constant and varying one question at a time to see which questions (explanatory variables) have the greatest impact on the key question (dependent variable).

Satisfaction Regression Analysis ▸▸

- In this study what aspects of respondents' demographics and public opinion drive their overall satisfaction with their electricity company?
- We use the factors that fed into the CSI but also add respondents' demographics, attitudes, and experiences to the model to see what matters most when everything else is held constant
- When respondents were asked about their overall satisfaction they were asked *specifically* about their respective company by name.

Attitudes and Performance Metrics factored ▸▸

- To further reduce the overlap of variables to be included in the regression model, we ran a factor analysis of all the key drivers, including the performance metrics from the CSI section of the report.
- The following slides describes the result of this analysis.

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Regression Analysis: *The Full Model*

Key Drivers

Customer Focus

Public Good

Billing Practices

Quality/Reliability and Outage Preparation

- **Quality & Reliability**
- **Outage Preparation**

Planned Outage Experience

- Communications during planned outage were proactive
- Satisfaction with planned outage communication

Price/Value

- Price reasonable for electricity in province
- Good value for price compared to other bills

Standalone

- Taking care of problems the first time you contact them
- Overall communication from [DISTRIBUTOR]
- Providing online services
- Electricity company has better customer service than other companies

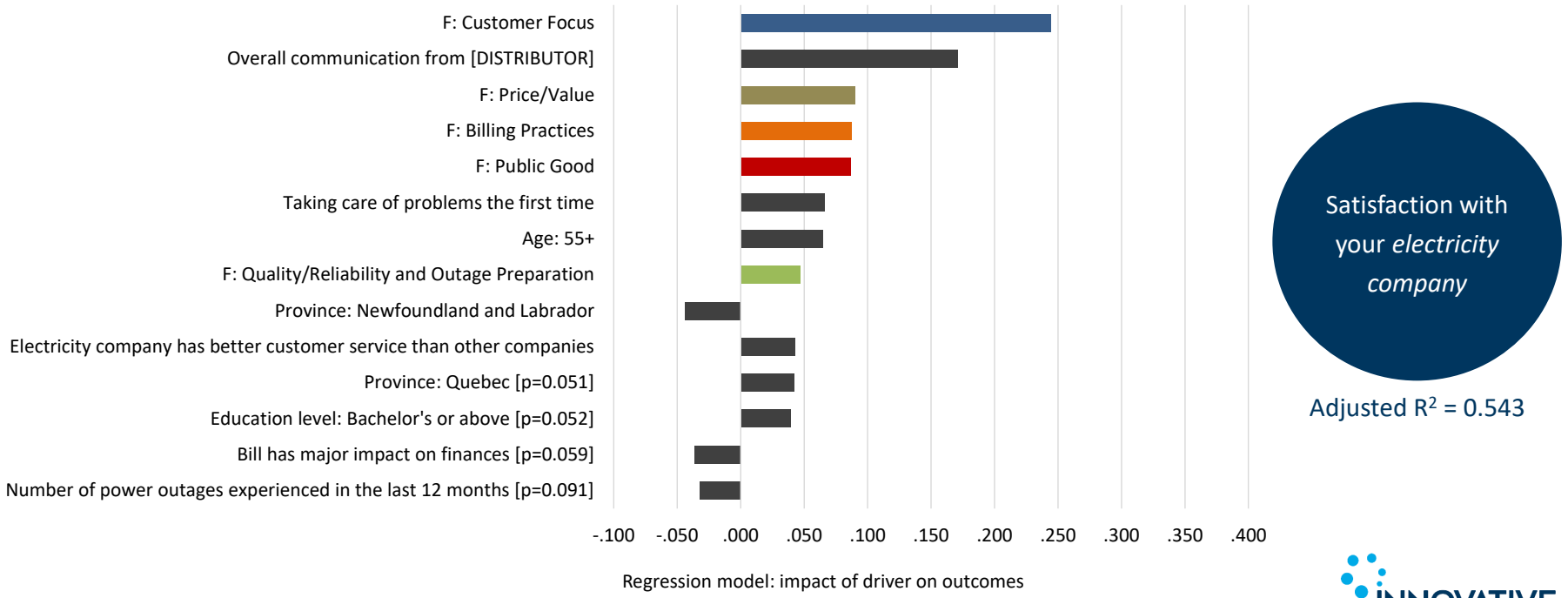
Controls

- Province
- Basic demos (age, gender, education, income)
- Primary heat source
- Bill has major impact on finances
- Satisfaction with provincial government's management of electricity system
- Familiarity with the electricity system
- Number of power outages experienced in the last 12 months

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Regression Analysis: *General Satisfaction*

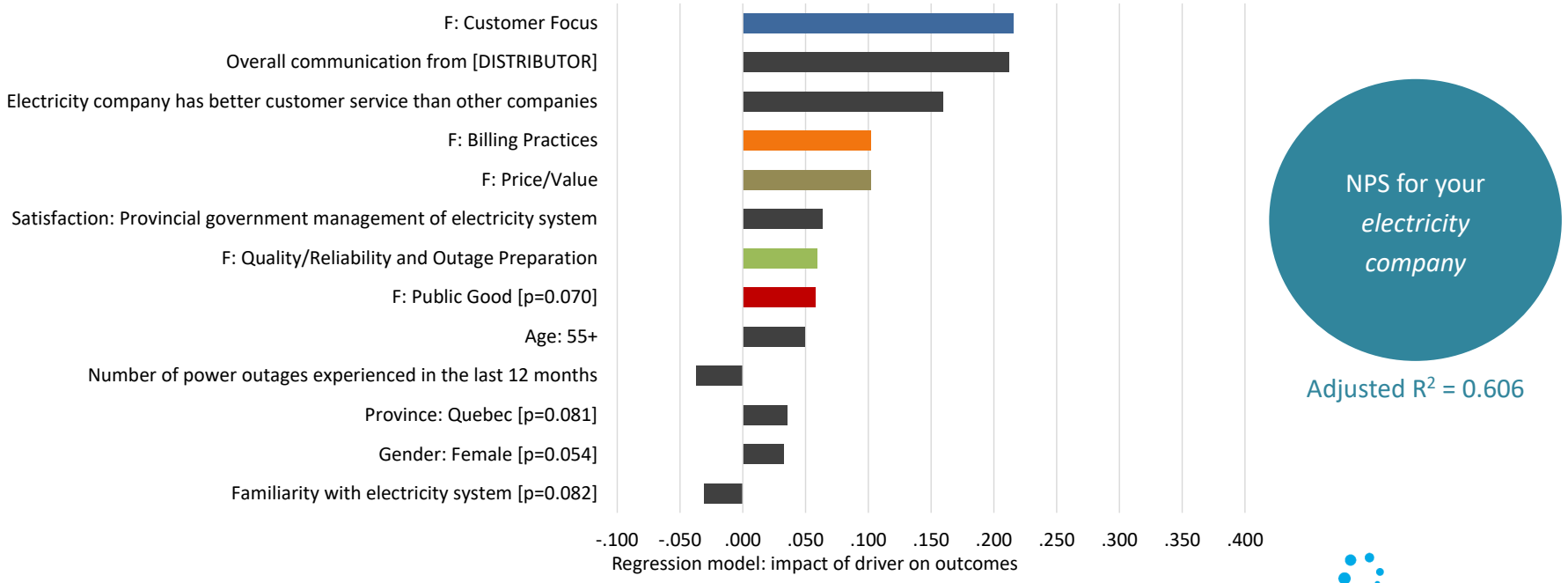
Customer Focus is by far the largest driver of satisfaction, followed by overall communication from the distributor. *Price/Value* is the third most influential driver. Struggling to pay electricity bills has a small negative effect.



NOTE: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

Regression Analysis: *Net Promoter Score (NPS)*

The top driver of NPS is the same as the general satisfaction: *Customer Focus*, followed by overall communication from the distributor. Feeling that one's distributor provides better customer service than other companies is also a strong driver of NPS.



NOTE: Chart shows standardized beta scores. All drivers significant at a 95% confidence interval unless indicated otherwise.

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Greg Lyle
President
416-642-6429
glyle@innovativeresearch.ca

Susan Oakes
Vice President
416-642-6341
soakes@innovativeresearch.ca

Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto ON | M5E 1A7
www.innovativeresearch.ca

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Appendices

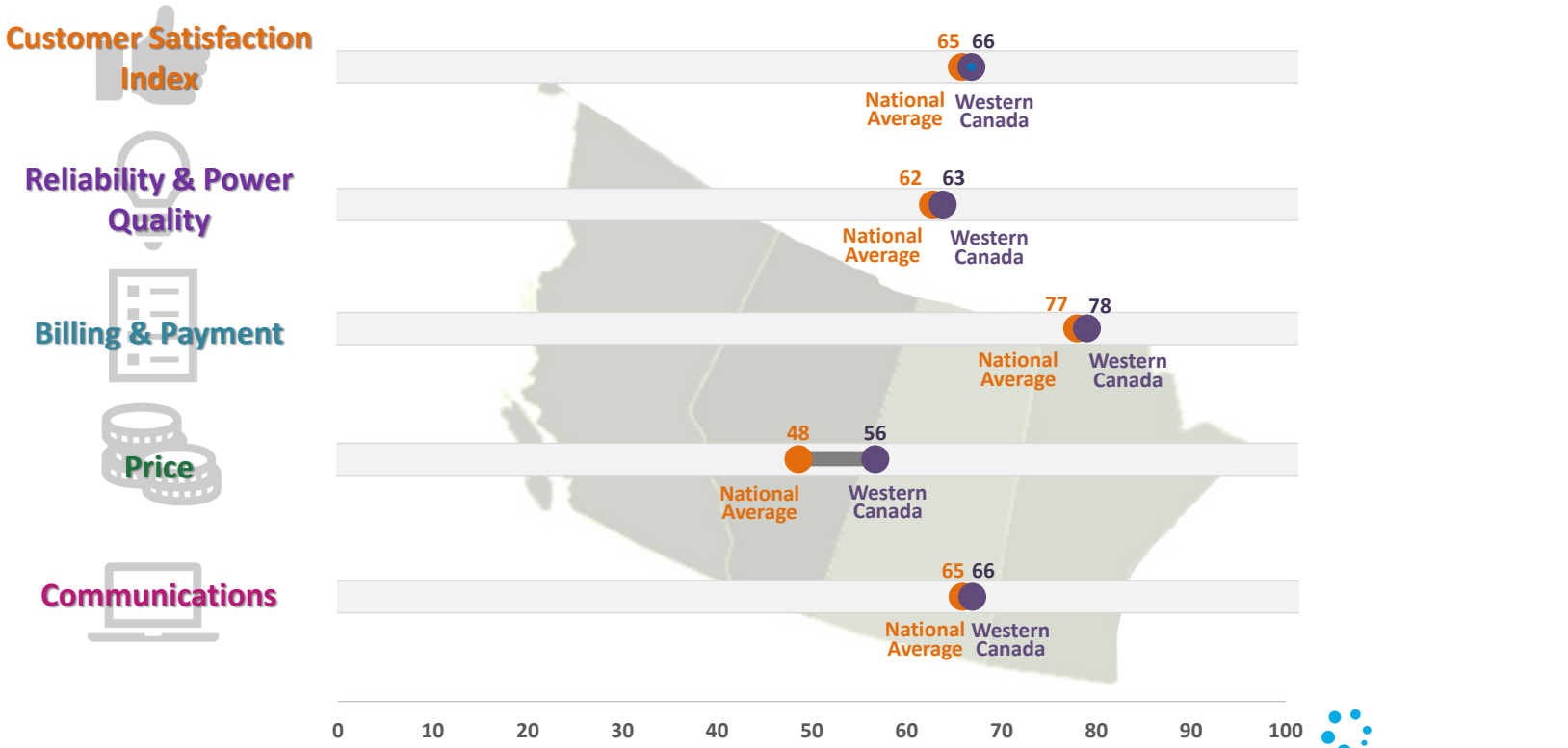
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Regional Summaries

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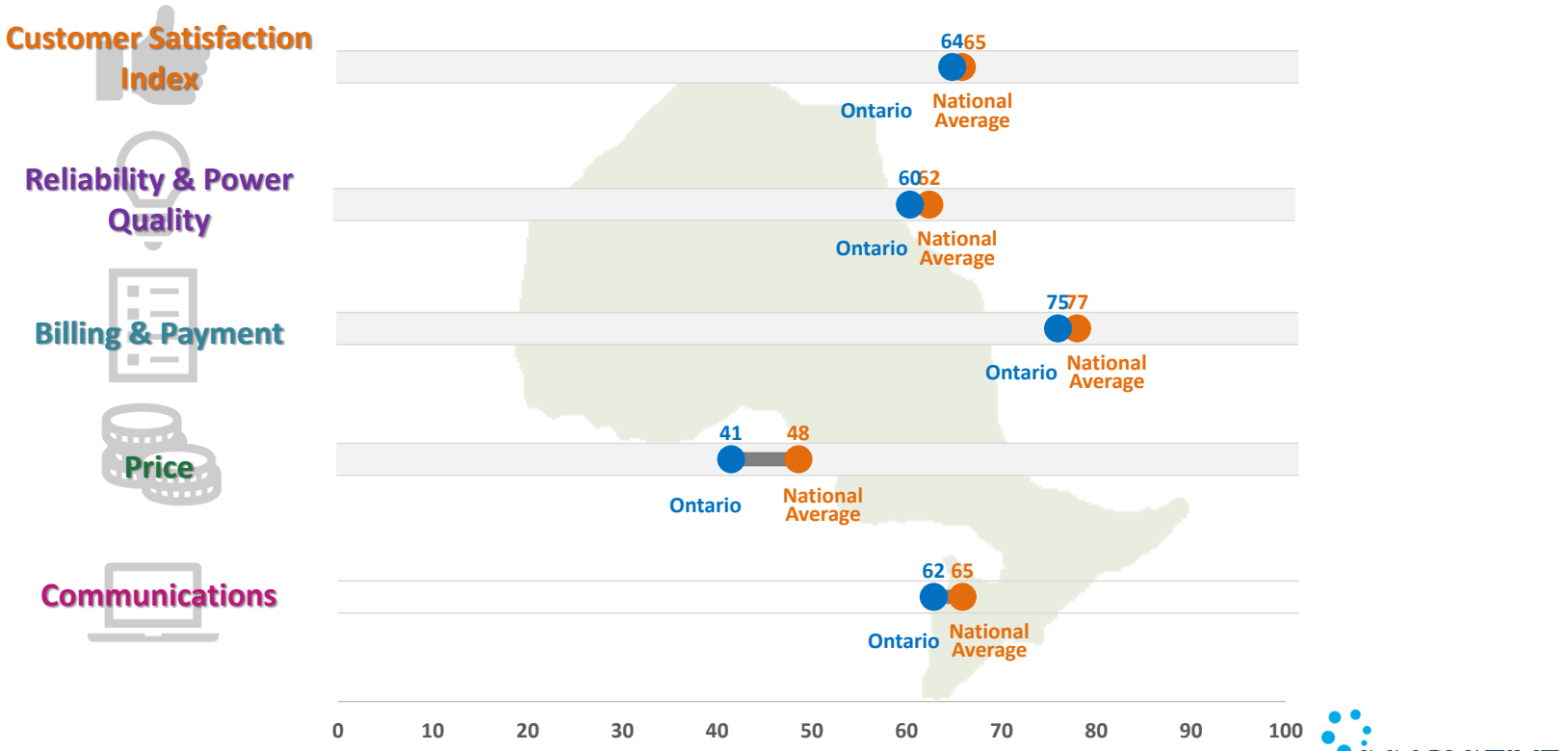
How Does Western Canada Differ From the National Average?



Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures.
"Reliability & Power Quality" and *"Billing & Payment"* represent an index of all measures of satisfaction within that dimension.

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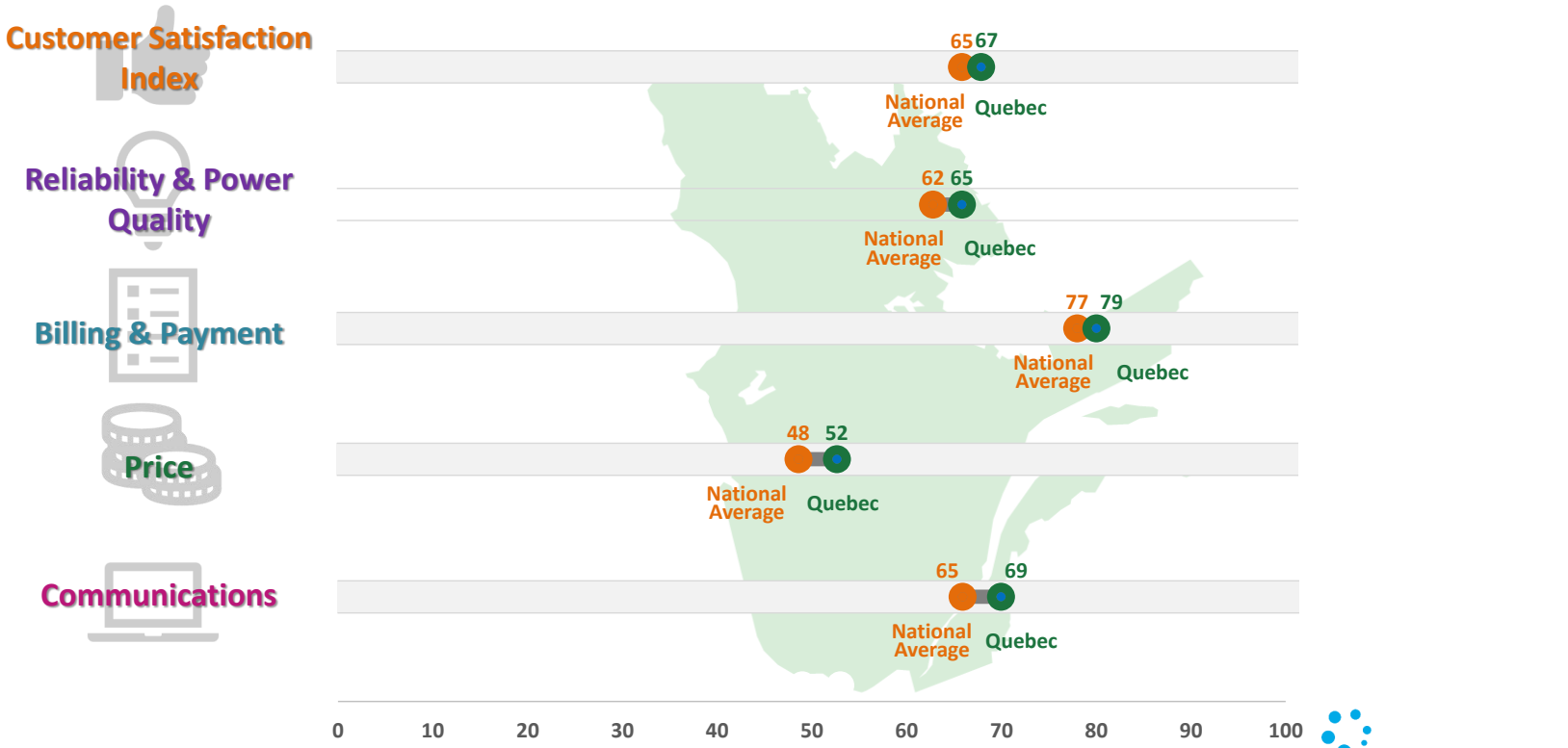
How Does Ontario Differ From the National Average?



Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures.
"Reliability & Power Quality" and *"Billing & Payment"* represent an index of all measures of satisfaction within that dimension.

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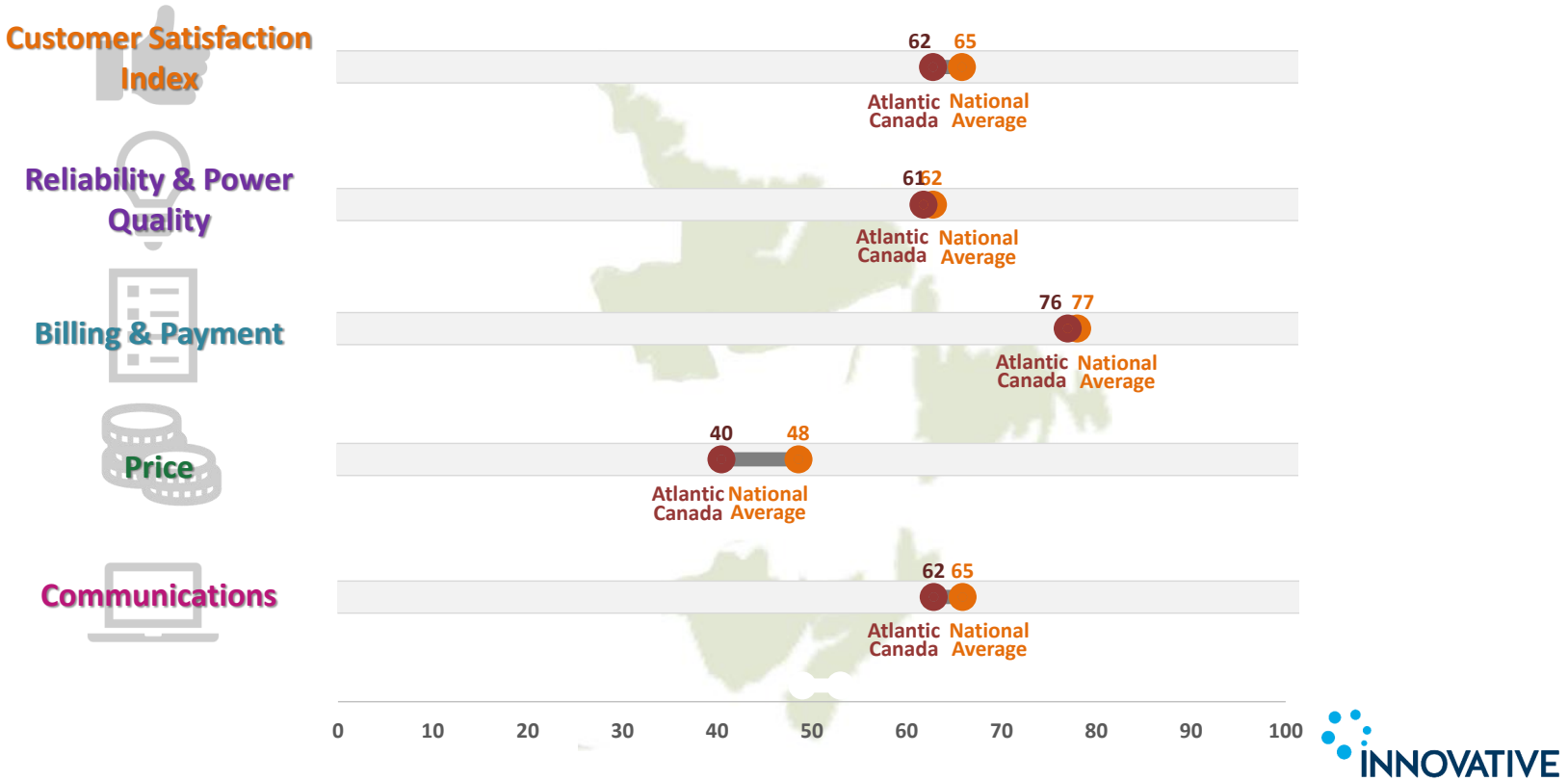
How Does Quebec Differ From the National Average?



Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures.
"Reliability & Power Quality" and *"Billing & Payment"* represent an index of all measures of satisfaction within that dimension.

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How Does Atlantic Canada Differ From the National Average?



Regional CSI scores were multiplied by 10. All other values indicate percentage of respondents satisfied (6,7,8,9,10) with the core measures.
"Reliability & Power Quality" and *"Billing & Payment"* represent an index of all measures of satisfaction within that dimension.

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Environmental Controls

A closer look

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Environmental Controls: *Uncontrollable External Factors*

It is important to distinguish between what is within, and what is outside of an electrical utility's influence or control when it comes to drivers of satisfaction.

Perceptions of electricity companies often tend to move with general perceptions of ***provincial government performance in the sector*** rather than in response to the utility itself.

In addition, perceptions of utilities are strongly correlated with **financial circumstances**. In tough times, perception and preference can change because customers are struggling with their bills, not because of anything the company has – or as not – done.

Control questions help distributors distinguish between two factors that impact public perception:

a) utility-driven programs; and

b) uncontrollable external factors.

In this survey, we include two environmental control questions to help capture external phenomena:



Government Performance: *How satisfied are you with the job your provincial government is doing to manage the electricity system?*



Financial Circumstances: *The cost of my electricity bill has major impact on my finances and requires I do without some other important priorities.*

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Summary: *Change Outside Controls*

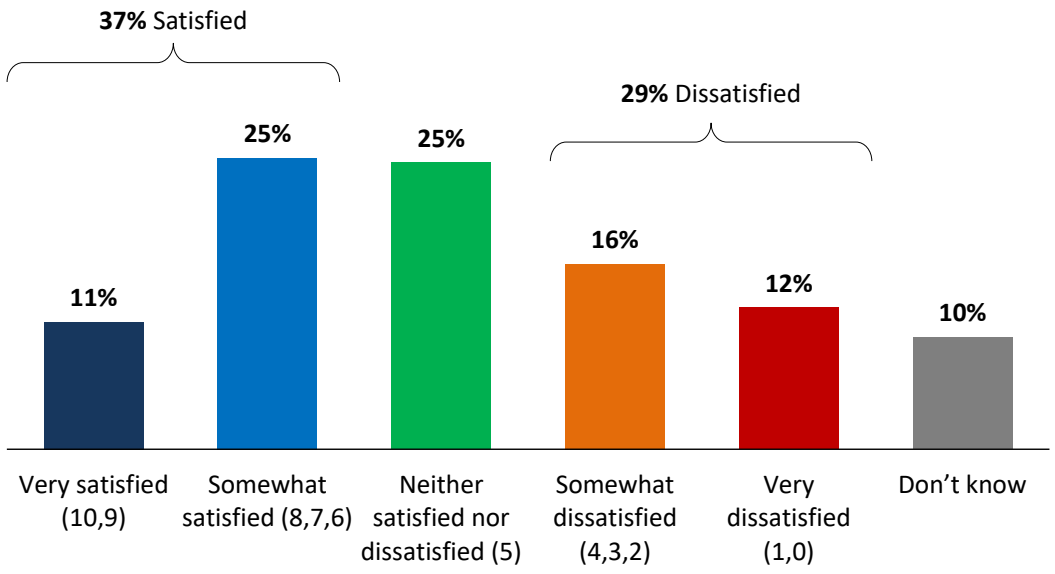
- For the second year running, there are more people who are *satisfied* with provincial government management of electricity than are *dissatisfied.*
- The proportion of those happy with the government who are also satisfied with their utility has not changed, but the actual number of people satisfied with the government is larger, resulting in a higher number of people satisfied with their utility.
- The upward trend on utility satisfaction among those unhappy with government management continues, suggesting that utilities are not only keeping happy people happy, but they are also overcoming dissatisfaction with government management. Those only neutral on gov't management are also marginally more satisfied with their electricity company this year.
- Perceived impact of electricity bills on financial circumstances has remain unchanged, as has the proportion of those whose bill has an impact who are satisfied with their electricity company.
- As we saw with the government control, utilities have sustained the gains they have been making in recent years in utility satisfaction among those who have the hardest time getting by financially.
- As such, as we saw last year, the increase in general satisfaction is not just a result of external factors. The actions of the utilities are also driving the higher levels of satisfaction.

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Provincial Gov't: Less than 4-in-10 (37%) are satisfied with provincial government's stewardship of the electricity system

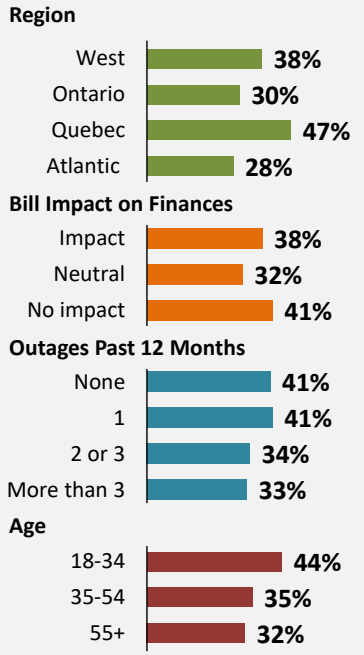
Q How satisfied are you with the job your provincial government is doing to manage the electricity system? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents; n=1,600]



Segmentation

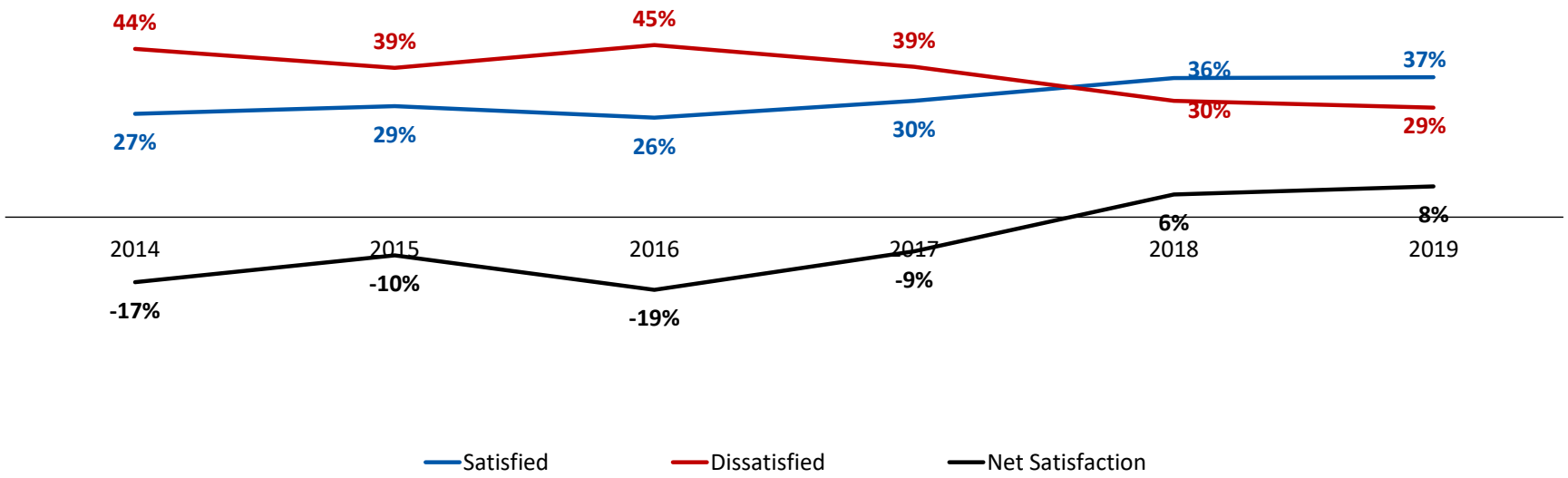
*Those who are **"satisfied"***



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Gov't Performance (Tracking): Satisfaction stable year-to-year; two years running, respondents are net satisfied with their provincial government

Q How satisfied are you with the job your provincial government is doing to manage the electricity system? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.
[asked of all respondents; n=1,600]

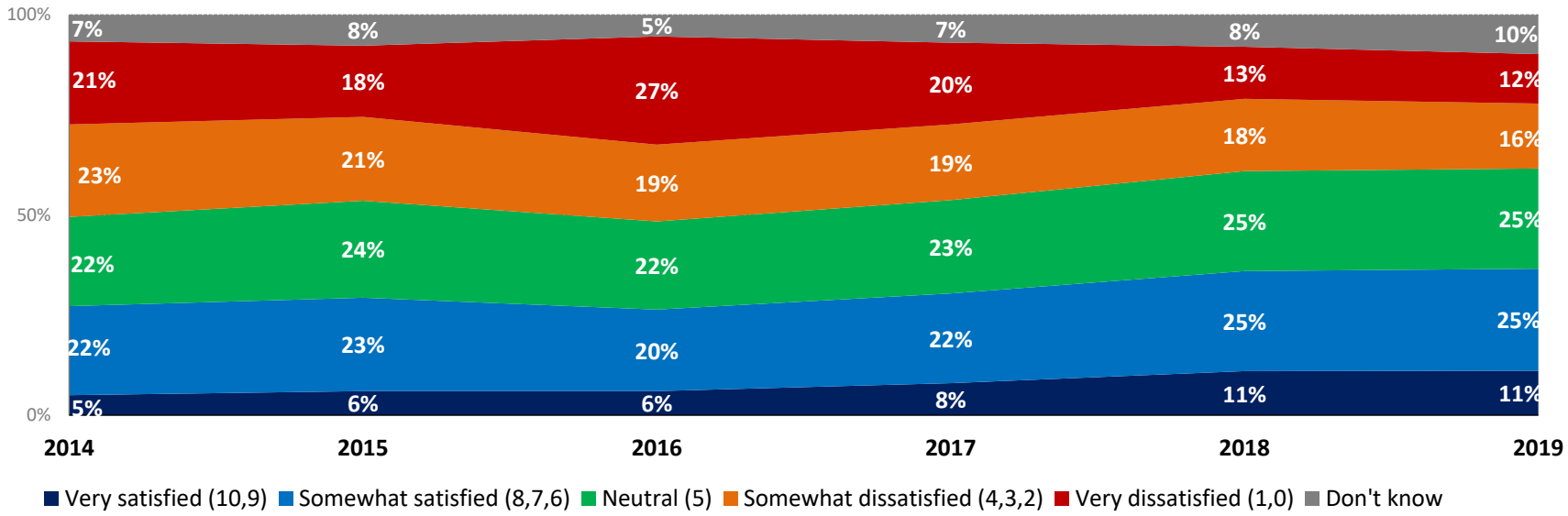


NOTE: 'Don't know' (10% in 2019) not shown.

