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LDC ASSET RENEWAL SERIES **Part 2: Climate Change**

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1.0 Executive Summary

Climate change is affecting our distribution sector. Weather influences our demand for electricity, how efficiently we generate it, and our ability to deliver it. Storms cause 58% of all outages and 85% of large-scale interruptions in the United States, costing that economy between \$18 and \$70 billion yearly (United States *Economic Benefits* 3, 8). In 2013, Hydro One customers were without power on average 7.3 hours excluding *force majeure* events. Including these events, the average customer spent over a day without electricity (Hydro One, “Service Quality Indicators” 11).

Predicted changes in long-term weather patterns must inform efforts to renew our distribution sector assets. Temperatures across Ontario will rise over the next 50 years. Winters will be warmer and shorter, while summers will be hotter. LDCs are installing equipment appropriately rated to meet these conditions. However, distributors will face a challenge in addressing the expected increase in severe weather events. With their capability for quick, widespread, and substantial damage, storms represent a significant threat to renewed LDC assets.

Several weather events over the past two decades – the ice storms of 1998 and 2013, Superstorm Sandy, the 2011 Goderich Tornado, among others – have had substantial impacts on electricity distribution. These case studies reveal that the sector must consider:

- Changes in asset planning, notably tradeoffs between resiliency measures – selective hardening, undergrounding – and cost;
- Threats to existing infrastructure;
- Adopting climate adaptation strategies;
- Staff training;
- An increased need to coordinate with municipalities, agencies, emergency services, and other utilities;
- Regulatory treatment of climate change impacts;
- The pace of smart grid technology implementation;
- The health, safety, economic, infrastructure, and insurance implications of mass outages; and,
- Customer attitudes and actions towards climate change.

1.1 Glossary

ADMS – Advanced Distribution Management System

AMI – Advanced Metering Infrastructure (Smart Meters)

Blue-Sky – Typical weather conditions

CEA – Canadian Electricity Association

CSA – Canadian Standards Association

ConEd – Consolidated Edison of New York

DG – Distributed Generation

EV – Electric Vehicle

Force majeure – An event outside the control of a contracted party

IESO – Independent Electricity System Operator (Ontario)

kV – kilovolt

LDC – Local distribution company

Line sag – the increase in the length of a line between two pylons as temperature rises

LIPA – Long Island Power Authority

LTEP – Long-Term Energy Plan

MISO – Midwest Independent System Operator

OEB – Ontario Energy Board

Nor'easter – Severe weather systems in Eastern Canada and the American Eastern Seaboard

PV – (Solar) photovoltaic

THESL – Toronto Hydro Electric System Limited

Tragedy of the Commons – a common good depleted as individuals act in self-interest

TS – Transformer station

Turbine – Wind-powered generation

SAIDI – System Average Interruption Duration Index

SAIFI – System average interruption frequency index

SCADA – Supervisory control and data acquisition

Vegetation management – Controlling plant growth in and around assets

2.0 Climate Change in Ontario

A review of climate projections for Ontario is included as an appendix to this report.

There appears to be consensus that:

- Average daily temperatures will rise between 3° and 4°;
- Summer highs should rise between 1° and 4°;
- Winter highs should rise anywhere from 2 to 7°;
- The greatest changes in temperature occur around James Bay;
- Yearly precipitation will increase, particularly in the winter months;
- The snow season could be shorter by 1.5 months; and,
- There will be more extreme storms.

3.0 Severe Weather: Case Studies

Severe storms are occurring more often. The Insurance Bureau of Canada calculated that severe weather resulted in over \$3.2 billion in insurable claims in 2013, the most claimed in a single year in Canadian history (“Canada inundated”). A 2014 TD Economics report estimates that natural catastrophes will cost the Canadian economy \$5 billion in 2020 and between \$21 and 43 billion by 2050 (1).

These low-probability, high-impact incidents are commonly referred to as a “once-in-a-time period” happenings. These events are happening with greater frequency: in Toronto, two “once in a decade” and six “once in a half century” events occurred between 1996 and 2011 (Feltmate 35, Toronto *Resilient City* 4). Since these storms are hard to predict, provide little warning, and cause significant infrastructure damage, severe weather poses an increasing threat to LDC assets. A number of case studies affirm this threat.

2000	Wettest summer in 53 years, with 13% more precipitation than normal
2001	Driest growing season in 34 years; first ever heat alert; 14 nights with temperature above 20°C (normal is 5 nights)
2002	Driest August at Pearson Airport since 1937; warmest summer in 63 years; 5th coldest spring
2003	Rare mid-Spring ice storm where Pearson Airport used a month's supply of glycol de-icer in 24 hours
2004	Year without a summer; May rainfall in Hamilton set an all-time record; all-time record 409 mm of rainfall was set at Trent University in July which was the equivalent to 14 billion litres of water in 5 hours (a one in 200 year event)
2005	Warmest January 17th since 1840; January 22nd blizzard with whiteouts; warmest June ever; number of Toronto days greater than 30°C was 41 (normal 14); August 19th rainstorm washed out part of Finch Avenue
2006	23 tornadoes across Ontario (normal is 14); record year for major storms; record one-day power demand of 27,005MW due to summer heat
2007	Protracted January thaw; 2nd least snow cover ever in Toronto (half the normal amount); snowiest Valentine's Day ever; chunks of ice fell from the CN Tower; 2-3 times the number of hot days in the summer; record latest-in-season string of +30°C days around Thanksgiving
2008	Toronto's 3rd snowiest winter ever; record for highest summer rainfall
2009	3rd rainiest February in 70 years; Hamilton had a 100-year storm; one of the wettest summers on record; tornadoes hit Vaughan-Woodbridge in late August; an unusually mild and storm-free November in Toronto; first snow-free November at Pearson Airport since 1937
2011	A new all-time July record maximum temperature of 37.9°C was set at Pearson airport
2012	Toronto's earliest official heat wave (June 19-21)
2013	July flood; December ice storm
Adapted from (Toronto, <i>Resilient City</i> 4)	

3.1 2013 Toronto Flood

Hot days can produce powerful thunderstorms that can quickly saturate soil and overwhelm storm water infrastructure. In the afternoon of July 8, 2013, one of these cells caused widespread flooding in the Greater Toronto Area. Pearson Airport reported a one-day record of 126mm, while the Toronto downtown core received 97mm of rain (Mills; Ogrodnik). Many of Toronto's roads were flooded, subway service was suspended, and a GO Transit train was stuck for hours in floodwaters of the Don River (Hydro One, "GTA Blackout" 2-6). Around 300,000 Toronto Hydro customers were without electricity at the height of the storm, along with 80% of Enersource's customers in Mississauga (Ogrodnik).

