Resilience in the electricity distribution sector and related policy questions

prepared by London Economics International LLC for the Ontario Energy Board

June 9th, 2023[1]

London Economics International LLC ("LEI") was engaged by the Ontario Energy Board ("OEB") to analyze and define resilience within the context of climate change and assess related policy questions as they apply to electricity distributors in Ontario. This report assesses the evolution of extreme weather events in Ontario and the outlook for future climate change impacts across the province, as well as the attendant risks to electricity infrastructure. Through a literature review of key resilience issues in the power sector and several case study examples, we then develop a set of ten recommended steps to begin addressing resiliency concerns in the province:

1. *convene a cross-government, multi-sector advisory body;*
2. *develop a common analytical framework;*
3. *agree on key input values;*
4. *assess customer needs;*
5. *identify key failure points via a comprehensive system inventory;*
6. *consider the role of back-up analogue solutions;*
7. *determine areas for potential co-funding or burden-sharing;*
8. *require each utility to file a multi-year resiliency strategy;*
9. *allocate funding via existing capital funding mechanisms; and*
10. *implement, monitor, and verify.*

Table of contents

[1] Content as of March 1st, 2023.

Table of figures

List of acronyms

ACM	Advanced Capital Module
AER	Australian Energy Regulator
BEIS	Department for Business, Energy & Industrial Strategy
CAISO	California Independent System Operator
CMEP	Community Microgrid Enablement Program
ConEd	Consolidated Edison Company of New York, Inc.
CPUC	California Public Utilities Commission
DER	Distributed energy resource
DNO	Distribution network operator
DNSP	Distribution network service provider
DOE	US Department of Energy
DSO	Distribution system operator
DSP	Distribution system plan
E3C	Energy Emergencies Executive Committee
EA	Finnish Energy Authority
EEA-3	Energy Emergency Alert Level 3
EMA	Finnish Electricity Market Act
EPE	El Paso Electric
EPRI	Electric Power Research Institute
ERA	Economic Regulation Authority, Western Australia
ERCOT	Electric Reliability Council of Texas
ESF	Economic Stabilization Fund
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
HVAC	Heating, ventilation, and air conditioning
IBC	Insurance Bureau of Canada
ICM	Incremental Capital Module
IEA	International Energy Agency
IESO	Independent Electricity System Operator
IIS	Interruptions Incentive Scheme
IOU	Investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IR	Incentive rate-setting
ISO	Independent System Operator
LBNL	Lawrence Berkeley National Laboratory

LDC	Local distribution company
LEI	London Economics International LLC
NARUC	National Association of Regulatory Utility Commissioners
NER	National Electricity Rules
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NSW	New South Wales
NY PSC	New York Public Service Commission
NYISO	New York Independent System Operator
NYS	New York State
NYSERDA	New York State Energy Research and Development Authority
OEB	Ontario Energy Board
OEIS	Office of Energy Infrastructure Safety
Ofgem	Office of Gas and Electricity Markets
PG&E	Pacific Gas and Electric
PJM	PJM Interconnection
PUCT	Public Utility Commission of Texas
QCA	Queensland Competition Authority
RAV	Regulatory asset value
ROE	Return on equity
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SSP	Shared Socio-economic Pathway
STPIS	Service Target Performance Incentive Scheme
UK	United Kingdom
VoLL	Value of Lost Load

1 Introduction

London Economics International LLC ("LEI") was engaged by the Ontario Energy Board ("OEB") to analyze and define resilience within the context of climate change and assess related policy questions as they apply to electricity distributors in Ontario. This report is intended to facilitate stakeholder discussions as part of the OEB's Distribution Sector Resilience, Responsiveness & Cost Efficiency consultation (EB-2023-0003), which was launched on January 25th, 2023, in response to one of the near-term priorities outlined in the Minister of Energy's Letter of Direction.[2] The consultation is expected to culminate in a report by the OEB to the Minister of Energy, providing the OEB's advice and proposals to improve distribution sector resiliency, responsiveness, and cost efficiency in an environment of more frequent extreme weather events.

This report begins by assessing the evolution of extreme weather events in Ontario, as well as the outlook for future climate change impacts across the province, and the attendant risks to electricity infrastructure. Through a literature review of key resilience issues in the power sector and several case study examples of how resiliency is being addressed in other jurisdictions, we then develop a set of recommended best practices, principles, and optimal approaches to:

- **defining resiliency and implementing resilience expectations** for electricity distributors;
- **the appropriate division of responsibility for resilience and continuity of service** between utilities, customers, and other agencies or government authorities at the local, provincial, or federal levels;
- **specific regulatory policies** regarding adaptation to elevated service risks stemming from extreme weather events, particularly in the context of increased electrification;
- **regulatory tools and methods for determining appropriate and cost-effective levels of investments**, spending, planning, and operations surrounding resiliency; and
- **assessing gaps, opportunities, and relevant building blocks** in the existing regulatory framework associated with resiliency.

Although the Minister's Letter of Direction encourages the OEB to leverage insights from the Ministry of Environment, Conservation and Parks' Provincial Climate Change Impact Assessment report, LEI notes that it has not yet been released,[3] and thus was not considered in coming to our conclusions.

[2] Ontario Ministry of Energy. *Letter of Direction from the Minister of Energy to the Chair.* October 21, 2022.

[3] An initial press release announcing the launch of the project was issued on August 14th, 2020 (*see* *Ontario Launches First-Ever Climate Change Impact Assessment*). The project will culminate in a final report which is expected to be released this year.

2 Defining resiliency

While the concept of reliability in the power sector is widely accepted,[4] with reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC"), resiliency is less clearly defined.

To develop a working definition and common understanding of resiliency for the remainder of this report, LEI reviewed the various definitions put forth by agencies across North America. In Canada, this includes the Independent Electricity System Operator ("IESO"), Emergency Management Ontario, and Electricity Canada – see Figure 1.

Figure 1. Definitions of resiliency among various Canadian agencies

Agency	Definition	Source
IESO	"the ability to reduce the magnitude and duration of disruptive events, to bounce back more quickly and more strongly, and to adapt and be prepared for potential future events."	Power Perspectives: Today's Challenges, Tomorrow's Opportunities (2019)
Emergency Management Ontario	"The ability to resist, absorb, accommodate and recover from the effects of a hazard in a timely and efficient manner."	Emergency management glossary of terms (2022)
Electricity Canada	"The [Intergovernmental Panel on Climate Change] describes resilience as "the amount of change that a system can undergo without changing state.""	Adapting to Climate Change: A Risk Management Guide for Utilities (2019)

In the United States, LEI reviewed the different resiliency definitions used by several agencies, which we have grouped into the following categories (see Figure 2):

- **the federal government:** a Presidential Policy Directive issued by then President Barack Obama, the US Department of Energy ("DOE"), the Federal Energy Regulatory Commission ("FERC"), and the National Renewable Energy Laboratory ("NREL");
- **reliability coordinators/independent system operators ("ISOs"):** NERC and the PJM Interconnection ("PJM");
- **industry associations:** the National Association of Regulatory Utility Commissioners ("NARUC") and the Electric Power Research Institute ("EPRI"); and
- **state regulators:** the New York Public Service Commission ("NY PSC") and California Public Utilities Commission ("CPUC").

[4] NERC defines reliable operation as "[o]perating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." (Source: NERC. *Glossary of Terms Used in NERC Reliability Standards.* Updated December 2, 2022)

Figure 2. Definitions of resiliency among various US agencies

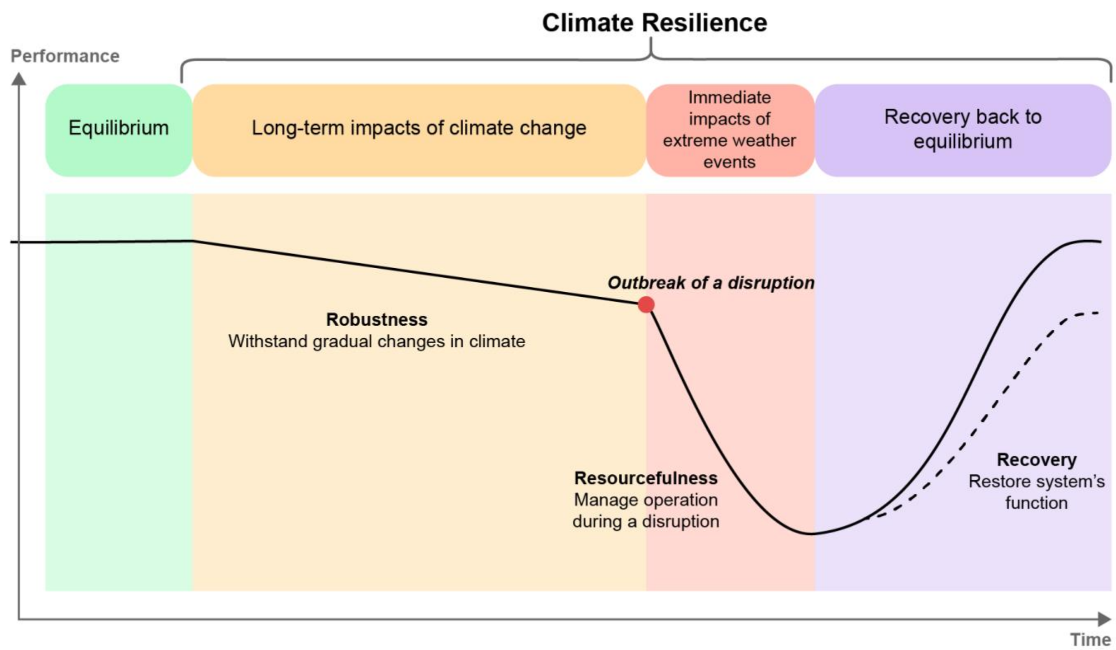
Agency	Definition	Source
Federal government		
The White House (under President Obama)	"the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, … [including] deliberate attacks, accidents, or naturally occurring threats or incidents."	Presidential Policy Directive – Critical Infrastructure Security and Resilience (2013)
US DOE	"the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions."	Quadrennial Energy Review Second Installment: Transforming the Nation's Electricity System (2017)
FERC	"The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."	Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, Docket Nos. RM18-1-000 and AD18-7-000 (2018)
NREL	"The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions to the power sector through adaptable and holistic planning and technical solutions."	Planning a Resilient Power Sector (2019)
Reliability coordinators/ISOs		
NERC	"Four outcome-based abilities of resilience are included as follows: • Robustness – the ability to absorb shocks and continue operating • Resourcefulness – the ability to detect and manage a crisis as it unfolds • Rapid recovery – the ability to get services back as quickly as possible in a coordinated and controlled manner and taking into consideration the extent of the damage • Adaptability – the ability to incorporate lessons learned from past events to improve resilience"	Reliability Issues Steering Committee – Report on Resilience (2018)
PJM	"Resilience, in the context of the bulk electric system, relates to preparing for, operating through and recovering from a high-impact, low-frequency event. Resilience is remaining reliable even during these events."	PJM's Evolving Resource Mix and System Reliability (2017)
Industry associations		
NARUC	"At its core, resilience is the ability to withstand and recover from an incident, be it weather, cyber, or other event."	Regulator's Financial Toolbox: Resilience Technologies Brief (2021)
EPRI	"the ability to withstand extreme (high impact, low frequency) events, with minimal interruption to the supply of electricity and enabling a quick recovery. Resiliency can encompass the following forms: Damage Prevention, Easier Repair, Isolation and Reconfiguration, Recovery, Community Sustainability."	Enhancing Energy System Reliability and Resiliency in a Net-Zero Economy (2022)
State regulators		
NYPSC	"the ability of a system to withstand shocks and stresses while still maintaining its essential functions."	Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case Nos. 13-E-0030 et al (2014)
CPUC	"the ability of the electric grid to withstand, adapt to, and recover from large-scale disruptive events. It is a distinct subset of electric system reliability, which more broadly refers to the reliable functioning of the electric grid."	Introduction to the North Coast Resiliency Initiative (2022)

Despite variations in wording across the definitions reviewed, two common elements emerge:

- **type of event:** resiliency commonly refers to the electric system's ability to respond to high-impact, low-frequency disruptive events, which can include natural disasters or cyber-attacks, for example. In this sense, whereas reliability standards and metrics focus more on low-impact, high-frequency disruptions (i.e., shorter duration outages that often exclude major events), resiliency deals with major events that cause longer duration outages and potentially longer-term impacts on the system (such as reducing the useful life of equipment as a result of event-related damage); and

- **response over time:** resiliency commonly refers to not only the electric system's response during a disruptive event, but also the activities undertaken prior to and following such events, hence the inclusion of words such as "prepare" or "anticipate" (before), "absorb" or "withstand" (during), and "recover" or "adapt" (after) in many definitions. Figure 3 illustrates this concept.

Figure 3. Timeline of climate resilience activities



Source: IEA. *Climate Resiliency: Electricity Security 2021.* April 2021.

For the purposes of this report, which focuses on Ontario's electricity distribution sector, LEI utilizes the following definition:

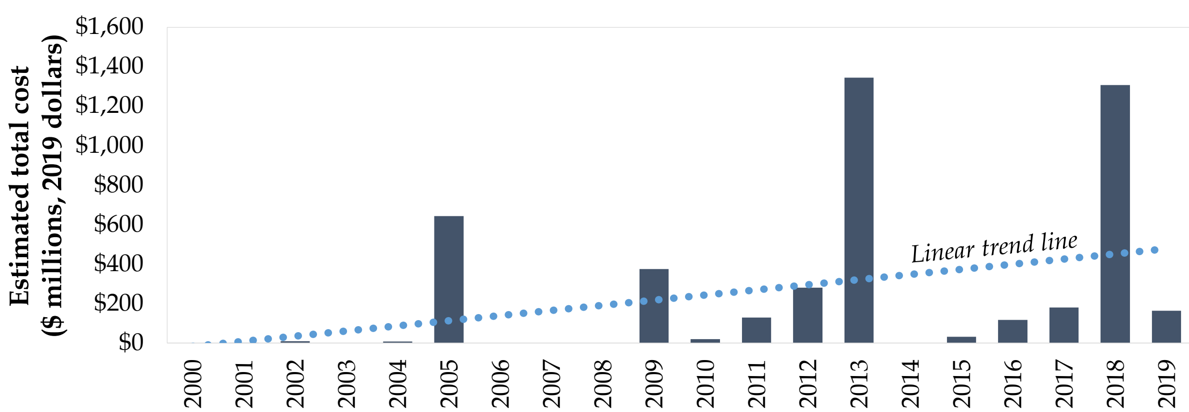
Resiliency: the ability of the electricity distribution network to respond to high-impact, low-frequency disruptions by adequately preparing for, withstanding, rapidly recovering from, and adapting to these events.

3 Evolution of weather events in Ontario

Extreme weather events have become increasingly frequent and costly in recent years. In Canada, insured catastrophic losses have risen from around $456 million per year on average over the late 1990s and early 2000s, to "routinely exceeding" $2 billion per year according to the Insurance Bureau of Canada ("IBC"), most of which is due to water-related damage. In 2022, insured losses across the country related to severe weather totaled $3.1 billion.[5] This accounts for only a portion of total losses, as IBC estimates that for every dollar of insured loss, there are between three to four dollars in uninsured losses borne by governments, homeowners, and business owners.[6]

A similar trend has been observed in Ontario. For example, using data from Public Safety Canada's Canadian Disaster Database, the estimated total cost of natural disasters in Ontario has increased from $104 million (in 2019 dollars) per year on average over the 2000-2009 period to over $357 million (in 2019 dollars) per year on average over the 2010-2019 period (the most recent year available in the database) – see Figure 4. As another example, eight of the top ten most costly natural disasters in the province over the 2000-2019 period occurred after 2010 – see Figure 5 for details on each of these events. Using more recent data from IBC, insured losses related to severe weather in Ontario climbed to $400 million in 2021 and $1.2 billion in 2022 (preliminary data).[7] The 2022 total includes over $720 million in insured losses from the derecho in May – a powerful windstorm that was accompanied by hail and torrential rain – that predominantly affected southern Ontario, causing extensive property damage, power outages, and loss of life.[8]

Figure 4. Estimated annual total cost of natural disasters in Ontario, 2000-2019



Note: 2019 is the most recent year for which data is available in the Canadian Disaster Database.

Source: Public Safety Canada. *The Canadian Disaster Database.* Last updated November 10, 2022.

[5] IBC. *Severe Weather in 2022 Caused $3.1 Billion in Insured Damage – making it the 3rd Worst Year for Insured Damage in Canadian History.* January 18, 2023.

[6] IBC. *Combatting Canada's Rising Flood Costs: Natural infrastructure is an underutilized option.* September 17, 2018.

[7] IBC. *IBC applauds the Government of Ontario on its first Emergency Management Strategy and Action Plan.* February 3, 2023.

[8] IBC. *Derecho Storm Ranks 6th Largest Insured Loss Event in Canadian History.* June 15, 2022.

Figure 5. Top ten most costly natural disasters in Ontario, 2000-2019

No.	Location	Event start date	Description	Estimated total cost
1	Toronto	July 8, 2013	A thunderstorm that produced 126 mm in precipitation caused flash-flooding in the Greater Toronto area. The flooding closed multiple transportation corridors, caused widespread property damage, and disrupted power to approximately 800,000 customers.	$940 million
2	Southern Ontario	May 4, 2018	The Highway 401 corridor through southern Ontario and southern Quebec experienced a fast-moving squall line with wind gusts of over 100 km/hr. The windstorm caused widespread power outages, roof damage and downed trees. Over 925,000 customers across Ontario and Quebec were without power; some were without power until May 9.	$680 million
3	Southern Ontario	August 19, 2005	A series of severe thunderstorms tracked eastward across southern Ontario from Kitchener to Oshawa. The system spawned two F2 tornadoes with gusts between 180-250 km/h. The tornadoes downed power lines, leaving around 10,000 customers without power, uprooted trees, ripped into several homes, cottages and barns, and overturned vehicles. Within one hour, torrential rains dumped 103 mm in North York, 100 mm in Downsview and 175 mm in Thornhill, leading to flash flooding.	$500 million
4	National Capital Region	September 21, 2018	6 tornadoes touched down in and near the National Capital Region. The strongest was an EF-3 tornado (estimated wind speeds up to 265 km/hr), as well as an EF-2 tornado (up to 220 km/hr), and four EF-1 tornadoes (between 138-177 km/hr). Over 300,000 customers in Ottawa, Gatineau, and Eastern Ontario were without power.	$334 million
5	Southern Ontario	December 21, 2013	A severe storm brought freezing rain and damaging ice accumulation across a large area of southern Ontario, which was further exacerbated by freezing temperatures. The ice storm left as many as 830,000 customers across Southern Ontario without power for several days.	$263 million
6	Thunder Bay	May 28, 2012	Heavy rain and subsequent flooding caused the city of Thunder Bay to declare a state of emergency. The flooding caused road closures, damage to thousands of homes, and interfered with utility services. Thunder Bay Hydro cut power to 50 customers as a precaution to prevent electrical fires in severely flooded areas.	$242 million
7	Southern Ontario	April 14, 2018	A large winter storm with high winds, heavy snow and ice accumulation affected parts of southern Ontario and southern Quebec. In Ontario, severed power lines caused outages for approximately 375,000 customers.	$190 million
8	Hamilton and Toronto	July 26, 2009	A storm cell stalled over the western end of Lake Ontario. Thunderstorms in Hamilton flooded basements and caused road closures.	$173 million
9	Windsor	August 28, 2017	Rain began to fall on August 28th and within 48 hours, 222 mm fell southwest of Windsor, 140-200 mm in Riverside-Tecumseh, and 285 mm in Lasalle.	$173 million
10	Eastern Canada	March 14, 2019	A significant low-pressure system tracked through Ontario, Quebec, New Brunswick and Nova Scotia. The winter storm produced warm temperatures and rain which caused significant flooding in parts of Ontario such as Bolton and Caledon along the Humber River, and in Quebec.	$124 million

Source: Public Safety Canada. *The Canadian Disaster Database.* Last updated November 10, 2022.

This trend of more frequent and damaging extreme weather events in the province is expected to continue going forward as a result of climate change. In August 2022, Natural Resources Canada released a Regional Perspectives Report focusing on climate change impacts in Ontario, which finds:

> "temperatures are increasing in the province, with the greatest warming observed in Northern Ontario and the largest increases occurring in the winter. With further warming, heat waves are projected to become more frequent. Annual precipitation is projected to increase along with extreme precipitation events, resulting in increased risk of flooding. Lake levels in the Great Lakes have been highly variable, experiencing both record lows and extreme highs. These changes are affecting Ontario's communities, environment and economy."[9]

The report further observes:

> "Canada's climate is warming at a rate about twice that of the global average. Ontario's mean annual temperature increased by 1.3ºC between 1948 and 2016, with mean annual precipitation increasing by 9.7% over the same period. Climate model projections indicate that these changes will continue, highlighting that the risks currently presented by climate change will become even greater in the future."[10] [citations omitted]

Figure 6 on the following page compares the number of hot days (above 30°C) experienced in the province historically (1951-2020) against the anticipated change through 2080, based on the high emissions scenario[11] of the CMIP6 (i.e., the sixth phase of the Coupled Model Intercomparison Project), a climate model used by the United Nations' Intergovernmental Panel on Climate Change ("IPCC").[12] Averaging across the province, the number of days where temperatures exceed 30°C is expected to increase from 23 days per year historically (1951-2020) to 51 days per year over the 2021-2050 period and 77 days per year over the 2051-2080 period.[13]

Figure 7 on the following page shows a similar comparison between historical (1951-2020) and projected data (2021-2050 and 2051-2080), this time for heavy precipitation days (more than 20 mm) in Ontario. Averaging across the province, the number of days where precipitation exceeds 20 mm is expected to increase from 2.8 days per year historically (1951-2020) to 3.4 days per year over the 2021-2050 period and 3.9 days per year over the 2051-2080 period.[14]

---

[9] Natural Resources Canada. *Minister Wilkinson Releases New Report Showing the Impacts of Climate Change and Necessity of Climate Adaptation in Ontario.* August 15, 2022.

[10] Natural Resources Canada. *Chapter 3: Ontario (in Canada in a Changing Climate: Regional Perspectives Report).* August 15, 2022.

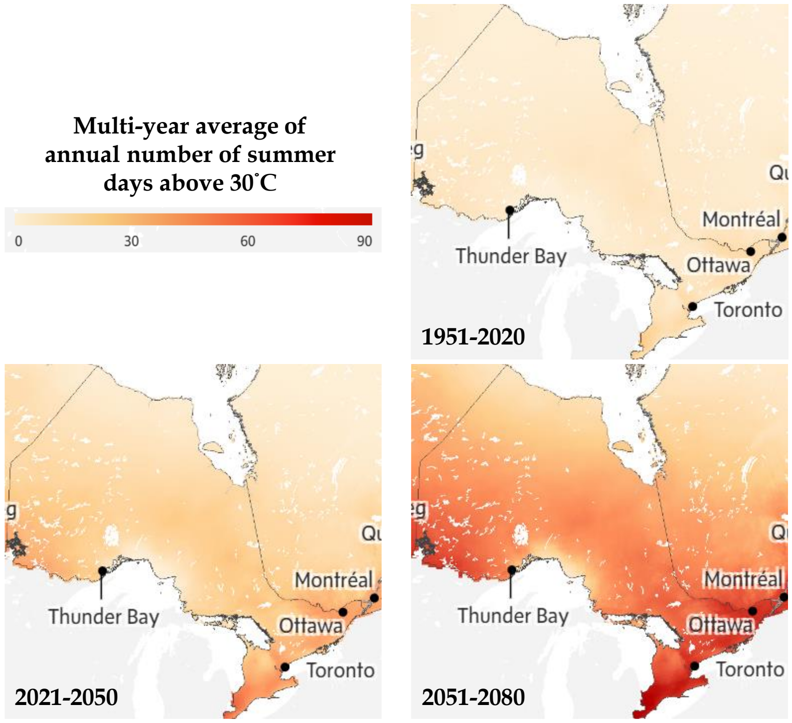
[11] Shared Socio-economic Pathway ("SSP") 5-8.5.

