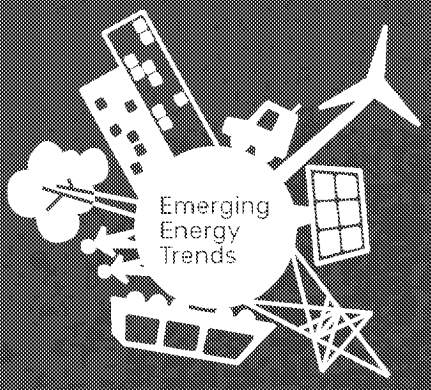
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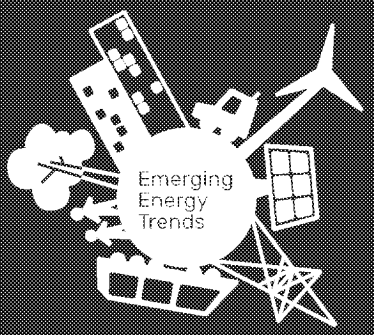
Emerging Energy Trends

REGULATORY RESPONSES TO ONTARIO'S ENERGY FUTURE



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Mowat Energy's *Emerging Energy Trends* is a comprehensive study of how technological and consumer disruptions in the energy sector could affect Ontario and beyond.

This report is the final report, informed by international research. All reports in the *Emerging Energy Trends* series are available at mowatcentre.ca/emerging-energy-trends.

The Mowat Energy research hub provides independent, evidence-based research and analysis on systemic energy policy issues facing Ontario and Canada. With its strong relationship with the energy sector, Mowat Energy has provided thought leadership to stakeholders, decision-makers and the public to help advance discussions on the challenges that energy is facing in Ontario.

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EXECUTIVE SUMMARY

In spring 2016 the Mowat Centre was engaged by the Ontario Ministry of Energy to commission international research on the role of distributed energy resources (DER) in energy distribution systems. After an international competition, Mowat selected acknowledged experts from Germany, the U.K., Scandinavia and the United States. As part of the project we also commissioned a very broad literature review, the purpose of which was to capture the voluminous scholarly work on this subject.[1]

This report analyzes the international work and provides our observations on the possible Ontario responses to the DER phenomenon.

DERs are generation, storage and demand management assets typically installed behind the distribution system meter. It can also include different configurations of customers into behind-the-meter microgrids. It includes small-scale generation such as wind, combined heat and power or electric vehicles.

In some jurisdictions the deployment of DERs, such as small-scale solar, has increased rapidly in recent years, often driven by incentives. The cost of some of these technologies has decreased in recent years.

In light of these developments, and the potentially revolutionary nature of the changes, we suggest that the transition should be governed through well-established economic regulatory principles. In this way the pace of, and the genuine economic effectiveness of, this transition can be responsibly accommodated, according to principled and transparent processes. Rate treatment should rest upon economic principles.

Regrettably, the peculiarities of energy systems in different jurisdictions make it impossible to directly transfer lessons from any other jurisdiction to Ontario.

From the research we found that properly integrating DERs could certainly provide value to the energy system, especially if the DER assets are deployed in specific locations. The research points to three crucial areas of interest when preparing for this transition:

» bottom-up regional planning process

» utility regulation and business model

» DER ratemaking.

1 All reports are available on our website at https://mowatcentre.ca/emerging-energy-trends/.



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Our paper suggests that the crucial first step in the appropriate accommodation of DERs into the energy distribution system is an enhanced regional planning process in Ontario, building on the current regional planning process. By engaging all relevant stakeholders in a transparent process, the true system value of DER deployments can be ascertained, and alternative sources of supply properly evaluated.

> *A fair, transparent and durable environment where DERs can compete on their own merits will allow for the development of an energy system that will benefit the entire province.*

As to utility regulation and business model considerations, there is a threat that material defection of load from distribution systems can have serious impacts on the system, the utilities and the respective rate classes. While some have posited that "freeing" utilities from the shackles of regulation is the answer, others argue that what is needed is an architecture that imposes some species of legacy obligation for defecting customers, arrived at through predictable processes and based on economic analysis. In this way the utility and its customers are protected from the effects of non-economic load defection.

DERs, if properly integrated, have the potential to provide numerous benefits to all utility customers, in addition to the developer. Developing appropriate rates that accurately price the cost and benefits of DERs to the system is necessary. It will also be necessary to move beyond simple flat feed-in tariffs or net energy metering to develop new sophisticated rate designs that take into account:

» location

» system services

» ancillary services

» avoided energy or infrastructure costs.

The textbox on the following page looks at how these three areas of transition can be incorporated into the Ontario energy sector.

A fair, transparent and durable environment where DERs can compete on their own merits will allow for the development of an energy system that will benefit the entire province.



Ontario's path forward

PLANNING

» The regional planning activity needs to be significantly more inclusive, formatted and comprehensive.

» All stakeholders, including developers, should play a larger role in the regional planning initiative.

» Integrated planning should enable local distribution companies to better coordinate operations with local and provincial stakeholders.

» During this process, suitable locations for DER development – locations that can provide system services – should be identified.

» Planning should be agnostic respecting technology and fuel sources, and should consider objectively the full scope of relevant energy options.

UTILITY REGULATION AND BUSINESS MODEL

» Any involvement of the utility should ensure that the competitive market can continue to function in a fair and economic manner.

» If utilities were to engage in competitive activities there are numerous material adjustments to the regulatory context that will need to be made.

» Any future rate design has to ensure that fixed and legacy system costs are covered, and that the system does not have to absorb undue new burdens.

DER RATEMAKING

» Any DER rate should be very locational and temporally specific.

» The locational rates where DERs could provide system services should be identified during the planning process.

» Rates should be technologically neutral, and driven only by value the proposed deployment provides to the system.

» Incentives should not be part of the ratemaking process.

» Compensation should be based on regulatory economics and the value the DER development brings to the energy system.



1 INTRODUCTION

Ontario's energy system is entering an era of transition. The impending reduction of our reliance on carbon-emitting energy sources, an increasing stream of technological advance and a growing consumer interest in the decentralization of energy management to give consumers a larger role in energy management, have the potential to alter the landscape of Ontario's energy system. This transition has implications for all stakeholders – including regulators, policymakers, consumers, generators and energy service entrepreneurs.

Distributed energy resources (DERs) are a critical component of this transition.

The opportunities opened up by DERs, as well as the disruptive risks they may entail, require a proactive approach from government and regulators. It is critical that Ontario gets this transition right, capturing maximum economic, social and environmental value from DERs while prudently managing the risks entailed in their disruptive impacts. Examining and learning from the successes and missteps of other jurisdictions in approaching DERs is an important learning opportunity for Ontario.

Mowat Energy was commissioned by the Ontario Ministry of Energy to procure a series of international research papers documenting the experience of other jurisdictions in accommodating DERs. Reports were procured from Germany, Scandinavia, the U.K. and the United States. We also commissioned a literature survey designed to capture the very large, and growing, body of scholarly work on the subject.

The purpose of this report is to distill the international research, consider its relevance for the Ontario context, and to provide possible *approaches* for the consideration of policymakers and regulators.

1.1 Distributed energy resources (DERs)

DERs are technologies and approaches directed to supplanting the highly centralized supply architecture that has characterized the North American energy system virtually from its beginnings a century ago. These technologies are "distributed" in so far as they are not centralized and typically are installed or effected behind the local distribution utility meter. They are "energy" to the extent that they are intended to influence the availability of energy to customers' premises, and they are "resources" to the extent



Types of distributed energy resources

DISTRIBUTED GENERATION (DG)

Power-generating technologies, including variable renewable energy sources such as solar and wind, as well as gas-fired and diesel-fired generators.

ENERGY STORAGE

Storage includes both electricity storage technologies such as batteries or fly wheels, and other forms that allow energy to be used at a later point (such as heat storage). Electric vehicles could be used as a form of energy storage.

DEMAND RESPONSE (DR)

Technologies that allow consumers to alter their consumption patterns based on some signal, such as market prices or grid congestion.

ENERGY EFFICIENCY

Technologies that reduce overall consumption, such as LED bulbs or more efficient air conditioning.

MICROGRIDS

Microgrids are small localized grids that can operate independently of the larger public grid. By using local sources of energy to serve local loads, microgrids can help in the integration of DG.

Source: Adapted from National Association of Regulatory Utility Commissioners (NARUC). Staff Subcommittee on Rate Design. *Draft NARUC Manual on Distributed Energy Resources Compensation*. 2016. At http://pubs.naruc.org/pub/88954963-0F01-F4D9-FBA3-AC9346B18FB2.

that they can include localized generation assets such as cogeneration plants and solar installations, storage assets of all kinds, including electric vehicles, demand management strategies intended to reduce consumption, especially at system peaks, and also varieties of consumer configurations – for example the development of microgrids, which are, in the nature of collectives, intended to produce a higher degree of cost control and reliability for members.

There are five main categories of DERs (see sidebar).

It is often the case that DERs are intended to create revenue opportunities for developers through the sale of surplus electrons back into the energy system, which can be an important incentive behind deployment. DERs can also be directed to solving reliability issues for customers who are intolerant of system interruptions, including momentary interruptions, a frustration that is an increasingly important phenomenon in the digital age.

DERs can also assist consumers who may simply want to gain insulation from rising and somewhat volatile electricity prices. The trajectory of electricity prices in Ontario has become a matter of real concern to consumers and policymakers.

There is also a category of customers who simply wish to participate in the evolution of an "environmentally friendly" energy system. The development of a low carbon economy, related to climate change policy, is a growing preoccupation of policymakers and some consumers. Varieties of DER implementation may also serve to support and accelerate the creation of a low carbon system.

Whatever the motivation, or combination of motivations, that consumers may have to make investments in DER deployment, it is expected that this phenomenon will become increasingly important as technologies evolve and costs moderate. One of the key challenges for policymakers and regulators in Ontario is to establish a regime that provides predictability of regulatory treatment for prospective DER deployers. Developers and consumers need to know what the economic factors are that will affect the cost-effectiveness of their investments.

Another key question concerns the pace at which DER deployment may occur. In some jurisdictions there has been a very rapid and transformative uptake of DER opportunities. In others deployment has been modest. Policymakers and regulators may need to create conditions that are flexible enough to accommodate a somewhat unpredictable pace of change.

1.2 The Ontario energy context

The Ontario energy market has some idiosyncrasies relevant to the accommodation of DERs, which are explained in a *Background Report on the Ontario Energy Sector*, prepared by Mowat Energy.[2] Out of province readers in particular are encouraged to read this report in order to have an appreciation of some of these local factors.

One of the key local factors that has relevance for DER deployment is the fact that for the foreseeable future Ontario has, through a combination of long-term energy purchase contracts and existing centralized generation resources, a significant surplus of supply. This is certainly true of the electricity market, which has recently led to the cancellation of several pending renewable energy projects by the Ontario government. There is also no indication that the supply of reasonably priced natural gas will contract any time soon. A recently announced agreement to purchase some electricity from, and to "park" some surplus electricity in, Quebec, may have some implications from a supply-side point of view, though the details of this agreement were not yet available at the time of this paper's writing.

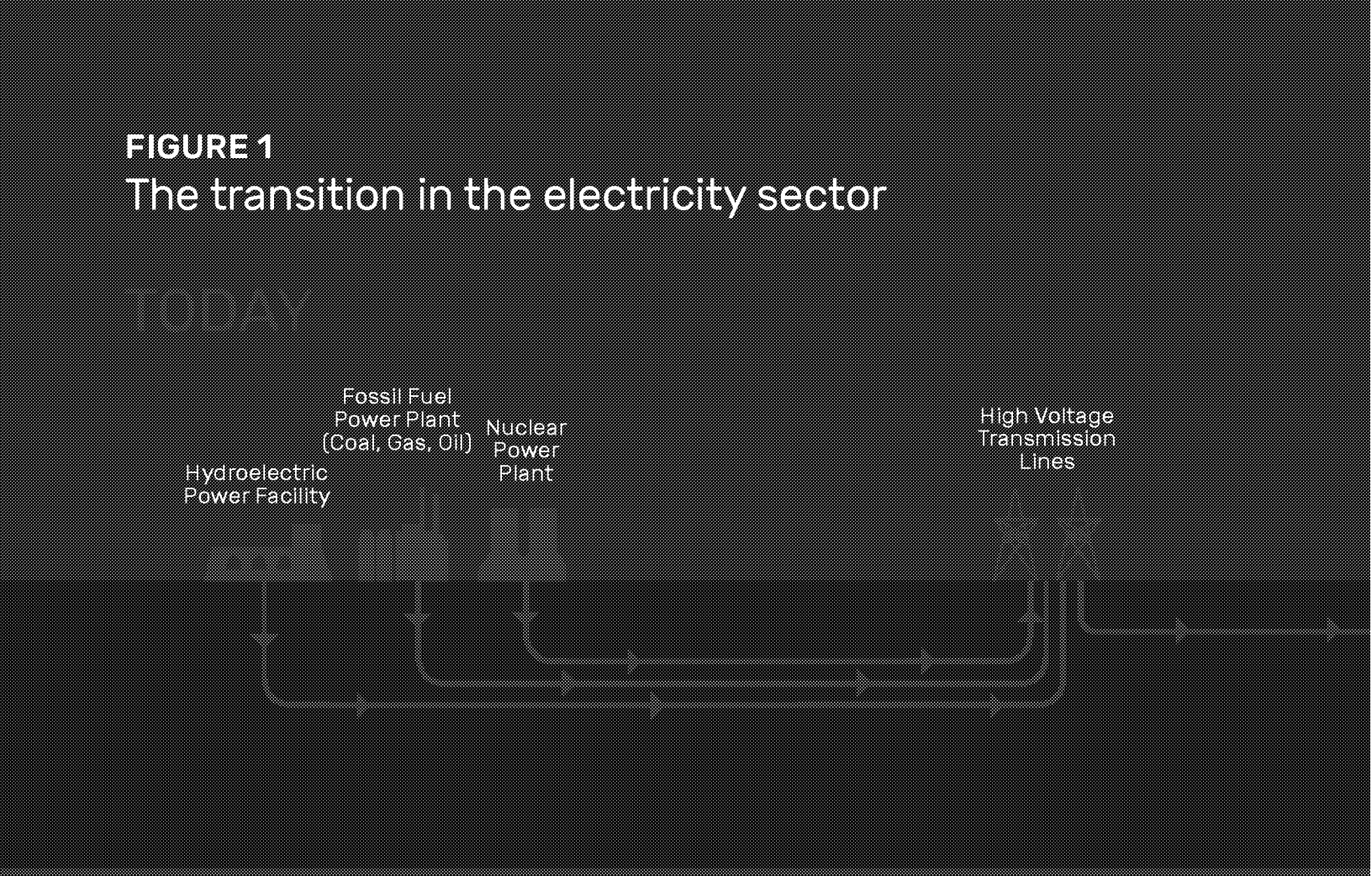
The current energy regulatory, market and governance system was established over the last century when overall energy demand was increasing and was assumed to continue doing so. It was also a time when large monopoly utilities dominated the sector. Energy was provided in a top-down way – from large central locations down to the different consumers. This top-down structure was evident in electricity (see Figure 1).

2 Mowat Energy, *Background Report on the Ontario Energy Sector*, Mowat Research #134, December 2016. At https://www.mowatcentre.ca/wp-content/uploads/publications/134_EET_background_report_on_the_ontario_energy-sector.pdf.



