nationalgrid

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October 31, 2016

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV)

NATIONAL GRID: DISTRIBUTED SYSTEM PLATFORM REV DEMONSTRATION PROJECT – Q3 2016 REPORT

Dear Secretary Burgess:

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") hereby submits for filing its quarterly update to the Distributed System Platform REV Demonstration Project Implementation Plans covering the period of July 1, 2016 to September 30, 2016 ("Q3 2016 Report") as required by the REV Demonstration Project Assessment Report filed by the New York State Department of Public Service Staff ("Staff") with the Commission on July 15, 2016 in Case 14-M-0101.

Please direct any questions regarding this filing to:

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National Grid looks forward to continuing to work collaboratively with Staff as it proceeds with the implementation of the Distributed System Platform REV Demonstration Project.

Respectfully submitted,

/s/ Karla M. Corpus

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Senior Counsel

Enc.

cc:
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Denise Gerbsch, DPS Staff, w/enclosure (via electronic mail)
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Distributed System Platform

REV Demonstration Project

Buffalo, New York

Q3 2016 Report

October 31, 2016

Table of Content

1.0 Executive Summary

Under the Commission's Reforming the Energy Vision ("REV") proceeding, the Distributed System Platform ("DSP") demonstration project (the "Project") aims to develop, deploy and test the first of its kind solution with the objective to create a new distribution-level energy market. The Project will identify the locational generation value of customer-owned distributed energy resources ("DER") and provide a platform that will allow these assets to participate and provide energy and/or ancillary services to the electric distribution system (*i.e.,* the "grid"). The Project was initially filed with the New York State Public Service Commission ("Commission") by Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") on July 1, 2015. A revised scope for the Project was filed with the Commission on June 15, 2016. The review of the revised scope for the Project was completed by the New York State Department of Public Service Staff ("DPS Staff") on June 22, 2016. DPS Staff subsequently filed an assessment report with the Commission on July 15, 2016 finding that the Project meets the Commission's REV policy objectives and demonstration project principles and complies with Ordering Clause 4 of the Commission's Track One Order.[1]

The Project will test services based on a local, small-scale, but centralized DSP that will communicate with network-connected Points of Control ("POCs") associated with the Buffalo Niagara Medical Campus Inc. ("BNMC") DERs. DSP is defined as "an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs" where the "DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system."[2]

The Project team consists of National Grid, BNMC, and Opus One Solutions ("Opus One"). Opus One will provide contracted services to National Grid. Opus One is a software engineering company which shares the vision for the Project to develop and deploy one platform that can accommodate a complete range of business models. Their role in the Project will encompass not only software development, but also thought leadership, planning and execution.

Image 1.1 – Part of the Buffalo Niagara Medical Campus

[1] 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"), p. 132.
[2] *Id*., p. 31.

The BNMC (*depicted in Image 1.1*), consisting of thirteen (13) member institutions and close to one hundred (100) public and private companies that are a dynamic mix of health care, life sciences, medical education, and private enterprise, is spurring significant growth in Western New York. As healthcare providers, most BNMC member institutions are required to have access to back-up or emergency power, which typically employ distributed generation ("DG"). However, even in an area that is affected by extreme weather such as Buffalo, these expensive DG assets sit idle most of the time. With the DSP, DER owners would have an option to extract more value from those DG assets by participating in the energy market through the DSP.

If successful, the DSP will create new revenue streams for both the DER owners and National Grid, and meet the other New York REV objectives as stated in the Track One Order. The DSP could then be extended across National Grid's service territory.

Image 1.2 – Images of the University at Buffalo, New York State Center of Excellence in Bioinformatics and Life Sciences (left) and the Roswell Park Cancer Institute (right), both members of the BNMC

The Model: LMP+D

In the near term, services transacted and purchased by the DSP will test the implementation of a "LMP+D+E" financial model approach for electric services. The value of "LMP+D" will be evaluated in the Project and is expected to generate sufficient financial incentives for DERs to participate in the DSP market. For LMP, the Project will consider New York Independent System Operator ("NYISO") location-based marginal prices ("LBMP") Zone-A West for day-ahead and real-time market prices[3] and any additional capacity constraints and transmission losses that may be priced into the local area through the New York Installed Capacity Market ("ICAP"), if they can be determined.