The main cause of the interruption was flooding at Hydro One's Manby and Richview transmission stations. Flooding at these stations marked the beginning of a series of disconnections in Toronto and the western GTA. Six LDCs reported interruptions after 25 230kV and 7 115kV transmission lines tripped, amounting to a load loss of just under 3,400MW. Hydro One, Toronto Hydro, and the IESO employed voltage reduction, load shedding, demand response, and load transfers to bring the system back up over two days (Hydro One, "GTA Blackout" 7, 11-17, 26-41).

At the stations, water levels reached six feet, submerging cables, breakers, and circuits. Hydro One lost significant remote monitoring and control functionality, while data exchange between the transmission system and LDCs was interrupted ("GTA Blackout" 18-25). The flood was the most costly natural disaster in Toronto to that date: insured property damage exceeded \$850 million, while direct costs to the City were \$65.2 million (Toronto, *Follow-up* 2-3).

3.2 2012 Superstorm Sandy and Nor'easter

On October 29, 2012, Superstorm Sandy made landfall near Atlantic City, New Jersey. Sandy's width and power was unprecedented: hurricane force and tropical storm winds emanated 175 miles and 500 miles from its eye at landfall, respectively. In the United States, Sandy caused 131 deaths, 8.5 million customer outages, and \$20 billion in property damage (United States, *Overview of Response* 1-2, 4; United States, *Comparing* 2, 10; Abrams and Lawsky 14).

The New York area was the hardest hit. Despite the efforts of Consolidated Edison (Con Ed) to build artificial flood barriers and initiate pre-emptive blackouts, 800,000 customers – or 2 million citizens – lost power (New York City 107, 113). Higher than expected storm surge flooded substations in Manhattan and the boroughs, overloaded transmission lines in Brooklyn and Staten Island, and caused significant damage to overhead equipment (New York City 115). The Long Island Power Authority (LIPA) suffered damage to 50 substations, 2,100 transformers, and 4,500 utility poles (United States, *Comparison* 8). Restoring 95% of those customers that lost power in the United States took 10 days; a process slowed by another storm – a snowy Nor'easter – on November 7th (United States, *Comparing* 10).

In Canada, 150,000 were without power after the storm. Insurable storm damage in Ontario and Quebec reached \$100 million (Insurance Bureau of Canada, "Preliminary").

3.3 2011 Goderich Tornado

In the afternoon of August 21, 2011, a tornado came ashore from Lake Huron and passed through the centre of Goderich, Ontario. The tornado caused:

- One death and 37 injuries;
- Widespread destruction of the downtown and harbour, leading to the demolition of 54 buildings and repairs to 283;
- 500 fallen trees; and,
- \$100 million in damages.

The Tornado destroyed Goderich Hydro's operations centre – along with many of their vehicles – and damaged one of its substations. It took eight hours to bring critical customers online, and two weeks to reconnect the entire system. Goderich Hydro and 50 mutual support crews repaired or replaced 100 poles, 20 transformers, and 4.7km of line (McCabe 2, 8, 10, 12, 17).

3.4 2003 Blackout and Heat Waves

Ontario was in the midst of a heat wave in the middle of August 2003. Temperatures in Toronto rose from a high of 28°C on the 11th to 31°C on Thursday, August 14th. Increased use of air conditioning resulted in a demand of just over 24,000MW that day. Record demand up to that point was 25,414MW (IESO, "IESO Demand Overview").

At 14:02, a transmission line tripped in Ohio after a wire touched an overgrown tree. The local system operator was unaware of the event as it was experiencing problems with its monitoring system. Over the next hour, two more lines tripped that were operating well within their operational limits when they contacted overgrown trees. Starting at 15:40, other transmission lines began to succumb to the additional load they carried from the tripped lines. Improper telemetry, software problems, and human error led to a cascading failure of the transmission system. By 16:20, most of New York State and Ontario, along with portions of Quebec, Michigan, Ohio, and five other states were dark (Canada and United States 45-102).

The IESO moved to coordinate the restoration of generation in the province. Most of Ontario spent that evening without electricity. The next morning, officials urged residents and businesses to conserve power, as the health of the grid remained unstable. Most of OPG's nuclear reactors entered full shutdown mode, which requires days for full restarts. Three units at Bruce and one at Darlington were the only nuclear baseload capable of producing electricity in the hours after the blackout (Spears). Government workers stayed home for two days, while large industrial customers operated at low demand, if at all ("Third Anniversary of August 2003 Blackout"). The blackout caused a loss of just under 19-million working hours in Canada (Canada and United States 1). It took eight days for provincial generation to return to normal levels (IESO, "Looking Back at Blackout 2003").

Although heat was only a contributing factor to the 2003 blackout, high temperatures can directly affect distribution networks, due to loading from air conditioners and asset derating. In

2006, 1.3 million Californians were without power when 2,000 distribution line transformers failed during a heat wave (United States, *U.S. Energy Sector Vulnerabilities* 12-13).

3.5 2013-2014 Polar Vortex

The winter of 2013-2014 was one of the coldest on record in Canada and much of the United States. Several cold snaps and weather events hit the region from early January to early March (United States, "Winter 2013-2014 Operations" 2-5). Toronto experienced its coldest winter in two decades, with 10 days where the temperature fell below -20°C. Meanwhile, above average snowfall and extreme cold were felt across the entire country ("This Winter is Miserable" *CTV News*). In the United States, the season brought historic levels of snow and cold to the Midwest and Northeast (United States, *State of the Climate*; Kuhne).

Record natural gas and electricity demand in the United States led to high commodity prices. System operators employed demand response, voltage reduction, and requested that generators produce electricity in excess of their ratings. Mechanical failures due to cold, fuel availability, and delivery problems exacerbated supply problems (United States, "Winter 2013-2014 Operations" 17-18). During the winter, Enbridge asked its major customers to cut back their usage as natural gas demand far outpaced supply:

"...the Company has called for curtailment on five different occasions for a total of 16 days of curtailment. In the [Eastern Delivery Area] the Company has called for curtailment on five different occasions for a total of 19 days of curtailment throughout the December 2013 to February 2014 period. In contrast, during the December 2012 to February 2013 period demand was such that the Company did not curtail any of its interruptible customers in the [Central Delivery Area] and only curtailed its interruptible customers in the [Eastern Delivery Area] on six days" (Enbridge Gas Distribution 4).

The OEB allowed Enbridge to raise rates significantly after the storm. Natural gas companies can only recover costs in their rates (OEB, *Natural Gas Utility Applications*).

3.6 2013 Ice Storm

On the evening of December 22-23, 2013, freezing rain fell across the Greater Toronto Area. The City of Toronto received two to three centimetres of frozen accumulation, more than two years' worth of freezing rain over several hours (Toronto Hydro Independent Review Panel 16).

Toronto Hydro, PowerStream and Veridian began tracking the storm four days before (EDA, *Distributor* 10; Hanes et. al. 4). On December 21, they mobilized crews for standby. On the evening of the storm, short-circuits and fires began to compromise the network. Accordingly, at 4:00am, Toronto Hydro declared their highest emergency level (Ballingall).

