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Distributed Energy Resources

The Role of Regional Planning, New Benefit-Cost Methodologies and the Competitive Landscape

BY PAUL B. SOMMERVILLE

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FOREWORD

This report is a continuation of work that Mowat Energy has been engaged in for the last couple of years respecting the implications of distributed energy resources (DER) for energy system stakeholders. Readers should access the following sources:

- Emerging Energy Trends: Regulatory Responses to Ontario's Energy Future
- Emerging Energy Trends stakeholder conference: video recordings
- Future Drivers and Trends Affecting Energy Development in Ontario: A Literature Review

OVERVIEW

Technological change and new approaches to electricity system investment can create opportunities for customers, system operators, technology developers, energy services companies, load aggregators, independent power producers, utilities and policy makers.

System maintenance, transformation and renewal can create the possibility of a migration from traditional infrastructure regulation and investment to a significantly more dynamic and diverse market model, which has the potential to maximize customer options, improve system reliability, as well as to optimize the system from a cost-effective point of view.

This transformation can create opportunities for enhanced competition within the sector, using market structures.

But this transition requires careful and methodical assessments of proposed distributed energy resource installations-assessments that can demonstrate the relative system value associated with any proposed distributed energy resources, when all associated costs and benefits are objectively considered. Not all, and perhaps not many, proposed DER installations will present system value when compared to conventional system investments made by regulated local distribution companies or existing supply arrangements.

This process requires a planning and regulatory architecture that provides an accurate and consistent methodology to inform system operators of the virtue of any particular distributed energy resource installation.

Such an architecture is critical to ensure that all stakeholders have a clear appreciation as to how any particular system enhancement will serve the overall purpose of providing a more cost-effective system through the adoption of distributed energy resources, and how the enhancement will be treated by regulators.

At the core of this evolved architecture stands a benefit-cost analysis that is intended to inform system planners, and all other stakeholders, about the consequences of a given installation, or suite of installations. It should include a description of the specific inputs that will be used to assess the relative value of any proposed DER installation and how those inputs will be applied to produce an overall value proposition.

Methodologies adopted must be transparent with respect to the inputs to be considered and must address and assess all the benefits and costs borne by or enjoyed by all of the parties. The evaluation must take the unique characteristics of the DER technology proposed, in the context of its proposed location.

Evaluation methodology should be the product of consultation with stakeholders.

This environment is a precondition for competition for the ownership, management and control of new distributed infrastructure. Projects identified and evaluated pursuant to the planning process represent the inventory of available potential DER installations. These projects may originate with local utilities, as part of their planning processes, the regional plan as it emerges, customers as they identify their evolving requirements, or technology developers and energy service providers who may have specific proposals for DER deployment.

The most reliable vehicle for the renewal and transformation of the system is a regional planning activity that enables the focused participation of all stakeholders within a transparent valuation environment. Technology developers, energy service companies, utilities, customers, municipalities – all may have an interest in being the owner and operator of specific DER installations. That is an inherently a competitive environment that should provide for the best possible enhancements, and the best price.

The role of local distribution companies (LDCs) in the emerging market-based environment is not without complication. Elsewhere in this report we address some of those complications that relate to the participation of LDCs in competitive processes, and the problems associated with potential cross-subsidization.

If the Distribution System Platform model adopted in the New York Reforming the Energy Vision initiative was to be adopted in Ontario, LDCs would generally be prohibited from ownership of DER assets developed under the program. Instead, they would serve as a kind of independent system operator for DER installations within their franchises. In this role the LDC would serve as a go-between, interfacing with the DER asset and the broader system operator so as to maintain visibility of the DER outputs into the system.

This new role would give rise to a new rate architecture, compensating LDCs for these services. Their independence is preserved under this model in part because they are precluded from ownership of the DER assets. The rate structures related to this model are still under development. It is not clear whether such rate structures would only compensate LDCs for their new platform role, or would also address loss of distribution system revenue occasioned by the defection, or partial defection of loads attributable to the DER deployment.

The regional planning process in Ontario falls within the mandate of the Independent Electricity System Operator (IESO). IESO has committed itself to a broad based market renewal initiative. The market renewal initiative is intended to improve the way electricity is priced, scheduled, and procured in order to meet Ontario's current and future needs reliably, transparently, efficiently, and at the lowest cost. This initiative is informed by input from a broad range of stakeholders, and offers an opportunity for significant change in how the Ontario electricity system operates and evolves. The effective and cost-effective accommodation of DER into the Ontario system should be an important consideration within this market renewal activity.

WHAT IS DER?

There are virtually as many definitions of distributed energy resources as there are commentators.

Different resources present different opportunities, and different challenges. Each technology has its own cost structure, suite of benefits, and locational relevance. These technologies are not interchangeable – what may provide system value in one setting, may present a completely different proposition in another.

IESO defines DER as:

> *Distributed energy resources (DERs) are electricity-producing and storage resources or controllable loads that are directly connected to a local distribution system or connected to a host facility within the local distribution system.*
>
> *DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fuelled generators, electric vehicles and controllable loads, such as HVAC systems and electric water heaters. These resources are typically smaller in scale than the traditional generation facilities that serve most of Ontario demand.*[1]

DERs falling within this definition can take a very wide variety of forms, and these technologies will evolve. The costs associated with the installation of these assets will also evolve. Just over the last few years the costs associated with photovoltaic installations, for example, have fallen considerably. A similar cost trajectory for other DER technologies is widely anticipated, and predictable. But if they are to be adopted costs and complications associated with intermittency issues need to be taken into account, especially in Ontario which is a dual peaking system.

The rate of adoption of DER varies considerably between jurisdictions, and appears to be driven by local considerations. For example, Hawaii has been extremely active in the adoption of photovoltaic generation. That initiative, as noted elsewhere in this report, has been considerably turbulent.

1 http://www.ieso.ca/en/learn/ontario-power-system/a-smarter-grid/distributed-energy-resources.

A number of American states have been active in the development of tools focused on the integration of DER into their grids.

The US Department of Energy commissioned a series of reports from the Lawrence Berkeley National Laboratory known as the Future Electric Utility Regulation Series, intended to provide guidance to regulators and system planners with respect to the evolution of the distribution grid through the application of DERs. The series, which can be accessed at FEUR.lbl.gov, was the product of participation from a wide spectrum of technical experts and stakeholders, and in one case also the Public Utility Commissions of California, New York, the District of Columbia, Hawaii, and Minnesota. Some of the reports in the series are cited in Appendix 3.

The purpose of the report was to provide state regulators, utilities, energy service companies, and technology developers with guidance as to how they might assess the role DER may play in a modern electricity grid and how they may serve to enhance reliability, resiliency, and operational efficiency and integrity.

The New York State Department of Public Service produced a Staff White Paper focused on the benefit-cost analysis associated with the evolution of the Reforming Energy Vision initiative adopted by that state.[2] It expressed a clear enthusiasm for the benefits associated with DER proliferation, and supported that state's commitment to their adoption, where the value of the resource can be demonstrated.

The White Paper presents a detailed framework for the economic evaluation of DER alternatives to traditional infrastructure investments made by regulated utilities. Importantly, the White Paper advances the proposition that a market-based DER procurement process is optimal.

2 New York Department of Public Service. (2015). *Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding*. New York Department of Public Service, 14-M-0101, July 1, 2015. https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/c12c0a18f55877e785257e6f005d533e/$FILE/Staff_BCA_Whitepaper_Final.pdf.

A useful compendium of sources documenting the American interest in DER accommodation was provided by the Smart Electric Power Alliance.[3] This compendium also provides sources addressing the perceived need for a new planning paradigm.

The need for refined planning and evaluation processes leading to the accommodation of DER solutions runs through the literature.

What is clear from the literature is that each specific DER technology carries distinct benefit and cost implications. These technologies are not inherently interchangeable. The cost structures, the associated system benefits, and the implications for system accommodation vary very considerably. In addition, the value proposition associated with any particular proposed installation varies with its location.

This means that the evaluation of the system value of any DER is likely to involve the application of valuation methodology that can be tailored to the specific technology proposed, considered in light of its specific location.

3 Advanced Energy Economy (AEE) Institute, Rocky Mountain Institute (RMI), and the Smart Electric Power Alliance (SEPA). (2017). *Beyond the Meter: Recommended Reading For A Modern Grid. Smart Electric Power Alliance, June 2017*. https://sepapower.org/resource/beyond-meter-recommended-reading-modern-grid/.

REGIONAL PLANNING

It is important to note at the outset that it is not the purpose of this segment of this report to provide a critique of current efforts or practices in Ontario related to regional planning. Rather, this report will focus on what appear to be the key components and preoccupations of effective regional planning processes, in light of the advancing technological opportunities and challenges presented by DER.

Planning processes are by their very nature evolutionary, and need to respond effectively to changing circumstances. There is no one methodology that fits all circumstances, and governing assumptions and inputs may need to evolve with circumstances.

Regional Planning provides an opportunity for generators, transmitters, customers, municipalities, LDCs, DER developers and regulators to come together in a disciplined process to assess viable opportunities for DER installation on a region-by-region basis.

To be effective, the process needs to be inclusive, principled, predictable, methodical, and definitive. A tall order. But the alternative is an unnecessarily fractured and diffuse process that can create dangers of uneconomic installations, inter-rate class conflict, and system reliability and security issues.