Gov't Performance (Tracking): Net satisfaction has improved two years running, now at highest point (+8) since tracking began

Q How satisfied are you with the job your provincial government is doing to manage the electricity system? Please use the scale from 0 to 10, where 0 means very dissatisfied and 10 means very satisfied.

[asked of all respondents; n=1,600]



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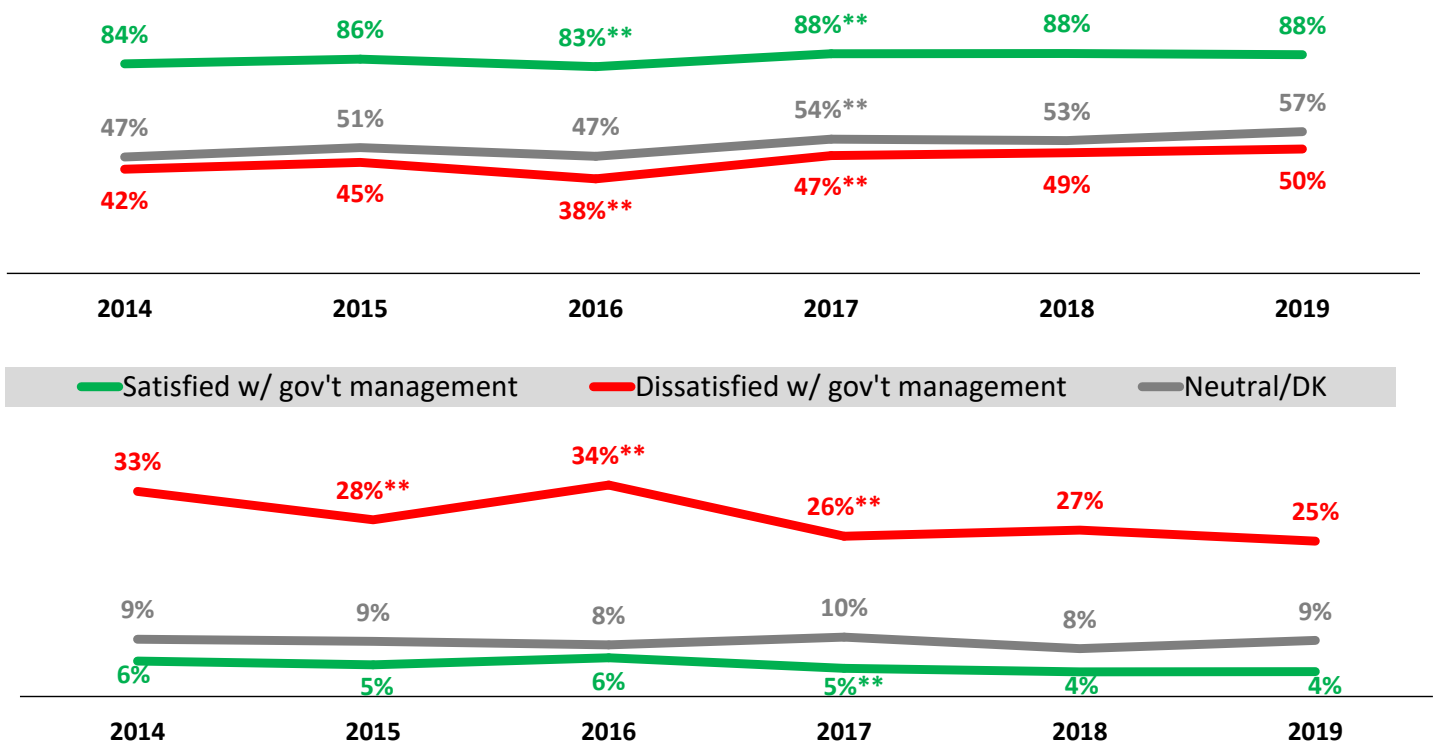
Government Performance: Those neutral on gov't management are marginally more satisfied with their electricity company



% Satisfied with Electricity Company



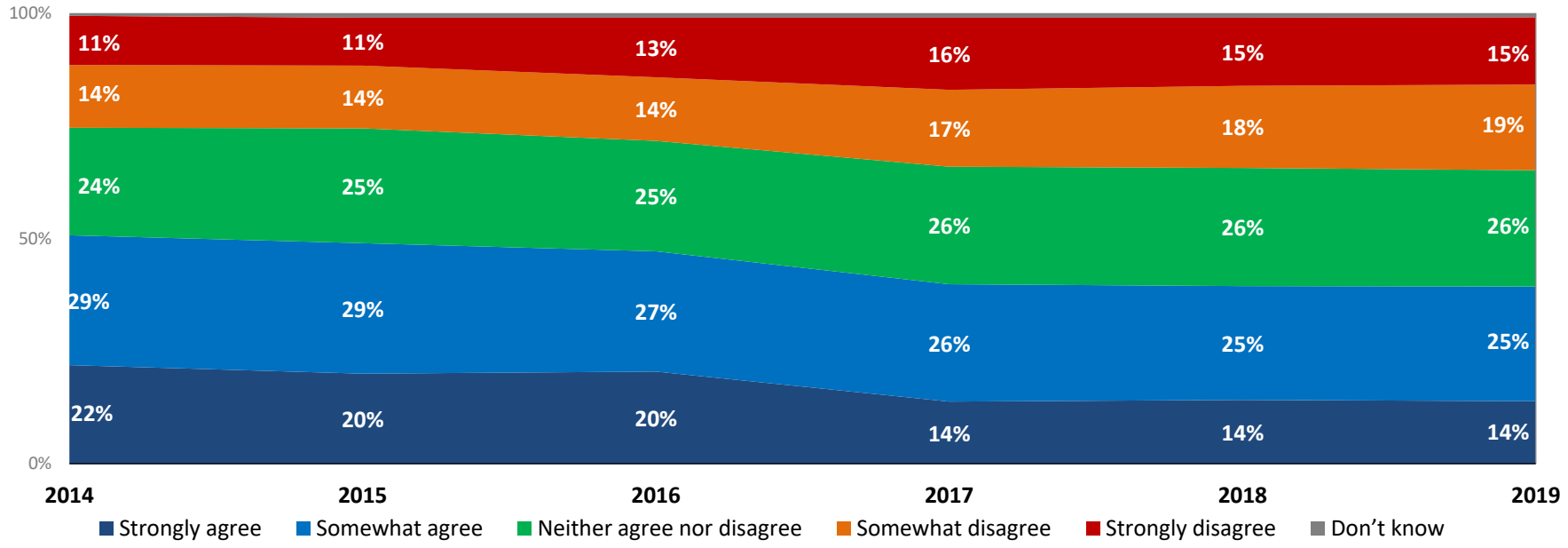
% Dissatisfied with Electricity Company



* Significantly different from the year prior at 90% confidence level
** Significantly different from the year prior at 95% confidence level

Financial Circumstances (Tracking): Plurality (39%) struggle to pay electricity bills, no change year-to-year

Q Do you agree or disagree with the following statement:
My electricity bill has major impact on my finances and requires I do without other important priorities.
[for tracking purposes, data filtered to show only those who receive a bill; n=1,441]



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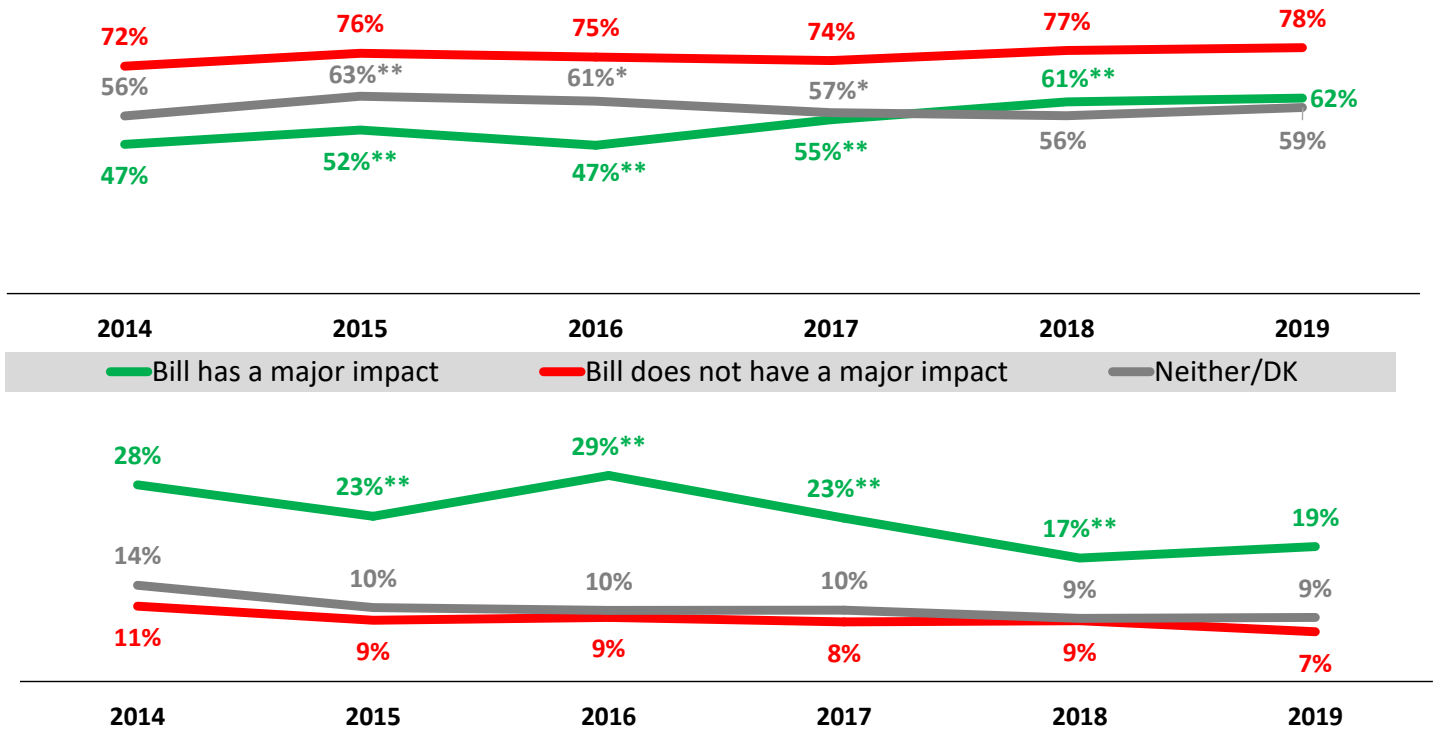
Financial Circumstances: Satisfaction with electricity company steady at 62% among those who feel their bill has a major impact on finances



% Satisfied with Electricity Company



% Dissatisfied with Electricity Company



* Significantly different from the year prior at 90% confidence level
** Significantly different from the year prior at 95% confidence level

INTERROGATORY RESPONSE - SEC-4

1-SEC-4

EXHIBIT REFERENCE:

[Ex.1]

SUBJECT AREA: Corporate Scorecard

Please provide a copy of Hydro Ottawa's corporate scorecard for each year between 2016 to 2020.

RESPONSE:

A copy of Hydro Ottawa's corporate performance scorecard for each year between 2016 and 2020 is appended to this response as Attachment SEC-4(A): 2016-2020 Corporate Performance Scorecards. The corporate scorecards have been redacted to remove information that relates to the performance of Hydro Ottawa's affiliates and that is therefore outside the scope of this proceeding.

Final - 2016 Corporate Performance Scorecard

HYDRO OTTAWA HOLDING INC. BOARD OF DIRECTORS
April 21, 2016

Background

- On November 26, 2015, the HOHI Board approved the 2016 Corporate Performance Scorecard appended at Annex 'A' ***subject to amendments that may be considered and approved by the Strategic Initiatives Oversight Committee (SIOC) at its next meeting to be held early in 2016***
  - *The Chair noted that there was a need to further integrate certain key priorities arising from the November 3, 2015 Board Strategy Session into the proposed scorecard, and that further consideration would be given to this by the Strategic Initiatives Oversight Committee at a meeting to be scheduled early in 2016*
  - *It was also noted that certain findings from the recently completed internal audit reports should be considered for integration into the scorecard as well*
- On February 4, 2016, SIOC received and discussed proposed amendments to the scorecard that further integrated the key priorities arising from the November 3, 2015 HOHI Board Strategy Session, and approved the amendments as presented.

Today

- The HOHI Board will formally receive the final 2016 Corporate Performance Scorecard.

Corporate Performance Scorecard Framework

We plan our course for a 5-year period	Hydro Ottawa's **Strategic Direction** • provides a comprehensive overview of our business strategy and financial projections for a 5-year period
We implement and operate in accordance with annual plans and budget	The annual business plan for the enterprise has two components • A budget including **summary key strategic priorities**, and • A corporate performance scorecard (**more comprehensive list of strategic priorities** and measures & targets) that we cascade to employees to align them to deliver against strategy
We monitor and report performance and progress against annual plans and budget	• Monthly reviews by the Executive Management Team • Quarterly President & CEO reports to the 2 Boards including ERM reporting and letters of representation • Quarterly financial reports and monthly updates to the Shareholder • Year end performance results reviews and President & CEO report to the 2 Boards • Annual Report to the Shareholder

Summary Key Strategic Priorities

Included in 2016 Business Plan and Budget

(excerpt from 2016 Corporate Performance Scorecard at Annex 'A', slide 19)

Financial Strength – ***grow revenues from new sources and enhance / protect revenues from existing business lines***

[redacted]

- Conservation and Demand Management - Deliver on year two of six-year plan to achieve GWh reductions

Customer Value – ***assist customers in managing their energy consumption and electricity costs; deliver on customer expectations for service quality and responsiveness; and maintain overall distribution system reliability***

- Distribution System Reliability - Continue improvements in maintenance and capital program execution and deliver on year one of five-year reliability plan leveraging Reliability Council
- Customer Experience Strategy and Roadmap - Continue implementation of initiatives / solutions with a focus on modernization, customer communications and customer self-serve

[redacted]

Summary Key Strategic Priorities (cont'd)

Included in 2016 Business Plan and Budget

(excerpt from 2016 Corporate Performance Scorecard at Annex 'A', slide 20)

Organizational Effectiveness – ***continue to enhance operational performance and productivity; maintain leading health and safety record; and enhance organizational and employee capability***

- Facilities Upgrade Implementation – Complete RFP, execute design / build contract, complete design and achieve site plan approval
- [redacted]

Corporate Citizenship – ***enhance our brand image in the community and the industry; improve our environmental performance and reduce our impact on the environment***

- [redacted]

HydroOttawa [redacted]









Annex 'A'

2016 Corporate Performance Scorecard

to support the advancement of the

~~*2012-2016 Strategic Direction in Year 5 of the Plan*~~

2016-2020 Strategic Direction in Year 1 of the Plan

Amendments in red font

BOARDS OF DIRECTORS – HYDRO OTTAWA LIMITED AND HYDRO OTTAWA HOLDING INC.
NOVEMBER 26, 2015

Board Decisions Required Today

- Review & approve the 2016 Corporate Performance Scorecard
- Specifically, for each of the 4 key areas of focus in the scorecard, review and approve
  - QUALITATIVE performance goals and priorities for 2016
  - QUANTITATIVE performance measures and targets for 2016

Context - Where We're At in this Year's Annual Board Business Planning Cycle

September 18, 2015	HOL Board endorsed Guidelines to guide preparation of 2016 HOL Business Plan Priorities and Budget
	HOHI Board endorsed Guidelines to guide preparation of 2016 HOL and Enterprise Business Plan Priorities and Budget
November 3, 2015	HOHI Board discussed critical issues and opportunities facing the company
September to November 2015	Development of 2016 Business Plan Priorities and Budget, and Performance Scorecard ▪ Takes into consideration previous year's approved plan, updated for the changing environment and business priorities
November 26, 2015	HOL Board endorses 2016 HOL Business Plan Priorities and Budget, and Performance Scorecard and recommends to HOHI Board
	HOHI Board receives for approval 2016 HOL and Enterprise Business Plan Priorities and Budget, and Performance Scorecard
April 2016	Year End Committee and Board meetings – for Year 2015
June 2016	Year 2015 Annual Reporting to the Shareholder – AGM

Context - Where the Performance Scorecard Fits into our Integrated Planning & Performance Management Framework

PLAN
our course for a 5-year period

- ***Hydro Ottawa's Strategic Direction*** *(comprehensive overview of our business strategy and financial projections for a 5-year period)*



IMPLEMENT & OPERATE
in accordance with annual plans and budget

- ***Annual Business Plan for the Enterprise*** *to drive the strategic direction – 2 components*
  1. ***Priorities, Budget & 2-Year Financial Outlook***
  2. ***Performance Scorecard***
- ***Annual Individual Contribution Plans (ICPs) & Performance Appraisal System*** *to align individual employees to deliver against strategy*



MONITOR & REPORT
performance and progress against annual plans and budget



REVIEW & ADJUST
our course as required

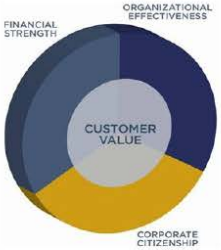
- *Adjustment of current plans as required to address identified areas for improvement*
- *Review of critical issues and opportunities facing the company and development of subsequent year plans and budget*



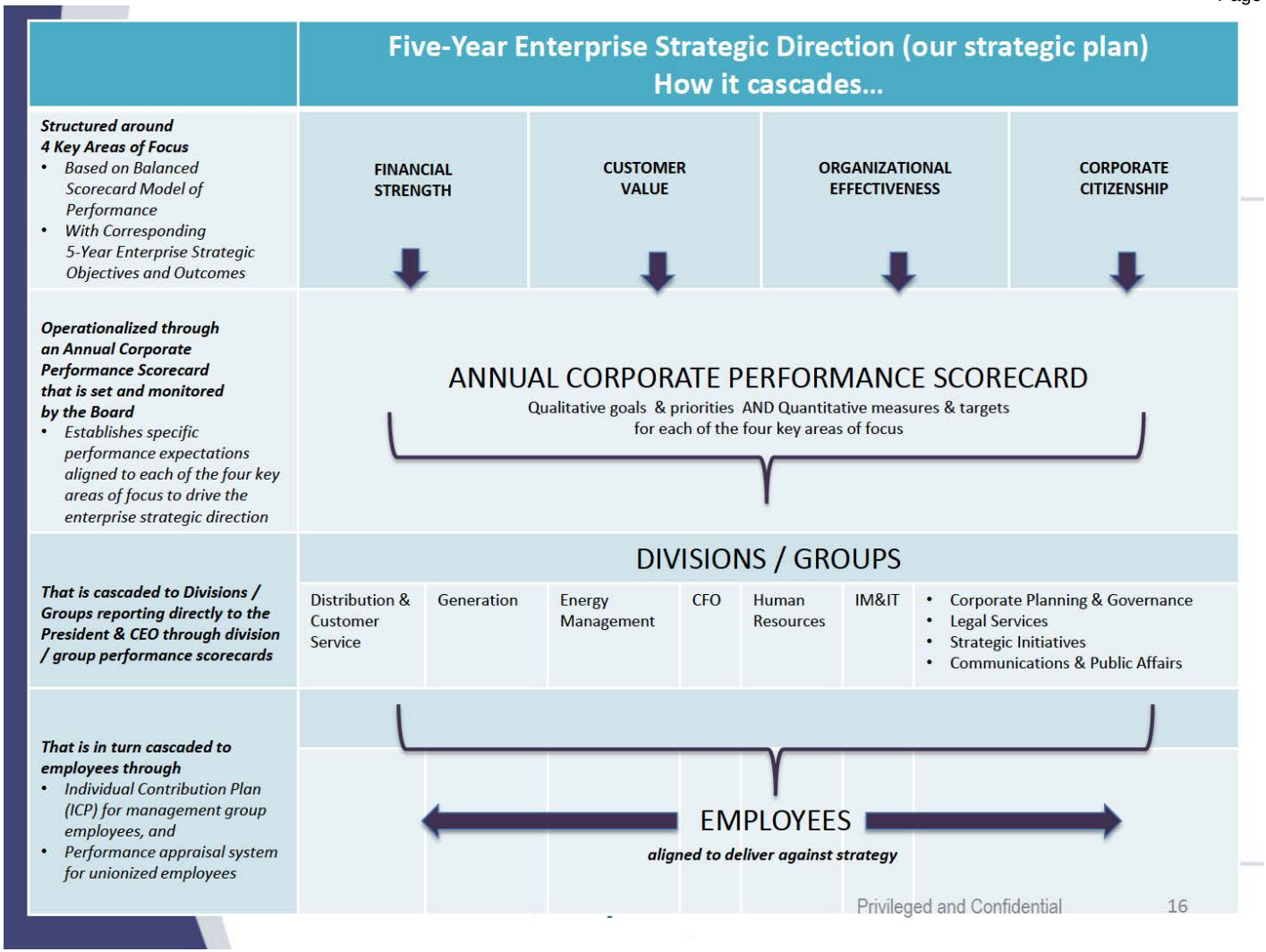
- *Monthly reviews by Executive Management Team*
- ***Quarterly President & CEO reports to the 2 Boards, including ERM reporting and letters of representation***
- *Quarterly Financial Reports and Monthly Updates to the Shareholder*
- *Year End Performance Results Reviews and President & CEO Report to the 2 Boards*
- *Annual Report to the Shareholder*

2016 Corporate Performance Scorecard

- As in previous years, the Board is being requested to approve **one corporate performance scorecard for the enterprise** for 2016
- The scorecard establishes qualitative performance goals and priorities and quantitative measures and targets in each of our four key areas of focus to support the advancement of the 2012-2016 Strategic Direction in **year five** of the five-year plan
  - Customer Value
  - Organizational Effectiveness
  - Corporate Citizenship
  - Financial Strength



- The scorecard also includes separate quantitative Financial Strength performance targets for the HOL entity
- Performance priorities for executive and management staff will be cascaded from the corporate performance scorecard (see next slide) to align individuals to deliver against strategy
- Results highlights and progress against the scorecard (including ERM assessment) will be reported quarterly to the HOHI and HOL Boards by the President & CEO


Five-Year Enterprise Strategic Direction (our strategic plan)
How it cascades…
Structured around 4 Key Areas of Focus
• Based on Balanced Scorecard Model of Performance
• With Corresponding 5-Year Enterprise Strategic Objectives and Outcomes
FINANCIAL STRENGTH
CUSTOMER VALUE
ORGANIZATIONAL EFFECTIVENESS
CORPORATE CITIZENSHIP
Operationalized through an Annual Corporate Performance Scorecard that is set and monitored by the Board
• Establishes specific performance expectations aligned to each of the four key areas of focus to drive the enterprise strategic direction
ANNUAL CORPORATE PERFORMANCE SCORECARD
Qualitative goals & priorities AND Quantitative measures & targets for each of the four key areas of focus
That is cascaded to Divisions / Groups reporting directly to the President & CEO through division / group performance scorecards
DIVISIONS / GROUPS
Distribution & Customer Service
Generation
Energy Management
CFO
Human Resources
IM&IT
• Corporate Planning & Governance
• Legal Services
• Strategic Initiatives
• Communications & Public Affairs
That is in turn cascaded to employees through
• Individual Contribution Plan (ICP) for management group employees, and
• Performance appraisal system for unionized employees
EMPLOYEES
aligned to deliver against strategy
Privileged and Confidential
16

Scorecard Principles for 2016

One Corporate Performance Scorecard for the Enterprise

- *Separate Financial Strength performance measures and targets for HOL 'entity'*
- *'Highlighted' qualitative supporting priorities have HOL Board oversight*

Weightings for each of 4 key areas of focus

- *Removed as per Board direction in 2015*

Targets associated with quantitative performance measures

- Reflect past performance and changing circumstances, and
- Encourage and reward continuous improvement where appropriate

Monitoring and Reporting

- Provides for more detailed measures / tracking tools for management use while keeping Board reporting at more strategic level
- Includes monthly monitoring of progress by the Executive Management Team, and quarterly reporting to the Boards as part of President and CEO's quarterly report and letters of representation

2016 Performance Goals Summary

5-Year Enterprise Strategic Objectives and Outcomes (2012-2016) to be validated for 2016-2020 as part of plan refresh		2016 Corporate Performance Goals
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	• *Grow revenues from new sources* • *Enhance / protect revenues from existing business lines*
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	• *Assist customers in managing their energy consumption and electricity costs* • *Deliver on customer expectations for service quality and responsiveness* • *Maintain overall distribution system reliability*
Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	• *Continue to enhance operational performance and productivity* • *Maintain leading health and safety record* • *Enhance organizational and employee capability*
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services* *Positive community impact*	• *Enhance our brand image in the community and the industry* • *Continue to improve our environmental performance and reduce our impact on the environment*

Key Strategic Priorities

Included in 2016 Business Plan and Budget

Financial Strength – ***grow revenues from new sources and enhance / protect revenues from existing business lines***

- [redacted]
- Conservation and Demand Management - Deliver on year two of six-year plan to achieve GWh reductions

Customer Value – ***assist customers in managing their energy consumption and electricity costs; deliver on customer expectations for service quality and responsiveness; and maintain overall distribution system reliability***

- Distribution System Reliability - Continue improvements in maintenance and capital program execution and deliver on year one of five-year reliability plan leveraging Reliability Council
- Customer Experience Strategy and Roadmap - Continue implementation of initiatives / solutions with a focus on modernization, customer communications and customer self-serve
- [redacted]

Key Strategic Priorities (cont'd)

Included in 2016 Business Plan and Budget

Organizational Effectiveness – ***continue to enhance operational performance and productivity; maintain leading health and safety record; and enhance organizational and employee capability***

- Facilities Upgrade Implementation – Complete RFP, execute design / build contract, complete design and achieve site plan approval
- [redacted]

Corporate Citizenship – ***enhance our brand image in the community and the industry; improve our environmental performance and reduce our impact on the environment***

- [redacted]

Financial Strength

QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Financial Strength
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2016 Corporate Performance Goals and Supporting Priorities	Assessment
1. Grow revenues from new sources	
[redacted]	
b. Distribution Expansion – ~~Hydro One Service Territory in Ottawa, other LDCs~~ i. Approach other LDCs in Ontario regarding potential acquisition/mergers/partnerships [redacted]	
c. Synergies – [redacted] **iv. Regional Training** – Develop and implement plan for Training Delivery Agent Status (dependent on MTCU decision)	

Financial Strength
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2016 Corporate Performance Goals and Supporting Priorities	Assessment
1. Grow revenues from new sources - continued	
e. Conservation and Demand Management – Deliver on year two of six-year plan to achieve GWh reductions and financial incentives, and update the plan as new technologies, programs and opportunities arise to set the stage for 2017-2020 i. As new technologies, programs and opportunities arise, update the approved six-year CDM plan to maximize GWh results by December 31, 2017 to achieve financial incentive s in the $3M range (target of 200 GWh) ii. While focusing efforts on the 2017 GWh results, set the stage for delivering strong GWh results in the 2018 to 2020 timeframe with the objective of achieving additional financial incentives in the $3M to $6M range (Target 200 GWh and spend < $100M of the $105M approved budget)	
2. Enhance / protect revenues from existing business lines	
[redacted]	
b. Collection of Bad Debts – apply more aggressive processes for collection of electricity customer accounts and damage to plant	
[redacted]	
[redacted]	
[redacted]	

Financial Strength - Proposed 2016 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will create sustainable growth in our business and our earnings *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*									
Enterprise Strategic Outcome	Growth in shareholder value									
2016 Corporate Performance Measures	2012A CGAAP	2013A CGAAP	2014A CGAAP	2015 CGAAP	2015T IFRS	Q3 YTD Target IFRS	Q3 YTD[7] Actual IFRS	Q3 YTD Assessment	Q3 ERM Rating	2016T IFRS
[redacted]										

Financial Strength - Proposed 2016 HOL Performance Measures and Targets

Enterprise Strategic Objective	We will create sustainable growth in our business and our earnings *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2016 HOL Performance Measures	**2012A**	**2013A**	**2014A**	**2015T IFRS [5]**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment**	**Q3 ERM Rating**	**2016T IFRS**
Net Income	$26.4M	$25.4M	$27.9M	$24.6M	$17.7M	$28.1M	●	X	$33.3M
Revenue *(excl CDM)*	$176.2M [1] $163.2M	$166.7M	$168.5M	$171.1M	$128.1M	$129.8M	●	●	$179.5M[7]
OM&A - Net *(excl CDM)*	$92.0M [1] $79.1M	$82.5M	$86.0M	$87.2M	$66.5M	$61.4M	●	▲	$87.5M[7]
Return on Equity	10.4%	9.6%	10.1%	8.6%	8.6%	11.4%	●	X	10.8%
Cash Flow from Operations	$73.5M	$38.9M	$94.3M	$61.2M	$25.0M	$44.8M	●	●	$80.6M
CAPEX System Renewal and Service (excluding Plant Failure) [9] Plant Failure [8] General (including Facilities Implementation Plan)	$51.7M $26.7M	$59.1M $34.7M	$74.0M $15.7M	$63.2M $19.0M	$42.5M $14.4M	$38.4M $7.1M	● ●	● X	$61.1M[9] $4.5M[8] $45.2M
Labour Allocation to CAPEX	56%	57%	60%	60%	59%	59%	●	N/A	59%
CDM – Cumulative PAB Spending	$3.3M [2] $5.1M 31%	$9.7M 59%	$13.5M 82%	N/A	N/A	N/A	N/A	N/A	N/A
CDM – Cumulative MW reduction	17 MW [3] 25MW 29%	27 MW [3] 45MW 53%	68 MW 88%	N/A	N/A	N/A	N/A	N/A	N/A
CDM – Cumulative GWh reduction	35.1GWh[4] 246GWh 66%	40GWh[4] 325GWh 87%	393 GWh 105%	50GWh	31GWh	32GWh[6]	●	N/A	70GWh

[1] In 2012, this measure was modified to exclude CDM & LRT
[2] In 2013, this measure was changed to cumulative spending, this is the annual amount
[3] In 2014, this measure was changed to cumulative MW reduction, these represent the annual MW reductions
[4] In 2014, this measure was changed to cumulative GWh reduction, these represent the annual GWh reductions
[5] No CGAAP to IFRS transitional adjustments for HOL
[6] Q3 2015 results are based on preliminary Q2 results received from the IESO plus management's estimate of Q3
[7] In 2016, this measure was modified to exclude CDM only
[8] Plant Failure is a new measure added in 2016. For reference, the actuals for 2012–2014 were $5.2M, $5.3M, and $6.8M.
[9] In 2016, this measure was modified to exclude Plant Failure

Customer Value

QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Customer Value
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2016 Corporate Performance Goals and Supporting Priorities	Assessment
1. Assist customers in managing their energy consumption and electricity costs	
a. CDM - Continue to enhance and deliver a wide range of CDM programs and bring to market new programs that are customer-centric, cost effective and generate strong GWh results	
b. Ontario Electricity Support Program (OESP) – Launch and manage the new Ontario Energy Board program that will provide ongoing financial assistance to qualifying low-income electricity consumers	
c. Customer Education Program – Continue to increase understanding of the industry and Hydro Ottawa's role and achievements within it; demystify and educate by leveraging multiple modes (digital and social media, video, open houses, workshops, etc.) and multiple channels (local media, Councillors, subject matter experts, executive and senior management)	
2. Deliver on customer expectations for service quality and responsiveness	
a. Improve Customer Service – Implement the integrated "whole of company" roadmap for customer service, including i. **Multi-Year Cultural Transformation Plan -** Develop multi-year plan aligning people and organization with Customer Experience Strategy and Roadmap, including change management, communications, training/awareness and performance alignment plans, talent segment profiles, and narratives of customer experience in action ii. **Customer Relationship Management System** – develop first phase requirements and recommendations iii. **Bill Redesign** – Complete the testing and roll out of bill redesign (paper and digital) including comprehensive customer communications campaign to facilitate seamless implementation iv. **Customer Contact Platform** – Expand the platform to allow multi-channel communication (voice, text, email, chat, etc.) v. **Voice of the Customer –** Expand transactional surveys, e.g. outages, service desk, tree trimming, service layout vi. **Strategic Account Management Plan** – Continue relationship building and product offerings (e.g. Energy dashboard) with key accounts, developers and contractors vii. **Website & Mobile Strategy** – Undertake major review of website, MHL and customer portal to provide customers a uniform platform and multi-channel experience viii. **Billing & Meter to Cash Enhancements** ix. **Mobile Workforce Management** – ~~Emergency restoration scheduling and management~~ deploy and optimize x. **2016 Go Paperless Marketing Campaign**	