[12] Government of Canada. *CMIP6 and Shared Socio-economic Pathways overview.* Last updated January 17, 2023.

[13] Canadian Centre for Climate Services. *Climate Atlas of Canada.*

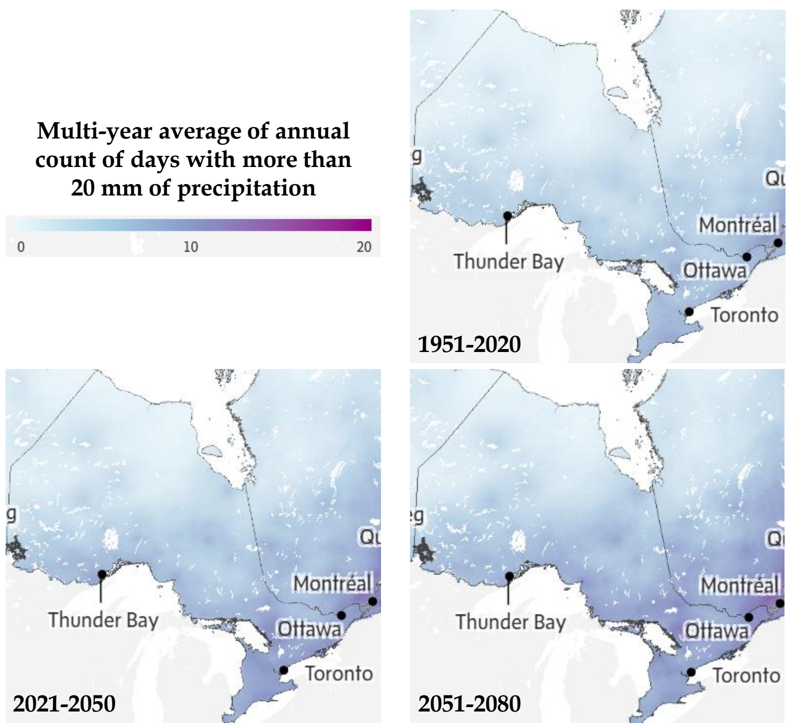
[14] Ibid.

Figure 6. Ontario hot days – historical (1951-2020) and projections (through 2080)



Source: The Globe and Mail. [*Code minimum: Why your home isn't built to last against extreme weather.*]() January 27, 2023.

Figure 7. Ontario heavy precipitation days – historical (1951-2020) and projections (through 2080)

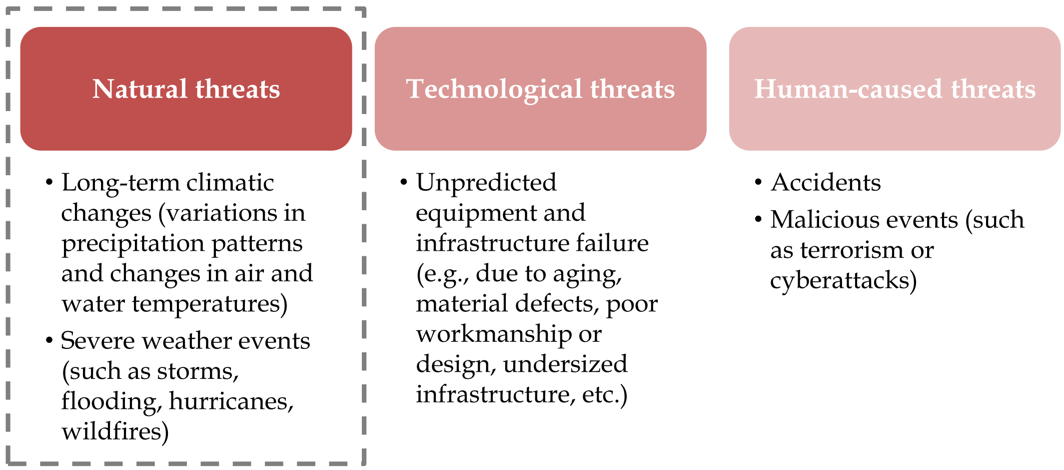


Source: The Globe and Mail. [*Code minimum: Why your home isn't built to last against extreme weather.*]() January 27, 2023.

4 Risks to electricity distribution infrastructure

Extreme weather events arising from climate change pose attendant risks to electricity infrastructure. While climate change impacts are only a subset of potential threats to the power system (see Figure 8), they are nonetheless the focus of this report.

Figure 8. Categories of threats to electricity infrastructure



Source: NREL. *Power Sector Resilience Planning Guidebook: A Self-Guided Reference for Practitioners.* June 2019.

As recognized by Electricity Canada in a 2019 risk management guide for utilities:

> "The [IPCC] suggests that the electricity sector is one of the sectors most at risk of disruption from climate change. ... The effects of climate change and extreme weather can have direct and indirect impacts on infrastructure. Examples of direct impacts include ice accretion and lightning strikes on overhead conductors, wind damage, premature aging, and conductor sag and annealing.[15] Indirect impacts include changes to vegetation management, ice road integrity, vector-borne disease, and supply chain issues, as well as precipitation overwhelming riverine and urban drainage systems, resulting in flooding. Changes to climate ... may affect natural systems that control snow cover, frost depth, permafrost, ice cover on waterways, and lake-effect snow, which may, in turn, affect the integrity of infrastructure."[16]

---

[15] Increased frequency of extreme temperatures may lead to premature aging of distribution infrastructure – for example, overheating can cause annealing of overhead conductors. Annealing "is the metallurgical process where applied temperature softens a hardened metal resulting in loss of tensile strength." (Source: PJM. *Transmission Owner Guidelines: VI.A. Bare Overhead Transmission Conductor Ratings.* October 2022)

[16] Electricity Canada. *Adapting to Climate Change: A Risk Management Guide for Utilities.* September 16, 2019.

In Ontario to date, four engineering-based climate change risk assessments have been conducted for electricity infrastructure, which provide a sense of the range of natural risks faced by the province.[17] These include:

- **Toronto and Region Conservation's 2015 study:** focused on impacts to the high-voltage transmission system from a range of climate-related hazards (ice storms, tornadoes, high intensity winds, extreme temperatures, and short-duration rainfall). The greatest identified risks were extreme ice accretion and high wind events, which can lead to system-wide outages and require costly repair or replacement of critical infrastructure components. The study also identified high temperatures and heat waves causing transmission lines to sag as a potential risk, and noted that this could become especially dangerous in transportation corridors, where lines may make contact with vehicles;[18]

- **Toronto Hydro's 2012 and 2015 studies:** the 2012 interim study focused on the impacts of current climate conditions in southwestern Ontario on Toronto Hydro-owned electric distribution infrastructure. The study found greatest risks stemming from high winds between 70-90 km/h snapping poles and bringing down overhead conductors, lightning strikes on overhead transformers, and tornadoes causing catastrophic damage to all above ground infrastructure.[19]

  The 2015 study focused on the impacts of a changing climate, with the study period extending from 2015 to 2050. The study identified the following vulnerabilities for Toronto Hydro: extreme daily maximum temperatures of 30°C or more were projected to occur more frequently (from 16 times per year on average historically, to 26 times per year by the 2030s and 47 times per year by the 2050s), limiting power transformer capacity and transmission efficiency; freezing rain, ice storms, high wind and tornado events causing outages due to severely damaged equipment; extreme rainfall events flooding underground feeder assets; de-icing salts applied in response to freezing rain events corroding civil structures; and lightning strikes causing system outages;[20] and

- **Hydro Ottawa's 2019 study:** the study was conducted following three extreme weather events in 2018 (freezing rain, heavy winds, and a series of tornadoes) that damaged Hydro Ottawa's distribution infrastructure and caused widespread outages.[21] The study period extended out to the 2050s and identified very high risks to distribution lines and poles

---

[17] Natural Resources Canada. *Chapter 3: Ontario (in Canada in a Changing Climate: Regional Perspectives Report).* August 15, 2022.

[18] Toronto and Region Conservation. *Climate Change Vulnerability Assessment of Ontario's Electric Transmission Sector.* July 2015.

[19] AECOM. *Toronto Hydro-Electric System Public Infrastructure Engineering Vulnerability Assessment Pilot Case Study.* September 21, 2012.

[20] AECOM. *Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment.* June 2015.

[21] Stantec. *Distribution System Climate Risk and Vulnerability Assessment (Prepared for Hydro Ottawa Limited).* September 11, 2019.

from extreme wind exceeding 120 km/h, daily maximum temperatures exceeding 40°C (which is projected to occur annually), and freezing rain storms that could result in ice accumulation exceeding 40 mm. A separate adaptation plan was also developed to prioritize actions that could mitigate these risks.[22]

There are a variety of resiliency measures that can be implemented to address these climate change-related risks. An essay prepared by the representatives of 17 regulatory bodies across the MISO footprint offers a useful perspective for categorizing resiliency measures, including:

- **event-agnostic physical improvements**, which bolster resilience against most, if not all, types of threats;
- **physical improvements to address specific weather events**; and
- **event-agnostic policy/practice improvements**, which are not physical improvements to infrastructure, but rather changes to policies and practices that bolster resilience regardless of the threat.[23]

Examples of resiliency measures in each of these three categories are listed in Figure 9.

Figure 9. Examples of electricity distribution resiliency measures

Event-agnostic physical improvements	Physical improvements to address specific weather events	Event-agnostic policy/practice improvements
• **Automated components** (smart meters, intelligent switching) to improve **problem detection** as well as **data collection** during an outage • **Protect key communication systems** used during a disaster • **Self-healing grid** components • **Microgrids** for critical facilities • **Replace aging infrastructure** • **Mobile substation equipment** • **DERs** to reduce load during a crisis • **Energy efficiency** to maintain livable conditions for longer periods • **Vegetation management**	• **Undergrounding** distribution lines • **Reinforce** poles • Install **guy wires** (i.e., tensioned cables to add stability to free-standing structures) • Install **hardened** pole-and-line designs and configurations • **Coat lines** to prevent ice buildup • **Elevate substations** • Use **advanced weather-prediction models**	• Develop **response protocols** • Develop **communications protocols** • Participate in **shared inventory/mutual assistance programs** • Develop business continuity and **emergency action plans** • Create **demand response programs** • **Regular testing** of backup generators • Utilize **drones** for damage inspections • **Regular security briefings** on emerging threats • Identify **critical infrastructure** and key resources

Source: Lawrence Berkeley National Laboratory. *Utility Investments in Resilience of Electricity Systems.* April 2019.

[22] Stantec. *Hydro Ottawa Climate Change Adaptation Plan.* November 11, 2019.

[23] Lawrence Berkeley National Laboratory. *Utility Investments in Resilience of Electricity Systems.* April 2019.

5 Provincial and federal policy context

This section provides a high-level overview of several initiatives undertaken at the federal and provincial levels of government to advance climate change adaptation efforts and bolster resilience across various sectors. We also discuss climate change adaptation measures taken by municipalities across Ontario.

5.1 Federal policy action

In November 2022, the federal government launched Canada's first **National Adaptation Strategy** to "reflect a shared vision for climate resilience in Canada, identify key priorities for increased collaboration and establish a framework for measuring progress at the national level."[24] The five key priorities are disaster resilience, health and wellbeing, nature and biodiversity, infrastructure, and the economy and workers. With respect to building and maintaining climate-resilient infrastructure systems, the strategy establishes the following objectives:

- updating or developing **technical standards** to embed climate change in all decisions to locate, plan, design, manage, adapt, operate, and maintain infrastructure systems across their lifecycle;
- ensuring public and private infrastructure decision-making is informed by **system-wide assessments** of, and planning for, climate change risks;
- prioritizing benefits for **marginalized populations and communities** at highest risk of climate change impacts when making infrastructure decisions; and
- ensuring all new investments in infrastructure apply **resilience criteria** and adopt climate change guidance, standards, and future design data to maximize the long-term benefits of infrastructure outcomes.[25]

Other notable federal initiatives, which include the electricity sector but apply across all forms of infrastructure, are presented in chronological order below:

- **Federal Adaptation Policy Framework (2011):** targets medium-term strategies to address climate change adaptation and is "intended to result in adaptation considerations being proactively and explicitly included in federal processes, in order that adaptation planning and programming occurs as part of ongoing federal activities." However, while the framework calls for agencies to consider climate change impacts it does not "[prescribe] how or when to adapt";[26]

---

[24] Environment and Climate Change Canada. *Climate change adaptation plans and actions.* Last modified February 2, 2022.

[25] Environment and Climate Change Canada. *Canada's National Adaptation Strategy: Building Resilient Communities and a Strong Economy.* November 24, 2022.

[26] Environment and Climate Change Canada. *Federal Adaptation Policy Framework.* Last modified August 12, 2016.

- **Pan-Canadian Framework on Clean Growth and Climate Change (2016):** outlines actions to achieve Canada's emissions reduction targets, and notably establishes a carbon pricing mechanism. The plan is centered on four main pillars, one of which is focused on adaptation and climate resilience. This pillar targets actions such as providing authoritative climate information, building regional adaptation capacity and expertise, and developing climate-resilient building codes and standards by 2020.[27] However, progress on revising building codes has been slow moving; an investigation by the Globe and Mail suggests that "[a]lthough climate adaptation has started to be addressed in policy, that still hasn't translated to specific technical priorities for the 2025 national code – and it's likely we won't see resilience measures put in place until the 2030 version";[28]

- **Climate-Resilient Buildings and Core Public Infrastructure Initiative (2016-2021):** a five-year initiative by the National Research Council of Canada that resulted in the development of future-looking climate data, 50 proposed changes to the Canadian Electrical Code to increase climate resiliency and reliability (notably, only five of these changes were subsequently implemented in the 2021 edition),[29] best practices for flood risk reduction in residential communities, a national guide to reduce the risks from wildland-urban-interface fires, among other outputs.[30] A second phase of the initiative was launched in June 2022 to build on the results from the first phase;[31] and

- **National Cross Sector Forum 2021-2023 Action Plan for Critical Infrastructure (2021-2023):** supports an approach to strengthening the resilience of critical infrastructure, including in the energy and utilities sector. The action plan focuses on three objectives: building partnerships (through multi-sector meetings, for example), sharing and protecting information (including developing threat and impact assessments), and practicing an all-hazards risk approach.[32]

While the federal initiatives described above may not apply directly to provincial activities, they nonetheless demonstrate how the federal government is considering climate resiliency in its planning efforts. However, this highlights the importance of intergovernmental engagement to clarify not only how but also who will be responsible for ensuring these activities are reflected at the provincial level. The cross-government, multi-sectoral body that LEI recommends later in Section 9 would be one such venue where these ambiguities could be resolved.

---

[27] Environment and Climate Change Canada. *Pan-Canadian Framework on Clean Growth and Climate Change: Canada's plan to address climate change and grow the economy.* 2016.

[28] The Globe and Mail. *Code minimum: Why your home isn't built to last against extreme weather.* January 27, 2023.

[29] National Research Council of Canada. *Integrating climate resilience into building and design guides, standards and codes through the Climate Resilient Buildings and Core Public Infrastructure (CRBCPI) Initiative.* May 27, 2022.

[30] Infrastructure Canada. *Climate-Resilient Buildings and Core Public Infrastructure Initiative.* Last modified June 23, 2022.

[31] Infrastructure Canada. *Government of Canada announces funds for climate resilient infrastructure initiatives.* June 28, 2022.

[32] Public Safety Canada. *National Cross Sector Forum: 2021-2023 Action Plan for Critical Infrastructure.* 2021.

5.2 Provincial policy action

In February 2023, the provincial government launched Ontario's first comprehensive **Emergency Management Strategy and Action Plan**. One of the plan's goals is proactive planning and monitoring, which will involve activities such as: developing a coordinated hazard and risk monitoring process in collaboration with provincial ministries by the end of the year; developing a provincial risk profile by the end of 2024; and creating resources for municipalities to conduct their own exercise drills. Another key component of the plan is transparency, requiring annual updates on the progress made on the plan's goals and actions.[33]

In addition, Ontario's **Critical Infrastructure Assurance Program** "identifies and assesses Ontario's key facilities, systems and networks, and their inter-dependencies, and provides a strategy to assure their continuance during threats from all hazards."[34] The program consists of several sector-specific working groups (including one for the electrical power system)[35] that report to a steering committee and engage in the following core activities:

- identifying critical infrastructure and assessing their dependencies and interdependencies using modeling software;
- identifying vulnerabilities and developing solutions to prevent and mitigate threats; and
- refining, enhancing, and promoting best practice in critical infrastructure assurance.

In terms of funding initiatives, the province has launched programs to support municipalities in their resiliency efforts. For example, the **Build Back Better** pilot was launched in 2019 (and most recently extended through 2023) to provide municipalities with funds to rebuild and make climate resilient improvements to infrastructure damaged by extreme weather. Eligible improvements include "raising roads to ensure better overland flow of water, improving the columns or footings of a bridge, or enlarging the size of ditches and catch basins to increase the capacity to hold water."[36] The pilot has provided $3 million in funding - $1 million through the initial launch in 2019 and an additional $2 million through the initiative's extension.

5.3 Recent municipal measures

The Climate Risk Institute recently surveyed and interviewed municipalities across Ontario with regards to the climate change adaptation actions they have conducted to date. According to representatives from 53 municipalities that responded to the survey, half have developed or are

---

[33] Emergency Management Ontario. *Provincial Emergency Management Strategy and Action Plan: A Safe, Practiced and Prepared Ontario.* February 3, 2023.

[34] Emergency Management Ontario. *Ontario Critical Infrastructure Assurance Program Strategy.* Last updated July 18, 2022.

[35] Emergency Management Ontario. *Emergency management program resources.* Last updated July 18, 2022.

[36] Ontario Municipal Affairs and Housing. *Ontario Helps More Municipalities Prepare for Extreme Weather.* February 24, 2021.

currently working on a climate change adaptation plan. Other commonly implemented actions include:

- improving stormwater infrastructure;
- updating emergency management plans;
- providing climate risk information on their website; and
- installing back-up power at critical municipal facilities.[37]

[37] Climate Risk Institute. *Benchmarking Climate Change Adaptation Action in Ontario: Summary Report.* August 2022.

6 How other jurisdictions are addressing resiliency

To inform the best practices and recommendations presented later in this report, LEI reviewed the resiliency efforts undertaken in six jurisdictions across the world: New York, California, Texas, Finland, the United Kingdom ("UK"), and Australia. We present each case study example in turn below and then conclude the section with a discussion of lessons learned and key observations for Ontario.

6.1 New York

6.1.1 Overview

Extreme weather has been the principal driver of resiliency efforts in New York. The first steps toward addressing resiliency in the state came in the wake of Hurricane Sandy in 2012, which caused widespread outages throughout New York City and the surrounding areas, as well as US$32.8 billion in damages across the state.

Following the storm, then-Governor Andrew Cuomo convened the New York State ("NYS") 2100 Commission[38] to examine and evaluate key vulnerabilities in the state's critical infrastructure systems and recommend actions to strengthen and improve their resilience. In parallel, the Consolidated Edison Company of New York, Inc. ("ConEd") established the Con Edison Resiliency Collaborative[39] alongside stakeholders to examine various topics related to electric system resiliency. The Collaborative produced reports that resulted in planning and activities that continue to this day, providing a helpful model for other utilities in the state to follow. More recently, the New York Public Service Commission initiated Case No. 22-E-0222 to establish resiliency planning requirements for electric utilities.

We summarize the work of the NYS 2100 Commission, ConEd and its Resiliency Collaborative, the NY PSC's statewide resiliency proceeding, and other state agencies in turn below.

6.1.2 NYS 2100 Commission

The NYS 2100 Commission was created to examine and evaluate the state's infrastructure systems, and to provide recommendations to the governor and state legislature on steps that should be taken to strengthen and improve the resiliency of those systems.

On January 11th, 2013, the Commission released its report and recommendations. Therein, the Commission stressed that the key to preparing for future extreme weather events is to make the state's infrastructure more resilient. The report defined resiliency as "the ability of a system to

---

[38] NYS 2100 Commission. *Recommendations to Improve the Strength and Resilience of the Empire State's Infrastructure.* January 11, 2013.

[39] NY PSC. *Order Approving Electric, Gas and Steam Rate Plans in Accord With Joint Proposal (Case No. 13-E-0030 et al).* February 21, 2014.

withstand shocks and stresses while still maintaining its essential functions."[40] The report offered both short- and long-term recommendations to create resilient infrastructure, which were centered around five pillars: building spare capacity; increasing system flexibility; designing systems for limited failure; creating mechanisms for rapid rebound; and constant learning.

The report also included specific recommendations in the areas of energy, transportation, land use, and infrastructure financing. The Commission was disbanded after publishing its report and recommendations. The concepts and definitions presented in the report were foundational to subsequent resiliency work done by agencies in the state. For example, the NY PSC adopted the NYS 2100 Commission's definition of resiliency in a 2014 order approving ConEd's rates.[41]

6.1.3 ConEd

ConEd defines resiliency as "resistance of the Company's facilities to weather–induced failure or the ability to restore service following a weather-induced service outage."[42] After Hurricane Sandy, ConEd established the Con Edison Resiliency Collaborative alongside stakeholders to examine electric system resiliency investments under the direction of the NY PSC. The Collaborative was in place for two years and produced two reports, the Storm Hardening and Resiliency Collaborative Report in 2013 and the Storm Hardening and Resiliency Collaborative Phase Two Report in 2014, outlining the steps ConEd was taking to strengthen its system in the face of increasingly extreme weather. The steps delineated in the reports included the prioritization of storm hardening projects based on the degree of risk reduction associated with each project, as well as the development of analytical tools to determine appropriate levels of resiliency investments.

ConEd developed its analytical framework to assess potential resiliency investments in 2017, when the NY PSC directed it to "develop and apply a cost/benefit analysis approach for future capital investment" related to resiliency.[43] The utility developed two models:

- a **risk assessment and prioritization model**, which aims to measure ConEd's efforts in terms of risk reduced per dollar spent; and
- a **cost-benefit analysis model**, which quantifies the risk reduction value of resiliency projects.[44]

---

[40] NYS 2100 Commission. *Recommendations to Improve the Strength and Resilience of the Empire State's Infrastructure.* January 11, 2013. P. 24.

[41] NY PSC. *Order Approving Electric, Gas and Steam Rate Plans in Accord With Joint Proposal (Case No. 13-E-0030 et al).* February 21, 2014.