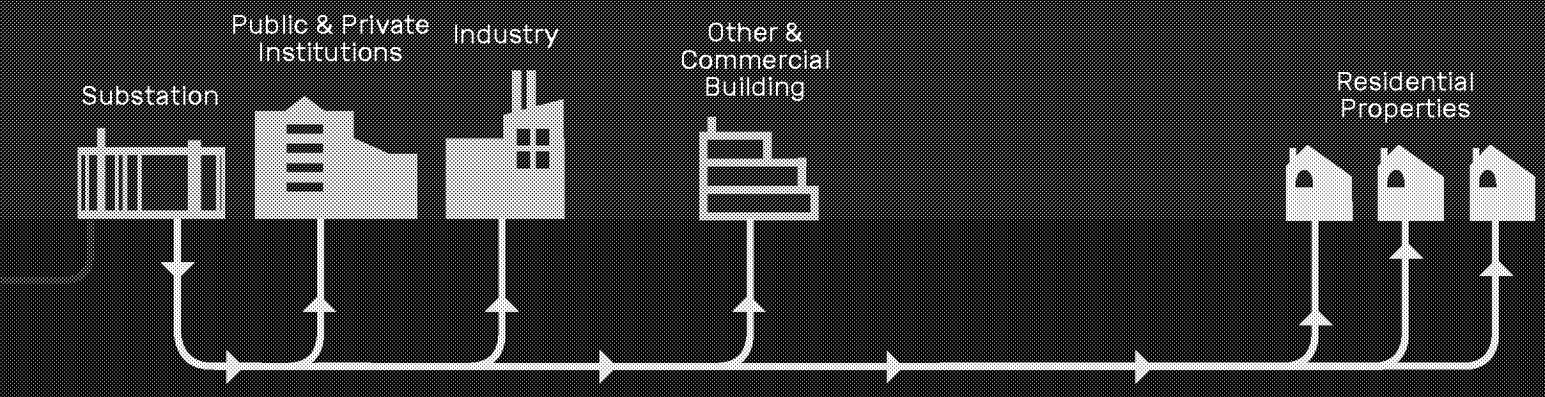
FIGURE 1

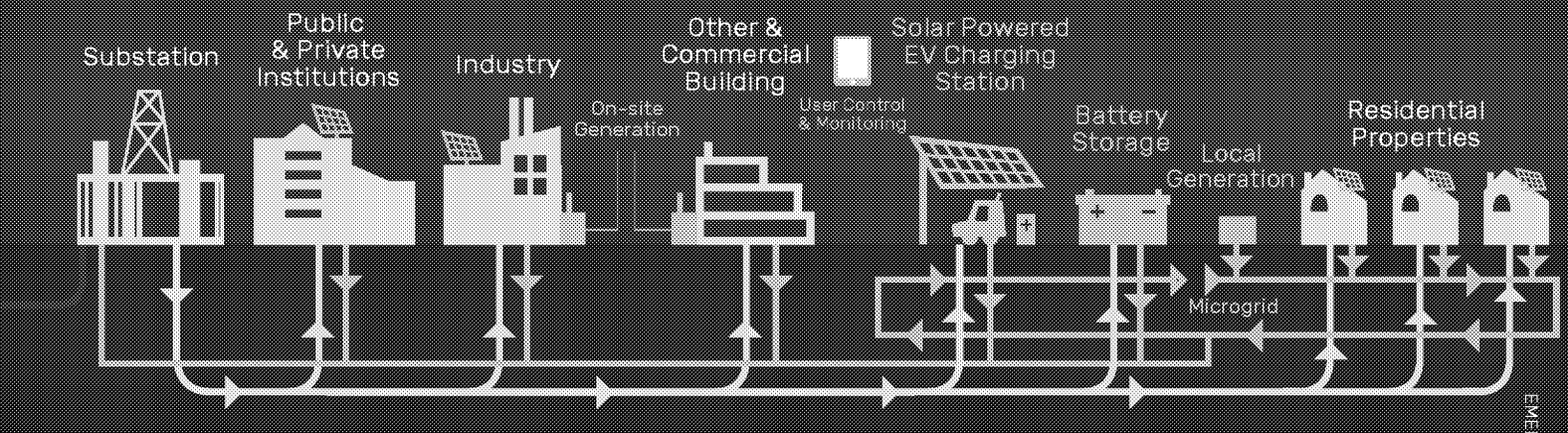
The transition in the electricity sector



Source: Adapted from Gil C. Quiniones, "Getting Smart about the Integrated Grid in New York: It's where we're staking our energy future," *Public Utility Fortnightly*, October 2015. At https://www.fortnightly.com/fortnightly/2015/10/getting-smart-about-integrated-grid.

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Substation
Public & Private Institutions
Industry
Other & Commercial Building
Residential Properties

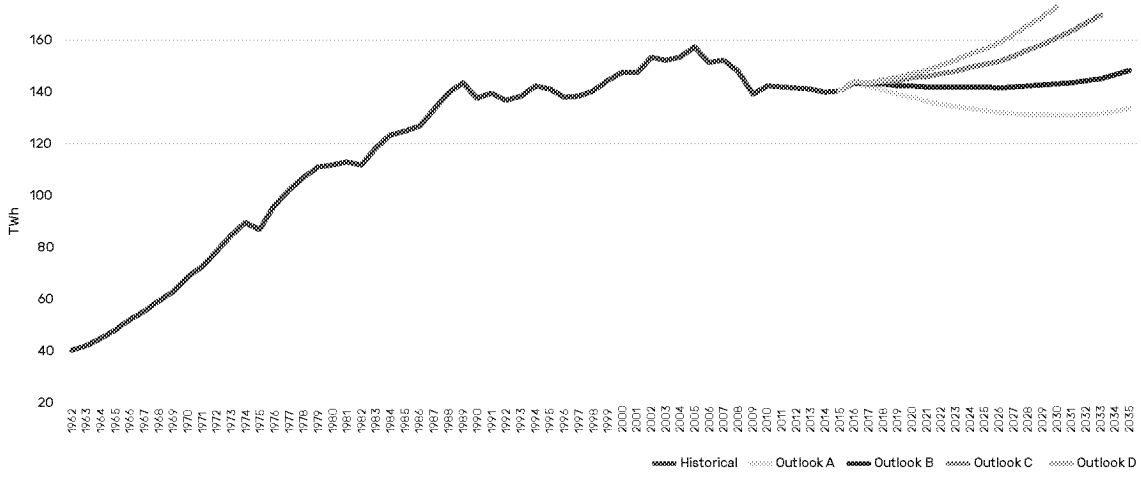

Substation
Public & Private Institutions
Industry
On-site Generation
Other & Commercial Building
User Control & Monitoring
Solar Powered EV Charging Station
Battery Storage
Local Generation
Residential Properties
Microgrid

Like elsewhere, in Ontario the generation of electricity has primarily been the business of large companies, both public and private, operating large generating stations far removed from where the electricity is actually used. The electricity is then moved down through the high-voltage system to be distributed and sold by local distribution companies (LDCs), such as Toronto Hydro, London Hydro or Hydro Ottawa. There are over 70 LDCs in Ontario.

Natural gas supply has been the domain of two large private companies, now operating as Enbridge Gas Distribution and Union Gas. The parent company of Enbridge Gas Distribution has recently acquired the parent company of Union Gas.

The sector has now changed. Electricity consumption is flat. As a result of economic and industrial conditions, as well as increases in energy efficiency, Ontario electricity consumption has seen no significant growth since 2009, and could remain flat in the foreseeable future depending on the outlook (see Figure 2). Natural gas demand has likewise been flat since 2000.[3]

FIGURE 2
Ontario electricity consumption between 1962 and 2015, and projections to 2035



Source: Independent Electricity System Operator, "Consolidated Figures and Data," *Ontario Planning Outlook*, September 2016. At http://ieso.ca/Pages/Ontario%27s-Power-System/Ontario-Planning-Outlook/default.aspx; Independent Electricity System Operator, "Demand: Total Annual Ontario Energy Demand." At http://www.ieso.ca/Pages/Power-Data/Demand.aspx; 1962 to 1996 figures from various Ontario Hydro statistical reports.

An important exception to this outlook arises in some urban areas. Urban densification can create situations where, despite flat overall energy demand, certain urban areas may actually have local pockets of supply constraints, reliability issues and congestion.

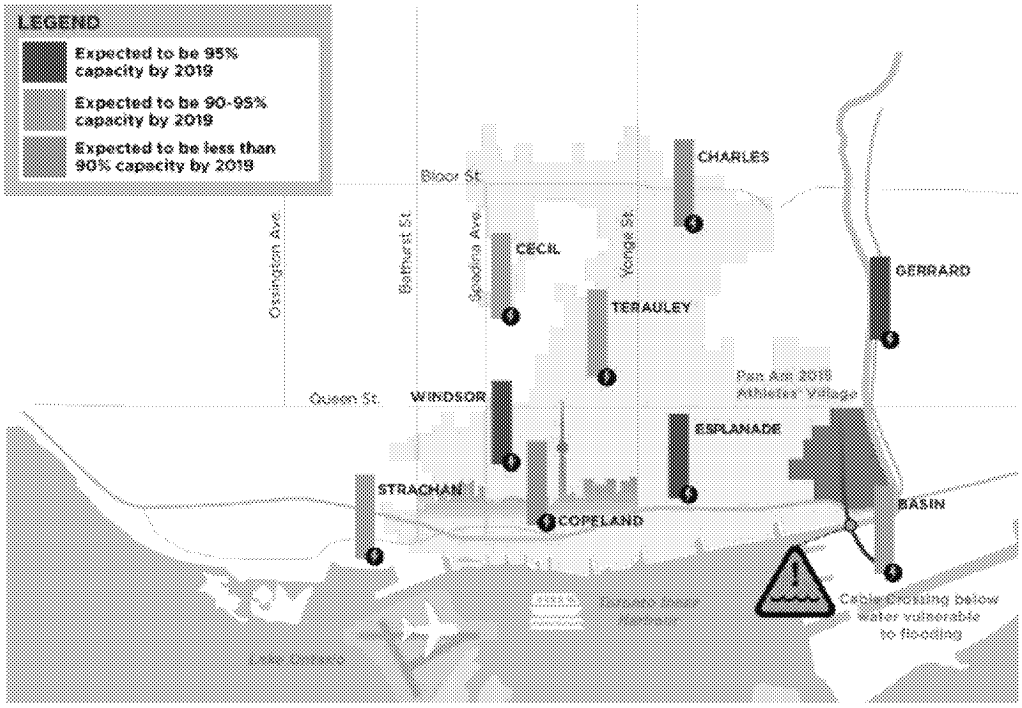
3 Ontario Energy Board, *Staff Report to the Board on the 2014 Natural Gas Market Review*, EB-2014-0289, March 31, 2015, pp. 9, 10 and 24. At http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0289/Staff_Report_to_the_Board_2014_NGMR_EB-2014-0289.pdf.

There may also be other local conditions which make the deployment of DERs especially effective. For example, it has been suggested that almost 80 per cent of downtown grid stations in Toronto will be at capacity by 2019 as a result of increased population growth and higher electricity demand due to increased urban development (Figure 3). A similar pattern characterizes Ottawa. This will likely lead to a need for new infrastructure investment. Later in this report we will highlight the opportunities such conditions may create for economic, location-specific DER deployment.

While this demand is primarily an urban phenomenon, other regions, such as the northwest, could also see an increase in energy demand as a result of expected new mining and forestry operations.[4]

FIGURE 3

Expected capacity of electricity substations in Toronto by 2019



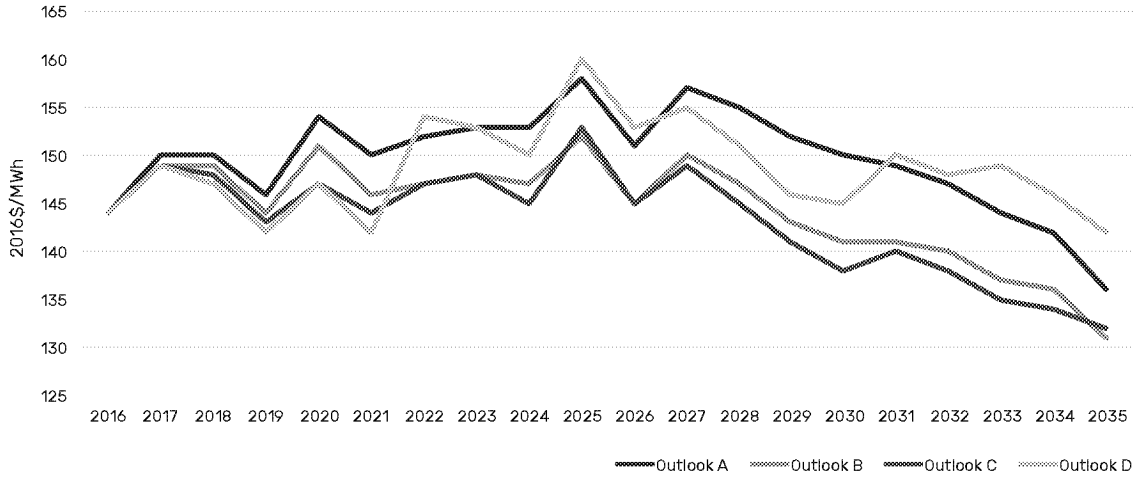
Source: Toronto Hydro, "Grid Challenges." At http://www.torontohydro.com/sites/electricsystem/GridInvestment/TorontosGrid/Pages/GridChallenges.aspx.

Energy prices, particularly electricity prices, have become a serious concern in the province. Over the last 10 years the commodity price for electricity in Ontario has increased substantially, a trend that is expected to continue until at least 2025 (see Figure 4).

4 Independent Electricity Systems Operator, *Northwest Region Scoping Assessment: Outcome Report*, January 28, 2015. At http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final_Northwest_Scoping_Process_Outcome_Report.pdf.

FIGURE 4

Average unit cost of electricity under different scenarios



Source: Independent Electricity System Operator, "Module 7: Electricity System Cost Outlook," *Ontario Planning Outlook*, August 2016. At http://ieso.ca/Documents/OPO/MODULE-7-Electricity-System-Cost-Outlook-20160901.pdf.

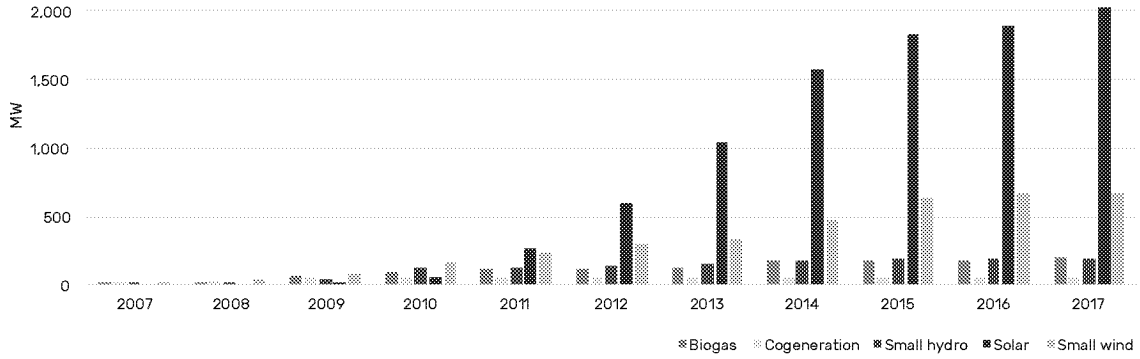
Note: For Outlook A, the high cost scenario was used, and cost scenarios C1 and D1 were used.

While electricity costs are increasing, natural gas prices are projected to remain at historically low levels. Average Dawn Hub prices, the main natural gas trading hub for Ontario, are expected to rise from an average of $2.62/MMBtu in 2015 to merely $3.72/MMBtu in 2021, well below historical levels.[5]

Ontario has also seen a large increase in DER, led by solar power which has more than doubled over the past five years (Figure 5).

FIGURE 5

Growth in small-scale DERs in Ontario



Source: Independent Electricity System Operator, Ontario Demand Forecast, December 2015. At http://www.ieso.ca/Documents/marketReports/18Month_ODF_2015dec.pdf.

5 Navigant, *2015 Natural Gas Market Review: Summary Report Prepared for the Ontario Energy Board*, December 28, 2015. At http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0237/Navigant_2015-NGMR_Summary_Report.pdf.

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1.3 Established principles for managing and regulating energy distribution systems

Energy distribution systems, in Ontario as elsewhere, provide an essential public service and are therefore closely regulated. Typically this is done through arm's-length independent organizations such as, in Ontario, the Ontario Energy Board (OEB). The OEB, the sector's economic regulator, is an independent quasi-judicial administrative body. The Independent Electricity System Operator (IESO), a government agency, manages the overall supply system. For a full description of the Ontario energy sector, its organization and regulation, please see the *Background Report on the Ontario Energy Sector*.[6]

In Ontario, the overwhelming majority of electricity distribution systems are owned by the municipalities in which they operate. While they are typically owned by the municipalities, they are incorporated as for-profit entities pursuant to the *Ontario Business Corporations Act*. These business-oriented actors must operate day-to-day as well as on a longer-term basis in an economically rational manner, within a closely regulated system in which the rates they receive as well as most of their key business decisions are subject to approval by the economic regulator.

Because of the capital-intensive nature of the distribution activity such systems optimally operate within a regulatory environment based on medium- to long-term planning horizons.

The infrastructure required to supply and distribute energy to consumers is very costly, and those investments must be paid upfront – if you have to add a power plant because there is not enough supply in the system to meet demand, you have to build it, and pay for it, now.

To ensure that the costs to consumers do not increase drastically in the short term as a result of infrastructure investments, and to reflect the long-term productivity of these assets, systems investments are typically recouped over the long term. This allows system costs to be spread out over decades. In other words, investments in the system are not recovered in their entirety from the current generation of customers, but are legacy assets, the costs of which are recovered from future customers who will also benefit from the long lifetime of such assets.

6 Mowat Energy, *Background Report on the Ontario Energy Sector*.



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The legal structures underlying the regulatory regime guarantee the recovery through rates of prudently made system investments. Utilities, as natural monopolies within their franchise territories, are obliged in return for this status to ensure the following:

» Non-discriminatory access to the distribution system.

» That system operation is safe, reliable, and cost-effective, according to prevailing standards.

» That they maintain an appropriate balance between costs and revenues within the system.

» That the system's cost burdens are fairly and rationally distributed across rate classes.

» That their management delivers economic value to consumers.

» That regulated pricing structures reflect true economic value.

» That system investments are made prudently, on the basis of the best available information at the time the investment is made.