Customer Value
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2016 Corporate Performance Goals and Supporting Priorities	Assessment
3. Maintain overall distribution system reliability	
a. Refresh Smart Grid Strategy	
b. Deliver on year one of the Five-Year Reliability Plan	
c. Continue our improvements in maintenance and capital program execution - *Emphasis on workforce scheduling and contractor management; Complete all budgeted programs / plans on time and within budget* i. Distribution Sustainment Capital Program – Ongoing implementation of refurbishment and enhancement programs with particular emphasis on aging infrastructure, areas with chronic reliability issues, and on new station capacity ii. Distribution Demand Capital Program – Ongoing implementation of new residential and commercial customer connections, system expansions, and third party driven plant relocations and upgrades iii. Distribution Maintenance Programs – Ongoing implementation of distribution asset evaluations (testing and inspections of poles, cable, manhole chambers and switches); forestry program analysis and overview; and increased removals as a result of Emerald Ash Borer and Storm Hardening Strategy	

Customer Value
Proposed 2016 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2016 Corporate Performance Measures	**2012A**	**2013A**	**2014A**	**2015T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment**	**Q3 ERM Rating**	**2016T**
SATISFACTION									
• Residential & Small Commercial	HO/ON Pre 88/86% Post 90/88%	HO/ON Pre 90/90% Post 90/90%	HO/ON Pre 83%/83% Post 79%/80%	90%	90%	HO/ON Pre 87%/86% Post 85%/83%	X	N/A	>91%
• Call Centre Transaction satisfaction - monthly	89%	89%	88%	>89%	>89%	90%	●	●	>90%
• The ability to deal with your issue (First Call Resolution)	86%	85%	84%	>86%	>86%	85%	X	●	>86%
• Total number of ~~escalations & inquiries~~ complaints	~~216~~ 145	~~202~~ 102	~~323~~ 140	~~<200~~ <115	~~<150~~ <86	~~193~~ 124	X	N/A	~~<200~~ <160
VALUE									
• Number of MyHydroLink customers	84,686	104,108	122,300	>135,000	>131,825	131,824	X	N/A	145,000
• Number of e-bill accounts	43,932	66,719	85,991	>100,000	>96,498	95,327	X	N/A	115,000
• Number of auto pay accounts	41,261	43,612	46,098	>47,500	>47,150	48,004	●	N/A	50,000

Customer Value - Proposed 2016 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2016 Corporate Performance Measures	**2012 A**	**2013A**	**2014A**	**2015T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment**	**Q3 ERM Rating**	**2016T*** **
PRODUCT RELIABILITY									
• SAIFI – 3 year average excluding loss of supply – OEB within range of previous 3 years	1.10	1.30	1.03*	<0.80	<0.80	0.93	●	●	<.80
• SAIFI - Annual reliability better than previous 5 year average excluding loss of supply and major event days	0.81T 1.11A	0.91T 1.24A	1.01T 0.74A	0.99	0.99	0.74	---	---	0.99
• SAIDI – 3 year average excluding loss of supply – OEB within range of previous 3 years	1.60	1.77	1.19	<1.0	<1.0	1.16	●	●	<1.0
• SAIDI - Annual reliability better than previous 5 year average excluding loss of supply and major event days	1.05T 1.24A	1.10T 1.25A	1.17T 1.08A	1.18	1.18	1.12	---	---	1.18
• FEMI* – Number of feeders with 10 or more interruptions per year	12	13	8	<10	<10	7	●	●	<9
• Capital Program Delivery • Distribution Sustainment Capital Program Completion	100%	105%	95%	100%**	>65%	56%	X	▲	>92%
• CUSTOMER EXPERIENCE ROADMAP - % COMPLETION OF AGREED ROADMAP INITIATIVES	---	---	---	---	---	---	---	---	80%

**excludes planned outages*
*** For 2014 and 2015, measurement of completion will be against planned work only. Plant Failure capital excluded. Prior years included plant failure.*
****Preliminary target – actual target will be set once full year outage statistics are available*

Organizational Effectiveness

QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Organizational Effectiveness
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2016 Corporate Performance Goals and Supporting Priorities	Assessment
1. Continue to enhance operational performance and productivity	
[redacted]	
[redacted]	
[redacted]	

Organizational Effectiveness
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2016 Corporate Performance Goals and Supporting Priorities	Assessment
1. Continue to enhance operational performance and productivity	
[redacted]	
f. Facilities Upgrade Implementation - Advance the implementation of the Board approved plan to replace the end of life main office and the south and east operations centres with purpose built facilities which will address location, energy efficiency, employee engagement, etc. i. Complete RFP, execute design / build contract, complete design and achieve site plan approval	

Organizational Effectiveness
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2016 Corporate Performance Goals and Supporting Priorities	Assessment
2. Maintain leading health and safety record	
a. Occupational Health, Safety and Environment (OHSE) Management System i. Further leverage ISN functionality for enhanced contractor management ii. Maintain registration of expanded ISO 14001/OHSAS 18001 OHSE Management System through annual internal and external audits iii. [redacted] iv. [redacted]	
3. Continue to enhance organizational and employee capability	
a. Union Management Relations – i. [redacted] ii. iii. Develop and obtain approval for 2017 collective bargaining strategy for Hydro Ottawa Limited	
[redacted]	

Organizational Effectiveness
Proposed 2016 Corporate Performance Measures & Targets

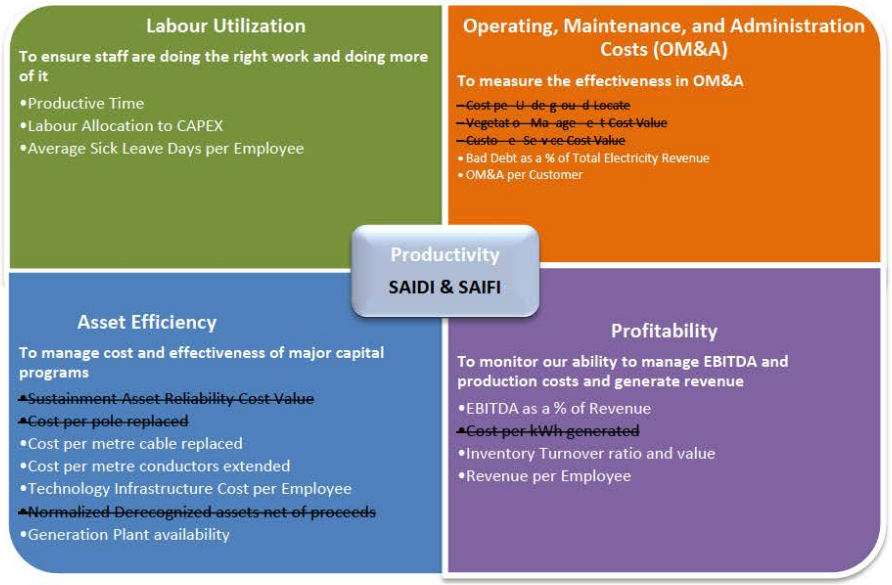
Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2016 Corporate Performance Measures	2012A	2013A	2014A	2015T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	Q3 ERM Rating	2016T
OM&A per customer - HOL only *(excl CDM & LRT)*	$256	$263	$269	$270	$207	$190	●	N/A	$267[2]
Revenue per employee *(excl CDM & LRT)*	$0.28M	$0.30M	$0.32M	$0.29M*	0.213M	0.230M	●	N/A	$0.30M[3]
[redacted]									

1 Under CGAAP, the 2015 target for revenue per employee would be $0.30M
2 In 2016, this measure was modified to exclude CDM only
3 In 2016, this measure was modified to exclude CDM & Street Lighting

Productivity Scorecard

- Targets were not initially assigned to the metrics
- We showed a comparison of year over year results with a description of trends
- At this time, we are focusing our reporting efforts on 10 of the 17 original metrics as identified on this and the following slide
- We are proposing that these 10 metrics and associated targets be included in the 2016 scorecard



Productivity Scorecard

Balanced Productivity Metrics

Measures	Description	2013	2014	Q3 2015		2016 T	
Productive Time	% of Billable Hours / Total Regular Hours	69%	71%	74%	●	74%	Recommended 74%, exceeded previous year actuals due to change in demographics, younger workforce & lower vacation entitlement. Risk: may require higher training hours.
Labour Allocation to CAPEX	% of Labour Time on Capital Activities / Total Productive Time	56%	60%	59%	▲	59%	Labour Allocation to CAPEX calculated based on 2016 budget 58%, stretch target 59%
Average Sick Days per FTE	Total Sick Days / Total Employees	6.0	5.9	6.1	●	6.0 Days	Average Sick Days per FTE average of 5.8 Days. Target recommended 6.0 Days.
[redacted]							
Bad Debt as a % of Total Electricity Revenue	Bad Debt / Total Electricity Revenue	0.25%	0.18%	0.04%	●	0.13%	Bad Debt expense as a % of Electricity Revenue target is calculated based on 2016 budget of $1.4M bad debt expense and $1115M total electricity revenue.
[redacted]							
Cost per metre Cable replaced	Cable Replacement Program Costs / metres of Cables Replaced	$328	$434	$548	●	$307	Cost per metre cable replaced target is calculated based on 3 year
Cost per metre Conductors extended	Line Extension Program Costs / metres of Conductors Extended	$136	$127	$153		$101	Cost per metre Conductors extended is calculated based on 3 year
Technology Infrastructure Cost per Employee*	(External IT support costs + computer hardware & software depn) / # of FTE	$22.2K	$21.5K	$22.1K	▲	$22.3K	Technology Infrastructure cost per employee target is calculated based on budget of $15.6M technology maintenance and depreciation and 702 full time employees budget
[redacted]							
EBITDA as a % Revenue	[redacted]						
	EBITDA $ / Total Revenue – Hydro Ottawa Limited	46%	44%	48%	●	51%	HOL EBITDA as a % of Revenue target exceeded 2015 trend due to increased distribution revenue and reduced expenses.
[redacted]							
Inventory Turnover Ratio and Value	Cost of Materials Used / Average Inventory	2.12	1.83	1.66	x	2.00	Inventory Turnover Ratio 5 year (2010 to 2015) monthly average of 2.03, average of 4 year 1.9. Target recommended 2.0.

*Q3 Results annualized for comparison, not based on forecast

*** Transition to IFRS on January 1, 2015. Joint Ventures are accounted for using equity method whereby the proportionate share of net results are presented on one line, resulted in different EBITDA, revenue, and costing comparison*

[redacted]

Labour Utilization | OM&A Measures | Asset Efficiency | Profitability Metrics

Corporate Citizenship

QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Corporate Citizenship
Proposed 2016 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2016 Corporate Performance Goals and Supporting Priorities	Assessment
1. Enhance our brand image in the community and the industry	
[redacted]	
2. Improve our environmental performance and reduce our impact on the environment	
[redacted]	

Corporate Citizenship - Proposed 2016 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2016 Corporate Performance Measures	2012A	2013A	2014A	2015T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	Q3 YTD ERM Rating	2016T
[redacted]									

Corporate Citizenship - Proposed 2016 Corporate Performance Measures and Targets

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2016 Corporate Performance Measures	2012A	2013A	2014A	2015T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	Q3 ERM Rating	2016T
[redacted]									

Corporate Citizenship
Proposed 2016 Corporate Performance Measures and Targets

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2016 Corporate Performance Measures	2012A	2013A	2014A	2015T	Q3 YTD Actual	Q3 YTD Target	Q3 YTD Assessment	Q3 ERM Rating	2016T
[redacted]									

2017 Corporate Performance Scorecard

Hydro Ottawa Holding Inc. and Hydro Ottawa Limited Boards of Directors

November 24, 2016

HydroOttawa

Board Decisions Required Today

- Review & approve the 2017 Corporate Performance Scorecard

- Specifically, for each of the 4 key areas of focus in the scorecard, review and approve

  - QUALITATIVE performance goals and priorities for 2017

  - QUANTITATIVE performance measures and targets for 2017

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Corporate Performance Scorecard Framework

We plan our course for a 5-year period	Hydro Ottawa's **Strategic Direction** • provides a comprehensive overview of our business strategy and financial projections for a 5-year period
We implement and operate in accordance with annual plans and budget	The annual business plan for the enterprise has two components • A budget including **summary key corporate priorities**, and • **A corporate performance scorecard** (**more comprehensive list of corporate priorities** and measures & targets) that we cascade to employees to align them to deliver against strategy
We monitor and report performance and progress against annual plans and budget	• Monthly reviews by the Executive Management Team • Quarterly President & CEO reports to the 2 Boards including ERM reporting and letters of representation • Quarterly financial reports and monthly updates to the Shareholder • Year end performance results reviews and President & CEO report to the 2 Boards • Annual Report to the Shareholder

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Where we're at in our annual board business planning and reporting cycle

HOHI & HOL Boards receive quarterly reports as part of CURRENT YEAR performance and progress monitoring

Timeline	Activity
APRIL	Year-end Committee and Board meetings for PREVIOUS YEAR
JUNE	PREVIOUS YEAR annual results reporting to the Shareholder – AGM
SEPTEMBER	HOHI Board receives budget guidelines to guide preparation of annual business plan priorities and budget for SUBSEQUENT YEAR
SEPT - NOV	Development of business plan priorities & budget and performance scorecard for SUBSEQUENT YEAR • Takes into consideration PREVIOUS YEAR approved plan, updated for the changing environment and business priorities
EARLY NOVEMBER	HOHI Board receives debrief and discusses critical issues and opportunities facing the company at its annual strategy session
LATE NOVEMBER	• HOL Board receives Budget Guidelines for SUBSEQUENT YEAR, endorses HOL Business Plan Priorities, Budget and Scorecard, and recommends to the HOHI Board • HOHI Board receives for approval HOL and Enterprise Business Plan Priorities, Budget and Scorecard for SUBSEQUENT YEAR

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2017 Performance Scorecard

- As in previous years, the Board is being asked to approve **one corporate performance scorecard for the enterprise**
- The scorecard establishes qualitative performance goals and priorities and quantitative measures and targets in each of our four key areas of focus to support the advancement of the Strategic Direction in a given year
  - Customer Value
  - Organizational Effectiveness
  - Corporate Citizenship
  - Financial Strength



- The scorecard also includes separate quantitative Financial Strength performance targets for the HOL entity
- Performance priorities for executive and management staff for 2017 will be cascaded from the corporate performance scorecard to align individuals to deliver against strategy
- Results highlights and progress against the scorecard (including ERM assessment) will be reported quarterly to the HOHI and HOL Boards by the President & CEO

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Scorecard Principles for 2017

One Corporate Performance Scorecard for the Enterprise

- Separate Financial Strength performance measures and targets for HOL 'entity'
- 'Highlighted' qualitative supporting priorities have HOL Board oversight

Weightings for each of 4 key areas of focus

- Removed as per Board direction in 2015

Targets associated with quantitative performance measures

- Reflect past performance and changing circumstances, and
- Encourage and reward continuous improvement where appropriate

Monitoring and Reporting

- Provides for more detailed measures / tracking tools for management use while keeping Board reporting at more strategic level
- Includes monthly monitoring of progress by the Executive Management Team, and quarterly reporting to the Boards as part of President and CEO's quarterly report and letters of representation

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2017 Performance Goals Summary

5-Year Enterprise Strategic Objectives and Outcomes (2016-2020)		2017 Corporate Performance Goals
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	• ***Grow revenues from new sources*** • ***Enhance / protect revenues from existing business lines***
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	• ***Assist customers in managing their energy consumption and electricity costs*** • ***Deliver on customer expectations for service quality and responsiveness*** • ***Maintain overall distribution system reliability***
Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	• ***Continue to enhance operational performance and productivity*** • ***Maintain leading health and safety record*** • ***Enhance organizational and employee capability***
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services* *Positive community impact*	• ***Enhance our brand image in the community and the industry*** • ***Continue to improve our environmental performance and reduce our impact on the environment***

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Financial Strength – Summary Key Corporate Priorities

Grow revenues from new sources and enhance / protect revenues from existing business lines

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
6.	**Complete PWGSC Asset Transfer**
7.	**Maximize CDM GWh results to achieve 2017 financial incentives**
[redacted]	[redacted]

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Customer Value – Summary Key Corporate Priorities

Assist customers in managing their energy consumption and electricity costs; deliver on customer expectations for service quality and responsiveness; and maintain overall system reliability

1.	Enhance the range of Conservation and Demand Management Programs including the implementation of the new Bidgely mobile application for residential customers
2.	Maintain or enhance our best in class reliability metrics
3.	Continue implementation of Customer Experience Roadmap key deliverables
4.	Smart Grid – continue implementation of the foundational grid transformation and modernization projects including SCADA renewal [redacted]
5.	Continue our improvements in maintenance and capital execution – ***emphasis on workforce scheduling and contractor management; complete all budgeted programs / plans on time and within budget***

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Organizational Effectiveness – Summary Key Corporate Priorities

Continue to enhance operational performance and productivity; maintain leading health and safety record; and enhance organizational and employee capability

[redacted]	
3.	**Facilities Renewal Program – execute the design/build of the administration building and the east and south operations centres**
4.	**Union Management Relations – achieve renewed collective agreement with IBEW (Hydro Ottawa Limited) consistent with the Board approved mandate**

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Corporate Citizenship – Summary Key Corporate Priorities

Enhance our brand image in the community and the industry; improve our environmental performance and reduce our impact on the environment



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Financial Strength

> QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Financial Strength
Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2017 Corporate Performance Goals and Supporting Priorities	Assessment
1. Grow revenues from new sources	
[redacted]	
b. Distribution Expansion i. Approach other LDCs in Ontario regarding potential acquisition/mergers/partnerships ii. Complete transfer of PWGSC Distribution Assets	
[redacted] **iii. Regional Training** – Develop and implement plan for Training Delivery Agent Status **iv. Expansion of Forestry Services**	

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Financial Strength
Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2017 Corporate Performance Goals and Supporting Priorities	Assessment
1. Grow revenues from new sources - continued	
e. Conservation and Demand Management – Deliver on year three of six-year plan to achieve GWh reductions and financial incentives, and update the plan as new technologies, programs and opportunities arise to set the stage for 2017-2020 i. As new technologies, programs and opportunities arise, update the approved six-year CDM plan to maximize GWh results by December 31, 2017 to achieve financial incentives in the $3M range (target of 200 GWh) ii. While focusing efforts on the 2017 GWh results, set the stage for delivering strong GWh results in the 2018 to 2020 timeframe with the objective of achieving additional financial incentives in the $3M to $6M range (Target 200 GWh and spend < $100M of the $105M approved budget)	
2. Enhance / protect revenues from existing business lines	
[redacted]	
b. Collection of Bad Debts – apply more aggressive processes for collection of electricity customer accounts and damage to plant	
[redacted]	
[redacted]	

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Financial Strength – Proposed 2017 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will create sustainable growth in our business and our earnings *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2017 Corporate Performance Measures	**2012A CGAAP**	**2013A CGAAP**	**2014A CGAAP**	**2015A IFRS**	**2016T IFRS**	**Q3 YTD Target IFRS**	**Q3 YTD Actual IFRS**	**Q3 YTD Assessment**	**2017T IFRS**
[redacted]									

[redacted]

HOL Financial Strength – Proposed 2017 Performance Measures and Targets

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2017 HOL Performance Measures	**2012A**	**2013A**	**2014A**	**2015A IFRS[5]**	**2016T IFRS**	**Q3 YTD Target IFRS**	**Q3 YTD Actual IFRS**	**Q3 YTD Assessment**	**2017T IFRS**
Net Income	$26.4M	$25.4M	$27.9M	$35.5M	$33.3M	$23.4M	$28.8M	●	$34.5M
Revenue *(excl CDM)*	$176.2M [1] $163.2M	$166.7M	$168.5M	$172.8M	$179.5M[7]	$134.2M	$135.7M	●	$187.4M[7]
OM&A - Net *(excl CDM)*	$92.0M [1] $79.1M	$82.5M	$86.0M	$84.5M	$87.5M[7]	$67.0M	$62.4M	●	$90.0M[7]
Return on Equity	10.4%	9.6%	10.1%	12.1%	10.8%	10.8%	11.3%	●	10.5%
Cash Flow from Operations	$73.5M	$38.9M	$94.3M	$69.0M	$80.6M	$49.6M	$54.6M	●	$65.6M
CAPEX **System Renewal and Service (excluding Plant Failure)** **Plant Failure** **General (including Facilities Implementation Plan)**	$51.7M N/A $26.7M	$59.1M N/A $34.7M	$74.0M N/A $15.7M	$54.5M N/A $10.2M	$61.1M[8] $4.5M[8] $45.2M	$40.7M $3.5M $21.8M	$37.5M $5.1M $7.8M	● X ●	N/A[9] N/A[9] N/A[9]
Cumulative Cap Additions **General Plant** **System Renewal & Service**	N/A N/A	N/A N/A	N/A N/A	N/A N/A	N/A N/A	N/A N/A	N/A N/A	N/A N/A	$25.1M[9] $106.1M[9]
Labour Allocation to CAPEX	56%	57%	60%	61%	59%	59%	61%	●	61%
CDM – Cumulative PAB Spending	$3.3M [2] $5.1M 31%	$9.7M 59%	$13.5M 82%	N/A	N/A	N/A	N/A	N/A	N/A
CDM – Cumulative MW reduction	17 MW [3] 25 MW 29%	27 MW [3] 45 MW 53%	68 MW 88%	N/A	N/A	N/A	N/A	N/A	N/A
CDM – Cumulative GWh reduction	35.1 GWh[4] 246 GWh 66%	40 GWh[4] 325 GWh 87%	415 GWh 111%	57GWh[6]	70GWh	55GWh	45GWh	X	200GWh[10]

[1] In 2012, this measure was modified to exclude CDM & LRT
[2] In 2013, this measure was changed to cumulative spending, this is the annual amount
[3] In 2014, this measure was changed to cumulative MW reduction, these represent the annual MW reductions
[4] In 2014, this measure was changed to cumulative GWh reduction, these represent the annual GWh reductions
[5] No CGAAP to IFRS transitional adjustments for HOL
[6] 2015 results restated based on IESO confirmed result received in 2016
[7] In 2016, this measure was modified to exclude CDM only
[8] Plant Failure is a new measure added in 2016. For reference, the actuals for 2012–2014 were $5.2M, $5.3M, and $6.8M. The overall Capex measure was modified to exclude Plant Failure.
[9] In 2017, the Capex measures have been removed from the HOL scorecard and replaced with capital addition measures to align with the OEB settlement , the capex measures including plant failure were retained on the Corporate scorecard.
[10] In 2017, this measure was changed to cumulative GWh reduction, 2015 and 2016 were the annual GWh reductions.

Customer Value

> QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Customer Value - Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2017 Corporate Performance Goals and Supporting Priorities	Assessment
1. Assist customers in managing their energy consumption and electricity costs	
a. CDM - Continue to enhance and deliver a wide range of CDM programs and bring to market new programs that are customer-centric, cost effective and generate strong GWh results, e.g. i. Residential Programs including the implementation of the Bidgely mobile application ii. Commercial Programs including a new commercial Refrigeration Program	
b. Ontario Electricity Support Program (OESP) – Continue to manage the new Ontario Energy Board program that provides ongoing financial assistance to qualifying low-income electricity consumers	
c. Customer Education Program – Continue to increase understanding of the industry and Hydro Ottawa's role and achievements within it; demystify and educate by leveraging multiple modes (digital and social media, video, open houses, workshops, etc.) and multiple channels (local media, Councillors, subject matter experts, executive and senior management)	
2. Deliver on customer expectations for service quality and responsiveness	
a. Improve Customer Service – Implement the integrated "whole of company" roadmap for customer service, including **i. Multi-Year Cultural Transformation Plan** - Develop multi-year plan aligning people and organization with Customer Experience Strategy and Roadmap, including change management, communications, training/awareness and performance alignment plans, talent segment profiles, and narratives of customer experience in action **ii. Bill Redesign** – Complete the testing and roll out of bill redesign (paper and digital) including comprehensive customer communications campaign to facilitate seamless implementation **iii. Enterprise Communications Platform (previously 'Customer Contact Platform')** – Expand the platform to allow multi-channel communication (voice, text, email, chat, etc.) **iv. Voice of the Customer –** Expand transactional surveys, e.g. outages, service desk, tree trimming, service layout **v. Strategic Account Management Plan** – Continue relationship building and product offerings (e.g. Energy dashboard) with key accounts, developers and contractors **vi. Digital Strategy (previously Website and Mobile Strategy')** aa. Implement Bidgely mobile application and integrate with Hydro Ottawa online presence to provide residential customers with appliance specific energy usage information, and to assist Hydro Ottawa in achieving its CDM targets bb. Customer Identity Management – implement authentication and authorization of customers for web and mobile access including social media logon **vii. Billing & Meter to Cash Enhancements –** e.g. HST rate mitigation, Jan, May and November rate changes, over generation penalty for microfit customers, direct deposit functionality, etc. **viii. Mobile Workforce Management** – deploy and optimize (Phase III) **ix. Annual Go Paperless Marketing Campaign**	

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Customer Value
Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2017 Corporate Performance Goals and Supporting Priorities	Assessment
3. Maintain overall distribution system reliability	
a. Smart Grid – Continue implementation of grid transformation and modernization projects	
b. Maintain or enhance our best in class reliability metrics	
c. Continue our improvements in maintenance and capital program execution *– Emphasis on workforce scheduling and contractor management; Complete all budgeted programs / plans on time and within budget* i. Distribution Sustainment Capital Program – Ongoing implementation of refurbishment and enhancement programs with particular emphasis on aging infrastructure, areas with chronic reliability issues, and on new station capacity ii. Distribution Demand Capital Program – Ongoing implementation of new residential and commercial customer connections, system expansions, and third party driven plant relocations and upgrades iii. Distribution Maintenance Programs – Ongoing implementation of distribution asset evaluations (testing and inspections of poles, cable, manhole chambers and switches); forestry program analysis and overview; and increased removals as a result of Emerald Ash Borer and Storm Hardening Strategy	

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Customer Value
Proposed 2017 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2017 Corporate Performance Measures	**2012A**	**2013A**	**2014A**	**2015A**	**2016T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assess-ment**	**2017T**
SATISFACTION									
• Residential & Small Commercial	HO/ON Pre 88/86% Post 90/88%	HO/ON Pre 90/90% Post 90/90%	HO/ON Pre 83%/83% Post 79%/80%	HO/ON Pre 87%/86% Post 85%/83%	>91%	NA	NA	NA	>91
• Call Centre Transaction satisfaction - monthly	89%	89%	88%	90%	>90%	>90	89	X	>90
• The ability to deal with your issue (First Call Resolution)	86%	85%	84%	85%	>86%	>86	>84	X	>86
• Total number of complaints	145	102	140	124	<160	<120	92	●	<140
VALUE									
• Number of MyHydroLink customers	84,686	104,108	122,300	136,890	>145,000	>142,973	153,215	●	>165,000
• Number of e-bill accounts	43,932	66,719	85,991	102,007	>115,000	>111,752	118,747	●	>130,000
• Number of auto pay accounts	41,261	43,612	46,098	48,751	>50,000	>49,688	50,659	●	>52,000

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Customer Value
Proposed 2017 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2017 Corporate Performance Measures	**2012 A**	**2013A**	**2014A**	**2015A**	**2016T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment**	**2017T**
PRODUCT RELIABILITY									
• SAIFI – 3 year average excluding loss of supply – OEB within range of previous 3 years	1.10	1.30	1.12	0.99	<.80	<.80	0.83	X	<.85
• SAIFI – Annual reliability excluding loss of supply and major event days better than previous 5 year average	1.11 (1.13*)	1.24 (1.36*)	0.74 (0.86*)	0.72 (0.75*)	0.98 (1.10*)	1.10	0.78 (0.83*)	●	**0.80 (0.90*)**
• SAIDI – 3 year average excluding loss of supply – OEB within range of previous 3 years	1.60	1.79	1.51	1.46	<1.0	<1.0	1.31	X	<1.25
• SAIDI – Annual reliability excluding loss of supply and major event days better than previous 5 year average	1.24 (1.31*)	1.25 (1.64*)	1.08 (1.59*)	1.08 (1.15*)	1.19 (1.62*)	<1.62	1.05 (1.22*)	●	**1.00 (1.25*)**
• FEMI – Number of feeders with 10 or more interruptions per year	12	13	8	9	<9	<9	4	●	<8
• Capital Program Delivery • Distribution Sustainment Capital Program Completion	100%	105%	95%**	94%**	>92%	>65%	66%	●	NA
~~• CUSTOMER EXPERIENCE ROADMAP – % COMPLETION OF AGREED ROADMAP INITIATIVES~~	—	—	—	—	~~80%~~				NA

*including major event days
** For 2014 and 2015, measurement of completion is against planned work only. Plant Failure capital excluded. Prior years included plant failure.

Organizational Effectiveness

> QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Organizational Effectiveness
Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2017 Corporate Performance Goals and Supporting Priorities	Assessment
1. *Continue to enhance operational performance and productivity*	
[redacted]	

Organizational Effectiveness
Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2017 Corporate Performance Goals and Supporting Priorities	Assessment
1. Continue to enhance operational performance and productivity	
[redacted]	
[redacted]	
[redacted]	
f. Facilities Renewal Program - Advance the implementation of the Board approved plan to replace the end of life main office and the south and east operations centres with purpose built facilities which will address location, energy efficiency, employee engagement, etc. i. Execute the design build of the Administration building and the East and South Operations Centres	

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Organizational Effectiveness
Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2017 Corporate Performance Goals and Supporting Priorities	Assessment
2. Maintain leading health and safety record	
a. Occupational Health, Safety and Environment (OHSE) Management System i. Further leverage ISN functionality for enhanced contractor management ii. Maintain registration of expanded ISO 14001/OHSAS 18001 OHSE Management System through annual internal and external audits iii. [redacted] iv. Complete required OHSE training	
3. Continue to enhance organizational and employee capability	
a. Union Management Relations – i. [redacted] ii. Achieve renewed collective agreement with IBEW (Hydro Ottawa Limited) consistent with the Board-approved mandate	
[redacted]	
[redacted]	

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Organizational Effectiveness
Proposed 2017 Corporate Performance Measures & Targets

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

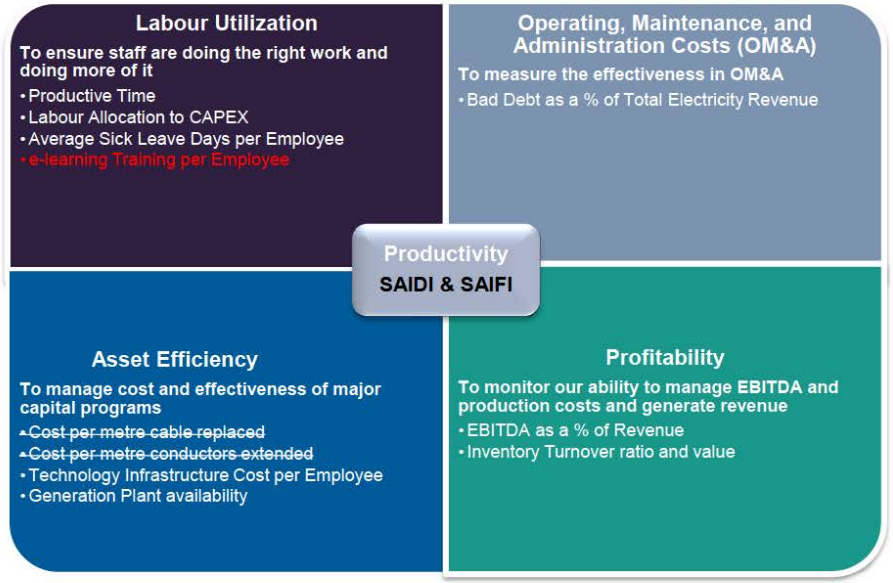
2017 Corporate Performance Measures	2012A	2013A	2014A	2015A	2016T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2017T
OM&A per customer - HOL only *(excl CDM & LRT)*	$256	$263	$269	$261	$267[2]	$206	$191	●	$272
Revenue per employee *(excl CDM & LRT)*	$0.28M	$0.30M	$0.32M	$0.31M	$0.30M[3]	$.226M	$.241M	●	$0.33M
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									

[1] Under CGAAP, the 2015 target for revenue per employee would be $0.30M
[2] In 2016, this measure was modified to exclude CDM only
[3] In 2016, this measure was modified to exclude CDM & Street Lighting

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Proposed Productivity Scorecard

At this time, we are proposing to focus our reporting efforts on 9 metrics as identified on this and the following slide



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Proposed Productivity Scorecard

Balanced Productivity Metrics

	Measures	Description	2013	2014	2015	Q3 2016	2016 Target	2017 Target
Labour Utilization	Productive Time	% of Billable Hours / Total Regular Hours	69%	71%	74%	75%	≥ 74%	≥ 74%
	Labour Allocation to CAPEX	% of Labour Time on Capital Activities / Total Productive Time	56%	60%	61%	61%	≥ 59%	≥ 61%
	Average Sick Days per FTE	Total Sick Days / Total Employees	6.0 Days	5.9 Days	6.3 Days	6.5 Days	≤ 6.0 Days	≤ 6.0 Days
	e-Learning Training per employee	Number of hours of e-learning / Total Employees	N/A	N/A	N/A	N/A	N/A	≥ 1 hour
OM&A	Bad Debt as a % of Total Electricity Revenue	Bad Debt / Total Electricity Revenue	0.25%	0.18%	0.01%	0.11%	≤ 0.13%	≤ 0.12%
Asset Efficiency	Technology Infrastructure Cost per Employee	(External IT support costs + computer hardware & software depn) / # of FTE	$22.2K	$21.5K	$23.3K	$23.7K	≤ $22.3K	≤ $23.6K
	[redacted]							
Profitability Metrics	EBITDA as a % Revenue	[redacted] EBITDA $ / Total Revenue - Hydro Ottawa Limited	46%	44%	46%	54%	≥ 51%	≥ 52%
	Inventory Turnover Ratio	Cost of Materials Used / Average Inventory	2.12	1.83	1.73	2.31	≥ 2.00	≥ 2.00

Notes

Labour Utilization

Productive Time recommended 74%, the same as 2016 target.