In Ontario there has been an evolving appreciation for the importance of comprehensive regional planning process culminating in integrated resource planning. The IESO has been mandated to lead regional planning activities, which are intended to take into account the inputs of a range of stakeholders.

IESO has identified 21 electricity regions across the province which are defined by electrical infrastructure boundaries. This process is intended to glean from the local distribution utilities, municipalities, business groups, Indigenous communities and individuals the ongoing and future requirements of the electricity system within the region.

The regional planning process involves the integration of identified potential system enhancements, occurring at whatever level of the electricity system, into an integrated plan.

The IESO process is partly informed by the Distribution System Plans (DSPs) filed by local distribution companies, which are mandated by the Ontario Energy Board, the input of regional municipalities, their community energy plans, and input from other stakeholders.

One goal of the integrated regional resource plan is to directly influence, if not determine, the procurement of resources identified by the plan, within the context of the overall provincial drivers. The plan should also project system characteristics over a meaningful horizon. This means that future system requirements must be identified. Accordingly, that assessment needs to address the extent to which DER is likely to be adopted within the region, and the likely nature of and impact of those assets.

To accomplish this goal the integrated resource plan must be sufficiently granular, comprehensive, and methodical. At the end of the day, procurement of assets that are to be supported in some fashion by the system must first and foremost demonstrate a clear benefit to the system and ratepayers.

In order to ensure the appropriate linkage between procurement and planning the plan must provide the regulator with a detailed representation of a number of key factors.

First, the plan should be able to provide the regulator, and policymakers with as accurate an inventory of existing and proposed DER assets within the regional construct as is reasonably possible. This would include:[4]

4 Burger, Scott B. et al (2018). *Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems*. MIT CEEPR, March 2018. http://ceepr.mit.edu/files/papers/2018-007.pdf; and Mills, Andrew et al (2016). *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning*. Lawrence Berkeley National Laboratory, August 2016. https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf.

- The current rate of adoption of DER within the region, their location, their attributes, including the extent to which the specific DER placements are communicative with the system, and are integrated into it.
- A description of the identified locations for proposed DER installations within the region, including the potential for combination of DER assets to optimize the regional system.
- A detailed and methodical assessment of the system value of proposed DER installations.
- A description of the benefit-cost analysis and methodology applied to proposed DER enhancements.
- A description of the options considered with respect to proposed DER installations, focusing on the extent to which the proposed asset should be subject to competitive processes on the one hand, or utility-owned and operated assets.

It should be noted that IESO has adopted an approach which is agnostic as to which specific technology, or combination of technologies ought to be employed to meet system needs.

Each of these subject matters, and they are not exhaustive, requires searching analysis, focused input from stakeholders and the application of tools to ensure that the genuine value and virtue of DER proliferation within a region is appropriately considered, and, to the extent possible, defined.

The question of pacing is also important. It is axiomatic that the best laid plans often require ongoing refinement. The Berkeley Lab's report into this subject provides insight into the kind of factors that can lead to an evolution of procurement decisions. In addition to the development of supporting data, the plan also needs to be reasonably dynamic to account for new proposals, or changing circumstances.[5]

5 Mills, Andrew et al (2016). *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning*. Lawrence Berkeley National Laboratory, August 2016. https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf. More generally, see the *Lawrence Berkeley National Laboratory's Future Electric Utility Regulation series*, found at https://emp.lbl.gov/projects/feur.

Not only does principled and measured pacing allow for course correction, it can serve to provide critical insight into developing rate and system impacts, especially for non-participating customers or customer classes. This is particularly important in the Ontario context where there is a very high degree of sensitivity to any developments that may result in increased rates.

Because DER most directly affects the distribution system, new regulatory tools may well be needed to ensure that the cost and revenue allocation consequential to DER installations are managed in a way that is transparent, fair as between rate classes, and reasonable utility expectation.

Regulatory structures may need renovation in order to account for the principled sharing of costs and benefits throughout the region, rather than on a "siloed" utility-by-utility basis.

The current regulatory model in Ontario is based on the periodic rebasing of utilities, one by one, on a cost-of-service basis. A key component of each of these cost-of-service rebasing proceedings is the respective capital spending plans of the individual utilities.

While the Ontario Energy Board (OEB) has implemented some refinements which could notionally examine utilities within the context of their respective regions, the process remains focused on the requirements of the individual utility franchises.

It is possible that an evolved regional planning process will identify possible regional advantages associated with the introduction of DERs throughout the region, located within individual utilities but serving a regional or broader system purpose. An enhanced regulatory process would acknowledge, in very practical and economic terms this fact and would enable an apportionment of cost and value on a regional basis. The fact that a shared DER asset is located in a particular utility ought not to deprive other utilities of the costs or benefits associated with it.

Where system needs or opportunities for enhancement are identified within the region, those interested in executing those programs can then submit costed proposals for implementation. This is a market, where the most effective and economic proposals should prevail. In such a process the potential for a suite of DER enhancements working together can be assessed by the system operator, and synergies and further cost savings or operational enhancements can be evaluated.

In addition, it may be that evolved practices accounting for the potential of cost shifting as between rate classes, occasioned by asymmetrical adoption of DER enhancements need to be developed.

Where a given large customer, or class of customers, is able to defect, in whole or in part, from dependency on the distribution utility in which they are located, cost shifting to non-participating customers can result.

Regulators may consider that this cost shifting, provided it is predicated on a rigorous benefit-cost analysis is perfectly appropriate. On the other hand, it may be that such impacts need to be taken into account when determining the value of any given installation or portfolio of installations.

Ratepayers have collectively invested in a distribution system over the course of decades, designed and capable of meeting the needs of all customers. To the extent that DER participating customers are able to avoid an ongoing contribution to the maintenance of the system, assets created in part for their benefit prior to the installation of the DER enhancements could be considered to be stranded assets. Stranded assets need to be accounted for in the consideration of DER value, and the regional plan.

The planning process would be materially easier in a period where there was anticipated significant growth in load. In that case, the placement of and configuration of new system assets can be more confidently accommodated within the existing system, including its regulatory architecture. This can still be true in localized situations where there is a demonstrable need for new infrastructure to meet confidently projected need. The Brooklyn/Queens Substation Project, discussed below, provides an example of this potential.

Where the large portions of the system are experiencing no identified requirement for significant infrastructure improvement, the installation of DER becomes much more problematic. In such cases the avoided costs related to generation and other infrastructure may be small or non-existent, at least over a near term or mid-term planning horizon. This will have a direct effect on the value benefit-cost analysis attending proposals that are related to generation. This effect may be offset in some cases where peak load issues are significant, and can be mitigated with the right kind of DER asset. This granular analysis is what is needed to ensure that only appropriate, right-sized, and cost-effective projects are supported by the system.

The following are generally accepted attributes of integrated resource plans:

- Coordination between the various levels of responsibility and interests. This involves a process that actively encourages the engagement of stakeholders.
- The creation of competent regulatory tools predicated on clear policy direction.
- Confident economic evaluation of *system* value as opposed to customer advantage – a process which requires predictable, transparent, and uncompromising methodologies.

There is significant potential for winners and losers in an environment where customer value may be in conflict with system value.

System benefits ought to be acknowledged and compensated to the extent of their actual value to the system. Customer costs and benefits ought to be relegated to customers to the extent that they do not represent system enhancements.

There may well be a sliding scale of customer and system benefits, and the regulatory system needs to be able to accommodate the economic reflection and treatment of these installations accordingly.

Erosion of load can be a significant issue insofar as load, or the established infrastructure needed to deliver it, underpins the rates architecture. Defecting customers, pursuing predominantly customer-centric enhancements may bear some ongoing responsibility for the loads they have been receiving from the system, and the infrastructure that has created their participation in the system through the application of stand-by rates.

It is reasonable to suggest that to the extent possible it is important for developers, municipalities, and other stakeholders to be fully invested in the integrated system plan development. In this way genuine system requirements can be developed and identified. Stakeholders also need to have as clear a picture as possible, as soon as possible, as to the economic methodologies that are going to be used to evaluate the relative system/customer value of any installations.

While planning may in the past have been a predominantly "top-down" process, the advent of DER opportunities favours a "bottom-up" process, at least in part. In some ways the process can be seen as a dialogue between stakeholders respecting the optimization of the system, according to well established and transparent valuation methods.

Included in the regulatory tools should be the application of the integrated resource plan for local distribution companies at the time of rebasing. Assuming an appropriately inclusive and rigorous regional planning process, its outcomes should be extremely persuasive, if not definitive at the time utility seeks to revise its rates.

In developing regional planning templates regulators need to embed considerations related to the reliability, affordability, and efficiency of the resulting distribution system. Across modern systems regulators and policymakers have tried to implement practices which provide an enhanced transparency and justification for distribution utility system expenditures. In Ontario this has taken the form of the requirement that distribution utilities submit DSPs as part of informational filings and as part of cost-of-service rate cases. The acuity of those DSPs and their effective translation into capital spending approvals is evolving.

"The idea that any given distribution system can absorb any given amount of DER is mistaken."[6] One of the first activities in any regional planning process involves the sober assessment of how much, if any, DER can be safely, economically and reliably integrated into a distribution system, and the region. This is a technical question as well as an economic question.