[42] ConEd. *Storm Hardening and Resiliency Collaborative Phase Two Report.* September 2, 2014. P. 6.

[43] ConEd. *Storm Hardening and Resiliency Collaborative Report.* December 4, 2013. P. 7.

[44] Ibid.

The analytical framework integrates the risks and probabilities of future climate events, along with other societal cost factors.[45] LEI summarizes the analytical framework in the textbox below.

ConEd's analytical framework to evaluate resiliency investments

For its **risk assessment and prioritization model**, ConEd seeks to "demonstrate a cost causality linkage between capital funding allocated for storm hardening and the reduction in risk obtained via that investment." The key components of the model include:

- location-specific information regarding high-rise residential buildings and critical municipal facilities;
- location-based flood probabilities obtained from proprietary New York City storm surge inundation prediction models, combined with asset elevation data to determine the risk of flood damage for targeted assets;
- wind damage probabilities derived from historical wind gust frequency distributions;
- data on heat wave events;
- storm hardening project costs;
- projected outage durations; and
- estimates of asset risk pre- and post-hardening, in terms of changes to damage probability and/or outage duration, which are informed by "engineering judgement reflecting system design and operating characteristics."

The model first calculates the product of the probability of flood and wind damage to a specific location, the total population affected by an outage at that location, and the duration of said outage. ConEd then compares the result to the calculation of the adjusted probability if the resiliency project were to be completed, based on the post-hardening asset risk estimates. The difference between the two values quantifies the risk reduction to customers and critical infrastructure, which ConEd then uses to calculate the amount of risk reduction per $1,000 spent on a project. These values are used to rank and prioritize projects in order to maximize risk reduction.

For its **cost-benefit analysis model**, ConEd seeks to evaluate "the relative value of each storm-hardening program from an avoided economic-cost perspective" and quantify the risk reduction in monetary terms. To provide an estimate of the monetary impact reduction that can be expected from a storm hardening initiative, ConEd used outage cost estimates from a

[45] NY PSC. *Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal (Case No. 13-E-0030 et al).* February 21, 2014.

2009 Lawrence Berkeley National Laboratory ("LBNL") study[46] and the pre- and post-hardening outage duration estimates from the risk assessment and prioritization model to calculate the difference in "pre and post resiliency monetary impact costs" for each asset. This estimate of monetary impact reduction is then compared to the capital costs for corresponding initiatives, which are increased by 20% to account for cost uncertainty. ConEd also combined this approach with Monte Carlo probability distributions, to provide a distribution of "monetary impact reductions within stated percentile levels."

Sources: ConEd. *Storm Hardening and Resiliency Collaborative Report.* December 4, 2013; ConEd. *Storm Hardening and Resiliency Collaborative Phase Two Report.* September 2, 2014.

Since Hurricane Sandy, ConEd has invested over US$1 billion in storm hardening and resiliency initiatives, which it estimates have reduced the number of storm-related customer interruptions by more than 680,000. Investments include: the undergrounding of distribution infrastructure; the installation of 100 miles of new cable, 4,000 poles, and 1,000 switches; retaining 1,000 additional contractors and securing heavy equipment to fly crews to locations for swifter power restoration; continuing tree trimming activities and removing hazardous trees; installing smart meters which have improved storm response efforts; and the implementation of digital tools to improve communication with customers during emergencies.[47] As part of its long-range electric plan out to 2031, ConEd anticipates spending an additional US$2.6 billion in climate resilience projects (or 5% of the total US$53.5 billion in 10-year planned capital expenditures), plus a further US$23.3 billion (or 44% of the total planned capex) in multi-value investments, which address numerous categories including climate resilience, clean energy, and core services.[48]

6.1.4 NY PSC's Case No. 22-E-0222

In 2021, the New York State Senate passed bill S4824A,[49] acknowledging the need for more resilient energy systems in the face of increasingly frequent extreme weather events. The legislation requires utilities in the state to complete a climate vulnerability study and implementation plan. The NY PSC initiated Case No. 22-E-0222 in response to the legislation and ruled that utilities must submit their climate change vulnerability studies by September 2023, followed by a climate vulnerability and resiliency plan by November 2023.[50] The climate change vulnerability studies will evaluate each utility's infrastructure, design specifications, and procedures to better understand the electric system's vulnerability to climate-driven risks. The

---

[46] The 2009 LBNL study includes outage cost estimates for three customer segments (residential, small commercial and industrial ("C&I"), and medium and large C&I) and for durations ranging from less than five minutes (i.e., momentary interruptions) to eight hours. Estimates were based on 28 customer value of service reliability studies conducted by ten US electric utilities between 1989 and 2005. *See Table ES-1 for the various estimates.* LBNL. *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* June 2009.

[47] ConEd. *Our Climate Change Resiliency Plan.* January 2021.

[48] ConEd. *Long-Range Plan: Our Electric System.* January 2022.

[49] The New York State Senate. *Senate Bill S4824A.* February 12, 2021.

[50] NY PSC. *Order Initiating Proceeding (Case No. 22-E-0222).* June 16, 2022.

subsequent resiliency plans, informed by the vulnerability studies, will then set out planned investments for the next ten and twenty years.

Specifically, the resiliency plans will detail how each utility will: mitigate the impacts of climate change on infrastructure and reduce restoration costs and outage times; incorporate climate change into planning and operations; and manage climate change risks and build resilience. In proposing a portfolio of resiliency initiatives, each utility must estimate the costs and benefits of the proposed investments, as well as the annual rate impact from the first five years of proposed investments. Each utility must also discuss implementation schedules and performance benchmarks. Finally, each utility must establish a working group to advise and make recommendations regarding the development and implementation of its resiliency plan.[51]

The utilities subject to this order are ConEd, Orange and Rockland Utilities, Inc., New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, Central Hudson Gas and Electric Corporation, and Niagara Mohawk Power Corporation (doing business as National Grid). Following a public hearing, the NY PSC must approve or modify each utility's plan by October 2024, and the plans must be updated and filed for approval every five years.

LEI reviewed comments in the proceeding – two key considerations stood out:

- **lack of standardized resiliency metrics:** the six utilities issued a statement commenting on the lack of standardized metrics to assess resiliency, stating that "it is [their] understanding based on their participation in national engineering and industry associations that widely accepted metrics or key performance indicators to assess resiliency have not yet been developed."[52] The utilities recommended that, going forward, the NY PSC should assess each utility on whether it has implemented the initiatives set out in its climate vulnerability and resiliency plan, instead of using specific performance metrics; and

- **need for collaboration with other agencies and stakeholders:** following the NY PSC's order initiating the proceeding, various stakeholders commented on the need for close collaboration between utilities, governments, and other parties in resiliency efforts. ConEd, for example, highlighted the need to collaborate with municipalities and industry groups, pointing out that it "has limited authority to address certain vulnerabilities, such as the capacity of the city's stormwater system"[53] – improper stormwater management exposes vulnerable underground assets that are not designed for contact with water to flood damage. Additionally, both the utilities and the City of New York have highlighted the importance of making utility resilience investments in conjunction with local,

---

[51] Ibid.

[52] Central Hudson Gas & Electric Corporation et al. *Joint Utilities' Comments on Commission Inquiries Regarding Climate Vulnerability Studies and Plans (Case No. 22-E-0222).* August 15, 2022.

[53] ConEd. *Climate Change Vulnerability Study*. December 19, 2020.

municipal, and county storm protection initiatives.[54] Furthermore, all utilities have met with NY PSC Staff to discuss how their vulnerability reports can use climate data that the New York State Energy Research and Development Authority ("NYSERDA") is developing for a forthcoming New York State Climate Impacts Assessment.[55]

The NY PSC has stated that it would allow utilities to recover the costs of implementing their resiliency plans in subsequent rate proceedings. Specifically, the costs of "capital projects placed into service and additional unrecovered costs incurred prior to base rates being reset" will be recovered through a climate resiliency cost recovery surcharge, and any unrecovered costs associated with the surcharge will be added into base rates when the utility's base rates are reset.[56]

6.1.5 Other state agencies

Beyond the requirements outlined in Senate Bill S4824A, there have been acknowledgements by other state agencies that the energy transition will pose resiliency challenges.

In 2022, NYSERDA announced US$3 million in funding through its Climate Resilience Initiative. The funding is designed to aid municipal electric utilities and rural electric cooperatives in "[providing] decarbonized and resilient energy services so that they can more effectively respond to stress events resulting from climate change and extreme weather."[57] Funding will be awarded for projects in three categories: demonstrations of net zero/deep decarbonization solutions, climate impact vulnerability assessments and resilience planning, and renewables and innovation analytics.

As another example, the New York Independent System Operator ("NYISO")'s recent vulnerability study integrates growing demand and climate impacts into its models.[58] NYISO's study simulates the potential impacts of climate change and climate policy on the operation of the New York power system.

Key lessons for Ontario

- **Resiliency requires collaboration and a whole-of-government approach:** resiliency efforts in New York have been initiated and pursued by all levels of government and involve extensive collaboration among utilities, industry groups, and other stakeholders.

---

54 City of New York. *Comments of the City of New York on Climate Vulnerability Studies (Case No. 22-E-0222).* August 15, 2022.

55 NYSERDA. *New York State Climate Impacts Assessment.*

56 NY PSC. *Order Initiating Proceeding (Case No. 22-E-0222).* June 16, 2022. P. 3-5.

57 NYSERDA. *NYSERDA Announces $3 Million to Assist Municipal Electric Utilities and Rural Cooperatives With Providing Decarbonized and Resilient Energy Services.* February 18, 2022.

58 NYISO. *Climate Change Impact and Resilience Study.* September 12, 2020.

- **Risk-based planning helps to prioritize investments:** ConEd's analytical framework to evaluate potential resiliency investments includes a risk assessment and prioritization model as well as a cost-benefit analysis model. Focusing on the probability of extreme weather events occurring and developing solutions that address the greatest risks to its system has allowed the utility to prioritize and sequence investments.

6.2 California

6.2.1 The need for resiliency in California

The state of California, with 33 million acres of forested land and a dry, warm climate, has faced increasingly intense and frequent wildfires and heatwaves, leading to a greater focus on resiliency. In 2020 alone, five of the largest ten wildfires in California's history occurred, including the August Complex fire, which burned over a million acres of land. Between 2000 and 2016, wildfires have resulted in utilities facing transmission and distribution damages totaling over US$700 million.[59] Furthermore, heatwaves are expected to occur more frequently as a result of climate change, with some projections indicating that extreme heat could occur twice as often by 2050. This too is expected to have a significant impact on the state's grid, increasing peak load and placing further strain on infrastructure.[60]

We review actions taken by various state agencies and utilities in turn below.

6.2.2 CPUC vulnerability assessments

In August 2020, the California Public Utilities Commission ("CPUC") issued Decision 20-08-046, which focuses on the responsibility of electric and gas utilities in the state to incorporate both climate change adaptation measures and consultation with disadvantaged communities in their planning processes. The CPUC's decision applies to the three investor-owned utilities ("IOUs") participating in the California Independent System Operator ("CAISO") region – Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric ("SDG&E"), and Southern California Edison ("SCE"). The decision requires the IOUs to conduct regular Utility Vulnerability Assessments, as well as engage with vulnerable communities before, during, and after their development, and regularly report on these efforts in Community Engagement Plans. We describe each report in turn below.

The **Utility Vulnerability Assessments** will examine three distinct time horizons: the near-term (10-20 years), mid-term (20-30 years), and long-term (30-50 years). They will be updated every four years in conjunction with each IOU's rate case cycle and will provide analysis to inform long-term investments and decision-making. Specifically, the utilities will be tasked with evaluating the potential climate risks to their infrastructure, operations, and services and proposing feasible

[59] California Energy Commission. *Assessing the Impact of Wildfires on the California Electricity Grid.* August 2018.

[60] California Natural Resources Agency. *Protecting Californians From Extreme Heat: A State Action Plan to Build Community Resilience.* April 28, 2022.

solutions to address any vulnerabilities, "ranging from easy fixes, where applicable, to more complicated, longer term mitigation."[61]

The CPUC requires utilities to use the state Department of Water Resources ("DWR")'s existing two-step vulnerability assessment methodology as a starting point in preparing their vulnerability assessments. The DWR methodology focuses on "combining exposure and sensitivity to determine risk and combining risk and adaptive capacity to determine vulnerability."[62] Specifically, the DWR methodology focuses on six climate variables (wildfire, extreme heat, sea level rise, long-term persistent hydrologic changes, short-term extreme hydrologic changes, and habitat and ecosystem services) throughout the 2030-2070 time period, and assesses vulnerabilities among its "people, places, and programs", with a specific emphasis on projects entirely under its control.[63] The resulting assessment is then used to formulate an adaptation plan and prioritize investments. The CPUC adopted this methodology as it "utilizes a generally accepted risk assessment paradigm, aligns with existing state guidance for climate adaptation, and includes operations and staff activities."[64]

The **Community Engagement Plans** are to be filed every four years, one year before filing the vulnerability assessments, and will describe the utility's planned approach to ongoing community engagement and involvement, as well as how it plans to ensure equity in its climate adaptation efforts (e.g., additional funding, outreach, or education), considering each community's adaptive capacity.

For both filings, the CPUC has established a set of minimum filing requirements for the utilities – these are to:

- identify **climate risks** to operations and service, as well as to utility assets;
- identify and communicate vulnerabilities of **third-party contracts**;
- assess **short-, medium-, and long-term horizons**;
- identify **sustainable remedies** for vulnerable infrastructure;
- identify **measures to promote equity** in vulnerable communities;
- outline the **plan to engage with vulnerable communities**;

---

[61] CPUC. *Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Decision 20-08-046).* August 27, 2020.

[62] Southern California Gas Company. *Working Group Session Report on Topic 5: Climate Change Adaptation and Decision-Making Framework.* January 15, 2020.

[63] Ibid.

[64] CPUC. *Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Decision 20-08-046).* August 27, 2020. P. 63.

- summarize **community engagement efforts before, during, and after** the vulnerability assessment process;

- address **actual or expected climatic impacts** on utility planning, maintenance, and construction, and **communicate solutions** to maintain safe, reliable, and **resilient operations**;

- use the state DWR's **vulnerability assessment methodology**;

- include **off-ramps** (i.e., exemptions from vulnerability analyses) for assets with low climate risk; and

- consider variables such as temperature, sea level, precipitation, drought, and wildfires, as well as **cascading impacts** (i.e., compounding incidents such as wildfires and rain causing mudslides) when performing vulnerability assessments.[65]

SCE was the first utility scheduled to submit its vulnerability assessment in 2022 – we summarize key findings from its filing in the textbox below. PG&E is scheduled to submit its assessment in 2024 and SDG&E in 2025. Utilities must submit their rate case one year later. Utilities will set up memorandum accounts to track costs directly related to the vulnerability assessments and associated community engagement efforts.[66]

It is currently unclear what tools or criteria the CPUC plans to utilize to evaluate resiliency investment proposals. On this point, the CPUC in its decision states "[t]he process of altering infrastructure to reduce or eliminate climate change impacts may involve billions of dollars in ratepayer funding to reduce the risk. This phase of the proceeding does not address funding, which should be part of utility [general rate cases] or other rate setting proceedings."[67]

Southern California Edison's 2022 Vulnerability Assessment

In its assessment, SCE evaluated the expected climatic impacts of five main variables – temperature, sea level, precipitation, wildfire, and cascading impacts – for the 2030, 2050, and 2070 timeframes. The report places special emphasis on the 2050 projections, noting that, as per the CPUC's order "the key time frame [to focus] the vulnerability assessment is the next 20-30 years." The CPUC cites several reasons for this focus on 2050 projections, including that it aligns with: the lifetime of long-lived infrastructure; the expected time over which several climate impacts are expected to occur; best practice in climate modeling of averaging values over a 30-year period to ensure valid statistical results; as well as state policy goals to be 100% carbon neutral by 2045.

65 Ibid. P. 124-126.

66 Ibid. P. 74.

67 Ibid. P. 55.

The report outlines the following potential adaptation options to address climate-caused vulnerabilities:

- **temperature:** constructing new tie lines to reduce the likelihood of distribution outages caused by extreme heat; upgrades to heating, ventilation, and air conditioning ("HVAC") systems at generation plants to prevent equipment overheating;
- **sea level rise:** asset waterproofing and constructing new distribution tie lines to reduce the potential for and impact of distribution outages caused by sea level rise;
- **precipitation and flooding:** constructing flood walls at selected substations, asset waterproofing, and constructing new distribution tie lines;
- **wildfires:** wrapping distribution poles in fire retardant materials, constructing new underground distribution tie lines, increasing vegetation management and pole brushing, and investing in smoke inhalation protection to enhance employee safety. Additionally, studies are being conducted to guide hardening efforts at specific assets exposed to high wildfire risk, such as the Big Creek Hydro System, which experienced a major fire in 2020; and
- **cascading impacts (rain-on-snow, debris flow):** performing studies to understand the effects of high runoff caused by rain-on-snow events on high hazard dam safety, as well as appropriate adaptation solutions in debris flow-prone slopes to prevent distribution outages; and installing debris booms to protect hydro assets from increased debris flow.

Source: SCE. *Climate Change Vulnerability Assessment.* May 13, 2022; CPUC. *Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Decision 20-08-046).* August 27, 2020.

6.2.3 Wildfire mitigation plans

In addition to the vulnerability assessments and community engagement plans, IOUs are also required to file and implement Wildfire Mitigation Plans to prevent electrical wildfires and minimize infrastructure damage. Utilities file their plans annually with the Office of Energy Infrastructure Safety ("OEIS"),[68] which is the agency responsible for their approval. Although this responsibility previously fell under the mandate of the Wildfire Safety Division within the CPUC, it was subsequently transitioned to OEIS after it was established in July 2021 as a separate state agency specifically focused on reducing utility-caused wildfire risk. However, the CPUC still maintains responsibility for evaluating the implementation costs associated with the Wildfire Mitigation Plans for the purposes of cost recovery.[69]

[68] OEIS. *Wildfire Mitigation Plan Compliance.* January 2023.

[69] CPUC. *Wildfire and Wildfire Safety.* December 2021.

In an attempt to avoid duplication of effort and overlapping authorities, the two agencies entered into a memorandum of understanding ("MOU") to clarify their roles and "shared priorities".[70] Despite the MOU, there still appears to be some degree of overlap in their duties; for example, while the CPUC is legislatively required to assess the organization-wide safety culture at each utility every five years, the OEIS is legislatively required to conduct similar assessments on an annual basis.[71] A recent report by the California Wildfire Safety Advisory Board, which is responsible for developing recommendations to the OEIS, recognized that the OEIS is "not yet a fully mature structure" and cautioned that coordinating wildfire mitigation efforts across two separate agencies and separate proceedings without appropriate synchronization could lead to "unnecessary duplication of effort" or "actual conflicts".[72]

California's IOUs have embarked on independent resiliency initiatives to protect their infrastructure and assets from extreme weather events. PG&E, for example, has pursued multiple resiliency initiatives in the face of wildfires in Northern California. The utility established a Community Wildfire Safety Program in 2018[73] and develops its annual Wildfire Mitigation Plans through extensive stakeholder consultation.[74] These programs encompass activities such as: undergrounding approximately 3,600 miles of distribution lines between 2022 and 2026,[75] prioritizing lines in high fire threat districts; system hardening by installing stronger poles and covering lines; enhancing powerline safety settings to automatically shut off power in the event of contact with an object; enhanced vegetation management; developing microgrids for critical facilities; and real-time monitoring and intelligence. We describe PG&E's microgrid program in the textbox below.

PG&E's Community Microgrid Enablement Program

In April 2021, PG&E launched the Community Microgrid Enablement Program ("CMEP") to support the development of customer-owned microgrids across its service territory, focusing in particular on wildfire-vulnerable and low-income areas. The program was facilitated in part by Senate Bill 1339, which was enacted in 2018 and directed the CPUC to undertake several activities related to the development of microgrids in the state. As a result of the legislation, the CPUC established the Microgrid Incentive Program, with a US$200 million budget to fund clean energy microgrids that support the critical needs of vulnerable communities impacted by

[70] CPUC and OEIS. *Memorandum of Understanding between the California Public Utilities Commission and the Office of Energy Infrastructure Safety.* July 12, 2021.

[71] CPUC. *Wildfire and Wildfire Safety.* December 2021.

[72] California Wildfire Safety Advisory Board. *Recommendations to Office of Energy Infrastructure Safety on Additional Wildfire Mitigation Plan Requirements and Performance Metrics.* Adopted April 26, 2022.

[73] PG&E. *Community Wildfire Safety Program.* September 11, 2019.

[74] PG&E. *2022 Wildfire Mitigation Plan.* February 25, 2022.

[75] PG&E. *Undergrounding 10,000 Miles of Powerlines.* May 2022.

grid outages. While SCE and SDG&E have also been exploring microgrid programs, neither have yet to make substantial progress.

Through the CMEP, PG&E offers support services for eligible projects, including project scoping, technical guidance, and design and execution assistance. In addition, PG&E also offers funding to eligible projects. The utility provides up to US$3 million for eligible equipment necessary for safe islanding capabilities, such as microgrid controllers and isolation devices; the utility does not cover generation or storage-related costs. In terms of eligibility requirements, the microgrid must serve a region that has been or will likely be severely impacted by seasonal wildfires, PG&E power outages, or both. This means that the project must be sited in one or more of the following areas:

- a **high fire threat district**, which the CPUC has identified through a statewide map and selected based on areas at higher risk for power line fires igniting and spreading rapidly;
- an **area that has been impacted by a prior Public Safety Power Shutoff event**, which is where utilities depower equipment when there is a risk of sparking fires; and/or
- an **outage prone area**, defined as the top 1% worst performing circuits in either total minutes or total number of outages based on data for the most recent two years.

Finally, an eligible project must also have a "community focus", such that it serves the energy needs of at least one critical facility (e.g., medical facilities or emergency services). Projects are also limited to 20 MW.

The first project supported by the CMEP was the Redwood Coast Airport Microgrid, which was completed in June 2022. The microgrid consists of a 2.2 MW solar project and a 2 MW/9MWh battery storage system serving approximately 20 customer meters, including the regional airport and a US Coast Guard Air Station.