"D" refers to distribution delivery value, which is the value that DERs can provide to the electric distribution system, such as load relief to help alleviate substation or feeder constraints. This evaluation effort will analyze potential issues with capacity provision by considering average demand, peak demand, forecasts of demand growth, day-ahead load forecast, and historical demand at the feeder and substation levels. After analyzing these issues, values can be

[3] NYISO LBMP and real-time pricing information. Source: http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp

assigned to each of these items. Energy supply, volt-ampere reactive ("VAR") support, voltage management, peak load modifications, and dynamic load management are some of the services that will be evaluated in the Project to test what drives new market opportunities. The value of D will be evaluated in the Project and is expected to generate sufficient financial incentives for DERs to participate in the DSP market. The value of D takes into consideration potential issues along the grid such as substation and feeder constraints.

"E" refers to external or societal value (*e.g.*, low carbon, renewable or domestic fuel source) that may be provided by DERs that are not captured in in LMP or D. The Project does not intend to evaluate a specific value of E.

2.0 Highlights since Previous Quarter

National Grid and the key partners in the Project have made substantial progress in the third quarter of 2016. The National Grid Project management team reviewed the July 15, 2016 Assessment Report filed by DPS Staff with the Commission and finalized and filed the Implementation Plan for the Project with the Commission on August 15, 2016. The official kick-off of the Project was held on September 8, 2016 at the BNMC Innovation Center with participation of all Project partners. In late September, the Project team held the first workshop to develop the financial model of the Project's Phase 1.

All Project team members are on track to deliver the expected outcomes laid out in the Implementation Plan. For a reference timeline emphasizing the major milestones and accomplishments, please see Figure 2.1.

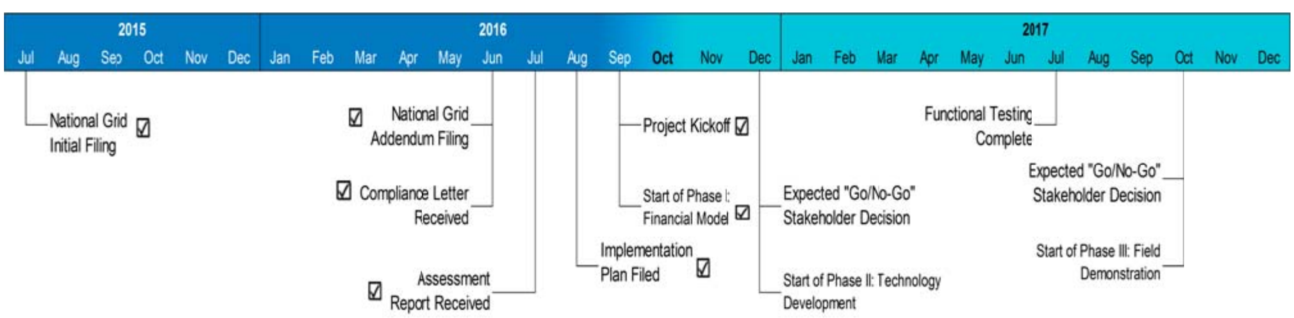

Figure 2.1 – Achievements and Milestones Timeline

2.1 Major Task Activities

1. **DPS Staff files Reforming the Energy Vision Demonstration Project Assessment Report, National Grid: Distributed System Platform Project (July 15, 2016)**
   The assessment report shows strong support and interest from DPS Staff as they find it represents a "*…relevant and innovative REV demonstration project*." Additionally, DPS Staff states in the assessment report:
   - *"Staff concludes that the DSP Project will enable National Grid to gain crucial experience in operating a DSP and transitioning to a new business model…"*

- *"One of the primary goals of REV is to animate the market for electricity and related services and increase the grid's leveraging private capital. This goal is the core of the [DSP] demonstration project."*[4]

Figure 2.2 - Excerpts from Assessment Report

2. **National Grid file DSP Implementation Plan (August 15, 2016)**
   The National Grid Project team worked closely with Opus One and the BNMC to review DPS Staff's Assessment Report and develop the DSP Implementation Plan with the Commission. Three (3) working sessions were held between the Project partners and DPS Staff to discuss the scope of information to be included and receive feedback discuss on the draft DSP Implementation Plan. The DSP Implementation Plan was then finalized and filed with the Commission on August 15, 2016.

