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PC: Alectra President and CEO sends recommendations for how the government can support the integration of Distributed Energy Resources (DER's).

S- LDCs

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Discover the possibilities

August 14, 2017

Hon. Glenn Thibeault
Ministry of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario M7A 2E1

Dear Minister Thibeault,

As you know, Alectra is committed to building on the successes of our predecessor utilities to become a premier integrated energy solutions provider, delivering excellence in customer service and choice.

We are highly cognizant of the changes taking place within the energy sector globally, the transformation of the energy market here in Ontario, and the evolving preferences of our customers, in particular, around choice over energy solutions. I know the theme of customer choice is important for you as well, and we commend the government for showing leadership on the issue of time of use rate optionality. To that end, Alectra is pleased to be proceeding with the expansion of our Advantage Power Pricing pilot with the support of the Ontario Energy Board (OEB).

Minister, one of the trends Alectra identified early on is an evolving customer desire for integrated energy solutions. In growing numbers, our customers are seeking Distributed Energy Resource (DER) solutions from Alectra in order to address their unique and independent energy needs, and we are keen to respond. As you know, we have had success in this area with the POWER.HOUSE pilot. The evolving adoption of DERs will benefit all customers through more efficient use of the electricity grid, improved resiliency, and, ultimately, lower costs. Alectra believes the most compelling basis for enhanced DERs rests on the benefits of customer choice and a sound economic outcome. On both fronts, Alectra is well positioned for success.

We are confident that working together with government and its agencies, we can create a policy and regulatory environment that maximizes the value of these resources in Ontario and optimize their deployment.

Distributed Energy Resources (DERs)
Resources located on the distribution system either close to or on the customer's premises. DERs are not simply supply or demand, as traditionally thought, but can be multiple types of resources, such as storage or advanced technology paired with a resource, capable of providing a variety of benefits and services to the customer and the grid. *(Adapted from National Association of Regulatory Utilities Commission)*

To that end, as the government prepares to release the 2017 Long Term Energy Plan, we thought it would be helpful to provide: Alectra's perspective on DERs; the current environment; how we are responding to this evolving trend; and the valuable role that local distribution companies (LDCs) play in integrating DERs. We have also taken this opportunity to provide a recommendation for how government can support the creation of a comprehensive policy and regulatory framework for DERs in Ontario.

Current policy and direction is largely supportive, but fragmented

In recent months, the government has signaled a shift in its energy policy, towards defined outcomes and away from prescriptive inputs, and towards greater choice between energy resources. This shift provides an opportunity to level the playing field for the treatment of DERs.

The Independent Electricity System Operator's (IESO's) Ontario Planning Outlook stated the following objectives, which pertain to and signal an opportunity for DERs:

- The need to create conditions in the distribution sector that are conducive to grid modernization and provide, at the same time, incentives for efficiencies, productivity gains and optimal levels of reliability;
- Policy and regulatory frameworks should promote cost-effective improvements to the quality, reliability and efficiency of distribution service, as well as more opportunities for conservation and reducing peak demand. In this regard, consideration should be given to harvesting the maximum value out of existing grid investment in order avoid a duplication of cost as DER becomes more prevalent i.e., stranded assets;
- Policy and regulatory frameworks also need to allow for enough flexibility in the LDCs' business models, so distributors can respond more effectively to increased efficiencies presented by emerging technologies.

We are aware of at least seven separate on-going initiatives that are either directly or indirectly considering the policy and regulatory framework for DERs in Ontario:

- Net metering regulation development;

- IESO Regional Planning;
- Conservation First Framework mid-term review;
- IESO Grid/LDC Interoperability Standing Committee;
- Green Ontario Fund;
- Long-term Energy Plan policy options for in-front of the meter conservation technologies; and
- Market Renewal.

Policy direction from the government and its agencies indicates a move towards further deployment of DER resources. Barriers that remain are included within this letter.

Alectra believes that Ontario needs a single comprehensive policy and regulatory framework for DERs that moves away from blunt-force incentives and instead creates a level playing field and a coordinated strategy for optimizing the value of these resources today and into the future. In this regard LDCs are uniquely positioned to accelerate the advancement of DERs through optimization and integration with their existing and future distribution system plans, their technical competency with these investments and associated integration within their distribution grid, leveraging existing customer relationships and most importantly, reducing the risk of stranding existing electrical infrastructure costs.