At peak, 313,000 of Toronto Hydro's 709,000 customers were without power, with over half of that company's customers losing power at one point. Sunnybrook Hospital, Toronto East General Hospital, and three water treatment pumps ran on generators for several days (Semeniuk). Toronto Hydro restored

about 86% of their customers within 72 hours, and 99% by New Year's Eve. Full restoration was completed two days later (Hanes et. al. 6, Toronto Hydro Independent Review Panel 4-5, 10).

Toronto Hydro CEO Anthony Haines characterized the event as the “most disruptive incident” the company had ever faced (3). The Ice Storm was Toronto's Hydro costliest and most complex operation. By the numbers, the company addressed:

- 374,000 calls in 10 days – 100 times the regular call volume;
- 7,000 social media events;
- 1,500 mass media interactions;
- 500 wires down;
- 800 traffic lights out;
- 45,000 e-mails;
- Finding room and board for over 400 mutual aid workers; and,
- Around the clock operations for two weeks (Davies 4; Hanes et. al. 6, 15).

The City of Toronto activated its Emergency Operations Centre at 1:30 pm the afternoon before the storm. The Toronto Emergency Management Planning Group coordinated the City's response protocols for the next eight days. Toronto opened warming centres, while the City's forestry, transportation, housing, and solid waste divisions worked with Toronto Hydro and emergency services. Those first responders dealt with well-above normal call volumes: from the 21st to the 30th, Toronto Fire responded to 2,351 calls about downed wires, up from seven calls during that same period in 2012. The City of Toronto estimated the cost of the storm to the city at \$106 million. (Toronto, “Impacts from the 2013 Extreme Storm Events” 8, 11, 29, 31).

Outside Toronto, Milton Hydro reported half of its customers were without power at the storm's peak. The company initially had difficulty finding mutual aid, but eventually 70 crewmembers from other areas responded. Crews restored full service on December 28th. Costs incurred were \$1.3 million, including:

- ~\$125,000 for Milton Hydro staff;
- ~\$80,000 in materials;
- ~\$120,000 for vegetation management;
- In excess of \$700,000 for mutual aid; and,
- Over \$200,000 for contractors (“Milton Hydro's Response” 2-3, 8, 21).

Veridian's service territories experienced three centimetres of freezing rain during the storm, while their assets were rated to a CSA standard of 1.25cm of ice (Veridian 8). The company's employees worked 16-hour shifts to restore 90% of their 65,000 consumers – half of their customer base – in Ajax, Pickering, Clarington, and Port Hope within two days (Veridian 4). Welland Hydro restored all its customers in 24 hours, Haldimand Hydro in 36 hours, and Centre Wellington within 48 hours (EDA, *Distributor* 10). PowerStream restored 77% of customers without power within one day (EDA, *Distributor* 10). It took three days for Horizon to restore power to 20,000 customers (Horizon 4). Finally, about 585,000 of Hydro One's

customer base sustained an outage at some point from the storm (Hydro One, “Service Quality Indicators” 18).

3.7 1998 Ice Storm

On the evening of January 4, 1998, light freezing rain began to fall across Ontario, Quebec and New York State, intensifying on the morning of the fifth, and continuing for another day. A second period of freezing rain began late on the eighth. Over five days, three separate freezing rain events covered an area from Lake Huron to Halifax. The hardest hit urban areas were Kingston, Ottawa, and Montreal. Ten centimeters of freezing rain fell on Montreal over 80 hours, more than what typically falls in two years. Such an ice storm had not hit this part of North America since the 1920s. The storm took 28 lives in Canada and dislocated 600,000 people (Risk Management Solutions 2-5, 7).

At its peak, over 4.8 million people were without electricity (Risk Management Solutions 2). The storm damaged approximately 3,110 of Hydro-Québec’s transmission assets, including 1,300 steel pylons and 116 lines. Only one of Hydro-Québec’s 735kV lines escaped “catastrophic” damage (Monirul Qader Mirza 219). The company’s distribution group – with the support of 220 tradespeople from other provinces – repaired or replaced 24,000 poles, 350 lines, and 4,000 transformers (Risk Management Solutions 7). Montreal nearly ran out of water as generators for municipal services ran low on fuel (Lecomte, Pang and Russell 2).

Over 600,000 people lost power in Eastern Ontario. Around 7,000 distribution poles and 1,800 pole-top transformers fell, damaging 40% of the Eastern Ontario distribution network. It took nearly three weeks of effort by municipal distributors, Ontario Hydro, and the Canadian Forces to reconnect every customer. Combined, Hydro-Québec and Ontario Hydro spent \$1 billion on repairs (Risk Management Solutions 7; Ontario Hydro 19).

A Government of Québec commission on the storm found that despite the utility’s insistence, Hydro-Québec’s transmission system was poorly constructed. Pylons, for instance, collapsed well below their rated thresholds. The firm lacked uniform standards for transmission infrastructure, failed to install de-icing technology, and used a climate model that structurally underestimated the threat of freezing rain (Monirul Qader Mirza 224-225).

3.8 Maryland Storms

A comprehensive study by the State of Maryland considered the consequences of three events across different seasons: the 2010 “Snowmageddon” blizzard, 2011’s Hurricane Irene, and the 2012 “derecho”, a line of severe thunderstorms.

With each storm, no failures occurred within the transmission network, nor did any distribution substations fail. The three utilities within the state had different failure profiles due to the unique properties of their networks: failures at BGE were split between fuses, reclosers, and lines; failures with Potomac Edison were split between substation supply lines, fuses, reclosers, and distribution lines; while the majority of failures on the Pepco system were lines.

Across the three companies, 45% of failures originated at the line. Of these, underground distribution lines fared at least twice as well as elevated systems. Fuses, reclosers, and substation supply lines were responsible for 15-20% of the failures respectively. Failures of substation supply lines affected many more customers than distribution line failures (Maryland Grid Resiliency Task Force 23-29).

4.0 Challenges and Changes

History demonstrates that severe weather can have a debilitating effect on electricity distribution. As time goes on, these events will only become more frequent and more intense. As much of our distribution sector requires renewal in the next two decades, best practices in planning and responding to climate change will be critical.

4.1 Resiliency, Reliability and Redundancy¹

The strength of a distribution grid can be measured by:

1. Reliability – the ability to consistently operate according to design;
2. Resiliency – as defined by the United States National Infrastructure Advisory Council, resilience is “...the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event” (United States, *Framework* 15); and,
3. Redundancy – providing alternatives and backups in the event of a reliability problem in a part of the system. A good example of redundancy is the N-1 standard for transmission (Keogh and Cody 4, 12).