Labour Allocation to CAPEX has increased to 61%, the same as 2017 budget assumption. 2016 Q3 result strongly support the assumption.

Average Sick Days per FTE as of end of Q3 2016 is 6.45 days. Target recommended 6.0 days.

e-Learning Training is a new measure added to 2017. Target of 1 hour e-learning training per employee.

OM&A Measures

Bad Debt expense as a % of Electricity Revenue target is calculated based on 2016 budget of $1.4M bad debt expense and $1,139M total electricity revenue.

Asset Efficiency

Technology Infrastructure cost per employee target is calculated based on budget of $16.6M technology maintenance and depreciation and 704 full time employees budget

[redacted]

Profitability

[redacted]

HOL EBITDA as a % of Revenue target exceeded 2016 target due to increased distribution revenue.

Inventory Turnover Ratio 6 year average 2.07, target recommended to remain 2.0

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Corporate Citizenship

> QUALITATIVE PERFORMANCE GOALS AND SUPPORTING PRIORITIES & QUANTITATIVE PERFORMANCE MEASURES AND TARGETS

Corporate Citizenship - Proposed 2017 Corporate Performance Goals and Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2017 Corporate Performance Goals and Supporting Priorities	Assessment
1. Enhance our brand image in the community and the industry	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
2. Improve our environmental performance and reduce our impact on the environment	
[redacted]	
[redacted]	

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Corporate Citizenship
Proposed 2017 Corporate Performance Measures and Targets

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2017 Corporate Performance Measures	2012A	2013A	2014A	2015A	2016T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assess-ment	2017T
[redacted]									

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Corporate Citizenship – Proposed 2017 Corporate Performance Measures and Targets

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2017 Corporate Performance Measures	2012A	2013A	2014A	2015A	2016T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2017T
[redacted]									

Corporate Citizenship
Proposed 2017 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*								
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***								
2017 Corporate Performance Measures	2012A	2013A	2014A	2015A	2016T	Q3 YTD Actual	Q3 YTD Target	Q3 YTD Assess-ment	2017T
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]									

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HydroOttawa


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A leading partner in a
smart energy future

Board Decisions Required Today

- Review & approve the 2018 Corporate Performance Scorecard

- Specifically, for each of the 4 key areas of focus in the scorecard, review and approve

  - QUALITATIVE performance goals and priorities for 2018

  - QUANTITATIVE performance measures and targets for 2018

Corporate Performance Scorecard Framework

We plan our course for a 5-year period	Hydro Ottawa's **Strategic Direction** • provides a comprehensive overview of our business strategy and financial projections for a 5-year period
We implement and operate in accordance with annual plans and budget	The annual business plan for the enterprise has two components • A budget including **summary key corporate priorities**, and • **A corporate performance scorecard** (**more comprehensive list of corporate priorities** and measures & targets) that we cascade to employees to align them to deliver against strategy
We monitor and report performance and progress against annual plans and budget	• Monthly reviews by the Executive Management Team • Quarterly President & CEO reports to the 2 Boards including ERM reporting and letters of representation • Quarterly financial reports and monthly updates to the Shareholder • Year end performance results reviews and President & CEO report to the 2 Boards • Annual Report to the Shareholder

Where We're At In Our Annual Board Business Planning And Reporting Cycle

HOHI & HOL Boards receive quarterly reports as part of CURRENT YEAR performance and progress monitoring

Timeline	Activity
APRIL	Year-end Committee and Board meetings for PREVIOUS YEAR
JUNE	PREVIOUS YEAR annual results reporting to the Shareholder – AGM
SEPTEMBER	HOHI Board receives budget guidelines to guide preparation of annual business plan priorities and budget for SUBSEQUENT YEAR
SEPT - NOV	Development of business plan priorities & budget and performance scorecard for SUBSEQUENT YEAR • Takes into consideration PREVIOUS YEAR approved plan, updated for the changing environment and business priorities
EARLY NOVEMBER	HOHI Board receives debrief and discusses critical issues and opportunities facing the company at its annual strategy session
LATE NOVEMBER	• HOL Board receives Budget Guidelines for SUBSEQUENT YEAR, endorses HOL Business Plan Priorities, Budget and Scorecard, and recommends to the HOHI Board • HOHI Board receives for approval HOL and Enterprise Business Plan Priorities, Budget and Scorecard for SUBSEQUENT YEAR

2018 Performance Scorecard

- As in previous years, the Board is being asked to approve **one corporate performance scorecard for the enterprise**
- The scorecard establishes qualitative performance goals and priorities and quantitative measures and targets in each of our four key areas of focus to support the advancement of the Strategic Direction in a given year
  - Customer Value
  - Organizational Effectiveness
  - Corporate Citizenship
  - Financial Strength



- The scorecard also includes separate quantitative Financial Strength performance targets for the HOL entity
- Performance priorities for executive and management staff for 2018 will be cascaded from the corporate performance scorecard to align individuals to deliver against strategy
- Results highlights and progress against the scorecard (including ERM assessment) will be reported quarterly to the HOHI and HOL Boards by the President & CEO

Scorecard Principles For 2018

One Corporate Performance Scorecard for the Enterprise

- Separate Financial Strength performance measures and targets for HOL 'entity'
- 'Highlighted' qualitative supporting priorities have HOL Board oversight

Weightings for each of 4 key areas of focus

- Removed as per Board direction in 2015

Targets associated with quantitative performance measures

- Reflect past performance and changing circumstances, and
- Encourage and reward continuous improvement where appropriate

Monitoring and Reporting

- Provides for more detailed measures / tracking tools for management use while keeping Board reporting at more strategic level
- Includes monthly monitoring of progress by the Executive Management Team, and quarterly reporting to the Boards as part of President and CEO's quarterly report and letters of representation

2018 Performance Goals Summary

5-Year Enterprise Strategic Objectives and Outcomes (2016-2020)		2018 Corporate Performance Goals
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	• ***Grow revenues from new sources*** • ***Enhance / protect revenues from existing business lines***
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	• ***Assist customers in managing their energy consumption and electricity costs*** • ***Deliver on customer expectations for service quality and responsiveness*** • ***Maintain overall distribution system reliability***
Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	• ***Continue to enhance operational performance and productivity*** • ***Maintain leading health and safety record*** • ***Enhance organizational and employee capability***
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services* *Positive community impact*	• ***Enhance our brand image in the community and the industry*** • ***Continue to improve our environmental performance and reduce our impact on the environment***

Financial Strength – Summary Key Corporate Priorities

Grow revenues from new sources and enhance / protect revenues from existing business lines

[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
6.	**Maximize CDM GWh results to achieve 2020 financial incentives**
[redacted]	

Customer Value – Summary Key Corporate Priorities

Assist customers in managing their energy consumption and electricity costs; deliver on customer expectations for service quality and responsiveness; and maintain overall system reliability

1.	Enhance the range of Conservation and Demand Management Programs including a. *the evolution of Hydro Ottawa's mobile application for residential customers (gamification), and* b. *the new booster pump program, overnight audit and business refrigeration for small / medium commercial customers*
2.	Maintain or enhance our best in class reliability metrics
3.	Continue implementation of Customer Experience Roadmap key deliverables including web/mobile multi-channel communication enhancements
4.	Actively pursue and participate in energy innovation projects
5.	Smart Grid – *continue implementation of the foundational grid transformation and modernization projects including SCADA renewal* [redacted]
6.	Continue our improvements in maintenance and capital execution – *emphasis on workforce scheduling and contractor management; complete all budgeted programs / plans on time and within budget*

Organizational Effectiveness – Summary Key Corporate Priorities

Continue to enhance operational performance and productivity; maintain leading health and safety record; and enhance organizational and employee capability

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
4.	**Facilities Renewal Program –** ***execute the design/build of the administration building and the east and south operations centres, operational integration and migration, regulatory case preparation and property disposition***
[redacted]	
5.	**Union Management Relations –** [redacted] ***manage outcome of application for certification by SEP for representation at HOL***

Corporate Citizenship – Summary Key Corporate Priorities

Enhance our brand image in the community and the industry; improve our environmental performance and reduce our impact on the environment



Financial Strength – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2018 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
1. *Grow revenues from new sources*	
[redacted]	
b. Distribution Expansion i. Approach other LDCs in Ontario regarding potential acquisition/mergers/partnerships	
[redacted]	
iii. Regional Training aa. Continue development and implementation of Training Delivery Agent Status Powerline Technician training and certification with Algonquin college bb. Continue to market and enhance provision of training services to other LDCs / contractors cc. Explore monetization of Live Line Simulator	
iv. Expansion of Forestry Services	
[redacted]	

Financial Strength – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2018 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
1. ***Grow revenues from new sources - continued***	
d. ***Conservation and Demand Management – Deliver on year four of six-year plan to achieve GWh reductions and financial incentives, and update the plan as new technologies, programs and opportunities arise*** i. Monitor and adjust the CDM Plan as new opportunities arise to encourage wide scale program participation for all HOL customer segments ii. Maximize 2018 GWh results and contribute to the longer term target of 400 GWhs by Dec 31, 2020 to maximize all available performance incentives (approx $3M) iii. Continue to grow the sales pipeline and select cost effective projects to ensure GWh targets are met within the prescribed budget allocation of $105M	
2. ***Enhance / protect revenues from existing business lines***	
[redacted]	
b. ***2021 Electricity Custom Incentive Rate Application*** – continue planning and preparations for the 2021-2025 rate application process	
c. ***Collection of Bad Debts –*** apply more aggressive processes for collection of electricity customer accounts and damage to plant, and implement necessary processes for the recovery of damages to street lighting infrastructure	
[redacted]	
[redacted]	

Financial Strength – Proposed 2018
Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will create sustainable growth in our business and our earnings *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	Growth in shareholder value								
2018 Corporate Performance Measures	2013A CGAAP	2014A CGAAP	2015A IFRS	2016A IFRS	2017T IFRS	Q3 YTD T IFRS	Q3 YTD A IFRS	Q3 YTD Assessment	2018T IFRS
[redacted]									
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[redacted]									
[redacted]									
[redacted]									

[redacted]

HOL Financial Strength – Proposed 2018
Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2018 HOL Performance Measures	**2013A CGAAP**	**2014A CGAAP**	**2015A IFRS**	**2016A IFRS**	**2017T IFRS**	**Q3 YTD T IFRS**	**Q3 YTD A IFRS**	**Q3 YTD Assessment**	**2018T IFRS**
Net Income	$25.4M	$27.9M	$35.5M	$34.3M	$34.5M	$24.8M	$27.3M	●	$35.3M
Revenue *(excl CDM)*	$166.7M	$168.5M	$172.8M	$182.0M[3]	$187.4M	$140.2M	$140.8M	●	$200.0M
OM&A - Net *(excl CDM)*	$82.5M	$86.0M	$84.5M	$87.9M[3]	$90.0M	$68.8M	$67.7M	●	$96.3M
Return on Equity	9.6%	10.1%	12.1%	11.0%	10.5%	10.5%	11.0%	●	10.2%
Cash Flow from Operations	$38.9M	$94.3M	$69.0M	$78.0M[4]	$65.6M	$36.3M	$47.4M[4]	●	$109.1M[4]
CAPEX System Renewal and Service *(excl Plant Failure)* Plant Failure General *(incl Facilities Renewal Program)*	$59.1M N/A $34.7M	$74.0M N/A $15.7M	$54.5M N/A $10.2M	$57.3M[5] $7.8M[5] $15.7M	N/A[6] N/A[6] N/A[6]	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A
Cumulative Capital Additions General Plant System Renewal & Service	N/A N/A	N/A N/A	N/A N/A	N/A N/A	$25.1M[6] $106.1M[6]	$13.7M $84.4M	$16.3M $86.4M	● ●	$32.2M $176.3M
Labour Allocation to CAPEX	57%	60%	61%	62%	61%	60%	60%	●	61%
CDM – Cumulative GWh reduction	40 GWh[1] 325 GWh 87%	415 GWh 111%	57GWh[2]	75GWh[2]	200GWh[7]	170GWh	187GWh	●	304GWh

[1] In 2013, this measure was changed to cumulative amounts vs annual amounts
[2] 2015 & 2016 results restated based on IESO confirmed result received in the subsequent years
[3] In 2016, these measures were modified to exclude CDM
[4] In 2016 & 2017, Cash flow from Operations on financial statement includes reclassifications of deferred revenue and customer deposits, the actual results are based on the previous reporting method to compare to the target, in 2018, target was aligned with financial statement reporting
[5] In 2016, Plant Failure was added as a separate measure and excluded from the overall CAPEX measure
[6] In 2017, the annual Capex measures have been replaced with cumulative capital addition measures to align with the OEB settlement
[7] In 2017, this measure was changed to cumulative GWh reduction (amounts shown for 2015 and 2016 are the annual GWh reductions)

Customer Value – Proposed 2018
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2018 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
3. Assist customers in managing their energy consumption and electricity costs	
a. CDM - Continue to enhance and deliver a wide range of CDM programs and bring to market new programs that are customer-centric, cost effective and generate strong GWh results, e.g. i. Residential Programs including the evolution of Hydro Ottawa's app (gamification) ii. Commercial Programs including new booster pump program, overnight audit and business refrigeration for small / medium commercial program	
b. Electricity Support Programs – Continue to manage the provincial program(s) that provide ongoing financial assistance to qualifying low-income electricity consumers including i. Ontario Fair Hydro Plan ii. Ontario Electricity Support Program (OESP) iii. Low-Income Energy Assistance Program (LEAP) iv. Affordability Trust	
c. Customer Education Program – Continue to increase understanding of the industry and Hydro Ottawa's role and achievements within it; demystify and educate by leveraging multiple modes (digital and social media, video, open houses, workshops, etc.) and multiple channels (local media, Councillors, subject matter experts, executive and senior management)	
d. Energy Innovation Projects – Actively pursue and participate in innovation projects to identify new energy saving product/service offerings for our customers i. Great Demand Response Project ii. eCamion Battery Energy Storage System	

Customer Value – Proposed 2018
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2018 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
4. Deliver on customer expectations for service quality and responsiveness	
a. Improve Customer Service – Implement the 'whole of company' Customer Experience (Cx) Strategy and Roadmap with a focus on modernization, customer communications and customer self-serve:	
i. Change Management Plan – Implement the first phases of a multi-year change management plan to align people and organization to the Cx Strategy and Roadmap, with a focus on increasing organization-wide awareness, support and alignment for a customer-centric culture consistent with the Organizational Culture Strategy	
ii. New Service Offerings – Work with existing customers to define and tailor product/service offerings	
aa. Annual Go Paperless campaign bb. Hydro Ottawa app engagement campaign cc. Suite-metering	
iii. Regulator: Billing & Meter to Cash Enhancements – e.g. provincial programs, migration to fixed rate and C1 class customers to HOEP	
iv. Bill Redesign – Complete roll out of bill redesign (paper and digital)	
v. Customer Management – Implement systems and processes to support a 1:1 conversation with customers	
aa. Customer Preference Dashboard – Develop a methodology/system to centralize customer data	
bb. Customer Relationship Management System – Map requirements to gain 360 degree view of customers cross-company and communication channel	
cc. Marketing Automation Platform – Implement a solution to automate and provide insightful analytics of marketing campaigns and communications	
dd. Email Management Platform – Evaluate Zendesk pilot to streamline routing of customer communications **ee. Strategic Account Management Plan** – Continue relationship building with, and develop of product offerings for, key accounts, developers and contractors	
vi. Web/Mobile Enhancements **aa. Website** - Plan for website renewal planning and analytics **bb. Enterprise Communications Platform -** Leverage platform functionality for multi-channel communication (voice, text, email, chat, etc.) **cc. App –** Identify and integrate rewards platform	
vii. Outage Communications – Incorporate technology solutions to support inbound/outbound outage reporting across multiple channels **viii. Business Intelligence** – Leverage Tableau Reporting tool to allow us to better target customer segments for different program / service offerings	

Customer Value – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*	
Enterprise Strategic Outcome	**Customer loyalty**	
2018 Corporate Performance Goals and Supporting Priorities		**Assessment** ● ▲ X
5. Maintain overall distribution system reliability		
a. Smart Grid – Continue implementation of grid transformation and modernization projects including e.g. i. SCADA system replacement ii. [redacted]		
b. Maintain or enhance our best in class reliability metrics		
c. Continue our improvements in maintenance and capital program execution *– Emphasis on workforce scheduling and contractor management; Complete all budgeted programs / plans on time and within budget* **i. Distribution Sustainment Capital Program** – Ongoing implementation of refurbishment and enhancement programs with particular emphasis on aging infrastructure, areas with chronic reliability issues, and on station capacity **ii. Distribution Demand Capital Program** – Ongoing implementation of new residential and commercial customer connections, system expansions, and third party driven plant relocations and upgrades **iii. Distribution Maintenance Programs** – Ongoing implementation of distribution asset evaluations (testing and inspections of poles, cable, manhole chambers and switches); forestry program analysis and overview; and increased removals as a result of Emerald Ash Borer and Storm Hardening Strategy	

Customer Value – Proposed 2018
Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2018 Corporate Performance Measures	**2013A**	**2014A**	**2015A**	**2016A**	**2017T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assess-ment**	**2018 Target**
SATISFACTION									
• Residential & Small Commercial	HO/ON Pre 90/90% Post 90/90%	HO/ON Pre 83%/83% Post 79%/80%	HO/ON Pre 87%/86% Post 85%/83%	HO / ON Pre 81%/81% Post 77%/74%	>91%	NA	NA	NA	>91%
• Large Commercial	NA	NA	NA	NA	NA	NA	NA	NA	>85%
• Call Centre Transaction satisfaction - monthly	89%	88%	90%	89%	>90%	>90%	87%	X	>90%
• The ability to deal with your issue (First Call Resolution)	85%	84%	85%	85%	>86%	>86%	81%	X	>86%
• Total number of complaints	102	140	124	106	<140	<105	41	●	<140
VALUE									
• Number of MyAccount customers	104,108	122,300	136,890	158,112	>165,000	>160,000	163,569	●	>170,000
• Number of e-bill accounts	66,719	85,991	102,007	123,801	>130,000	>125,000	131,164	●	>140,000
• Number of Auto pay accounts	43,612	46,098	48,751	51,520	>52,000	>52,000	53,024	●	>57,500
• Number of App Registrants (i.e. downloads)	NA	NA	NA	NA	3,600	2,400	5,946	●	>20,000

Customer Value – Proposed 2018
Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2018 Corporate Performance Measures	**2013A**	**2014A**	**2015A**	**2016A**	**2017T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment**	**2018 Target**
PRODUCT RELIABILITY									
• SAIFI – 3 year average excluding loss of supply – OEB within range of previous 3 years	1.30	1.12	0.99	0.80	<0.85	<0.85	0.80	●	<0.85
• SAIFI – Annual reliability excluding loss of supply and major event days better than previous 5 year average	1.24 (1.36[1])	0.74 (0.86[1])	0.72 (0.75[1])	0.69 (0.78[1])	0.80 (0.90[1])	0.80	0.74 (0.85[1])	●	0.75 (0.90[1])
• SAIDI – 3 year average excluding loss of supply – OEB within range of previous 3 years	1.79	1.51	1.46	1.29	<1.25	<1.25	1.29	X	<1.25
• SAIDI – Annual reliability excluding loss of supply and major event days better than previous 5 year average	1.25 (1.64[1])	1.08 (1.59[1])	1.08 (1.15[1])	1.00 (1.13[1])	1.00 (1.25[1])	1.0	1.03 (1.54[1])	X	1.00 (1.25[1])
• FEMI – Number of feeders with 10 or more interruptions per year	13	8	9	5	<8	<8	13	X	<8

[1] *including major event days*

Organizational Effectiveness – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2018 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity	
[redacted]	
[redacted]	

Organizational Effectiveness – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2018 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity	
[redacted]	

Organizational Effectiveness – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*	
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***	
2018 Corporate Performance Goals and Supporting Priorities		**Assessment** ●▲X
6. Continue to enhance operational performance and productivity		
[redacted]		
[redacted]		
[redacted]		
f. Facilities Renewal Program - Advance the implementation of the Board approved plan to replace the end of life main office and the south and east operations centres with purpose built facilities which will address location, energy efficiency, employee engagement, etc. i. Execute the design build of the Administration building and the East and South Operations Centres, operational integration and migration, regulatory case preparation, and property disposition		

Organizational Effectiveness – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2018 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
7. Maintain leading health and safety record	
a. Occupational Health, Safety and Environment (OHSE) Management System	
i. Maintain registration of expanded and updated ISO 14001 / OHSAS 18001 OHSE Management System through annual internal and external audits	
ii. [redacted]	
iii. Complete required OHSE training	
iv. Address findings from the OHSE compliance audit of Hull 2 Generation facility	
v. Research, develop and implement educational and awareness campaigns to enhance safety mindset	
8. Continue to enhance organizational and employee capability	
a. Union Management Relations – [redacted]	
[redacted]	
iii. Application for certification by SEP for representation at HOL	

Organizational Effectiveness – Proposed 2018 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2018 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
8. Continue to enhance organizational and employee capability	
[redacted]	
[redacted]	

Organizational Effectiveness – Proposed 2018 Corporate Performance Measures And Targets

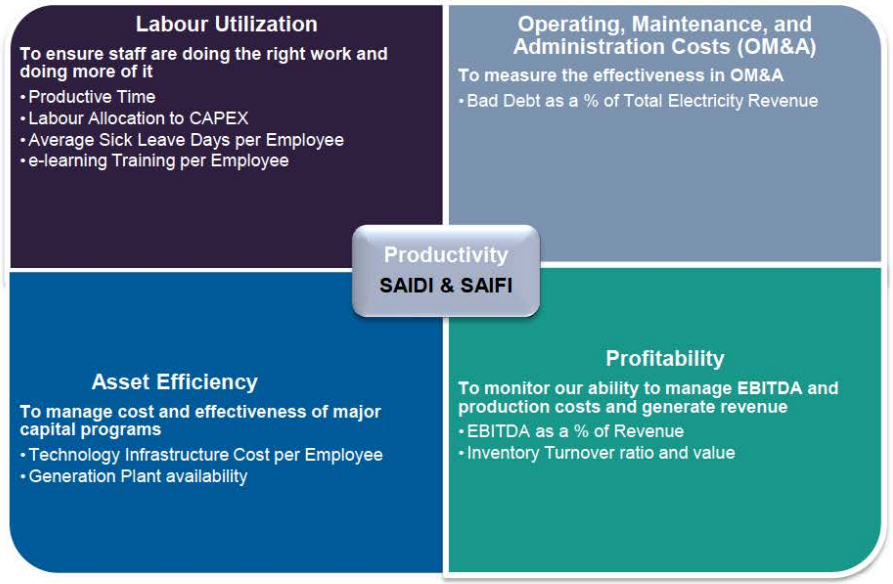
Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2018 Corporate Performance Measures	2013A	2014A	2015A	2016A	2017T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2018 Target
OM&A per customer - HOL only *(excl CDM)*	$263	$269	$261	$268[1]	$272	$209	$205	●	$287
Revenue per employee *(excl CDM & Streetlighting)*	$0.30M	$0.32M	$0.31M	$0.32M[2]	$0.33M	$0.237M	$0.242M	●	$0.35M
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									

[1] In 2016, this measure was modified to exclude CDM only
[2] In 2016, this measure was modified to exclude CDM & Street Lighting

Proposed 2018 Productivity Scorecard

At this time, we are proposing to continue focusing our reporting efforts on 9 metrics as identified on this and the following slide



Proposed 2018 Productivity Scorecard

	Measures	Description	2013 A	2014 A	2015 A	2016 A	2017 T	2017 Q3 YTD A	2018 Target
Labour Utilization	Productive Time	% of Billable Hours / Total Regular Hours	69%	71%	74%	74%	≥ 74%	73%	≥ 74%
	Labour Allocation to CAPEX	% of Labour Time on Capital Activities / Total Productive Time	56%	60%	61%	62%	≥ 61%	60%	≥ 61%
	Average Sick Days per FTE	Total Sick Days / Total Employees	6.0 Days	5.9 Days	6.3 Days	5.9 Days	≤ 6.0 Days	6.4 Days	≤ 6.0 Days
	e-Learning Training per employee	Number of hours of e-learning / Total Employees	N/A	N/A	N/A	N/A	≥ 1 hour	1.1 Hours	≥ 1 hour
OM&A	Bad Debt as a % of Total Electricity Revenue	Bad Debt / Total Electricity Revenue	0.25%	0.18%	0.01%	0.13%	≤ 0.12%	0.14%	≤ 0.12%
Asset Efficiency	Technology Infrastructure Cost per Employee	(External IT support costs + computer hardware & software den) / # of FTE	$22.2K	$21.5K	$23.3K	$24.4K	≤ $23.6K	$22.7K	≤ $25.3K
	[redacted]								
Profitability Metrics	EBITDA as a % Revenue	EBITDA $ / Total Revenue - Hydro Ottawa Limited	46%	44%	46%	52%	≥ 52%	52%	≥ 52%
	Inventory Turnover Ratio	Cost of Materials Used / Average Inventory	2.12	1.83	1.73	2.27	≥ 2.00	1.88	≥ 2.00

Notes

Majority of the targets remain consistent with the 2017 Targets, except the following two items adjusted based on the 2018 budget:

Technology Infrastructure Cost per Employee target increased from previous years to reflect the increase in Technology investment

[redacted]

Corporate Citizenship – Proposed 2018
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2018 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
9. Enhance our brand image in the community and the industry	
[redacted]	
[redacted]	
[redacted]	

Corporate Citizenship – Proposed 2018
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2018 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
9. Enhance our brand image in the community and the industry	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
10. Improve our environmental performance and reduce our impact on the environment	
[redacted]	
[redacted]	

Corporate Citizenship – Proposed 2018
Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2018 Corporate Performance Measures	2013A	2014A	2015A	2016A	2017T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2018 Target
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2018 Corporate Performance Measures	2013A	2014A	2015A	2016A	2017T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2018 Target
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									

Corporate Citizenship – Proposed 2018
Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*								
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***								
2018 Corporate Performance Measures	2013A	2014A	2015A	2016A	2017T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assess-ment	2018 Target
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]									


HydroOttawa
A leading partner in a smart energy future
2019 Corporate Performance Scorecard
November 29, 2018
HOHI and HOL Boards of Directors

Board Decisions Required Today

- Review & approve the 2019 Corporate Performance Scorecard

- Specifically, for each of the 4 key areas of focus in the scorecard, review and approve

  - QUALITATIVE performance goals and priorities for 2019

  - QUANTITATIVE performance measures and targets for 2019

Corporate Performance Scorecard Framework

We plan our course for a 5-year period	Hydro Ottawa's **Strategic Direction** • provides a comprehensive overview of our business strategy and financial projections for a 5-year period
We implement and operate in accordance with annual plans and budget	The annual business plan for the enterprise has two components • A budget including **summary key corporate priorities**, and • **A corporate performance scorecard** (**more comprehensive list of corporate priorities** and measures & targets) that we cascade to employees to align them to deliver against strategy
We monitor and report performance and progress against annual plans and budget	• Monthly reviews by the Executive Management Team • Quarterly President & CEO reports to the 2 Boards including ERM reporting and letters of representation • Quarterly financial reports and monthly updates to the Shareholder • Year end performance results reviews and President & CEO report to the 2 Boards • Annual Report to the Shareholder

Where We're At In Our Annual Board Business Planning And Reporting Cycle

HOHI & HOL Boards receive quarterly reports as part of CURRENT YEAR performance and progress monitoring

Timeline	Activity
APRIL	Year-end Committee and Board meetings for PREVIOUS YEAR
JUNE	PREVIOUS YEAR annual results reporting to the Shareholder – AGM
SEPTEMBER	HOHI Board receives budget guidelines to guide preparation of annual business plan priorities and budget for SUBSEQUENT YEAR
SEPT - NOV	Development of business plan priorities & budget and performance scorecard for SUBSEQUENT YEAR • Takes into consideration PREVIOUS YEAR approved plan, updated for the changing environment and business priorities
EARLY NOVEMBER	HOHI Board receives debrief and discusses critical issues and opportunities facing the company at its annual strategy session
LATE NOVEMBER	• HOL Board receives Budget Guidelines for SUBSEQUENT YEAR, endorses HOL Business Plan Priorities, Budget and Scorecard, and recommends to the HOHI Board • HOHI Board receives for approval HOL and Enterprise Business Plan Priorities, Budget and Scorecard for SUBSEQUENT YEAR

2019 Performance Scorecard

- As in previous years, the Board is being asked to approve **one corporate performance scorecard for the enterprise**
- The scorecard establishes qualitative performance goals and priorities and quantitative measures and targets in each of our four key areas of focus to support the advancement of the Strategic Direction in a given year
  - Customer Value
  - Organizational Effectiveness
  - Corporate Citizenship
  - Financial Strength



- The scorecard also includes separate quantitative Financial Strength performance targets for the HOL entity
- Performance priorities for executive and management staff for 2019 will be cascaded from the corporate performance scorecard to align individuals to deliver against strategy
- Results highlights and progress against the scorecard (including ERM assessment) will be reported quarterly to the HOHI and HOL Boards by the President & CEO

Scorecard Principles For 2019

One Corporate Performance Scorecard for the Enterprise

- Separate Financial Strength performance measures and targets for HOL 'entity'
- 'Highlighted' qualitative supporting priorities have HOL Board oversight

Weightings for each of 4 key areas of focus

- Removed as per Board direction in 2015

Targets associated with quantitative performance measures

- Reflect past performance and changing circumstances, and
- Encourage and reward continuous improvement where appropriate

Monitoring and Reporting

- Provides for more detailed measures / tracking tools for management use while keeping Board reporting at more strategic level
- Includes monthly monitoring of progress by the Executive Management Team, and quarterly reporting to the Boards as part of President and CEO's quarterly report and letters of representation

2019 Performance Goals Summary

5-Year Enterprise Strategic Objectives and Outcomes (2016-2020)		2019 Corporate Performance Goals
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	• ***Grow revenues from new sources*** • ***Enhance / protect revenues from existing business lines***
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	• ***Assist customers in managing their energy consumption and electricity costs*** • ***Deliver on customer expectations for service quality and responsiveness*** • ***Maintain overall distribution system reliability***
Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	• ***Continue to enhance operational performance and productivity*** • ***Maintain leading health and safety record*** • ***Enhance organizational and employee capability***
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services* *Positive community impact*	• ***Enhance our brand image in the community and the industry*** • ***Continue to improve our environmental performance and reduce our impact on the environment***

Financial Strength – Summary Key Corporate Priorities

Grow revenues from new sources and enhance / protect revenues from existing business lines

[redacted]	
[redacted]	
[redacted]	
[redacted]	
5.	2021 – 2025 Electricity Custom Incentive Rate Application – finalize planning, preparations, and submission by end of 2019
[redacted]	
7.	Maximize CDM GWh results to achieve 2020 financial incentives
[redacted]	

Customer Value – Summary Key Corporate Priorities

Assist customers in managing their energy consumption and electricity costs; deliver on customer expectations for service quality and responsiveness; and maintain overall system reliability