Pilots have identified value in an integrated solution (to customers and the electricity system)

DERs have received tremendous support to-date in Ontario, either through full-scale programs, such as Ontario's Feed-in Tariff and micro Feed-in Tariff; or pilot programs, such as the Smart Grid Fund, IESO procurements and Conservation or Technology Innovation Funds.

Alectra has participated in several pilots via the above mechanisms including, of course, POWER.HOUSE and a Vehicle-to-Home charging pilot. We have found these experiences to be instructive on many fronts. They have provided us with a much-needed test bed to evaluate the potential of emerging technologies, and have allowed us to better understand the new business models that facilitate bringing these solutions to market.

The pilots that Alectra and others in the industry completed, demonstrate the multiple benefit streams that can be realized from the deployment of DERs, including benefits to:

- Participating customers through bill savings and reliability while promoting choice and engagement;
- Both the distribution and transmission system by providing localized capacity resources for peak management through geotargeting of DERs to meet specific,

local needs while avoiding or deferring the need for traditional poles and wires solutions;
- The distribution system through localized system visibility and management capabilities; and,
- The transmission system through ancillary services, demand response potential, and additional options for regional planning; and
- The entire system through added planning flexibility and the ability to scale resources incrementally over time and avoid large investments that could become stranded/underutilized if forecasts vary widely from reality.

Finally, the pilots have demonstrated that while DERs provide onsite customer value and support, when aggregated, they are equally beneficial to the broader distribution grid.

There are several policy directions from government and its agencies identified or confirmed through Alectra's pilot experience that either support or create opportunities for DERs. These policies are highlighted below, along with any remaining barriers.

Net Metering

Net metering policies have advanced, and Phase II of the regulation continues to move forward. The Ministry of Energy has made significant progress on net metering over the past several months and it's anticipated that Phase II will tackle many of the remaining barriers and opportunities that could arise from taking a comprehensive approach.

Barriers & Opportunities

The MDM/R is currently not capable of applying time of use pricing to net metered customers but it is our understanding that the government is currently reviewing the business case for enabling this (as well as asking LDCs to determine the costs on their side).

Net metering improves the economics for customers implementing DERs by allowing them to sell electricity back to the grid, but aggressive adoption could also present a challenge around the stranding of regulated utility assets. LDCs such as Alectra are uniquely positioned to play a clearly defined role in integrating behind-the-meter DERs that are participating in net metering. Additionally, LDCs are best positioned to act as distributors/installers, owner/operators, or even competitively procure grid balancing services through community owned DERs, to maximize the benefits on both sides of the meter. At present, access to ancillary services markets and other market services is restricted for most distributed energy resources. A good example of this is the recent regulation request for proposals issued by the IESO, which has a minimum participation threshold of two megawatts and which must be supplied from a single location.

Ancillary Service Markets

Ancillary and other market services have the potential to provide additional revenue streams for DERs. Storage resources are currently participating in IESO pilots and some restricted activities have occurred recently. By working in partnership with the IESO, Alectra successfully demonstrated, through the POWER.HOUSE feasibility study, that DER resources are capable of providing ancillary services on a broader scale than currently deployed.

Barriers & Opportunities

Market constructs need to be built in such a way that they accurately reflect the potential benefits that DERs can provide. This would include ensuring that market participation rules do not necessarily favor centralized solutions, and the capabilities and flexibility that DERs provide are appropriately accounted for when building market products to enable the electricity system to realize their value. If markets reflected the value of DERs, LDCs would be very well suited to capture their value and hence support increased adoption.

Other Initiatives

It is also important to highlight that efforts are also underway to consider the integration of DERs from a system perspective through the IESO's Grid Interoperability Standing Committee.

The Committee's objectives are to:

- Establish a partnership to discuss issues and opportunities for a more coordinated operation of Ontario's electricity system;
- Increase awareness of upcoming changes at both the grid and distribution levels to understand the impact on system operations and identifying practical ways to leverage these opportunities; and,
- Identify existing capabilities that can be better leveraged to support efficient and reliable operation of Ontario's electricity system.