Reliability is the primary objective and risk management concept of distribution system planning (United States, *Framework* 15, 22). Resiliency, however, includes the ability to withstand externalities and recover quickly in the event of failure. It is more than just physical assets: workers, planning and coordination are important to resiliency. Redundancy can help achieve a resilient network. In the face of more events that threaten reliability, there must be balance among the “Rs.”

4.2 New Technology and Standards

Smart grid technology can help build system resiliency. Batteries can provide reliable backup power during an interruption to critical facilities, micro-grids can minimize large-scale interruptions, and technologies such as AMI, SCADA, automated switching, and ADMS can pinpoint and isolate outages while providing real-time system information (United States, *Economic Benefits* 10-11, 14-15). These new tools were effective during Superstorm Sandy,

¹ This section is inspired by Marshall and Chapman. Some literature adds “restoration” to make for four “Rs.” United States *Framework* also addresses to “robustness... resourcefulness... [and] rapid recovery” (16).

and turned out to be “quite useful” during the 2013 Ice Storm (EDA, *The Distributor* 15; Ballingall; United States, *Economic Benefits* 10).

Sometimes, however, a utility can have too much data: many smart meters reporting failure is redundant information when an LDC knows that a substation is offline. Accordingly, parts of a smart grid have limited application during a major weather event (Maryland Grid Resiliency Task Force 50). During the 2013 Ice Storm, Toronto Hydro was unable to “ping” or query smart meters en masse to determine connectivity. Even had that technology been in place, the company’s IT infrastructure was already challenged by the large amount of data produced by existing meters (Toronto Hydro Independent Review Panel 85, 87).

Groups like the CSA and the Standards Council of Canada establish guidelines for electrical equipment. Yet, they are well behind Ontario’s effort to modernize their grid. In October 2012, nearly a decade after smart meters began to appear in this province, the SCC recommended:

“[that] governments and regulators... be very cautious about enshrining any [smart meter] standard into regulation in the near term. Some of these standards are not yet mature enough to have a proven track record. Also, forced early conversion to a new standard may prematurely render current infrastructure investments obsolete, unnecessarily adding cost burdens” (3).

The SCC’s establishment of a Smart Grid Steering Committee was years behind efforts in Ontario. That said, Ontario’s pro-activeness came with risk: Toronto Hydro’s early adoption of smart meters did not include “last gasp” architecture that would have helped with the restoration after the 2013 Ice Storm (Toronto Hydro Independent Review Panel 87). Accordingly, regulators and standards councils must immediately and rapidly address climate change before utilities are forced to move ahead without them. Already, several studies have suggested that North American utilities install above-code infrastructure (Abrams and Lawsky 36; New York City 125).

4.3 Threats to Existing Assets

In 2010, AECOM consultants held a workshop to consider the vulnerability of Toronto Hydro’s assets to climate change. Teams examined weather phenomena and assessed their risk to seven feeders and their associated assets. The majority of these assets were 25 to 35 years old, and approaching the end of their life cycle. Participants included Utilities Kingston, the City of Burlington, and Hydro One (2-3, 15).

The threat to assets in cold weather appear to be declining as Ontario warms, although the winter of 2013-2014 reminds us that cold spells are still very much a characteristic of a Canadian winter. The study characterized the following events as low risk:

- Increased cable tension in overhead conductors;
- Overheating transformers due to condensed and frozen oils;
- De-icing salts accelerating corrosion of at-grade assets; and,

- Temperature variability and freeze-thaw cycles causing underground wire failures (AECOM 23-25; NERC 1).

The group found that ice storms represented a medium risk to THESL, although recent events may warrant examining this conclusion.

Warmer temperatures, greater humidity, storms, and flooding in the summer

present a much greater challenge. More afternoon thunderstorms cells may produce downpours and tornados. We will also experience more extra-tropical cyclones. These former hurricanes will maintain wind speeds and moisture for longer periods and accordingly will bring more severe weather inland.

Summer weather events considered as high risk by the AECOM workshop included high winds and direct lightening impacts on overhead transformers (26). The group predicted that medium risk occurrences include:

- Growing summer loads associated with increased air conditioner use;
- De-rating of overhead and underground wires;
- Rainfall and flooding affecting:
 - Below-grade switches;
 - Flooding of at or below-grade vault rooms, substation, or transformer facilities; and,
 - Exacerbation of conditions through failures in other municipal infrastructure, such as water and sewer systems.
- All other overhead infrastructure damage from wind; and,
- Switch and pole failures due to direct lightning strikes (23-26).

Low risk threats include:

- Lower soil moisture content, lessening the conductivity required for grounding;
- More rapid deterioration of concrete used in structures supporting assets.
- Hail;
- Lightening on ground based or underground equipment;

Table 2: Expected Extreme Weather for Toronto by 2049

Weather Extreme	Parameter	Short-term (2000-2009)	Long-term (2040-2049)
Extreme Rain	Maximum Amount in One Day	66 mm	166 mm
	Number of Days with More Than 25 mm	19 days	9 days
	Mean Annual Daily Maximum	48 mm	86 mm
Extreme Heat	Extreme Maximum Daily	37°C	44°C
	Number of Days with Temperature Greater than 30°C	20 days	66 days
	Number of Heat Waves (3 or more consecutive days with temperatures greater than 32°C)	0.57 (3-day events)	2.53 (3-day events)

Adapted from (Toronto, *Resilient City* 5).

- Above ground equipment and underground cable faults from rainfall (23-25).

Higher temperatures presents several challenges. It leads to less efficient operation and greater load losses on distribution networks, while derating overhead lines, underground cables, and transformers (United States, *U.S. Energy Sector Vulnerabilities I*; Ward 34). An increase of 5°C can decrease the capacity of current substation technology by 2% to 4% (Sathaye et. al. 19-20, 25-26). Heat waves will stress transformers as they have in California, as peak ambient temperatures often coincide with peak demand (Jurgens). Higher temperatures will shorten the lifecycle of electronics embedded in the distribution system; this may become of considerable concern as the grid continues to become “smarter” (Allan). The increasing threat of forest fires will increase the probability of damage to Hydro One assets in Northern Ontario.

4.4 Combined Heat and Power

After Sandy, New York noted the significant benefits of incorporating combined heat and power (CHP) into the generation mix:

“...amidst the widespread electric outages, there were some cases where facilities performed well on either backup generators or CHP systems. For example, at least five hospitals relied on backup generator systems in order to stay in operation during the storm and its aftermath. Meanwhile, New York University had success keeping key buildings on its Washington Square campus lit and heated thanks to a newly installed gas-fired CHP system, which it was able to operate seamlessly in isolation from the grid when the grid failed” (New York City 117).

CHP offers several advantages over traditional contingency generation including:

- They provide both heat and power;
- Stations with “black-start” technology do not need electricity to operate;
- Backup generators are used rarely; CHP systems continuously. As such, CHP is more likely to be properly monitored and maintained;
- As a backup, CHP relies on a direct supply of natural gas, while generators usually depend on traditional fuels that need to be replenished;
- CHP systems can allow for continuous operations; the time for generators to come online may lead to an interruption;
- CHP burns quickly, cheaply, cleanly, and efficiently (Hampson, Bourgeois, Dillingham, and Panzarella 4-6).