1.	Continue to deliver a range of CDM programs that are customer-centric, cost effective and generate strong GWh results, including a. Residential Programs including Hydro Ottawa's app b. Commercial Programs including Small Business Lighting and building retrofit
2.	Maintain or enhance our best in class reliability metrics
3.	Continue implementation of Customer Experience Roadmap key deliverables including using data to drive decisions impacting customers
4.	Actively pursue and participate in energy innovation projects
5.	Smart Grid – continue implementation of the foundational grid transformation and modernization projects [redacted] and further leverage new SCADA system
6.	Continue our improvements in maintenance and capital execution – emphasis on workforce scheduling and contractor management; complete all budgeted programs / plans on time and within budget

Organizational Effectiveness – Summary Key Corporate Priorities

Continue to enhance operational performance and productivity; maintain leading health and safety record; and enhance organizational and employee capability

[redacted]	
[redacted]	
[redacted]	
4.	**Facilities Renewal Program – complete the design/build of the administration building and the east and south operations centres, operational integration and migration, change management and employee engagement, regulatory case preparation and property disposition**
5.	**Union Management Relations – manage outcome of application for certification by SEP for representation at HOL;** [redacted]

Corporate Citizenship – Summary Key Corporate Priorities

Enhance our brand image in the community and the industry; improve our environmental performance and reduce our impact on the environment

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Financial Strength – Proposed 2019
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2019 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
1. *Grow revenues from new sources*	
[redacted]	
b. ***Distribution*** i. Continue to approach other LDCs in Ontario regarding potential acquisition/mergers/partnerships ii. Continue to expand our distribution system through acquisition of customer-owned assets (e.g. Ottawa International Airport, DND Uplands)	
[redacted]	
d. ***Other ancillary services that leverage Hydro Ottawa's brand and competitive advantage in the industry*** i. **Electrical service and construction offerings -** emergency repair and replacement of customer-owned distribution assets, meter services for other entities such as OPG, distribution sub-station services to other LDCs and private businesses, forestry services	
ii. **Regional Training** aa. Continue development and implementation of all levels of Training Delivery Agent Status Powerline Technician training and certification with Algonquin College bb. Continue to market and enhance training services to other LDCs / contractors	
[redacted]	

Financial Strength – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2019 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
2. Enhance / protect revenues from existing business lines	
[redacted]	
b. 2021-2025 Electricity Custom Incentive Rate Application – finalize planning, preparations, and submission by end of 2019	
[redacted]	
[redacted]	

Financial Strength – Proposed 2019
Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will create sustainable growth in our business and our earnings *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2019 Corporate Performance Measures	**2014A CGAAP**	**2015A IFRS**	**2016A IFRS**	**2017A IFRS**	**2018T IFRS**	**Q3 YTD Target IFRS**	**Q3 YTD Actual IFRS**	**Q3 YTD Assessment ●X**	**2019T IFRS**
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[redacted]

HOL Financial Strength – Proposed 2019
Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2019 HOL Performance Measures	**2014A CGAAP**	**2015A IFRS**	**2016A IFRS**	**2017A IFRS**	**2018T IFRS**	**Q3 YTD Target IFRS**	**Q3 YTD Actual IFRS**	**Q3 YTD Assessment ●X**	**2019T IFRS**
Net Income	$27.9M	$35.5M	$34.3M	$36.5M	$35.3M	$25.6M	$31.1M	●	$34.9M
Revenue *(excl CDM)*	$168.5M	$172.8M	$182.0M [3]	$187.1M	$200.0M	$149.3M	$150.0M	●	$208.7M
OM&A - Net *(excl CDM)*	$86.0M	$84.5M	$87.9M [3]	$87.5M	$96.3M	$73.2M	$69.5M	●	$96.4M
Return on Equity	10.1%	12.1%	11.0%	11.1%	10.2%	10.2%	11.1%	●	9.4%
Cash Flow from Operations	$94.3M	$69.0M	$78.0M [4]	$78.3M [4]	$109.1M [4]	$80.9M	$75.6M	X	$110.3M
CAPEX System Renewal and Service *(excl Plant Failure (Emergency Renewal))* Plant Failure (Emergency Renewal) General *(incl Facilities Renewal Program)*	$74.0M N/A $15.7M	$54.5M N/A $10.2M	$57.3M [5] $7.8M [5] $15.7M	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A
Cumulative Capital Additions General Plant System Renewal & Service	N/A N/A	N/A N/A	N/A N/A	$31.0M $116.0M	$32.2M $176.3M	$29.8M $140.6M	$33.4M $149.1M	● ●	$39.8M $220.0M
Labour Allocation to CAPEX	60%	61%	62%	60%	61%	60%	58%	X	60%
Debt to Capitalization Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	65%[6]
CDM – Cumulative GWh reduction	415 GWh	78GWh [1,2]	90GWh [1,2]	276GWh [2]	304GWh	272GWh	311GWh	●	375GWh

[1] 2015 and 2016 are annual reductions not cumulative
[2] 2015, 2016, & 2017 results restated based on IESO confirmed result received in the subsequent years
[3] In 2016, these measures were modified to exclude CDM
[4] In 2016 & 2017, Cash flow from Operations on financial statement includes reclassifications of deferred revenue and customer deposits, the actual results are based on the previous reporting method to compare to the target, in 2018, target was aligned with financial statement reporting
[5] In 2016, Plant Failure (Emergency Renewal) was added as a separate measure and excluded from the overall CAPEX measure
[6] New measure added in 2019

Customer Value – Proposed 2019
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*
Enterprise Strategic Outcome	**Customer loyalty**

2019 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
3. Assist customers in managing their energy consumption and electricity costs	
a. CDM - Continue to deliver a range of CDM programs that are customer-centric, cost effective and generate strong GWh results, e.g. i. Residential Programs including Hydro Ottawa's app ii. Commercial Programs including Small Business Lighting and building retrofit	
b. Electricity Support Programs – Continue to manage the provincial program(s) that provide ongoing financial assistance to qualifying low-income electricity consumers including i. Ontario Electricity Support Program (OESP) ii. Low-Income Energy Assistance Program (LEAP) iii. Affordability Trust	
c. Customer Education Program – Continue to increase understanding of the industry and Hydro Ottawa's role and achievements within it; demystify and educate by leveraging multiple modes (digital and social media, video, open houses, workshops, etc.) and multiple channels (local media, Councillors, subject matter experts, executive and senior management)	
d. Energy Innovation Projects – Actively pursue and participate in innovation projects to identify new energy saving product/service offerings for our customers i. Great Demand Response Project (IESO Smart Grid funding in partnership with industry and academia, e.g. Ottawa and Gloucester Community Housing, Ottawa U, Panasonic, Tabouchi) ii. EV Support Equipment Manifold (EVSEM) - charging infrastructure pilot project for constrained urban environments (pending funding by NRCAN) iii. EV Innovation Development/Deployment (EVID) – working with local taxi company to facilitate the charging infrastructure for an electric taxi fleet (pending funding from NRCAN) iv. Distributed Energy Resources – continue to monitor and engage on opportunities	

Customer Value – Proposed 2019
Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*	
Enterprise Strategic Outcome	**Customer loyalty**	
2019 Corporate Performance Goals and Supporting Priorities		**Assessment** ● ▲ X
4. Deliver on customer expectations for service quality and responsiveness		
a. Improve Customer Service – Implement the 'whole of company' Customer Experience (Cx) Strategy and Roadmap with a focus on modernization, customer communications and customer self-serve:		
i. Change Management Plan – Implement the multi-year change management plan to align people and organization to the Cx Strategy and Roadmap, with a focus on increasing organization-wide awareness, support and alignment for a customer-centric culture consistent with the Organizational Culture Strategy		
ii. New Service / Product Offerings – Work with existing customers to define and tailor product/service offerings, e.g. EV and energy storage solutions		
iii. Regulatory: e.g. provincial programs, migration to fixed rate and C1 class customers to HOEP		
iv. Customer Touchpoint Improvements –		
aa. Outage communications - Incorporate technology solutions to support outbound outage reporting across multiple channels / app & SMS		
bb. Annual Go Paperless campaign		
cc. Hydro Ottawa app engagement campaign		
v. Understanding Customers – Implement systems and processes to support a 1:1 conversation with customers		
aa. Customer Preference Dashboard (database) – continue development of interface to centralize customer data points to support targeted and personalized communications		
bb. Marketing Automation Platform – extend solution to automate and provide insightful analytics of marketing campaigns and communications for HOL		
cc. Email Management Platform – Implement email management solution to streamline routing of customer communications		
dd. Strategic Account Management Plan – Continue relationship building with, and develop of product offerings for, key accounts, developers and contractors; capture market intelligence, improve internal collaboration, increase customer value and create trusted advisor role		
ee. Business Intelligence – Leverage Tableau Reporting tool to allow us to better target customer segments for different program / service offerings		
vi. Technology and Process Enhancements		
aa. Website – Upgrade external websites		
bb. Enterprise Communications Platform - Leverage platform functionality for multi-channel communication (voice, text, email, chat, etc.)		

Customer Value – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*	
Enterprise Strategic Outcome	**Customer loyalty**	
2019 Corporate Performance Goals and Supporting Priorities		**Assessment** ●▲X
5. Maintain overall distribution system reliability		
a. Smart Grid – Continue implementation of grid transformation and modernization projects including i. New SCADA system - implement additional modules ii. [redacted]		
b. Maintain or enhance our best in class reliability metrics		
c. Continue our improvements in maintenance and capital program execution – *Emphasis on workforce scheduling and contractor management; Complete all budgeted programs / plans on time and within budget* **i. Distribution System Renewal and Service (Sustainment Capital Program)** – Ongoing implementation of refurbishment and enhancement programs with particular emphasis on aging infrastructure, areas with chronic reliability issues, and on station capacity **ii. Distribution System Access (Demand Capital Program)** – Ongoing implementation of new residential and commercial customer connections, system expansions, and third party driven plant relocations and upgrades **iii. Distribution Testing, Inspection and Maintenance Programs** – Ongoing implementation of distribution system and station asset evaluations (testing and inspections of poles, cables, manhole chambers and switches); forestry program execution	

Customer Value – Proposed 2019
Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2019 Corporate Performance Measures	**2014A**	**2015A**	**2016A**	**2017A**	**2018 T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment ●X**	**2019T**
SATISFACTION									
Residential & Small Commercial Annual Satisfaction Survey	HO/ON Pre83%/83% Post89%/80%	HO/ON Pre 87%/86% Post85%/83%	HO / ON Pre81%/81 Post77%/74%	HO / ON Pre90%/85% Post87%/81%	>91%	Annual Metric	Annual Metric	Annual Metric	>91%
Large Commercial Annual Satisfaction Survey	N/A	N/A	N/A	90%	>85%	Annual Metric	Annual Metric	Annual Metric	>85%
Call Centre Monthly Transaction Survey	88%	90%	89%	87%	>90%	90%	N/A [1]	N/A [1]	>90%
Ability to deal with issues (First Call Resolution)	84%	85%	85%	84%	>86%	85%	N/A [1]	N/A [1]	>86%
Complaints – Total Number Complaints – At Fault	140 N/A	124 N/A	106 N/A	71 N/A	<140 N/A	<55 N/A	44 N/A	● N/A	<120 <20 [2]
VALUE									
Number of hydrottawa.com sessions [3]	1,047,749	1,267,505	>1,500,000	6,088,429	4,500,000	2,250,000	2,396,587	●	>2,500,000
Number of MyAccount customers	122,300	136,890	158,112	167,114	>170,000	168,557	178,950	●	>186,000
Number of e-bill accounts	85,991	102,007	123,801	134,761	>140,000	137,381	145,920	●	>160,000
Number of Auto pay accounts	46,098	48,751	51,520	54,789	>57,500	56,145	60,250	●	>70,000
Number of App Registrants (Downloads) Number of Mobile App Sessions [3]	N/A N/A	N/A N/A	N/A N/A	12,519 8,585	>20,000 >120,000	15,886 66,260	22,503 106,089	● ●	>30,000 >130,000
Number of Twitter Followers [3]	7,630	10,825	12,976	15,687	>17,000	16,344	33,140	●	>40,000
Number of Facebook Followers [3]	N/A	482	2,006	3,039	>3,500	3,270	7,225	●	>8,500
Number of LinkedIn Followers [3]	N/A	2,500	3,358	4,892	>4,500	3,375	5,630	●	>6,200

[1] No actuals for Q3 2018 as monthly customer satisfaction survey was taken off-line in Q3 for modifications
[2] Added At Fault Complaints as a new measure in 2019 in addition to the total number of complaints
[3] Moved these metrics from Corporate Citizenship Scorecard to Customer Value Scorecard

Customer Value – Proposed 2019
Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2019 Corporate Performance Measures	**2014A**	**2015A**	**2016A**	**2017A**	**2018T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment** ●X	**2019T**
PRODUCT RELIABILITY									
SAIFI – Average Number of Times that Power to a Customer is Interrupted **5 year average** [1] ~~**3 year average**~~ [4]	0.99 ~~1.12~~	0.97 ~~0.99~~	0.89 ~~0.80~~	0.82 ~~0.80~~	N/A ~~<0.85~~	N/A ~~<0.85~~	N/A ~~0.99~~	N/A ~~X~~	≤0.75 ~~N/A~~
SAIFI – Average Number of Times that Power to a Customer is Interrupted **Annual excluding LOS and MEDs** [2] **Annual including LOS and MEDs** [3]	0.74 0.86 [4]	0.72 0.75 [4]	0.69 0.78 [4]	0.79 0.87 [4]	<0.75 <0.90	<0.75 <0.90	0.87 1.40	X X	≤0.75 N/A [3]
SAIDI – Average Number of Hours that Power to a Customer is Interrupted **5 year average** [1] ~~**3 year average**~~ [4]	1.07 ~~1.51~~	1.13 ~~1.46~~	1.09 ~~1.29~~	1.10 ~~1.29~~	N/A ~~<1.25~~	N/A ~~<1.25~~	N/A ~~3.34~~	N/A X	≤1.00 ~~N/A~~
SAIDI – Average Number of Hours that Power to a Customer is Interrupted **Annual excluding LOS and MEDs** [2] **Annual including LOS and MEDs** [3]	1.08 1.59 [4]	1.08 1.15 [4]	1.00 1.13 [4]	1.19 1.58 [4]	<1.00 <1.25	<1.00 <1.25	1.01 7.40	X X	≤1.00 N/A [3]
FEMI (Feeders Experiencing Multiple Interruptions) – Number of feeders with 10 or more interruptions per year	8	9	5	15	<8	<8	17	X	≤12

[1] Excludes Loss of Supply and Major Event days, previously this measure was a three year average, however both industry and the OEB reports on a 5 year average
[2] LOS = Loss of Supply, MED = Major Event Days
[3] No target set for SAIFI and SAIDI including LOS and MEDs
[4] Previously this metric included MEDs but still excluded LOS

Organizational Effectiveness – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	We will achieve performance excellence *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2019 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity	
[redacted]	
[redacted]	

Organizational Effectiveness – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2019 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity	
[redacted]	

Organizational Effectiveness – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2019 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity (continued)	
[redacted]	
[redacted]	
f. Facilities Renewal Program - Advance the implementation of the Board approved plan to replace the end of life main office and the south and east operations centres with purpose built facilities which will address location, energy efficiency, employee engagement, etc. i. Complete the design build of the Administration building and the East and South Operations Centres, operational integration and migration, regulatory case preparation, and property disposition	
7. Maintain leading health and safety record	
a. Occupational Health, Safety and Environment (OHSE) Management System i. Maintain registration of OHSE management system and prepare for update to new ISO 45001 standard (replacing OHSAS 18001) ii. Complete required OHSE training iii. [redacted] iv. Continue implementation of OHSE Targeted Action Plan v. Renew physical demands analysis for positions requiring significant physical effort	

Organizational Effectiveness – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2019 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
8. Continue to enhance organizational and employee capability	
a. Union Management Relations – i. Application for certification by SEP for representation at HOL	
[redacted]	
[redacted]	
[redacted]	

Organizational Effectiveness – Proposed 2019 Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will achieve performance excellence *By cultivating a culture of innovation and continuous improvement*								
Enterprise Strategic Outcomes	• *Efficient and effective operations* • *Safe and healthy work environment* • *Engaged, aligned and prepared workforce*								
2019 Corporate Performance Measures	2014A	2015A	2016A	2017A	2018T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment ●X	2019T
OM&A per customer - HOL only *(excl CDM)*	$269	$261	$268[1]	$264	≤$287	≤$219	$208	●	$284
Revenue per employee *(excl CDM)*	$0.32M	$0.31M	$0.32M[2]	$0.34M	≥$0.35M	≥$0.264M	$0.282M	●	≥$0.38M [2]
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									

[1] In 2016, this measure was modified to exclude CDM
[2] In 2016, these measures were modified to exclude CDM & Street Lighting, and in 2019 the measure was modified to exclude CDM only, streetlighting included in Envari base revenue

[redacted]

Organizational Effectiveness – Proposed 2019 Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

	2019 Corporate Performance Measures	Description	2014A	2015A	2016A	2017A	2018T	Q3 Target	Q3 Actual	Q3 Assessment	2019T
Labour Utilization	Productive Time	% of Billable Hours / Total Regular Hours	71%	74%	74%	73%	≥ 74%	≥ 74%	73%	X	≥ 74%
	Labour Allocation to CAPEX	% of Labour Time on Capital Activities / Total Productive Time	60%	61%	62%	60%	≥ 61%	≥ 60%	58%	X	≥ 60%
	Average Sick Days per FTE	Total Sick Days / Total Employees	5.9	6.3	5.9	6.0	≤ 6.0	≤ 6.3	7.2	X	≤ 6.0
	e-Learning Training per employee	Number of hours of e-learning / Total Employees	N/A	N/A	N/A	1.0	≥ 1	≥ 1	2.0	●	≥ 2.0
OM&A	Bad Debt as a % of Total Electricity Revenue	Bad Debt / Total Electricity Revenue	0.18%	0.01%	0.13%	0.20%	≤ 0.12%	≤ 0.12%	0.09%	●	≤ 0.12%
Asset Efficiency	Technology Infrastructure Cost per Employee	(External IT support costs + computer hardware & software depn) / # of FTE	$21.5K	$23.3K	$24.4K	$22.8K	≤ $25.3K	≤ $25.2K	$26.3K	X	≤ $24.9K
	[redacted]										
Profitability Metrics	EBITDA as a % Revenue*	[redacted]									
		EBITDA $ / Total Revenue - Hydro Ottawa Limited	44%	46%	52%	53%	≥ 52%	≥ 51%	56%	●	54%
	Inventory Turnover Ratio and Value	Cost of Materials Used / Average Inventory	1.83	1.73	2.27	1.93	≥ 2.00	≥ 1.95	1.49	X	≥ 2.00

Corporate Citizenship – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2019 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
9. Enhance our brand image in the community and the industry	
[redacted]	
[redacted]	
[redacted]	

Corporate Citizenship – Proposed 2019 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2019 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
9. Enhance our brand image in the community and the industry (continued)	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
10. Improve our environmental performance and reduce our impact on the environment	
[redacted]	
[redacted]	

Corporate Citizenship – Proposed 2019 Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*								
Enterprise Strategic Outcomes	• *Leading governance and business practices* • *Engaged stakeholders* • *Safe, secure and environmentally responsible services* • *Positive community impact*								
2019 Corporate Performance Measures	2014A	2015A	2016A	2017A	2018 T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2019T
[redacted]									

Corporate Citizenship – Proposed 2019 Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*								
Enterprise Strategic Outcomes	• *Leading governance and business practices* • *Engaged stakeholders* • *Safe, secure and environmentally responsible services* • *Positive community impact*								
2019 Corporate Performance Measures	2014A	2015A	2016A	2017A	2018 T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment ●X	2019T
[redacted]									

Annex “A”


HydroOttawa
A leading partner in a smart energy future
2020 Corporate Performance Scorecard
November 28, 2019
HOHI and HOL Boards of Directors

Board Decisions Required Today

- Review & approve the 2020 Corporate Performance Scorecard

- Specifically, for each of the 4 key areas of focus in the scorecard, review and approve

  - QUALITATIVE performance goals and priorities for 2020

  - QUANTITATIVE performance measures and targets for 2020

Corporate Performance Scorecard Framework

We plan our course for a 5-year period	Hydro Ottawa's **Strategic Direction** • provides a comprehensive overview of our business strategy and financial projections for a 5-year period
We implement and operate in accordance with annual plans and budget	The annual business plan for the enterprise has two components • A budget including **summary key corporate priorities**, and • **A corporate performance scorecard** (**more comprehensive list of corporate priorities** and measures & targets) that we cascade to employees to align them to deliver against strategy
We monitor and report performance and progress against annual plans and budget	• Monthly reviews by the Executive Management Team • Quarterly President & CEO reports to the 2 Boards including ERM reporting and letters of representation • Quarterly financial reports and monthly updates to the Shareholder • Year end performance results reviews and President & CEO report to the 2 Boards • Annual Report to the Shareholder

Where We're At In Our Annual Board Business Planning And Reporting Cycle

HOHI & HOL Boards receive quarterly reports as part of CURRENT YEAR performance and progress monitoring

Timeline	Activity
APRIL	Year-end Committee and Board meetings for PREVIOUS YEAR
JUNE	PREVIOUS YEAR annual results reporting to the Shareholder – AGM
SEPTEMBER	HOHI Board receives budget guidelines to guide preparation of annual business plan priorities and budget for SUBSEQUENT YEAR
SEPT - NOV	Development of business plan priorities & budget and performance scorecard for SUBSEQUENT YEAR • Takes into consideration PREVIOUS YEAR approved plan, updated for the changing environment and business priorities
EARLY NOVEMBER	HOHI Board receives debrief and discusses critical issues and opportunities facing the company at its annual strategy session
LATE NOVEMBER	• HOL Board receives Budget Guidelines for SUBSEQUENT YEAR, endorses HOL Business Plan Priorities, Budget and Scorecard, and recommends to the HOHI Board • HOHI Board receives for approval HOL and Enterprise Business Plan Priorities, Budget and Scorecard for SUBSEQUENT YEAR

2020 Performance Scorecard

- As in previous years, the Board is being asked to approve **one corporate performance scorecard for the enterprise**
- The scorecard establishes qualitative performance goals and priorities and quantitative measures and targets in each of our four key areas of focus to support the advancement of the Strategic Direction in a given year
  - Customer Value
  - Organizational Effectiveness
  - Corporate Citizenship
  - Financial Strength



- The scorecard also includes separate quantitative Financial Strength performance targets for the HOL entity
- Performance priorities for executive and management staff for 2020 will be cascaded from the corporate performance scorecard to align individuals to deliver against strategy
- Results highlights and progress against the scorecard (including ERM assessment) will be reported quarterly to the HOHI and HOL Boards by the President & CEO

Scorecard Principles For 2020

One Corporate Performance Scorecard for the Enterprise

- Separate Financial Strength performance measures and targets for HOL 'entity'
- 'Highlighted' qualitative supporting priorities have HOL Board oversight

Weightings for each of 4 key areas of focus

- Removed as per Board direction in 2015

Targets associated with quantitative performance measures

- Reflect past performance and changing circumstances, and
- Encourage and reward continuous improvement where appropriate

Monitoring and Reporting

- Provides for more detailed measures / tracking tools for management use while keeping Board reporting at more strategic level
- Includes monthly monitoring of progress by the Executive Management Team, and quarterly reporting to the Boards as part of President and CEO's quarterly report and letters of representation

2020 Performance Goals Summary

5-Year Enterprise Strategic Objectives and Outcomes (2016-2020)		2020 Corporate Performance Goals
Financial Strength	**Enterprise Strategic Objective:** **We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people* **Enterprise Strategic Outcome:** *Growth in shareholder value*	• ***Grow revenues from new sources*** • ***Enhance / protect revenues from existing business lines***
Customer Value	**Enterprise Strategic Objective:** **We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates* **Enterprise Strategic Outcome:** *Customer loyalty*	• ***Assist customers in managing their energy consumption and electricity costs*** • ***Deliver on customer expectations for service quality and responsiveness*** • ***Maintain overall distribution system reliability***
Organizational Effectiveness	**Enterprise Strategic Objective:** **We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement* **Enterprise Strategic Outcomes:** *Efficient and effective operations* *Safe and healthy work environment* *Engaged, aligned and prepared workforce*	• ***Continue to enhance operational performance and productivity*** • ***Maintain leading health and safety record*** • ***Enhance organizational and employee capability***
Corporate Citizenship	**Enterprise Strategic Objective:** **We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen* **Enterprise Strategic Outcomes:** *Leading governance and business practices* *Engaged stakeholders* *Safe, secure and environmentally responsible services* *Positive community impact*	• ***Enhance our brand image in the community and the industry*** • ***Continue to improve our environmental performance and reduce our impact on the environment***

Financial Strength – Summary Key Corporate Priorities

Grow revenues from new sources and enhance / protect revenues from existing business lines

[redacted]	
[redacted]	
[redacted]	
[redacted]	
5.	Rate Application – Defend 2021-2025 Custom Incentive Rate Setting application as part of Ontario Energy Board proceedings in 2020, including defense of Facilities Renewal Program; monitor and execute approved 2016-2020 rate application
[redacted]	
[redacted]	

Customer Value – Summary Key Corporate Priorities

Assist customers in managing their energy consumption and electricity costs; deliver on customer expectations for service quality and responsiveness; and maintain overall system reliability

1.	Maintain or enhance our best in class reliability metrics
2.	Continue implementation of Customer Experience Roadmap key deliverables including using data to drive decisions impacting customers
3.	Actively pursue and participate in energy innovation projects
4.	CDM – continue to deliver Interim Conservation Framework (wind down) programs and actively pursue and participate in regional CDM programs that are customer centric, cost-effective and generate strong GWh results
5.	Smart Grid – continue implementation of the foundational grid transformation and modernization projects [redacted] and Distribution Management System (leveraging and building on SCADA, Outage Management System and Geographic Information System information)
6.	Continue our improvements in maintenance and capital execution – emphasis on workforce scheduling and contractor management; complete all budgeted programs / plans on time and within budget

Organizational Effectiveness – Summary Key Corporate Priorities

Continue to enhance operational performance and productivity; maintain leading health and safety record; and enhance organizational and employee capability

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
4.	**Union Management Relations – manage outcome of application for certification by SEP for representation at HOL; [redacted], and 2021 collective bargaining strategy for HOL**

Corporate Citizenship – Summary Key Corporate Priorities

Enhance our brand image in the community and the industry; improve our environmental performance and reduce our impact on the environment

Financial Strength – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2020 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
1. *Grow revenues from new sources*	
[redacted]	
b. Distribution i. Continue to approach other LDCs in Ontario regarding potential acquisition/mergers/partnerships ii. Continue to expand our distribution system through acquisition of customer-owned assets (e.g. Ottawa International Airport, DND Uplands)	
[redacted]	
d. Other ancillary services that leverage Hydro Ottawa's brand and competitive advantage in the industry i. **Electrical service and construction offerings -** emergency repair and replacement of customer-owned distribution assets, meter services for other entities, distribution sub-station services to other LDCs and private businesses, forestry services	
ii. **Regional Training** aa. Continue development and implementation of all levels of Training Delivery Agent Status Powerline Technician training and certification with Algonquin College bb. Continue to market and enhance training services to other LDCs / contractors	
[redacted]	

Privileged and Confidential

Financial Strength – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people*
Enterprise Strategic Outcome	**Growth in shareholder value**

2020 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
2. ***Enhance / protect revenues from existing business lines***	
[redacted]	
b. ***Rate Application*** – Defend 2021-2025 Electricity Custom Incentive Rate Setting application as part of Ontario Energy Board proceedings in 2020, including defense of Facilities Renewal Program; monitor and execute approved 2016-2020 rate application	
c. ***Government Relations, Policies and Consultations*** – *Actively participate and influence OEB policy reviews and consultations, New York state renewable energy proposals, and other government announcements which may impact or foster future success*	
[redacted]	
[redacted]	

Financial Strength – Proposed 2020
Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will create sustainable growth in our business and our earnings *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	Growth in shareholder value								
2020 Corporate Performance Measures	2015A IFRS	2016A IFRS	2017A IFRS	2018A IFRS	2019T IFRS	Q3 YTD Target IFRS	Q3 YTD Actual IFRS	Q3 YTD Assessment ●X	2020 Target IFRS
[redacted]									

HOL Financial Strength – Proposed 2020 Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will create sustainable growth in our business and our earnings** *By improving productivity and pursuing business growth opportunities that leverage our strengths, our core capabilities, our assets and our people*								
Enterprise Strategic Outcome	**Growth in shareholder value**								
2020 HOL Performance Measures	**2015A IFRS**	**2016A IFRS**	**2017A IFRS**	**2018A IFRS**	**2019T IFRS**	**Q3 YTD Target IFRS**	**Q3 YTD Actual IFRS**	**Q3 YTD Assessment ●X**	**2020 Target IFRS**
Net Income	$35.5M	$34.3M	$36.5M	$37.2M	$34.9M	$25.7M	$26.6M	●	$34.7M
Revenue *(excl CDM)* [1]	$172.8M	$182.0M	$187.1M	$199.2M	$208.7M	$157.1M	$155.7M	X	$212.7M
OM&A - Net *(excl CDM)* [1]	$84.5M	$87.9M	$87.5M	$95.1M	$96.4M	$73.9M	$77.8M	X	$101.8M
Return on Equity	12.1%	11.0%	11.1%	10.7%	9.4%	9.4%	10.0%	●	9%
Cash Flow from Operations [2]	$69.0M	$78.0M	$78.3M	$114.3M	$110.3M	$72.4M	$55.3M	X	$115.7M
CAPEX System Renewal and Service *(excl Plant Failure)* [3] Plant Failure [3] General *(incl Facilities Renewal Program)* [3]	$54.5M N/A $10.2M	$57.3M $7.8M $15.7M	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A	N/A N/A N/A
Cumulative Capital Additions General Plant System Renewal & Service	---	---	$31.0M $116.0M	$37.9M $186.4M	$39.8M $220.0M	$39.8M $220.0M	$49.5M $235.7M	● ●	$54.8M $301.1M
Labour Allocation to CAPEX	61%	62%	60%	58%	60%	60%	58%	X	N/A
Labour Allocation to Maintenance & Administrative Work (Regular Hrs) [6]	---	---	---	---	---	---	---	---	≤ 34%
Debt to Capitalization Ratio [4]	---	---	---	---	65%	64.7%	67.0%	X	67%
CDM – Cumulative GWh reduction [5]	78 GWh	90 GWh	276 GWh	324 GWh	375 GWh	N/A	N/A	N/A	N/A

[1] In 2016, these measures were modified to exclude CDM
[2] In 2016 & 2017, Cash flow from Operations on financial statement includes reclassifications of deferred revenue and customer deposits, the actual results are based on the previous reporting method to compare to the target, starting 2018, result was aligned with financial statement reporting
[3] In 2016, Plant Failure was added as a separate measure and excluded from the overall CAPEX measure
[4] New measure added in 2019
[5] 2015 and 2016 are annual reductions not cumulative. 2015 , 2016, and 2017 results restated based on IESO confirmed results received in subsequent years. Announced on March 2019, LDCs will no longer receive incentive payments for achieving assigned targets for electricity savings
[6] In 2020, replaced Labour Allocation to Capex measure with Labour Allocation to Mtnce & Admin to further support performance management

Customer Value – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*	
Enterprise Strategic Outcome	**Customer loyalty**	
2020 Corporate Performance Goals and Supporting Priorities		**Assessment** ●▲X
3. Assist customers in managing their energy consumption and electricity costs		
a. CDM - Continue to deliver the Interim Conservation Framework (wind down) programs and actively pursue and participate in regional CDM programs that are customer-centric, cost effective and generate strong GWh results		
b. Electricity Support Programs – Continue to promote and support the provincial program(s) that provide ongoing financial assistance to qualifying low-income electricity consumers including i. Ontario Electricity Support Program (OESP) ii. Low-Income Energy Assistance Program (LEAP) iii. Affordability Fund Trust		
c. Customer Education Program – Continue to increase understanding of the industry and Hydro Ottawa's role and achievements within it; demystify and educate by leveraging multiple modes (digital and social media, video, open houses, workshops, etc.) and multiple channels (local media, Councillors, subject matter experts, executive and senior management)		
d. Energy Innovation Projects – Actively pursue and participate in innovation projects to identify new energy saving product/service offerings for our customers		

Customer Value – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*	
Enterprise Strategic Outcome	**Customer loyalty**	
2020 Corporate Performance Goals and Supporting Priorities		**Assessment** ● ▲ X
4. Deliver on customer expectations for service quality and responsiveness		
a. Improve Customer Service – Implement the 'whole of company' Customer Experience (Cx) Strategy and Roadmap with a focus on modernization, customer communications and customer self-serve:		
i. Change Management Plan – Implement the multi-year change management plan to align people and organization to the Cx Strategy and Roadmap, with a focus on increasing organization-wide awareness, support and alignment for a customer-centric culture consistent with the Organizational Culture Strategy		
ii. New Service / Product Offerings – Work with existing customers to define and tailor product/service offerings, e.g. EV and energy storage solutions		
iii. Regulatory: e.g. provincial programs, migration to fixed rate and C1 class customers to HOEP		
iv. Customer Touchpoint Improvements –		
aa. Outage communications - continue to incorporate technology solutions to support outbound outage reporting across multiple channels / app & SMS		
bb. Direct Serve – continue to incorporate technology solutions to support self-service for customers		
v. Understanding Customers – Implement systems and processes to support a 1:1 conversation with customers		
aa. Customer Preference Dashboard (database) – continue development of interface to centralize customer data points to support targeted and personalized communications		
bb. Strategic Account Management Plan – Continue relationship building with, and develop of product offerings for, key accounts, developers and contractors; capture market intelligence, improve internal collaboration, increase customer value and create trusted advisor role		
cc. Business Intelligence – Continue to leverage Tableau Reporting and marketing automation tools to allow us to better target customer segments for different program / service offerings		
vi. Technology and Process Enhancements		
aa. Enterprise Communications Platform - Leverage platform (e.g. Avaya, Salesforce) functionality for multi-channel communication (voice, text, email, chat, etc.)		