Barriers & Opportunities

As illustrated by the committee objectives, the focus appears to be more towards visibility and control rather than the regulatory structures to advance DERs. This initiative provides a valuable opportunity for LDCs and the IESO to work collaboratively to build an understanding of how to capture the value from DERs and to advance their adoption. This initiative should be connected to a broader, comprehensive framework to fully understand how different policies interact to support or hinder the realization of the substantial benefits to customers and the electricity system and the valuable role of LDCs with respect thereto.

LDCs are best positioned to enable the value of DERs to be realized

Many of the policies and regulations that have been enacted to date have indirectly reduced some of the barriers to DER adoption from an LDC perspective (e.g., revenue decoupling, Bill 112, and Renewed Regulatory Framework, including Distribution System Plans). While these changes have been a step in the right direction, they are still fragmented and do not explicitly encourage the thoughtful proliferation of DERs. We suggest more direct enabling regulation is required to take advantage of the unique position of LDCs in accelerating investment in DER within their distribution grids.

<u>Revenue Decoupling</u>
Revenue decoupling helps to remove some of the volumetric volatility in LDC revenues that is inconsistent with its underlying fixed cost structure. This is indirectly supportive of increased DER penetration and customer energy efficiency gains.

Barriers & Opportunities
Currently, this change in rate-making policy is limited to residential customers, although it might be expanded to larger customers in the future. Such expansion supports setting distribution revenue in a manner consistent with an LDC cost structure such that it is motivated to advance customer choice, such as DER, without risk to its revenue stream. Customers would benefit from a policy/ regulatory approach that motivates DER adoption by aligning costs and benefits with locational impact of DER products and services. This could include locational rates for DERs that incorporate the benefits they provide at a specific location in the system. Such a re-consideration may advance broader adoption of residential DERs. LDCs are uniquely positioned to develop associated rate strategies given their knowledge of the total life-cycle cost of DER investment and associated benefit.

<u>Scope of Business (Bill 112)</u>
Bill 112 repealed the section of the Ontario Energy Board Act that restricted the types of business activities that a municipally-controlled distributor's affiliates can undertake. In theory, a utility could now, directly or through an affiliate business, support other distributed energy resources such as generation, storage or integrated solutions for customers.

Barriers & Opportunities
No specific barriers remain on this front although this new allowance remains untested. The changes to the *Ontario Energy Board Act* give the Ontario Energy Board discretion to allow LDCs to "own" these types of assets and pursue these types of businesses. However, it is unclear whether these may be included as rate recoverable assets. It is Alectra's contention that LDCs are uniquely positioned to accelerate DER investment

through integration with rate-based assets considering that all LDCs in Ontario operate with capital envelopes which may be used to optimize the grid to the evolving benefit of all customers. The OEB should be encouraged to work with LDCs to develop rate-making options that fairly allocate the costs of DER investments among benefitting customers. Such an approach also allows LDCs to harvest the maximum amount of benefit from existing rate base investments which supports cost efficiency and effectiveness and avoids the inefficient cost of stranded assets. Otherwise, there is no compelling business case for LDCs to pursue or enable DER investment which is a clear barrier to DER investments in the best interests of customers.

<u>Renewed Regulatory Framework for Electricity (RRFE)</u>
In the sense that the RRFE was designed to support public policy initiatives, it opened the possibility that rate regulated utilities could engage in broader business activities. The experience of Alectra and its predecessor companies with the RRFE was positive and, in theory, utilities are enabled to deliver on the outcomes of the framework (e.g., services delivered that are responsive to needs, support public policy objectives, financial viability is maintained, system reliability is maintained).

Barriers & Opportunities
In theory, Alectra Utilities could use the Custom Incentive Regulation Framework under the RRFE to embed DERs in its distribution system and recover the cost through rates. However, in practice, the application timing is not conducive to this type of investment and there are few practical examples or clear guidelines to move DER assets forward into the rate base. Flexibility from the OEB with regards to use of existing capital envelopes would support increased adoption of DERs.

<u>Regional Planning</u>
Regional planning processes are beginning to consider non-traditional (poles and wires) resources and, in Alectra's case, customers and stakeholders in these processes are starting to demand change. The IESO leads regional planning processes that rotate across 21 planning regions in Ontario. This process is completed in collaboration with Hydro One Networks and LDCs. Alectra is currently engaged in four of these processes: York Region, Barrie, Parry Sound / Muskoka and the Greater Hamilton area.