» That regulatory and planning decisions are made in a transparent, inclusive and comprehensive manner with ample opportunity for affected stakeholders to participate and be heard effectively.

» Take into account only system-related costs and benefits, with extraneous social objectives, however worthwhile, not pursued through rate-setting, planning, or system management activities.

While DERs have the potential to disrupt many current practices and common behaviours, the introduction of DERs into the energy distribution system does not change the fundamental realities and obligations described above. In fact, customers, DER developers and suppliers are themselves, for the most part, often business-oriented entities that need a similar business environment to make their own investments and risk-taking economically viable. Therefore, DERs should be introduced into the system in a manner that is consistent with established regulatory and economic principles. Our analysis in this report is guided by this observation.

While the outcome of a redesigned and reconfigured distribution and transmission system for electricity may be revolutionary, the path to get there should not be. It should be based on conventional regulatory economics and the principles of utility regulation and governance that have emerged over the course of the last century.





PART A

The international experience: Key issues in DER deployment

There is a recognition in the various jurisdictions represented in the research that the DER transition can provide substantial benefits to the sector and to all consumers if DERs are well integrated into the overall energy sector. But the international experience also reveals that DER deployment can create costs within the energy system, create tensions between rate classes, and increase the possibility of revenue instability for utilities. In some cases, an action/reaction cycle occurred when DER deployment got caught between differing and sometimes competing policy objectives.

Following an overview of the drivers of the DER transition, this section reviews the benefits and the costs that the changes entail, and, based on a review of international initiatives in integrating DERs, summarizes the best practices that have been identified.

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2 THE NEW ENERGY CONSUMER

While consumers are leading the way, not all customers are at the forefront of DER penetration. Recent years have seen energy customers bifurcate into active customers, those who actively look for opportunities to participate, and passive customers, those that are content with the current model.

Active customers generally want a wide array of possible services to choose from, and greater opportunities to participate in the market. Passive consumers, on the other hand, want reliable service at stable prices.[7]

This bifurcation of customers challenges regulators and policymakers to develop system architecture that can accommodate customers with different levels of interest and ability to participate in a DER environment. Because each class of ratepayer finds itself in a co-dependent relationship with each other rate class, balancing interests requires careful preparation. This is especially true when the pace of DER uptake is unpredictable.

Commercial and industrial customers have generally become active customers due to rising electricity prices, and the need to control costs. In a poll of U.S. businesses in 2016 it was found that over half generated some portion of their energy needs at their own location.[8] Others were trying to procure renewable energy, and many more were trying to reduce energy consumption.

Residential customers, on the other hand, are split and may remain so for a long time. While a growing number of residential customers are interested in becoming active customers, a majority at present would prefer to remain as passive customers, getting the energy services they need at the lowest possible cost.

While economics and rising costs are seen as a major factor in making customers more active, other factors also play an important role.[9] Customers become active customers for a number of different reasons.

7 NRRI, *Future Drivers and Trends Affecting Energy Development in Ontario: Lessons Learned from the U.S.*, Mowat Research #137, December 2016, pp. 8-10. At https://www.mowatcentre.ca/wp-content/uploads/publications/137_EET_future_drivers_united_states.pdf.
8 Deloitte, *Deloitte Resources Study 2016*, p. 27. At http://www2.deloitte.com/us/en/pages/energy-and-resources/articles/resources.html.
9 Waters Wye, *Future Drivers and Trends Affecting Energy Development in Ontario: Lessons Learned from Great Britain*, Mowat Research #139, December 2016, pp. 73-74. https://www.mowatcentre.ca/wp-content/uploads/publications/139_EET_future_drivers_great_britain.pdf.

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The following reasons were identified in Sweden, and are likely similar in many jurisdictions:

» the ability to control costs

» preference for "green energy"

» technological innovation for its own sake

» quality and reliability

» using it to manage aspects of customer's life is considered more normal.

Passive customers, by contrast, are either not interested in the possibilities offered and prefer current offerings, or remain passive out of habit and the sense that they have other, more pressing priorities.[10]

Some of our research suggests that once some active customers start to use more DER technology the "social effect" will lead to wider adoption among passive consumers. It has been seen through bulk purchasing programs and when technologies reach widespread tipping points that neighbours push other neighbours to adopt. As a result the growth rate in usage of new technology can be slow at first, and then accelerate quickly, as was seen with solar power in Australia.[11] Hawaii is another example of a jurisdiction where residential solar deployment occurred relatively rapidly.

Some technologies are close to reaching or have reached "tipping points" where consumer use becomes widespread. Energy efficiency, LED, insulation and high efficiency heating and cooling are such examples. For electricity the technologies are still developing, and may not be entirely transformative of the sector.

Active consumers, while motivated, are still very discerning about the relative economic treatment of DER deployments, and carefully evaluate programs to discover good or bad deals. In the U.K., for example, the feed-in tariff (FIT) system offered high rates of return and active customers quickly applied to participate. On the other hand, the U.K. government's Green Deal, a system for the on-bill financing of energy efficiency improvements, was seen as a bad deal with a cumbersome application and approval process. The Green Deal was eventually cancelled due to lack of interest.[12] That customers flocked to one program – the FIT – while avoiding another – the Green Deal – demonstrates that consumers make decisions on the basis of predictable outcomes that are favourable to their interest.

10 Sweco, *Future Drivers and Trends Affecting Energy Development in Ontario: Lessons Learned from Sweden*, Mowat Research #138, December 2016, p. 34. At https://www.mowatcentre.ca/wp-content/uploads/publications/138_EET_future_drivers_sweden.pdf.
11 IET and Meisters Consulting Group (MCG), *Future Drivers and Trends Affecting Energy Development in Ontario: Lessons Learned from Germany, the U.S. and Beyond*, Mowat Research #136, December 2016, pp. 9-12. At https://www.mowatcentre.ca/wp-content/uploads/publications/136_EET_future_drivers_germany_us_beyond.pdf.
12 Waters Wye, pp. 73-75.



3 THE ROLE OF TECHNOLOGY

3.1 Overview

Our international research reveals that all jurisdictions are dealing with the same general array of DER technologies, already outlined in section 1.1.

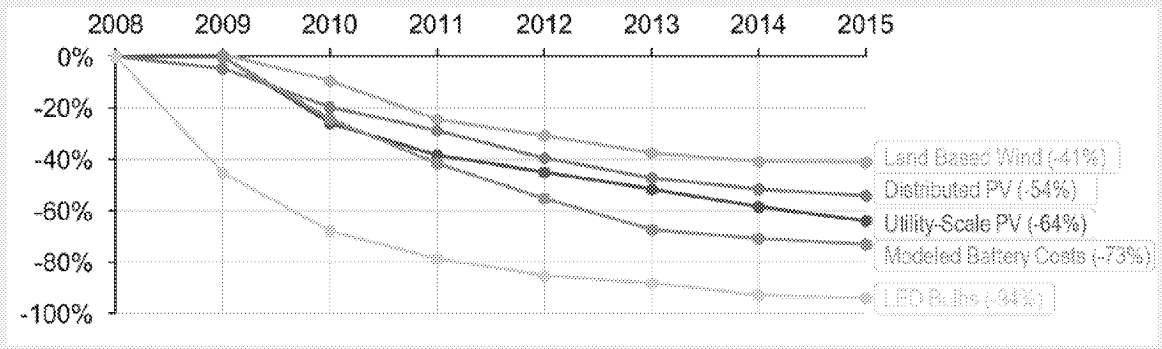
Some jurisdictions have seen a rapid proliferation of DERs due to incentives and other subsidies. In the U.S. large incentive-driven penetrations of DERs can be found in California, Hawaii, Texas and New Jersey.

An important factor that augurs well for possible proliferation is that costs for some DER technologies are coming down. In the U.S., costs for small-scale distributed solar PV decreased by over 50 per cent between 2008 and 2015. Costs for other technologies, such as batteries and LED bulbs, also saw decreases during that period (see Figure 6).

It is expected that this trend will continue in the near term. Some speculate that the costs associated with distributed solar PV may decrease by up to 30 per cent by 2020.[13]

FIGURE 6

Cost reductions in selected technologies between 2008 and 2015



Source: U.S. Department of Energy, *Revolution...* Now, p. 1.

13 U.S. Department of Energy, *Revolution... Now: The Future Arrives for Five Clean Energy Technologies – 2016 Update*, September 28, 2016, p. 7. At http://energy.gov/sites/prod/files/2016/09/f33/Revolutiona%CC%82%E2%82%ACNow%202016%20Report_2.pdf.

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Benefits associated with DER development

FLEXIBILITY

With an increase in the use of variable renewable energy sources such as wind and solar, the electricity network will need to become more flexible. Small-scale DG, DR and storage could be able to balance the system following rapid changes in electricity supply and demand.

LOWER LOSSES

As DERs are located closer to the customer, line losses will be lower.

INCREASED RESILIENCY

Increasing DERs could increase the diversity of the system, decreasing the chance that a localized event will disrupt the large system. In addition, microgrids could help support localities when the larger grid system is disrupted.

ENVIRONMENTAL IMPACT

The flexibility will help integrate more renewables into the electricity system, and the development of combined heat and power systems could be encouraged.

ANCILLARY SERVICES

Ancillary services such as frequency, voltage or reactive power could be more efficiently met at the distribution system with DER resources, especially DR and storage solutions. A market-based approach to ancillary services could reduce costs.

REDUCED INVESTMENTS IN NEW INFRASTRUCTURE

DER investments could reduce the need for new infrastructure, especially in the distribution grid, by offering an alternative way of meeting system needs rather than the traditional capital build. (See page 26)

Source: Derived from Sweco, pp. 59–60; Waters Wye, pp. 99–100.

3.2 Cost-benefit analysis of DERs

Integrating DERs into the energy grid could provide value to the energy system, the participating customer, the local community and society. But there are also costs and risks associated with DER deployment. Obviously, understanding the cost-benefit balance of DERs is necessary when considering possible responses to the transition.

For the energy sector, DERs can provide many of the similar services that are provided by other technologies now, in many cases at a lower cost or more efficiently (see sidebar).

Many of the benefits of DER for the energy system will be to a large extent contingent on the location of these technologies on the grid, as well as the duration and quality of power supply provided. From a utility's perspective, evolving insights into the locational benefits of DERs allow for more specific knowledge of how DERs can be applied to specific upgrades to the system.[14]

14 Steve Fine et al., *The Value in Distributed Energy: It's All About Location, Location, Location*, ICF White Paper.

But any changes in the technology, regulatory treatment and market structures that exist now may have significant cost implications for consumers, whether active or passive.

One of the major implications of DER development in a jurisdiction is cost-shifting. As consumers that install a DER system reduce their use of the larger grid, or even disconnect from the grid entirely, their ongoing revenue contribution to the system is likely to decrease — that is, after all, one of the prime motivations for DER implementation. As many grid costs are fixed and are not dependent on the number of customers or the amount of energy services provided, in the short term at least, customers that are not able to install DER will likely see their unit costs of electricity increase to cover the consequential loss in system revenue.

It is also important to highlight the fact that a highly disproportionate amount of system revenue derives from large load customers. These are often the customers in the best position to fund and implement DER deployment. Their defection, in whole or in part, can create significant impacts for other rate classes, especially residential customers who will, as a class, be obliged to take over a higher and higher proportion of system costs.

Secondly, DERs can introduce physical and technical costs to the system. Increasing DER penetration, especially with renewables, can lead to a more volatile load curve and reverse power flows, with electricity flowing from the distribution to the transmission grid at times when DERs supply more electricity than there is demand. With the possible need for system reinforcement due to more resources connected to the grid, the utility may need to invest in new infrastructure, which would increase costs for all consumers.[15]

A third area of concern would be the stranding of existing assets due to the development of DERs. The deployment of DERs may mean that parts of the existing energy system may not be necessary in the future, perhaps even before they reach the end of their projected lifespan. As noted above, the costs of grid-scale infrastructure and other asset investments made by utilities are typically recovered over the course of decades. If centralized distribution, transmission or generation assets are retired early, this will result in stranded assets. One way or another, the costs associated with these stranded assets have to be addressed. They can be recovered through rate increases for existing customers, a very unattractive option in Ontario where there is already very considerable concern over prices, borne by the respective consumers implementing a DER deployment through the application of regulatory economic principle, or borne by society at large.[16]

15 Sweco, pp. 63, 90-91; Waters Wye, p. 101.
16 Cynthia Chaplin, *Future Drivers and Trends Affecting Energy Development in Ontario: A Literature Review*, Mowat Research #140, December 2016, pp. 46. At https://www.mowatcentre.ca/wp-content/uploads/publications/140_EET_future_drivers_literature_review.pdf.



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As the increase in DER installations is relatively new, methods to accurately assess the cost-benefit of these installations are still evolving. The economic value of many of the costs and benefits of DER expansion are elusive and would impact different actors in the energy system (see Table 1)

TABLE 1
Summary of benefits and costs of DER expansion

	Utilities	Consumers	Communities	Sys Op	Public	Regulators
BENEFITS						
Flexibility	✓			✓		
Energy services at lower costs	✓	✓			✓	
Reduced need for large capital investments	✓	✓				✓
Increased resiliency	✓	✓			✓	
More control over energy use		✓			✓	
Lower emissions		✓	✓			
Local economic benefits			✓		✓	
COSTS						
Connections costs	✓					
Operations and balancing	✓			✓		
Cost-shifting		✓			✓	✓

Trying to artificially constrain the development of DERs in any given system would appear from the research to be a futile exercise. What is important is the development of a predictable and principled environment so that DER developers can assess their investments realistically, and utilities and ratepayers can have confidence that system costs, including stranded costs, will be covered fairly.[17]

Based on developments in other industries, when customers have more options and choices they become increasingly active and have higher standards for service. There is no reason to think that the energy sector will be any different.[18] In addition, there is speculation that the number of active customers will increase in the future.[19]

17 Elisabeth Graffy and Steven Kihm, "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?" *Energy Law Journal*, Vol. 35, No. 1, 2014. At https://www.seventhwave.org/sites/default/files/graffy-kihm-elj-article-may-2014.pdf.
18 NRRI, pp. 10-12.
19 Accenture, *The New Energy Consumer: Thriving in the energy ecosystem*. At https://www.accenture.com/us-en/insight-new-energy-consumer-thriving-new-retail-ecosystem.

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The long-term public interest will be well served with the effective and economic accommodation of DERs. This means finding the right balance between customers and utilities, and respective customer classes. "If grid defection occurs at scale, we will have failed from a societal prospective."[20]

> *Trying to artificially constrain the development of DERs in any given system would appear from the research to be a futile exercise.*

Effective integration of DERs can ensure that society experiences the benefits of DERs, without unduly compromising the interests of respective customer groups or classes.

20 Lorenzo Kristov and Paul De Martini, *Presentation: Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight*, November 13, 2015. At https://emp.lbl.gov/sites/all/files/lbnl-1003797_presentation.pdf.



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New York's "Reforming the Energy Vision"

New York is attempting to undertake bold measures to get ahead of the transition to a more decentralized energy system through its "Reforming the Energy Vision" or REV.

Led by the state governor, and the governor's "energy czar," Richard Kaufmann, REV is an attempt by the state regulator, the Public Utility Commission (PUC), to develop an energy policy that it believes will lead to better consumer choices, allow for the development of new products and services and lead to economic development.

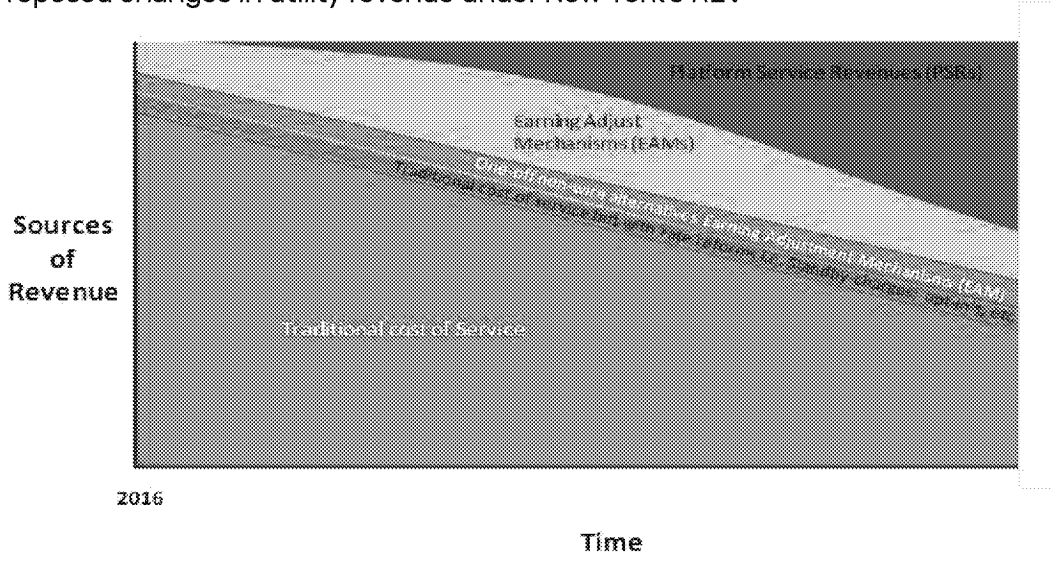
REV is a two-track plan. The first track is to create a market-oriented utility business model, and the second is to create a true rate for DER.