Sources: PG&E. *Community Microgrid Enablement Program.* May 2021; CPUC. *Resiliency and Microgrids.* May 2022; Redwood Coast Energy Authority. *Redwood Coast Airport Microgrid.* June 22, 2022; CPUC. *Fire-Threat Maps and Fire-Safety Rulemaking.*

As for the other IOUs in the state, SCE published its first Wildfire Mitigation Plan in 2019, and has since developed annual revisions. Approximately 15% of its transmission and distribution assets lie within utility-defined high fire risk areas.[76] SCE's resiliency measures in the face of frequent and intense wildfires include: the installation of over 2,900 total circuit miles of covered conductors, representing approximately 20% of SCE's transmission and distribution lines in high fire risk areas; over 870,900 inspections on transmission and distribution structures (of which 36,000 inspections were conducted in high fire risk areas), with corresponding repairs and pre-emptive replacements; strategic planning and investment in grid hardening; and improved coordination with fire departments. SCE has also deployed new technologies, such as weather

[76] SCE. *SCE Wildfire and PSPS Risk Models.* October 5, 2021.

stations and high-resolution cameras, to better monitor fire conditions and respond more quickly to potential threats.[77]

SDG&E has implemented similar resiliency measures in the face of wildfires. 56% of SDG&E's transmission lines and 38% of its distribution lines lie within high fire threat districts.[78] The utility's 2022 report outlines resiliency work in numerous areas, such as risk assessment and mapping, forecasting, system hardening, inspections, and asset management. Specific initiatives include the hardening of over 400 miles (or 24%)[79] of its transmission lines and over 900 miles (or 5.5%)[80] of its distribution lines, including 25 miles of strategic undergrounding, since 2007. According to the utility, strategic undergrounding refers to the prioritization of undergrounding activities in high fire threat districts as well as in areas where substantial Public Safety Power Shutoff event reductions can be gained.[81] Since 2020, SDG&E has installed 190 weather stations integrated with artificial intelligence forecast systems to monitor high-risk areas. The utility has also placed a heavy emphasis on its inspection capabilities, including drone inspections on approximately 1,000 transmission structures and over 21,000 distribution structures, as well as the inspection of over 500,000 trees.[82]

Furthermore, all three IOUs have Public Safety Power Shutoff or "de-energization" procedures in place, which proactively turn off power in high-risk areas during extreme weather conditions to reduce the risk of wildfires caused by electrical equipment.[83] These procedures are related to inverse condemnation rules in the state, which holds a utility strictly liable for damages caused by wildfires found to be ignited by its equipment, even if the utility has complied with all rules and regulations.[84]

6.2.4 Recent legislative action

On June 30th, 2022, Governor Gavin Newsom signed Assembly Bill 205 into law. Among other provisions, the legislation establishes the Strategic Reliability Reserve Fund to help improve electric grid reliability and resiliency in the face of climate change and extreme weather events, such as storms and fires. The fund will provide financial assistance to entities that own and operate electric transmission and distribution systems to help them upgrade, modernize, and secure their infrastructure.[85] As outlined in the 2022-2023 California state budget, this is a one-time fund that will set aside US$2.2 billion to be spent over a period of five years. While the fund

---

[77] SCE. *Wildfire Mitigation Plan.* February 18, 2022.

[78] SDG&E. *OIR Fire Threat Mapping.* August 2018.

[79] California State Geoportal. *California Electric Transmission Lines.* November 3, 2022.

[80] Ibid.

[81] SDG&E. *2020-2022 Wildfire Mitigation Plan Update.* February 11, 2022.

[82] Ibid.

[83] PG&E. *Safety Power Shutoffs.* October 17, 2019.

[84] Fitch Ratings. *Upgrades for CA IOUs Dependent on Fewer Utility-Linked Wildfires.* August 31, 2022.

[85] California Assembly. *Assembly Bill No. 205.* June 30, 2022.

aims to increase the state's ability to withstand extreme and coincident climate events, it "will not take the place of the longstanding obligations of all load serving entities to procure sufficient resources to maintain reliability."[86]

The 2022-2023 California state budget includes several other funding measures aimed at improving resiliency in the face of extreme weather, these include:

- **Distributed Electricity Backup Assets Program:** provides US$550 million to incentivize the development of up to 5,000 MW of low-carbon back-up generation assets in fire-prone areas, for data centers, and to support critical infrastructure (e.g., hospitals, clinics, water facilities, and fire stations). This will supplement the existing 14,000 MW of fossil fuel-fired back-up generation systems across the state;[87]

- **Demand Side Grid Support Program:** a US$200 million one-time fund that will offer incentives to electric customers that provide load reduction and back-up generation services to support the state's electrical grid during periods of peak demand; and

- **Long Duration Storage Incentives:** provides US$140 million to invest in pre-commercial long duration storage projects throughout the state, aimed at improving grid resilience and providing support during emergencies such as wildfires.[88]

Finally, CAISO has also taken steps to strengthen grid resiliency in the wake of recent extreme weather events in California, including heat waves and wildfires. CAISO is pursuing multiple short- and long-term measures to address grid resiliency, such as improving coordination with utilities and other stakeholders, enhancing forecasting capabilities, and increasing the use of DERs.[89]

In addition to the aforementioned legislative actions promoting resiliency initiatives, there have been multiple suggestions to further improve the resiliency of the state's energy systems. The Clean and Resilient: Policy Solutions for California's Grid of the Future report, for example, outlines policy suggestions to promote a clean and resilient grid, which was developed through consultations with several local and state leaders and other stakeholders – see the textbox on the following page for further details.

---

[86] California Department of Finance. *2022-23 State Budget.* June 27, 2022. P. 62.

[87] California Department of Finance. *Energy Reliability, Relief and Clean Energy Investments – Budget Change Proposal DF-46.* May 17, 2022.

[88] California Department of Finance. *2022-23 State Budget.* June 27, 2022.

[89] CAISO. *ISO Board Acts to Strengthen Grid Resiliency and Reliability.* September 19, 2017.

Clean and Resilient: Policy Solutions for California's Grid of the Future

Written by a partnership of UC Berkeley School of Law's Center for Law, Energy & the Environment and UCLA School of Law's Emmett Institute on Climate Change and the Environment, the report was developed alongside leaders from state and local government and representatives from stakeholder groups to identify a vision for California's clean and resilient grid of the future and propose actionable solutions to overcome key barriers.

The report identified three main barriers: the cost and scale of the transition to a decarbonized, resilient grid; the slow, top-down nature of current regulatory processes; and the inadequacy of current data-generation and sharing mechanisms. To overcome these challenges, the report suggested various actionable solutions, such as directing the CPUC to advance performance-based regulation, encouraging utility and public investment in low-carbon resilience infrastructure, and restructuring low-income ratepayer assistance programs. Additionally, the report recommended initiating a regulatory process to identify data necessary to successfully transition to a clean and resilient grid, sharing the data in agreed formats on a single platform, and assessing the strength of security and customer privacy claims to improve secure energy data access.

Source: UC Berkeley Center for Law, Energy & the Environment, et al. *Clean and Resilient: Policy Solutions for California's Grid of the Future.* June 2020.

Key lessons for Ontario

- **Leverage resources developed by other agencies:** in preparing their filings, the CPUC requires utilities to adopt the California DWR's vulnerability assessment methodology. This ensures consistency in resiliency approaches across sectors in the state.
- **Consider impacts on vulnerable communities:** along with the vulnerability assessments, the CPUC also requires utilities to submit community engagement plans to consider disadvantaged vulnerable communities throughout the planning process.
- **Overlapping agency responsibilities introduces significant uncertainty:** establishing the OEIS to take over some of the wildfire mitigation oversight responsibilities from the CPUC will require extensive coordination between the two agencies. Separating authority for approval of proposed wildfire mitigation activities from the approval of the associated cost recovery creates uncertainty and risk in the utility planning process.
- **Balance government and utility responsibilities for resiliency:** California's policy of inverse condemnation holds utilities responsible for wildfires caused by utility equipment even if the utility has acted prudently. As a result, utilities are forced to consider preventative system shutdowns when weather conditions that increase the probability of fire are present (e.g., extreme heat, strong winds). The strict definition of liability impacts the financial viability of California utilities and contributes to increased costs to ratepayers as utilities seek to reduce their system's susceptibility to wildfires.

6.3 Texas

Texas' experience with extreme weather events highlights the consequences of taking inadequate action to address resiliency concerns. We begin by describing the 2011 Groundhog Day Blizzard event and the findings from subsequent inquiries performed by government agencies, before describing the more recent 2021 Winter Storm Uri and the policy responses that followed.

6.3.1 2011 Groundhog Day Blizzard

In February 2011, the Groundhog Day Blizzard brought extreme weather including heavy snow, ice, freezing rain, and frigid wind to Texas. A combination of record winter load, multiple forced outages, failures to start electric generating plants, and generating plant derates led the electric system operator, the Electric Reliability Council of Texas ("ERCOT"), to issue an Energy Emergency Alert Level 3 ("EEA-3")[90] and implement rolling blackouts of 4,000 MW.[91]

Following the Groundhog Day Blizzard, state and federal officials conducted several inquiries. For example, a 2012 joint investigation by FERC and NERC concluded that 67% of generator failures were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, and low temperature cutoff limits. Another 12% were indirectly attributable to the cold, including natural gas curtailments and difficulties in fuel switching. While generators claimed to have winterization procedures in place prior to the storm, these proved inadequate. FERC and NERC concluded that "[m]any generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment."[92]

The winterization procedures noted above were putatively the result of actions by the Public Utility Commission of Texas ("PUCT") in response to a severe winter storm in 1989, over two decades prior to the 2011 storm. The PUCT instituted rule §25.53 Electric Service Emergency Operations Plans which, among other provisions, required market participants to file emergency operations plans with the PUCT.[93] However, there were no substantial penalties for entities that were not in compliance with what were essentially their own voluntary plans – the maximum

---

90 According to its operating guide, an EEA-3 is declared by ERCOT when operating reserves can no longer be maintained above 1,375 MW. At this point, ERCOT may instruct transmission companies to institute rotating outages. (Source: ERCOT. *ERCOT's use of Energy Emergency Alerts.* March 2019)

91 FERC/NERC Staff. *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations.* August 2011.

92 Ibid. P. 203.

93 PUCT. *Chapter 25. Substantive Rules Applicable to Electric Service Providers. §25.53. Electric Service Emergency Operations Plans.*

fine was only US$25,000.[94] The rule was thus more-or-less ignored; the FERC/NERC joint investigation in 2012 found that the same units that failed in 1989 also failed in 2011.[95]

With no effective action taken to make the power grid more resilient to cold weather, the 2021 Winter Storm Uri, described in further detail below, devastated Texas.

6.3.2 2021 Winter Storm Uri

In February 2021, Texas was hit with a record-setting storm, Winter Storm Uri, which caused one of the largest power crises in the United States since the blackouts of the northeast in 2003. The storm saw 164 hours of freezing temperatures across the state, reaching a record low temperature of -15°C (6°F) and over six inches of snow.[96] Winter Storm Uri is reported to have caused "69% of Texans to lose electricity for an average of 42 hours, and 49% to lose access to running water for an average of more than two days."[97] Although estimates of the damage vary, the storm was believed to have resulted in US$295 billion in damage[98] and nearly 250 deaths.[99]

At the time, Texas was relying on natural gas to generate 38% of its electricity[100] and heat approximately 40% of its homes.[101] As the storm began, natural gas demand for heating and electricity generation not only exceeded historical winter demand levels, but also exceeded levels that ERCOT had planned for in a worst case scenario winter event.[102] As demand increased, supply actually declined due to inclement weather – the infrastructure that was in place to generate electricity and transport natural gas was not adequately winterized and froze over during the storm. Wind turbines also froze over and led to further outages in generation. A lack of resilient generation and transmission against the elements drove a mismatch between supply and demand. During the storm, ERCOT reported that 46,000 MW of total generating capacity (equivalent to 45% of available winter capacity) had been forced offline – approximately 28,000 MW of this capacity was thermal, with the remaining 18,000 MW consisting of renewables.

---

94 Of the 97 units spot checked in 2019, 33 units that were deficient "agreed to improve preparations and/or records management." (Source: Allgower, A. *Presentation at ERCOT Generator Winter Weatherization Workshop.* September 5, 2019)

95 FERC/NERC Staff. *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations.* August 2011. P. 18.

96 City of Austin & Travis County. Office of Homeland Security and Emergency Management. *2021 Winter Storm Uri After-Action Review Findings Report.* 2021.

97 University of Houston. *New Report Details Impact of Winter Storm Uri on Texans.* March 29, 2021.

98 Ibid.

99 Texas Tribune. *Texas puts final estimate of winter storm death toll at 246.* January 3, 2022.

100 ERCOT. *Fuel Mix Report: 2021.* March 7, 2022.

101 US EIA. *Texas uses natural gas for electricity generation and home heating.* March 12, 2021.

102 Outages of 30 GW were recorded compared to planned worst case scenario outages of 14 GW. (Source: Busby, Joshua, et al. "Cascading risks: Understanding the 2021 winter blackout in Texas." *Energy Research & Social Science.* July 2021)

Through these extreme events, the wholesale electricity price spiked to the cap of $9,000/MWh for several hours on multiple days.[103]

6.3.3 Policy responses

In the aftermath of 2021 Winter Storm Uri, policymakers in Texas sought more stringent weatherization requirements for the power sector (focusing on generation and transmission in particular) with the passage of Senate Bill 3 in June 2021, which also mandated the reform of ERCOT towards improving grid reliability and resiliency.[104] By October 2021, the PUCT adopted new winter weatherization requirements, which include stipulations for Winter Weather Emergency Preparation measures, an annual Winter Weather Readiness Report filing requirement, a good-cause clause for noncompliance with the weatherization rules,[105] as well as inspections by ERCOT. If an entity is found to be noncompliant with the rules set out by the PUCT, they will have a grace period to correct the issue, before being charged a fine of $25,000 per day that the issue remains unresolved following that grace period.[106]

The first report on ERCOT's inspections was submitted to the PUCT in January 2022. The 2021/2022 winter inspections required more than 3,600 hours of effort from ERCOT staff and contractors.[107] Inspections were carried out on a total of 324 facilities (302 generators and 22 transmission service provider substations), of which only 10 generation facilities and 6 transmission substations were found to be deficient of the PUCT requirements. By January 17th, 2022, all the deficiencies had been addressed. ERCOT also noted that it received Winter Weather Readiness Reports from all 847 generation facilities and 54 transmission substations that were required to submit one.[108]

Aside from the new weatherization requirements, other responses to the 2021 Winter Storm Uri included:

- **market design changes towards improved grid reliability and resiliency:** the PUCT under Senate Bill 3 mandated ERCOT to carry out numerous market design changes, which are to be implemented in two distinct phases. The first phase involves enhancements to the current market design and is already underway – such as: lowering

---

103 Reuters. *Texas wholesale electric prices spike more than 10,000% amid outages.* February 15, 2021.

104 Utility Dive. *Texas lawmakers approve bill mandating power plant weatherization, market reforms.* June 4, 2021.

105 Under this clause, a generator or transmission service provider that believes it has a good cause for not complying with a specific weatherization rule can state its case as part of its Winter Weather Readiness Report filing. If the PUCT denies the initial assertion of good cause, the generator or transmission service provider can request approval of an exception on a temporary or permanent basis. *See* Vinson & Elkins. *After the storm: Public Utility Commission of Texas Adopts New Winter Weatherization Rule Requirements for ERCOT-based Generators and Transmission Service Providers.* November 10, 2021.

106 Ibid.

107 ERCOT. *Electric Generation Fleet Ready for Winter Weather Following ERCOT On-site Winterization Inspections.* December 30, 2021.

108 ERCOT. *ERCOT's Final Report on Winter Weather Readiness Inspections.* January 21, 2022.

the systemwide annual offer cap from $9,000/MWh to $5,000/MWh so that prices "plateau at a lower maximum price in deeper reserve shortages";[109] increasing the minimal contingency level (i.e., reserve capacity required to avoid cascading blackout) from 2,300 MW to 3,000 MW; improving demand response through the pursuit of higher energy efficiency standards, price transparency, and assessing the incorporation of virtual power plants; developing a firm fuel-based reliability service product with a goal to "provide added grid reliability and resiliency during extreme weather and compensate units with higher resiliency standards."[110] The second phase is expected to alter the current market design more radically;

- **securitization and financing of debt:** the Texas legislature passed House Bill 4492 along with Senate Bill 1580. Together, these two pieces of legislation enable ERCOT to utilize securitization and financing from the state's Economic Stabilization Fund ("ESF") for the outstanding balances that electric cooperatives and retail energy providers accumulated through Winter Storm Uri (US$3 billion in short-payments – i.e., amounts owed but not paid to ERCOT). The legislation also releases US$2.1 billion of financing towards reliability deployment price adder[111] and ancillary services charges in excess of the systemwide $9,000/MWh cap that were incurred during the storm;[112] and

- **community resiliency hubs:** at the local level, governments in cities such as Houston and Austin have established community resiliency hubs to provide vulnerable communities with shelter and back-up power during emergencies, as well as accelerated residential weatherization programs.[113]

Notably, El Paso Electric ("EPE") provides a useful example of how resiliency investments can mitigate the impacts of extreme weather events – see the textbox below.

El Paso Electric – the exception

Like other utilities with power plants in Texas, El Paso Electric experienced equipment failures owing to freezing temperatures during the 2011 Groundhog Day Blizzard. EPE's old Newman and Rio Grande power plants were forced out, and EPE customers experienced rolling blackouts. The freeze left the city of El Paso without water as well as without power.

---

109 Potomac Economics, Independent Market Monitor for ERCOT. *2021 State of the Market Report for the ERCOT Electricity Markets.* May 2022.

110 PUCT. *Project No. 52373, Review of Wholesale Electric Market Design: Memorandum.* December 6, 2021.

111 The real-time on-line reliability deployment price adder compensates "the market when generation that is priced out of the energy market is deployed for reliability purposes." (Source: S&P Global Commodity Insights. *ERCOT panel advances market changes driven by mid-February winter storm.* June 23, 2021)

112 Moody's. *Securitization will be a shock absorber for ERCOT defaults from February storm.* June 7, 2021.

113 RMI. *Are We Ready for Another Uri?* February 15, 2022.

Unlike other Texas power plant owners, however, after the 2011 storm EPE took measures to prevent a repeat of the same problems. It spent US$4.5 million to repair and better winterize its older power plants (Newman, Rio Grande, and Copper), and designed and built new units to withstand below-freezing temperatures – a new 93 MW combustion turbine at the existing Rio Grande plant, as well as the 372 MW Montana plant. EPE went from a plus-10-degree equipment design standard to a minus-10-degree design standard for these installations.

During the 2021 Winter Storm Uri, some units tripped offline, but unlike the rest of the state, EPE's customers did not experience major power outages – EPE reported that only 875 customers had been impacted by an outage of less than five minutes. By the end of 2021, EPE had also equipped one of its units to run on diesel fuel, which enables black-start generation in case of an emergency or systemwide outage.

Sources: El Paso Times. *Electricity primer: Not being connected to rest of Texas helped El Paso in cold wave.* February 17, 2021; Texas Tribune. *You might have heard that Texas has its own power grid. Did you know not all parts of the state use it?* February 18, 2021; KVIA ABC 7. *El Paso's not seeing power outages like the rest of Texas – here's why.* February 15, 2021; El Paso News. *El Paso Electric power plants can handle -10° weather.* February 2, 2022.

Key lessons for Ontario

- **Do not ignore a close call:** more than a decade ago, a major winter storm hit Texas, the 2011 Groundhog Day Blizzard. Most of the Texas power grid failed to learn lessons from the storm, with deadly consequences during the subsequent 2021 Winter Storm Uri.
- **Penalties need to be appropriately sized to initiate action:** following the 2011 Groundhog Day Blizzard, financial penalties capped at US$25,000 were imposed for failure to comply with essentially voluntary emergency operations plans. Following the 2021 Winter Storm Uri, higher fines of US$25,000 per day of noncompliance were introduced, alongside stricter inspection requirements.

6.4 Finland

Finland provides an example of a country which embedded significant resiliency-related incentives into its utility regulatory regime following a major storm. Whereas North American examples tend to follow cost of service approaches, several European countries use an incentive-based approach.

6.4.1 Overview of the Finnish regulatory system

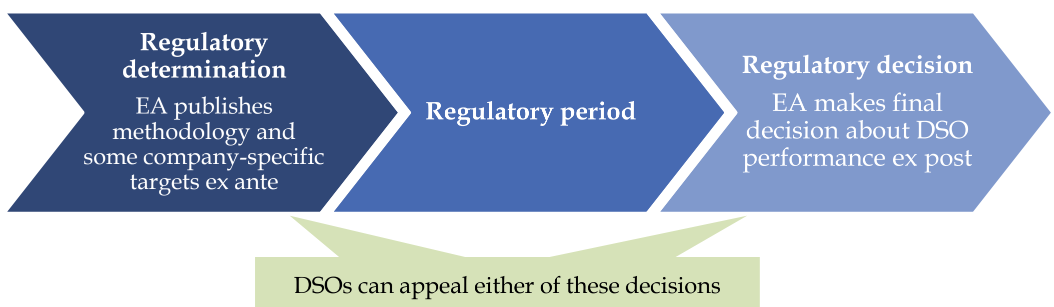
The Finnish electricity market is regulated by the Energy Authority ("EA") and was liberalized for large customers in 1995 and for all customers in 1997. The regulator must make determinations for 77 distribution system operators ("DSOs") in total, the largest three of which make up a combined market share of 41% (by metering points).[114] The EA has stated that a guiding principle of its regulatory framework is that all DSOs must be treated equally, regardless of their size or ownership; the regulation therefore follows a 'one size fits all' approach.[115]

The current regime was introduced in 2005 and four regulatory periods have been completed thus far:

- RP1 from 2005 to 2007;
- RP2 from 2008 to 2011;
- RP3 from 2012 to 2015; and
- RP4 from 2016 to 2019.

RP5 is ongoing and will run from January 1st, 2020 until December 31st, 2023.[116] Under the current regime, the regulatory process for electricity distribution networks in Finland is set for two four-year regulatory periods. Figure 10 below illustrates that the framework is essentially ex-ante in nature, with an ex-post review of performance to determine whether the appropriate quantum of revenue has been recovered.

Figure 10. Regulatory process in Finland



Source: Energy Authority. *Regulation methods in the fourth regulatory period of 1 January 2016 – 31 December 2019 and the fifth regulatory period of 1 January 2020 – 31 December 2023.* November 30, 2015.

6.4.2 Resiliency targets and the security of supply incentive

A key characteristic of the Finnish regulatory regime is a strong focus on security of supply. Severe outages were caused by major storms between 2010 and 2015, as shown in Figure 11 below. Most notable was the severe winter windstorm Tapani in 2011, which toppled trees in large forest

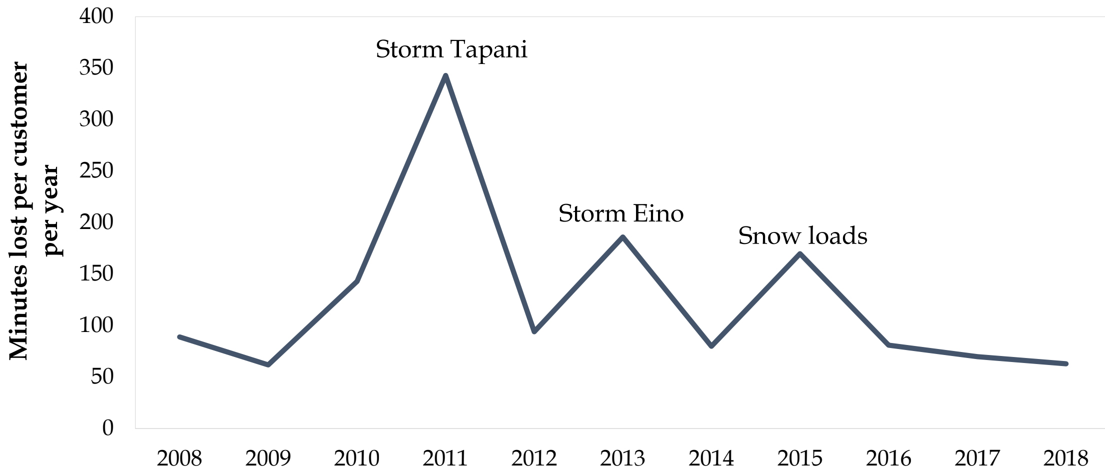
[114] Energy Authority. *National Report on the state electricity and gas markets in Finland to the Agency for the Cooperation of Energy Regulators and to the European Commission: Year 2021.* July 11, 2022.