Processes are intended to begin with a scoping assessment which considers the "best mix of available options" to meet regional needs followed by an integrated regional resource plan (IRRP). The planning process is informed by a Local Advisory Committee (LAC), comprised of local business people and other community leaders who provide advice to the IESO and LDCs on solutions that might best serve their communities. In theory, the IRRP could consider alternative solutions, such as DERs, but the solutions have thus far tended to be traditional poles and wires options. In Alectra's experience, this has been frustrating to members of the LACs. Our experience with the York

Region's LAC has been that the committee members, on behalf of their communities, have a high level of interest in clean, sustainable, distributed energy resources to fulfil future load growth.

Barriers & Opportunities

While the IRRPs were intended to consider alternative solutions to meet demand, in practice, the process has only recently begun to consider non-traditional solutions such as DERs, in large part due to feedback from LAC members as well as companies like Alectra. As such, the process to consider non-traditional and the tests and/ or decision criteria is nascent. It is unclear how the upstream benefits of DER investments can be captured. For example, is the IESO responsible for identifying and implementing potential benefits of a solution? What mechanisms would they use? Finally, although the IRRP process could serve as a viable framework for integrating DERs, it is complicated by the fact that multiple entities are involved with decision-making that may not be aligned in terms of respective objectives.

One solution is enabling regulation for a more robust Distribution System Planning (DSP) process that encourages DER investments in the interests of customers. In this regard, the OEB is well-positioned to ensure that LDC DSPs balance these concerns and DERs are considered in promoting government objectives with respect to the electricity grid.

Distribution System Plans (DSPs)

The Ontario Energy Board provides an expected framework for DSPs, which addresses renewable generation connection investments. The current regulations suggest renewable generation connections be integrated with other planned asset investments so rate setting can be optimized. There is also a specific section of the DSP framework which addresses smart grid development and implementation.

Barriers & Opportunities

The guidance in the DSP framework has been useful for LDCs in accommodating government policy direction with respect to smart grid deployment and the integration of costs associated with the feed-in tariff program. However, there are no apparent provisions in place for the treatment of LDC-owned DERs. There are also no criteria or specific principles that guide the LDC in justifying the inclusion of DERs as a non-traditional alternative investment within its DSP. The OEB should work with the sector to develop application guidelines that will support the inclusion of DERs in DSPs.

Conclusion & Recommendation: A comprehensive framework for DERs should be developed

Ontario's energy system is unique and, based on our research, there is not a clear example of a jurisdiction it could emulate in successfully integrating DERs into the grid. There are, however, important lessons to be learned with regard to how other jurisdictions have addressed these challenges and supported more wide-spread adoption in the interest of both enabling a reduced reliance on GHG emitting resources as well as in providing customers with the larger role in energy management that they are increasingly demanding.

California and New York are leading discussions on addressing the integration of DERs into the grid. Current thoughts focus on the concept of integrated DER (iDER), which is a custom, portfolio-based, DER adoption approach at every level of energy markets and encourages customer choice and flexibility while addressing aggregation issues at the grid operator and utility level. In addition, both jurisdictions require some sort of distribution system plan from utilities to demonstrate a degree of DER integration. For more information, please refer to the appendix which also includes references to examples of rate-based DER assets.

Identifying the benefits associated with DERs (and their management) has been a critical first step in determining whether or not they represent a long term risk or opportunity for the electric system at large. The IESO has made considerable progress on this front through its work on grid interoperability and the POWER.HOUSE feasibility study; and Alectra continues to be pleased to support them in this work.

The next step in capitalizing on DER benefits is to quantify them, preferably through real-world evaluation. This is where LDC and regulatory collaboration is critical. Furthermore, clarity around the role of the regulated utility in the face of a proliferation of net-metering as a result of enabling time of use for net-metered customers is also necessary to ensure the transition from an incentive based renewables market (FIT and micro-FIT) to one with a strong and sustainable business case. LDCs will play a critical role in enabling that transition.