Track one aims to change the utility business model to allow for more third-party investment in the grid. Utilities will become "Distribution System Platform" (DSP) operators that provide services to facilitate the operations of third-party DER providers, rather than monopoly providers of electricity services.

Moving to the DSP model requires changes in the way utilities earn revenue. Currently utilities receive a regulated rate of return based on their cost of service. In the future, the PUC sees the importance of cost-of-service regulation decreasing, as utilities replace that revenue with "platform service revenues", essentially revenue from facilitating third-party actors on the network (See Figure 7).

During the transition to the full DSP model, utilities will receive "earnings adjustment mechanisms" to compensate for lower regulated cost-of-service revenue until the REV market is fully functioning and market-based earnings can replace the regulated revenue. Utilities are expected to file proposals outlining how they intend to function as DSPs.

FIGURE 7
Proposed changes in utility revenue under New York's REV



Source: Catherine Mitchell, "US Regulatory Reform: NY utility transformation," IGov, Exeter University, June 13, 2016. At http://projects.exeter.ac.uk/igov/us-regulatory-reform-ny-utility-transformation/.

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Track two focuses on developing rates for DERs. In October 2016, Commission staff prepared a report recommending a value of resource (VOR) framework.[21]

The VOR tariff is expressed as LMP+D, where LMP is the locational marginal price, the locational wholesale electricity price, and D is the value the system provides to the grid.

The LMP in the new DER rate will be set the same way that hourly-priced customers are billed plus the revenue from the capacity market. The capacity benefit for a DER installation will be based on the facility's performance during the peak the year prior, or if it is an intermittent generator such as solar, the capacity compensation will be based on the capacity portion of a local utility's supply charge for the service class, using a load profile that is most similar to the solar generation's load profile.

The distribution value of an installation has been the trickiest to price, and it is recognized that this current formula is a first attempt and will likely be modified later. Initially the value of demand response, as already prepared by utilities for use in the demand response market, will be used base distribution compensation. It is recognized that this is an imprecise basis to calculate the value of DERs to the system, but it provides a start for utilities to create new prices. Utilities will also be required to identify high-value locations where DERs could provide system benefits.[22]

All installations will be provided with an "environmental" value equal to the price of the renewable energy credits that utilities are required to purchase to meet their renewable energy targets.

The new DER rate will be implemented slowly. First, all existing contracts will be honoured. Second, new residential behind-the-meter customers will continue with net energy metering until 2020. Community-owned DERs will be phased in slowly and will receive transition credits, with industrial and consumer installations the first to see the new rate. Phase two of the value-of-DERs project is expected to begin immediately, with more details available in late 2018.

21 New York Public Utilities Commission, *Staff White Paper on Ratemaking and Utility Business Models*, Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, July 28, 2015, pp. 75-76. At http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A2355185257DEA007DCFE2?OpenDocument

22 New York Department of Public Service, *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding*, 15-E-0751, October 27, 2016. At http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751.

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Brooklyn-Queens Demonstration Project



A good example of the use of DERs to solve locational issues on local distribution networks can be found in New York. Consolidated Edison (ConEd), a large electricity utility in New York State, was faced with rising demand in the Brooklyn-Queens area. Rather than spend $1.2 billion to build a new substation to meet demand, ConEd decided to launch a pilot project, the Brooklyn-Queens Demand Management (BQDM) program, to try to meet the need through non-utility investments. Rather than build the new infrastructure ConEd has signed contracts for 52 MW of customer-side solutions, including DG and DR, at a cost of $200 million, a significant saving from the traditional utility capital proposal.[23]

23 Consolidated Edison, New York PUC case 14-01390/14-E-0302. At http://documents.dps.ny.gov/public/Matter-Management/CaseMaster.aspx?MatterSeq=45800.

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4 BEST PRACTICES IN THE INTEGRATION OF DERS

How the decentralization of the energy system will roll out is still unclear. Many of the developments so far regarding DERs – such as cost reductions and the pace of development (in some cases very fast, in others slow) – have been a surprise for almost everyone.

One of the reasons for the uncertainty is that many of the underlying contextual conditions are not known. Previously, the energy sector only had to concern itself with supply – ensuring that there were enough electrons, whether electricity or natural gas electrons, available at any one time to meet the demand. What was needed to serve demand was known, and, with enough lead time, could be made available.

Now, the demand side – in other words, the consumer – presents new challenges. DERs change flows, and consumers are examining their overall energy portfolios closely. The path of, and the pace of, DER uptake is uncertain. Given this uncertainty, regulators and policymakers should be wary of accepting claims that any one technology or any one business model will dominate the future.[24]

It is also clear that *integrating* DERs, rather than merely *connecting* DERs, is a key aspect of the overall value proposition offered by the DER transition. DER assets can be of value to their proponents, but of little value to the system. This should have implications for the regulatory treatment of such deployments.[25] Effectively integrating DERs into the energy system requires careful economics-based planning from LDCs, DER proponents, policymakers and regulators.

Our research examined a number of different peer jurisdictions – the U.S., Germany, Sweden and the U.K. – to identify best practices and lessons that could be instructive for Ontario. Regrettably, the peculiarities of energy systems in different jurisdictions make it impossible to directly transfer lessons from any other jurisdiction to Ontario.

24 NRRI, pp. 38-40.
25 Electric Power Research Institute, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, February 10, 2014. At http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733.



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The research findings point to three areas that need to be examined to ensure that Ontario will be able to gain the most value from the energy transition:

» planning

» utility operations and business models

» DER ratemaking.

4.1 Planning

In a number of jurisdictions, the system planning process will need to change if the right environment for economic DER proliferation is to be created.

Traditionally the energy system has been planned from the top down, with total demand projected into the future and then supply and infrastructure measured up to that demand. In electricity, for example, networks have historically been planned and built from the top down, from high-voltage networks down to low voltage consumers, in other words from the centre out toward what is now called the "grid edge". With DERs, what is needed is the reverse: starting at the customers' and distribution feeders at the grid edge, and then moving through the distribution system to the central supply.[26]

Lack of data and uncertainty about future developments complicates planning. Many different factors, such as technological development, or the customer take-up of connected appliances and the rollout of efficiency programs, will greatly affect the sector and cannot be adequately predicted. Consumers themselves are changing, and are becoming increasingly hard to lump into existing categories.[27]

Planning may also have to get out of its energy silos-instead of planning only natural gas or only electricity, to look at community energy planning that coordinates and optimizes all energy sources.

Planning may also have to get out of its energy silos-instead of planning only natural gas or only electricity, to look at community energy planning that coordinates and optimizes all energy sources. With DERs, all forms of energy have to be considered.[28] For example, some forms of DERs rely on the natural gas network, and thus electricity planning will affect natural gas planning. A greater use of district heating could also change future energy dynamics. A greater rollout of electric vehicles or electrification of public transit could also affect any future planning scenarios.

Uncertainty, and the need to consider more factors and enhanced data, some of which is not available in some systems, will make planning more complex. Energy planning has traditionally been done using what is referred to as a "solving mode", which looks at

26 NRRI, p. 87.
27 See Section 2 on the new energy consumer.
28 NRRI, p. 88.



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how systems that operate in a mechanical and linear way function. For many decades this was sufficient. But in an increasingly complex energy system some commentators see a need to move to a "learning mode", which relies on constant revision and the collaboration of many different stakeholders.[29]

Many commentators emphasize the limitations of a planning approach that has traditionally started at the top, and then looked at forecasting how consumers will use energy services. To improve planning this paradigm has had to shift toward a more granular, bottom-up approach.

One possible element of this would be to look at the customer-adoption modelling, which starts with forecasting how consumers will use energy services, and then models that on up through the system. New tools are becoming available that improve the reliability of what are, at the end of the day, speculations. As noted, the pace of DER uptake is currently unknown. A sharply revised planning process should serve to improve projections, through the identification of economic DER installations within the planning area. We discuss this in the Ontario context in Part B of this report.

Another key component of creating an effective planning regime for the future is to treat DERs as a resource rather than as a way to reduce net energy demand, which is the way they are generally treated at the moment.[30]

In addition, the increased deployment of some DERs could further complicate operations and planning when coupled with the development of more renewable electricity. Maximizing the potential of renewable energy requires planning and operating interconnectedly across larger areas so that periods of oversupply can be averaged out by diverting surplus electricity to areas of undersupply. By contrast, some DERs operate to maximize the efficiencies accrued from local energy networks requiring a more localizing and cellular planning focus.[31]

Some jurisdictions are changing their planning system to allow for more DERs. California utilities are required to produce distribution systems plans that identify the best locations on their networks for DER development based on system needs and capacity availability. The plans are also required to show how much capacity is available on the network at the granular level, down to the line section or node level, or on a represented circuit level.[32] In our view this is an important innovation.

29 Jefferson W. Tester, Elisabeth M. Drake and Michael J. Driscoll, *Sustainable Energy: Choosing Among Options*, MIT Press, October 2012, pp. 957-958.
30 Andrew Mills, Galen Barbose, Joachim Seel, Changgui Dong, Trieu Mai, Ben Sigrin and Jarett Zuboy, *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning*, LBNL-1006047, Ernest Orlando Lawrence Berkeley National Laboratory, August 2016. At https://emp.lbl.gov/sites/all/files/lbnl-1006047_0.pdf.
31 IET, p. 56-57.
32 See California Public Utility Commission, "Distribution Resources Plan (R.14-08-013)." At http://www.cpuc.ca.gov/General.aspx?id=5071.



New York under the REV project requires distribution utilities to submit distributed system integration plans (DSIP) system. The Public Utility Commission sees these plans as the first stage in the REV project. The plans are also expected to be "predictive" rather than "prescriptive" and to allow for flexibility if developments change. The key areas of the plans are integrated planning that predicts developments in the networks and information on granular network capacity to inform developments. The plans will include capital investment budget, but as the goal of REV is to rely on DERs rather than new capital spending by the utility, the plans will identify locations where DERs could replace the need for new capital spending.[33] Again, we see this as a valuable insight, relevant to the Ontario context.

In Ontario the OEB has imposed a distribution planning requirement, and mandates that stakeholder engagement form part of the system operator's regional planning process. Execution of this requirement has been variable.

4.2 Utility regulation and business models

4.2.1. The so-called "death spiral" and calls for utility business model diversification

The future of utilities has attracted considerable attention, due to concerns over the so-called "utility death spiral", namely the risk that the defection of DER customers would lead to the progressive and fatal erosion of system revenue to the point where a small number of remaining customers have to, but fail to, cover system costs. This has led some utilities to propose alternative business models that would enable them to absorb this presumed risk of DER deployment, usually involving the addition of new sources of revenue for "services". This typically involves a fundamental change in the monopoly status of the utility combined with engagement in what are, or otherwise would be, competitive businesses.

> *The engagement of utilities in competitive markets also has important implications for the risk profile of the utilities and ultimately the security of the system.*

33 New York Public Utility Commission, *Staff Proposal: Distributed System Implementation Plan Guidance*, October 15, 2015. At http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument.

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Initial enthusiasm for fundamental utility business model change is, however, eroding. There is growing interest in protecting utility revenues and ratepayer equity through principled and economic treatment of DER deployment, taking the true system costs and system benefits into account in the regulatory architecture.

It is important that utilities not use their position in competitive markets to dominate the sector and make it more difficult for third-party companies and entrepreneurs to engage, where it is economic for them to do so.[34] Regulators will need to ensure that utilities and utility affiliates do not use their utility status to dominate any competitive market.[35] This can be a complex and challenging exercise.

The engagement of utilities in competitive markets also has important implications for the risk profile of the utilities and ultimately the security of the system. Currently, monopoly utilities have extremely low risk profiles, which is reflected in the return-on-capital component of rates. Engagement in competitive business presumably would result in a fundamental re-assessment of the risk profile, and possibly the introduction of analytical tools to ensure that competitive business failure does not result in the compromise of the reliability of system per se.

34 IET and MCG, p. 55.
35 IET and MCG, p. 55.





Heating in Sweden: District heating networks and the effect of technological competition

In comparison to Ontario, heating in Sweden relies heavily on district heating and heat pumps.

Swedish cities typically have district heating systems in their dense urban cores, providing heat to apartment and commercial buildings. Biomass or municipal solid waste is typically the fuel for district heating, with fossil fuels playing a limited role.

Where there is no district heating network, Swedes rely upon heat pumps, both air- and ground-sourced. The growth in heat pump installations started 10-15 years ago, as there was a general move away from fossil fuel and direct electricity heating. Approximately half of Swedish single-family homes now rely on heat pumps.

In what is potentially a preview of what to expect for other utilities, even urban customers in Sweden are now increasingly turning away from district heating to heat pumps due to both decreasing cost for the heat pumps and lower electricity prices. Yet while the customers installed heat pumps, many also retained connection to the district heating network for backup.

Urban customers switching to heat pumps has reduced demand on the district heating networks, meaning that prices for the remaining customers have had to rise to meet the networks' largely fixed costs. If left unchecked, this could lead to a death spiral for the district heating networks as rising costs could push even more customers off the networks.

District heating providers are trying to come up with innovative solutions and new tariffs to customers installing heat pumps. One such example is Peak Load Tariffs, which prices heating during peak load hours for customers who do not rely primarily on the heating network. This has helped offset shrinking revenues while protecting existing customers who rely primarily or exclusively on the heating network year-round.[34]

36 Sweco, see p. 10, p. 89 and pp. 111-113.

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4.2.2 DER-driven changes to utilities' operations

DERs may change how system operators manage their networks. Depending on the regulatory model currently in use in a given jurisdiction, this could apply to the larger transmission system operators or fall on LDCs.

Increasing DER penetration, especially with renewables, can lead to a more volatile load curve and reverse power flows, with electricity flowing from the distribution to the transmission grid at times when DERs are supplying more electricity than is needed or wanted by the system. Traditionally local network operators have built more lines or expanded the network to solve these problems. Yet dealing with individual problems as they arise may be inefficient with higher levels of DER penetration, and new creative, expensive and unwelcome solutions may be called for.[37]

Managing these flows and ensuring reliability may require greater coordination and communication between the transmission and distribution grids.[38] Innovative technological solutions can help in meeting the challenges of high penetration of DERs. "Consumer-facing" technology such as smart meters and advanced thermostats can enable customers to control their own energy demand. Potentially even more important in modernizing the grid and dealing with high levels of DER penetration are "grid-facing" technologies that automatically optimize voltage and power factors of the distribution grid.[39]

An example of grid-facing technologies is using remote control power transformers. Such transformers can provide stepped voltage regulation, which can be more cost-effective than the traditional method of voltage regulation, expanding the grid.[40] Smart inverters can control reactive power, and thus become network assets in regulating voltage and frequency.[41] So-called smart grid implementation is an important priority in many jurisdictions, but it requires careful planning and pacing. It can also be expensive.

The need to manage a grid with large amounts of DERs may lead to a change in the role of the distribution company and in the relationship with the central transmission system operator. Controlling this flow of energy around the system will mean that local distribution utilities, especially in electricity, may, under some regulatory models, need to take on a more active role in managing energy flows, similar to the roles that a system operator plays now.[42]

37 Sweco, pp. 63, 90-91
38 IET and MCG, p. 56.
39 IET and MCG, pp. 57-58.
40 IET and MCG, p. 58.
41 Sweco, p. 93.
42 Sweco, p. 95.



Just how this relationship will evolve in Ontario is open to question. Managing flows is a necessary and integral system cost, and to the extent that new related costs emerge, whether incurred by the transmission utility, the distribution utility or the system operator, need to be incorporated into rate structures and recovered through rates.

There are two visions on how roles are to be divided between the distribution company and the centralized transmission system operator.[43]

One vision has the centralized transmission system operator controlling the entire flow of energy on the networks, as it generally does now. As a result the centralized system operator would be responsible for balancing the entire network, and for controlling or dispatching DERs. The local distribution utility would remain essentially a wires-only or pipes-only company.

Another vision is that of a system where local distribution system operators are responsible for balancing supply and demand in the local area. The transmission system operator would be responsible for balancing the transmission grid, but would not have responsibility below the transmission-distribution interface. This would require the local distribution company to become a small regional system operator, controlling their own territory separate from the central system operator.

Either the centralized or the more distributed vision would be able to respond to the changes in the sector and the rise of DERs, and both have benefits. The centralized vision would be able to ensure that the system develops holistically. The decentralized vision would ground any changes in physical reality, and be able to respond to local interests or concerns, potentially increasing flexibility.[44]

Aggregators or third-party service companies could also play a role. Aggregators could be potentially useful as some consumers may only be interested in being active in a few areas, allowing the aggregator to leverage the remaining services for the benefit of the grid as a whole and, where demonstrable, lower system costs.

One researcher described the options as seen in Table 2.