After the release of the *Long-Term Energy Plan (LTEP)*, the Minister of Energy asked the OPA to recommend a procurement mechanism for CHP. Four previous rounds of CHP procurement have incorporated 414 MW of CHP into Ontario’s supply mix. The *LTEP* anticipates the need for new CHP from 2019 to help address local generation shortages, even though the government finds that “CHP projects work better if they are driven primarily by the need for heat, with electricity as a by-product” (Ontario, *Long-Term Energy Plan* 44). Nevertheless,

LDCs should be planning for small-scale CHP installations as part as an overall move towards DG; projects under 20MW are installed into the distribution network.

4.5 Climate Adaptation Planning: Weather and Risks

Managing risk is part of any business. However, as a warming planet becomes more of a certainty, governments and corporations are increasingly embracing climate adaptation plans as part of long-term planning. The electricity sector may be lagging behind: the Canadian Electricity Association (CEA) notes that "...adaptation has become one of the biggest emerging issues for the electricity sector... all stakeholders, including governments, must work to address this issue on a more urgent level." In 2012, only half of CEA members had a climate change program in place, while just over half worked with third parties on global warming, like the IESO and Hydro One's work with the Toronto WeatherWise Partnership (CEA 20-21).

The challenge of climate change is that it extends beyond short-term planning cycles. It is climate change that leads to, among other things, weather change. LDCs may have to anticipate requirements that historical weather models cannot predict. Barrett, Harner, and Thorne address this as "future risk":

"Another significant gap is addressing so-called future risk, a notion that stems from the need to focus not only on linear historical patterns but also on changing trends, processes, and technologies that will affect interdependent critical infrastructure resiliency in unforeseen ways. This is crucial to address because long-term planning assumptions tend to be built around historical patterns, but these patterns may be very, very wrong as the evolving picture of future risk means the frequency or magnitude of outages changes sharply over time. This type of risk is emerging as a major concern given that changing weather patterns are resulting in more and more days at the extreme ends of the temperature range and some of the underlying systems were not designed to operate under such conditions for prolonged periods." (10-11).

4.6 Asset Planning: Resiliency and Traditional Assets

LDCs can purchase, improve or retrofit assets to increase resiliency. Options include:

- Burying overhead wires;
- Steel poles;
- Substation elevation;
- Submersible switches and transformers;
- Covered/insulated conductors;
- Strengthening poles with guy wires;
- Hydrophobic coatings;
- Enclosed substations; and,
- Mobile transformers and substations.

As LDCs increasingly integrate IT into the grid, these electronics will need to withstand changes in weather, including extreme events. As seen during the July 2013 flood, severe weather can damage network infrastructure and disrupt communications, reducing the information that LDCs have available while increasing interruption durations. As new asset types enter into service and smart and micro-grids emerge, coordinated operation of an increasingly complex network requires a high level of situational awareness. Data interruptions can cripple operators, turning a smart grid “dumb” at the very moment that its data is needed.

The decision to integrate resiliency and redundancy requires an assessment of risks, costs and value. Regulators and consumers will expect an appropriate balance. This analysis should include both the direct and indirect costs to the entire community. Consider moving Toronto’s entire distribution network underground. Although Toronto Hydro’s assets would arguably be more reliable and resilient, such an exercise would lead to:

- \$11-16 billion in direct expenditure;
- Stranded overhead assets;
- Increased maintenance costs;
- Less expenditures on other parts of the system;
- Impacts on other overhead infrastructure, e.g., telephone and cable;
- Increased duration of outages due to longer restoration times of underground infrastructure;
- Lost business revenue; and,
- Traffic and landscape disruptions (Ballingall; Maryland Grid Resiliency Task Force 49-50; Toronto Hydro Independent Review Panel 91).

ConEd undertook a rapid resiliency program after Sandy, earmarking \$1-billion in spending over three years, including investments in ‘traditional’ assets:

- Reconfiguring the distribution and transmission network to separate flood and non-flood areas;
- Upgrading underground equipment to be submersible;
- Upgrading overhead equipment, while burying others;
- Hardening electric , steam production facilities, tunnels, IT infrastructure, and substations; and,
- Using poles rated to 110mph (*Summary 8, 10-13; Fortifying the Future 1*).

Other options can increase resiliency of a distribution network. For instance, keeping a stockpile of interchangeable parts for a particular asset type can speed restoration during a storm. These interchangeable parts can also save LDCs money on maintenance (Barrett, Harner, and Thorne 18)

4.7 Regulating the Unforeseen

Currently, the OEB treats unforeseen events and natural disasters as “Z-factor” events. Z-factor costs recovery is possible if:

- Claims are directly related to the event;
- Costs incurred are prudent and “must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.”
- Costs surpass a materiality based on the size of the LDC (OEB, *Supplemental Report VII-VIII*).

The LDC must:

- Notify the OEB within six months;
- Demonstrate that the event could not be planned for or budgeted for under reasonable expectations; and,
- Demonstrate that the costs associated with the event are over and above those already recovered in rates (OEB, *Filing Requirements for Electricity 11*; OEB, *Supplemental Report IX*).

As LDCs make decisions on the balance between reliability and resiliency, they will ultimately need to justify their plans to the OEB. The *Renewed Regulatory Framework* promotes customer focus, operational effectiveness, public policy responsiveness, and financial performance. Operational effectiveness requires that LDCs “...deliver on system *reliability and quality* objectives” (2).

Climate change requires a planning horizon beyond five years. Short-term rate decisions may not reflect optimum, long-run planning. Moreover, as we have seen with natural gas in early 2014, even short-term planning can prove difficult. In the face of climate change, the OEB and the Ministry might consider:

- A resiliency or climate change investment metric on future iterations of the scorecard;
- Allowing LDCs to fund resiliency through a dedicated funding stream – decoupled or not;
- Where LDC assets should lie along the resiliency-reliability spectrum;
- Time-of-restoration targets;
- Government direction to build a resilient network;
- A Government requirement for municipalities to develop climate adaptation plans (presumably following the lead of a Federal or Provincial plan); and,
- A regulatory requirement for LDCs to develop climate adaptation plans (presumably guided by a design basis established by the regulator).

4.8 Staff

LDC employees protect, maintain, and repair physical capital. Sharing experiences and lessons from severe weather will be invaluable to the next generation of front-line workers. As a

substantial part of the LDC workforce approaches retirement, human capital renewal is required. Enshrining institutional knowledge can only help prepare future crews for the storms to come.