Recommendation

We are all interested in the challenge of how best to enable mass adoption of DERs. Alectra believes that LDCs are uniquely positioned in this regard and has offered several suggestions that it believes will accelerate DER investment in an integrated, cost effective manner that delivers both customer and government policy objectives for electricity delivery.

We believe we need to work together to determine how to value these assets and how to incorporate them into our planning frameworks and enable the system to realize the value of these assets. Though intention around policy direction is clear, the supporting regulation, practices, and procedures are emerging and not yet mobilized to advance DERs in Ontario. Our recommendation is that the government use the upcoming LTEP to clearly identify intent and next steps around necessary grid modernization. In our view, the OEB is best positioned to lead this work in close collaboration with the IESO and the LDC community.

We look forward to ongoing discussions with the Ministry of Energy, the IESO and the OEB on how we can work together to bring the benefits that DER integration offers to our customers and to the distribution and transmission systems in Ontario. I would be happy to discuss any of this further at your convenience. Please always feel free to contact Tamar Heisler, Alectra's Director of Government and Industry Affairs, if you wish to set up a meeting.

Sincerely,

Brian Bentz
President and Chief Executive Officer
Alectra Inc.

CC:
John Basilio, Chief Financial Officer, Alectra Inc.
Max Cananzi, President, Alectra Utilities Corporation
Andrew Teliszewsky, Chief of Staff to the Minister of Energy
Serge Imbrogno, Deputy Minister of Energy

Appendix to Alectra LTEP Addendum: DER Jurisdictional Scan

California and New York are leading discussions on tackling the integration of DERs. Current thoughts focus on the concept of integrated DER (iDER) which is a custom, portfolio-based, DER adoption approach at every level of energy markets which encourages customer choice and flexibility while addressing aggregation issues at the grid operator and utility level. In addition, both jurisdictions require some sort of distribution system plan from utilities to demonstrate some degree of DER integration.

This section reviews DER policies in California and New York in detail providing an overview of the relevant activities related to DER integration, review of specific policies, and highlighting examples of rate based DER assets. Additional examples are also provided.

California

California is undertaking a DER Action Plan that consists of three groupings. Each grouping contains specific "action elements" described in the table below

Grouping	Elements
Rates and tariffs	TOU, rate design, next generation net energy metering, demand charges, forum for innovative rates
Distribution grid infrastructure, planning, interconnection, and procurement	• Distribution resource plans include consideration of specific components (including locational net benefit methodologies, infrastructure deferral framework, DER growth scenario forecasts) • Integrated DER proceeding (includes integrated DER valuation and cost-effectiveness framework, utility incentive mechanism pilot) • Streamlining interconnection of generation and storage • Consideration of societal cost test in DER valuation • How DER sourcing mechanisms (e.g., programs and tariffs) should reflect locational value • Consider developing guidelines to clarify circumstances in which utility affiliate ownership of DER is appropriate • Independent distribution planning process to ensure DERs are adequately evaluated
Wholesale DER market integration and interconnection	Consideration of market rules and regulatory policies for DER multi-use applications, issues regarding the use of DER to meet transmission and distribution system needs, and eligibility of NEM resources in wholesale markets

http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20(5-3-17)%20REDLINE.pdf

The overarching goals of the DER legislation passed to date are to:

1. Drive innovations in products and services offered by utilities.
2. Provide outstanding reliability and power quality in the evolving interconnected electric grid.
3. Increase/maintain affordability to avoid undue burden on all stakeholders.
4. Reduce emissions and demonstrate environmental responsibility.
5. Increase grid reliability, resilience, and efficiency.
6. Ensure the continued safety for customers, employees, and the public.
7. Provide robust security—both physical and cyber.

Distribution Resource Plans

DRPs (Distribution Resource Plans) require many components that are intended to advance DER adoption in the state

- Analyses of distribution planning (integrated capacity analysis, locational net benefits methodology, and DER penetration scenario analysis)
- Demonstration projects
- Bi-directional data sharing between utilities and third parties
- Modifications to relevant tariffs and contracts
- Safety considerations of greater DER penetration
- Identification and categorization of barriers to DER penetration
- Coordinate distribution planning with system planning
- Phased rollout of required projects and processes

In parallel, the Integrated Demand Side Resource (IDSR) proceeding is focused on

- *"the integration of distributed energy resources in a holistic way that includes not only what the utilities offer customers (integrated demand-side management) but also what customers offer the utility (integrated distributed energy resources)."*
- **Integration of distributed energy resources:** *"A regulatory framework, developed by the Commission, to enable utility customers to effectively and efficiently choose from an array of distributed energy resources taking into consideration the impact and interaction of resources on the grid as a whole, on a customer's energy usage, and on the environment."*

Net Energy Metering (NEM)

NEM 2.0 requires customer-generators to cover the costs for services they obtain from the utility. The components included are outlined in the table below.