43 Lorenzo Kristov, Paul De Martini and Jeffrey D. Taft, "A Tale of Two Visions: Designing a Decentralized Transactive Electric System," *IEEE Power and Energy Magazine*, Vol. 14, Issue 3, May/June 2016, pp. 63-69.
44 Kristov, De Martini and Taft, pp. 63-69.



TABLE 2
Options for the future utility distribution model

Platform provider	Service provider	Network provider
Here the utility acts as a platform provider and as a system operator. The business model rests on facilitating others.	Here the utility also acts as platform provider, but in addition invests in DERs. This may include investing in DERs at points of congestion on the system, or in owning and operating behind-the-meter DERs on consumer premises.	Here the utility solely maintains the wires and relies upon the transmission system operator to operate the system, and for retailers to connect with the consumers. This is similar to what can be seen in the U.K.

Source: Adapted from NRRI, pp. 29-30.

Under the service provider model the utility itself could directly invest in DERs, such as electric vehicle charging stations. The utility could then operate the facility in the market, and if the facility benefits the grid as a whole by providing a grid service it could even be included in the rate base. The utility would transition from a provider of energy services to a systems integrator and network operator, with the attendant change in risk profile.

4.2.3 DERs and the move toward outcomes-based regulation

Utility regulation has traditionally been based on a cost-of-service approach. This means that utilities apply to regulators to build new infrastructure, or to recover costs already prudently incurred in building infrastructure. If the regulator approves, the utility earns a rate of return on that capital expenditure (CAPEX). While the traditional cost-of-service regulation has been modified and improved over the years, with performance requirements of various types inserted into the calculation, a key component is still a regulated rate of return on CAPEX.

One researcher opined that while this regulatory model has prevented utilities from exploiting their market power or charging unreasonable rates, it has not encouraged utilities to innovate or find more efficient ways of delivering energy.[45] This observation appears to be based on utilities that had no regulatory obligation to implement conservation or demand management programs, or meet explicit performance and consumer service standards as has been the case here in Ontario.

Some regulators have been looking at other regulatory options that place value on performance and outcomes. The U.K. was one of the first to try to move away from the traditional regulatory model with its RIIO regulatory model. RIIO stands for "Revenue = Incentives + Innovation + Outputs", and is intended to change the way revenue is

45 Kenneth Costello, "Major Challenges of Distributed Generation for State Utility Regulators," *The Electricity Journal*, Vol. 28, Issue 3, April 2015, p. 12.



calculated, moving from CAPEX-only to one based on incentives and performance rewards. Some of the key characteristics of the RIIO model are:

» prescribed outcomes for the utility based on a comprehensive business plan

» requirement for extensive stakeholder engagement and rewards and penalties based on customer services (based on independent surveys)

» targets for the use and condition of network assets

» multi-year rate plans (eight years)

» a move to a "total expenditures" (TOTEX) incentive regulatory mechanism, compared to the previous model which focused on CAPEX and ignored "operational expenditures" (OPEX)

» consideration of uncertainty.[46]

RIIO makes funding available for network companies to invest in innovation, and the TOTEX regime is seen as helping network operators find innovative ways of solving issues rather than the traditional method of building new capital. The network operator is able to receive 60 per cent of any cost savings, with consumers receiving the benefit of the remaining 40 per cent.[47]

RIIO is still in its early days, and a mid-period review by the regulator is planned.[48] But while RIIO specifically applies to the unique conditions of the U.K. energy sector, its use of performance indicators and incentives is being examined by other jurisdictions, and it appears to have been somewhat influential for the Ontario regulator.

4.3 Ratemaking and the utility of the future

4.3.1 DERs impact on existing models of ratemaking

Regardless of the regulatory system, the costs of running the utility and providing service to customers' need to be met. Utility regulation is predicated on the precise balance between utility costs and revenues.

Another key element is that those costs are recovered based on the principle of cost causality, which means the customers are fairly paying for the costs they impose on the system.[49]

46 Waters Wye, p. 94; NRRI, p. 45.
47 Eurelectric, *Innovation Incentives for DSOs - A Must in the New Energy Market Development*, July 2016, pp. 13-16. At http://www.eurelectric.org/media/285583/innovation_paper-2016-030-0379-01-e.pdf.
48 Office of Gas and Electricity Markets, "Ofgem opens mid-period review into price controls for National Grid Electricity Transmission and National Grid Gas Transmission," May 12, 2016. At https://www.ofgem.gov.uk/publications-and-updates/ofgem-opens-mid-period-review-price-controls-national-grid-electricity-transmission-and-national-grid-gas-transmission.
49 Sweco, pp. 61-63.



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Given these guideposts, utilities need to be able to tailor their tariffs to their operating circumstances and their customers. One approach would introduce flexibility in rate-setting so as to provide the utility with opportunities to incent customer behaviours in ways that provide value.[50] For example, in a congested area there is more value to energy efficiency or installing DERs than in non-congested areas. New York's REV (see page 24) and regulatory initiatives in California have looked at how to design rates incentivizing behaviour that reduces system costs, such as avoiding expensive system upgrades.[51]

The fact is that such approaches are not necessarily new. Conventional rates and ratemaking is predicated on the cost causality principle, which has emerged as a net calculation: system costs set off against system benefits. Additionally, specific customers are subject to special levies at times of service enhancement, especially for new or improved connections.

Costs should be recovered based on the principle of cost causality, which means the customers are fairly paying for the costs they impose on the system

As DERs will change how systems are operated and planned, the way a system is paid for will also need to reflect an objective assessment of the relative system value or system costs associated with any DER deployment. In Part B of this report we will suggest a way of proceeding that has the effect of rewarding DER deployers for the value they produce for the system, while protecting utilities and ratepayers from the consequential costs associated with the deployment.

The researchers have showcased a number of options, most of which have varying relevance depending on the particular characteristics of any given system architecture. For example, there is much debate over the use of fixed and variable charges in distribution rates and decoupling utility revenue from the amount of electricity that is sold.

Capacity charges, where a customer's rate is based not on fixed charges but on how high their demand from the system is, are one option for equating customer costs with system costs.[52] With capacity charges, DERs could change a customer's demand, thereby possibly changing their costs. That is dependent presumably on an objective assessment of the system benefits associated with the associated reduction in demand.

50 Sweco, p. 82.
51 IET and MCG, pp. 53-54.
52 Sweco, p. 84



One paper suggested that utilities in general should examine ways to introduce more reactive and time-sensitive charges to reflect the value of increasing flexibility, assuming that there is system value in the flexibility created by the specific installation.[53] According to some researchers, rates may become more granular, as the various components are disaggregated to allow for customer choice and flexibility. These components could be very location- or time-specific, with costs reflecting system conditions.[54]

It should be noted that taking such factors into account doesn't necessarily involve a fundamental change in rate design or methodology. It means that regulators would be exercising conventional care in assessing the relative system costs and values associated with the installation. This assessment, in one form or another, is not unfamiliar to many regulators.

Another researcher highlighted concerns related to passive customers and their exposure to higher system costs when active customers leave the grid or drastically reduce consumption, resulting in defecting system revenues. Australia includes a third category of vulnerable consumer – "on the edge" consumers[55] – that may require additional assistance. Of course, the best protection for ratepayers in general is the rigorous application of the cost causality/revenue principle to DER deployments. Overall, costs utilities incur to accommodate active customers will need to be apportioned fairly. If passive customers do not benefit from the changes made, they should be held harmless to the costs incurred.

While under some proposals rates may become more complicated, and potentially harder for customers to understand, the same technology that is making the new complexity necessary can also make the new rate structures possible through simplifying the presentation to the customer.[56] So long as rates are rooted in well-accepted regulatory principles, they should have a higher degree of acceptance from ratepayers. Ratepayers who have confidence that their rates reflect an appropriate balance between system costs and revenues, without fragile or artificial incentives, are more likely to accept them.

53 Waters Wye, p. 17. See also Bernstein et al, *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Lawrence Berkeley Lab Report No. 5, June 2016. At https://emp.lbl.gov/sites/all/files/lbnl-1005742_1.pdf.
54 Devi Glick, Matt Lehrman and Owen Smith, *Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future*, e-Lab Rocky Mountain Institute, August 2014, p. 38. At http://www.rmi.org/elab_rate_design#pricing_paper.
55 CSIRO and Energy Networks Association, *Electricity Network Transformation Roadmap: Interim Program Report*, December 2015. At http://www.ena.asn.au/sites/default/files/roadmap_interim_program_report.pdf.
56 Chaplin, p. 44.



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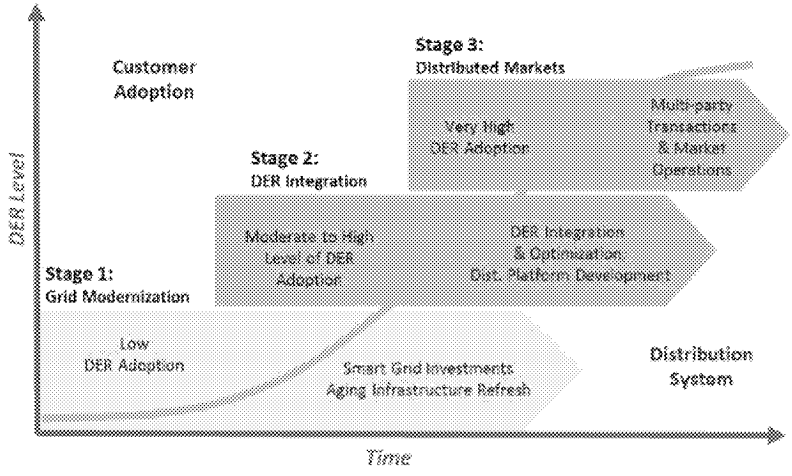
4.3.2 DER ratemaking

Not surprisingly, many researchers offer observations on the implications of DERs for ratemaking paradigms. This is after all where the "rubber meets the road" for developers, utilities, ratepayers and policymakers.

Future ratemaking paradigms would likely be different from the current structure. Partly this is due to the need for more sophisticated rate designs as DER becomes more commonplace in the system (see Figure 8).

FIGURE 8

The evolution of DER rate making



Source: Lorenzo Kristov and Paul De Martini, *Presentation: Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight*, November 13, 2015, p. 11. At https://emp.lbl.gov/sites/all/files/lbnl-1003797_presentation.pdf.

The initial stage of rate design policy for DER consisted of mechanisms intended to induce adoption of renewable energy technologies. There were two primary incentives for this initial phase: feed-in tariffs and net energy metering. As we move to the second stage – integration – there have been attempts to find more sophisticated rates providing appropriate economic signals that could reveal the system value of DER investments.

Feed-in tariffs (FITs) are payments made to grid-connected customers for the electricity they generate and export to the grid from renewable energy sources such as solar PV and wind. Customers are assigned long-term contracts with set prices based on the technology and the size of the installation. This creates a stable price environment for investment.



Another incentive system, one that Ontario is planning on migrating to, is net energy metering (NEM). Under an NEM system DER systems are compensated for surplus generation they export to the broader electricity grid at the full retail rate. Many U.S. states use NEM for small-scale solar.[57]

While FIT and NEM have been useful in spurring development, they have been criticized for being too imprecise and not promoting developments that add value to the grid. One of the concerns with both NEM and FIT is that they do not target places on the grid where investment would make economic or system sense. As a result, a number of states, including New York and California, are looking into modifying their NEM system in order to incentivize investment that provides benefits to the grid.[58]

Given the concerns with FITs and NEM, jurisdictions are developing more sophisticated DER rate designs, such as value of resource (VOR) and value of service (VOS) rates.

The VOR is a rate design methodology that attempts to quantify the value of a resource to the grid. Generally a regulator periodically sets value for different categories of DER, considering the effect of a specific resource on:

» avoided energy or fuel

» avoided capacity

» ancillary services

» avoided pollution or carbon emissions

» utility integration, and

» environmental impact.[59]

Examples of VOR are value of solar tariffs.[60] While VOR attempts to value the potential benefits and costs of deployment, it does not take into account how these values may change over time depending on market and local circumstances. Assigning a fixed value to a form of DER may be problematic over the long term.[61] The system value of deployments may well decrease as more deployments are executed. New York's REV ratemaking framework uses VOR framework (see pgs. 24-25).

57 Susan F. Tierney, *The Value of "DER" to "D": the Role of Distributed Energy resources in Supporting Local electric Distribution System Reliability*, March 2016, p. 6. At http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf.
58 Tierney, p. 10.
59 Adapted from NARUC, pp. 45-46.
60 For more on the value of solar design see Rocky Mountain Institute, *A Review of Solar PV Benefit & Cost Studies*, 2nd edition, 2013. At http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCostDeck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies.
61 NARUC, 2016, pp. 45.

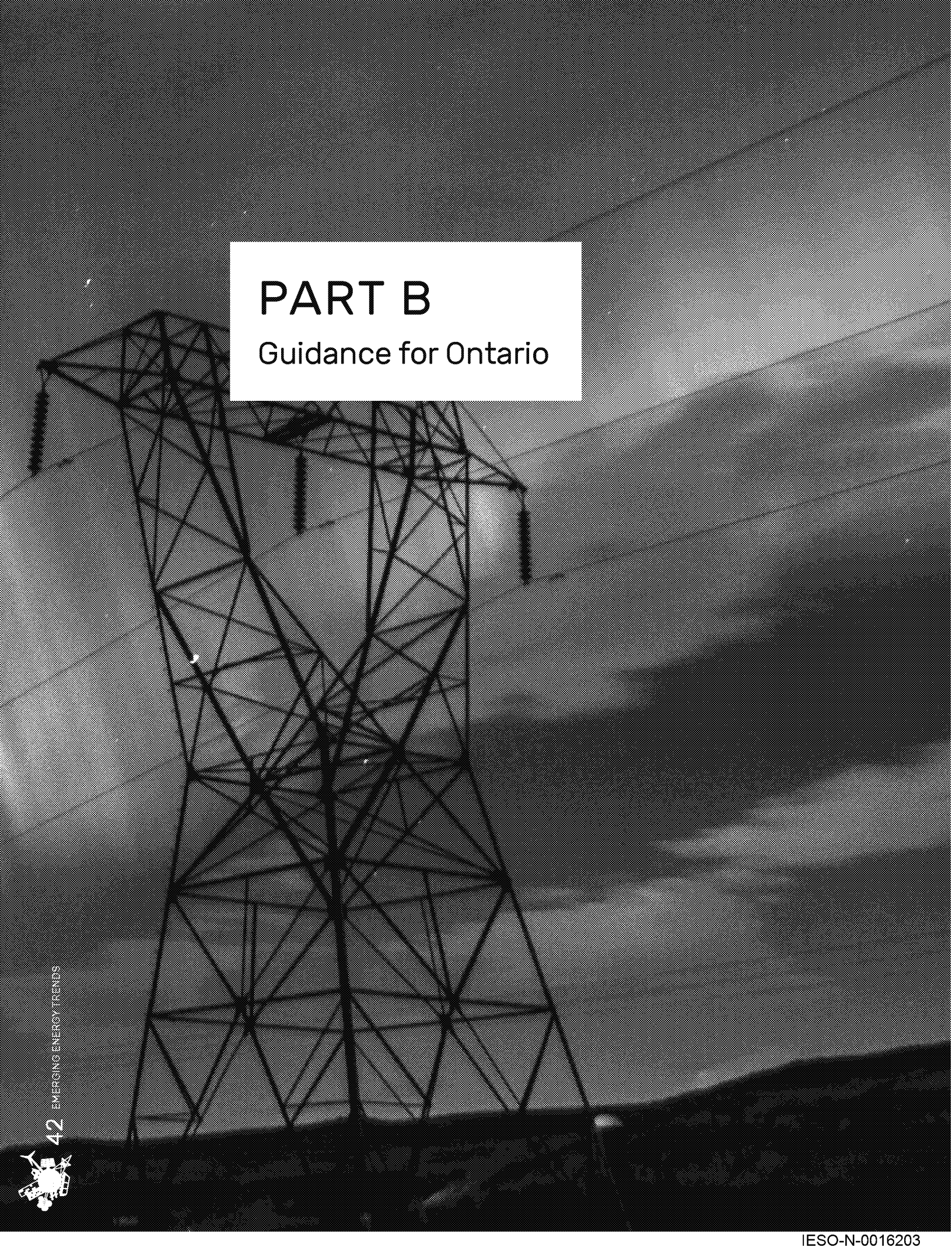
A related rate design methodology is the VOS tariff. A VOS tariff attempts to place a value on the benefits that the installation brings to the system, based on location and, possibly, temporal considerations. For example, a solar PV installation would receive benefit for avoided infrastructure build, as well as adjustment to demand.[62]

Rate design may need to be reconsidered as we move into the next stage – the possible advent of distributed markets. Distributed market rates may include elements of transactive energy as multiple generators and customers buy and sell energy services between themselves using such technologies as "blockchains". While pilot projects directed to this kind of environment have been started, such developments are still in the early stages, and a great deal more work and evolution is needed before this presents itself as a viable design option.

62 NARUC, p. 47.



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PART B

Guidance for Ontario

5 INTEGRATING DERS INTO A FUTURE ENERGY SYSTEM FOR ONTARIO

What does this international research mean for Ontario?