[115] Energy Authority. *Regulation methods in the fourth regulatory period of 1 January 2016 – 31 December 2019 and the fifth regulatory period of 1 January 2020 – 31 December 2023.* November 30, 2015.

[116] Energy Authority. *Regulatory methods 2016-2023.*

areas, downing overhead lines and leaving over 500,000 customers without electricity, some for more than 15 days. DSOs faced total repair costs of approximately €102.5 million as a result of the damage caused by the storm, and had to pay around €71 million in compensation to customers.[117]

Figure 11. Average interruptions in Finnish distribution networks, 2008-2018



Source: Energy Authority. *National Report 2018 to the Agency for the Cooperation of Energy Regulators and to the European Commission.* July 11, 2019.

In the wake of Storm Tapani, and after power disruptions were cited as posing the largest threat to Finnish society's capability to function properly, policymakers sought a change in legislation to protect customers from the impact of severe storms. Climate risks vary across Finland's landscape, including regular snowstorms, the potential for more frequent forest fires, as well as sea level rise and coastal floods.[118]

In 2013, the Electricity Market Act ("EMA") was amended to enshrine resiliency targets in law based on restoration times. Specifically, the legislation required DSOs to ensure that any outage caused by storms or heavy snowfall is limited to a maximum of 6 hours in urban and suburban areas and 36 hours in rural areas. These targets were to be enforced gradually and were applicable to:

- 50% of customers by the end of 2019;
- 75% of customers by the end of 2023; and
- 100% of customers by the end of 2028.[119]

---

[117] OECD. *Critical infrastructure resilience case-study: Electricity transmission and distribution in Finland.* July 2019.

[118] Ibid.

[119] Caruna. *Annual Report 2018.*

To meet these targets, many DSOs chose to underground their medium to low voltage lines, although this is a relatively costly approach. For example, Finland's largest DSO, Caruna, which accounts for around 20% of electricity distribution in the country, has made significant progress in its weather-proofing program, having undergrounded 62% of its distribution network as of 2021 (see Figure 12), up from 40% in 2016.[120]

Figure 12. Caruna underground cabling rates, 2019-2021

Indicator	2019	2020	2021
Length of network	87,370 km	88,350 km	88,100 km
Total undergrounding	56%	59%	62%
Undergrounding in low voltage network	53%	55%	58%
Undergrounding in medium voltage network	64%	69%	72%

Source: Caruna. *Annual Report 2021.*

For the fourth and fifth regulatory periods (RP4 from 2016-2019, and RP5 starting in 2020), the EA incorporated a security of supply incentive to encourage resiliency investments to meet the EMA targets. The security of supply incentive has two components, investment and operational. Both are designed to compensate DSOs for any unexpected costs incurred to meet the legislative requirements:

- **investment component:** compensates DSOs that have to make early replacement investments by demolishing certain assets (e.g., overhead lines) before the end of their regulatory lifetime as a direct consequence of needing to make investments to meet the EMA targets. In this case, the incentive compensates the DSO for the revenues lost as a result of the reduction in the regulatory asset value ("RAV") (the write-down) associated with early demolition of the existing assets. Only components whose age is below the lower limit of the regulatory lifetime replacement interval (set by the regulator) can be remunerated through early demolition. The RAV write-down is calculated with reference to the shortest regulatory lifetime in the range determined by the EA, irrespective of the DSO's chosen regulatory lifetime; and

- **operational component:** compensates DSOs for carrying out extra maintenance measures on forests in the vicinity of their network by treating certain costs as pass-through items. These costs include activities for improving the management of forests located close to a network (which pose a security of supply risk), analysis and observation of tree risk, and pre-emptive tree cutting outside of line corridors.[121]

---

[120] Ibid.

[121] Energy Authority. *Regulation methods in the fourth regulatory period of 1 January 2016 – 31 December 2019 and the fifth regulatory period of 1 January 2020 – 31 December 2023.* November 30, 2015.

Notably, DSOs who could meet the EMA targets through normal replacement investments and maintenance could not utilize the security of supply incentive. The incentive was only intended to compensate DSOs for unexpected costs that became necessary as a result of the EMA targets.

However, in August 2021, policymakers again amended the EMA, making two notable changes. First, policymakers lowered the annual ceiling for increases in electricity network tariffs from 15% to 8%. Second, they extended the security of supply target date by eight years from 2028 to 2036, mainly for DSOs in sparsely populated areas that are required to undertake significant investments to meet their security of supply obligations. In describing the amendments, policymakers stated:

> "From now on, network operators must plan, build and maintain their grids in a way which ensures that the company delivers its service cost-effectively. Operators must compare alternative investments and consult customers during planning. The Energy Authority may order an operator to adjust its plans if the measures are not cost-effective. The legislative amendment seeks to ensure that, in addition to underground cabling, operators take all existing measures for upgrading networks, expanding capacity and improving security of supply into consideration more comprehensively. ... This also helps avoid premature investments in peripheral networks that would later prove unnecessary as alternatives to underground cabling currently under development become available for use in upgrading networks."[122]

In response to the amended legislation, the EA modified RP5, with changes taking effect in the beginning of 2022. Specifically, the EA removed the security of supply incentive from the regulatory framework.[123]

Key lessons for Ontario

- **Balancing resiliency and affordability is a key challenge:** in the aftermath of Storm Tapani, resiliency became a top priority for policymakers, resulting in ambitious security of supply targets and updates to the regulatory framework to introduce supportive incentives. However, as time went on, customers' cost sensitivity increased, and affordability became the preeminent concern, leading to an extension of resiliency target deadlines and a focus instead on cost containment.

- **Cost-effective investments require comprehensive planning:** many utilities chose to pursue undergrounding as the primary means to achieving resiliency targets. However, going forward, utilities will be required to evaluate alternative measures and consult with stakeholders as part of their planning efforts.

---

122 Finnish Ministry of Economics Affairs and Employment. *Legislative amendments curbing electricity distribution prices to take effect in early August.* July 15, 2021.

123 Energy Authority. *National Report on the state electricity and gas markets in Finland to the Agency for the Cooperation of Energy Regulators and to the European Commission: Year 2021.* July 11, 2022.

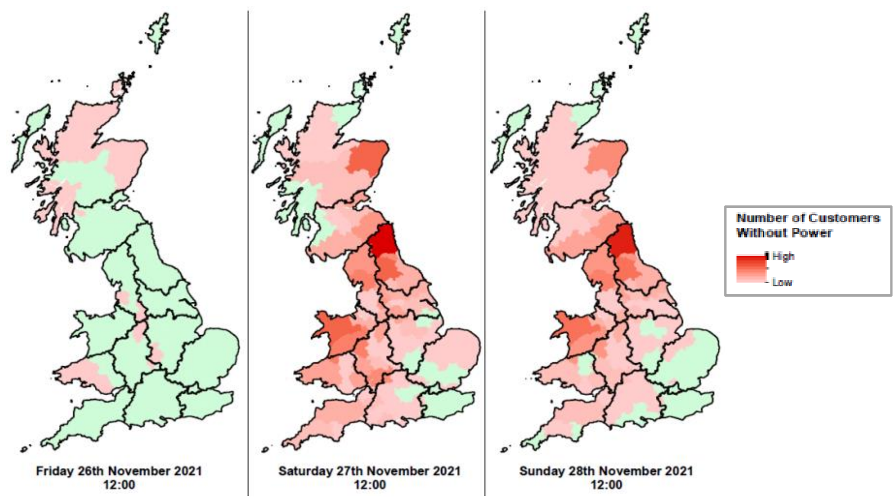
6.5 United Kingdom

The UK's attention on severe weather resilience sharpened following Storm Arwen in November 2021. Since then, two separate reviews assessing the distribution network operators' ("DNOs") response to the storm have been conducted, leading to a package of recommendations which have been reflected in the framework for the forthcoming regulatory period (RIIO-ED2). We discuss these initiatives in further detail below.

6.5.1 2021 Storm Arwen and subsequent investigations

The Office of Gas and Electricity Markets ("Ofgem"), the UK's energy regulator, and the Department for Business, Energy & Industrial Strategy ("BEIS"), through its Energy Emergencies Executive Committee ("E3C"),[124] have recently performed comprehensive reviews of how DNOs approach resilience and severe weather events.[125] These two reviews were triggered by Storm Arwen which, in late November 2021, brought severe weather to the UK, with winds reaching up to 158 km/h in some areas, knocking trees and branches onto power lines, as well as substantial snowfall in large parts of the country. Storm Arwen resulted in over one million customers losing power, 40,000 of whom were without power for more than three days, and approximately 4,000 of whom were without power for over a week, in many cases with poor communication and inadequate support (see Figure 13).[126]

Figure 13. Storm Arwen outages



Source: *See Figure 2*. Ofgem. *Final report on the review into the networks' response to Storm Arwen.* June 9, 2022.

[124] E3C was established by BEIS to oversee the UK's energy emergency planning and response efforts. *See* BEIS. *Preparing for and responding to energy emergencies.* Last updated February 23, 2021.

[125] Ofgem's final report reviewing the DNOs' response to Storm Arwen was published in June 2022 (*see* Ofgem. *Final report on the review into the networks' response to Storm Arwen.* June 9, 2022). E3C also published its review in June 2022 (*see* BEIS. *Energy Emergencies Executive Committee Storm Arwen Review: Final Report.* June 9, 2022).

[126] Ofgem. *RIIO-ED2 Final Determinations Overview document.* November 30, 2022.

The storm resulted in the DNOs paying nearly £30 million in mandatory customer compensations as well as voluntarily offering up an additional £10 million for customers, in recognition of some customer service and communication failings during the storm. Further storms in early 2022 (e.g., Storms Eunice and Franklin) further increased attention on this issue.

Following its review, Ofgem proposed several actions to minimize the impact of future severe weather events after it found that "thousands of customers were provided with an unacceptable service" during Storm Arwen.[127] Ofgem's recommendations, which will be taken forward and implemented primarily by E3C, involve actions to:

- **improve network resilience:** reviewing standards/guidance including those for vegetation management and overhead line design; improving the way asset health is monitored;
- **improve planning and preparation for storms:** introducing better processes to contact vulnerable customers prior to forecast storms hitting; requiring DNOs to submit annual Winter Preparedness Planning reports to Ofgem;
- **improve the handling of storm incidents to speed up restoration times:** reviewing industry standards for remote monitoring equipment on low voltage networks; improving mutual cooperation between DNOs in the event of storms, such as by sharing use of call centers and mobile back-up generators;
- **improve communication and support for customers during storms:** strengthening worst case scenario planning assumptions for call volumes and stress testing telephony systems/websites; improving communication channels; improving the measurement of restoration time that is required, so as to provide accurate customer compensations; and
- **improve customer support post-storm**: ensuring timely payment of compensations.

Similar recommendations were also reached by the E3C review.

6.5.2 RIIO incentives

At a high level, Ofgem, through its regulatory framework, RIIO (which is an acronym for **R**evenues = **I**ncentives + **I**nnovations + **O**utputs), provides DNOs with incentives and funding to ensure highly reliable and economical service. The DNOs are penalized through compensation payments to customers who experience specific levels of disruption (as pre-defined by Ofgem). In practice, this means that DNOs invest in ways to both prevent disruption and minimize the length of disruption when it does occur. Various industry codes dictate minimum standards on

[127] Ofgem. *Ofgem publishes full report following six-month review into networks' response to Storm Arwen.* June 9, 2022.

practices such as vegetation management – principal among these is the Electricity Safety, Quality and Continuity Regulations 2002.[128]

Ofgem reached its final decision on the forthcoming RIIO-ED2 price control in November 2022. Notably, outages due to storms and severe weather events will now be excluded from contributing to DNO performance under the standard reliability incentive – the Interruptions Incentive Scheme ("IIS"). The IIS is focused solely on "business as usual" outage circumstances. Under RIIO-ED2, action related to exceptional events will now be incentivized separately through the following mechanisms:

- **Storm Arwen re-opener:** Ofgem will allow DNOs to apply to re-open their cost allowances during RIIO-ED2 (specifically, in January 2024) if they are required to incur additional costs to implement Ofgem or E3C's recommendations. Ofgem can also trigger the re-opener outside of the January 2024 application window;

- **Severe Weather 1-in-20/Climate Resilience pass-through:** Ofgem will allow a pass-through for efficient costs incurred in the course of restoring service after a storm and supporting affected customers. A severe weather 1-in-20 event is classified as one where a DNO experiences at least 42 times its mean daily faults across its high voltage network within a 24-hour period;

- **increasing mandatory customer compensation for delayed storm response:** DNOs are required to provide customers with direct compensation for long duration outages due to severe weather under the Guaranteed Standards of Performance. For a Category 1 storm (causing between 8 to 12 times the daily average number of faults in a 24-hour period), DNOs have 24 hours to restore electricity supply before affected customers become eligible for compensation; for a Category 2 storm (causing more than 13 times the daily average number of faults in a 24-hour period), DNOs have 48 hours to restore service. Under RIIO-ED2, Ofgem is expected to increase mandatory customer compensation levels as follows: a customer that is eligible for compensation will receive an £80 initial payment, with an additional payment of £80 for every subsequent 12-hour period that a customer is off supply. Payments will be capped at £2,000 per customer, which is equal to 13 days off supply for a Category 1 storm and 14 days off supply for a Category 2 storm.[129] For reference, an average customer in the UK paid £91 per year in electricity distribution costs in 2021-2022.[130] The compensation cap would therefore be nearly 22 times higher than the distribution component of an average annual bill; and

- **planning and reporting requirements:** Ofgem has placed other requirements on the DNOs to provide information to Ofgem and customers. This includes filing an annual

---

128 UK Legislation. *The Electricity Safety, Quality and Continuity Regulations 2002.*

129 Ofgem is currently reviewing its severe weather compensation arrangements for electricity customers. These standards represent the proposed framework after the implementation of the latest recommendations. *See* Ofgem. *Review of Severe Weather Compensation Arrangements for Electricity Customers.* November 28, 2022.

130 Ofgem. *RIIO-ED1 Network Performance Summary 2020-21.* March 8, 2022.

Winter Preparedness Planning report, which is part of a wider annual report on how DNOs are approaching the protection of vulnerable customers. DNOs are also required to report data for a range of metrics aimed at targeting improvements in customer service, after the Storm Arwen reviews found that "during the storm, customers received poor service when attempting to contact their DNO."[131] Communication channel metrics that have been introduced in RIIO-ED2 are listed in Figure 14 below.[132]

Figure 14. RIIO-ED2 communication channel metrics

- Number of inbound communications that are received by the DNO's public contact channels
- Number of visits to the DNO's website
- Number of unique visitors to the DNO's website
- Maximum concurrent visitors to the DNO's website
- Average and maximum load time for the DNO's website
- Percentage of website load times that exceed 5 seconds
- Number of inbound communications received by the DNO's social media channels that are responded to by an automated message and agent
- Percentage of inbound queries or complaints received by the DNO's social media channels that are responded to
- Average and maximum response time for inbound communications received from the DNO's social media channels

Source: Ofgem. *RIIO-ED2 Final Determinations Core Methodology Document.* November 30, 2022.

Key lessons for Ontario

- **Unlike Texas, recommendations from inquiries should be acted on in a timely manner:** by the end of November 2022, a year after Storm Arwen hit the UK, most of the recommendations from Ofgem and E3C's investigations had been completed as planned and integrated into the forthcoming RIIO-ED2 framework where relevant.[133]

- **There should be a strong focus on customer service during major disruptions:** the RIIO-ED2 regulatory framework incorporates several resiliency-specific mechanisms, with a particular focus on customer protection. Following communication failings during Storm Arwen, Ofgem has introduced several metrics to target improvements in customer service and is also expected to raise mandatory customer compensation levels for delayed storm response.

[131] Ofgem. *RIIO-ED2 Final Determinations Core Methodology Document.* November 30, 2022. P. 111.

[132] Ofgem. *RIIO-ED2 Final Determinations Overview document.* November 30, 2022.

[133] Ibid. P. 88.

6.6 Australia

Extreme events such as bushfires, floods, and storms have led government agencies across Australia to focus on resiliency, especially at the state level. We begin by reviewing how resiliency investments fit into the current regulatory framework in Australia, and then present examples of climate resiliency initiatives launched in several states.

6.6.1 AER's approach to resiliency

The Australian Energy Regulator ("AER") has conducted limited work on resilience to date and does not directly incentivize resiliency investments in the current regulatory framework. Although resilience is not explicitly referenced in the National Electricity Rules ("NER"), which, among other things, govern the economic regulation of the services provided by electricity distribution networks,[134] the AER has recently defined network resilience as follows:

> "a performance characteristic of a network and its supporting systems (e.g., emergency response processes, etc.). It is the network's ability to continue to adequately provide network services and recover those services when subjected to disruptive events."[135]

While distribution network service providers ("DNSPs") are subject to reliability targets, similar expectations for resiliency have yet to be established. In terms of reliability, DNSPs' regulated maximum allowed revenues are subject to a reward or penalty each year under the Service Target Performance Incentive Scheme ("STPIS"), depending on whether they have over- or under-performed against a benchmark level of reliability (which is based on past performance). Notably, this assessment normalizes out and excludes certain extreme weather events (major event days).

Even though resilience is not explicitly mentioned in the NER, and resiliency expectations have not yet been established, the AER considers resilience-related funding to be accommodated by the NER through two mechanisms:[136]

1. **ex-ante**, via DNSPs' revenue proposals, forecasting the expected costs to be incurred in the upcoming five-year regulatory control period. Indeed, Ausgrid (the largest electricity distributor on the east coast) is expected to incorporate resiliency investments in its upcoming 2024-2029 regulatory proposal, as described in the textbox on the following page; and

2. **ex-post**, via a cost pass-through mechanism to recover actual costs related to pre-defined exogenous events, such as extreme weather events. This is similar to the Z-factor mechanism in Ontario, which we discuss later in Section 7.3. For example, AusNet Services was allowed to pass through restoration and repair costs related to a windstorm

---

[134] AEMC. *National Electricity Rules.*

[135] AER. *AER note on network resilience.* April 13, 2022.

[136] Ibid.

that occurred in October 2021 in Victoria, as described in the textbox on the following page.

In finding the optimal balance between the two funding mechanisms, the AER recognizes that "the right balance may need to change over time if we are seeing a material shift in more reactive outcomes that are higher cost than a proactive response to limiting the damage from extreme weather events."[137]

Ex-ante: Ausgrid's 2024-2029 regulatory proposal

In developing its 2024-2029 regulatory proposal, Ausgrid conducted extensive stakeholder engagement, and with respect to resilience, sought to gather "views on how our customers expect us to respond to climate change, its impact on our network and our customers." The utility is expected to file its plan with the AER shortly.

According to the draft plan, Ausgrid intends to invest approximately AU$310 million in building resilience over the 2024-2029 regulatory period, including AU$204 million to address climate risks and support network and community resilience, and AU$106 million to protect against cyber-attacks. The AU$310 million set aside for resiliency represents approximately 11% of the AU$2.9 billion in total expenditures envisioned as part of the 2024-2029 regulatory proposal. Through extensive stakeholder consultations, Ausgrid agreed to cap climate-related resiliency investments at AU$204 million to "support affordability" and ensure "price impacts are contained and climate risk is managed."

Resilience investments are informed by Ausgrid's first Climate Impact Assessment, with a study period out to 2090, which calculated the dollar value of network interruptions due to extreme weather events using the Value of Customer Reliability – an input developed by the AER. Investments are expected to be prioritized based on Ausgrid's Climate Resilience Framework, which was developed alongside stakeholders and requires the utility to "apply scientific evidence, analyze opportunities and options, report back on [its] findings via accountability measures, and engage with the community at all stages." An overview of the Climate Resilience Framework is included in Appendix A (Section 10).

Sources: Ausgrid. *Have your say: Climate Resilience*; Ausgrid. *Customer Engagement: Network Resilience Consultation*; Ausgrid. *Regulation: Regulatory Reset*; Ausgrid. *Our Draft Plan for 2024-29: For consultation.* September 2022.

[137] AER. *AER note on network resilience.* April 13, 2022. P. 8.

Ex-post: AusNet Services' October 2021 storm cost pass-through

In March 2022, AusNet Services sought to recover AU$6.1 million in costs related to a windstorm that occurred in October 2021 in Victoria, which saw wind gusts exceeding 100 km/h, and resulted in flooding, fallen trees, extensive damage to its system, and power outages for over 230,000 of its customers (30% of AusNet Services' customer base).

In June 2022, the AER approved AusNet Services' application, after it determined that the following criteria had been satisfied:

- **meets the definition of a natural disaster pass-through event,** namely a "cyclone, fire, flood, earthquake or other event, provided the event was not a consequence of the acts or omissions of the service provider." The AER further found that the storm was "responded to by State and Federal Governments as a natural disaster, unexpected, and caused severe damage to property";
- **meets the materiality threshold set forth in the NER,** namely 1% of the maximum allowable revenue in a regulatory year;
- **the DNSP submitted an application within 90 business days of the event,** although the AER can extend this deadline;
- **costs are not included in the annual revenue requirement and do not include business-as-usual costs –** to track its storm-related costs, AusNet Services created a specific project code in its accounting software and retained an independent consultant to review its financial records. AusNet Services also excluded fixed fees paid to contractors and costs related to office-based staff time from its claim; and
- **costs were prudent, efficient,** and were required to rectify the damage caused by the storm.

Source: AER. *Determination: October 2021 storm cost pass through – AusNet Services.* June 2022.

Ultimately, these costs are borne by consumers of network services. The AER publishes an Expenditure Forecast Assessment Guideline for DNSPs preparing expenditure forecasts to support their ex-ante revenue proposals.[138] The guideline allows for augmentation capex that is not triggered by demand, but includes triggers such as net market benefits. The AER's assessment of such capex may incorporate modelling of cost measures for such projects and detailed engineering reviews. When assessing resilience funding ex-ante, the AER recognizes the uncertainty that climatic conditions will have on electricity networks, and considers the following factors in its evaluation:

[138] AER. *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution.* August 2022.