Customer Value – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will deliver value across the entire customer experience** *By providing reliable, responsive and innovative services at competitive rates*	
Enterprise Strategic Outcome	**Customer loyalty**	
2020 Corporate Performance Goals and Supporting Priorities		**Assessment** ● ▲ X
5. Maintain overall distribution system reliability		
a. Smart Grid – Continue implementation of grid transformation and modernization projects including	[redacted]	
	ii. Distribution Management System – continue to develop system leveraging and building on SCADA, Outage Management System and GIS information	
b. Maintain or enhance our best in class reliability metrics		
c. Continue our improvements in maintenance and capital program execution – *Emphasis on workforce scheduling and contractor management; Complete all budgeted programs / plans on time and within budget*		
	i. **Distribution System Renewal and Service (Sustainment Capital Program)** – Ongoing implementation of refurbishment and enhancement programs with particular emphasis on aging infrastructure, areas with chronic reliability issues, and on station capacity	
	ii. **Distribution System Access (Demand Capital Program)** – Ongoing implementation of new residential and commercial customer connections, system expansions, and third party driven plant relocations and upgrades	
	iii. **Distribution Testing, Inspection and Maintenance Programs** – Ongoing implementation of distribution system and station asset evaluations (testing and inspections of poles, cables, manhole chambers and switches); forestry program execution	

Customer Value – Proposed 2020
Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2020 Corporate Performance Measures	**2015A**	**2016A**	**2017A**	**2018 A**	**2019T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment ●X**	**2020 Target**
SATISFACTION									
Residential & Small Commercial Annual Satisfaction Survey	HO/ON Pre 87%/86% Post85%/83%	HO / ON Pre81%/81 Post77%/74%	HO / ON Pre90%/85% Post87%/81%	HO / ON Pre 94%/91% Post 93%/89%	≥91%	Annual Metric	Annual Metric	Annual Metric	≥90%
Large Commercial Annual Satisfaction Survey	N/A	N/A	90%	HO / ON Pre 94%/93% Post 95%/93%	≥85%	Annual Metric	Annual Metric	Annual Metric	≥90%
Call Centre Monthly Transaction Survey	90%	89%	87%	78%	≥90%	≥90%	88%	X	≥85%
Ability to deal with issues (First Call Resolution)	85%	85%	84%	86%	≥86%	≥85%	90%	●	≥85%
Complaints – Total Number Complaints – At Fault	124 N/A	106 N/A	71 N/A	182 N/A	≤120 ≤20 [2]	≤90 ≤15	16 4	● ●	≤120 ≤20
VALUE									
Number of hydrottawa.com sessions [1]	1,267,505	3,170,766	6,088,429	6,623,907	>2,500,000	>1,875,000	2,136,682	●	>2,500,000
Number of MyAccount customers	136,890	158,112	167,114	184,067	>186,000	>185,517	196,600	●	>210,000
Number of e-bill accounts	102,007	123,801	134,761	150,991	>160,000	>157,748	163,075	●	>175,000
Number of Auto pay accounts	48,751	51,520	54,789	63,014	>70,000	>68,254	67,934	X	>75,000
Number of App Registrants (Downloads) Number of Mobile App Sessions [1]	N/A N/A	N/A N/A	12,519 8,585	24,363	>30,000 >130,000	>28,591 >97,500	32,308 36,592	● X	>40,000 >40,000
Number of Social Media Followers (Twitter, Facebook, LinkedIn, Instagram) [1, 2]	13,807	18,340	23,618	46,859	>54,700	>52,394	51,809	X	>64,500

[1] These metrics were moved from Corporate Citizenship Scorecard to Customer Value Scorecard
2 In 2020, the Social Media follower measures were combined into one, with the historical figures updated to include all platforms with Instagram included in the targets as of 2020

Customer Value – Proposed 2020
Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will deliver value across the entire customer experience *By providing reliable, responsive and innovative services at competitive rates*								
Enterprise Strategic Outcome	**Customer loyalty**								
2020 Corporate Performance Measures	**2015A**	**2016A**	**2017A**	**2018A**	**2019T**	**Q3 YTD Target**	**Q3 YTD Actual**	**Q3 YTD Assessment** ●X	**2020 Target**
PRODUCT RELIABILITY									
SAIFI – Average Number of Times that Power to a Customer is Interrupted **5 year average [1]** ~~**3 year average [1]**~~	0.97 ~~0.99~~	0.89 ~~0.80~~	0.82 ~~0.80~~	0.73 [4]	≤0.75	≤0.75	0.74	●	≤0.72
SAIFI – Average Number of Times that Power to a Customer is Interrupted **Annual excluding LOS and MEDs [2]** **Annual including LOS and MEDs [3]**	0.72 0.75	0.69 0.78	0.79 0.87	0.78 1.78	≤0.75 N/A [3]	≤0.59 N/A [3]	0.58 0.86	●	≤0.75 N/A [3]
SAIDI – Average Number of Hours that Power to a Customer is Interrupted **5 year average [1]** ~~**3 year average [1]**~~	1.13 ~~1.46~~	1.09 ~~1.29~~	1.10 ~~1.29~~	0.99 [4]	≤1.00	≤1.00	0.96	●	≤0.92
SAIDI – Average Number of Hours that Power to a Customer is Interrupted **Annual excluding LOS and MEDs [2]** **Annual including LOS and MEDs [3]**	1.08 1.15	1.00 1.13	1.19 1.58	0.85 22.724	≤1.00 N/A [3]	≤0.79 N/A [3]	0.53 0.95	●	≤0.95 N/A [3]
FEMI (Feeders Experiencing Multiple Interruptions) – Number of feeders with 10 or more interruptions per year	9	5	15	10	≤12	≤12	8	●	≤11

[1] Excludes Loss of Supply and Major Event days (previously this measure was a three year average, however both industry and the OEB reports on a 5 year average), as of 2018 only 5 year average reported
[2] LOS = Loss of Supply, MED = Major Event Days
[3] No target set for SAIFI and SAIDI including LOS and MEDs
[4] Value previously reported for 2018 SAIFI 5 year average of 0.93 and 2.05 for SAIDI were incorrect

Organizational Effectiveness – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2020 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity	
[redacted]	
[redacted]	

Organizational Effectiveness – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2020 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
6. Continue to enhance operational performance and productivity	
[redacted]	

Organizational Effectiveness – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*	
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***	
2020 Corporate Performance Goals and Supporting Priorities		**Assessment** ●▲X
6. Continue to enhance operational performance and productivity (continued)		
[redacted]		
[redacted]		
f. Facilities Renewal Program i. Finalize deficiency review and continue transition to optimize facility functionality and efficiency		
7. Maintain leading health and safety record		
a. Occupational Health, Safety and Environment (OHSE) Management System i. Maintain registration of OHSE management system and prepare for update to new ISO 45001 standard (replacing OHSAS 18001) ii. Complete required OHSE training [redacted] iv. Continue implementation of OHSE Targeted Action Plan v. Renew physical demands analysis for positions requiring significant physical effort		

Organizational Effectiveness – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

2020 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
8. Continue to enhance organizational and employee capability	
a. Union Management Relations – i. Application for certification by SEP for representation at HOL	
[redacted], and 2021 collective bargaining strategy for HOL	
[redacted]	
[redacted]	

Organizational Effectiveness – Proposed 2020 Corporate Performance Measures and Targets

Enterprise Strategic Objective	We will achieve performance excellence *By cultivating a culture of innovation and continuous improvement*								
Enterprise Strategic Outcomes	• *Efficient and effective operations* • *Safe and healthy work environment* • *Engaged, aligned and prepared workforce*								
2020 Corporate Performance Measures	2015A	2016A	2017A	2018A	2019T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment ●X	2020 Target
OM&A per customer - HOL only *(excl CDM)* [1]	$261	$268	$264	$284	≤$284	≤$219	$230	X	≤$297
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									
[redacted]									

[1] In 2016, this measure was modified to exclude CDM
[2] In 2016, these measures were modified to exclude CDM & Street Lighting, and in 2019 the measure was modified to exclude CDM only, streetlighting included in Envari base revenue

[redacted]

Organizational Effectiveness – Proposed 2020 Corporate Performance Measures And Targets

Enterprise Strategic Objective	**We will achieve performance excellence** *By cultivating a culture of innovation and continuous improvement*
Enterprise Strategic Outcomes	• ***Efficient and effective operations*** • ***Safe and healthy work environment*** • ***Engaged, aligned and prepared workforce***

	2020 Corporate Performance Measures	Description	2015A	2016A	2017A	2018A	2019T	Q3 Target	Q3 Actual	Q3 Assessment	2020T
Labour Utilization	Productive Time	% of Billable Hours / Total Regular Hours	74%	74%	73%	72%	≥ 74%	74%	73%	X	≥ 74%
	Labour Allocation to CAPEX	% of Labour Time on Capital Activities / Total Productive Time	61%	62%	60%	58%	≥ 60%	60%	58%	▲	N/A
	Labour Allocation to Mtnce & Admin (regular hours)*	% of Labour Time on Mtnce & Admin / Total Productive Time	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	≤ 34%
	Average Sick Days per FTE (annualized)	Total Sick Days / Total Employees	6.3	5.9	6.0	7.1	≤ 6.0	6.3	8.1	X	≤ 6.0
	e-Learning Training per employee (annualized)	Number of hours of e-learning / Total Employees	N/A	N/A	1.0	1.8	≥ 2.0	2.0	2.5	●	≥ 2.0
OM&A	Bad Debt as a % of Total Electricity Revenue	Bad Debt / Total Electricity Revenue	0.01%	0.13%	0.20%	0.13%	≤ 0.12%	≤ 0.12%	0.06%	●	≤ 0.12%
Asset Efficiency	Technology Infrastructure Cost per Employee	(External IT support costs + computer hardware & software depn) / # of FTE	$23.3K	$24.4K	$22.8K	$26.5K	≤ $24.9K	≤ $24.6K	$22.9K	●	≤ $25.8K
	[redacted]										
Profitability Metrics	EBITDA as a % Revenue	[redacted]									
		EBITDA $ / Total Revenue - Hydro Ottawa Limited	46%	52%	53%	54%	≥ 54%	53%	50%	X	≥ 52%
	Inventory Turnover Ratio and Value	Cost of Materials Used / Average Inventory	1.73	2.27	1.93	1.55	≥ 2.00	≥ 1.95	1.55	▲	≥ 2.00

- In 2020, replaced Labour Allocation to Capex measure with Labour Allocation to Mtnce & Admin to further support performance management
- [redacted]

Corporate Citizenship – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2020 Corporate Performance Goals and Supporting Priorities	Assessment ● ▲ X
9. Enhance our brand image in the community and the industry	
[redacted]	
[redacted]	
[redacted]	

Corporate Citizenship – Proposed 2020 Corporate Performance Goals And Priorities

Enterprise Strategic Objective	**We will contribute to the well being of the community** *By acting at all times as a responsible and engaged corporate citizen*
Enterprise Strategic Outcomes	• ***Leading governance and business practices*** • ***Engaged stakeholders*** • ***Safe, secure and environmentally responsible services*** • ***Positive community impact***

2020 Corporate Performance Goals and Supporting Priorities	Assessment ●▲X
9. Enhance our brand image in the community and the industry (continued)	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
10. Improve our environmental performance and reduce our impact on the environment	
[redacted]	
[redacted]	

Corporate Citizenship – Proposed 2020 Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*								
Enterprise Strategic Outcomes	• *Leading governance and business practices; Engaged stakeholders; Safe, secure and environmentally responsible services; Positive community impact*								
2020 Corporate Performance Measures	2015A	2016A	2017A	2018 A	2019T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment ●X	2020 Target
[redacted]									

Corporate Citizenship – Proposed 2020 Corporate Performance Measures And Targets

Enterprise Strategic Objective	We will contribute to the well being of the community *By acting at all times as a responsible and engaged corporate citizen*								
Enterprise Strategic Outcomes	• *Leading governance and business practices* • *Engaged stakeholders* • *Safe, secure and environmentally responsible services* • *Positive community impact*								
2020 Corporate Performance Measures	2015A	2016A	2017A	2018 A	2019T	Q3 YTD Target	Q3 YTD Actual	Q3 YTD Assessment	2020 Target
[redacted]									

[redacted]

INTERROGATORY RESPONSE - SEC-5

1-SEC-5

EXHIBIT REFERENCE:

[Ex. 1-1-5, p.19]

SUBJECT AREA: Bill Impacts

Please provide Table 15 in excel format.

RESPONSE:

Table 15 from UPDATED Exhibit 1-1-5: Application Summary has been provided in excel format in Attachment SEC-5(A): Bill Impacts.

Please note that the table is also available in excel in UPDATED Attachment 8-12-1(A): Bill Impacts Model 2021-2025. The table can be found on the Tab named “Summary with $ and %”.

INTERROGATORY RESPONSE - SEC-6

1-SEC-6

EXHIBIT REFERENCE:

[Ex.1-1-10]

SUBJECT AREA: Custom Incentive Rate-Setting Framework

a) Please confirm that based on the Hydro Ottawa's proposed rate-setting methodology, there is no stretch or productivity factor applied to any portion of the revenue requirement with the exception of OM&A costs. If confirmed, please explain why this is appropriate.

RESPONSE:

a) Hydro Ottawa confirms that there is no stretch factor or productivity factor applied to any part of the revenue requirement other than OM&A.

As noted in response to interrogatory OEB-3 and as outlined in UPDATED Exhibit 2-4-1: Capital Expenditure Summary, in preparing this Application Hydro Ottawa administered a rigorous capital expenditure prioritization process. During this process, capital expenditure levels were reduced by approximately $50M per year over the course of the 2021-2025 period. The initially proposed expenditures were prioritized through a process that took into account customer impacts (including growth), financial impacts, asset needs, resourcing considerations, system reliability (including aging infrastructure), and health and safety considerations. Some of the savings were achieved by incorporating productivity savings into the 2021-2025 capital program. For more information on Hydro Ottawa's productivity and continuous improvement initiatives, please see Exhibit 1-1-13: Productivity and Continuous Improvement Initiatives.

In addition, Hydro Ottawa notes that this Application builds upon the Custom IR

approach employed and approved in the utility's 2016-2020 rate application. This latter approach applied a custom escalation formula to OM&A expenses alone. Furthermore, the Renewed Regulatory Framework ("RRF") does not stipulate that all local distribution companies ("LDCs") are required to use the same approach in crafting their Custom IR rate applications. The RRF contemplates that utilities would use a custom approach (emphasis added) that suits each LDC's particular circumstances.[1]

[1] Ontario Energy Board, *Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 18, 2012), pages 18-19; Ontario Energy Board, *Handbook for Utility Rate Applications* (October 13, 2016), page 24.

INTERROGATORY RESPONSE - SEC-7

1-SEC-7

EXHIBIT REFERENCE:

[Ex.1]

SUBJECT AREA: Custom Incentive Rate-Setting Framework

Please identify all instances where Hydro Ottawa's application deviates from the OEB's Rate Handbook. Please explain why the deviations are appropriate.

RESPONSE:

Hydro Ottawa is interpreting this question as requesting the utility to identify all instances where its Application deviates from the OEB's *Handbook for Utility Rate Applications*, issued on October 13, 2016.

There is only one aspect of Hydro Ottawa's Application which deviates from the *Handbook for Utility Rate Applications*. There are two instances (page 10 and page 12) in which the Handbook states that a utility's business plan should be included in the Executive Summary of the application. In this Application, Hydro Ottawa has included its Business Plan as a standalone Schedule, located immediately following the Executive Summary. The Executive Summary is UPDATED Exhibit 1-1-8 and the Business Plan is UPDATED Exhibit 1-1-9.

In light of the Business Plan's function in underpinning the rate application as a whole, Hydro Ottawa believed that it would serve the interests of OEB Staff, intervenors, customers, and other stakeholders if the Business Plan was made available in a prominent, accessible location within the Application. Moreover, given the manner in which both the Executive Summary and the Business Plan evolved during the drafting process, Hydro Ottawa took the view that it would have disrupted the flow, structure, and narrative of both documents if the Business Plan were to have been embedded within the Executive Summary itself.

To view the checklist of all the OEB Filing Requirements which the Application fulfills (many of which are directly or indirectly informed by provisions in the *Handbook for Utility Rate Applications*), please see Exhibit 1-1-3: Checklist and Compliance with Ontario Energy Board Filing Requirements.

INTERROGATORY RESPONSE

1-SEC-8

EXHIBIT REFERENCE:

[Ex.1-1-10]

SUBJECT AREA: Custom Incentive Rate-Setting Framework

Please explain how the proposed rate-setting methodology, and any customer protections (i.e. ESM, etc.) differ from what was approved as part of the Hydro Ottawa's last Custom IR application. Please explain why the changes are appropriate and benefit customers.

RESPONSE:

The approach used by Hydro Ottawa in its current Custom IR application is similar to the one that was approved by the OEB for the 2016-2020 period.[1] The approach used in the 2016-2020 application was deemed to be consistent with the Renewed Regulatory Framework ("RRF") and with the RRF's expectations for Custom Incentive Rate-setting applications.[2]

In UPDATED Exhibit 1-1-10: Alignment with the Renewed Regulatory Framework, Hydro Ottawa discusses this Application's consistency with the RRF. Details relating to customer protection are summarized on pages 26-35.

One feature of the utility's approved 2016-2020 rate plan that Hydro Ottawa is not proposing to sustain as part of this Application is the use of an Efficiency Adjustment Mechanism ("EAM"). For more details on Hydro Ottawa's rationale, please see the response to interrogatory OEB-9.

[1] Ontario Energy Board, *Decision and Rate Order*, EB-2015-0004 (December 22, 2015).
[2] *Ibid*, page 1.

INTERROGATORY RESPONSE - SEC-9

1-SEC-9

EXHIBIT REFERENCE:

[Ex.1-1-10]

SUBJECT AREA: Custom Incentive Rate-Setting Framework

Please provide a table that shows for each year of the rate plan, the difference in the forecast revenue collected from base distribution rates under the following different rate-setting methodologies:

a) Hydro Ottawa's proposed Custom IR rate-setting methodology

b) Hydro Ottawa's 2015-2020 OEB approved Custom IR methodology (EB-2015-0004)

c) OEB approved Toronto Hydro-Electric System Limited methodology in EB-2018-0165

d) OEB approved Hydro One Networks Inc. Distribution methodology in EB-2017-0049

e) 2021 Cost of Service with 2022-2025 adjusted by way of Price-Cap IR

Please include in your response the live excel spreadsheet showing the calculations.

RESPONSE:

a) The forecast of revenues from base distribution rates for Hydro Ottawa's proposed Custom IR methodology is summarized in UPDATED Exhibit 1-1-8: Executive Summary.

b) For Hydro Ottawa's 2016-2020 OEB-approved Custom IR methodology, please see the Approved Settlement Agreement in proceeding EB-2015-0004.[1]

c) Hydro Ottawa is not able to develop a response to this question in the timeframe allotted for interrogatory responses. A response to this question would require Hydro Ottawa to build and test several new models for each section of the question. For each section, Hydro Ottawa would need to know all the specific features to be modelled and would be required to confirm a host of detailed assumptions. In addition, there would need to be assumptions made with respect to the disposition of Group 1 and Group 2 deferral accounts, as well as to the Facilities Renewal Program ("FRP").

It is also unclear what value the response would bring to this proceeding. It is not clear that the OEB favours one approach over the other, especially given that each Custom IR proposal is unique and tailored to the specific circumstances of each local distribution company ("LDC").

In summary, Hydro Ottawa sees little value in performing the comparisons requested by SEC because this means taking a plan crafted for the particular circumstances of one LDC and applying that plan in a way that was never intended (i.e. applying it to the unique circumstances of another LDC). The value of the requested comparisons is questionable in light of the extent of the assumptions and uncertainties associated with applying a Custom IR plan to the circumstances of a different LDC.

Hydro Ottawa would also note that the Renewed Regulatory Framework ("RRF") does not stipulate that all LDCs are required to use the same approach in crafting their Custom IR rate applications. The RRF contemplates that utilities would use a custom approach (emphasis added) that suits each LDC's particular circumstances.[2] Although

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Approved Settlement Proposal*, EB-2015-0004 (December 7, 2015).
[2] Ontario Energy Board, *Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 18, 2012), pages 18-19; Ontario Energy Board, *Handbook for Utility Rate Applications* (October 13, 2016), page 24.

Hydro Ottawa closely monitors the rate proceedings and OEB Decisions related to other regulated utilities, and seeks to incorporate lessons learned where appropriate, the utility is not of the view that a specific OEB Decision for a particular LDC needs to dictate the approach that must be used by another LDC. Hydro Ottawa's understanding is that, consistent with the principles of administrative law and procedure, the Decisions and Orders issued by individual OEB panels are binding on the parties to the specific proceeding, but are neither binding on other parties nor future OEB panels. Accordingly, Hydro Ottawa understands that the aforementioned OEB Decisions are applicable to the unique circumstances of the respective rate applications submitted by the utilities in question, and do not impose obligations on Hydro Ottawa to adopt similar types of approaches.

d) Please see the response provided in part (c) above.

e) Please see the response provided in part (c) above.

INTERROGATORY RESPONSE - SEC-10

1-SEC-10

EXHIBIT REFERENCE:

[Ex.1-1-10, p.15]

SUBJECT AREA: Custom Incentive Rate-Setting Framework

With respect to the inflation forecast:

a) What is the date of the Conference Board of Canada forecast used by Hydro Ottawa?

b) Please provide a copy of the most recent Conference Board of Canada forecast available.

RESPONSE:

a) Hydro Ottawa used a Conference Board of Canada forecast dated May 9, 2019.

b) Table A below provides the most recent Conference Board of Canada forecast used for the inflation forecast. This data was obtained from the Conference Board of Canada on May 16, 2020.[1]

[1] Note that the latest projection data for GDP-IPI and AWE is available up to 2024 only. Consistent with the inflation indices used in Clearspring Energy Advisors' *Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability* (Attachment 1-1-12(A)), the 2024 inflation rate was applied to 2025.

Table A – Updated 2017-2025 GDP-IPI (FDD) Index and AWE (Ontario) Index

Year	GDP-IPI	AWE
2017	2.43%	0.83%
2018	1.80%	3.41%
2019	1.91%	4.08%
2020	0.14%	4.82%
2021	3.17%	1.24%
2022	2.55%	2.16%
2023	1.90%	2.33%
2024	1.88%	2.33%
2025	1.88%	2.33%

INTERROGATORY RESPONSE - SEC-11

1-SEC-11

EXHIBIT REFERENCE:

[Ex.1-1-10, p.21-23]

SUBJECT AREA: Custom Incentive-Rate Setting Framework

With respect to the proposed growth factor:

a) [p.21] Please provide a copy of the referenced documents, or a hyperlink if available, included at footnotes 30-31.

b) [p.23] Hydro Ottawa states: “Hydro Ottawa proposes to employ a scaling factor of 0.35 to determine its growth factor, consistent with the approved approaches for FortisBC and Hydro Québec. The selection of this scaling factor was made by considering the scaling factors used in other jurisdictions and taking into account the substantial growth in population and customers in the Ottawa area.” Please explain the basis for using a 0.35% factor, including what jurisdictions Hydro Ottawa used, and how the “substantial growth” referred to would result in the specific number chosen.

c) Please confirm as part of the EB-2015-0004 settlement, Hydro Ottawa agreed to a 0.14% growth factor.

d) If (c) is confirmed, based on the approved load forecast, what would have been the ‘scaling factor’ that would have resulted in a 0.14% growth factor.

e) [EB-2015-0003, Section II, Tab 1, Ex. F-1, p.6, Section III, Tab 2, F-Energy Probe-6] In EB-2015-0003, PowerStream estimated that their utility specific ‘scaling factor’ was 11.45% (1% increase of customer growth resulted in a 0.1145% increase in OM&A. Please explain why this is not a more appropriate scaling factor to use. Also, please

explain why Hydro Ottawa has not attempted to undertake their own specific utility specific analysis, as PowerStream has.

f) Does Hydro Ottawa believe that conceptually the ideal 'scaling factor' should be based on the utility specific costs or a benchmark of costs.

RESPONSE:

a) Footnote 30: Please note that Footnote 30 erroneously refers to an older proceeding (EB-2007-0615). The correct footnote reference is Ontario Energy Board, Decision and Order (September 12, 2019) in the matter of an Application for 2019 Rates filed by Enbridge Gas Distribution (EB-2018-0305). The Decision and Order can be retrieved at: http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2018-0305&sortBy=recRegisteredOn-&pageSize=400

Footnote 31: Régie de l'énergie, Décision, D-2017-043 (April 7, 2017). This decision was in the matter of the establishment of a regulatory incentive mechanism to ensure efficiency gains by Hydro-Québec Distribution and Hydro-Québec TransÉnergie. http://publicsde.regie-energie.qc.ca/projets/272/DocPrj/R-3897-2014-A-0142-Dec-Dec-2017_04_07.pdf

b) The explanation of the selection of the scaling factor of 0.35 is detailed on page 23 of UPDATED Exhibit 1-1-10: Alignment with the Renewed Regulatory Framework, as follows: "Hydro Ottawa proposes to employ a scaling factor of 0.35 to determine its growth factor, consistent with the approved approaches for FortisBC and Hydro Québec. The selection of this scaling factor was made by considering the scaling factors used in other jurisdictions and taking into account the substantial growth in population and customers in the Ottawa area."

The customer and population growth in the Ottawa area was subjectively applied to the selection of the scaling factor, and is below the ranges compared to those seen in other

jurisdictions (e.g. 0.75 scaling factor in Québec and a 0.5 scaling factor in British Columbia). A lower scaling factor indicates a lower correlation with customer growth, making Hydro Ottawa's assumption very conservative compared to other jurisdictions.

c) Yes, Hydro Ottawa confirms that, as part of the EB-2015-0004 Settlement process, Hydro Ottawa agreed to a 0.14% growth factor.

d) Based on the approved load forecast, (and depending on the specific years' growth accounted for), a scaling factor of between 0.11 and 0.13 would have resulted in a 0.14% growth factor in the EB-2015-0004 proceeding.

e) In step with its response to interrogatory OEB-3, Hydro Ottawa notes that the Renewed Regulatory Framework ("RRF") contemplates that utilities would use a customized approach in crafting their Custom IR rate applications that suits each utility's unique circumstances. Hydro Ottawa respectfully submits that it has not been demonstrated why there is a need to speculate on whether the specific scaling factor employed by PowerStream in EB-2015-0003 is appropriate for adoption in the context of Hydro Ottawa's proposed 2021-2025 Custom IR rate term. In addition, Hydro Ottawa observes that it has not been explicitly confirmed whether PowerStream's proposed scaling factor in EB-2015-0003 was even deemed to be appropriate for PowerStream's own use in the Decision and Order ultimately issued by the OEB in that proceeding. Hydro Ottawa makes this observation, in light of the fact that the OEB determined that PowerStream's rate plan did not meet the expectations of a Custom IR application.[1]

With regards to the preparation of analysis that is specific to Hydro Ottawa so as to support the proposed scaling factor, Hydro Ottawa believes that the robust information provided regarding expected growth within the City of Ottawa and the utility's service territory serves as an adequate basis upon which to extrapolate an appropriate scaling factor for the utility.

[1] Ontario Energy Board, *Decision and Order*, EB-2015-0003 (August 4, 2016), page 3.

f) Hydro Ottawa believes that conceptually, the ideal scaling factor should be based on the utility's specific costs and the utility's unique circumstances.

INTERROGATORY RESPONSE - SEC-12

1-SEC-12

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment A]

SUBJECT AREA: Total Cost and Reliability Benchmarking

With respect to the Clearspring Energy Advisors, Economic Benchmarking Study of Hydro Ottawa's Total Cost and Reliability:

a) [p.10-11] With respect to the sample:
   i) The report notes that specific customer count cut-off used for the Ontario sample was chosen to mirror the cut-off in the US sample. What is the basis for the US sample cut-off?
   ii) Is the proposed consumer cut-off, customers as of 2018, or in 2002?
   iii) If the response to part (ii) is 2002, how many additional US distributors would in 2018 have greater than 59,807 customers? Please list them.
   iv) Please confirm that based on the 2018 OEB Yearbook the following additional utilities had a total of 59,807 customers or more, Veridian Connections Inc., Oakville Hydro-Electric Distribution Inc., Energy+ Inc. and Burlington Hydro Inc.

b) [p.4] Please update Table 1 using Hydro Ottawa's 2019 actual information.

c) [p.12] Please provide a table showing that for each category of excluded costs and for each year, the amounts excluded in each year of the historical data period from each of the Ontario distributors, including Hydro Ottawa, included in the expert's dataset. For Hydro Ottawa, please also advise the amounts of each of those categories excluded for each of the years 2021-2025.

RESPONSE:

The Exhibit reference in this interrogatory is unclear. Hydro Ottawa is interpreting the question as referring to Attachment 1-1-12(A): Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability.

a) In response to intervenor comments in Toronto Hydro's recent rate application proceeding[1] regarding the desire to have a consistent definition for sample inclusion between the U.S. and the Ontario utilities, Clearspring set this minimum inclusion criteria to match the U.S. sample. The cut-off was the minimum customer count in the U.S. sample, irrespective of year. This value was 59,807 for Black Hills Power in 2002. To be included in the sample, the observation must have 59,807 customers or higher. Any exclusions for utilities above 59,807, such as the utilities listed in question (a)(iv) of this interrogatory, are due to other explanatory variables not being available, and are not due to the customer cut-off.

b) This research cannot be completed within the allotted timeline for interrogatory responses as it requires inserting new data into the analysis.

c) Table A below shows the customer service and information expenses excluded for each Ontario distributor. Clearspring does not have expense forecasts for Hydro Ottawa for 2019-2025. OM&A expenses were escalated by the growth rate in total OM&A expenses for 2019, 2020, and 2021 and then by the proposed I-X formula during the years within the Custom IR rate term.

[1] Toronto Hydro-Electric System Limited, *2020-2024 Custom Incentive Rate-setting Distribution Rate Application*, EB-2018-0165 (August 15, 2018).

Table A – Customer Service and Information Expenses Excluded for Ontario Distributors

Year	Hydro Ottawa	Alectra	EnWin	Hydro One	Kitchener	London	THESL
2006	$6,640,283	$7,831,913	$38,570	$1,454,398	$702,223	$2,140,934	16,919,402
2007	$5,123,598	$7,490,425	$43,602	$12,408,529	$791,303	$552,459	$3,959,667
2008	$5,499,318	$2,495,834	$59,781	$2,667,870	$207,677	$341,246	$5,794,134
2009	$4,470,513	$2,078,837	$39,117	$2,473,223	$227,140	$352,152	$ 5,497,429
2010	$4,747,257	$2,170,333	$53,370	$2,271,325	$212,185	$251,175	$3,993,629
2011	$4,918,673	$2,921,576	$106,603	$2,138,761	$198,223	$178,731	$3,644,212
2012	$5,561,017	$1,972,844	$39,925	$2,234,670	$164,909	$43,960	$2,949,933
2013	$5,351,621	$2,097,984	$48,192	$1,875,310	$218,138	$147,950	$2,855,212
2014	$5,339,557	$2,465,511	$61,327	$1,650,554	$199,353	$194,361	$2,570,549
2015	$4,504,232	$2,338,427	$48,725	$1,367,282	$238,030	$150,794	$ 3,497,636
2016	$5,041,949	$2,685,592	$55,286	$1,016,177	$269,179	$189,176	$ 2,525,811
2017	$4,901,919	$3,054,348	$132,385	$1,579,347	$220,473	$160,968	$2,334,674
2018	$4,426,723						

Table B shows the bad debt expenses excluded for each Ontario distributor. Clearspring does not have expense forecasts for Hydro Ottawa for 2019-2025.