The National Infrastructure Advisory Council researched various methods to increase resilience through staff training. They found that American utilities use a number of strategies, including:

- Business continuity drills, often utilizing a “hot site” to duplicate real-world conditions;
- Stress exercises to deliberately “break” the system in order to find gaps in resilience;
- Tabletop exercises with compounding effects reaching deep within the company and into bordering service areas;
- Announced and unannounced drills;
- Joint drills with city and county agencies;
- Annual coordination meetings with responders to talk about recent events and identify lessons learned and best practices;
- Tabletop exercises for black start situations to recover from a complete shutdown of the system;
- Use of vulnerability response teams to test and exercise emergency response plans across the company; and
- Participation in national exercises to ensure local emergency response plans (United States, “Framework” 34).

4.9 Vegetation Management

Trees are a significant cause of LDC infrastructure damage. Wind tosses branches while ice brings down trees even days after a storm. Maintaining vegetation alongside LDC assets will become more important into the future. Longer growing seasons will result in taller and broader trees and shrubs. New plant species may migrate to different areas as weather conditions evolve. Flooding from thunderstorms will increasingly compromise tree roots. Vegetation can also interfere with critical communications networks that are the backbone of smart grids. These conditions may require shorter vegetation management cycles.

In Maine, they found that a complex structure of state and local laws, regulations, ordinances, and private property rights affect the tree trimming, clearing, and vegetation management practices of their electric utilities (Maryland Grid Resiliency Task Force 53). Ontario lacks the complicated legal frameworks in the United States for vegetation management. The *Electricity Act* states that “A... distributor may enter any land for the purpose of cutting down or removing trees, branches or other obstructions if, in the opinion of the... distributor, it is necessary to do so to maintain the safe and reliable operation of its ...system” (“Electricity Act”). LDCs accept the industry practice of cycling: visiting and maintaining vegetation areas on a schedule, varying from two to eight years (ESA 9).

Tree cover represents a significant aesthetic and environmental benefit to communities. Vegetation management may anger property owners, neighbourhood associations, and municipal shareholders. As the growing season becomes longer, trade-offs between tree

canopy and system reliability will be required. Which stakeholder will make the decision, and who will bear the cost of a tree-related outage: municipalities, governments, the regulator, LDCs, or even homeowners?

4.10 After the Storm: Response, Staff, Service Coordination and Mutual Aid

With any natural disaster comes the requirement for coordinated efforts and prioritization of tasks. Restoring electricity is one part of a complex process, including other municipal services, utilities, first responders, and multiple levels of government. Many City of Toronto agencies note that there is “a large degree of interdependency among City assets,” all of which rely on Toronto Hydro (Toronto, *Resilient City* 8).

Liaison allows for better coordination and quicker restoration of all essential services. New York utilities were slow to share information with the City and telecom, slowing the recovery process (Abrams and Lawsky 48, 51). LDCs should continue to strengthen relationships and communications between other levels of government and services in their community, and continue to incorporate their plans into regional emergency protocols. After Sandy, ConEd now invites municipal partners to participate in yearly drills. The City of New York now has access to a private site that will provide decision makers with in-depth and real-time information from ConEd’s network (ConEd, *Post Sandy Enhancement Plan* 16-17). Caution here is due: providing detailed, technical information to other decision makers can politicize the process, send mixed messages to the public, and create liability by spreading misinterpreted information. LDCs should keep their municipal colleagues informed, but should not provide so much information to jeopardize restoration and the provision of accurate information.

Other recommendations arising from Sandy include joint exercises amongst utilities, common communications and coordination protocols to expedite recovery, sharing information and open protocols between all utilities (cable TV, telephone, internet, and electricity) to improve condition awareness, and the allocation of contractors as well as distributor assets before a storm on a regional level (Abrams and Lawsky 48-53). During the 2013 Ice Storm, Veridian found that designating one person as a point-of-contact for municipalities was effective, along with ongoing teleconferences between that LDC and its municipal partners (11).

Distributors can call on other utilities in unaffected areas to help in the restoration of power. The practice of mutual aid is standard in North America. It can decrease interruption times during localized events, like the Goderich Tornado. Wide-scale events like Sandy stress the mutual aid system. Many utilities are reluctant to share their resources until witnessing the effects of an event in their own community, leading to competition for scarce emergency contractors. On the eve of Sandy, only 32 of 1,800 requested workers were at ConEd’s disposal (Abrams and Lawsky 49), in part because of the logistical difficulty of transporting crews from the West Coast (Toronto Hydro Independent Review Panel 38). Toronto’s experience with the 2014 Ice Storm was much different: crews coming from Manitoba were transported, outfitted, equipped, housed, and deployed within 48 hours (EDA, *The Distributor* 17 Toronto Hydro Independent Review Panel 38).

5.0: Customer Attitudes

5.1 Climate Change

Consumers will have access to a plethora of new technology over the coming years that will help mitigate their energy consumption. The *LTEP* projects that residential intensity will drop by 4 MWh/hh from 1990 levels by 2031. Intensity will also fall in commercial and industrial sectors (12). Is the average consumer changing their consumption patterns in response to climate change?

Since 2007, Environics has conducted research on Canadian attitudes towards climate change. They found that as of late 2013:

- 60% of Canadians believe that science proves that global warming is caused by humans; 23% do not believe the science is conclusive, while 13 % do not believe that global warming is occurring;
- Of those who do not believe in global warming, 45% believe no action should be taken until more scientific evidence emerges;
- Only 13% of Canadians believe that adjustment in consumer lifestyles is the best way to address climate change. This number has steadily declined since 2007. Canadians are looking to institutions – 60%-50% to government, 17% to 20% to industry – to lead the way;
- 56% believe that we are not ready to move ahead with known solutions to climate change; and,
- Only 24% of Canadian consumers were willing to pay a premium for renewable generation (2-6).

Consumers seem to continue to believe that climate change is an institutional issue. Ignorance, uncertainty, deference towards government, perception of global warming as a distant threat, financial constraints, unwillingness to sacrifice, and the concept of the tragedy of the commons may explain the public's hesitation to "take the lead" (Gifford 291-297).

The challenge of building a resilient network is that its value is only apparent to the customer during crisis. Hardening and building resiliency is inherently a speculative exercise. Since resiliency is more expensive than reliability, already significant cost pressures will likely lessen the acceptance of these investments (United States, "Framework" 9, 26).

It is likely that much of the reduction in residential intensity will be a result of new building codes and energy efficient appliances replacing older, less environmentally friendly options. The move towards greater efficiency will likely come from regulation and passively reducing energy intensity, not the desire to reduce emissions or build resiliency.

If electricity costs rise and the number and duration of outages cause significant economic harm to the family or business, consumers will likely react by reducing demand, buying generators, or creating their own supply. Perhaps one argument against resiliency (and for

continued focus on reliability) is that economically rational individuals will respond and take responsibility to protect themselves. It may be that it will be the responsibility of the distributor to build a reliable grid and focus on resiliency through emergency response, while consumers own assets for outage contingencies. Providing customers with emergency generators or building local CHP facilities may be cheaper than hardening the distribution system.