- future network needs may not be the same as they are today;
- there is uncertainty as to what the future network needs are;
- there is also uncertainty from other related areas such as changes in demand and energy mix, as well as technological advances; and
- consumer and community preferences will be very important in the AER's consideration.[139]

Furthermore, in assessing whether proposed ex-ante resilience investments are prudent and efficient, the AER requires DNSPs to demonstrate the following, "within reason":

- there is a causal relationship between the proposed resilience expenditure and the expected increase in the extreme weather events;
- the proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered; and
- consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and they are supportive of the proposed expenditure. The AER also notes its interest in DNSPs conducting customers' willingness to pay studies based on "genuine engagement."[140]

6.6.2 State-level activities

At the state level, government agencies across Australia are addressing resiliency in their own way:

- **Economic Regulation Authority ("ERA"), Western Australia:** the ERA is responsible for the economic regulation of Western Power, the state-owned electricity transmission and distribution network. In September 2022, the ERA published its draft decision on Western Power's 2022-2027 regulatory proposal – the fifth access arrangement ("AA5")[141] – and characterized the AA5 regulatory period as pivotal to making "sure the grid is in as good a shape as it can be to enable this transformation to continue at pace."[142] As part of the draft decision, the ERA approved expenditures related to undergrounding power lines in urban areas.[143] Costs are generally shared between the local government, state

---

[139] AER. *AER note on network resilience.* April 13, 2022.

[140] Ibid.

[141] ERA. *Access Arrangement 2022-2027.* Last updated January 19, 2023.

[142] ABC News. *Grid renewal generates billion-dollar shock as costs of energy transition become clear.* September 25, 2022.

[143] ERA. *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27, Attachment 3B: AA5 Capital Expenditure.* September 9, 2022.

government, property owners, and consumers through programs such as the State Underground Power Program.[144] The shared funding arrangement reflects the benefits to various stakeholders through: improved reliability and security of electricity supply for customers; enhanced streetscapes and visual amenity, which increases property values for property owners; reduced street tree maintenance costs for local governments; improved street lighting and community safety; and reduced maintenance costs for Western Power;[145]

- **Electricity Distribution Network Resilience Review, Victoria:** in response to storms in 2021 that left communities without power for extended periods of time, the Victorian Government convened an expert panel to conduct a resiliency review,[146] which put forth a package of recommendations. In terms of short-term reforms (by 2025), the panel recommends implementing obligations for distribution utilities (with penalties for noncompliance) to invest in "locations that are at the highest risk of prolonged power outages due to extreme weather, and aim to reduce the likelihood of prolonged outages such as those experienced in 2021."[147] Medium- and longer-term reforms include establishing a process for utilities to "regularly (at least every 5 years) assess and report on the risk of extreme weather to their networks, and identify and implement solutions," and seeking to amend the national regulatory framework "to require investments in distribution network resilience from the next regulatory period (from 2026 onwards)";[148]

- **Queensland Competition Authority ("QCA"), Queensland:** as the state's regulator of water, rail, and ports, the QCA is currently reviewing whether to refine its regulatory approach to consider climate change risks.[149] QCA is the first economic regulator in Australia to conduct a full review of its regulatory approaches against the risks and opportunities provided by climate change (transitional and physical risks); and

- **Reconstruction Authority, New South Wales ("NSW"):** the NSW Reconstruction Authority was established through legislation in December 2022, in response to recent flood events.[150] The agency will lead the state's disaster prevention, preparedness, recovery, reconstruction, and adaptation efforts, including "[d]eveloping a State disaster mitigation plan and material to guide councils to prepare adaptation plans."[151]

---

144 Western Power. *Underground power.*

145 Government of Western Australia. *State Underground Power Program 2022-23.* Last updated November 14, 2022.

146 Victoria State Government. *Electricity Distribution Network Resilience Review.*

147 Victoria State Government. *Electricity Distribution Network Resilience Review: Final Recommendations Report.* May 2022.

148 Ibid.

149 QCA. *Climate change expenditure review 2022-23.*

150 NSW Government. *NSW Reconstruction Authority.*

151 NSW Department of Planning and Environment. *NSW Reconstruction Authority to be established.* September 11, 2022.

Key lessons for Ontario

- **Resiliency investments can be funded through existing mechanisms:** despite limited activity to date by the AER in evolving the regulatory framework to address climate resiliency concerns, distribution utilities are still able to propose resilience investments as part of their five-year forward-looking proposals, or recover costs related to extreme weather events through an ex-post pass-through mechanism.

- **Resiliency planning should incorporate stakeholder feedback and inputs:** Ausgrid's 2024-2029 regulatory proposal was developed through extensive stakeholder engagement, including an open comment period, focus groups, online forums, working group meetings, roundtable workshops, and surveys. This was in response to an AER directive requiring utilities to demonstrate consumer support for their ex-ante resiliency investment proposals.

6.7 Case study observations

The six case study examples show that resiliency initiatives are often reactive and are catalyzed by a specific major event – such as the 2012 Hurricane Sandy in New York, the 2013 Storm Tapani in Finland, or the 2021 Storm Arwen in the UK – or type of event – wildfires in California and bushfires in Australia. In Texas, it took two major events – the 2011 Groundhog Day Blizzard and 2021 Winter Storm Uri – before appropriate changes were pursued. The case study examples also demonstrate the variety of potential approaches that exist to addressing resiliency concerns:

- **New York** exemplifies a whole-of-government approach, where agencies throughout the state are involved in and actively consider climate resilience;

- **California** demonstrates how action can evolve over time – initially, there was a narrower focus on addressing wildfire risk, before an expanded climate vulnerability assessment process was introduced for the three largest IOUs;

- **Texas** serves as a cautionary tale about the consequences of taking inadequate action in response to extreme weather events, including a reluctance to impose appropriately sized financial penalties on noncompliant entities;

- **Finland** highlights the challenge of balancing ambitious resiliency targets and affordability, and shows that as time goes on, cost sensitivity increases;

- **the UK** shows a strong emphasis on customer protection, with Ofgem employing mandatory customer compensation payments for delayed storm restoration efforts, as well as introducing metrics to monitor and target improvements in customer service during severe weather events; and

- **Australia** suggests that resiliency investments can be supported despite limited evolution to the current regulatory framework.

7 Theoretical principles for addressing resiliency

The Minister's Letter of Direction states that "[a]s our climate changes, the OEB will have an important role to play in ensuring [local distribution companies ("LDCs")] are preparing their distribution infrastructure for these kinds of events. ... The time to reconsider the structure and regulation of the distribution sector is now."[152] Before identifying areas in the current regulatory framework that could be improved to support resiliency efforts, we first review the OEB's guiding regulatory principles and approach to capital planning. Because resiliency efforts require significant investments, a review of these principles will address the questions of how and who pays.

7.1 Bonbright principles

Professor James C. Bonbright published his seminal work, Principles of Public Utility Rates, in 1961 and through it, established several frequently cited principles for effective rate design. Specifically, Bonbright refers to "three primary criteria" or fundamental ratemaking objectives:

1. **recovery of the revenue requirement:** ultimately, rates should be effective in "yielding total revenue requirements under the fair-return standard";

2. **fair or equitable apportionment of costs among customers:** this objective "invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service"; and

3. **economic efficiency:** rates should be designed to "discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received."[153]

The principle of cost causation is central to criterion (2) above and should be a key guiding principle in developing an approach to resiliency. The basic idea is that the rates that customers pay should reflect the costs that their usage imposes on the system. If a customer that causes a certain cost also pays that cost, she will not unfairly burden other customers. In this way, cost causation ensures an equitable allocation of costs among customers. If cost causation is properly set, cross-subsidies (either between or within customer classes) are avoided. The term "beneficiary pays" is simply another way of expressing the idea that rates should follow cost causation principles. Use of a beneficiary pays approach to allocating costs produces economically efficient outcomes by providing customers with correct price signals; if there is divergence between the allocation of costs and the distribution of benefits, there is greater risk of uneconomic outcomes.

---

[152] Ontario Ministry of Energy. *Letter of Direction from the Minister of Energy to the Chair.* October 21, 2022.

[153] Bonbright, James C. *Principles of Public Utility Rates.* 1961 (Reprinted in 2005).

Bonbright also refers to other principles of a desirable rate structure, which he views as "ancillary" to the three criteria listed above, including:

- achieving the ""practical" attributes of simplicity, understandability, public acceptability, and feasibility of application";
- "freedom from controversies as to proper interpretation";
- "revenue stability from year to year";
- rate stability; and
- "avoidance of "undue discrimination" in rate relationships."[154]

These "ancillary" objectives serve to reinforce the "three primary criteria" – for example, a practical and simple rate design ensures increased transparency and greater understanding of rates, which ultimately advances equity and efficiency goals; similarly, avoiding undue discrimination reaffirms the objective of equity in rate design.

7.2 Ontario guiding regulatory principles

The Ontario Energy Board Act provides the OEB's mandate for electricity and natural gas regulation. With respect to electricity, the Board is guided by the following objectives in carrying out its responsibilities:

1. to inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service;
2. to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry;
3. to promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances; and
4. to facilitate innovation in the electricity sector.[155]

Although not explicitly referenced in the objectives above, resiliency can be thought to fall primarily under the first objective. This objective also highlights the crucial balancing act that is

[154] Ibid.

[155] *Ontario Energy Board Act, 1998.* From December 8, 2022.

central to the OEB's mandate: ensuring affordability (by "[protecting consumer] interests with respect to prices") while maintaining adequate electricity service.

7.3 Status quo: current Ontario regulatory processes to address resiliency

Under the current regulatory framework, the OEB approves capital investments through a five-year distribution system plan ("DSP"), which electricity distribution utilities must file in support of their rate applications, regardless of the rate-setting approach chosen.[156] The DSP details the distributor's asset management process and five-year capital expenditure plan. The investments included in the plan are informed by and prioritized using an asset condition assessment, which sets out "equipment testing results, maintenance and usage history, historical failures or system weaknesses" as well as "the consequences of the failure of assets (such as how many customers will be affected, the type of customers and the time to restore the system)."[157]

In addition to asset condition considerations, distributors generally plan their system to meet reliability targets set out by the OEB in the electric utility scorecards, as well as to meet load growth expectations. Proposed capital investments must fall into one of four eligible categories (see Figure 15), which are described by the OEB as follows:

- **system access investments:** modifications that a distributor is obligated to perform to provide customer(s) with access to electricity services via the distribution system;

- **system renewal investments:** replacing and/or refurbishing assets to extend their original service life and maintain the ability of the distribution system to provide customers with electricity services;

- **system service investments:** modifications made to ensure the distribution system continues to meet operational objectives while addressing anticipated future customer electricity service requirements; and

- **general plant:** modifications, replacements, or additions to assets that are not part of a distributor's system.[158]

---

[156] OEB. *Handbook for Utility Rate Applications.* October 13, 2016.

[157] Ibid. P. 13.

[158] OEB. *Filing Requirements for Electricity Distribution Rate Applications (2023 Edition): Distribution System Plan.* December 15, 2022.

Figure 15. Eligible investment categories for DSP filings

Investment category	Example drivers	Example projects/programs
System access	Customer service requests	• New customer connections • Modifications to existing customer connections • Expansions for customer connections or property development
	Other third-party infrastructure development requirements	• System modifications for property or infrastructure development
	Mandated service obligations	• Metering • Long-term load transfer
System renewal	Assets/asset systems at end of service life due to: • Failure • Failure risk • Substandard performance • High performance risk • Functional obsolescence	• Programs to refurbish/replace assets or asset systems
System service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	• Property acquisition • Capacity upgrade • Line extensions • Conservation and demand management activities that reduce peak demand
	System operational objectives: • Safety • Reliability • Power quality • System efficiency • Other performance/ functionality	• Protection and control upgrade • Automation • Supervisory control and data acquisition • Distribution loss reduction • New technologies/capabilities
General plant	• System capital investment support • System maintenance support • Business operations efficiency • Non-system physical plant	• Land acquisition • Structures and depreciable improvements • Equipment and tools • Supplies • Finance/admin/billing software and systems • Rolling stock • Intangibles

Source: *See Table 1.* OEB. *Filing Requirements for Electricity Distribution Rate Applications (2023 Edition): Distribution System Plan.* December 15, 2022.

In reviewing DSPs, the OEB considers the following questions:

- have filing requirements been addressed?
- does the plan provide a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized plan and corresponding capital and operational plans and budgets?

- how has the plan addressed the information and preferences gathered from the utility's customer engagement work?

- does the plan deliver quantifiable benefits for customers?

- does the plan support the achievement of the utility's identified outcomes, and the outcomes of the Renewed Regulatory Framework (customer focus, operational effectiveness, public policy responsiveness, and financial performance)?

- has the company controlled costs through optimization, prioritization and pacing?

- has the plan appropriately integrated conservation, renewable generation connection, regional plans, smart grid, and any relevant public policies?[159]

Incremental requests for capital funding in between rebasing periods are handled through the Incremental Capital Module ("ICM") and Advanced Capital Module ("ACM") mechanisms, provided the projects meet a materiality threshold, which is determined by a formula approved by the OEB.

The ICM is a capital tracker mechanism that allows for funding of significant capital investments for discrete projects during the incentive rate-setting ("IR") period, between cost-of-service applications to rebase rates. ICM capital projects must satisfy a materiality threshold to demonstrate that the incremental capital amounts are beyond the normal level of capex expected to be funded by rates, including the effect of customer and load growth. ICM treatment is requested and approved as part of the Price Cap IR application.[160] The ICM request must include the following:[161]

- an explanation for any ICM capital project that could not have been foreseen or sufficiently planned for as part of the utility's DSP;

- an established need for and prudence of the proposed projects;

- the materiality threshold calculation;

- the means test calculation,[162] and an explanation if the utility over-earned in the most recently completed year;

---

159 OEB. *Handbook for Utility Rate Applications.* October 13, 2016. P. 15.

160 Ibid.

161 OEB. *EB-2014-0219. New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.* September 18, 2014.

162 If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.

- the incremental revenue requirement calculation and proposed ICM rate riders; and
- an explanation for any significant differences between the capital budget forecast and the utility's DSP forecast.

The ACM is an evolution of the ICM. An ACM proposal is made during a utility's cost-of-service rebasing application to identify, based on the five-year DSP, qualifying incremental capital investments during the subsequent IR period that are necessary but require funding beyond what is sustained by IR-adjusted rates and customer and load growth. However, rate riders to fund ACM projects are only activated once the assets enter service during the IR period.[163]

Finally, the Z-factor mechanism allows for cost recovery during the IR period related to unforeseen events that are outside of the distributor's control. To be eligible for Z-factor treatment, costs must meet three criteria – causation, materiality (such that costs related to a single event must exceed a materiality threshold set by the OEB), and prudence.[164] However, while the Z-factor mechanism can provide ex-post recovery of costs related to extreme weather events, it is, by definition, a reactive measure. In contrast, the resiliency planning process envisioned in the remainder of this report is proactive in nature, and so would be expected to reduce the frequency of Z-factor applications related to severe weather going forward.

7.4 Key resulting questions

While resiliency is not explicitly mentioned as an investment driver under one of the four eligible DSP investment categories, resiliency would appear to fall most appropriately under either the "system renewal" or the "system service" categories, alongside other system operational objectives such as safety, reliability, power quality, and system efficiency (see Figure 15 shown previously on page 58).

The key questions that remain are determining the appropriate levels of resiliency investments and ensuring alignment with cost causation principles. To address these questions, clear resiliency expectations must be set, and standardized analytical frameworks and underlying assumptions developed to evaluate investment proposals. We explore these and other issues of concern in the next section.

---

163 OEB. *EB-2014-0219. New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.* September 18, 2014.

164 OEB. *Filing Requirements for Electricity Distribution Rate Applications (2022 Edition): Incentive Rate-Setting Applications.* May 24, 2022.

8 Issues of concern

LEI has been tasked with assessing five key issues of concern with respect to climate resilience, as summarized in the textbox below. We explore each issue in turn in the sections that follow, referring to the case study examples or presenting excerpts from relevant literature where appropriate. LEI views Issues #1 and #3 as being closely related, and so explores them in parallel in Section 8.1.

Issue #1: Defining and implementing resilience expectations for rate-regulated entities and the electric power distribution sector specifically.

Issue #2: The appropriate division of responsibility for resilience and continuity of service as between utility service providers, their customers, and other agencies or authorities, including local, provincial, or federal governments, and methods for doing so.

Issue #3: Regulatory policy, requirements, and expectations in response to elevated service risks stemming from increasing frequency and severity of extreme weather events, especially in the context of increased electrification.

Issue #4: Regulatory tools and methods for ensuring appropriate and cost-effective levels of investments, spending, planning, and operations in response to increased service continuity risk as a result of changing weather.

Issue #5: Assessment of gaps, opportunities, and relevant building blocks present in the current provincial framework for the regulation of electric power distribution in the context of ensuring appropriate, timely, and cost-effective responses to extreme weather events and customer expectations for reliable service.

Notably, these issues of concern are consistent with the key themes that LEI has observed in its review of resiliency literature. As an example, a study published by LBNL in April 2019 gathered representatives from state regulatory bodies, investor-owned utilities, co-operatives, and consumer advocacy agencies to present their views on five key resiliency questions, which align very closely with the issues explored in this section. The questions were:

1. What level and scope of resilience do we need and how much are we willing to pay?

2. Who's responsible for resilience, and how should other entities coordinate with utilities when there are mutual benefits?

3. What types of utility investments have the most impact on improving resilience, and how can utilities and regulators tell whether utility investments in resilience are impactful?

4. Should utilities take more proactive approaches to investments in resilience?

5. How can decision-making about resilience investments be improved?[165]

8.1 Resilience expectations and regulatory requirements

Utilities in Ontario need to have a clear understanding of the levels of resiliency they should target, the funding mechanism for achieving it, and the timeframe in which to do so. The current Ontario regulatory framework monitors two system reliability-related metrics – the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI") – which focuses utility attention on maintaining such metrics within five-year averages. Traditionally, North American utility regulators have tended to exclude, or track separately, outages due to major events.[166] European regulators have been narrowing the exceptions, and in some cases linking penalties for missed benchmarks to some form of Value of Lost Load ("VoLL").

Furthermore, while North American jurisdictions have tended to focus on review-intensive methods for resiliency planning and investment proposals (such as the statewide proceedings in New York and California discussed previously in Section 6.1 and Section 6.2, respectively), other jurisdictions have adopted an outputs-based approach, which links penalties for outages to costs to consumers (such as the mandatory compensation payments which serve as penalties for utilities in Finland and the UK, as discussed previously in Section 6.4 and Section 6.5, respectively). Notably, while many North American utilities face criticism over the speed of storm restoration efforts, the expectations are not always codified in advance.

Resiliency expectations can be considered under four categories: system hardening, speed of recovery, quality of customer communication, and development of temporary partial service offerings during outages. Examples of each might include:

- **system hardening:** increasing specifications for new equipment, and identifying "weakest links", assuming a greater frequency of severe events; the OEB could provide broad guidance about expectations of how, for example, revised definitions of 20-year and 100-year storms should impact capital planning and system awareness;
- **speed of recovery:** the OEB can clarify expectations with regards to speed of system recovery on average and for the last customers to be recovered, providing clear timeframes linked to the severity of the event, while recognizing that meeting new expectations requires funding. In the UK for example, Ofgem has employed mandatory customer compensation payments for delayed storm restoration efforts, which differ based on the severity of the storm (Category 1 or 2) – see Section 6.5 for further details.

---

165 LBNL. *Utility Investments in Resilience of Electricity Systems.* April 2019.

166 For example, the OEB excludes the impact of "Major Events" (also referred to as "high impact, infrequent weather events") from the data used to assess reliability performance, because these outage events are considered to be atypical, idiosyncratic, and outside of the distributor's control. (Source: OEB. *Report of the Board: Electricity Distribution System Reliability Measures and Expectations (EB-2014-0189).* August 25, 2015)

Finland similarly set its resiliency targets based on restoration times in rural versus urban and suburban areas (see Section 6.4 for further details).

There is a tension between assessing utilities' productivity and encouraging them to hold resources in reserve to accelerate recovery; the latter is inefficient in all years in which it is not needed, but precious when a severe event occurs. As demonstrated in Finland, memories fade; there may be a temptation to cut back on reserve resources after several years of limited events. The OEB will need to emphasize both recovery expectations and that reasonable investments to accelerate recovery will not be deemed imprudent;

- **quality of customer communication:** customer expectations with regards to the speed and accuracy of utility communications surrounding outages have been evolving as the range of communication methods has increased. Some behavioural economics studies[167] suggest that customers value reliable information about timing over the speed of a service or good's arrival; this suggests that investment in predictive algorithms linked to customer alerts may be one way of gaining a bit more time for system recovery. The OEB may wish to set specific standards regarding timeliness and accuracy of customer communication, by augmenting existing scorecard metrics related to service quality and customer satisfaction[168] and differentiating performance during major disruptions. The communication channel metrics introduced as part of the UK's RIIO-ED2 price control, such as average and maximum load time for the utility's website, and the average and maximum response time for inbound communications through the utility's social media channels, provide additional examples of potential metrics (see Figure 14 shown previously on page 48); and
- **development of temporary partial service offerings:** resiliency should be thought of not in terms of poles and wires, but rather in terms of access to the services for which customers are paying. During longer duration outages, having the opportunity to charge phones, household rechargeable batteries, laptops, and other devices can make a great difference in customer comfort. Initially, some with appropriately configured electric vehicles ("EVs") will be able to draw power from them for their houses; one can imagine utilities also contracting with EV owners to provide such services to others, or using a fleet of such vehicles to set up in parking lots, or leveraging strategically placed DERs

[167] Studies have focused mostly on transit systems. *For example, see* US Department of Transportation, Federal Highway Administration. *Does Travel Time Reliability Matter?* October 2019. However, similar findings have also been demonstrated in the utility sector. For example, Ofgem's investigation into the DNOs' response to Storm Arwen found that "[o]ne of the biggest issues customers faced related to communication around estimated time of restoration." Specifically, "28% of customers were given a restoration time that was not within 24 hours of their actual restoration time, with the worst affected customers being restored 12 days after their estimated restoration time." Quoting one customer's experience during the storm, Ofgem notes that "[i]f they had said from the outset that it could take 4, 5, or 6 days people would have made better, safer and more informed choices." Ofgem's investigation also found that "customers prefer knowing the worst-case scenario and being kept up to date with progress." *See* Ofgem. *Final report on the review into the networks' response to Storm Arwen.* June 9, 2022.

[168] *See* OEB. *Scorecard – Performance Measure Descriptions.*

along with larger mobile batteries to provide charging services. While these programs may be contestable, they may require a coordinating body (e.g., the utility) to then contract these services out to a third party. The OEB needs to explore the extent to which such programs are appropriate to fund through ratebase, which customers would be eligible, and how the programs would be implemented in the case of a severe event, and then develop an associated standard.[169] These programs could be piloted and tested through the OEB's Innovation Sandbox,[170] for example. LEI generally views temporary partial service offerings for residential customers as a continuation of distribution service, rather than as a supply activity.

There is also an equity component at play here in that lower income customers are less likely to have access to EVs or small back-up generators, and it may be worthwhile to consider programs targeting such customers. While it may be argued that higher consuming and/or higher income residential customers have the means to procure back-up services, the competitive market may fail to provide sufficient temporary service to low-income customers. As is the case in California, utilities are specifically required to engage with and consider vulnerabilities for disadvantaged communities throughout their resiliency planning processes (see Section 6.2 for further details). If there is a push towards electric heating, development of temporary partial service offerings will become more acute, particularly in winter; larger mobile battery units may need to be paired with heating centers, for example. However, as with improved customer communication, well thought out temporary service offerings may allow for greater tolerance of slightly longer recovery times, helping to manage affordability. Furthermore, although requiring a certain amount of back-up generation for low-income housing could fall under a landlord's responsibility through building codes or rental housing standards, this has implications for affordability; utilities would likely be best positioned to cost-effectively provide targeted temporary partial service offerings.