Regrettably, there is no silver bullet embedded within the international reports which provides a clear or definitive direction to policymakers or regulators in Ontario. The primary reason for this is that each energy system, whether in Germany, Scandinavia, the U.K. or the U.S., has emerged with a unique architecture suitable to its local context. One key distinction in some of the systems canvassed is that they are populated by vertically integrated utilities – utilities that provide generation, distribution and transmission services. Ontario is unlikely to move toward vertical integration.

Ontario's energy system has evolved to meet its very specific requirements, and its drivers are, beyond the most basic formulation, unique.

We conclude from the international research a few key observations:

1. The pace of DER deployment is highly variable and – in the absence of very specific incentive programs, which have proven themselves to be problematic – unpredictable.
2. The policymaking and regulatory environment needs to be orderly and settled. Action/reaction/action cycles create less-than-optimal conditions for responsible DER development.
3. In this era of technological innovation planning DER deployment and energy systems in general becomes exceedingly important.
4. The deployment of DERs should be accomplished from a regulatory point of view according to well-established principles. In this way appropriate signals can be delivered to all stakeholders, and the interests of all stakeholders can be responsibly and reasonably protected.

The trajectory of the future market and the consumer and technological circumstances that will frame a future business model are still not clear. The pace of DER deployment has varied widely from jurisdiction to jurisdiction. Given this uncertainty, regulators should be wary of accepting claims that any one technology or any one business model will dominate the future.[63] Policymakers and regulators are good at picking technologies, but not so good at picking winners.

63 NRRI, pp. 38-40.



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A useful antidote to dysfunctional policymaking and regulatory policy is reliance on competitive processes and regulatory economic principles to create the appropriate conditions for economic DER deployment.[64] This means avoiding, wherever possible, incentives intended to skew the markets in favour of specific technologies, approaches, and outcomes.[65] It is true that incentives will spur DER uptake, but that uptake is not always in the best interest of the system as a whole.

One method of developing a flexible "no regrets" policy for the energy system is to ensure that, wherever it is reasonably appropriate to do so, competitive processes are allowed to guide deployment. It is also key that the regulatory treatment of DER assets, wherever they are located, reflects both their true value to the system and the costs that they cause the system to incur. Those values and those costs need to be appropriately allocated so that the utility, its ratepayers and the DER deployer are appropriately protected.[66]

The most important and durable incentive for DER deployment is the creation of a fair, predictable, transparent, and principled policy and regulatory environment in keeping with the principles outlined in section 1.3.

By "principled" we mean well-established regulatory economic principles consisting generally of the application of cost causality, leading to an appropriate allocation of costs and revenues between specific customers or rate classes, equity as between customer classes and, more generally, the integrity of the ratemaking process.

With the Rocky Mountain Institute we suggest that in responding to the transition in the energy sector it is useful to look to the principles developed by James Bonbright in *The Principles of Public Utility Rates*. Bonbright's principles reflect the idea that rates should be designed fundamentally around principles of fairness and efficiency. While much has changed in the sector since his first expression of them, the principles are equally relevant today, and can be applied to the new trends in the sector (see Table 3).

64 Sweco, pp. 38.
65 Waters Wye, pp. 65-70.
66 NRRI, pp. 26-28.



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TABLE 3

A 21st century interpretation of the Bonbright principles of public utility ratemaking

Bonbright Principles	21st Century Interpretation
Rates should be practical: simple, understandable, acceptable to the public, feasible to apply... and free from controversy in their interpretation.	The customer experience should be practical, simple, and understandable ... even if underlying rate structures become more sophisticated.
Rates should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.	Rates should keep the utility viable by encouraging economically efficient investment in both centralized and distributed energy resources.
Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.	Customer bills should be relatively stable even if the underlying rates include dynamic and sophisticated price signals.
Rates should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.	Rate design should be informed by a more complete understanding of the impacts (both positive and negative) of DERs on the cost of service. This will allow rates to become more sophisticated while avoiding undue discrimination.
Rates should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.	Price signals should be differentiated enough to encourage investment in assets that optimize economic efficiency, improve grid resilience and flexibility and reduce environmental impacts in a technology-neutral manner.

Source: Adapted from Devi Glick, Matt Lehrman and Owen Smith, *Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future*, e-Lab Rocky Mountain Institute, August 2014, p. 38. At http://www.rmi.org/elab_rate_design#pricing_paper.

Of key importance in the development of a renovated delivery system is predictability in outcome. Customers, and developers hoping to serve those customers, need to know just what the economic implications of behind-the-meter investments are before they make them. Certainty is an elusive quality in any era of significant change, but to the extent possible, governments and regulators need to provide customers and developers with an appropriate level of coherent, predictable and principled guidance.

This can mean that governments and regulators should avoid attempts to skew a market-driven development of DER alternatives within the energy system. It is attractive, but demonstrably dangerous, to attempt to pick winners, incentivize behaviours that are not market-driven, and to undermine fundamental principles in favour of ulterior goals.[67]

Those goals may include economic development, social priorities or environmental objectives. Such goals are seductive but can prove to be seriously dysfunctional when applied to the regulation and management of the energy delivery system, as explained in section 1.3. Support of such goals within the energy delivery system threatens to compromise its orderly evolution based on fundamental regulatory principle, economics, and market-driven behaviour.

67 Waters Wye discusses the implications of this in the GB electricity system.



One of the genuinely unpredictable aspects of this new era is the pace of DER change. But while consensus is in itself not a fully reliable underpinning, it would appear that most observers predict material change in some of the fundamentals of the current energy delivery systems.

> *Governments and regulators should avoid attempts to skew a market-driven development of DER alternatives within the energy system.*

The growth of renewables, especially solar PV, seems to be inevitable, but it is not clear in all jurisdictions just how quickly that evolution will occur. While breakthroughs in energy storage, particularly battery storage technology, have been promised for some decades now, progress has not reached a genuinely transformative point. That may come, and when it does delivery systems need to be ready, willing and able to accommodate it. New methods of organizing consumers into buying groups may have similar transformative implications, but it is not clear at this stage, in this jurisdiction, when or if these developments will actually materialize.

The appetite of customers for innovation is difficult to predict. We have seen in the international research that customers often have a very imperfect understanding of the electricity distribution and transmission systems, and should not be expected to be students of what has become an extremely complicated subject matter. This is also likely to be the case in Ontario.[68]

If the experience of other jurisdictions teaches us anything it is that it is important to avoid precipitous actions in order to avoid dysfunctional, inefficient, and dangerous outcomes. Indeed the Ontario experience in trying to shape events with prediction is as good a case study as any of the inadvisability of trying to macromanage or micromanage energy systems at a time when there is very considerable volatility in markets, technologies and societal goals.

Just a few years ago it was conventional wisdom that North America would become a significant importer of liquid natural gas from international markets delivered to coastal conversion plants.[69] Very significant investments were made on the strength of those predictions. The rapid development of low-cost natural gas from shale deposits has

68 See earlier work on the topic at Richard Carlson and Eric Martin, *Re-Energizing the Conversation: Engaging the Ontario Public on Energy Issues*, October 2014. At https://mowatcentre.ca/re-energizing-the-conversation/.
69 Natural Resources Canada, "LNG Projects." At https://www.nrcan.gc.ca/energy/natural-gas/5683.



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completely undermined that predicted outcome, and there are few, if any, liquid natural gas conversion plants in current development for supply to the North American market.[70]

In our own jurisdiction very considerable effort and expense was directed toward developing employment opportunities in renewable infrastructure manufacturing, which were intended to accompany the rapid deployment of renewable energy generation across the province. That effort was found to be inconsistent with international trade conventions.

What is clear from the jurisdictional scan underlying this report is that there is a general consensus that there will be a considerable impact on energy distribution systems brought about by technological change and a desire on the part of consumer classes to exercise more control over their energy usage and cost. While that consensus, qua consensus, as we have seen, is an unreliable guide, it would be equally foolish to ignore what seems to be a rational response on behalf of consumers and markets to the advent of new technologies that seem to offer a variety of benefits.

In this way the pace of system evolution can also be accommodated and managed. It is evident that in Ontario any measure which has the effect of materially increasing rates to consumers is unpalatable. Not only has the increase in electricity rates over the last period complicated economic development policy, but burdens on residential, agricultural and industrial customers have become the subject of focused attention by the regulator and policymakers.

Rate impacts caused by system enhancement, whether for DER deployment or smart grid rollout, or for whatever other reason can be effectively identified and integrated into the regional planning process, so that any inflationary rate impacts can be measured, predicted and appropriately staged.

This opportunity is important given the extreme sensitivity in Ontario for any increases in energy prices to consumers. For a number of reasons, electricity pricing in Ontario has seen substantial increases in recent years – increases that have proven to be unpopular with industry, residential customers and governments. There is very little tolerance left within the system for any increases that cannot be fully justified and explained to consumers.

Regulatory and planning processes should seek to optimize both electricity and natural gas, including renewable natural gas, infrastructure. It is suggested that in the highly cost-sensitive environment that is Ontario, policymakers and planners should

70 As an example, in 2007 the Quebec government approved plans by Petro-Canada and TransCanada for an LNG import terminal at Gros-Cacouna. The project was cancelled in 2009. See Rhéal Séguin, "Quebec okays Gros-Cacouna LNG terminal," *Globe and Mail*, June 28, 2007. At http://www.theglobeandmail.com/report-on-business/quebec-okays-gros-cacouna-lng-terminal/article20405149/.



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ensure that at least as a transitional measure, the full scope of energy options, not just electricity options, are evaluated objectively and to best effect. Using all of the technologies and fuels may be able to facilitate a more balanced and resilient system.

At the planning level all options need to be given sober consideration. One goal of that process should be to arrive at the most cost-effective system solution to the challenges presented, regardless of the technologies involved or the fuel source. Ratepayers (electricity and gas) would benefit if the planning and regulatory silos evaluated energy outcomes by considering a more integrated future of pipes and wires and other technologies working together.

At the end of the day, if overriding broader public policy favours one approach over another, at least the decision makers will have a clear picture as to the nature of the choices they are making and their net consequences.

Based on the research from the different jurisdictions, to ensure that the most benefits from the transition are realized jurisdictions should consider the principles in Table 4.

TABLE 4
Principles for the effective integration of DER

Area of Transition	Principles
Planning	Flexibility
	Locational
	Holistic
DER ratemaking	Fair cost-benefit allocation
	Locational
Utility regulation and business models	Flexibility
	Allow for competition
	Outcomes-based



5.1 Renewed and enhanced regional planning

What this leads to is the need for an enhanced planning process that is designed to lay the critical groundwork for the responsible, flexible, transparent, cost-effective and predictable accommodation of DER deployment throughout the energy system.

5.1.1 An inclusive and comprehensive regional planning process

The regional planning process needs to be significantly more inclusive, programmatic and comprehensive than has been the case to date. In Ontario, the economic regulator, the OEB, has imposed an obligation on LDCs to demonstrate that they have engaged in a planning exercise that supports the capital budget that they seek to recover in rates.

While this is a very positive gesture, and is directionally correct, in its execution it has not been a particularly effective tool in identifying system requirements, or the appropriate regional responses to existing, conventional capital spending requirements. Most pointedly, it has not been an instrument that has been focused on the relevance of DERs within a given rational planning zone. It is critical that the planning process be undertaken on a regional basis so that the appropriate system requirements can be identified using all of the conventional and emerging energy resources, wires and non-wires, within a rational, technically cohesive region.

The regional planning process has evolved considerably since its inception just a few years ago. But further evolution is needed if it is to provide the key information and guidance it is capable of providing. It should include the relevant regional distributors, ratepayers, the transmitter, potential DER developers, natural gas distributors, municipalities, relevant government departments and any other stakeholders who have a legitimate interest in the energy distribution system. It needs to engage these stakeholders in a rigorous and well-formatted process that is capable of providing executable plans, not merely aspirational visions.

This enhanced planning process can also help to integrate the community and municipal energy plans prepared by many cities in Ontario with the utilities and other relevant stakeholders. The Ontario Ministry of Energy funds the development of these plans, but some may not be informed by, or responsive to, utility capital plans, for whatever reason. Planning integration – of municipal and utility planning – will help ensure that all stakeholders are appropriately involved and that municipal official plans and utility plans are aligned.

Considerable emphasis has been given to the concept of social license as it concerns government activities. Inclusiveness and transparency are important precursors to the procurement of genuine social license for change. Social license is dependent



on the credibility of the underlying process leading to action. It is important that the process intended to identify optimization of the energy delivery system be appropriately inclusive so that all of the relevant stakeholders have an opportunity to be informed and to inform the process. What proceeds out of such an inclusive and fully informed process is a planning product that has the twin virtues of being based on the best available information, and which has the benefit of having been exposed to all relevant points of view in a formatted environment. We suggest that this is a crucial first step in the appropriate accommodation of DERs throughout the energy delivery system.

It is also important that the planning process is explicitly open to non-wires solutions to regional energy issues, and that any non-wires solutions identified are appropriately and objectively considered and evaluated. It may be that regulatory instruments, such as OEB Codes, may need to be modernized to enable utilities to take up and accommodate wires and non-wires solutions alike with confidence that any costs incurred can be recovered.

Regulatory instruments should also enable the effective upgrading of system elements where appropriate, and not directly or indirectly reward or enable like-for-like replacement of system elements when better alternatives may be available.

The regulatory process needs to recognize that some equipment may have regional system value, and that there should, in some circumstances, be an apportionment of allocation to rate base for the respective regional utilities.

This enhanced planning process can also help to integrate the community and municipal energy plans prepared by many cities in Ontario with the utilities and other relevant stakeholders.

Once the regional requirements are identified through the planning process, which would include apparent optimal applications for innovative DERs (and grid optimization), the next step is to develop an appropriate rate response and approaches for their accommodation. We discuss how to best develop a DER rate in section 5.3 below.

As noted above, one of the key issues in developing a regional planning exercise is to produce a blueprint for the most effective locations for DER deployment, and as reliable a forecast as to the location of and pace of uptake as possible.



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Statistical tools are under development which make the difficult task of predicting DER uptake less elusive. Together with an enhanced regional planning process, which can actually identify points within a regional system that would specifically benefit from DER deployment, the uncertainty around the pace of uptake can be significantly reduced. In addition, this approach can actually provide reasonably precise information enabling regulators, customers, and developers to make informed decisions about where DER deployments are most valuable and how valuable they actually are.[71]

DER developers, individual customers, or collections of customers should be presented with an opportunity to fill gaps or correct deficiencies within the system. The system value of those contributions will vary according to their location within the system. The dispatchability of the resource, the extent to which the enhancement may cause upstream or downstream accommodation costs, the extent to which the enhancement is customer specific as opposed to system enhancement, the extent to which there may be an accelerated uptake after a tipping point is reached – these are all factors that need to be and can be carefully considered in the course of a regional system plan.

Some of these considerations have special meaning within the Ontario context where additional generation, at least in the near to mid-term, would seem to have little value, given what appears to be a surplus of baseload generation.[72] Undo encouragement of categories of DER could have significant negative implications for a broader system that already has too much generation. However, the regional planning process may identify local or regional conditions that give rise to genuine local or regional system value from DER generation assets that provide congestion relief. In such cases the monetary value of those enhancements should not be impossible to assess.

5.1.2 DERs, regional planning and energy distribution system consolidation

The regional planning process should be seen as a key input for the development of functional – i.e., economic – consolidation in the electricity distribution sector. While considerable effort has been spent in considering and even encouraging legal consolidation, it is not at all clear that legal consolidation should be expected to produce tangible system or customer benefits. On the other hand, optimization of the system and implementation of genuine savings through functional consolidation – such as the sharing of surplus capacity of rolling stock, vegetation control procurement, etc. – should be seen as one promising approach to controlling costs and, consequentially, rates.

71 For discussion on modelling techniques, see Andrew Mills, Galen Barbose, Joachim Seel, Changgui Dong, Trieu Mai, Ben Sigrin and Jarett Zuboy, *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-1006047, August 2016. At https://emp.lbl.gov/sites/all/files/lbnl-1006047_0.pdf.
72 Independent Electricity System Operator, *Ontario Planning Outlook*, September 1, 2016, p. 3. At http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf.



It is also likely that a genuine regional planning process could lead to what has become an increasingly elusive objective: consolidation within the electricity delivery system. The creation of over 300 separately owned and operating local electricity distribution companies in the 1990s was the product of the history and unique circumstances of Ontario, and not necessarily the product of a plan to effectively manage the electricity sector.[73] Since 2000 policymakers have been preoccupied with trying to effect progressive consolidation of the sector, with halting success. At the time of writing there are over 70 distinct, typically municipally owned, LDCs which are operated as distinct business entities.

This architecture has come under increasing scrutiny as being not optimal. A genuine regional planning process would provide the best possible information related to the consolidation of the many LDCs in the electricity market. A genuine regional planning exercise should have the effect of identifying where genuine economies can be achieved between local energy distribution companies. It can also identify an optimal energy mix approach that is genuinely inclusive of all available energy resources, techniques and designs – including DERs.