NEM change	Description

http://www.scottmadden.com/wp-content/uploads/2016/12/SEPA-ScottMadden-51st-State-Report_DER-Integration-CA-NY.pdf
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M154/K464/154464227.PDF

NEM change	Description
One-time interconnection fee	New charge, cost incurred by utility to connect the customer-generator
Non-bypass charges	Not new, before NEM 2.0 customers only incurred charges on net kWh consumed – now charged on all kWh consumed
Min monthly bill	Existing requirement, reinforced by NEM 2.0
TOU	Customer-generators must participate in TOU, economics will be weakened for customers to help manage integration

Examples of Rate Base DER Assets

Proceedings recognize the disconnect between utilities encouraging DERs and financial objectives to earn regulated returns on assets. A pilot regulatory incentive structure was proposed to tackle this issue. Proposal seeks to align shareholder interests with the goal of increasing the adoption of DERs

PG&E submitted a proposal to replace the needs associated with a nuclear decommissioning with DERs. This proposal contemplates the procurement costs being recovered through non-bypass charges. PG&E proposed a competitive procurement and highlighted that they would work with stakeholders to determine an appropriate cost and benefit allocation.

Several utilities own solar assets to assist in meeting their renewable portfolio standards

New York

In New York, the Renewing the Energy Vision (REV) proceeding, which was initiated in April 2014, is the set of linked proceedings focused on the integration of DERs. NY REV includes two tracks: track one is focused on enabling and encouraging utilities to promote DERs and track two is focused on regulatory design and incentive structures. It has six stated goals:

1. **Enhance customer knowledge and tools that support effective management of the total energy bill**
2. **Increase market animation and leverage of customer contributions**
3. **Improve system-wide efficiency**
4. **Implement fuel and resource diversity**
5. **Increase system reliability and resiliency**
6. **Reduce carbon emissions**

There is a focus on evolving the cost of service model and transitioning from net metering to a value stacking approach to manage the impact on non-participants. Gradual shift in rate structure aligning with principles: cost causation, encouraging outcomes, policy transparency, decision making, fair value, customer orientation, stability, access, and gradualism. The table below highlights the modifications to rates/regulatory support that is or will be implemented

https://www.pge.com/includes/docs/pdfs/safety/dcpp/diablo-canyon-retirement-joint-proposal-application-prepared-testimony.pdf

http://www.scottmadden.com/wp-content/uploads/2016/12/SEPA-ScottMadden-51st-State-Report_DER-Integration-CA-NY.pdf

Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV Proceeding), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order).

http://www.scottmadden.com/wp-content/uploads/2016/12/SEPA-ScottMadden-51st-State-Report_DER-Integration-CA-NY.pdf

Modification	Description
Demand charge	Utilities required to offer demand charges, opt-in basis
TOU rates	Utilities required to offer TOU rates, opt-in basis
Smart home rate	Combo of TOU and value of DER, TOU rates with value based compensation for DERs (demo projects were expected Feb. 2017).
Improved C&I rate	Rates more accurately capture peak and off-peak demand to encourage a shift in behaviour
Standby tariffs	Utilities required to adjust tariffs to better capture (1) reward customers who provide system value (2) allocation of contract and daily as-used charges (3) distinction between new load and existing load (4) identify marginal cost of service and apply add-on for non-capital related cost recovery.
Earnings adjustment mechanisms	Performance incentives to encourage customer savings and develop market-enabling tools: interconnection, system efficiency, energy efficiency, customer engagement, clean energy standard
Platform service revenues	Opportunities for utilities to earn revenue from growth and/or operation of market solutions beyond traditional cost-of-service model, approval considers whether service is (1) required as part of market development (2) provides additional value to customers while tied to utility's core business (3) cannot be more efficiently provided by a third party (4) utility taking on an appropriate amount of risk with the project
Value of DER proceeding	New approach to net metering for DER resources moving beyond retail rate net metering to a method that aligns the compensation to the value