Standards for interoperability of DER equipment with the rest of the system are a key consideration. Particularly in circumstances where two-way flow of electricity is contemplated there is a real potential for disruption upstream unless standards are imposed which ensure effective interoperability and visibility to the system operator.[7]

In some instances jurisdictions require the distribution utility to develop detailed assessments of circumstances where, within each system, DER can be confidently implemented. This has surfaced in Ontario from time to time, but this would appear to require a specific mandate to LDCs to develop and document these possibilities in a programmatic way. Such insight would be invaluable to the system operator/regional planner as it considers the shape of the regional system in its plan.

Market participants, regulators and customers should steel themselves to the possibility that a significant number of installations may not be economic or advisable now. Just because it can be done does not mean that it should be done. Genuinely cost-effective DER installations may present themselves as attractive innovation, but there is a very real possibility that many such installations will not be economic either from a customer point of view, a system point of view, or from a regulatory point of view.

6 NARUC Staff Subcommittee on Rate Design (2016). *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. The National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

7 Burger, Scott B. et al (2018). *Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems*. MIT CEEPR, March 2018. http://ceepr.mit.edu/files/papers/2018-007.pdf.

It is also important to note that the cost of DER technologies is likely to decrease over time, making once uneconomic projects economic. This is a dynamic environment, and one of the key aspects of the planning process should be the ability to reasonably respond to changing circumstances.

The most important first step in the preparation of the electricity system for DER deployment is to gather stakeholder input in a process that is genuinely rigorous, economics-based and definitive. The regional planning architecture adopted in Ontario creates the conditions necessary for such a process. The planning process needs to be seen as a genuine practical exploration of system requirements over the planning horizon, the relative values of potential or proposed DER deployment within the region, the implications of system enhancements, whether DER or otherwise, on system reliability, and inter-rate class implications. The product of the planning process needs to be recognized from a regulatory point of view as a virtually definitive game plan for the evolution of the regional system.

The model adopted by municipalities involving the creation of Official Plans is somewhat analogous to the process that could result in an integrated regional plan. In that model, a plan is developed using relevant inputs and projects outside of the official plan are presumed to be not executable. Proponents need to meet a burden of proof to overcome the direction captured within the plant.

A similar architecture for the regional electricity plan may be appropriate. Not only would such a process inspire focused attention by potential developers, it would be likely to provide the regulator with a head start on its consideration of capital spending plans for distribution systems within the region. In other words, projects that have been favoured after a rigorous economic, reliability and regulatory review during the planning process would be presumptively approvable.

This is a daunting task. The development of genuine value propositions for proposed DER deployments is a highly locational and nuanced exercise. The value of a distributed energy resource in any particular utility is dependent on a variety of factors including the age of the existing infrastructure, the load forecast relevant to that utility, including DER contributions, the relationship from a technical point of view between distribution utilities within the region, and parochial implications within any particular utility and regional collection of utilities.

The use of pilot projects where more research is needed to develop the value propositions associated with the installation deployment is an important tool for the system planner and the regulator. Locational, technology-specific, and load organization models can be tested before deployment is advanced.

This is a process which is to some extent underway in Ontario. It should also be noted that the scope of the value proposition needs to be carefully considered. In some instances it may well be the case that impact on a single utility does not in itself provide sufficient justification, or in fact may even produce negative local results. But that same installation may have broader, more regional positive implications. The planning process needs to be sufficiently robust so that it can differentiate between these eventualities.

This may also require significant revision of rate design and rate models that have typically been exceedingly parochial in nature. Most rates in Ontario are driven exclusively by the cost of service attendant on a single distribution utility. In a system that takes a regional approach, benefits accruing to neighbouring distributors and their ratepayers, and benefits accruing on a regional basis need to be taken into account. This may mean that a utility may bear some cost associated with a capital project or installation of DER in a neighbouring or upstream distribution utility.

Rate design is predicated on a few principles which have populated virtual libraries of commentary over the years. At its most basic, rate design is intended to focus on collection of the revenue requirement necessary to provide the service mandated for the distribution utility, including a cost of capital, and the appropriate allocation of those costs to roughly homogeneous rate classes on a cost causality basis.

The overwhelming majority of utility costs are not sensitive to throughputs of energy. The majority of costs are attributable to the fundamental infrastructure that the utility ratepayers have invested in over the years to enable the utility to provide electricity to its customers as and when they need it.

To the extent that revenues ride with usage, defection of partial or full loads has the effect of increasing the burden on non-participating customers. It is also true that certain rate designs can have the effect of causing DER-adopting customers to defect entirely from the system. If rates are predicated primarily or exclusively on fixed charges, intended to capture the cost of the utilities infrastructure, without significant contribution from throughput charges, the tendency will be for adopting customers to leave the system and to scale DER installations to address their electricity requirement independently. The fixed costs of the utility must then be redistributed among those customers who do not participate, or who cannot participate in DER deployment. This may have significant implications in Ontario where any upward pressure on rates, to say the least, is a highly problematic proposition. While defection from the grid may not currently be attractive for smaller customers, the defection of customers with large loads can have very serious consequences for local distribution companies and their non-participating customers. This is so because large customers typically represent a very high proportion of local distribution system revenue. Loss of this revenue has consequences rooted in the re-allocation of system cost to non-participating customers. Regulators need to be mindful of the effects that rate design can have on customer's decisions to defect, in whole or in part from the local distribution system.

Successive governments have tried to address rising energy costs in the province and any innovation which would have the effect of increasing rates to non-participating customers may not be implementable.

BENEFIT-COST ANALYSIS

Simply put, the benefit-cost analysis should provide a reliable tool for the comparison of the traditional utility distribution investment methodology currently in use, on the one hand, and that developed for DER alternative installations, on the other.

Utilities are currently required to file 5-year Distribution System Plans (DSPs). In these DSPs utilities catalogue specific capital spending plans to cover a 5-year span. These spending plans are intended to inform the regulator's determination of the prudence of the investments proposed as part of rate applications. Proposed investments that are not considered to be prudent, are not approved for the purposes of rate setting.

The benefit-cost analysis for proposed DER installations is intended to provide a programmatic assessment of the system value of the installation. In this way, all stakeholders can compare the associated costs and benefits.

In addition, to ensure that only prudent investments in DER are made, this vetting of proposed DER investments is key to the introduction of competitive processes to enable technology developers, energy service companies, and utilities to compete within a fair, consistent, and predictable environment.

A precondition for effective competition for DER installations is a reasonably acute appreciation of net system value of the resource, and its regulatory treatment.

Such an environment is only achievable where outcomes are derived from the application of coherent, transparent, predictable and capable methodologies. The development of these methodologies is key to the effective transformation and renewal of the electricity system through distributed energy resource innovation.

The literature is clear in support for an enhanced integrated system planning process, which can first identify, and then assess proposed DER improvements. In Ontario, that process is the regional planning activity of the system operator.

This regional system perspective is important to ensure that the needs of a particular region are identified and assessed within the system as a whole. One important attribute of this approach is the capability within the plan to consider the implications of not just one DER installation at a time, but the combined value of a possible suite of DER programs within the region, whose combined value and consequences can be assessed.

The benefit-cost analysis needs to take into account all relevant costs and benefits. The literature suggests that this would normally include a consideration of the following factors:

- avoided generation capacity
- avoided energy
- avoided transmission capacity
- infrastructures and related operations and maintenance costs
- avoided transmission losses
- avoided ancillary services such as operating reserves regulation
- wholesale market impacts
- avoided distribution capacity infrastructure
- avoided operations and maintenance costs
- avoided distribution losses
- with respect to reliability and resiliency, a key consideration, net avoided restoration costs and net avoided outage cost

On the cost side, such items as program administration costs, including the cost of market interventions and measurement and verification costs, added regulatory costs, incremental transmission and distribution costs including incremental metering and communications costs, lost utility revenue, and attendant increased cyber security costs need to be taken into account.

To the extent that some DER installations may be incentivized by public funds such incentives should also form part of the cost equation.

The role of incentives is complex. While incentives may be introduced to advance broader (or narrower) policy objectives, it is suggested that their inclusion in the benefits-costs analysis is appropriate. This is especially so where incentives are created to foster environmental or economic development objectives. Apart from the difficulty in monetizing the costs of such initiatives on a principled basis, policies can change. What may be an attractive, or even compelling policy driver today may not be so tomorrow. Including the costs of the incentives provides a sound economic basis for assessment.

The best way to illustrate this process is with reference to real life examples of how the value of a resource can be determined through the application of this kind of methodology.

In 2013 the State of Minnesota passed legislation which mandated the development of a Value of Solar tariff as an alternative to net metering. The Minnesota Department of Commerce, Division of Energy Resources was tasked with the creation of an architecture which would take into account the respective costs and benefits associated with photovoltaic installations, and to provide definitive guidance to utilities in their relationship with adopting customers. The Department of Commerce contracted with Clean Power Research to produce the Handbook.[8]

The purpose of the tariff was to replace the net energy metering policy that had governed PV systems. The underlying assumption was that net metering had deficiencies that needed to be corrected. Specifically, it was thought that if the Value of Solar tariff was set correctly it would reflect the real value of the PV generated electricity, and that the utility and its other customers would be indifferent as to whether the electricity was supplied from a customer owned photovoltaic installation or by other means.

As noted elsewhere in this report, Net Metering has been criticized for its potential to create cross-subsidization from one ratepayer to another. It was also thought that the development of a rigorously adopted rate structure for photovoltaic adopting customers would provide a critical signal to potential adopters.

8 Clean Power Research (2014). *Minnesota Value of Solar: Methodology. Minnesota Department of Commerce, Division of Energy Resources, April 1, 2014*. http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf.