Table B – Bad Debt Expenses Excluded for Ontario Distributors

Year	Hydro Ottawa	Alectra	EnWin	Hydro One	Kitchener	London	THESL
2006	$2,992,045	$5,070,285	$395,737	$18,587,508	$203,719	$545,728	$7,157,864
2007	$1,806,162	$4,717,895	$688,664	$13,454,471	$171,223	$534,840	$6,219,054
2008	$1,448,101	$5,602,770	$1,242,639	$14,614,487	$166,754	$524,950	$5,102,623
2009	$1,516,311	$6,404,106	$624,562	$18,216,564	$187,446	$825,000	$7,664,933
2010	$360,760	$6,838,461	$(272,472)	$18,719,227	$(46,363)	$1,120,000	$5,740,658
2011	$1,468,389	$7,963,601	$523,574	$19,343,678	$103,015	$800,000	$8,559,585
2012	$1,432,802	$5,378,296	$436,378	$19,036,877	$146,917	$325,000	$6,019,547
2013	$2,182,068	$3,464,931	$546,478	$34,087,040	$154,263	$400,000	$7,018,491
2014	$1,824,661	$5,708,236	$865,464	$67,493,218	$116,143	$700,000	$6,500,000
2015	$54,796	$5,628,870	$620,595	$26,000,600	$147,190	$650,400	$6,630,000
2016	$1,414,476	$4,812,925	$860,382	$6,785,401	$128,978	$700,200	$5,229,919
2017	$2,183,513	$4,275,321	$376,725	$16,129,283	$155,399	$840,200	$5,299,255
2018	$1,537,436						

INTERROGATORY RESPONSE - SEC-13

1-SEC-13

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment A]

SUBJECT AREA: Total Cost and Reliability Benchmarking

With respect to the Clearspring Energy Advisors, Economic Benchmarking Study of Hydro Ottawa's Total Cost and Reliability:

a) Please detail all differences in the methodology as between this report and that authored by Mr. Fenrick for: i) Toronto Hydro in EB-2018-0165, ii) Hydro One in EB-2017-0049, and iii) Hydro Ottawa in EB-2015-0004.

b) [p.17] Please confirm that 'rural density' variable Clearspring uses is a business condition variable that is based on service area.

c) [Decision and Order (EB-2017-0049), p.29] How has Clearspring addressed the OEB's comments in its decision in Hydro One's 2018-2022 Custom IR proceeding regarding concerns with the use of service area as a business condition variable for benchmarking?

d) [p.17] Please confirm that Clearspring uses a 'congested urban' variable in its study.

e) [Decision and Order (EB-2018-0165, p.29] In its decision in Toronto Hydro's 2020-2024 application, OEB found that the "congested urban variable needs further research and refinement before it can be accepted as a meaningful adjustment to the assessment of cost benchmarking performance." Please explain what additional research and refinement Clearspring has done with respect to the 'congested urban' variable.

RESPONSE:

The Exhibit reference in this interrogatory is unclear. Hydro Ottawa is interpreting this question as referring to Attachment 1-1-12(A): Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability.

a) The overall methodology is similar in all applications. Below are improvements that Clearspring recalls and which are significant.

Please see the response to interrogatory OEB-17 for a discussion on the variable differences between this study and the Toronto Hydro study.[1] Compared to all three cited applications, Clearspring has changed the ratcheted peak demand variable to be the maximum for the prior five years, rather than the maximum for the historic duration of the sample. This is in response to SEC comments in prior cases.

In Hydro One Networks' recent distribution rate application,[2] PSE included a % CSI variable to address the CDM differences between Ontario and the U.S. In Hydro Ottawa's previous Custom IR application,[3] PSE added CDM expenses into the Hydro Ottawa definition. However, starting with the Toronto Hydro case, a consensus with PEG and other intervenors seems to have been reached in that the best approach is to subtract all the customer service and information ("CSI") expenses from the sample to make a consistent cost definition. That is the same approach taken by Clearspring with this current study for Hydro Ottawa.

Another large improvement has been with respect to the congested urban variable. In the study included in Hydro Ottawa's prior application, PSE included an urban core dummy variable. In Hydro One Networks' distribution rate proceeding, PSE upgraded to

[1] Toronto Hydro-Electric System Limited, *2020-2024 Custom Incentive Rate-setting Distribution Rate Application*, EB-2018-0165 (August 15, 2018).
[2] Hydro One Networks Inc., *2018-2022 Custom Incentive Rate-setting Distribution Rate Application*, EB-2017-0049 (March 31, 2017).
[3] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

a percent artificial surfaces variable. Then in Toronto Hydro's recent application, PSE produced a substantial upgrade to the percent congested urban variable. This same percent congested urban variable (with minor revisions) is the same one utilized by Clearspring in the research for Hydro Ottawa.

Clearspring now uses the Driscoll-Kraay estimation method for its benchmarking research. This method uses the Ordinary Least Squares ("OLS") estimates as the basis for the benchmark calculations and can easily be replicated using popular econometric software packages, like STATA.

b) Clearspring confirms that the 'rural density' variable which it uses is a business condition variable that is based on service area.

c) Please see the response to interrogatory OEB-18 part (b).

d) Clearspring confirms that it uses a 'congested urban' variable in its study.

e) Clearspring has conducted minor revisions to the variable but has not changed the definition or approach relative to the Toronto Hydro case. It is not clear to Clearspring what research or refinements need to be conducted. Clearspring conducted an enormous research effort in developing the variable and believes that it accurately captures the cost challenges of serving in highly dense urban environments.

INTERROGATORY RESPONSE - SEC-14

1-SEC-14

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment A]

SUBJECT AREA: Total Cost and Reliability Benchmarking

SEC seeks a better understanding of the difference between the Clearspring model and that of the PEG model used by the OEB to determine annual stretch factors. For each other Ontario distributor included in Clearspring benchmarking model, please provide a separate table that shows their individual total cost benchmarking results, by providing for each year between 2006 and 2018, their: i) actual total cost, ii) benchmark total costs, and iii) % difference.

RESPONSE:

The Exhibit reference in this interrogatory is unclear. Hydro Ottawa is interpreting this question as referring to Attachment 1-1-12(A): Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability.

The sample ends in 2017. As such, Clearspring cannot provide 2018 results for the Ontario sampled utilities. Please see Tables A-F below for the requested information from 2006-2017.

Table A – Total Cost Benchmarking Results - Alectra Utilities

Year	Actual	Benchmark	% Difference
2006	$408,112	$496,156	(19.5)%
2007	$444,239	$518,503	(15.5)%
2008	$493,800	$570,245	(14.4)%
2009	$522,991	$602,265	(14.1)%
2010	$526,638	$628,086	(17.6)%
2011	$544,550	$661,343	(19.4)%
2012	$590,350	$667,847	(12.3)%
2013	$602,510	$674,763	(11.3)%
2014	$639,889	$714,978	(11.1)%
2015	$692,407	$750,266	(8.0)%
2016	$704,229	$756,585	(7.2)%
2017	$682,210	$748,094	(9.2)%

Table B – Total Cost Benchmarking Results - EnWin

Year	Actual	Benchmark	% Difference
2006	$50,455	$58,064	(14.0)%
2007	$54,727	$59,927	(9.1)%
2008	$58,784	$65,038	(10.1)%
2009	$60,887	$68,124	(11.2)%
2010	$67,979	$70,992	(4.3)%
2011	$66,549	$68,835	(3.4)%
2012	$69,041	$68,108	(1.4)%
2013	$65,372	$67,946	(3.9)%
2014	$68,415	$71,714	(4.7)%
2015	$71,939	$74,986	(4.1)%
2016	$72,176	$74,132	(2.7)%
2017	$74,392	$72,822	(2.1)%

Table C – Total Cost Benchmarking Results - Hydro One Networks

Year	Actual	Benchmark	% Difference
2006	$1,394,916	$1,119,995	22.0%
2007	$1,546,715	$1,206,593	24.8%
2008	$1,657,957	$1,322,294	22.6%
2009	$1,764,741	$1,393,741	23.6%
2010	$1,841,717	$1,430,013	25.3%
2011	$1,887,843	$1,502,594	22.8%
2012	$1,872,882	$1,491,611	22.8%
2013	$1,947,220	$1,642,733	17.0%
2014	$2,069,080	$1,735,086	17.6%
2015	$2,096,981	$1,806,201	14.9%
2016	$2,122,030	$1,791,103	17.0%
2017	$2,058,132	$1,773,963	14.9%

Table D – Total Cost Benchmarking Results - Kitchener-Wilmot Hydro

Year	Actual	Benchmark	% Difference
2006	$37,977	$41,108	(7.9)%
2007	$40,146	$43,964	(9.1)%
2008	$44,425	$48,662	(9.1)%
2009	$47,016	$52,165	(10.4)%
2010	$48,901	$54,328	(10.5)%
2011	$51,418	$57,337	(10.9)%
2012	$55,070	$58,072	(5.3)%
2013	$54,177	$58,757	(8.1)%
2014	$56,463	$63,111	(11.1)%
2015	$57,842	$66,447	(13.9)%
2016	$59,377	$67,531	(12.9)%
2017	$58,898	$67,798	(14.1)%

Table E – Total Cost Benchmarking Results - London Hydro

Year	Actual	Benchmark	% Difference
2006	$56,397	$71,133	(23.2)%
2007	$61,508	$75,194	(20.1)%
2008	$67,716	$82,444	(19.7)%
2009	$70,907	$87,800	(21.4)%
2010	$73,731	$91,134	(21.2)%
2011	$76,628	$95,386	(21.9)%
2012	$79,884	$96,344	(18.7)%
2013	$78,551	$97,044	(21.1)%
2014	$81,861	$103,468	(23.4)%
2015	$87,650	$108,470	(21.3)%
2016	$90,383	$109,338	(19.0)%
2017	$89,937	$109,091	(19.3)%

Table F – Total Cost Benchmarking Results - Toronto Hydro

Year	Actual	Benchmark	% Difference
2006	$ 469,102	$588,654	(22.70%
2007	$514,562	$617,314	(18.2)%
2008	$576,615	$673,840	(15.6)%
2009	$616,335	$709,456	(14.1)%
2010	$670,178	$740,996	(10.0)%
2011	$728,756	$762,054	(4.5)%
2012	$721,114	$765,018	(5.9)%
2013	$759,701	$774,990	(2.0)%
2014	$810,361	$818,188	(1.0)%
2015	$855,880	$859,369	(0.4)%
2016	$897,790	$865,330	(3.7)%
2017	$900,054	$852,127	(5.5)%

INTERROGATORY RESPONSE - SEC-15

1-SEC-15

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment A]

SUBJECT AREA: Total Cost and Reliability Benchmarking

With respect to the Clearspring Energy Advisors, Economic Benchmarking Study of Hydro Ottawa's Total Cost and Reliability, Appendix A - Alternative Results Excluding Large Projects:

a) [p.25] Please provide Figure 4 in tabular format.

b) Please provide the specific costs that were removed for the Facilities Renewal Program and South Nepean Municipal Transformer Station.

c) [p.24, Ex.9-1-3, p.9] For the Facilities Renewal Project, did Clearspring use the $66M approved to be included in rates, or the actual cost of $99.5M, in which the difference was recorded in a variance account? If it is not the entire actual amount, please revise the benchmarking results to include the full cost.

RESPONSE:

The Exhibit reference in this interrogatory is unclear. Hydro Ottawa is interpreting this question as referring to Attachment 1-1-12(A): Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability.

a) Please see Table A below for Figure 4 in tabular format.

Table A – Hydro Ottawa's Total Costs - Actual vs. Benchmark

Year	Actual Costs	Benchmarking	% Difference
2006	$116,871	$148,790	(24.1)%
2007	$127,517	$159,137	(22.2)%
2008	$145,237	$175,106	(18.7)%
2009	$153,164	$188,368	(20.7)%
2010	$159,131	$194,702	(20.2)%
2011	$173,080	$206,218	(17.5)%
2012	$173,128	$208,265	(18.5)%
2013	$180,633	$213,799	(16.9)%
2014	$199,719	$226,248	(12.5)%
2015	$215,851	$239,466	(10.4)%
2016	$218,320	$239,490	(9.3)%
2017	$215,614	$238,832	(10.2)%
2018	$228,925	$246,959	(7.6)%
2019	$244,690	$256,022	(4.5)%
2020	$250,294	$264,582	(5.6)%
2021	$259,275	$274,287	(5.6)%
2022	$269,308	$284,020	(5.3)%
2023	$274,256	$294,316	(7.1)%
2024	$279,777	$305,065	(8.7)%
2025	$289,331	$316,199	(8.9)%
2016-2018			**(9.0)%**
2021-2025			**(7.1)%**

b) For each project, Clearspring only subtracted plant additions. These reductions will then lower the capital costs, similar to how the revenue requirement is reduced if the rate base is lowered. For the Facilities Renewal Program, Clearspring subtracted $200,000 in 2017 and $79.9M in 2019. For the South Nepean Municipal Transformer Station, Clearspring subtracted $49.6M in 2021 and $27.1M in 2022.

c) Please see the response to part (b) above. Clearspring conducted the analysis based on the cost data provided by Hydro Ottawa.

INTERROGATORY RESPONSE - SEC-16

1-SEC-16

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment A]

SUBJECT AREA: Total Cost and Reliability Benchmarking

With respect to the Clearspring Energy Advisors, Economic Benchmarking Study of Hydro Ottawa's Total Cost and Reliability, Appendix A - Alternative Results Excluding Large Projects:

a) Clearspring states that it was asked by Hydro Ottawa to determine the "total cost benchmarking results would change if the "once in a generation" Facilities Renewal Program and the South Nepean Municipal Transformer Station projects had not been pursued." Did Clearspring make any other adjustments besides removal of capital costs related to the two large projects to reflect a scenario in which the projects did not go forward. For example, increase facilities maintenance costs or other OM&A costs?

b) Please confirm that in undertaking this analysis, Clearspring did not remove from the data of the peer group utilities the cost of similar projects they undertook. If not confirmed, please explain how it made such similar adjustments.

c) Please confirm that Clearspring's understanding is that one of the purposes of the South Nepean Municipal Transformer Station is to "accommodate customer load growth and increase supply capacity in the South Nepean area of Ottawa".

d) Please confirm that while it removed the costs of the South Nepean Municipal Transformer Station in conducting this analysis, it did not make any adjustments to the customer and load related output variables to account for demand that is now able to be served due to the South Nepean Municipal Transformer Station.

e) If (d) is confirmed, directionally, what impact would it have had on the benchmark results if Clearspring had made such an adjustment?

RESPONSE:

The Exhibit reference in this interrogatory is unclear. Hydro Ottawa is interpreting this question as referring to Attachment 1-1-12(A): Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability.

a) No. Clearspring only subtracted the capital costs of the projects from the total cost benchmarking analysis, with no other adjustments made. Clearspring notes that page 34 of the report states the following: “The two alternative results with the investments excluded are for information-purposes only. Clearspring Energy’s recommended stretch factor of 0.3% is based on the results that include all capital additions.”

b) Clearspring confirms that it did not remove from the data of the peer group utilities the cost of similar projects they undertook.

c) Clearspring did not investigate and has no understanding of the underlying purposes or rationale of the South Nepean/Cambrian MTS project.

d) See the response to part (a) above.

e) Clearspring has no understanding of the underlying impacts of the project and cannot comment on what customer or load counts would be for Hydro Ottawa if the project had not been undertaken.

INTERROGATORY RESPONSE - SEC-17

1-SEC-17

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment A]

SUBJECT AREA: Total Cost and Reliability Benchmarking Study

Please confirm that Clearspring was asked to provide this alternative scenario by Hydro Ottawa, it is not itself recommending that the benchmarking results of this alternative scenario be the basis for the Hydro Ottawa stretch factor.

RESPONSE:

Hydro Ottawa confirms that the utility requested Clearspring to develop this alternative scenario.

INTERROGATORY RESPONSE - SEC-18

1-SEC-18

EXHIBIT REFERENCE:

[Ex.1-1-12, Attachment, p.33, Ex.1-1-10, p.25]

SUBJECT AREA: Total Cost and Reliability Benchmarking

Based on the results of its total cost benchmarking analysis, Clearspring recommends that Hydro Ottawa's stretch factor be at 0.3%. Hydro Ottawa is proposing to apply a stretch factor to only its OM&A costs. Please revise the benchmarking analysis to create a separate benchmark of Hydro Ottawa's capital and OM&A costs.

RESPONSE:

It is not feasible within the timeframe allotted by the OEB for interrogatory responses to revise the benchmarking analysis and create separate benchmarks of Hydro Ottawa's capital and OM&A costs. However, it is Hydro Ottawa's understanding that its OM&A costs would be very close in value to its total cost benchmark, while its capital costs would be slightly higher. What's more, to perform a comprehensive benchmarking analysis of OM&A and capital costs separately, the model would need to be optimized for OM&A variables only and capital costs only.

For additional information, please see the response to interrogatory OEB-6.

INTERROGATORY RESPONSE - SEC-19

1-SEC-19

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment B]

SUBJECT AREA: UMS Unit Cost Benchmarking Study

With respect to the UMS, Hydro Ottawa Unit Cost Benchmarking Study:

a) Please provide a copy of the retainer and any other instructions provided to UMS.

b) [p.9] UMS notes that "the six asset categories represent almost 72 percent of the system renewal capital budget over the 2016 through 2018 period" and "Hydro Ottawa spends approximately 48 percent of all preventative and predictive maintenance costs on the OM&A programs / practices that comprise this study, with the exception of meter maintenance, which is a reactive program." Please provide these calculations.

c) [p.12] Please explain how the various asset categories and OM&A programs/practices were selected. Please provide a list of others that were considered, and reasons for why they were not selected.

d) Please detail all methodological differences in this study as compared to the UMS study filed in Toronto Hydro's 2020-2024 application (EB-2018-0165, Ex.1B-2-1, App B).

e) Please explain the difference in the peer group selected for this study and that filed in the Toronto Hydro's 2020-2024 application (EB-2018-0165, Ex.1B-2-1, App B).

f) Please provide a copy of the underlying excel spreadsheet(s) used to produce the results of the study, with all formulas intact.

g) [p.27] Please provide a copy of the results that include the following 'normalization' adjustments only: a) measurement conversion, b) current conversion, and c) indirect/overhead accounting practices adjustments.

h) [p.40] Please provide a copy of Hydro Ottawa's response to Appendix F.

RESPONSE:

a) Please see Attachment SEC-19(A): Executed Agreement for a Unit Cost Benchmarking Study.

b) The six asset categories represent $105.6M of the $146.5M System Renewal capital budget over the 2016-2018 timeframe (72 percent). The maintenance programs represent $13.9M of the $28.9M preventative / predictive maintenance and meter maintenance costs over that same period (48 percent).

c) The initial Statement of Work, which served as the basis for UMS' proposal, listed seven asset categories and four maintenance programs for examination of unit costs:

Asset Categories:

- Wood Pole Replacement
- UG Cable (XLPE)
- OH Switches
- OH Transformer Replacement
- UG Transformer Replacement
- UG Switchgear
- Station Breaker Replacement

Maintenance Programs:

- Vegetation Management
- Pole Test and Inspection
- Overhead Line Patrol
- Station Breaker and Relay

Three maintenance programs (Billing-Paper, Billing-Online, and Meter Maintenance) were added during the initiation phase of the project, following Hydro Ottawa's review of the OEB Staff Discussion Paper on Activity and Program Based Benchmarking for Electricity Distributors.[1] Having reviewed the paper upon its publication, Hydro Ottawa signalled interest to UMS in incorporating several categories into the scope of the study that had been flagged by OEB Staff as worthwhile candidates for benchmarking in Ontario's distribution sector. In addition, the asset category UG Switchgear was eventually removed, as there were not enough projects within Hydro Ottawa or across the Peer Group to present a valid comparison.

What's more, as signalled on page 12 of the Unit Costs Benchmarking Study, the assessment of the viability of these asset categories and OM&A programs/practices to serve as valid proxies for Hydro Ottawa's effectiveness and efficiency in performing work was informed by the following considerations: the overall percentage of the System Renewal capital budget represented by the asset categories; the overall percentage of preventative and predictive maintenance costs represented by the OM&A programs/practices; and the inclusion of categories and programs that are relevant in the assessment of a distributor's historical reliability performance.

In addition, as likewise signalled in the study, finalizing the selection of asset categories and OM&A programs/practices was informed by the availability of relevant unit cost information from the Peer Group Panel.

[1] Ontario Energy Board, *Staff Discussion Paper - Activity and Program Based Benchmarking For Electricity Distributors* (February 25, 2019).

d) There were no methodical differences between this study and the study that was filed in Toronto Hydro's 2020-2024 rate application proceeding.

e) Please see the response to interrogatory OEB-42 part (a).

f) Please see excel Attachment SEC-19(B): Unit Cost Excel Calculations.

g) Please see excel Attachment SEC-19(C): Measurement, Currency and Accounting Normalization.

h) Please see excel Attachment OEB-44(A): 2016-2018 Unit Costs.

HydroOttawa

1 April, 2019

UMS Group Inc.
Morris Corporate Center 1
300 Interspace Parkway, Suite C380
Parsippany, NJ 07054 USA

Attention: Mr. Jeffery W. Cummings

Dear Mr. Cummings,

RE: Executed Agreement for a Unit Costs Benchmarking Study

For your records, here is UMS Group Inc. copy of the fully signed Agreement for a Unit Costs Benchmarking Study.

For invoicing purposes, please reference PO number: 109049.

Please submit a copy of your insurance certificate with coverages as outlined in Section 14 of the Agreement.

Sincerely,

Farah Butt

Farah Butt
Senior Procurement Agent / Agent principal, approvisionnement
Tel. / tél. 613-738-5499 | ext. / poste 2554
farahbutt@hydroottawa.com

109049

THIS AGREEMENT dated the ~~22nd~~ 1st day of ~~March~~ April, 2019. ("Effective Date")

BETWEEN:

Hydro Ottawa Limited ("Hydro Ottawa")

- and -

UMS Group Inc. ("the Consultant")

WHEREAS Hydro Ottawa issued a Request for Proposals on February 28, 2019 for a Unit Costs Benchmarking Study (the "RFP");

AND WHEREAS the Consultant submitted a proposal dated March 10, 2019 in response to the RFP (the "Proposal");

AND WHEREAS the Consultant has represented that it can provide such services as more fully set out in Schedule A, in accordance with the terms and conditions hereinafter set forth;

AND WHEREAS the Consultant's Proposal was selected by Hydro Ottawa and, accordingly, Hydro Ottawa and the Consultant wish to execute this Agreement;

NOW THEREFORE in consideration of the mutual covenants, terms and conditions contained herein and for other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the parties hereto agree as follows:

1. Retainer

Hydro Ottawa hereby retains the Consultant to perform the services set out in Schedule A and the Consultant agrees to provide the Services under the general direction and control of Hydro Ottawa. The Consultant shall be solely responsible for the supply of all hardware, software, or other equipment required to satisfactorily perform the Services.

2. Definitions

In addition to terms defined in the body of these Terms and Conditions and the Schedules thereto, the following terms shall have the meanings set out below:

"Affiliate" means, with respect to any party,

(i) any legal entity of which the securities or other ownership interests representing fifty per cent (50%) or more of the equity or fifty percent (50%) or more of the ordinary voting power or fifty percent (50%) or more of the general partnership interest are, at the time such determination is being made, owned, Controlled or held, directly or indirectly, by such legal entity, or

(ii) any legal entity which, at the time such determination is being made, is Controlling or under common Control with, such legal entity. As used herein, the term "Control", whether used as a noun or verb, refers to the possession, directly or indirectly, of the power to direct, or cause the direction of, the management or policies of a legal entity, whether through the ownership of voting securities, by contract or otherwise.

"Agreement" means this written contract resulting from the RFP and executed between Hydro Ottawa and the Consultant.

"Applicable Law" means any domestic or foreign law, rule, statute, subordinate legislation, regulation, by-law, order, ordinance, protocol, code, guideline, treaty, policy, notice, direction or judicial, arbitral, administrative, ministerial or departmental judgment, award, decree, treaty, directive, or other requirement or guideline published or in force at any time during the Term which applies to or is otherwise intended to govern or regulate any Person, property, transaction, activity, event or other matter, including any rule, order, judgment, directive or other requirement or guideline issued by any Government Authority.

"Business Day(s)" means the hours from 07:00 to 16:30:00, Eastern Time, on the weekdays from Monday to Friday, inclusive, with the exception of statutory holidays observed by Hydro Ottawa.

"Claim" means any actual, or threatened civil, criminal, administrative, regulatory, or arbitral demand, action, suit, investigation or proceeding or any other claim or demand.

"Consultant" means party in contract with Hydro Ottawa or the duly authorized representative. This shall include the Consultant, its officers, directors, employees, agents, assigns, and subcontractors.

"Effective Date" shall mean the date the second party executes this Agreement.

"Governmental Authority" means any government, parliament, legislature or any regulatory authority, agency, commission or a board of any government, parliament or legislature, or any political subdivision thereof, or any court or, without limitation to the foregoing, any other law, regulation or rule making entity or any person acting under the authority of any of the foregoing or any other authority charged with the administration or enforcement of laws.

"Hydro Ottawa" and "HOL" mean Hydro Ottawa Limited.

"Intellectual Property" means:

(a) any and all proprietary rights anywhere in the world provided under:
    (i) patent law;
    (ii) copyright law (including moral rights);
    (iii) trade-mark law;
    (iv) design patent or industrial design law;
    (v) semi-conductor chip or mask work or integrated circuit topography law; or any other statutory provision or common law principle applicable to this Agreement, including trade secret law, that may provide a right in either hardware, software, content, documentation, confidential information, trade-marks, ideas, formulae, algorithms, concepts, inventions, processes or know-how generally, or the expression or use of such hardware, software, content, documentation, confidential information, trade-marks, ideas, formulae, algorithms, concepts, inventions, processes or know-how;

(b) any and all applications, registrations, licences, sub-licences, franchises, agreements or any other evidence of a right in any of the foregoing; and

(c) any and all licences and waivers and benefits of waivers of the intellectual property rights set out in paragraphs (a) or b) above, all future income and proceeds from the intellectual property rights set out in paragraphs (a) or (b) above, and all rights to damages and profits by reason of the infringement or violation of any of the intellectual property rights set out in paragraphs (a) or (b) above.

"Losses" means:

(a) any and all damages, Claims, fines, penalties, deficiencies, losses, liabilities (including settlements and judgments) in a monetary settlement or finally awarded by a court, arbitration panel or other adjudicative or quasi-adjudicative panel, having competent jurisdiction, and

(b) related and reasonable costs and expenses (including interest, court costs, reasonable fees and expenses of lawyers, accountants and other experts and professionals or other reasonable fees and expenses of litigation or other proceedings or of any Claim, default or assessment).

"OHSA" means the Occupational Health and Safety Act, R.S. 0. 1990, c. 0.1, as amended or replaced from time to time.

"Person" means any individual, partnership, franchise holder, association, corporation or any Government Authority and their respective employees, agents or representatives.

"Personnel" means the Consultant's employees, agents, Consultants, and subcontractors

"Personal Information" means information about an identifiable individual, including without limitation any information defined or deemed as such pursuant to any Applicable Laws or regulations related to privacy or data protection.

"Representatives" in reference to party, means the party's directors, officers, employees, agents, subcontractors, and suppliers, the party's Affiliates, and all such Affiliates' respective directors, officers, employees, agents and suppliers.

"Services" means the requested services set out in Schedule A.

"Subcontractor" means a Person having a contract with the Consultant for the supply and or performance of any part of the Services, but does not include one who merely furnishes material.

3. Priority of Documents

The documents specified below form part of and are incorporated into this Agreement. If there is a discrepancy between the wording of these Terms and Conditions and the wording of any document which appears on the list, the wording of these Terms and Conditions shall prevail. If there is a discrepancy between the wording of any documents which appear on the list, the wording of the document which first appears on the list shall prevail over the wording of any document which subsequently appears on the list:

(a) These General Terms and Conditions
(b) Schedule A - Statement of Work
(c) Schedule B - Cost Summary

4. Contract Authority

The Contract Authority is:

Joe Brannen, Senior Procurement Agent, Hydro Ottawa
1970 Merivale Road,
Ottawa, ON K2G 6Y9

Telephone: (613) 738-5499 ext. 7143
Email: joebrannen@hydroottawa.com

The Contract Authority is responsible for the management of this Agreement. Only changes to this Agreement that are authorized in writing by the Contract Authority are binding on Hydro Ottawa. The Consultant shall not perform services outside the scope of the Services without the written authorization of the Contract Authority.

5. Project Manager

Project Manager is:

Patrick Brown, Manager, Regulatory Policy and Research
3025 Albion Road North
Ottawa, ON K1V 9V9

Telephone: (613) 738-5499 ext. 7663
Email: patrickbrown@hydroottawa.com

The Project Manager is responsible for all matters concerning the technical content of the Services under this Agreement. Any proposed changes to the scope of the Services must be discussed with the Project Manager, but only the Contract Authority has the authority to amend this Agreement.

6. Consultant's Contact

The Consultant's Contact is:

Jeffrey W. Cummings, Senior Vice President
UMS Group Inc.
Morris Corporate Center 1
300 Interpace Parkway, Suite C380
Parsippany, NJ 07054 USA
Telephone: (630) 561-2146
Email: jcummings@umsgroup.com

7. Compliance with Applicable Laws

(1) The Consultant shall, at its sole expense, obtain and maintain all permits, licenses and approvals required by Applicable Law or Governmental Authority to conduct its business generally and to perform its duties under this Agreement and to undertake and complete the Services. The Consultant and its Representatives shall comply with all Applicable Law, in undertaking and completing the Services

(2) Where there is a conflict between any provisions of the above-mentioned authorities, the most stringent provision will govern.

8. Term

Subject to the termination rights contained in this Agreement, this Agreement shall commence on the Effective Date and shall terminate on December 31, 2020 (the "Term").

9. Termination and Default

(1) Each of the following will constitute an Event of Default by the Consultant:

(a) The Consultant becomes insolvent, makes a general assignment for the benefit of creditors, permits a Receiver to be appointed for its business or assets or becomes subject to any proceedings under the Bankruptcy *and Insolvency* Act or any statute of any provinces, state or other jurisdiction relating to insolvency or the protection of creditor's rights.

(b) The Consultant fails to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default) if such failure is not remedied within ten (10) Business Days after written notice of such failure from Hydro Ottawa.

(c) Any representation made by the Consultant is not materially true or correct in any material respect when made and is not made materially true or correct within two (2) Business Days after receipt by the Consultant of written notice of such fact from Hydro Ottawa.

(d) The Consultant fails to conform to all Applicable Law.

(e) The Consultant has breached or is in breach of Section 22.

(2) If any Event of Default occurs, upon written notice to the Consultant, Hydro Ottawa may terminate this Agreement.

(3) Despite the foregoing, upon the occurrence of an Event of Default referred to in paragraph 1(a), this Agreement shall automatically terminate without notice, act or formality, effective immediately before the occurrence of such Event of Default.

(4) Any termination shall be without prejudice to the rights accruing and remedies subsisting under this Agreement at the date of such termination. In addition, Hydro Ottawa shall be entitled to obtain damages from the Consultant for any losses incurred directly resulting from such Event of Default. Furthermore, in addition to its rights of set-off available to it under this Agreement or at law, Hydro Ottawa may hold back payment or set-off its obligation to make such payment against any payments owed to it if the Consultant fails to comply with its obligations on termination.

(5) Notwithstanding anything to the contrary contained herein, Hydro Ottawa may, at any time prior to the completion of the Services, terminate the Agreement as regards all or any part of the uncompleted services, by giving written notice to the Consultant. Upon receipt of a termination notice, the Consultant shall cease work in accordance with the notice, but shall proceed to complete such part or parts of the Services that are not affected by the termination notice.

(6) In the event of a termination notice being given pursuant to this subsection 5 the Consultant shall be entitled to be paid, to the extent that costs have been reasonably and properly incurred for the purposes of performing the Agreement and to the extent that the Consultant has not already been so paid or reimbursed by Hydro Ottawa, on the basis of the pricing set out in the Agreement, for all work completed, inspected and accepted in accordance with the Agreement.

(7) Notwithstanding Section 10, if an event of force majeure continues for 30 days or more, Hydro Ottawa, in its absolute discretion, may terminate this Agreement. In such case, the parties agree that neither will make a claim against the other for damages, costs, expected profits or any other loss arising out of the termination or the event that gave rise to the force majeure.

(8) Upon termination, whether pursuant to this Section or the expiry of the Agreement, at Hydro Ottawa's request the Consultant shall provide a copy of all Hydro Ottawa's records in the format acceptable and indexing to Hydro Ottawa without any delay.