Much of the focus has been on the legal consolidation of the sector, the acquisition and merger of LDCs by way of share purchases and exchanges. Legal consolidation may not necessarily bring desirable cost savings which can be passed on to consumers. But functional consolidation may be of more pragmatic value. Functional consolidation refers to the evolution of the system in such a way that regardless of the legal ownership of the LDCs genuine economies in their operation can emerge. Not only does the regional planning exercise offer the potential for the identification of material economies in back office services, vegetation control, optimized use of rolling stock, but also in regional capital investment.

An important goal of the regional planning process should be the creation of what could be described as a regional capital plan, one that places regional assets at its centre. Through a critical and fully informed process the needs of the region can be identified across local distribution boundaries. This may lead to an integrated regional capital investment plan, requiring a degree of allocation of regional resources among participating LDCs. Managing DER deployment within such a regional capital plan would help ensure such deployment adds value to the energy system.

73 Murray Elston, Floyd Laughren and David McFadden, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, The Report of the Ontario Distribution Sector Review Panel, December 2012. At http://www.energy.gov.on.ca/en/files/2012/05/LDC_en.pdf.



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5.1.3 The critical importance of locational planning

To date the regional planning process for electricity has been largely a top-down, transmission-focused exercise. Without intending criticism of any party, it has not evolved in a manner that would make the kind of determinations needed in this new environment.

We suggest that without a genuinely informative resource plan none of the other steps required to efficiently accommodate DER can be accomplished. A new and more effective rate treatment is only possible in a context where the genuine value of proposed system enhancements can be established. This means that the specific characteristics of any regional system must be fully understood and existing deficiencies and future optimization opportunities identified.

Once these needs and opportunities are identified, the process of assigning appropriate value can be accomplished, the financial consequences can be narrowed, and an appropriate rate treatment for customers can be established.

At the same time it would be unsafe to ignore the current priority given to the development of the low carbon economy. The potential penetration of electric vehicles and a more robust electrification of the energy environment using sources other than fossil fuel should be considered as part of the planning process. However it has proven to be easy to overestimate these developments in the planning process and what is needed is an architecture that is genuinely flexible and incremental in nature.

Ideally the planning process should create the conditions that can accommodate varying paces of DER deployment, through the application of a principled regulatory treatment, and should not make casual assumptions about the phase-out of fossil fuels, in any of their applications, that are more aspirational than economic. This is particularly so in an environment that is very sensitive to increases in energy pricing within the Ontario economy and body politic.

The evolution to a low carbon economy in a measured, cost-controlled manner can only be accomplished if it can be managed within a fully informed and principled environment. Opportunities for innovation leading to low carbon evolution need to be seen within the context of a viable, cost-sensitive, and technologically astute regional plan. In this way non-optimal duplications and uneconomic investments can be avoided, and viable opportunities for clean technologies can be identified on a regional basis.

Inherent in such analysis is the extent to which non-monetary inducements or incentives may be offered to advance social or economic development goals. We suggest that the accommodation of such goals by way of incentive or subsidization is a matter best addressed after core system requirements are identified. It is suggested



that there is virtue in ensuring that the regional planning process incorporates such goals, but that the resulting regulatory treatment is predicated on purely economic considerations, related solely to the efficient operation of the distribution and transmission systems. To the extent that governments have additional priorities they should be accommodated after the regulatory and economic position has been identified, and through mechanisms outside the ratemaking process.

The integrity of the ratemaking process should not be compromised by incentives intended to encourage or discourage certain outcomes. One good reason for that is that the economic treatment of DERs should change with the amount of penetration of these technologies into the distribution system. The value of a single DER deployment at a specific location within the system changes the calculation for all other future DER deployments within that system. For example, once an asset is placed within a distribution system so as to address a specific supply shortage or congestion condition, subsequent placements will have diminished value, simply because the original deployment changes the economics that govern the regulatory and rate treatment.

> *The evolution to a low carbon economy in a measured, cost-controlled manner can only be accomplished if it can be managed within a fully informed and principled environment.*

Predictions based on incentives as we have seen in other jurisdictions often lead to dysfunction and the less-than-optimal rollout of technologies.[74] In some cases picking winners has shown to be a perilous course, leading to an unnatural, embedded and costly rate environment, which can produce skewed systems.[75]

Given the seminal importance of the regional planning process, and the central role it should play in system development and renovation, it needs to be executed within a rigorous and formatted procedure. It is fundamental that all relevant stakeholders have an effective opportunity to become engaged in the process. The resulting plan will only have requisite credibility and authority if it has been developed in a manner that ensures that all relevant information has been elicited, thoughtfully considered and included. It should not prove to be overly challenging to develop a comprehensive regional planning procedural format that would include appropriate notice provisions, a format for submissions and responses, information exchanges and conventions.

74 Chaplin, p. 12.
75 Waters Wye, p. 11.



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It should be expected that there is very considerable knowledge of local system characteristics and the areas within them in need of renewal. Developers should be able to develop plans for DER deployment within those systems, and municipalities typically have sophisticated plans for regional development. The point is that there is considerable system knowledge that can fuel the planning process and allow it to occur within a reasonable timeframe.

A mechanism should be considered that would endow proposals for specific system enhancement and renovation made during the course of the regional planning process with a somewhat settled status and treatment. Proposals that come along after the process has reached milestones should be subject to negative, but not disqualifying presumptions.

The process may also need to recognize the existence of system enhancements within specific utilities, allocating the costs and rate base treatment of such system assets across all members of the region. This would mean that a specific asset that plays a role in the overall regional capital fleet should be allocated as part of the rate base of each of the distribution companies, and perhaps also that of the transmission utility.

Where the regional plan or the utility identifies a capacity shortage within the system, the utility should establish a transparent costing for its response to the issue. It could then produce a request for proposals to address the issue at the customer level. Solutions may involve generation or storage installations, demand management, or any other viable solution, or combination of solutions. The proposals would then be vetted by the utility, and a choice made to accept the proposals or, where the proposals are too expensive or ineffective, reject them and proceed with the utility-based solution. At all stages the utility would be accountable to the regulator for the fairness of its processes, and safeguards will need to be imposed to ensure that there is no bias unduly favouring the utility-based resolution, or those advanced by DER developers.

This process is analogous to the process followed in the Brooklyn-Queens Demonstration Project undertaken by ConEd in New York City (see page 26). With necessary variations this kind of process can be employed to arrive at lowest reasonable cost solutions leading to system optimization in Ontario.

Reliability standards present unique issues. At one level reliability is an ever-evolving concept, and endless amounts of money can be spent in pursuing reliability standards that would avoid outages or power variations altogether. But we suggest that the regulator needs to establish a conventional system expectation that provides a reasonable standard, without pursuing very expensive additional protection. Customers seeking enhanced reliability over and above that conventional standard should be required to cover the costs associated with that enhanced standard themselves, without any expectation of support or contribution from other customers.



5.1.4 Smart grid enhancements and DERs

It was anticipated that the system planning requirement identified by the OEB would be the path toward the economic and effective roll out of smart grid technology into the energy delivery environment. Generally speaking that has proven to be elusive. New expenditures related to smart grid innovation need to pass through an effective filter that can only be developed in a genuine and credible regional planning process.

While the delivery component of the electricity bill represents about a quarter of the overall burden to ratepayers, it is important to control these costs as effectively as possible. Equally important is the rational and planned development of an energy delivery system that is as reliable as is practical, as cost-effective as possible when that serves reasonable low carbon economy objectives, and one which provides appropriate signals to private capital so that repairs are not the only source of investment in the system. There is also an opportunity to enable energy entrepreneurs to engage in the system.

One of the attributes of the new world of energy distribution across the world is an increasing role for private capital as an adjunct to the monopoly system. This arises because technologies can now provide individual customers or collections of customers with genuine behind-the-meter options for their energy needs. There is also a commercial aspect in circumstances where customers can, under the right circumstances, sell back into the system surplus power produced by their behind-the-meter generation assets, or provide storage units and other DER services or values to the system.

This is clearly a welcome development provided it can be accommodated without placing the system as a whole at risk or placing certain classes of ratepayers in the unenviable position of paying for a system that other classes of customers are abandoning. A key driver for the introduction of private capital into the energy distribution system is the development of a predictable economic model for the accommodation of DERs. Unless investors have a clear idea as to how their investments are going to be treated, what legacy obligations they may have to adopt, and the pricing structure for energy sold back into the system, etc., they will be reluctant to make significant investment unless there is a material other driver such as a customer-specific reliability standard that substantially exceeds the default reliability standard provided by the utility.

So this renewed and enhanced regional planning process should be seen as providing a number of important value propositions. The key to its credibility is its inclusivity. Engaging in a reasonably granular regional planning process should be seen as an opportunity for its system operators and regulators to gain a very sophisticated picture of near and mid-term system requirements and opportunities for optimization.



A comprehensive and properly designed regional planning process should have the effect of avoiding unnecessary system costs, providing the basis for the execution of functional consolidation within the distribution system as well as a credible basis upon which capital expenditures can be identified. It provides a rational basis for cost control, system savings and social license for system expenditures.

5.2 Utility regulation and business models

5.2.1 The fundamental system-wide risks of business model diversification

Over the last few years there has been considerable interest in the development of "new" business models for utilities, as a response to a perceived "death spiral" risk (see section 4.2.1. for details). The advent of DERs was said to threaten to accelerate this process materially. Not only would the unit price of electricity rise for customers remaining within the system, a particularly intractable form of rate increase, but the utility's ability to effectively renovate the system would be impaired.

Many of these proposed new business models for distribution utilities focus on enabling utilities to engage in competitive markets for DER procurement and the provision of enhanced services for customers. To date in Ontario local distribution utilities have been sharply restricted in their business activities. In effect, with the exception of a role in conservation and demand management, and very modest and rare renewable generation activities, they have been restricted to the role of a classic, wires-based, delivery entity. The interest in engaging them in competitive activities appears to be driven by a perceived need to provide additional sources of revenue to counteract the uptake of behind-the-meter DER, and the concomitant decrease in delivery-based revenue. Ontario has recently passed legislation which authorizes the regulator to approve the engagement of local distribution utilities in competitive businesses.

Recent credible projections of the trajectory of load for Ontario confirm that there is unlikely to be significant growth in load outside of specific special circumstance locations, casting severe doubt over the death spiral warnings. Furthermore, as explained in section 4.2.1, there is growing scepticism in the literature respecting the engagement of electricity distribution entities in competitive DERs or in services businesses, and it may be that the development of principle-based rate structures is a much better approach to ensuring that the LDCs have sufficient revenues to effectively sustain and develop their systems.

It is important to appreciate the very fundamental nature of the reform contemplated by those who wish to see local distribution utilities engaged in competitive businesses. It is a very significant paradigm shift from current practice that cascades into a series of issues that may suggest that the cure is worse than the disease.



The engagement of utilities in behind-the-meter enhancements would have to be undertaken in such a way that ratepayers do not face undue risks and cost burdens, and that the competitive market can fairly and fully express itself.

It has been a key component of the regulatory regime in Ontario that ratepayers ought to bear the costs associated with the provision of service to them, but no more than that. The risk of subsidization by ratepayers for costs not attributable to their service has been the subject of very precise mandatory regulatory prohibitions in order to ensure that ratepayers are not unintentionally subsidizing forays by the utility into risky competitive environments.[76] Those measures, intended to protect ratepayers, would have to be scrupulously maintained and indeed enhanced should utilities be allowed to enter secondary business areas in the DER space. There is a considerable regulatory burden associated with ensuring that this objective is met.

The rate of return established for local distribution utilities is predicated on an enterprise risk profile that does not contemplate their engagement in what, by definition, is the riskier competitive environment of new technologies.

But the engagement of the local distribution company in competitive businesses also carries risks for the non-utility business community, interested in developing DER products, systems, and services independent of the utility. The simple fact that LDCs have a highly predictable revenue source derived from distribution rates could have the effect of tainting the competitive market. The risk of intentional or unintentional subsidization, in a variety of ways, may have the effect of skewing the market for these products and services. Energy service entrepreneurs could be undermined unless a very rigorous process is in place to prevent competitive advantages for LDCs.

We suggest that the most appropriate method, at least on an interim basis, to protect utilities from revenue shortfalls associated with DER development and system enhancement is to be found in providing a DER rate option that provides the utility with a principled environment for the recovery of operating and capital costs.



76 As an example see the recent decision by the Ontario Energy Board on natural gas expansion in Ontario: Ontario Energy Board, Decision with Reasons, EB-2016-0004, November 17, 2016. At http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2016-000.

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Load/customer defection and DER

Virtually every commentator regards load and customer defection from distribution systems to be a key challenge for policymakers and regulators. This phenomenon is the primary cause of the so-called "utility death spiral" (see section 4.2.1). In fact, the true victim of the death spiral is likely not the utility, but rather some of its rate classes.

For the purposes of this discussion "load defection" describes the material reduction in throughput occasioned by the customer's deployment of DER assets or energy management services. "Customer defection" describes the case where customers actually withdraw from the distribution system and rely virtually exclusively on their own behind-the-meter resources for energy.

In both cases, the effect is to reduce the amount of energy purchased from the distributor, and hence reduce the distributor's revenue.

The issue is especially significant given the fact that for many electricity distribution companies a very high proportion of revenue is derived from larger commercial and industrial customers. This is the very cohort most likely to implement significant and sudden DER deployment.

To the extent that utility revenues are derived from throughput, the effect of load defection is obvious: less throughput, less utility revenue.

In Ontario the economic regulator recently imposed a "fixed costs" rate regime for electricity distribution rates. This means that the rates charged by utilities for delivery are designed to cover the fixed costs of the utility, and are not dependent on throughput. Under such a regime the issue becomes customer defection because this rate design materially blunts the effect of reduction of load for customers – that is, they are not incented to reduce their load, but are instead rewarded for outright defection. Numerous commentators regard fixed costs rate design to be inconsistent with the evolution to a DER-enhanced future, and could exacerbate the problem of grid defection.[77]

There are serious implications associated with the loss of significant utility revenue. One way or another, the costs of operating the distribution systems have to be met. By definition, the fixed cost rate regime is designed to cover the fixed costs of the utility. When those costs are not covered because a significant amount of revenue has been lost, remaining customers are burdened by increased rates to cover them. This represents a meaningful transfer of costs from the larger commercial/industrial rate classes, which are able to fund and deploy significant DER assets, to residential and small commercial customers. This is particularly important given the high degree of sensitivity in Ontario to rate increases of any description.

Elsewhere in this paper we suggest that there are responsible responses to these phenomena – to effectively manage the pace of change and the integration of DERs, which would mitigate, on a demonstrably economic basis, the erosion of utility revenues so as to avoid the death spiral.

77 See the discussion at Chaplin, p. 22.



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5.2.2 The recovery of stranded assets and legacy obligations

There are important issues related to the extent to which customers who now choose to significantly reduce their load or leave the system entirely may be thought to have some species of obligation or legacy liability related to the system as a whole. This is based on the view that the current system has been developed and maintained in order to serve the needs of all existing customers, and that there is a legacy obligation to maintain a revenue contribution, even after the customer has significantly reduced its load or left the system entirely. It is also thought that because the energy system as a whole has a cultural or societal role serving the interest of the departing customer that some value needs to be assessed for this dependence.

As noted in section 5.2.1, there has been considerable amount of commentary concerning the so-called "utility death spiral". This involved speculation that significant load defection, and hence revenue defection, could lead to a condition wherein the decreasing number of load customers cover an ever-increasing share of system costs, until they, and the utility, reach a breaking point.

The rate-design process needs to take into account the concept that the legacy system must be reasonably and economically supported throughout all of the transitions, and that utilities, acting prudently, should be able to rely upon a stable and adequate revenue stream to ensure proper maintenance, sustainment, and where indicated, development of the system. The economically based quantification of these legacy liabilities is therefore a crucial step in the evolution of rates.

The extent to which existing customers ought to be burdened to maintain their legacy obligation can then be assessed. Currently, new customers seeking connection are required to contribute an amount necessary to cover any shortfall in revenue over and above construction costs, over a stipulated horizon period. A similarly symmetrical regime would seem to be appropriate for assessing existing customers' legacy obligations

While the death spiral speculation seems overstated, at least at the current level of load defection, utilities do face risks associated with loss of load and/or customers – risks that vary with the rate of customer defection and the resulting stranding of distribution assets facilitated by greater DER penetration.

It should be remembered that investments in distribution assets, for example transmission stations, are often very costly, with the costs incurred upfront, and then recouped over time through customers' electricity rates. When customers defect, or significantly reduce consumption, due to DER technology, the demand levels that economically justified this infrastructure investment are no longer there, making the assets redundant. These sunk costs are sometimes referred to as legacy costs or stranded assets.

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The key feature of a regulated system is that system costs are confidently recovered by utilities through rates. Rate structures designed to accommodate DERs need to take into account the potential for an accelerated defection of load customers from the system by recognizing an ongoing time-limited obligation for customers who defect from the system, or who substantially reduce their reliance upon it.