The process adopted by the Minnesota Department of Commerce process is instructive with respect to the categories of benefits it included. Without examining the various formulae, which are available in the Clean Power report, the following categories of benefits were seen to be most relevant:

- avoided fuel cost
- avoided plant operations and maintenance cost
- avoided generation capacity cost
- avoided reserve capacity cost
- avoided transmission capacity cost
- avoided distribution capacity cost
- avoided environmental cost
- voltage control (deferred)
- integration cost (deferred)

This roster is roughly consistent with other methodologies directed to the same purpose, for example the New York Staff White Paper referenced earlier, and the NARUC guidance contained in its manual.[9]

It was expected that the tariff would be renovated on an annual basis to reflect current values for application to new adopting customers, and the rate would be adjusted annually for inflation for all customers. The methodology is very detailed and as noted, was intended to provide definitive guidance to utilities, regulators and adopters. Inputs for the calculation of the tariff include generation expectations given the specific nature, and geographic location of the assets and their anticipated output over the course of a year, and also seek to match generation to system requirements, including peak load reduction.

9 New York Department of Public Service. (2015). Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding. New York Department of Public Service, 14-M-0101, July 1, 2015. https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/c12c0a18f55877e785257e6f005d533e/$FILE/Staff_BCA_Whitepaper_Final.pdf; NARUC Staff Subcommittee on Rate Design (2016). NARUC Manual on Distributed Energy Resources Rate Design and Compensation. The National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

The tariff methodology also includes a loss savings analysis that focuses on the avoidance of transmission and distribution system losses during the year.

Importantly, the tariff focuses on avoided system costs, which takes into account the existing infrastructure, stranded assets, and the investments made in it.

What the Minnesota methodology does not address are costs that are not avoided, and which in fact may be additional or increased as a result of the adoption of a photovoltaic installation.

One of those costs concerns the problem of revenue erosion for utilities. To the extent that revenue to the utility is dependent upon throughput to customers, the adoption of DER assets by customers will have a material impact on utility revenue. Given that utility costs are in large part fixed, and do not vary materially with throughput, such lost revenue must be reallocated among non-adopting ratepayers and/or rate classes.

As noted earlier, utilities have developed their respective systems to accommodate existing loads, and loads anticipated throughout various planning horizons. The costs to design, construct, operate and maintain the existing system may not be substantially reduced by defecting, DER-adopting customers, and the difference between lost revenue and the abiding system cost has to be made up somehow, by somebody.

These issues are not particularly significant where there is a very low rate of adoption of DER assets. But it can become important where substantial levels of adoption occur within a given utility franchise, or region. Some of these effects may impact different classes of customers differently. For example, the NARUC Handbook references customers living in multifamily housing units who may have no independent opportunity to take advantage of whatever advantages there may be to DER installation.[10] But they may be materially impacted by cost shifting occasioned by

10 NARUC Staff Subcommittee on Rate Design (2016). *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. The National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

the adoption of DER by other ratepayers. Other Residential class customers could be impacted where Commercial or Industrial customers reduce their contribution to the revenue requirement of a given utility, through the adoption of DER.

An additional issue not expressly addressed by the Minnesota model relates to increased system costs associated with the adoption of DER within a given utility. Current systems are not necessarily designed to accommodate variable sources of generation, particularly at the distribution level. An associated issue is the visibility of the DER installations within a given utility to the system operator.

System operators typically have the obligation to ensure that there is a real-time capacity to serve all of the reasonably anticipated requirements of the system. To the extent that DER installations may be blind to the system operator this can create complication, possible reliability issues through voltage variation, and cost. This phenomenon argues for the development of definitive technical standards and interoperability specifications, which would be mandatory for DER adopters. The costs associated with these attributes need to be part of the equation when determining the value of the resource to the system in question.

Again, without exploring in detail the granular nature of the methodology developed for the solar adopters in Minnesota, it can be seen that the appropriate economic accommodation of DER installations can be a complex and impactful exercise.

It is perhaps made somewhat more so given the fact that avoided generation cost, transmission cost, and distribution cost may be elusive in an Ontario context where system load has been flat over the last period and is not expected to increase substantially over the near or middle term. The system value of DER installations may be highly locational in nature, and may vary substantially with the specific nature of the kind of DER asset that is proposed. The benefit-Cost analysis needs to take these aspects into account.

As the Minnesota example illustrates, the Value of the Resource/ Cost of Resource calculation is intended to capture the relative system costs and benefits associated with a DER installation. As noted above, this can be a locational, technology-specific, and distribution utility-specific exercise. What may be a particularly high value deployment in one location for one distribution utility may have very minor system benefits in another. This can be so because the utility infrastructure that the DER replaces or supplants is near its end of life, and the load profile at that location is of such a nature that significant utility costs may be avoided as a result of the deployment. On the other hand, in another utility, an identical deployment may have virtually no system benefit.

The methodologies developed need to take into account these differences, which are fundamental to a consideration of the economic impact and implications of DER deployment.

There are a couple of other examples that may inform this process.

Con Edison is a distribution utility in the greater New York City area. As a result of urban development it faced the prospect of designing and building a new substation, as well as new switching equipment and sub transmission feeders to accommodate substantial increased loads.

Instead of proceeding with a conventional design and construction project for the increased infrastructure Con Edison was mandated to assess alternative approaches.

In the result, Con Edison assembled a suite of measures, including DER components as well as conventional utility investments that met the need, without the construction of the substation.

Con Edison initially performed a benefit-cost assessment which resulted in a projected $9.2 million saving using the combination of DER and conventional utility investments in its initial filing with the New York Public Service Commission. The savings estimation has evolved and is evolving. The savings calculation is rooted in part to the deferral of conventional utility investments, first to 2024, and now to 2026. These savings reflect a reduction in the interim load transfer costs associated with peak loads and overall load reduction, which was the primary driver for the project from the start. The selection of successful bidders is overseen by an independent consultant. As part of the market-based implementation plan for the project Con Edison was required to seek requests for information and proposals from third parties with respect to the installations required both on the customer and utility side of the connection. The savings calculation is somewhat controversial- critics point to the fact that unless further deferral of load transfer costs is achieved prior to 2026, there will be an impact on customers at that time. Critics also point to the fact that slower than projected economic growth and new construction mitigates, to some extent, the overall value of the project.

This project, typically cited as the Brooklyn/Queens Substation Project, is complex and involves a wide variety of installations on both sides of the connection. Customer involvement is a key component for the ultimate success of the project, and the ultimate success of the program may not be known for some years.

It is seen as a positive example as to how utilities and regulators may approach system investments in a future that includes DER approaches.

Hawaii's experience provides a more cautionary example.

As the result of a gubernatorial directive Hawaii became very active in the adoption of solar energy through a net energy metering architecture. A large number of permits for solar installations have been issued over the years, leading to the expectation that a large part of the state's electricity peak demand would be met with these resources.

Concern with the effect of the program has led to a sharp curtailment in the issuance of permits. At the heart of this decrease in activity was a decision to implement new tariff programs respecting the net energy metering option.

Under one option, the flow of electricity back into the Hawaiian grid, which forms the basis of compensation for adopters, would be subject to curtailment by the system operator when grid conditions did not require the energy produced by the solar units.

Adopters would also have the obligation to have "acceptable telemetry interface" to allow for communication between the solar unit and the utility supplied Smart production meter.

The other option has a similar feature which allows the utility to control the amount of energy flowing back into the grid.

Among other things, this example demonstrates the importance of a sober and programmatic consideration of DER installations and their relative value to the system. What was thought to be a clear path to renewable DER adoption has become materially nuanced and tentative with experience.

The development of such methodologies should be, and has been in other jurisdictions the product of a multi-stakeholder consultation where all points of view on these complex issues can be canvassed in detail. It is important from the standpoint of all stakeholders that the economic treatment of DER installations becomes well understood. Only in this way can DER developers and their customers have the necessary level of knowledge and confidence that any specific deployment identified as part of the regional planning process will prove to be a positive value proposition and a good investment.

In the same way, utility customers need to have confidence that their interest in the distribution system, and their long-term investments in it are not being sacrificed for the private benefit of other customers who have chosen to change their relationship with the utility.

NET METERING

Net metering, or net energy metering (NEM) is a regulatory tool that mandates compensation for customers who produce energy directed back into the system. The Long Term Energy Plan (LTEP), created by the Ontario Ministry of Energy, has acknowledged the role that NEM can play in fostering the adoption of DER technology. Receiving compensation for energy produced back in to the system encourages adoption.

Net energy metering is not without complication and controversy. The process requires the development of effective and predictable two-way communication between the DER adopter and the system it is connected to. This facility is not universally available and it comes with significant costs.

Further, there can be issues associated with cross-subsidization. To the extent that the net energy metering arrangement is not predicated on a thorough benefit-cost assessment net energy metering customers can enjoy a disproportionate benefit, the cost of which is carried by other ratepayers, or ratepayer classes.

As is true of virtually every aspect of DER proliferation, a searching, comprehensive, methodical and principled assessment of the virtues and costs of the resource is crucial. It should be noted that the Minnesota PV tariff was explicitly developed to replace net energy metering. The New York State White Paper suggests that the development of an effective valuation methodology is preferable to net energy metering for the reason that the methodology should take all of the relevant factors into account in a more programmatic fashion. The NARUC Handbook expresses a similar point of view.[11] The example of Hawaii's relatively turbulent experience with net energy metering is instructive.