3. **Conducts Project Kick-off Meeting (September 8, 2016)**
   The Project Team held a kick-off meeting at the BNMC Innovation Center in Buffalo, New York on September 8. 2016. Participants included over twenty (20) National Grid key Project stakeholders, the Opus One Project team, and a representative of the BNMC. The meeting consisted of a Project overview presentation and a walking tour of the BNMC facilities.

4. **Commence Phase 1 of the Project: Financial Model (September 29, 2016)**
   The first of a series of workshops was held at National Grid's offices on September 29, 2016. Leadership from Opus One and members of several National Grid business units attended that meeting. The National Grid business units attending were:
   - Advanced Data Analytics;
   - Engineering;
   - Wholesale Pricing;
   - Rate Engineering;
   - New York Regulatory Strategy;
   - Electric Operations New York;
   - Interconnections;
   - Information Systems;
   - Asset Management;
   - Digital Risk & Security; and
   - New Energy Solutions.

[4] REV Proceeding, Reforming the Energy Vision Demonstration Project Assessment Report, National Grid: Distributed System Platform Demonstration Project (filed July 15, 2016), pp. 5, & 6.

2.2 Challenges, Changes, and Lessons Learned

Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Daniel Payares Luzio was named Project Manager and Dennis Elsenbeck appointed as Executive Sponsor for National Grid.	None	None	Involvement of the Executive Sponsor and Project Manager in the early planning phase of the Project is beneficial for a better understanding of the business case and improve planning and implementation.
Contract negotiations with vendor (Opus One) were delayed.	The Project timeline will be slightly impacted by delays in concluding contract negotiations.	Both parties proceeded with Project development in good faith in anticipation of contract finalization in order to avoid additional adverse Project impacts. Additional re-scheduling of tasks will be necessary to avoid further delays.	The Project team should always allocate sufficient time for contract negotiations.
Some or all of the BNMC's DERs may not be NYISO Tier 4 compliant.	A DER that is not NYISO Tier 4 compliant cannot operate in non-emergency situations (e.g., cannot participate in NYISO markets).	Additional investment may be needed in order to comply with regulations or to acquire other types of DG.	

3.0 Next Quarter Forecast

During the 4th Quarter of 2016, the Project team will be developing the Financial Model for the DSP. The team has chosen to hold a series of workshops with involvement from different business units within National Grid, the BNMC, and Opus One. In Phase 1, the Project will aim to uncover the real-time locational value of DERs to the distribution network; best described as the "LMP+D" framework. Additionally, Opus One will conduct a simulation of the Financial Model with historical data to corroborate the operation and validity of the Financial Model. Moreover, the team will begin gathering the technical requirements needed for the technology development of the DSP and its integration with National Grid's servers and operations in anticipation of Phase 2 of the Project.

The Project team plans to conduct the first Go/No-Go decision checkpoint between the BNMC stakeholders, Opus One, and National Grid in December 2016. In the event all Project partners reach a positive decision to move forward, the Project will continue to Phase 2, Technology Development of the DSP and POCs.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	Financial Model Development	8/16/16 – 11/7/16	9/30/16 – 11/10/16	●
2	Financial Model Simulation	10/11/16 – 11/7/16	11/11/16 – 12/8/16	●
3	Phase 1 Stakeholder Go/No-Go Decision	11/7/16	12/30/16	●
3	Start of Phase 2: Technology Development	11/8/16 – 9/25/17	1/2/17 – 11/17/17	●

Key

● On-Track

● Delayed start, at risk of on-time completion, or over-budget

● Terminated/abandoned checkpoint

1. Financial Model Development

Status: [●]
Start date: 9/30/16
End date: 11/10/16

National Grid and the Project partners have commenced DSP Financial Model development. Opus One is leading a series of workshops with the objective of uncovering the necessary inputs for the "LMP+D" model, determining the necessary data and its availability for the DSP software development, and gathering the requirements for integration with National Grid's Information Security ("IS") and Operating Systems ("OS"). Thereafter, Opus One will design and develop the DSP Financial Model, including determining the methodology to be utilized for the LMP+D computations in order to calculate the locational marginal value of DERs based on data from National Grid, NYISO (LMP and ICAP), and BNMC (+D values). This work will include, but is not limited to, the quantification of the DERs' capabilities for voltage management, VAR support, peak load management, and dynamic load management for acceptance by National Grid.