In such cases, it is suggested, the defecting customers should bear responsibility for costs incurred in the provision of the system up to the date of their defection, including the portion of those costs they have not yet been paid for. The architecture for imposing these legacy obligations should reflect the economic impact of their defection – that is, the loss of their revenue to the system – in a measured and principled way.

Under current rate structures, customers who wish to connect to the system, and whose connection causes increased system costs, are obliged to make formulaic capital contributions to offset the deficiency in revenue divided by the costs associated with the connection. This capital contribution architecture is a common form of system protection which has been in place in Ontario since market opening. It is key that these capital contributions are formulaic in nature and derived from well-understood and predictable rules.

There is a similarly reasonable symmetry that can be applied to customers who choose to defect from the system or to significantly reduce their load. We suggest that such customers have a reasonable responsibility to support the system for a period of time following their defection, based on well-understood and well-stakeholdered rules. In other words, where the revenue anticipated from a given customer is going to fall short over a specific horizon period because of a business decision to arrange other forms of supply, that customer should be required to support the system, in whole or in part, to the extent necessary to offset that deficiency.

Not only does this provide the utility with reasonably anticipated revenue, but it also protects the interests of the remainder of the system, that is the remainder of the customers on the system, from unit price increases which may be unsustainable. While this may be seen as a disincentive for innovation with respect to DERs, properly understood it is a reasonable and principled response intended to protect the system from defection and takes into account the genuine economic environment created by decades of investment and sustainment of the energy delivery system.



5.3 An effective DER rate for Ontario: Essential components and considerations

5.3.1 Keys to developing a provincial DER rate

As the international experience demonstrates, precipitous action is often followed by retraction. While the endpoint of DER penetration may well be revolutionary, the path to it, we suggest, should be incremental and evolutionary.

There is no virtue in establishing an uneconomic and ultimately unsustainable pricing regime out of enthusiasm for DER deployment, or in the pursuit of ancillary of-the-moment policy goals. If policymakers wish to artificially advance the take-up of certain technologies, incentives should come not from utility rates but rather from independent funding programs.

A great deal of attention has been paid around the world to the question of developing rate designs intended to appropriately capture the value of DERs within a given energy delivery environment and to assess the appropriate costs associated with them. It is not always clear that the value proposition works for either side of the ledger – the system provider, and its ratepayers, or the behind-the-meter developer. In many instances the value proposition is highly dependent on locational and timing considerations. Clearly, system enhancements at congestion points have materially more value than those undertaken elsewhere within the system. It is also true that it is not necessarily the case that generation wherever it is produced is of value to the system now, or in the near or the mid-term.

> *Not only does this provide the utility with reasonably anticipated revenue, but it also protects the interests of the remainder of the system,*

We suggest that the necessary first step in the Ontario context, after or coincident with the significant enhancement of the regional planning process described in section 5.1, is to develop the architecture for a provincial DER rate, available to any and all customers upon request. Such a rate-architecture should be indifferent as to which specific kind or combination of DER assets are under consideration.

The main issues presented by DERs in the various jurisdictions studied include accounting for the costs incurred by the system, loss of revenue where that is a factor,



plus the benefits or services provided by DER to the system, and ensuring that the specific deployment does not compromise or cause technical disruption to the existing system.

While valuation of these benefits and the costs can be complicated, that is not a good reason to avoid them or to defer establishment of working monetization models to inform regulators, DER developers, LDCs, the system operator, and customers. Tools have been developed to enable regulators to assess with relative precision the value of services presented by a DER deployment to the system, as well as the costs, including foregone revenue associated with the same deployment.[78]

Development of these elements of a DER rate is a crucial first step in enabling customers and those wishing to provide DER assets or services to them to understand the economic context in which they will be operating. As things stand today, there is very little guidance on these subjects from the regulator.

Developers and customers need to be able to confidently establish the payback period for DER investment, in a context that is reasonably and economically protective of the overall distribution environment.

Rate design is the subject of voluminous scholarly and pragmatic observation. As already noted, the abiding and fundamental principles of rate design have more or less been captured in the authoritative text in the area – Bonbright on the rates for utilities.[79]

Even though DERs represent a relatively new and unique disruption in the energy distribution system, our international research showed no reason that the Bonbright principles should not apply to the design of a DER rate. As mentioned above, the Rocky Mountain Institute adapted the Bonbright principles for the 21st century.[80]

Key to the process of developing a viable DER rate that is fair to both implementers and existing system customers is identifying in a sober and objective manner the relative costs and benefits associated with a particular, location-specific DER installation. Some costs and some benefits will apply equally to any and all DER placements. But others may well be heavily influenced by the location of the asset within the system. For example, there are areas of congestion, particularly within urban distribution systems, which present very particular challenges for the safe, reliable and cost-effective operation of the system. Often the solution to these congestion issues is enhancement of the transformer stations serving these locations, typically at considerable system cost. A DER installation which has the effect of avoiding that cost to any degree should be credited with a system benefit commensurate with that avoidance.

78 NRRI, pp. 15-16, 22-23, 44.
79 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, *Principles of Public Utility Rates*, Columbia University Press, 1961.
80 Glick, Lehrman and Smith, *Rate Design for the Distribution Edge*. See Section 5 above.



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Some jurisdictions have experienced extremely high penetration of DER assets behind the meter. Hawaii, for example, has experienced an extremely active DER segment where fully half of the peak demand for the system is being met by DER assets.[81] Hawaii too has undergone a degree of action and retraction as the full implications of aggressive DER deployment have materialized and it has introduced less advantageous rates.[82]

The rollout of net metering in some jurisdictions has proven to be somewhat problematic. While DER customers have a legitimate, indeed compelling, expectation for compensation for energy sold back into the system, it is important to ensure from the beginning that the pricing structure is genuinely reflective of the economic value of this "contribution" to the system.

Externalities, such as broader social policies associated with climate change, economic development, or other drivers, should not form part of fundamental rate design for DER.

As with Hawaii, a number of jurisdictions are currently substantially revising net metering architecture to scale back prices for energy sold back into the system. In Ontario this may be particularly important given the fact that Ontario has an abiding surplus of supply. In such an environment additional supply, whether peak or off-peak, may have marginal value to the system, unless it arises at specific locations where it has demonstrable value.

As noted above, we suggest that it is important that the rate-design activity restrict itself to the rather narrow subject of system-related costs and benefits. Externalities, such as broader social policies associated with climate change, economic development, or other drivers, should not form part of fundamental rate design for DER. The deployment of DERs within the energy distribution system should be a discrete, and inherently balanced and objective process, and introduction of other elements can only have the effect of producing the kind of unnatural, and potentially dysfunctional (and expensive) outcomes that were, for example, seen in Great Britain.[83]

As laudable as other social objectives may be, their funding should be accomplished outside of the rate structures which are designed to create a balance between cost

81 Chaplin, pp. 46; NRRI, pp. 63.
82 Mark Dyson and Jesse Morris, "Hawaii Just Ended Net Metering for Solar. Now What?", *RMI Outlet*, October 16, 2015. At http://blog.rmi.org/blog_2015_10_16_hawaii_just_ended_net_metering_for_solar_now_what.
83 Waters Wye, p. 11

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and revenue within the energy distribution system. That is not to say that public policy should remain silent on these objectives. But incentivizing certain technologies, uneconomic deployments, or blurring in any way the genuine economic context is, we have seen, destined to create future problems.

It is suggested that if the government wants to particularly support the proliferation of DER deployments, it is best to do so by way of direct project subsidy effected after the objective rate/capital contribution has been determined. Making any subsidies available to the proponent after the objective value/cost determination is made on the application would allow the government to support only those projects which make objective economic sense, and only to the extent necessary to make them economic and effective. The interests of the remaining ratepayers would be protected, and the pace of proliferation would be coincident with rational deployment.

As already noted, a key consideration is that system rates are predicated on the coverage of system costs by the respective rate classes, that is by the revenues produced by each rate class. This is in effect a zero-sum reality: what one rate class does not pay, other rate classes must pay. Where externalities are introduced into the ratemaking process that reduce system revenues from one rate class, other rate classes will likely be burdened with additional costs, increasing the unit cost of electricity to those classes. In this way, DER deployment by certain customers that reduces what they pay into the system in effect could end up being subsidized by other customers and rate classes.

This is particularly germane given the fact that in most systems commercial and industrial users represent a disproportionate amount of revenue given their numbers. To the extent that the commercial and industrial users are able to implement DER deployments, there is the potential for a significant amount of revenue to leave the system. That revenue shortfall must be made up by other rate classes, most notably residential customers.

As noted above, the value of any DER deployment may decrease if a material number of such deployments are made. For example where a DER deployment has been valued as a solution to a specific congestion issue within a distribution system, subsequent developers on that system may not receive a similar valuation of benefit.

The development of an effective and economic DER rate, available on request to DER developers and customers, should also have the effect of blunting, or indeed eliminating, any requirement for substantial changes to the local distribution company business model. The rate should be designed in such a fashion that reasonable revenue expectations are met over time, that identified system benefits, including cost avoidances, are appropriately compensated for, and that the economic balance between DER deployers and other system customers is protected and observed.



In the same way other enhancements which reduce line losses or increase system reliability or responsiveness need to have concrete values assigned to them within the regional system so that the rate treatment can be as efficient and reflective of genuine value as possible.

It should be remembered that system value is distinct from customer value. *System* value, which is the appropriate economic consideration for regulators based on the principles outlined in section 1.3, requires that a given DER deployment provide measurable benefits to the system. Customer value relates solely to the value a *customer* places on such a deployment. Such value may include enhanced reliability, insulation from system outage, or simple cost control.

In establishing the rate treatment for DER deployments the only values of interest to the regulator should be system costs and benefits. Customer values need to be evaluated independently by customers as they make DER investments.

The tools developed during the regional planning process should prove to be an ongoing source of guidance to rate makers, always operating from a clear set of principles. In this way future developments can be appropriately monetized and "rewarded" where appropriate. It should also make it possible for regulators to identify enhancements that are customer-specific and of little or no system benefit.

The rate of penetration, predicted with a measure of precision, can also enable regulators to develop rates for new classes of customers who are sufficiently homogeneous to warrant distinct rate treatment. For example, a significant residential uptake of photovoltaic generation could reasonably lead to the development of distinct rate structures to accommodate these customers. However, significant penetration of this kind could lead to a fairly volatile assessment of the value of generation fed back into the system. Such generation, especially under current conditions, may have little or no value from a system perspective. A rate structure needs to reflect the genuine value of such generation.

In developing a rate structure for those customers some important factors would have to be considered. First, if the investment in residential photovoltaic equipment is predicated on the sale of surplus power back into the system, what is the value of that power? In Ontario, generally speaking, additional energy has very little or no value. In most circumstances the power generated by these solar installations would not only be surplus to the generator, but also surplus to the system. A recent IESO report suggests that the Ontario energy system will be in a surplus baseload position for a considerable period into the future.[84] Current activities directed to net metering should take into account the genuine value of the power available from such customers, and

84 Independents Electricity System Operator, *Ontario Planning Outlook*, p. 3.



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policymakers and regulators need to be clear about the value that they anticipate will derive from surplus power generated in this fashion and in these locations.

This is important information for developers and customers considering significant investment in DERs. Again, developers and customers should be in a position to make sound economic decisions based on enunciated principle and clear guidance.

And, as we discussed above, this analysis of system costs and benefits should include an accounting for revenue loss to the system as a result of the DER installation, and the reasonable expectations of the system for coverage of legacy costs and stranded assets.

5.3.2 Technical standards

It is important that the development of appropriate technical standards form part of the overall DER environment. The system has an important interest in ensuring that any equipment installed, whether in front of or behind the meter, has technical standards that are compatible with the safe and reliable operation of the system. It is also important to develop mandatory communication protocols reasonably required by the system operator or the local distribution company. Costs associated with such protocols are costs that should be borne by the customer implementing the DER deployment and should therefore be incorporated into the DER rate.

5.3.3 Competitive process

Where the regional planning process identifies a particular congestion problem within a distribution system it may well make sense to conduct a request for proposals for solutions to that problem. That is, rather than having the utility, as is now the case, undertake an enhancement process to manage the congestion issue using whatever tools it has at its disposal, create an opportunity for the private sector to address the issue behind the meters of relevant customers.

The incorporation of the costs associated with this fix within the overall rate structures should not be overly complicated. In the event that no private actor is prepared to make a proposal, the utility itself can be the supplier of last resort for the solution of the problem. Where private interests submit proposals, but are in excess of the utility's estimate of the cost of the "fix", once again the utility should be the supplier of last resort. The Brooklyn-Queens project highlighted on page 26 is an example where a competitive process can offer real system value.





6 CONCLUSION

Looking at the energy system holistically, there are four key considerations that should guide the introduction of DERs into the energy distribution systems:

» Enhanced performance-based regulation that looks at value and outcomes.

» Empowered local energy utilities that can meet local needs.

» Fair and equitable apportioning of costs and benefits.

» Ensuring that all consumers benefit, and vulnerable consumers are protected.[85]

The interaction of all these factors makes it difficult to balance competing signals and to allocate the costs and benefits of the transition. It is also clear that we may not want to be starting from where we are. However, that is what we have to do.

Properly integrating DER development into the energy system could provide cost savings to customers in terms of reduced future capital expenditures. Integration would allow all customers to benefit from the system resources offered. On the other hand, trying to halt DER development could lead to higher costs in the future due to the potential of grid defection and higher capital expenditures.

It has been suggested that the advent of DERs as a significant component of the electricity distribution and transmission systems is analogous to the restructuring of such systems undertaken across the world in the late 90s and early 2000s. It is certain that a significant uptake of DER will have important implications for these systems and that new approaches, including new rate structures, may be required to ensure system solvency, fairness and reliability.

This is so because DERs fundamentally change the relationship of the customer to the system from a financial point of view. In many cases, the sole rationale for the installation of a DER is reduction of energy cost. In other cases the rationale relates to stability of costs, an important driver for some customers. In still others the rationale is enhanced reliability.

85 Adapted from National Renewable Energy Laboratory, *Power Systems of the Future: A 21st Century Power Partnership Thought Leadership Report*, NREL/TP-6A20-62611, February 2015. At http://www.nrel.gov/docs/fy15osti/62611.pdf.



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Each of these choices can have important implications for the distribution utility and the system operator. At the most basic level they can represent raw loss of revenue. At some point, and not a distant point, this loss of revenue can result in increased unit costs to the rest of the system. This is a particularly intractable kind of rate increase for nonparticipating consumers. For those investing in DER there is often an expectation first of reduced energy costs, and second the possibility of revenue derived from the generation and sale of surplus energy back into the distribution and/or transmission system.

> *Integration would allow all customers to benefit from the system resources offered.*

Every jurisdiction therefore needs to develop a well-defined principled approach to the development of new rate structures to accommodate these developments. One of the key obligations of policymakers and regulators is to provide as much clarity as possible for those considering investments in DERs. And every jurisdiction needs to approach the subject in a distinct, idiosyncratic manner. As we see from the international reports, many jurisdictions have struggled to find the right formula for the accommodation of DER from a rates point of view.

This paper has identified that a materially enhanced regional planning exercise is central to the success of any effort to accommodate the introduction of DERs into the Ontario energy system.

In order to be successful the regional planning exercise needs to engage all relevant stakeholders in a transparent, inclusive, principled, and accountable process. Relevant participants will include potential DER developers, municipal authorities, local business interests, utilities, consumers of all classes, regional distribution utilities, and transmitters. The process will require periodic updates. This will require a considerable renovation of the existing process.

A good beginning has been made in this kind of planning process, but the process needs to evolve and intensify considerably if it is to produce the kind of product needed. While broad power system planning exercises have been mandated, they have been substantially unsuccessful in producing a viable product that policymakers and regulators could rely upon to evaluate options and to inform capital investments in system infrastructure. Given the emerging challenges of disruptive technology, the planning process needs to be seen as the fundamental building block of policy development and capital expenditure guidance.



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Having said that, it is a consistent theme throughout the international papers commissioned as part of this study that the energy system per se is a very poor vehicle for incentivizing social or economic development policy, and that any incentives contemplated should be provided outside of regulatory and planning exercises. That is to say that where government intends to provide incentives they should not be embedded in rate structures, but rather be provided from the tax base. That does not mean that this development should be opaque to the regional planning process, merely that any incentives to be offered for the development of clean energy technologies should be external to the ratemaking process.

Policymakers have adopted numerous methods to drive the creation of a low carbon economy. Most notably in our case, the Ontario government has adopted the Climate Change Action Plan which includes a cap and trade system intended to impose an appropriate price on carbon, designed to meet the stated goals of the Ontario government, and to support the federal government's international climate change undertakings. In a context in which electricity pricing is so sensitive, doubling down with additional climate change expenditures within the rate structures may be seen by consumers of all classes as a form of double dipping.

The advent of DERs should be seen as an opportunity rather than as a threat. Designing a new energy system that properly integrates DERs can allow the sector to evolve into a 21st century system, one that meets customers' needs in the most environmentally and economically efficient manner possible.



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