11 NARUC Staff Subcommittee on Rate Design (2016). *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. The National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

Net metering has had a checkered history in Ontario. Between 1998 and 2005, when the net metering regulation (O.Reg. 541/05) was introduced, net metering was inhibited by the OEB's interpretation of the Rate Handbook regarding "net benefits" to all distributor customers.

With the inception of the Ontario Renewable Energy Standard Offer Program (RESOP) in 2007, net metering had little attraction to consumers. There is anecdotal evidence that some Renewable Energy Standard Offer Program and later Feed-in Tariff (FIT) contract holders chose to net meter their installations during the periods within which were there were delays in getting connected and securing contracts. OEB has data on net metering, collected under its Reporting and Record-keeping Requirements (RRR) authority, but this data is not public. The OEB is currently consulting on the possible implications for OEB policy of a recent amendment to the net metering regulation.[12] The changes allow for third-party net metering and for "virtual" net metering under the supervision of the IESO. The current status of the OEB consultation is unknown.

12 The new regulation came into force in April 2018.

COMPETITION

As noted in Appendix 1, the structure of the electricity market for about the last hundred years has been dominated by a monopolist structure predicated on the commitment to economies of scale associated with the grid. In Ontario regulation has been expressly positioned as a replacement for competition, in order to prevent abuses that can flow from monopolist arrangements.

DER changes this assumption. DER installations are site-specific, technology-specific points of system enhancement. As such, the deployment of DER throughout electricity systems can create opportunities for competitive procurement of these assets. A competitive environment is dependent on the development of assessment tools that can reliably determine the relative system value, if any, of proposed DER installations.

This theme is very usefully explored in a recent paper in The Electricity Journal.[13] In that paper, the authors provide the following observation:

> *Ensuring that system costs are included in time- and, where appropriate, location-varying prices is especially important now due to the emergence of distributed energy resources and beneficial electrification technologies ... The price signal should emulate a level playing field between third party resources and system resources ... For example, a third party customer with on-site storage should be able to compete with utility-owned distribution capacity to meet a localized demand.*

Technology development companies, energy services companies, customers and other stakeholders have an interest in taking advantage of the opportunities for DER deployment wherever they arise.

13 Linvill, Carl and Lazar, Jim (2018). "Smart non-residential rate design: Aligning rates with system value." *The Electricity Journal, 31* (8), October 2018, pp 1-8. https://www.sciencedirect.com/science/article/pii/S1040619018302306.

The first step in the evolution of this market is the identification of viable DER projects within the system through a disciplined regional planning process using competent evaluation tools.

The creation of an “inventory” of valuable DER interventions is key to the market. This argues for a regional planning process that includes the strategic engagement of potential market players. Earlier in this report we suggested that the regional planning process should be a dialogue between the system planner and potential market players.

There are two preconditions for that dialogue: the development of valuation methodologies through a consultation process that engages the full range of interests, and the transparent application of the resulting valuation methodologies to proposed DER placements.

This is a complex, expensive and time-consuming undertaking. It is helpful that the current state of system-relevant penetration of DER is relatively modest. A material assist to this process would be a requirement that local distribution companies develop and publish their assessments as to where DER installations may be most valuable within their respective franchise areas. Such assessment should include the development of estimated utility costs associated with those identified.

Assuming that the dialogue between the system planner and the potential market participants has produced a roster of viable projects, it would then be possible to initiate a request for proposals to implement the identified DER projects.

Participants would have the advantage of a transparent and predictable valuation of the enhancement in question, a key input into the competitive bid process.

This process is analogous to that mandated by the New York State Utility Commission in its consideration of the Brooklyn/Queens Substation Project. That project involves a complex mixture of conventional utility investments and activity, working in combination with a variety of other approaches. It appears that all of the potential investments are subject to a request for proposal process. This architecture reflects the Commission's interest in developing a methodology that is intended to produce the required outcome at the lowest achievable price in a market environment.

While projects identified within the Ontario regional planning process may not all be of the same magnitude as the Brooklyn/Queens Substation Project this methodology would seem to be compelling for a wide variety of DER proposals, of all sizes.[14]

It would also seem to be translatable to circumstances where the regional plan identifies a combination of resources, DER and otherwise, to solve a particular regional issue, in a cost-effective manner.

The extent to which local distribution companies (LDCs) ought to be entitled bid on DER installations in their own right is controversial. The key concern is the possibility that local distribution companies will be able to leverage their network ownership to create an unfair competitive environment. Other market participants will resist utility participation in Requests for Proposals (RfPs) where there is a possibility for the subsidization, directly or indirectly, of utility bids through the tacit reliance of the utility on its ratepayer-funded network.

14 See the regulatory filing of Con Edison Company of New York, Inc: Reilly, Griffin (2018). *Brooklyn Queens Demand Management Program Implementation and Outreach Plan*. Consolidated Edison Company of New York, Inc., January 29, 2018. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B8FF8D6D6-7E2B-4D83-9B9C-8B3E54612B8C%7D.

This phenomenon is explored in a recent Berkeley Lab Report.[15] There, the advantages and disadvantages associated with utility engagement in competitive processes involving DER installations is explored from utility, third-party provider, and consumer advocacy points of view. This report provides perspectives from the utility, third-party service provider and consumer point of view.

The engagement of local distribution companies through affiliates theoretically eliminates the potential for cross-subsidization. In Ontario the OEB's Affiliate Relationship Code (ARC) is intended to isolate utility affiliates from utility advantage in competitive environments. The integrity of the competitive processes is dependent on ensuring that the ARC is an adequate barrier to inappropriate utility leverage and advantage.

A number of jurisdictions are committed to or interested in the development of a distribution system operator role for local distribution companies. This is seen as an antidote to revenue erosion for the utility through the loss of load to DER assets, and can also serve as a new system tool to enable the system operator to be fully aware of the real-time implications of DER installations. The New York State Reforming the Energy Vision (REV) initiative is a notorious example.

This role would require the local distribution company to gain visibility into the operation of system-relevant DER installations and to interface with the system operator respecting the same. The Distribution System Platform model would also coordinate the DER engagement so as to optimize its system, the regional system, and the electricity system as a whole.

15 Blansfield, Jonathan et al (2017). *Value-Added Electricity Services: New Roles for Utilities and Third-Party Providers*. Lawrence Berkeley National Laboratory, October 2017. https://www.nasuca.org/nwp/wp-content/uploads/2013/11/Final-Paper-FEUR-9-Value-Added-Electricity-Services.pdf.

The local distribution companies would be compensated for these services. The rate of compensation for the variety of services to be provided under the system platform model would presumably be derived from a conventional principled application of costs incurred analysis, and these costs would also form part of the valuation of the DER asset itself. The development of rate structures for these services has proven to be challenging.

It is useful to describe the current state of LDC engagement in DER in Ontario.

The overall landscape relevant to DER for LDCs is challenging from a regulatory, utility and customer perspective. The range and impacts of these resources can be very broad from a technological and scale perspective.

Under the current environment LDCs have explored and implemented DER initiatives, often through affiliates, and there is a complementary trend for LDCs to explore affiliate opportunities that are aligned with their organizational direction and capacity.

It is more typical for larger LDCs to explore these opportunities since they have more flexibility due to their scale, and there are more potential customer sites available to assess opportunities that may align with LDC aspirations.

Projects range from gas fired cogeneration plants to systems fuelled through renewable sources, and it is expected that energy storage technology (primarily battery storage) and other smart grid innovation will take a more prominent role into the future as costs associated with these installations decrease and the level of comfort with new technologies increases.

Demand response initiatives are viable for larger customers, but the rate differential and 25 per cent discount (proposed to be increased by another 12 per cent by the current government) for smaller customers currently makes these opportunities a more challenging proposition.

IESO operates the Demand Response Auction, in which aggregated demand response is expected to be eligible in the Incremental Capacity Auction, which is being developed as part of its market renewal initiative.

Integrated solutions that provide more customer choice and grid innovation have been encouraged in Ontario through the IESO[16] and the OEB.[17] The Province of Ontario has also provided policy and financial incentives such as those through the Smart Grid Fund.[18]

Innovative solutions have also been supported by the other key stakeholders such as the federal government including a recent commitment of $1.4 million from Natural Resources Canada to support an Enmax pilot project, intended to enable two-way power flow in urban downtown cores, allowing customers to send extra renewable self-generated electricity back into Calgary's electricity grid for others to use.[19]

This trend is not specific to Ontario or even Canada and there are many jurisdictions globally that seek to provide a leadership for effective approaches and technologies for DER. One recent example is the commissioning of Tesla's 100 MW battery in South Australia which is estimated to have reduced grid service costs by 90 per cent, while increasing grid reliability.[20] Another example is the aforementioned Brooklyn/Queens Substation Project in New York which is expected to deliver system cost savings when compared to conventional solutions.

16 http://www.ieso.ca/en/get-involved/funding-programs/conservation-fund/cf-overview.
17 Ontario Energy Board (2017). *Strategic Blueprint 2017-2022: Keeping Pace With an Evolving Energy Sector*. Ontario Energy Board. https://www.oeb.ca/sites/default/files/OEB-Strategic-Blueprint-2017-2022-E.pdf.
18 https://www.ontario.ca/document/projects-funded-smart-grid-fund.
19 Hudes, Sammy (2018). "Feds commit $1.4 million for Enmax grid modernization project." *Calgary Herald*. August 28 2018. https://calgaryherald.com/news/politics/feds-commit-1-4-million-for-enmax-electricity-buy-back-project.
20 Vorrath, Sophie and Parkinson, Giles (2018). "The stunning numbers behind success of Tesla big battery." *Renew Economy*. May 11 2018. https://reneweconomy.com.au/the-stunning-numbers-behind-success-of-tesla-big-battery-63917/.