Resiliency expectations will become especially important to clarify in the context of increasing electrification. The increased reliance on electricity to meet heating and transportation needs will reduce customer tolerance for power outages, especially in the winter when prolonged disruptions would present a health and safety concern for customers requiring electricity for heating. Overall, electrification will increase load growth projections, and a lack of clear resiliency expectations to spur needed investments may make the goal of achieving electrification more difficult as customers fear lengthy outages interrupting electric heating.

In developing resiliency expectations, a report by the US DOE provides useful examples of potential resiliency metrics – see Figure 16 – which are categorized by consequence type and are

---

[169] For example, one can imagine requiring utilities to undertake reasonable efforts to develop temporary partial service offerings for low income residential customers that provide a minimum of X hours of charging capabilities per customer, such that no customer was more than Y km away from a charging center, and provided that the relevant municipality shoulders Z% of the cost.

[170] OEB. *Innovation Sandbox.*

grouped as either direct (i.e., a direct result of a major outage) or indirect (i.e., cascading impacts of the major outage on other sectors).

Figure 16. Examples of potential resiliency metrics

Consequence Category	Resilience Metric
Direct	
Electrical Service	Cumulative customer-hours of outages Cumulative customer energy demand not served Average number (or percentage) of customers experiencing an outage during a specified time period
Critical Electrical Service	Cumulative critical customer-hours of outages Critical customer energy demand not served Average number (or percentage) of critical loads that experience an outage
Restoration	Time to recovery Cost of recovery
Monetary	Loss of utility revenue Cost of grid damages (e.g., repair or replace lines, transformers) Cost of recovery Avoided outage cost
Indirect	
Community Function	Critical services without power (e.g., hospitals, fire stations, police stations) Critical services without power for more than *N* hours (e.g., *N* > hours of backup fuel requirement)
Monetary	Loss of assets and perishables Business interruption costs Impact on Gross Municipal Product or Gross Regional Product
Other Critical Assets	Key production facilities without power Key military facilities without power

Source: *See Table S.1.* US DOE, Grid Modernization Laboratory Consortium. *Grid Modernization: Metrics Analysis (GMLC1.1) – Resilience Reference Document, Volume 3.* April 2020.

Furthermore, incorporating resiliency in the regulatory framework means revisiting some traditional concepts. For example, the idea that all items in ratebase must be "used and useful" needs to be adjusted for equipment kept in reserve to improve resiliency. Likewise, a program where utilities purchase capacity or energy from EV owners (potentially including moving the vehicle itself) may require waivers from the restrictions on LDCs procuring electricity resources, even though it does not involve direct participation in Ontario wholesale markets. Alternative cost-benefit tests may need to be considered: for example, accelerated replacement of vehicle fleets may not be justified on its own, but if vehicles can provide limited service-restoration services as reverse flow batteries, such an investment might be justified. Similarly, undergrounding of selected distribution feeders may need to be reviewed from a resiliency perspective before being rejected as too costly.

The above examples suggest that a detailed, policy by policy review though a resiliency lens may be useful. This is not to say that because a policy or program is reviewed, it has to change. New vehicles or underground cables may still be a bad deal for ratepayers when resiliency is factored in; the benefit is in encouraging the conversation, rather than requiring a specific outcome as a result.

8.2 Division of responsibility for implementation and costs

Delivering resiliency in Ontario will be the work of many sectors and actors within them, acting with a degree of coordination to assure some commonality of expectations and standards. The International Energy Agency ("IEA") recognizes that there are "a range of actions needed by all stakeholders" to build climate resilient energy systems (see Figure 17 for some examples).[171] Implementation should clearly be left to the entity most capable of doing it; LDCs, for example, will not be repairing roads or fixing water treatment plants. However, the implementing entity may require supplemental funding. Resiliency can be paid for either by utility ratepayers, taxpayers at various levels of government, or by the customers of other goods and services into which a resiliency premium can be embedded. While in the short-term company shareholders could also be viewed as a theoretical source of funding through reduced margins, over time we would expect companies to attempt to recover such a margin by modifying their prices.

Figure 17. Climate resiliency measures by stakeholder group

Supply-side	Demand-side	Authorities and governments
• Conduct climate risk and impact assessment • Implement physical system improvement • Switch to water-efficient and heat-resilient production process • Diversify energy supply chain • Better monitoring for early warning and emergency response	• Ensure climate proofing in design and performance • Increase awareness and promote behavioural changes • Improve energy efficiency • Use smart and advanced technologies for better management • Adopt nature-based solutions • Switch to climate-resilient materials	• Enhance knowledge about climate risks and impacts • Establish appropriate policy frameworks • Mainstream climate resilience into relevant regulations • Mobilize financing and investment • Support adequate climate insurance • Ensure emergency preparedness

Source: IEA. *Climate Resilience for Energy Security.* November 2022.

Clarity with regards to resiliency expectations also provides clarity with regards to what customers are paying for. A recent report published by LBNL, which included an essay prepared by the representatives of 17 regulatory bodies across the MISO footprint, describes the cost allocation challenge posed by resiliency investments:

> "accurately charging for resilience costs may be difficult. First, resilience improvements in the utility sector may confer benefits beyond the service territory of the utility making those improvements. ... Second, resilience planning and improvements likely affect a broad swath of sectors, not just utilities. ... Whether and how beneficiaries that lie outside

[171] IEA. *Climate Resilience for Energy Security.* November 2022. P. 13.

> of the utility footprint or sector should contribute to the cost of resilience improvements may need to be considered by regulators and other governmental entities."[172]

Just as utilities have an obligation to serve only up to a standard connection, with additional fees charged beyond the standard connection, customers who need higher levels of resiliency will need to pay for it themselves. For example, data centers often require uninterrupted power supply for IT operations and are typically designed and built to meet high degrees of resilience, including through redundant electrical systems and onsite back-up generation[173] – this resiliency requirement is beyond what utilities and ratepayers would be expected to pay for. This aligns with the principle of cost causation; if customers require immediate recovery – a level of service which is clearly impossible for utilities to provide cost effectively across their systems – the customer that desires it should pay for it. Regulations in other sectors may need to evolve to incorporate this principle; for example, banks investing in back-up power for ATMs, or, given the increasing reliance on electronic payments, payment providers being required to have back-up power for both servers and their associated communications providers. Electricity customers would not pay for this; banking customers ultimately would.

But utilities may be asked to implement selected resiliency initiatives which may increase costs beyond what their customers broadly would be willing or able to pay. Many of these may fall into the temporary partial service category: for example, assuring that every town in its service territory has power to a warming center within 12 hours of an outage expected to last more than 24 hours. Warming centers have characteristics of public goods: it is unlikely that anyone would be asked for payment or turned away from one, making it difficult for any private investor to contemplate building one. Similarly, putting hospitals and police stations on separate circuits and providing back-up power within them may go beyond what is reasonable to incorporate into utility ratebase. The province, OEB, utilities, and municipalities need to work together to identify resiliency activities that the utility is best positioned to provide, but which due to their nature as public goods need to be paid for by taxpayers. Tabletop emergency preparedness exercises are just one example of a venue through which stakeholder responsibilities can be clarified.

Utilities may also need to identify codependent infrastructure and assure alignment. If LDCs are building infrastructure to meet 20-year storms, but that infrastructure can only be accessed on roads maintained to 100-year standards, LDC funding may be inefficient. Except for roads that solely or largely reach utility infrastructure, it is unreasonable to expect utility ratepayers to contribute to road improvements given that other users garner the bulk of the benefits. Funding for such infrastructure also needs to come from taxpayers unless each user can be charged directly for their usage. The federal resiliency initiatives described earlier in Section 5.1 demonstrate that some federal tax dollars are being directed at this area, providing one example of delineation between taxpayer and ratepayer financing.

---

[172] LBNL. *Utility Investments in Resilience of Electricity Systems.* April 2019.

[173] US DOE, Office of Energy Efficiency & Renewable Energy. *Designing and Managing Data Centers for Resilience: Demand Response and Microgrids.* December 3, 2019.

Outside of the power sector, the belief that electricity customers have a vertical demand curve (i.e., will not reduce usage regardless of price) persists; however, as alternatives to LDC service proliferate, it will be more difficult to push payment for public goods onto electricity ratepayers. This makes it critical that electricity ratepayers only be charged for the amount of resiliency that they demand (as assessed through surveys or other means), rather than that needed for either customers of other services, or for meeting public needs.

8.3 Determining appropriate and cost-effective levels of resiliency investments

Utilities require clear metrics and processes for considering resiliency investments. For example, Electricity Canada has developed a framework and several resources[174] to guide utilities through climate change adaptation planning (see Figure 18), which conform with best practices for risk-based management systems and align with the analytical tools used by utilities in the case study jurisdictions reviewed previously.

Figure 18. Eight step process for climate change adaptation planning

Source: *See Figure 1.* Electricity Canada. *Climate Change & Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada.* April 6, 2021.

However, developing risk-based assessments requires information that is currently scarce. This information falls into two categories: outage probability and cost. System models focusing on critical points of failure, which assess sensitivity to various impacts from volatile weather (extreme heat and cold, flooding, rapid temperature fluctuation, etc.), and the probability of those weather types, need to be updated and run. Then, the costs of addressing the issues need to be calculated. Finally, those costs need to be compared to value.

---

[174] *See* Electricity Canada. *Climate Change & Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada.* April 6, 2021; Electricity Canada. *Adapting to Climate Change: A Risk Management Guide for Utilities.* September 16, 2019.

New techniques, such as the use of digital twinning,[175] can help in assessing risks and impacts. However, VoLL calculations for Ontario are neither as recent, nor as granular, as needed for rational decision making. By developing, and periodically updating, VoLL, the OEB can provide utilities with a clear means of assessing the value of investments to improve resiliency. VoLL needs to be assessed regionally, seasonally, and for the time of day; as the ways in which customers use electricity change, VoLL needs to be updated appropriately.

The value from a VoLL study is not in precision, but rather in standardizing a framework for investment decisions. Saying that an investment will accelerate storm recovery by 24 hours is not sufficient information for a regulator to approve it; saying that the investment avoids expected outages of a net present value that is a multiple of the required investment may be. Not all resiliency investments are worthwhile, and regulators need to be cautious about being presented with ad hoc statements about the value of VoLL that may be inflated. By establishing a clear framework upfront, the OEB can both guide the discussion and streamline decision making. As was the case in Australia, Ausgrid utilized the regulator's Value of Customer Reliability metric to assess various resiliency investment options and develop its 2024-2029 regulatory proposal (see Section 6.6). As another example, Figure 19 summarizes how VoLL has been derived in selected European jurisdictions, which is used in determining reliability incentives.

Figure 19. VoLL in selected European jurisdictions

Germany	Norway	United Kingdom
• 2020 VoLL: €12.78/kWh • Macroeconomic approach to calculating VoLL • VoLL first calculated separately for households and the industrial, transport, and agricultural sector, and then aggregated into a uniform VoLL (i.e., no differentiation between customer types and/or network levels) • VoLL calculation based on three years of data • VoLL embedded within the incentive rate, to represent the €-value lost to customers during an interruption	• VoLL calculated for six customer groups and based on "willingness to pay" determined through customer surveys • Correction of VoLL based on month, days, time of day, and planned interruptions	• Single, uniform national VOLL used to compute the incentive rate - £16/kWh; indexed to inflation • The VOLL in the next price control period will be updated to reflect changes in electricity usage

Sources: Bundesnetzagentur; NVE-RME; Ofgem.

[175] A digital twin is a real-time, digital replica of a physical asset, which can incorporate engineering, construction, and operational data. Digital twinning can enhance asset design, project execution, and asset operations by allowing utilities to get a better understanding of asset condition and conduct tests and simulations, for example. *See* National Grid ESO. *Virtual Energy System.* February 2022.

8.4 Gaps and opportunities in the current provincial regulatory framework

The question of resiliency can largely be addressed within the current provincial regulatory framework. The matter is not one of developing new procedures or regulatory regimes; rather, it is a question of infusing consideration of resiliency into existing processes such as distribution system plans, the ACM, and the ICM. This means, for example, demonstrating how capex plans take resiliency into account; considering cost recovery for provisions for temporary partial service recovery plans; excluding resiliency investments from assessments of utility productivity; and augmenting reporting related to storm recovery communications.

However, there are gaps, which can primarily be addressed by collecting data, updating documentation, commissioning further research, and engaging with stakeholders. For example, the OEB's filing requirements for electricity distribution rate applications, including the section on developing DSPs,[176] could be augmented to explicitly discuss resiliency investments and incorporate risk-based planning requirements. The filing requirements could also be augmented to explicitly require utilities to incorporate climate projections in their planning approaches, acknowledging that future weather expectations differ from what the province has experienced historically as a result of climate change. Utilities should also be asked explicitly how the predictive value of historical data is impacted by climate change. Other gaps that would need to be addressed include developing a clear definition of resiliency, drafting common input parameters, and obtaining a greater understanding of the value customers put on resiliency. A more challenging task is to put in place regular intersectoral consultation pathways on resiliency, and further delineating responsibility for payment.

These observations are converted to illustrative recommendations in the following section.

[176] *See* OEB. *Filing Requirements for Electricity Distribution Rate Applications (2023 Edition): Distribution System Plan.* December 15, 2022.

9 Recommendations

9.1 Guiding factors

In assessing policies related to resiliency, LEI believes the OEB should bear in mind six guiding factors. Policies should:

1. be **data centered**, with a clear understanding of the magnitude of the risk being addressed;[177]

2. be **within the control** of the utilities being incentivized or penalized;

3. limit expectations to **reasonably foreseeable** risks;

4. incorporate an understanding of **customer willingness to pay** based on their own resiliency expectations;[178]

5. follow **principles of cost causation**, such that customers with greater need pay for their share; and

6. **discourage double dipping**, such that utilities are prevented from gaining funding for the same activity through multiple mechanisms, such as ratepayer funding for activities for which the utility ultimately receives full reimbursement through a tax credit.

9.2 Summary of illustrative recommendations

LEI recommends a series of ten steps to begin addressing resiliency concerns in Ontario – see Figure 20 on the following page. The steps were developed bearing in mind activities observed in other jurisdictions, while also taking into account Ontario's own regulatory framework.

Notably, LEI's recommendations are consistent with best practices cited in the resiliency literature. For example, the IEA outlines several policy measures which it views as effective in improving climate resilience of the electricity system – these include: assessing climate change risks and impacts using an evidence-based, scientific approach; mainstreaming climate resilience by integrating it as a core element of national plans and strategies; identifying cost-effective resilience measures through comprehensive planning processes; creating appropriate incentives for utilities to encourage timely investments; implementing measures such as physical system

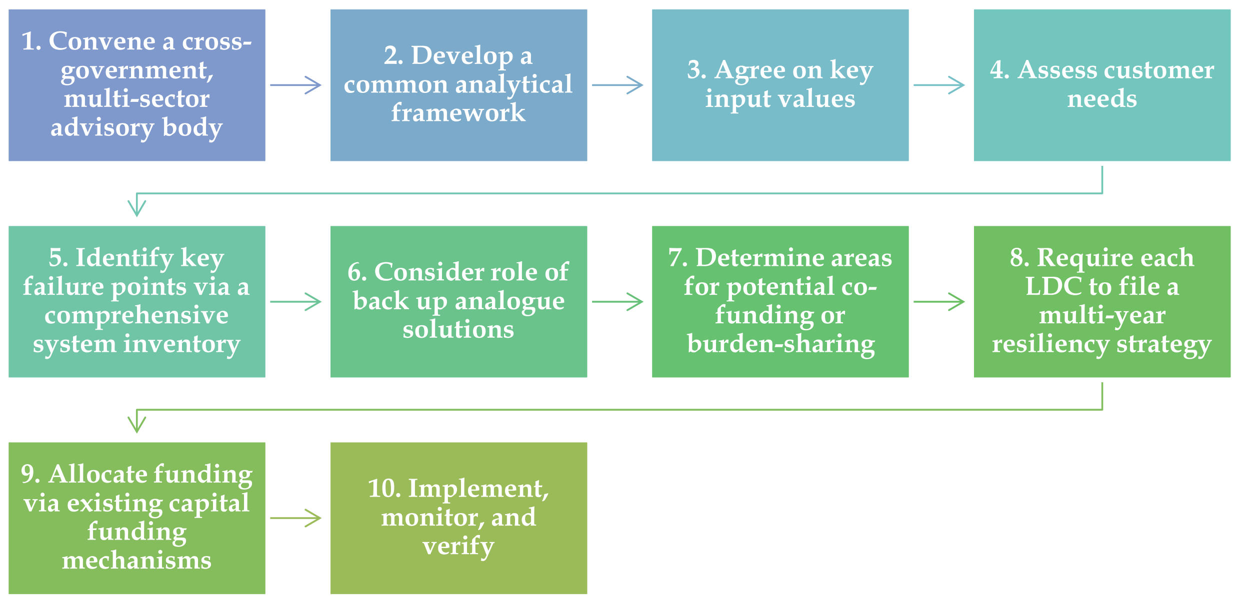
[177] Existing reliability data provides a foundation for a data centered approach, but needs to be translated into a predictive metric based on expected events and impacts.

[178] The customer willingness to pay estimates and customer resiliency expectations can be used to define a standard offering with regards to resiliency.

hardening, advanced system operation, and coordinated recovery efforts; and evaluating the effectiveness of resilience measures and adjusting accordingly.[179]

LEI's recommendations focus on actions that are within the OEB's control; given that resiliency is a cross-sectoral challenge, regular interaction with other relevant regulators and ministries would be helpful. As with all activities, there are tradeoffs: increasing investment in resiliency may impact affordability (though it may also reduce future disaster recovery expenditure); requiring resiliency planning may be viewed as an increase in red tape, although processes can be designed to streamline compliance.

Figure 20. LEI's illustrative recommendations



Note: In LEI's view, all ten steps need to be completed, but some steps could take place simultaneously.

9.2.1 Convene a cross-government, multi-sector advisory body

While there are a number of actions the OEB can pursue on its own to infuse resiliency into its regulatory procedures, regularly consulting with leaders in other sectors could help inform the OEB's initiatives. A similar multi-sectoral approach has been utilized in Finland, where ministries are assigned responsibility for critical infrastructure resilience and public private cooperation is encouraged through the National Emergency Supply Organization.[180] Although the OEB cannot compel other regulators, ministries, or entities outside its jurisdiction to participate, it can create terms of reference, develop the body, and invite members to join. By hosting a regular forum on

[179] *See* IEA. Climate Resilience. April 2021.

[180] *See* OECD. *Critical infrastructure resilience case-study: Electricity transmission and distribution in Finland.* July 2019.

resiliency, the OEB can raise awareness of the issue across the broader economy, including reminding those outside of the electricity sector that they share responsibility.

9.2.2 Develop a common analytical framework

A basic analytical framework for a resiliency investment would incorporate the cause of failure, the impact of the failure in terms of hours of supply loss, the probability of occurrence, the cost to reduce the frequency of occurrence, and VoLL. If the net present value of the avoided VoLL is greater than the cost to reduce the frequency of occurrence, a resiliency investment should be considered. Ideally, scenario analysis would be required. This is consistent with the analytical framework used by ConEd in New York, which combines a risk assessment and prioritization model and cost-benefit analysis model (see Section 6.1), as well as the decision-making framework developed by Ausgrid in Australia (see Appendix A, Section 10 for further details). While this business case style of analysis is not new for system investments,[181] it is important that the projects tagged as increasing resiliency are not given a free pass.

9.2.3 Agree on key input values

The OEB should develop a library of shared assumptions which serve as the starting point for applications which reference resiliency. These should include base levels of VoLL, assumptions regarding weather sensitivity of key distribution sector equipment (which can be assessed through a comprehensive system inventory, discussed in further detail later in Section 9.2.5), base level assumptions about policy goals such as electrification, and common climate and weather change assumptions that utilities can incorporate. For example, Ausgrid in preparing its 2024-2029 regulatory proposal used the Value of Customer Reliability developed by the AER as an input to its resiliency planning process (see Section 6.6). By setting up a shared assumptions library, the OEB should be able to narrow the field of debate in applications, in a similar fashion to the way in which the formulaic return on equity ("ROE") calculations reduce the number of hearings on ROE parameters. While utilities would still be able to claim special circumstances for using different assumptions in the resiliency plans envisioned in Section 9.2.8 below, they would be required to include the shared assumptions as a base scenario.

9.2.4 Assess customer needs

While calculation of VoLL, possibly through a process which includes customer surveys, will help to define customer needs, customers likely have specific views about the length of long-term outages and their willingness to pay to reduce them. For example, in Australia, the AER has encouraged utilities to conduct customer willingness to pay studies based on "genuine engagement", as a way to demonstrate the prudency and efficiency of proposed resiliency investments (see Section 6.6). In addition, customer feedback is needed regarding how best to design temporary partial service restoration measures which would be of greatest value and least

---

[181] For example, as part of their DSP filings, LDCs are required to provide "the cost-to-benefit analysis of the recommended alternative" in justifying their material investments. *See* OEB. *Filing Requirements for Electricity Distribution Rate Applications (2023 Edition): Distribution System Plan.* December 15, 2022.

inconvenience. This assessment need not be performed with the same frequency as updating the VoLL, but it should be performed periodically to have a full understanding of customer tastes and preferences.

9.2.5 Identify key failure points via a comprehensive system inventory

To ease the burden on utilities of pulling together a resiliency strategy, the OEB should consider commissioning an engineering firm to conduct a high-level inventory of material distribution system components and their sensitivity to climate change, with a particular focus on the types of climate impacts reasonably expected in Ontario. The inventory would highlight those system components most sensitive to extreme temperatures and flooding and the impact on the useful life of the equipment, which can be disseminated through the library of shared assumptions envisioned in Section 9.2.3 above. The inventory would also highlight cost effective resiliency aware asset management strategies observed in jurisdictions with similar climates to Ontario's. Although individual LDCs would need to perform their own analyses, similar to the vulnerability assessments required of utilities in New York and California (see Section 6.1 and Section 6.2, respectively), the system inventory would narrow the areas in which the LDCs should look, and potentially enable the analysis to be performed internally.

9.2.6 Consider role of back-up analogue solutions

Digitization continues to produce gains in efficiency and system reliability. This requires investments in back-up procedures such as cloud storage. However, just as the power system itself requires black-start capabilities to restart after an outage, resiliency plans need to consider how to restart the system when communications links are down. This may mean deliberately retaining some older systems and processes, retaining paper copy back-ups for system procedures, and periodically testing means of system operation when various digital components are out of service.

9.2.7 Determine areas for potential co-funding or burden-sharing

The OEB should develop a list of projects and project types which would require co-funding before being pursued by LDCs. This could include, for example, undergrounding service to key infrastructure such as mass transit or wastewater treatment facilities, creating islanding capability for public safety or health facilities, or other such infrastructure where the system investment is primarily to enhance a public good. Because a public good has beneficiaries that go beyond ratepayers, services that support a public good should not be disproportionately paid for by ratepayers.