This section focuses on two components of the NY REV proceeding: Distribution System Implementation Plans (DSIPs) and the Value of DER order

Distribution System Implementation Plans

Utilities are viewed as Distribution System Platform (DSP) providers intended to enable the adoption of third party DERs to customers. They are required to file a Distributed System Implementation Plan (DSIP) which communicates a five year plan with updates every two years

The DSIPs are intended to provide dynamic plans which include plans for pilots and innovation, additional information to enable third parties to adopt DERs, and specific consideration of where, how, and when DERs could be integrated. Utility investments in the future appear to be intended to focus on increasing visibility, control, and information to enable third party access

The Commission only allows utility ownership of DERs under certain circumstances, for example "... a project is being sponsored for demonstration purposes."

Value of DER Proceeding

As stated in the Value of DER order: "In order to incentivize customers and DER providers to install and operate DER in a manner that maximizes the benefits for themselves, the integrated electric system, and society as a whole, compensation must accurately reflect the values created at a granular level." VDER order, page 20

Furthermore, "By failing to accurately reflect the values provided by and to the DER they compensate, [NEM] will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers." VDER order, page 3

The new approach replacing net metering pays exported power using a value stack that captures commodity, capacity value, environmental benefits, and demand reduction values and local system relief. During a transition period, existing resources will be paid a transition credit that keeps the value at the NEM value. The figure below illustrates how the new value of DER compares to traditional net NEM

Examples of Rate-Based DER Assets

Con Edison – mobile storage project (demo) – owns batteries – intended to understand how much capital should go to rate-base vs. competitive markets. Used to advance the principles of the framework, test potential business models, and identify regulatory and market barriers

Con Edison – solar-storage (demo) – purchase, own and control solar and storage – funded by a Monthly Adjustment Clause (MAC) and revenues credited back to customers, customers offered lease arrangement through project partner

Others

Colorado

Xcel received deferred ratebase approval for two customer-sited solar-storage projects. Deferred rate base approval by the CO PUC indicates that Xcel can claim the resource as part of its rate base of system assets and earn recovery on the resource through retail rates. Rate base recovery provides for recovery of capital and operating costs including a PUC determined rate of return

Page 8 of the CO PUC's Decision allows for "rebuttable presumption of prudence for the ICT projects proposed in the Application for capitalized costs, and authorize deferred accounting of these capitalized expenditures"

In addition, Colorado has a general initiative on new power system technologies that includes research staff for emerging issues and a special legislative monetary set aside for new energy resources. This initiative, called Section 123 Resources, requires the commission to provide complete consideration and possible rate based financing to alternative technologies without a need for them to be economically competitive

There must however, be a compelling reason for their use, primarily that the resource shows a potential of being economically competitive with other resources in the near future (In the Manner of the Emergency Rules Amending the Commission's Electric Resource Planning Rules, 2007, pp. 10-11). The Section 123 Resources initiative does not specify specific technologies or the exact amount installed for

Case 15-E-0751 - Value of Distributed Energy Resources. Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. March 24, 2017 each year. Total capacity is determined in the resource planning process. It is estimated that for the current (2013) process, this may be in the 120 MW range.

Arizona

TEP and APS have both filed approval for fairly sizable customer-sited DER pilot programs as part of their 2017 IRPs (both linked). APS notes two customer-sited programs AZ Sun II and Solar Innovation Study.

New Jersey

PSEG has implemented some distributed solar as part of its Solar4All program, most recently **approved** in May 2016. The program includes customer-sited generation, including one 40 MW segment of small solar units mounted upon utility and streetlight poles.

Washington/Idaho

Avista included two categories of DERs, "customer-owned generation" and solar in its 2015 Integrated Resource Plan (attached)

Missouri

While Missouri utilities have not yet ratebased DERs, Ameren recently had an application **approved** authorizing that significantly simplifies the path to ratebasing DERs by allowing the utility to "... construct, install, own, operate, maintain and otherwise control and manage various small solar generation facilities at different locations within its service territory as part of a pilot program."