A thorough jurisdictional scan is beyond the scope of this report but an examination of examples from relevant jurisdictions is an important step in understanding how issues of risk and genuine system enhancement can be accommodated in a sustainable and cost-effective manner.

This includes the maintenance of an ongoing stable supply, which is a precondition for a number of DER technologies, as well as an important safeguard as the performance and durability of DER is demonstrated.

A number of States within the United States have developed evolutionary practices to accommodate DER within their energy systems.

On a related note, LDCs in Ontario have a requirement to promote energy conservation as a component of their Ontario Energy Board license.[21]

Additionally, Conservation and Demand Management (CDM) programs and funding is coordinated through the IESO in alignment with approved LDC CDM plans. Under these plans, many LDCs have included forms of DER (e.g. cogeneration) as a custom measure for customers, and have provided incentives to customers interested in reducing their system electricity consumption through on-site generation. It should be noted that the new Ontario government has indicated its intention to transition such programs to a taxpayer-funded model.

LDCs promoting this option have also provided audit funding and technical assistance in addition to project incentives. In Ontario, gas utilities such as Enbridge and Union Gas, which are under common ownership and control, have also provided technical support in cases where the project intends to use natural gas as a fuel source. These projects have ranges from micro-cogen in the range of a few kWs to large installations such as the 117 MW cogeneration plant commissioned for the Greater Toronto Airports Authority.

21 Ontario Energy Board (2010). *Conservation and demand management code for electricity distributors*. Ontario Energy Board. September 16 2010. https://www.oeb.ca/oeb/_Documents/EB-2010-0215/Conservation%20and%20Demand%20Management%20(CDM)_Code.pdf.

LDCs have specific mandatory requirements under their OEB conditions of license, but they are also impacted by a much broader set of factors from a customer, infrastructure and environmental perspective.

Assets within the regulated utility typically have very low financial risk since they are part of a broader regulatory portfolio that is well established, well understood, and provides a regulated financial return.

This benefit does not accrue to affiliate-related investments since such investments fall outside of the regulatory architecture and, provided the appropriate protections are in place, occur within a fair competitive environment where there is no guaranteed rate of recovery, nor unintended “backstopping” by the regulated utility.

Some utilities may embrace DER as an opportunity to manage supply constraints in regional planning, while others may see it as erosion to load and a potential source of increased rates for non-participating customers. This can be a barrier to LDC support or participation unless there are other benefits to the LDC such as credits for CDM plan results or other business drivers, including

compensation for a possible system platform role. Trying new DER approaches may also not align with the culture of many LDCs since it has the potential to increase risk and competes against “safer” routine investment for capital allocation. This is compounded by the regulatory capital approval process where LDCs may be capital constrained and are typically and increasingly compared against their peer group for metrics. Additional rate case funding is not typically available to incent longer-term system innovation.

Another factor affecting LDCs interest and support for DER is their ownership structure. Most LDCs in Ontario still have municipal ownership and in many cases the direction of the municipality has a direct impact on the appetite of the LDC for such accommodations. In Ontario there has been a considerable push toward LDC consolidation, blunting the role of any specific municipality in the direction and control of the resulting LDC. If LDC consolidation continues this will have a lesser impact. However, regardless of the ownership model, the LDC must remain a key partner when a municipality conducts community energy planning that considers energy use in addition to climate change, economic development, local job and economy or other factors. As noted elsewhere in this report, municipal goals need to be closely linked to the regional planning process, in the technical and economic assessment of specific proposed DER installations and other options.

REGULATORY FACTORS IMPACTING DER SUPPORT FROM LDCS

A traditional utility perspective has typically led LDCs and regulators in Ontario, and elsewhere, to focus on metrics that relate to system reliability, including cyber security, operational metrics (e.g. service standards), distribution rates and overall customer bills. In Ontario, some customers are receiving a reduction on electricity rates which negatively affects the respective business cases associated with investments in local conservation, storage or generation.

Customer satisfaction metrics are not currently granular enough to provide useful, or better yet, operational information on the advantages available to customers in DER technologies, or their interest in such innovations. It is generally assumed that customers want choice and innovation when it comes to energy options and this is embedded as a principle in the Ontario Energy Board's Strategic Blueprint.[22] However, it is not clear that this assumption is accurate or that customers have actually considered in a practical way the advantages and disadvantages associated with any such options. In part this may be due to uncertainty as to how DER installations will be evaluated and dealt with from a regulatory point of view. Increased focus by LDCs and customers will be required to achieve these goals. Response rates to customer engagement surveys are notoriously low.

It is also reasonable to expect that market solutions outside of LDCs will be an important part of achieving these goals. The markets for consumer products that enable differing degrees of energy efficiency already exist to provide customer choice for innovation. The OEB will need to ensure that LDC barriers do not impede progress, while ensuring that these innovations do not create risks for overall system operation and reliability. Innovation should not come at the cost of customer reliability, inter-rate class conflict or overall cost effectiveness.

22 Ontario Energy Board (2017). *Strategic Blueprint 2017-2022: Keeping Pace With an Evolving Energy Sector*. Ontario Energy Board. https://www.oeb.ca/sites/default/files/OEB-Strategic-Blueprint-2017-2022-E.pdf.

Policy Example: Ontario's 2017 Long Term Energy Plan

In 2017, the Province of Ontario released the 2017 Ontario Long Term Energy Plan which sets the vision for Ontario's energy sector for the next five years. Entitled "Delivering Fairness and Choice" this report included many elements that supported innovation and customer choice in Ontario. DER was specifically called out as an important element to the energy future of Ontario and supplemental support was also identified through support for elements such as enhanced Community Energy Planning and regional planning. Following the report release the IESO received a Directive on October 26, 2017 removing behind-the-meter fossil-fuelled generation from LDC CDM Plan eligibility.

LDCs are impacted by current and future policy and regulatory factors in a variety of ways and this has a direct impact on their interest and ability to promote or support DER. This paper is not meant to be an exhaustive list of these factors. However, an example is provided to illustrate the point and to reinforce the importance for alignment across policy and regulatory decisions.

The example in the side bar has been interpreted as a policy against the support of certain types of DER in Ontario and could appear counter to other policy drivers in support of DER. The pursuit of a low carbon economy may conflict directly with major important DER options, particularly in an environment where natural gas prices are low, and expected to continue to be low.

When assessed against other policy support outlined in this paper, it could also be interpreted that Ontario policy supports DER, but that some forms may no longer require financial incentives. These types of voids create uncertainty that become a potential barrier to investments on DER. The new government in Ontario has announced that is repealing Cap and Trade for Ontario and will replace the Climate Change Action Plan with a new direction in fall 2018. This creates uncertainty in the market and has the potential to negatively impact DER development in Ontario.

It is suggested that whatever else may be true, system supported DER proliferation needs to progress only where it can be demonstrated that it represents system value.

FINANCIAL RISK AND REWARD FOR LDCS

The current LDC regulatory framework through the OEB provides a specific rate of return for regulated utility assets, which is correlated to the risk profile of the utility asset portfolio. These risk factors are typically based on the traditional monopoly supply and distribution model, which is characterized by very low risk. The regulated rate of return assumes this very low risk profile.

Engagement in DER proliferation by the regulated utility may not be consistent with this architecture. If LDCs were to be authorized to engage in DER through their regulated operations, a number of questions are raised, and the OEB's guidance on smart grid, contained within its 2012 Renewed Regulatory Framework for Electricity Report (RRFE) explicitly prohibited LDCs from engaging in behind-the-meter installations.

Should the rate of return for DER investments be subject to a higher rate of return than other capital expenditures? Does the rate of return need to be increased to reflect the higher risk profile associated with a diversified supply chain, and lower revenue stream? These are some of the questions that need to be addressed from a policy and regulatory perspective.

Further, to what extent are LDCs conforming to the guidance set out in the RRFE? Are they specifically engaging with their customers as hoped for, to identify DER opportunities within their respective franchises regardless of who might own them, and to identify the operational and data format and collection services that might be needed to accommodate them? These are key inputs to the regional planning process.

Should incentives be made available to incent LDCs taking those risks?

Incenting LDCs in this area may simply undermine the unregulated market for these products or services, and, as noted elsewhere, incentives should form part of the benefit-costs assessments central to the determination of locational DER value.

Another approach would be to require LDCs to include a roadmap for achieving certain DER goals as part of their annual or periodic rate case applications. This type of approach would make the strategic goal more tangible.

But more fundamentally, is the advent of DER an unprecedented opportunity to mitigate the monopoly status of of LDCs in the distribution of electricity?

Perhaps more reasonable is a measured approach rooted in system economics, cyber security, and reliability. This would involve the preservation of a stable centralized supply, augmented by new supply generated in demonstrated economic applications.

DER offers a broader business opportunity for independent developers to gain a meaningful, market driven foothold in the energy market. Competition for these engagements may provide an evolutionary opportunity for a diversified energy market, freeing the activity in some part of a rigid regulatory compact that may have outlived its usefulness in the face of technological change.