10. Force Majeure

(1) Neither party shall be liable in damages or have the right to terminate this Agreement for any delay or default in performing hereunder if such delay or default is caused by conditions beyond the party's control including, but not limited to Acts of God, Government restrictions (including the denial or cancellation of any permits or other necessary license), wars, insurrections, fires, floods or unusually severe weather, disruptions resulting from labour disputes, governmental or regulatory action and/or any other cause beyond the reasonable control of the party whose performance is affected.

(2) The delivery requirements specified in the Agreement and affected by such causes shall be extended by periods equal to the duration of the event that gave rise to the force majeure. The Consultant shall immediately notify Hydro Ottawa of any event or situation that might possibly create a situation of force majeure. Acknowledgement of any force majeure is subject to the submission by the Consultant of a written confirmation of proof of the events or circumstances forming the basis of the Consultant's claim regarding force majeure.

11. Representations and Warranty

The Consultant covenants and agrees with and represents and warrants to Hydro Ottawa as follows and covenants and agrees that such representations and warranties shall remain true and correct throughout the Term of this Agreement:

a) Status. The Consultant is duly constituted, validly existing and in good standing under the laws of its governing jurisdiction;

b) Authority. The Consultant has the necessary power, authority and capacity and good and sufficient right to enter into this Agreement on the terms and conditions herein set forth, and the execution and performance of this Agreement will not conflict with, or constitute a breach under, any agreement to which it is a party or any judgment, order, statute or regulation which is applicable to it;

c) Conflict of Interest. The Consultant warrants that it presently has no interest and will not acquire any interest, direct or indirect, which would conflict in any manner or degree with the lawful and ethical performance of the Services under this Agreement;

d) Experience and Financial Capacity. The Consultant has the experience, ability and financial capacity to perform and fulfill its obligations hereunder, and covenants to maintain during the Term, the financial and other ability and authority to perform and fulfill its obligations hereunder;

e) Care and Skill. The Services rendered hereunder are in compliance with Schedule A and shall be performed to that degree of care and skill as is normally performed in the industry in the provision of Services of a similar nature on projects of comparable scope and complexity;

f) Certifications and Qualifications. The Consultant has obtained, at its expense, the necessary valid and current certifications and qualifications that are normally required pursuant to Applicable Laws, if any, and in the industry for the provision of the Services;

g) Valid, Binding and Enforceable. This Agreement constitutes a valid and binding obligation of the Consultant, enforceable against it in accordance with its terms and conditions; and

h) HST Registrant. The Consultant is an "HST Registrant" in good standing; and the Consultant is not a non-resident of Canada within the meaning of the Income Tax Act (Canada), as amended.

12. Intellectual Property

(1) All Intellectual Property Rights derived from the performance of the Consultant's Services in connection with this Agreement, including all newly-created material, shall immediately, as and when they come into existence, vest in and remain the property of Hydro Ottawa. The Consultant shall have no right in or to any such Intellectual Property Rights in the newly-created materials and Consultant's Services except any right that may be granted in writing by Hydro Ottawa.

(2) Pre-existing Intellectual Property Rights – All intellectual Property Rights existing immediately prior to the date of the Agreement shall be retained by each party and each third party that owned such rights immediately prior to such date.

(3) Notwithstanding the foregoing, Hydro Ottawa will own the non-identifiable aggregated and statistical data derived from the Services. Hydro Ottawa will own the number of records in the Services, the number and types of transactions, configurations, all personally identifiable data and reports processed in connection with this Agreement.

(4) Hydro Ottawa acknowledges the Consultant may leverage third party Intellectual Property Rights in certain Services. Consultant agrees to acquire all required consents, rights, title and interest in the third party intellectual property rights so that Consultant is granted a limited, revocable, non-exclusive, non-transferable license during the Term to use the third party intellectual property related to the Services as required and contemplated by this Agreement.

13. Indemnification

(1) The Consultant shall indemnify, defend, and save harmless Hydro Ottawa, together with Hydro Ottawa's Representatives and assigns, from and against any and all loss, damage, injury, or safety infraction of the Consultant, or its Representatives, under all conditions and all actions, causes of action, proceedings, suits, claims, demands, losses, damages, penalties, costs (including the payment of all legal fees), expenses, obligations and liabilities in connection therewith, attributable to, related to or arising out of:

(a) breaches of the Consultant's, or its Representatives', obligations herein,

(b) any misrepresentation, inaccuracy, incorrectness or breach of any representation or warranty made by the Consultant contained in this Agreement and/or
(c) any of the Consultant's, its Representatives' or transferees', acts or omissions, which constitute negligence, willful misconduct or fraud
(d) breach of Applicable Law by Consultant,
(e) bodily injury, death, or damage, loss or destruction of tangible property caused by the negligence of Consultant.

(2) Hydro Ottawa shall give notice to the Consultant of any claim, action, suit or proceeding referred to in subsection 13(1) and the Consultant shall at its own expense, to the extent requested by Hydro Ottawa, participate in or conduct the defence of any such claim, action, suit or proceeding and any negotiations for settlement of the same, but the Consultant shall not be liable to indemnify Hydro Ottawa for payment of any settlement unless it has consented to the settlement.

(3) Unless prohibited by law, Hydro Ottawa shall indemnify and hold harmless Consultant and its affiliates, including each of their respective employees, from and against any and all liabilities, losses, costs, and reasonable expenses, including but not limited to, reasonable legal fees and expenses and billable hours of client service personnel, which are i) incurred in responding to court orders, discovery, or other similar inquiries associated with or arising from the engagement or ii) arising from or relating to third-party claims based on reliance or purported reliance on Consultant's work product or other alleged loss or damage caused to or alleged by any non-client entity arising from unauthorized access to or reliance upon Consultant's work product. The foregoing indemnification obligations shall not apply in the event that a court of competent jurisdiction finally determines that such claims resulted directly from the negligence, willful misconduct, or fraudulent acts of Consultant.

(4) Hydro Ottawa may elect to participate in or conduct the defence of any such claim, action, suit or proceeding by notifying the Consultant in writing of such election without prejudice to any other rights or remedies of Hydro Ottawa under this Agreement, at law or in equity. Each party participating in the defence shall do so by actively participating with the other's counsel. If the Consultant is requested by Hydro Ottawa to participate in or conduct the defence of any such claim, action, suit or proceeding, Hydro Ottawa agrees to co-operate with and assist the Consultant to the fullest extent possible in the claim, action, suit or proceeding and any related settlement negotiations. If Hydro Ottawa conducts the defence of any such claim, action, suit or proceeding, the Consultant agrees to co-operate with and assist Hydro Ottawa to the fullest extent possible in the claim, action, suit or proceeding and any related settlement negotiations.

14. Insurance

(1) Before commencing any Services under this Agreement, the Consultant shall provide its liability insurance certificate on an Acord form issued by the broker attesting its coverage by a Commercial General Liability Insurance Policy. Hydro Ottawa and its Affiliates must be named as an additional insured by general endorsement on the Consultant's policy. The coverage shall be one million dollars ($1,000,000) for each occurrence involving bodily injury or property damage. Such coverage must be maintained continuously during the course of the work under the Agreement, and renewal certificates must be provided as required.

(2) The Consultant shall carry Third Party Automobile Liability Insurance Policy, with a minimum limit of One million dollars ($1,000,000) per Occurrence.

(3) The Consultant shall maintain Professional Liability insurance coverage (minimum $1,000,000 per claim) throughout the Term of the Agreement, and for a period of three (3) years after the date of contract completion.

(4) Failure by the Consultant to ensure that the required insurance coverage remain in force during the course of the Agreement will result in the immediate termination of the Agreement without notice and without penalty to Hydro Ottawa.

(5) The Consultant shall maintain Workplace Safety and Insurance Board ("WSIB") coverage at all times during the performance of the Services and during the term of this Agreement for the Services, and shall ensure that any Subcontractor of the Consultant maintain WSIB coverage at all times during their performance of the Services. The Consultant shall provide a WSIB Clearance Certificate indicating that premiums are paid up to date. Failure to maintain up to date WSIB premiums, may result in the immediate termination of this Agreement without penalty to Hydro Ottawa.

15. Subcontracting

(1) In providing the Services contracted for under this Agreement, the Consultant shall act as a single point-of-accountability vendor and shall assume complete and overall contractual responsibility for the provision of the Services and related activities and provide for all ongoing product and performance warranties to the extent set out in this Agreement. The provision of any products or services by any of the Consultant's subcontractors shall not in any way whatsoever release or discharge the Consultant or derogate from the covenants, representations and warranties provided by the Consultant under this Agreement. Notwithstanding the provision of products or services by any subcontractors, the sole responsibility for the provision of all products or services during the Term lies with the Consultant and in no event shall Hydro Ottawa be compelled to seek or pursue remedy against any of the Consultant's subcontractors.

(2) Notwithstanding subsection 15(3), the Consultant agrees that it is liable for the acts and omissions of its Representatives and Subcontractors in performing the Services. This subsection 15(2) is in addition to any and all of the Consultant's liabilities under the Agreement and under the general application of law. The Consultant shall advise its Representatives of their obligations under the Agreement and shall be responsible for their compliance with the applicable terms of the Agreement. In addition to any other liabilities of the Consultant pursuant to the Agreement or otherwise at law or in equity, the Consultant shall be liable for all Losses or Claims arising from any breach of the Agreement resulting from the actions of the above mentioned Representatives in performing the Services. This subsection shall survive the termination or expiry of this Agreement.

(3) The Consultant shall not subcontract or assign the whole or any part of the Agreement without the prior written consent of Hydro Ottawa. Such consent shall be in the sole discretion of Hydro Ottawa and subject to the terms and conditions that may be imposed by Hydro Ottawa. Without limiting the generality of the conditions which Hydro Ottawa may require prior to consenting to the Consultant's use of a subcontractor, every contract entered into by the Consultant with a subcontractor shall adopt all of the terms and conditions of this Agreement as far as applicable to those parts of the Services provided by the subcontractor. Nothing contained in the Agreement shall create a contractual relationship between any subcontractor or the subcontractor's Representatives and Hydro Ottawa.

(4) In performing this Agreement, the Consultant shall operate as an independent Consultant, maintaining its own organization as a distinct and separate legal entity from Hydro Ottawa. The Consultant and the Consultant's Representatives shall have no authority to hold themselves out as acting on behalf of or to legally bind Hydro Ottawa. Nothing in this Agreement shall be deemed to constitute a partnership or a joint venture or to create any fiduciary relationship between Hydro Ottawa and the Consultant.

16. Personnel

(1) The Consultant shall employ, and continue to employ throughout the Term, Personnel with the qualifications and business experience necessary to competently undertake and complete the Services pursuant to this Contract.

(2) The Consultant shall provide the services of the resources specified in the Consultant's Proposal dated March 10, 2019 to perform the Services unless it is impossible to do so for reasons which are beyond its control. In such case, the Consultant shall be responsible for providing replacement(s) that shall be of equal or superior ability and attainment.

(3) In no event shall the Consultant allow replacement personnel perform any of the Services until the Consultant has obtained the approval of Hydro Ottawa in accordance with subsection (4).

(4) Prior to replacing personnel, the Consultant shall give written notice to Hydro Ottawa no later than ten (10) business days before the date the proposed replacement is to take effect. The notice shall include the reason for the replacement; and the name, qualifications and experience of the proposed replacement.

17. Invoices

(1) Invoices must be submitted in the name of the Consultant and are not to be submitted prior to the performance of the Services. They must show the name and address of the Consultant, together with date, reference to purchase order number, amount charged for services performed during the period, additional charges if applicable, applicable taxes, and description of services provided.

(2) The preferred method of receiving invoices is via e-mail addressed to the Accounts Payable Department at accountspayable@hydroottawa.com. Invoices can also be mailed to the Accounts Payable Department at Hydro Ottawa's office at P.O. Box 8700, Ottawa, Ontario, K1G 3S4.

18. Payment

(1) The Consultant's pricing information is contained in Schedule B. Payment shall be based as rates in Schedule B, excluding taxes, and, subject to subsections 18 (2), (3), and (4).

(2) Payment will only be made if a duly completed invoice and any other documents required by the Agreement have been submitted, and verified by Hydro Ottawa, in accordance with the terms of the Agreement.

(3) Hydro Ottawa shall notify the Consultant, within five (5) Business Days of receipt of an invoice or revised invoice, of any inadequacy of the invoice or of the supporting documentation, and where any such notice is given within that period, the date for payment of the amount invoiced shall be postponed until the Consultant remedies the inadequacy to the satisfaction of Hydro Ottawa.

(4) Subject to subsection 18(3), payment will be made within 30 (thirty) days following the date of receipt of a duly completed invoice, in accordance with Section 17.

19. Withholding Taxes

If the Consultant is a non-resident of Canada and has not obtained and provided to Hydro Ottawa a non-resident withholding tax waiver at such time as Hydro Ottawa makes any payment to the Consultant for services rendered by it to Hydro Ottawa in Canada, Hydro Ottawa shall withhold such percentage of any payment made by it for the services as is from time to time mandated under the Income Tax Act (Canada) (the "ITA") and shall remit the withheld amount to Canada Revenue Agency in the manner and at the time required by the ITA. In the event that Hydro Ottawa is assessed for any non-resident withholding taxes payable to Canada Revenue Agency, the Consultant agrees to forthwith reimburse Hydro Ottawa for such amount together with applicable interest and penalties, if any.

20. Acceptance

No part of the Services will be accepted unless approved by Hydro Ottawa and Hydro Ottawa is satisfied that the work completed fully complies with the true meaning and intent of the specifications set out in Schedule A - Statement of Work, as confirmed by and through Hydro Ottawa's review of each draft appraisal report. Such acceptance, however, shall not impair any claim that Hydro Ottawa may have for the replacement of defective work or material.

21. Records and Audit

(1) The Consultant shall keep proper accounts and records of the cost to the Consultant of the Services provided and of all expenditures or commitments made by the Consultant in connection therewith, and shall keep all books and records including invoices, receipts, vouchers, cheques, and bank statements relating thereto. The Consultant shall not, without the prior written consent of Hydro Ottawa, dispose of any such accounts, records, invoices, receipts or vouchers until the expiration of seven (7) years after final payment under this Agreement, or until the settlement of all outstanding claims and disputes, whichever is later.

(2) All such accounts and records as well as any invoices, receipts, vouchers, cheques, and bank statements shall at all times during the retention period referred to in subsection 21 (1) be open to audit, inspection and examination by the authorized representatives of Hydro Ottawa, who may make copies and take extracts thereof. Consultant shall furnish all such information as the representatives of Hydro Ottawa may from time to time require with respect to such accounts, records, invoices, receipts and vouchers.

22. Confidentiality

(1) Each party agrees to
   (a) keep confidential all Confidential Information disclosed to by the other party during the Term of this Agreement and
   (b) not disclose any of such Confidential Information to any third party or any of the third party's Representatives except to such of them to whom disclosure is necessary in connection with this Agreement and who have agreed to be bound by the obligations of confidentiality under this Agreement.

"Confidential Information" means any proprietary ideas, plans and information, including without limitation, information of a technical or business nature (including without limitation, all trade-secrets, technology, financial information, intellectual property, any information relating to human resources matters, data, summaries, reports, the terms of this Agreement, or customer lists, whether oral or written and if written, however produced or reproduced) of a party or any of the party's Affiliates that is received by or otherwise disclosed by one party to the other party that is marked proprietary or confidential, or that would logically be considered proprietary or confidential under the circumstances of its disclosure. In addition, no party shall directly or indirectly use to the party's own advantage any such Confidential Information. If this Agreement is terminated at any time, the parties agree that such Confidential Information provided and all copies thereof (excluding Confidential Information in oral form that has not been put into tangible form) will be immediately returned to the disclosing party or, at the disclosing party's option, destroyed. Notwithstanding the foregoing, the receiving party shall be entitled to keep, subject always to all the provisions of this Agreement, one copy of any notes, analyses, reports or other written material prepared by, or on behalf of, the receiving party that contain Confidential Information for the receiving party's records. In the event of any destruction of Confidential Information as set forth above, the receiving party shall provide to the disclosing party, upon request, a certificate of one of the party's senior officers certifying such destruction.

(2) The Consultant shall:
   (a) collect, use, disclose, and retain Personal Information only as required to fulfil its obligations pursuant to this Agreement;
   (b) take appropriate measures to ensure the privacy and security of all Personal Information, including taking measures to prevent unauthorized access, collection, use, disclosure, copying, modification or disposal; and
   (c) comply with all applicable laws or regulations related to privacy or data protection.

(3) Confidential Information shall not include information that:
   (a) is already known to the recipient at the time of disclosure;
   (b) is or becomes publicly known otherwise than by a breach of this Agreement by the receiving party or the receiving party's Representatives or any third person to whom the receiving party discloses such Confidential Information;
   (c) is communicated to a third party with the express written consent of the disclosing party;
   (d) is independently developed by the recipient without the benefit of having received said

confidential information;

(e) is lawfully required to be disclosed, provided that, prior to making such disclosure, to the extent permitted by law, the recipient shall immediately give the disclosing party written notice and cooperate with the disclosing party in applying for an order to prohibit or restrict such disclosure and/or to assure confidential handling of such Confidential Information and the disclosing party shall be responsible for the recipient party's out-of-pocket expenses, including legal fees, and personnel time incurred in responding to such order to prohibit or restrict such disclosure.

(4) Each party shall be responsible for any breach of this Agreement by the party, the party's affiliates, Representatives and any person to whom the party discloses any Confidential Information. Full and faithful performance by each of the parties hereto of all obligations under this Agreement is the essence of this Agreement. Each of the parties hereto acknowledges that monetary damages are not an adequate remedy for violations of the obligations of confidentiality under this Agreement and that any non-compliance or breach thereof shall result in irreparable harm to the disclosing party, and that in such event the disclosing party shall be entitled to equitable relief, including injunctive relief, without prejudice to any other remedies available to the said disclosing party.

(5) The obligations of confidentiality herein shall survive the termination or expiry of this Agreement.

23. Dispute Resolution

(1) The Parties agree that they will utilize commercially reasonable efforts to resolve any dispute that arises relating to the validity, construction, meaning, performance or effect of this Agreement or the rights and liabilities of the parties or any other matter arising out of or connected with this Agreement (each, a "Dispute"), promptly and in an amicable manner by negotiation.

(2) Upon the written request of either Party, a senior executive representative of each of the parties, or their respective designates (the "Executive Committee"), shall meet for the purpose of endeavouring to resolve a Dispute. The Executive Committee shall meet as soon as is reasonably possible after a Dispute is referred to it, giving due regard to the nature and impact of the issue under consideration but in no event within ten (10) Business Days (defined below) after the Dispute has been referred to it.

(3) In the event that the Executive Committee cannot resolve a Dispute within fifteen (15) Business Days, then the Parties agree to seek to resolve the dispute or controversy through mediation with Canadian Arbitration Association before pursuing any other proceedings. Nothing herein shall preclude any Party from seeking injunctive relief in the event that the Party perceives that without such injunctive relief, serious harm may be done to the party. Any Party to the dispute may serve notice on the others of its desire to resolve a particular dispute by mediation. The mediator shall be appointed by agreement between the Parties or, if the Parties cannot agree within five (5) Business Days after receipt of the notice of intention to mediate, the mediator will be appointed by Canadian Arbitration Association. The mediation will be held at Ottawa. The Parties agree to attempt to resolve their dispute at mediation. The costs of the mediator shall be shared equally by the Parties. If the dispute has not been resolved within thirty days of the mediation, any Party may terminate the mediation and proceed to a court of competent jurisdiction in the Province of Ontario.

24. Notices

Any notice required to be given shall be in writing and shall be delivered by hand to the party for which it is intended or sent by electronic mail, prepaid registered mail or prepaid courier directed to such party at the address indicated below, or such other address as any party may stipulate by notice to the other. Any notice delivered by hand or prepaid mail or courier shall be deemed to be received on the date of actual delivery thereof. Any notice delivered by electronic mail shall be deemed to be received on the next day following the date the electronic mail was sent.

Hydro Ottawa Limited

Mailing Address: P.O. Box 8700, Ottawa, Ontario K1G 3S4
Courier Address: Up to 15 May 2019: 3025 Albion Road North, Ottawa, Ontario K1V 9V9
Courier Address: After 15 May 2019: 2711 Hunt Club Road, Ottawa, Ontario K1G 5Z9

Attention: Mr. Joe Brannen
Email: joebrannen@hydroottawa.com

UMS Group Inc.

Morris Corporate Center 1
300 Interpace Parkway, Suite C380
Parsippany, NJ 07054 USA
Attention: Jeffrey W. Cummings, Senior Vice President

25. Successors and Assigns

(1) This Agreement shall enure to the benefit of and be binding upon the parties thereto, and except as otherwise provided therein, upon the executors, administrators, successors, and permitted assigns.

(2) Notwithstanding subsection 25 (1), the Consultant shall not assign its rights under this Agreement, in whole or in part, without the prior written consent of Hydro Ottawa. Hydro Ottawa may apply terms and conditions in respect of such consent.

(3) Hydro Ottawa may assign its rights under this Agreement, in whole or in part, without the prior written consent of the Consultant.

26. Performance

The Services shall be performed in accordance with the approved industrial practices and carried out by technicians or workers skilled and qualified in the type of services required. The Consultant shall conduct itself with the utmost professionalism to ensure good working relations.

27. Time of Essence

Time shall be of the essence of this Agreement.

28. Conflict of Interest

The Consultant warrants that it presently has no interest and will not acquire any interest, direct or indirect, which would conflict in any manner or degree with the performance of the Services under this Agreement.

29. Entire Agreement

The terms and conditions set forth in this Agreement constitute the full and final expression of the contract in respect of the Services, and all matters contemplated in this Agreement, and supersedes all prior quotations, purchase orders, correspondence or communications whether written or oral between the Consultant and Hydro Ottawa. Notwithstanding any contrary language in the Consultant's purchase order, correspondence or other form of acknowledgement, the Consultant shall be bound by this Agreement. ANY ADDITIONAL OR ANY DIFFERENT TERMS ARE REJECTED UNLESS EXPRESSLY AGREED TO IN WRITING BY BOTH HYDRO OTTAWA AND THE CONSULTANT.

30. Amendments and Waivers

No amendment or waiver of any provision of this Agreement shall be binding on either party unless agreed to in writing by such party. No waiver of any provision of this Agreement shall constitute a waiver of any other provision, nor shall any waiver constitute a continuing waiver, unless otherwise provided.

31. Survival

Any terms, which by their nature are intended to survive the termination of this Agreement, shall

continue in full force and effect after termination, which terms shall include, but not be limited to Sections 11, 13, 14, 15, 21 & 22.

Hydro Ottawa Limited	UMS Group Inc.
Signature:	Signature:
Name: GREG VAN DUSEN	Name: Jeffrey Cummings
Title: DIRECTOR - REGULATORY AFFAIRS	Title: Senior Vice President
Date: APRIL 1/19	Date: 22 March 2019
I have authority to bind the corporation	I have authority to bind the corporation

SCHEDULE A - STATEMENT OF WORK

1. Project Overview

The Consultant shall prepare a unit costs benchmarking study (hereinafter referred to as "Unit Costs Benchmarking Study"). This Unit Costs Benchmarking Study will (i) review how Hydro Ottawa determines the unit costs underlying its distribution system capital and operational programs, (ii) perform benchmarking comparisons with a selected peer group of utilities in Canada and the United States, and (iii) provide recommendations on how Hydro Ottawa can improve its unit costing practices in the future.

This Unit Costs Benchmarking Study will be included as evidence in the next five-year Custom Incentive Rate-setting ("Custom IR") application which Hydro Ottawa is planning to submit to the Ontario Energy Board ("OEB"). This application will seek OEB approval of Hydro Ottawa's proposed distribution rates and other charges for the years 2021-2025. In compliance with OEB requirements and guidelines, Hydro Ottawa plans to submit several benchmarking studies (including the Unit Costs Benchmarking Study) to demonstrate (i) the reasonableness of the revenue forecasts which will be included in its forthcoming Custom IR application, (ii) the efficiency with which Hydro Ottawa executes its capital and operational programs, and (iii) the strength of Hydro Ottawa's continuous improvement and overall performance relative to its peers.

In part, Hydro Ottawa's interest in commissioning this Unit Costs Benchmarking Study is informed by the OEB's stated intention to develop an Activity and Program Based Benchmarking framework to encourage continuous improvement by regulated utilities in Ontario.[1]

Hydro Ottawa expects that this Unit Costs Benchmarking Study will mimic the methods used in the preparation and presentation of the unit costs benchmarking study which was included in the Custom IR application submitted by Toronto Hydro Electric-System Limited to the OEB on August 15, 2018 (OEB File No. EB-2018-0165), prepared by UMS Group.

(I) Asset Categories and Maintenance Programs

For purposes of this Unit Costs Benchmarking Study, Hydro Ottawa is interested in examining the unit costs associated with the following categories of assets and maintenance programs:

Asset Categories

- Wood Pole Replacement
- UG Cable (XLPE)
- OH Switches (Manual and Remote / Motor Operated)
- OH Transformer Replacement
- UG Transformer Replacement
- UG Switchgear
- Station Breaker Replacement (SF6, Oil and Vacuum)

Maintenance Programs

- Vegetation Management
- Pole Test and Inspection
- Overhead Line Patrol
- Station Breaker and Relay

While the foregoing lists reflect Hydro Ottawa's view on what content would be the most appropriate for a study of this nature, Hydro Ottawa recognizes that these lists may need to be modified as the project moves forward, depending upon certain factors (especially the availability of relevant unit cost information from the selected group of peer utilities).

2. Scope of Work

(i) Deliverable #1 – Preparation of Unit Costs Benchmarking Study

The Consultant shall:

[1] *See:* Letter from the OEB re: Activity and Program Based Benchmarking (ABP) Initiative, (EB-2018-0278), October 10, 2018.

SCHEDULE A - STATEMENT OF WORK

- Conduct all necessary research and analytics to support the preparation of the Unit Costs Benchmarking Study;

- Collaborate with Hydro Ottawa in obtaining and compiling relevant data from the company, pursuant to information sharing agreements and/or requests, where appropriate;

- Coordinate administrative logistics for conference calls and/or site visits with Hydro Ottawa staff that will be held over the course of the project;

- Collaborate with Hydro Ottawa in refining the list of asset categories and maintenance programs to include in the Unit Costs Benchmarking Study, based on any preliminary analysis and/or normalization, as well as on the availability of relevant unit cost information from the comparator utilities in the sample peer pool;

- Ensure that the Unit Costs Benchmarking Study does the following:

    - Reviews how Hydro Ottawa derives the unit costs underlying its distribution system capital and operational programs;
    - Fully normalizes unit costs comparators, taking into account applicable factors and variables;
    - Performs benchmarking comparisons with a selected peer group of utilities in Canada and the United States; and
    - Sets forth key findings, conclusions, and recommendations (where appropriate) on the topic of unit costs, based on the results of its review and benchmarking.

Hydro Ottawa acknowledges that, in order to complete the aforementioned Scope of Work, the Consultant may require access to commercially sensitive or confidential data belonging to the company. Hydro Ottawa is prepared to authorize release of this data to the Consultant, pending the finalization of a contractual arrangement with the Consultant, which may include the establishment of safeguards to ensure the confidentiality of Hydro Ottawa's data.

(ii) Deliverable #2 – Expert Witness Support for OEB Hearing

The Consultant shall, over the course of the applicable OEB adjudicative proceeding:

- Comply with applicable provisions of the OEB's *Rules of Practice and Procedure* regarding the provision of expert evidence; and

- Attend technical conferences, provide expert witness testimony, assist in answering relevant interrogatories, and provide other such support, as necessary and as requested.

3. Completion Date

Hydro Ottawa is planning to file its 2021-2025 Custom IR application to the OEB by early December 2019. Accordingly, Hydro Ottawa's targeted date for the completion of Deliverable #1 is **July 15, 2019.**

The dates and timelines for Deliverable #2 are not yet known, as they are subject to the timing of the notices received from OEB staff that Hydro Ottawa's Custom IR application has fulfilled all relevant OEB filing requirements and that formal review through a hearing can commence. Such notices are typically issued within one to two months of the application's submittal. Hydro Ottawa will keep the Consultant posted on relevant details pertaining to the dates and timelines for Deliverable #2.

SCHEDULE B – COST SUMMARY

DESCRIPTION OF SERVICES:	**Unit Costs Benchmarking Study**
CONSULTANT:	**UMS Group Inc.**
PRICE: Fixed Price for Deliverable #1-Preparation of Unit Costs Benchmarking Study (Canadian $):	**$155,290.00 /plus HST***
PRICE: Time and Materials Based on Hourly Rates for Deliverable #2-Expert Witness Support for OEB Hearing (Canadian $):	**See Table 1 Below**
ESTIMATED EXPENSES (IN ACCORDANCE WITH SCHEDULE B, APPENDIX 1) (Canadian $):	**$18,600.00 / plus HST***

***Milestone Invoicing Schedule:**

Milestone	Amount (Includes Estimated Expenses)
Mobilize the Project Team / Start the Project	$17,250.00 CAD
Complete Initial Targeted Interviews	$34,500.00 CAD
Complete the Peer Group Panel Survey	$34,500.00 CAD
Present Preliminary Results	$34,500.00 CAD
Issue DRAFT Final Report	$34,500.00 CAD
Hydro Ottawa Acceptance of Final Report	$18,640.00 CAD

Table 1: Hourly Billing Rates

Role Description	Hourly Rate
CEO / Senior Vice President	$575.00
Vice President	$520.00
Principal	$460.00
Director	$350.00
Senior Associate	$320.00
Associate / Consultant	$275.00
Senior Business Analyst	$240.00
Analyst	$200.00
Admin	$125.00

APPENDIX 1 TO SCHEDULE B

Hydro Ottawa's Expense Policy

TRAVEL

1. The Consultant personnel and/or Subcontractor shall travel by the most practical and economical means possible.
2. When travelling by automobile or taxi, if feasible, The Consultant personnel and/or Subcontractor should travel together to reduce costs.
3. When available and practical, air travel should be booked in economy class.
4. Premium class rail travel is permissible providing it is less expensive than economy air travel.
5. The use of personal automobiles in lieu of rental vehicles or taxis is acceptable when it is more economical to do so.
   Note: Other than the mileage rate referenced below, Hydro Ottawa does not assume any financial and/or insurance responsibility when The Consultant personnel and/or Subcontractor use personal automobiles for business purposes.
6. The Consultant will be reimbursed for the business use of personal automobiles based on current Hydro Ottawa mileage rates which the Consultant shall confirm with Hydro Ottawa prior to a request for reimbursement
7. When renting automobiles for business travel, The Consultant and/or Subcontractor shall rent up to "mid-size" automobiles unless travelling in a group of 3 or more, when "full-size" rentals are permitted.

MEALS

1. The Consultant will be reimbursed for all reasonable meal expenses while travelling on Hydro Ottawa business.
2. Gratuities related to business dining are not to exceed 15%.
3. Individual bills should be obtained when travelling on business and dining with fellow Hydro Ottawa employees.
4. Room service and/or mini bar food items are not reimbursable.

ACCOMMODATION

1. Accommodation expenses will be reimbursed for standard guestrooms.
   Note: Room upgrades are permissible due to last minute/urgent travel when standard rooms are unavailable.

OTHER

1. Original receipts (with details on the date, description of item/service purchased, purchase amount and itemized taxes) must be kept and be made available upon request.
   Note: On an exception basis, a credit card summary can be used to replace a lost receipt.
2. Travel and/or accommodation cancellation charges for reasons outside the control of The Consultant are reimbursable.

EXCLUSIONS

Examples of items that are not reimbursable include:

1. fines/traffic violations
2. premium rates for luxury hotels and automobiles
3. alcohol
4. entertainment/hospitality

Note: *Emergency dry cleaning costs are reimbursable.*

INTERROGATORY RESPONSE - SEC-20

1-SEC-20

EXHIBIT REFERENCE:

[Ex.1-1-1, Attachment B, p.9]

SUBJECT AREA: UMS Unit Cost Benchmarking Study

On a similar basis as provided on p.9 of the UMS study, for each year between 2020 and 2026:

a) Please provide the percentage of system renewal capital spending represented by the six asset categories benchmarked.

b) Percentage of preventative and predictive maintenance costs represented by the programs/practices benchmarked.

In your response, please provide the underlying calculations.

RESPONSE:

a) Please see the response to interrogatory OEB-44 part (b) for an explanation of why Hydro Ottawa is not able to provide the requested information.

b) Please see the response to interrogatory OEB-44 part (b) for an explanation of why Hydro Ottawa is only able to provide a portion of the information that serves as an essential input into the information request for the present interrogatory. In light of the response to interrogatory OEB-44, Hydro Ottawa is likewise precluded from providing the information that has been requested as part of the present interrogatory.