5.2 Severe Weather: Customer Impact Costs

Severe weather interruptions present unique challenges to LDC crews. Unlike a localized outage, restoring the grid becomes part of a much larger process to get society moving again. A residential customer is faced with longer outages as distributors focus on high-priority customers – hospitals, utilities, roads, and transit – are reconnected. Extended outages cause greater risk to human health and safety such as documented cases of carbon monoxide poisoning from extended, improper use of generators. Industrial and commercial customers – even if they have electricity – may be required to implement emergency demand response and curtailment. The cost of severe weather is both the direct economic and infrastructure implications and the indirect, non-GDP related effects like health.

Consumer assets are also at risk during severe weather. Many consumers are unaware that they are responsible for their connection to the LDC assets. In Milton, customers struggled to find workers to reconnect them to the grid. Although Milton Hydro provided a list of ESA approved contractors, many were unavailable or refused to work (Milton Hydro 13). After Sandy, New York City sent teams of city inspectors and contractors to provide temporary or expedite complete restoration of power where failure existed on the customer side (United States, *Comparing* 38). The ESA, local contractors, LDCs, and municipal officials may consider establishing emergency plans that include multidisciplinary teams to reduce the length and hardship caused by interruptions at the customer side. The ESA could make contractors pledge to participate during states of emergency as part of their certification. No legislation mandates that contractors or electricians participate in the restoration of power; indeed the *Emergency Management and Civil Protection Act (Ontario)* prohibits it (McCabe 17).

5.3 Severe Weather: Communicating with Customers

Communication is essential during a crisis. Contingencies must be in place to address the massive influx of calls during a sustained and widespread interruption. During the 2013 Ice Storm, Toronto Hydro averaged 37,000 calls a day for 10 days; Milton Hydro received 3,500 calls on December 22 to the company's 16 phone lines (11-12). The Electrical Distribution Association acknowledged that "bottlenecks" existed communicating with the public amongst many of its members (*The Distributor* 8).

In addition to voice calls, mobile devices allow customers to access the Internet during interruptions. They are increasingly turning to company websites for information. During severe weather, smartphone users have a limited window to access the Internet. Their experience so far has been of glitches, slow loading, and outright downtime in New York area utilities during Sandy (Abrams and Lawsky 47-48). LDC websites were slow and often out-of-date during the 2013 Ice Storm. This was due in part to the volume of visitors: Burlington Hydro experienced a

40-fold increase in their website traffic; while Hydro One's website had over 500,000 visits (EDA *The Distributor* 22). As the Toronto Hydro Independent Review Panel noted, LDCs must ensure that digital information is timely, correct, and monitored (68-69).

We believe that into the future customers will increasingly turn to social media to communicate with LDCs. Accenture found that 50% of consumers would be encouraged to use social media if they received quick and convenient service (28). Horizon has stated that "social media is proving to be an invaluable tool for connecting with our customers, and this was never more apparent than during the two major storms in 2013 (Horizon 11)." Waterloo North, Milton Hydro Guelph, Haldimand, Halton Hills, and Veridian experienced significant increases in social media engagement (Milton Hydro 14, EDA *The Distributor* 22). Hydro One's iPhone application became one of the "top downloads" on iTunes (*The Distributor* 22). In the future, LDCs will reach out to their customers more and more on Facebook, Twitter, SMS, e-mails, and apps.

Innovation in consumer technology is accelerating at an increasing pace. Technological integration in watches, glasses, "big data," and smart homes may allow for two-way transmission – giving utilities the ability to assess storm damage down to the household level. If these devices maintain battery supply, communications may become inseparable from restoration operations. LDCs could receive localized system status from users, then conceivably "push" information to them – changing the communications paradigm with individual customers from reactive to proactive communication.

Although digital communication may become more important than traditional call centre operations, there will always likely be a need that some people will want to speak to a live agent. Although their call centre was overwhelmed with queries, Toronto Hydro relied on a private call centre for non-outage related calls, relieving some pressure on their telephone systems during the 2013 ice storm (Toronto Hydro Independent Review Panel 60-61, 63). There may be an opportunity to contract private sources to handle overflow during a mass outage, or arranging a "mutual assistance" plan for call centres.

The most important piece of information that can be provided to a customer is the estimated time of restoration. ETRs allow consumers to make rational choices; families will act differently if they know the power will be out for a week. After Sandy, utilities struggled with providing accurate and timely ETRs (Abrams and Lawsky 47-48). Toronto Hydro struggled to provide this information during the 2013 Ice Storm (Toronto Hydro Independent Review Panel 47-48). LDCs should aim to provide accurate ETR information as quickly as possible.

Appendix: Ontario Climate Data

Sources
Bourdages and Huard, Consortium on Regional Climatology and Adaptation to Climate Change.
Colombo et. al., Government of Ontario. Ministry of Natural Resources.
McBean and Henstra.
Ontario, Ministry of the Environment. Expert Panel on Climate Change Adaptation.
Bruce.

Projection	Change by 2050s	... from XXXX levels	Impact trends
Average Daily Temperature	+3°C to +4°C	1980-1989	Uniform
	+2.5°C to +5°C		Gradient: Northeast (greater) to Southwest
Average Daily Max Temperature	+2°C to +4°C	1980-1989	Gradient: East(greater) to West
	+2.3°C to +4°C	1961-1990	Gradient: Northeast (greater) to Southwest
	Very likely	2003	N/A
Difference between daily highs and lows	>-1°C	1980-1989	Gradient: North(greater) to South
	Very likely	2003	N/A
Max Daily Mean Temperature (Warmest Day)	+2°C to +8°C	1980-1989	Uniform
Max Daily Mean Temperature (Coldest Day)	+4°C to +7°C	1980-1989	Gradient: Northeast (greater) to Southwest
Summer (June-August)	+1°C to +4°C	1980-1989	Uniform
	+1°C to +4°C	1971-2000	Uniform
	+2.1°C to +2.6°C	1961-1990	Uniform
	+2°C to +4°C	2010	Gradient: Northeast (greater) to Southwest
Winter (Mid-December – Mid-March)	+4°C to +6°C	1980-1989	Gradient: Northeast (greater) to Southwest
	+3°C to +7°C	1971-2000	Gradient: Northeast (greater) to Southwest
	+2.8°C to +7°C	1961-1990	Gradient: North (greater) to South
	+2°C to +6°C		Gradient: Northeast (greater) to Southwest
Heat Waves per year (3 consecutive days over 32°C)	+0 to +2.5 (+2 for Toronto)	1980-1989	Gradient: South(greater) to North
Increase in Heat Index	Very likely	2003	
Annual Precipitation	+3% to +12%	1980-1989	Gradient: Northeast (greater) to Southwest
	+3.5% to +14%	1961-1990	Gradient: Northeast (greater) to Southwest