Evolutionary because, as noted above, DER installations need to be system effective, cost effective and protective of unreasonable inter-rate class allocations. To the extent that DER installations represent merely the parochial interest of a specific customer, or other proponent, at the expense or risk of others, they should carry their own weight, including the possibility of legacy obligations to protect other customers from system revenue erosion or cyber security or reliability compromises.

And evolutionary because any emerging new reality needs to ensure that the system supply continues to be stable and highly predictable. The role of the LDC as the supplier of last resort to all of its customers would seem to be a compelling need for the foreseeable future.

The aggressive dissemination of new DER supply on anything other than a system-focused economic basis can create risk for customers, including those participating in DER innovation.

CUSTOMER CHOICE

These impacts can also be quantified at the community level. For example, as part of its Community Energy Plan, the City of London estimated that its community spends over $1.6 billion per year on energy products such as electricity, gasoline, natural gas, diesel. Most of this money – about 90 per cent – leaves London.[23] DER and other related energy solutions provide potential opportunities to retain a larger portion of these costs within the local economy. This proportion would also increase as DER solutions become available or are linked to local economic development opportunities such as manufacturing or in cases where waste heat is utilized to offset the need for additional energy purchases.

It is clear that LDCs will play a role in relation to DER in the future. At the very least an LDC is likely to continue to play the role of provider of last resort for electricity. This is a critical societal role that aligns with an LDCs license conditions and is the price of entry for a regulated utility.

23 QUEST (2018). "Six Best in Class Communities Selected to Pilot the Smart Energy Communities Scorecard." *QUEST*. March 14 2018. https://questcanada.org/project/six-best-in-class-communities-selected-to-pilot-the-smart-energy-communities-scorecard/.

APPENDIX 1: The Current System

For over 100 years the electricity transmission and distribution systems in Ontario have been largely composed of large centralized generation assets, typically not located near customers, and connected by high-voltage transmission facilities, and at the point of contact with most customers through lower voltage assets.

This architecture perfectly reflected the fundamental rationale for regulation of the sector, which was based in economies of scale and management of a monopolist system.

The advent of technological change which makes possible a much more decentralized system of assets creates a need to consider changes to the regulatory landscape to properly accommodate and integrate these resources.

The regulatory construct that was adopted was predicated on provision of electricity through monopolist providers, who were regulated according to a series of principles developed over the course of the last century. At the distribution level there was little room for competition for assets. Utilities planned for, procured and owned and operated distribution system assets. Their capital spending proposals were subject to systematic and principled oversight by the regulator, the Ontario Energy Board, and the assets formed an integrated inventory of capital within a protected franchise area. The capital plant, once approved by the regulator formed the basis for the utility's return at a regulated rate.

This architecture reflected the commitment of the system to the economies of scale.

The DER environment fundamentally challenges this model. There is no necessary technical or economic rationale for the use of a monopolist model with respect to the adoption of DER enhancements. These assets are discrete and can rise or fall on their locational value. They interface with the grid, but their procurement need not be tied to the local distribution company (LDC).

This creates opportunities for other actors to become involved in the provision of DER assets or services on a competitive basis – competitive with each other and with the utility.

It is noteworthy that the New York State REV initiative strongly discourages ownership of DER installations by local distribution companies. The 2015 New York State Energy Plan has this to say:

> *Rather than picking and choosing solutions, utilities will act as a market platform for third parties and customers to actively engage with in building a clean, resilient, and more affordable energy system.*[24]

It is important to appreciate that DER represent an evolutionary enhancement of the system, not a full scale replacement of it. It is considered likely that, as technology develops and costs fall DER will assume a larger and larger role, but that eventuality in most systems is a longer-term proposition.

The centralized generation, transmission, and distribution systems will continue to be essential while this evolution progresses. This means that the evaluation of DER installations needs to take into account the existing centralized system, with its associated costs, investments, integrity and regulatory structures.

A benefit-cost analysis, which according to virtually every commentator, lies at the heart of the evolution toward a DER enhanced system, is intended to balance the strong interest in diversification and innovation with the abiding role to be played by the centralized system.

The role of baseload power for example, needs to be placed within evaluation technologies, so that an accurate and objective assessment can result.

This argues for the development of objective and rigorous evaluation methodologies that can provide system operators and regulators with the relative system value of DER enhancements.

24 New York State Energy Planning Board (2015). *The Energy to Lead: 2015 New York State Energy Plan*. #27, p 95. https://energyplan.ny.gov/-/media/nysenergyplan/2015-state-energy-plan.pdf.

The New York REV process is strongly supportive of as rapid a deployment of DER as can be economically justified. The evaluation approaches advanced by the New York Public Utilities Commission Staff White Paper are objective and rigorous. It advances various approaches to this evaluation, which is intended to capture all of the relevant inputs. One such approach, the total societal model includes various "external" factors associated with broader social objectives such as carbon emission reductions and other environmental improvements. The role of external factors, and their monetization for the purposes of the evaluation, is an important threshold question in the development of valuation methodologies.[25] The NARUC manual approach is more conservative.[26]

The implications of DER deployment are highly relevant for all institutional stakeholders, but perhaps particularly so for local distribution companies.

Elsewhere in this report we examine the role that Ontario LDCs may play in the DER-driven transition.

The following tables and figures illustrate the current state of the electricity system from the standpoint of generation contributors and projected load profile.

Table 2 provides the most recent energy production numbers by generation type.

Table 1

Ontario's Total and Expected Capacity by Generation Source

Nuclear	13,009	9,782
Hydroelectric	8,472	5,815
Gas/Oil	10,277	8,561
Wind	4,412	601
Biofuel	495	453
Solar	380	38
Total	37,044	25,251

Sources: IESO. http://www.ieso.ca/en/power-data/demand-overview/historical-demand, and the OEB Yearbooks.

25 See the discussion of the Value of Resource and Cost of Resource assessment models earlier in this report.

26 NARUC Staff Subcommittee on Rate Design (2016). *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* The National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

Table 2

Energy Production by Generation Type, Ontario

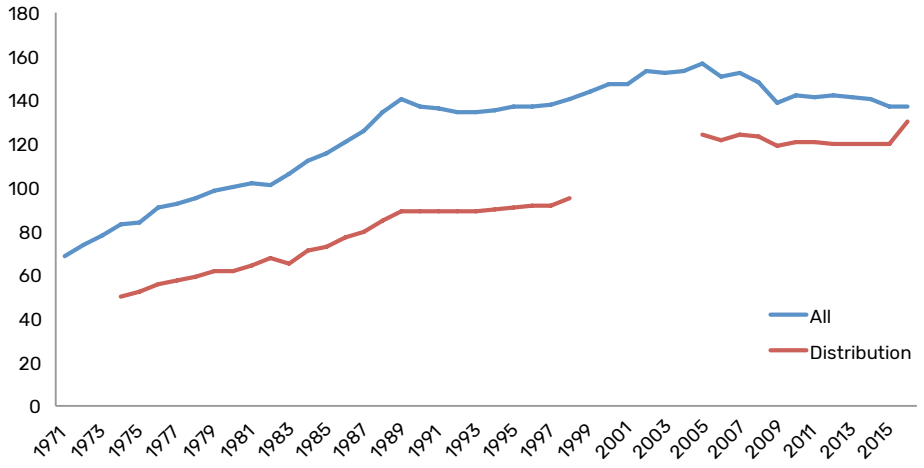
Year	Nuclear	Hydro	Gas/Oil	Wind	Biofuel	Solar
2017	90.6 TWh 63%	37.7 TWh 26%	5.9 TWh 4%	9.2 TWh 6%	0.4 TWh <1%	0.5 TWh <1%
2016	91.7 TWh 61%	35.7 TWh 24%	12.7 TWh 9%	9.3 TWh 6%	0.49 TWh <1%	0.46 TWh <1%

Sources: IESO. http://www.ieso.ca/en/power-data/demand-overview/historical-demand, and the OEB Yearbooks.

Load has been declining or flat for almost a decade, as shown in Figure 1.[27]

Figure 1

Ontario Electricity Load 1974-2016 (TWh)



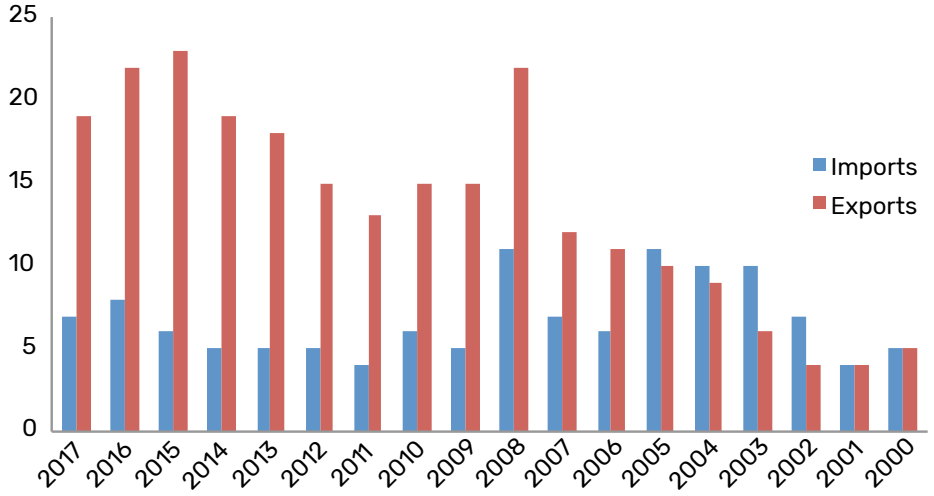
Sources: IESO. http://www.ieso.ca/en/power-data/demand-overview/historical-demand, and the OEB Yearbooks.