9.2.8 Require each LDC to file a multi-year resiliency strategy

LDC resiliency strategies would inform their capital plans. The strategies would commence with region-specific information about climate change and its implications for the LDC's system. It would then identify key points of potential failure and lay out an approach to address them. The strategy need not include detailed costing; this can be reserved for subsequent rate filings. However, the strategy should consider various scenarios, note tradeoffs for customers, and provide assurance that the utility is thinking holistically about its investments and operations with regards to resiliency. Similar multi-year planning and reporting requirements have been introduced in New York, for example, as discussed previously in Section 6.1.

9.2.9 Allocate funding via existing capital funding mechanisms

The strategy above would feed into the various capital funding applications filed by the LDCs, as described previously in Section 7.3. The message should not be that all capital requests need to include a funding request for resiliency; rather, it is that utilities should demonstrate that resiliency has been considered in capex planning. There will be times when the most resilient approach is not the most cost-effective, and thus was rejected. As long as the question has been asked, then the utility has satisfied the requirement. However, it is likely that as resiliency is infused into decision making, new approaches will be developed which lead to different system designs, system monitoring, and operational decisions.

9.2.10 Implement, monitor, and verify

While plans and analysis are a necessary first step, until they result in action, they are useless. The failure of stakeholders in Texas to heed previous recommendations about winterization contributed to the system collapse after Winter Storm Uri; subsequently, inspections and consequences have both increased (see Section 6.3). The OEB will need to monitor whether LDCs are including consideration of resiliency in their applications, whether common frameworks and assumptions are being utilized, and whether cost sharing is being sought when appropriate.

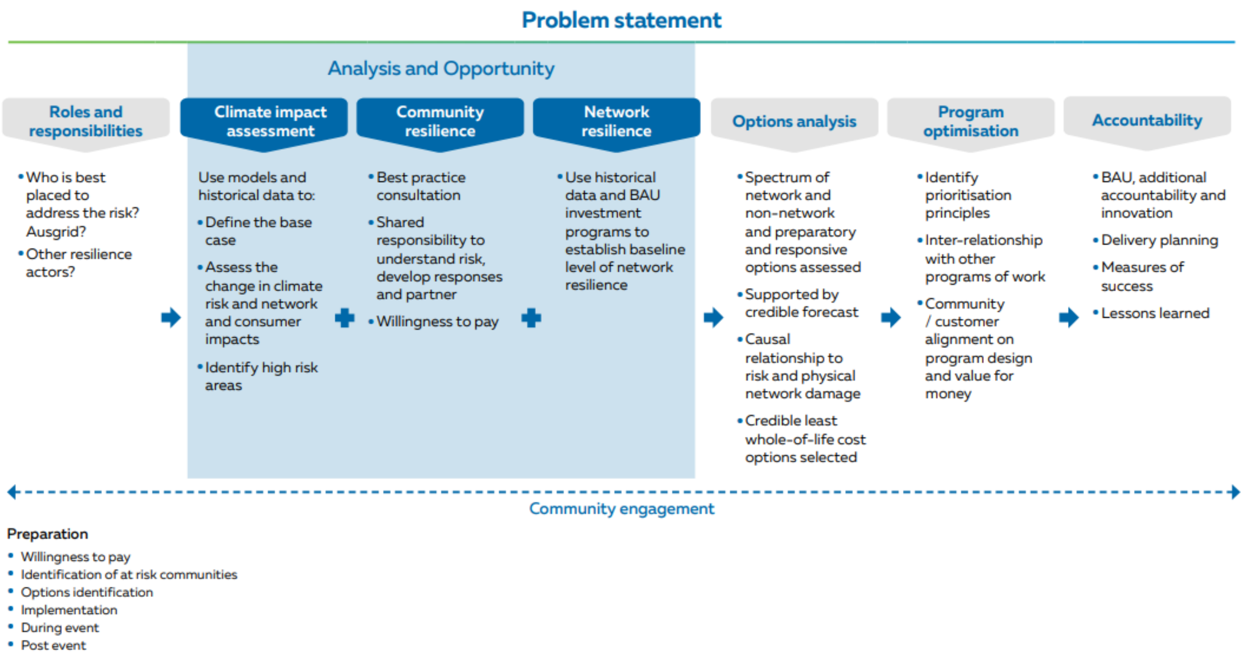
9.3 Concluding remarks

While Ontario has been experiencing warmer and more volatile weather, to date it has been spared events such as the catastrophic flooding in British Columbia or the wildfires of Australia and California. This, however, should not be cause for complacency. Although data analysis may reveal that the magnitude of the challenge for Ontario is presently lower than in coastal or drought-stricken regions, the cost of planning is far lower than the cost of responding to a disaster, which planning could have mitigated. Through careful assessment of risks and the cost and value of mitigation, Ontario can be better prepared for climatic threats to electricity infrastructure.

10 Appendix A: Ausgrid's Climate Resilience Framework

Ausgrid's Climate Resilience Framework is an evidence-based decision-making framework that was developed alongside stakeholders to prioritize resiliency investments included in the utility's 2024-2029 regulatory proposal. A high-level overview of the decision-making process is illustrated in Figure 21 below.

Figure 21. Ausgrid's Climate Resilience Framework process flow



Source: *Figure 2.2.* Ausgrid. *Promoting the long-term interests of consumers in a changing climate: A decision-making framework (for consultation).* September 2022.

The framework entails five key steps – these are:

1. **defining roles and responsibilities:** in order to clarify the roles and responsibilities of various entities that provide essential services and critical infrastructure, Ausgrid will distinguish between activities it is best placed to provide versus activities best provided by other entities. Ausgrid will also partner with government, local councils, resilience organizations, and local communities to develop localized resilience plans;

2. **conducting a climate impact assessment:** establishing a base case using historical data and conducting risk and impact modeling using climate change projections (assessing impacts on assets, network performance, and customers);

3. **identifying, reviewing, and evaluating options:** in determining viable investment options, Ausgrid will demonstrate fulfilment of the following criteria:

    - modeling is mature enough to support a credible forecast;

- investment decisions are based on the highest risks to customers using modeling of weather-related perils overlayed with their expected impact on customers;
- all resilience solutions have been considered and tested;
- Ausgrid has collaborated and engaged with customers and other resiliency actors;
- a causal relationship can be demonstrated between the proposed resiliency expenditure (by category or project/program) and a reduction in customer impacts from the increase in extreme weather which would otherwise be expected;
- the suite of benefits is supported by evidence (e.g., cost-benefit analysis) or, where required, trials are run concurrently with prioritized investments. The credible, least whole-of-life cost option(s) that promotes the maintenance of service levels is selected;
- there is customer support for the selected resilience options;
- Ausgrid can demonstrate that the benefitting communities are actively engaged in resiliency efforts at the local level and implementing their own resilience solutions in conjunction with Ausgrid investments; and
- intergenerational equity issues have been considered.

4. **preparing a resiliency portfolio:** once all economically viable options have been identified, Ausgrid will assess their inter-relationships with other program areas and develop an optimized portfolio of investments for the upcoming regulatory period based on principles such as: net present value, risk appetite, strategic alignment, balance between preparatory and responsive programs, customer feedback, and consistency with community resilience plans; and
5. **continuous accountability:** after the resiliency portfolio has been approved by the AER, Ausgrid will report on metrics related to stakeholder satisfaction and customer engagement outcomes, community preparedness, and network performance, as well as conduct a post-implementation evaluation of the Climate Resilience Framework before the end of the 2024-2029 regulatory period.[182]

[182] Ausgrid. *Promoting the long-term interests of consumers in a changing climate: A decision-making framework (for consultation).* September 2022.

11 Appendix B: List of works cited

ABC News. *Grid renewal generates billion-dollar shock as costs of energy transition become clear.* September 25, 2022.

AECOM. *Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment.* June 2015.

AECOM. *Toronto Hydro-Electric System Public Infrastructure Engineering Vulnerability Assessment Pilot Case Study.* September 21, 2012.

AEMC. *National Electricity Rules.*

AER. *AER note on network resilience.* April 13, 2022.

AER. *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution.* August 2022.

AER. Determination: October 2021 storm cost pass through – AusNet Services. June 2022.

Allgower, A. *Presentation at ERCOT Generator Winter Weatherization Workshop.* September 5, 2019.

Ausgrid. *Customer Engagement: Network Resilience Consultation.*

Ausgrid. *Have your say: Climate Resilience.*

Ausgrid. *Our Draft Plan for 2024-29: For consultation.* September 2022.

Ausgrid. *Promoting the long-term interests of consumers in a changing climate: A decision-making framework (for consultation).* September 2022.

Ausgrid. *Regulation: Regulatory Reset.*

BEIS. *Energy Emergencies Executive Committee Storm Arwen Review: Final Report.* June 9, 2022.

BEIS. *Preparing for and responding to energy emergencies.* Last updated February 23, 2021.

Bonbright, James C. *Principles of Public Utility Rates.* 1961 (Reprinted in 2005).

Busby, Joshua, et al. "Cascading risks: Understanding the 2021 winter blackout in Texas." *Energy Research & Social Science.* July 2021.

CAISO. *ISO Board Acts to Strengthen Grid Resiliency and Reliability.* September 19, 2017.

California Assembly. *Assembly Bill No. 205.* June 30, 2022.

California Department of Finance. *2022-23 State Budget.* June 27, 2022.

California Energy Commission. *Assessing the Impact of Wildfires on the California Electricity Grid.* August 2018.

California Natural Resources Agency. *Protecting Californians From Extreme Heat: A State Action Plan to Build Community Resilience.* April 28, 2022.

California State Geoportal. *California Electric Transmission Lines.* November 3, 2022.

California Wildfire Safety Advisory Board. *Recommendations to Office of Energy Infrastructure Safety on Additional Wildfire Mitigation Plan Requirements and Performance Metrics.* Adopted April 26, 2022.

Canadian Centre for Climate Services. *Climate Atlas of Canada.*

Caruna. *Annual Report 2018.*

Caruna. *Annual Report 2021.*

Central Hudson Gas & Electric Corporation et al. *Joint Utilities' Comments on Commission Inquiries Regarding Climate Vulnerability Studies and Plans (Case No. 22-E-0222).* August 15, 2022.

City of Austin & Travis County. Office of Homeland Security and Emergency Management. *2021 Winter Storm Uri After-Action Review Findings Report.* 2021.

City of New York. *Comments of the City of New York on Climate Vulnerability Studies (Case No. 22-E-0222).* August 15, 2022.

Climate Risk Institute. *Benchmarking Climate Change Adaptation Action in Ontario: Summary Report.* August 2022.

ConEd. *Climate Change Vulnerability Study*. December 19, 2020.

ConEd. *Long-Range Plan: Our Electric System.* January 2022.

ConEd. *Our Climate Change Resiliency Plan.* January 2021.

ConEd. *Storm Hardening and Resiliency Collaborative Phase Two Report.* September 2, 2014.

ConEd. *Storm Hardening and Resiliency Collaborative Report.* December 4, 2013.

CPUC and OEIS. *Memorandum of Understanding between the California Public Utilities Commission and the Office of Energy Infrastructure Safety.* July 12, 2021.

CPUC. Fire-Threat Maps and Fire-Safety Rulemaking.

CPUC. *Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Decision 20-08-046).* August 27, 2020.

CPUC. *Resiliency and Microgrids.* May 2022.

CPUC. *Wildfire and Wildfire Safety.* December 2021.

El Paso News. *El Paso Electric power plants can handle -10° weather.* February 2, 2022.

El Paso Times. *Electricity primer: Not being connected to rest of Texas helped El Paso in cold wave.* February 17, 2021.

Electricity Canada. *Adapting to Climate Change: A Risk Management Guide for Utilities.* September 16, 2019.

Electricity Canada. *Climate Change & Extreme Weather: A Guide to Adaptation Planning for Electricity Companies in Canada.* April 6, 2021.

Emergency Management Ontario. *Emergency management program resources.* Last updated July 18, 2022.

Emergency Management Ontario. *Ontario Critical Infrastructure Assurance Program Strategy.* Last updated July 18, 2022.

Emergency Management Ontario. *Provincial Emergency Management Strategy and Action Plan: A Safe, Practiced and Prepared Ontario.* February 3, 2023.

Energy Authority. *National Report 2018 to the Agency for the Cooperation of Energy Regulators and to the European Commission.* July 11, 2019.

Energy Authority. *National Report on the state electricity and gas markets in Finland to the Agency for the Cooperation of Energy Regulators and to the European Commission: Year 2021.* July 11, 2022.

Energy Authority. *Regulation methods in the fourth regulatory period of 1 January 2016 – 31 December 2019 and the fifth regulatory period of 1 January 2020 – 31 December 2023.* November 30, 2015.

Energy Authority. *Regulatory methods 2016-2023.*

Environment and Climate Change Canada. *Canada's National Adaptation Strategy: Building Resilient Communities and a Strong Economy.* November 24, 2022.

Environment and Climate Change Canada. *Climate change adaptation plans and actions.* Last modified February 2, 2022.

Environment and Climate Change Canada. *Federal Adaptation Policy Framework.* Last modified August 12, 2016.

Environment and Climate Change Canada. *Pan-Canadian Framework on Clean Growth and Climate Change: Canada's plan to address climate change and grow the economy.* 2016.

ERA. *Access Arrangement 2022-2027.* Last updated January 19, 2023.

ERA. *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27, Attachment 3B: AA5 Capital Expenditure.* September 9, 2022.

ERCOT. *Electric Generation Fleet Ready for Winter Weather Following ERCOT On-site Winterization Inspections.* December 30, 2021.

ERCOT. *ERCOT's Final Report on Winter Weather Readiness Inspections.* January 21, 2022.

ERCOT. *ERCOT's use of Energy Emergency Alerts.* March 2019.

ERCOT. *Fuel Mix Report: 2021.* March 7, 2022.

FERC/NERC Staff. *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations.* August 2011.

Finnish Ministry of Economics Affairs and Employment. *Legislative amendments curbing electricity distribution prices to take effect in early August.* July 15, 2021.

Fitch Ratings. *Upgrades for CA IOUs Dependent on Fewer Utility-Linked Wildfires.* August 31, 2022.

Government of Canada. *CMIP6 and Shared Socio-economic Pathways overview.* Last updated January 17, 2023.

Government of Western Australia. *State Underground Power Program 2022-23.* Last updated November 14, 2022.

IBC. *Combatting Canada's Rising Flood Costs: Natural infrastructure is an underutilized option.* September 17, 2018.

IBC. *Derecho Storm Ranks 6th Largest Insured Loss Event in Canadian History.* June 15, 2022.

IBC. *IBC applauds the Government of Ontario on its first Emergency Management Strategy and Action Plan.* February 3, 2023.

IBC. *Severe Weather in 2022 Caused $3.1 Billion in Insured Damage – making it the 3rd Worst Year for Insured Damage in Canadian History.* January 18, 2023.

IEA. *Climate Resilience.* April 2021.

IEA. *Climate Resilience for Energy Security.* November 2022.

IEA. *Climate Resiliency: Electricity Security 2021.* April 2021.

Infrastructure Canada. *Climate-Resilient Buildings and Core Public Infrastructure Initiative.* Last modified June 23, 2022.

Infrastructure Canada. *Government of Canada announces funds for climate resilient infrastructure initiatives.* June 28, 2022.

KVIA ABC 7. *El Paso's not seeing power outages like the rest of Texas – here's why.* February 15, 2021.

LBNL. *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* June 2009.

LBNL. *Utility Investments in Resilience of Electricity Systems.* April 2019.

Moody's. *Securitization will be a shock absorber for ERCOT defaults from February storm.* June 7, 2021.

National Grid ESO. *Virtual Energy System.* February 2022.

National Research Council of Canada. *Integrating climate resilience into building and design guides, standards and codes through the Climate Resilient Buildings and Core Public Infrastructure (CRBCPI) Initiative.* May 27, 2022.

Natural Resources Canada. *Chapter 3: Ontario (in Canada in a Changing Climate: Regional Perspectives Report).* August 15, 2022.

Natural Resources Canada. *Minister Wilkinson Releases New Report Showing the Impacts of Climate Change and Necessity of Climate Adaptation in Ontario.* August 15, 2022.

NERC. *Glossary of Terms Used in NERC Reliability Standards.* Updated December 2, 2022.

NREL. *Power Sector Resilience Planning Guidebook: A Self-Guided Reference for Practitioners.* June 2019.

NSW Department of Planning and Environment. *NSW Reconstruction Authority to be established.* September 11, 2022.

NSW Government. *NSW Reconstruction Authority.*

NY PSC. *Order Approving Electric, Gas and Steam Rate Plans in Accord With Joint Proposal (Case No. 13-E-0030 et al).* February 21, 2014.

NY PSC. *Order Initiating Proceeding (Case No. 22-E-0222).* June 16, 2022.

NYISO. *Climate Change Impact and Resilience Study.* September 12, 2020.

NYS 2100 Commission. *Recommendations to Improve the Strength and Resilience of the Empire State's Infrastructure.* January 11, 2013.

NYSERDA. *New York State Climate Impacts Assessment.*

NYSERDA. *NYSERDA Announces $3 Million to Assist Municipal Electric Utilities and Rural Cooperatives With Providing Decarbonized and Resilient Energy Services.* February 18, 2022.

OEB. *EB-2014-0219. New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.* September 18, 2014.

OEB. *Filing Requirements for Electricity Distribution Rate Applications (2022 Edition): Incentive Rate-Setting Applications.* May 24, 2022.

OEB. *Filing Requirements for Electricity Distribution Rate Applications (2023 Edition): Distribution System Plan.* December 15, 2022.

OEB. *Handbook for Utility Rate Applications.* October 13, 2016.

OEB. *Innovation Sandbox.*

OEB. *Report of the Board: Electricity Distribution System Reliability Measures and Expectations (EB-2014-0189).* August 25, 2015.

OEB. *Scorecard – Performance Measure Descriptions.*

OECD. *Critical infrastructure resilience case-study: Electricity transmission and distribution in Finland.* July 2019.

OEIS. *Wildfire Mitigation Plan Compliance.* January 2023.

Ofgem. *Final report on the review into the networks' response to Storm Arwen.* June 9, 2022.

Ofgem. *Ofgem publishes full report following six-month review into networks' response to Storm Arwen.* June 9, 2022.

Ofgem. *Review of Severe Weather Compensation Arrangements for Electricity Customers.* November 28, 2022.

Ofgem. *RIIO-ED1 Network Performance Summary 2020-21.* March 8, 2022.

Ofgem. *RIIO-ED2 Final Determinations Core Methodology Document.* November 30, 2022.

Ofgem. *RIIO-ED2 Final Determinations Overview document.* November 30, 2022.

Ontario Energy Board Act, 1998. From December 8, 2022.

Ontario Ministry of Energy. *Letter of Direction from the Minister of Energy to the Chair.* October 21, 2022.

Ontario Ministry of Environment, Conservation and Parks. *Ontario Launches First-Ever Climate Change Impact Assessment.* August 14, 2020.

Ontario Municipal Affairs and Housing. *Ontario Helps More Municipalities Prepare for Extreme Weather.* February 24, 2021.

PG&E. *2022 Wildfire Mitigation Plan.* February 25, 2022.

PG&E. *Community Microgrid Enablement Program.* May 2021.

PG&E. *Community Wildfire Safety Program.* September 11, 2019.

PG&E. *Safety Power Shutoffs.* October 17, 2019.

PG&E. *Undergrounding 10,000 Miles of Powerlines.* May 2022.

PJM. *Transmission Owner Guidelines: VI.A. Bare Overhead Transmission Conductor Ratings.* October 2022.

Potomac Economics, Independent Market Monitor for ERCOT. *2021 State of the Market Report for the ERCOT Electricity Markets.* May 2022.

Public Safety Canada. *National Cross Sector Forum: 2021-2023 Action Plan for Critical Infrastructure.* 2021.

Public Safety Canada. *The Canadian Disaster Database.* Last updated November 10, 2022.

PUCT. *Chapter 25. Substantive Rules Applicable to Electric Service Providers. §25.53. Electric Service Emergency Operations Plans.*

PUCT. *Project No. 52373, Review of Wholesale Electric Market Design: Memorandum.* December 6, 2021.

QCA. *Climate change expenditure review 2022-23.*

Redwood Coast Energy Authority. *Redwood Coast Airport Microgrid.* June 22, 2022.

Reuters. *Texas wholesale electric prices spike more than 10,000% amid outages.* February 15, 2021.

RMI. *Are We Ready for Another Uri?* February 15, 2022.

S&P Global Commodity Insights. *ERCOT panel advances market changes driven by mid-February winter storm.* June 23, 2021.

SCE. *SCE Wildfire and PSPS Risk Models.* October 5, 2021.

SCE. *Climate Change Vulnerability Assessment.* May 13, 2022.

SCE. *Wildfire Mitigation Plan.* February 18, 2022.

SDG&E. *2020-2022 Wildfire Mitigation Plan Update.* February 11, 2022.

SDG&E. *OIR Fire Threat Mapping.* August 2018.

Southern California Gas Company. *Working Group Session Report on Topic 5: Climate Change Adaptation and Decision-Making Framework.* January 15, 2020.

Stantec. *Distribution System Climate Risk and Vulnerability Assessment (Prepared for Hydro Ottawa Limited).* September 11, 2019.

Stantec. *Hydro Ottawa Climate Change Adaptation Plan.* November 11, 2019.

Texas Tribune. *Texas puts final estimate of winter storm death toll at 246.* January 3, 2022.

Texas Tribune. *You might have heard that Texas has its own power grid. Did you know not all parts of the state use it?* February 18, 2021.

The Globe and Mail. *Code minimum: Why your home isn't built to last against extreme weather.* January 27, 2023.

The New York State Senate. *Senate Bill S4824A.* February 12, 2021.

Toronto and Region Conservation. *Climate Change Vulnerability Assessment of Ontario's Electric Transmission Sector.* July 2015.

UC Berkeley Center for Law, Energy & the Environment, et al. *Clean and Resilient: Policy Solutions for California's Grid of the Future.* June 2020.

UK Legislation. *The Electricity Safety, Quality and Continuity Regulations 2002.*

University of Houston. *New Report Details Impact of Winter Storm Uri on Texans.* March 29, 2021.

US Department of Transportation, Federal Highway Administration. *Does Travel Time Reliability Matter?* October 2019.

US DOE, Grid Modernization Laboratory Consortium. *Grid Modernization: Metrics Analysis (GMLC1.1) – Resilience Reference Document, Volume 3.* April 2020.

US DOE, Office of Energy Efficiency & Renewable Energy. *Designing and Managing Data Centers for Resilience: Demand Response and Microgrids.* December 3, 2019.

US EIA. *Texas uses natural gas for electricity generation and home heating.* March 12, 2021.

Utility Dive. *Texas lawmakers approve bill mandating power plant weatherization, market reforms.* June 4, 2021.

Victoria State Government. *Electricity Distribution Network Resilience Review.*

Victoria State Government. *Electricity Distribution Network Resilience Review: Final Recommendations Report.* May 2022.

Vinson & Elkins. *After the storm: Public Utility Commission of Texas Adopts New Winter Weatherization Rule Requirements for ERCOT-based Generators and Transmission Service Providers.* November 10, 2021.

Western Power. *Underground power.*