	+5% to +15%	2010	Gradient: North (greater) to South
Precipitation - Summer	+10% (North) -10% to -20% (South)	1980-1989	Gradient: Northeast (greater) to Southwest
	-10% to +0% (North) -10% (South)	1971-2000	N/A
	5 to 20% (South) 0% to +10% (North)	2010	
Precipitation - Winter	+20% to +30%	1980-1989	Uniform
	-30% to +20% (North) -10% (South)	1971-2000	N/A
	+10% to +29% (North) +10% to +7% (South)	1961-1990	Gradient: North (greater) to South
	+10% to +30% (North) +5% to +20% (South)	2010	
Days below 0°C	45 to 28 days less	1980-1989	Gradient: South(greater) to North
Length of First Snow Period (Days from July 1 – Dec 31. with more than 10cm of snow on the ground)	8 to 13 days less	1980-1989	Uniform
Length of Second Snow Period (Days from Jan. 1 – June 30th with more than 10cm of snow on the ground)	0 to 25 days less	1980-1989	Higher in Southern and Far Northern Ontario Lower in the remainder of Northern Ontario
Length of Snow Period	15 to 30 days less	1980	Gradient: South(greater) to North
Freezing Rain	60%-85% increase of events (North) 40%-65% (South)	1965-2005	N/A
Extreme weather	Increasing, Very Likely.		
	“Observations have not yet clearly shown that the frequency of extreme events is increasing in Ontario, but... [they] can be expected [to increase]...”		
	Intense precipitation events to nearly double in frequency; increase 5 to 10% in severity.		

The Future of the Distribution Sector: Climate Change

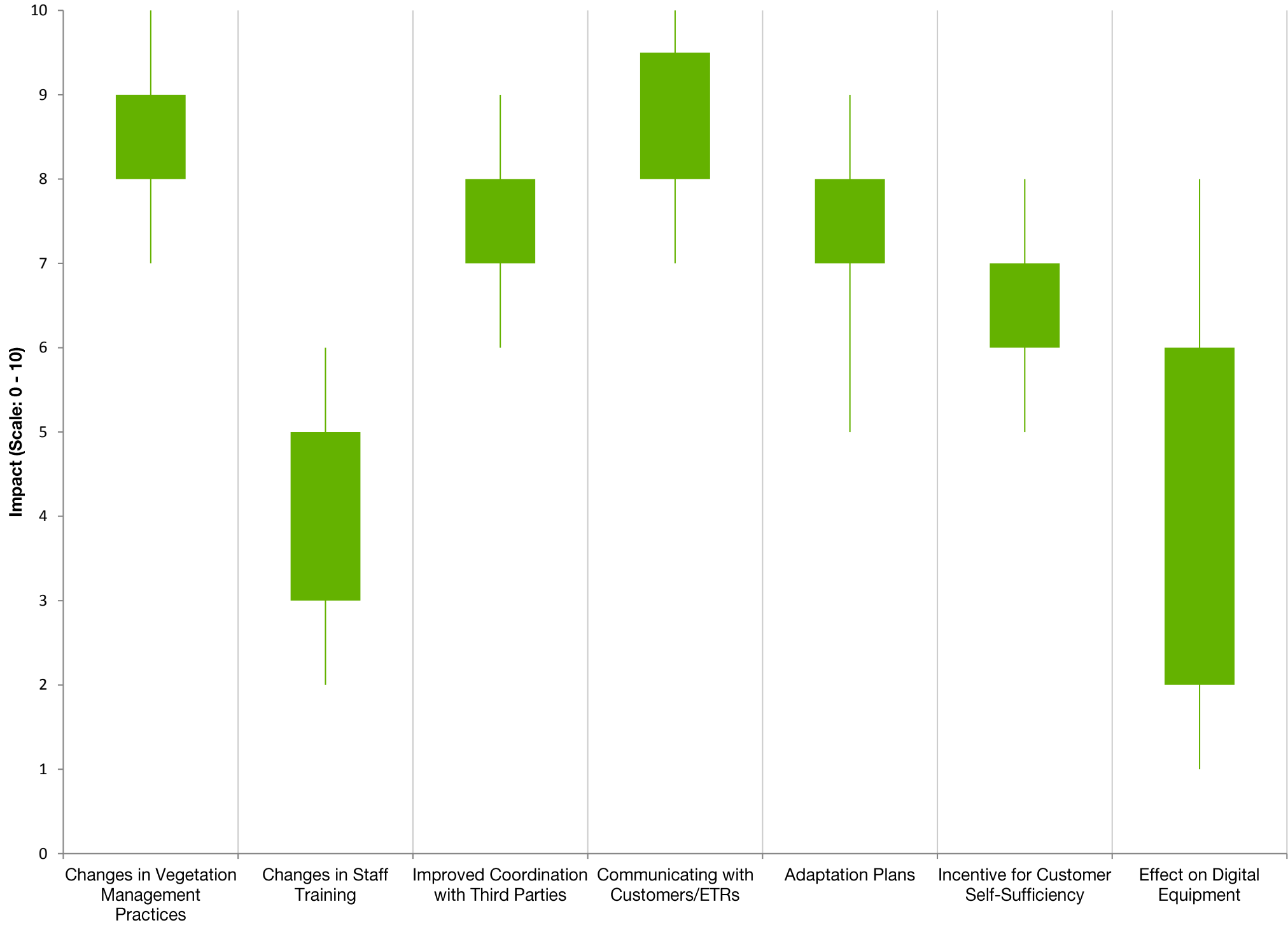
Visual:

An analysis of the predicted impact of climate change on the LDC sector. Projected importance is ranked from one to ten on the vertical axis. Each topic on the horizontal axis includes a “bar and line.” The line represents the possible range of the topic’s importance, while the bar represents our predicted importance.

Observations

- The projected increase of severe weather represents the greatest climate challenge faced by LDCs;
- All participants in the sector need an adaptation strategy that addresses matters such as asset management, equipment standards, higher insurance premiums, staff implications, and customer needs;
- New smart grid technologies such as smart meters, weather modeling, advanced distribution management systems, and remotely controlled switching can help LDCs to prepare for, mobilize a response to, and minimize damage from events that disrupt supply;
- Hardening all distribution infrastructure is a costly proposition. Building a resilient system can include cost-effective investments, better staff training, improved mobilization, and consumer investments in resiliency;
- Climate change may encourage customers to seek greater electricity independence through batteries, solar panels, and other backup solutions;
- The sector will continue to balance investing in equipment that meets code requirements with the need to be flexible and occasionally install more robust infrastructure, depending on local conditions;
- Vegetation management will become more important;
- Coordination between the sector and other public entities during a major event is important; and,
- LDCs need to work on improving customer communication and timely Estimated Times to Restoration during outages.

Climate Change Importance Predictions





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