Figure 2 shows annual imports and exports from 2000 to 2017. Since 2009 exports have been more than double imports.

27 There is no data available for distributors 1999-2004. Load from 1975-1998 does not include OHR load (which became the major part of HONI load).

Figure 2

Ontario Electricity Imports and Exports 2000-2017 (TWh)



Sources: IESO. http://www.ieso.ca/en/power-data/demand-overview/historical-demand, and the OEB Yearbooks.

APPENDIX 2:
The Current Status of DER in Ontario

DERs present a potentially important opportunity and challenge for system operators and distribution. However, it is useful to make an assumption that the focus is on the next ten years, with the existing IESO system generation capacity assumed to be largely a "given." This approach represents the view that it is important to maintain, under all known conditions, a supply stream that guarantees a stable and viable environment for all existing customers and any new entrants. The fundamental principle of guaranteed connection for all remains an important system and cultural value.

Is also important to note that this stable and reliable supply is a precondition for the viability of certain emerging DER technologies. Energy storage, for example, can be dependent on system supply to create value to the system, and customers.

Table 3
DER Deployments

Fuel Category	Under Development		Commercial Operation		Total	
	NO. OF CONTRACTS	TOTAL CAPACITY (MW)	NO. OF CONTRACTS	TOTAL CAPACITY (MW)	NO. OF CONTRACTS	TOTAL CAPACITY (MW)
Bio-energy	38	11.0	63	108.7	101	119.8
CHP	10	71.9	14	163.1	24	235.0
Hydroelectricity	30	78.7	82	277.3	111	356.0
Other	-	-	2	24.2	2	24.2
SC/CC	-	-	4	108.4	4	108.4
Solar	1,207	451.4	29,585	2,028.5	30,792	2,479.9
Wind	7	21.0	66	590.5	73	611.5
Total	1,292	634.0	29,816	3,300.7	31,107	3,934.7

There is also a small amount on “net metered” distributed generation. These generators are not covered by RESOP or FIT contracts. The output of the distributed generation at each load location is netted against supply, subject to O.Reg 541/05. This allows the loads to avoid all “upstream” charges except for the fixed payments to distributors.

At the time of writing installation of energy storage appears to be limited. At the distribution level, there are a few projects that have received funding from the Smart Grid Fund, e.g. Niagara on the Lake Hydro, Toronto Hydro, Sudbury and Ottawa, At the grid level, by the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the IESO’s Phase II energy storage competitive procurement process. At present, two projects have achieved Commercial Operation and the remaining seven are in development. It appears that the IESO anticipates these contracts will achieve Commercial Operation by November 2019.

Phase II complements the approximately 34 MW of grid energy storage procured in the earlier (2014) in Phase I energy storage program by the IESO to offer ancillary services to support grid reliability. As of May, 2018, seven Phase I energy storage facilities completed commissioning and become operational at various locations around the province. This includes five facilities providing Reactive Support and Voltage Control service, and two facilities providing Automated Generation Control (AGC) service.

In the City of Toronto there is now about 120MW of generation capacity within the franchise and the LDC, Toronto Hydro Electric System Limited (THESL), is planning for this to expand to 650MW by the end of 2019. (Toronto’s peak load is 4.3 GW.) This capacity is dominated by solar PV, which is unsuitable for providing baseload unless an extensive program of incorporating battery storage is developed to support this capacity. THESL has a modest storage program.[28]

28 OEB has begun a consultation on net metering.

APPENDIX 3
Other Sources and Reading

There is a great deal of material addressing the effective integration of DERs into distribution systems. The materials cited within the report and in this list are by no means exhaustive. Of special interest is the Lawrence Berkeley National Laboratory Future Electric Utility Regulation Series, which over a series of reports addresses key issues for utilities, customers, regulators, system planners and policymakers.

- **Getting Out in Front: Distribution System Planning for a Modern Grid**. August 29, 2017, AEE webinar presentation materials. Hannah Polikov, Nancy Lange (MN PUC), Alana Lemarchand 9Nexant), forest small (Black & Veatch).

  Very useful snapshot of key aspects of distribution system planning, valuation techniques, and plan flexibility.

- **New York PSC establishes Con Edison's demand management program in Brooklyn, Queens**. TransmissionHub, Corina Rivera Linares, 12/18/2014.

  A detailed description of the Con Edison Brooklyn/Queens Substation Project as described in its filings with the New York PSC

- **NARUC manual on distributed energy resources rate design and compensation**, NARUC staff subcommittee on rate design, 2016.

  A very useful document focused on DER valuation and utility interface.

- **Staff white paper on ratemaking and utility business models, State of New York Department of Public Service**, Case 14 – M – 0101, July 28, 2015.

  Produced as part of the reforming the energy vision program, this is a useful, detailed report focused on the proposed platform role for LDCs. The report provides insight into DER valuation methodologies.

- **Are residential demand charges the next big thing in electricity rate design?** Matt Lehman, http://blog.rmi.org/blog_2015_05_21_residential_demand_charges.
- **Distribution system pricing with distributed energy resources**. Lawrence Berkeley National Laboratory, LBNL-1005180, Report No. 4, May 2016, Ryan Hledik (Brattle Group), Jim Lazar (The Regulatory assistance Project), Lisa Schwartz, Project Manager.

  This comprehensive report examines pricing issues related to the business relationship between electric distribution utilities and the owners of DERs. It provides insight into methodology for developing rates related to DERs in a number of different settings.
- **Electric Utility Business Models of the Future**. The Brattle group, presented to the IEE eForum, Peter Fox – Penner, July 15, 2010
- **Exploring the relationship between planning and procurement in Western US electric utilities**. Carvallo, Sanstad, Larsen, Lawrence Berkeley National Laboratory, June, 2017.

  A useful discussion of the dynamics related to the implementation of integrated resource plans.
- **Staff white paper on benefit – cost analysis in the reforming energy vision proceeding, State of New York Department of Public service.** case 14 – M – 0101, July 1, 2015.

  Produced as part of the reforming energy vision initiative, this comprehensive report assesses various valuation methodologies, addresses the need for integrated analysis of distributed energy resources, provides a guide for states' monetization of externalities in connection with some of those methodologies, and proposes valuation horizons.
- **A framework for Integrated Analysis of Distributed Energy Resources: Guide for States**. Natalie Mims, Lisa Schwartz, Lawrence Berkeley National Laboratory presentation, 2018.

- **Hawaii Solar Permits See Sharp Decline in 201.** Greentech Media, Julia Piper, February 2019.

  Documents the relatively volatile experience respecting integration of solar DER into the Hawaiian grid.

- **Beyond the Meter Recommended Reading for a Modern Grid**. Smart Electric Power Alliance, June 2017.

  A very useful compendium of sources focused on integration of DER into electricity systems.

- **Minnesota Value of Solar: Methodology, Minnesota Department of Commerce**. division of energy resources, April, 2014.

  Very useful example of benefit-cost methodology used in developing valuation of DER.

- **Future drivers and trends affecting energy development in Ontario: a literature review**. Mowat Energy, Chaplin, June 10, 2016.

  Produced as a component of the MowatEnergy Emerging Trends program, very useful literature review.

- **Summary of Electric Distribution System Analyses with a Focus on DERs, Grid Modernization Laboratory Consortium**. US Department of Energy, Tang, Homer, McDermott, Coddington, Sigrin, Mather, PNNL-26272, April, 2017.

  A useful report for system operators focused on the technical implications of DER integration into existing distribution systems.

- **How leading utilities are planning for distributed energy resources**. Utility Dive, Herman K Trabish, February, 2018. https://www.utilitydive.com/news/how-leading-utilities-are-planning-for-distributed-energy-resources/516260/.

  A discussion of software tools which may assist distribution companies.

- **Restructuring Revisited: Competition and Coordination and Electricity Distribution Systems.** MIT Centre for Energy and Environmental Policy Research, Burger, Jenkins, Batlle, Perez-Arriaga, March 2018.

  A very useful paper focused on the regulatory architecture and its effects on competition, infrastructure development, and investment efficiency.

- **Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning**. Lawrence Berkeley National Laboratory, LBNL-1006047, numerous authors, August 2016.

  A comprehensive examination of approaches to planning for and incorporating solar DER into distribution systems.

- **Value – Added Electricity Services: New Roles for Utilities and Third-Party Providers.** Lawrence Berkeley National laboratory, Report No. 9, Blansfield, Katofsky, NASUCA, Lisa Schwartz, Project Manager, October 2017.

  A very useful examination of the possible models that may be used for the introduction of DER into distribution systems, viewed from the distinct perspectives of utilities, third-party providers, and consumer advocates.

- **Will distributed energy in the utility natural monopoly?** Electricity Daily (newsletter), Corneli, Kihm, Publication of Electricity Policy, June 2016.

- **NARUC rate design manual reignites debate over cost shift, value of solar.** Utility Dive, Herman K. Trabish, August, 2016

- **A Framework For Integrated Analysis of Distributed Energy Resources: Guide For States**. Lawrence Berekely National Laboratory, Mims, Schwartz, Taylor-Anyikire, August, 2018.

  Presents possible frameworks for the assessment of DER integration.