2. Financial Model Simulation

Status: [●]
Start Date: 11/11/2016
End Date: 12/08/2016

Opus One will conduct DSP Financial Model simulations with historical data, examples of real-time data, and forecasted data for defined test scenarios in order to generate LMP+D values for evaluation by DER participants and acceptance by National Grid. The scenarios will include multiple DER types and locations including, but not limited to:

- Diesel engine, building energy management system ("BEMS"), solar photovoltaic ("PV"), natural gas internal combustion engine, natural gas turbine, battery storage, and combinations of DER types;
- Locations within and surrounding the BNMC, and one (1) or two (2) other feeders from different NYISO zones in New York, up to a maximum of ten (10) distribution feeders.

Opus One will document the DSP Financial Model, generate pricing, and model simulation results in terms of value generated for DER participants (*e.g.,* the ability to utilize existing DERs or to invest in new DERs) and for National Grid (*e.g.,* new revenue streams).

3. Phase 1 Stakeholder Go/No-Go Decision

Status: [●]
Start Date: 12/30/2016
End Date: 12/30/2016

Phase 1 will end with a "Go/No-Go" decision from the major Project stakeholders (BNMC and National Grid). After the development, modeling, simulation and validation of the Financial Model, the results will be shared with the Project partners to evaluate if the results provide enough incentive to continue with the Project.

4. Start of Phase 2: Technology Development

Status: [●]
Start Date: 1/2/2017
End Date: 11/17/2017

If a "Go" decision is reached by all Project stakeholders at the end of Phase 1, the Project will continue to Phase 2 (Technology Development of the DSP and POCs). This phase will focus in designing, developing, testing and implementing the DSP and POC architecture and software.

4.0 Work Plan & Budget Review

4.1 Updated Work Plan

An updated version of the Gantt chart found in the DSP Project Implementation Plan is set out below.

ID	Task Name	Start	Finish
1	**Phase 0**	**Mon 8/15/16**	**Thu 9/8/16**
2	Implementation Plan Filed	Mon 8/15/16	Mon 8/15/16
3	Contracts executed, project charter developed	Wed 9/7/16	Wed 9/7/16
4	Project Kickoff	Thu 9/8/16	Thu 9/8/16
5	**Phase 1 - Financial Model**	**Fri 9/30/16**	**Fri 12/30/16**
6	**Design and development**	**Fri 9/30/16**	**Thu 11/10/16**
25	Initial model stakeholder GO/NOGO	Thu 11/10/16	Thu 11/10/16
26	**Startup - infrastructure definition**	**Fri 10/14/16**	**Thu 11/10/16**
32	**Financial Model Simulation**	**Fri 11/11/16**	**Thu 12/8/16**
36	Phase 1 Stakeholder GO/NOGO	Fri 12/30/16	Fri 12/30/16
37	**Phase 2 - Technology Development**	**Mon 1/2/17**	**Fri 11/17/17**
38	**DSP & POC**	**Mon 1/2/17**	**Fri 11/17/17**
39	**Requirements definition**	**Mon 1/2/17**	**Fri 1/13/17**
42	**Solution Design**	**Mon 1/16/17**	**Fri 2/10/17**
45	**Solution Development**	**Mon 2/13/17**	**Fri 7/28/17**
52	**Solution Testing**	**Mon 7/31/17**	**Fri 11/3/17**
59	**Implemention**	**Mon 11/6/17**	**Fri 11/17/17**
63	Phase 2 stakeholder GO/NOGO	Fri 11/17/17	Fri 11/17/17
64	**Phase 3 - Field demonstration**	**Tue 9/26/17**	**Mon 10/8/18**
65	Phase 3 Kick off	Tue 9/26/17	Tue 9/26/17
66	Market Structure and Economics	Tue 9/26/17	Mon 10/9/17
67	Market Deployment	Tue 9/26/17	Mon 10/9/17
68	Market Deployment complete	Mon 10/9/17	Mon 10/9/17
69	Market Integration into DSP and POC Build Environment	Tue 9/26/17	Mon 10/23/17
70	Testing and Op Demonstration	Tue 10/24/17	Mon 11/6/17
71	**DSP, POC and Market Monitoring and Measurement**	**Tue 11/7/17**	**Mon 10/8/18**

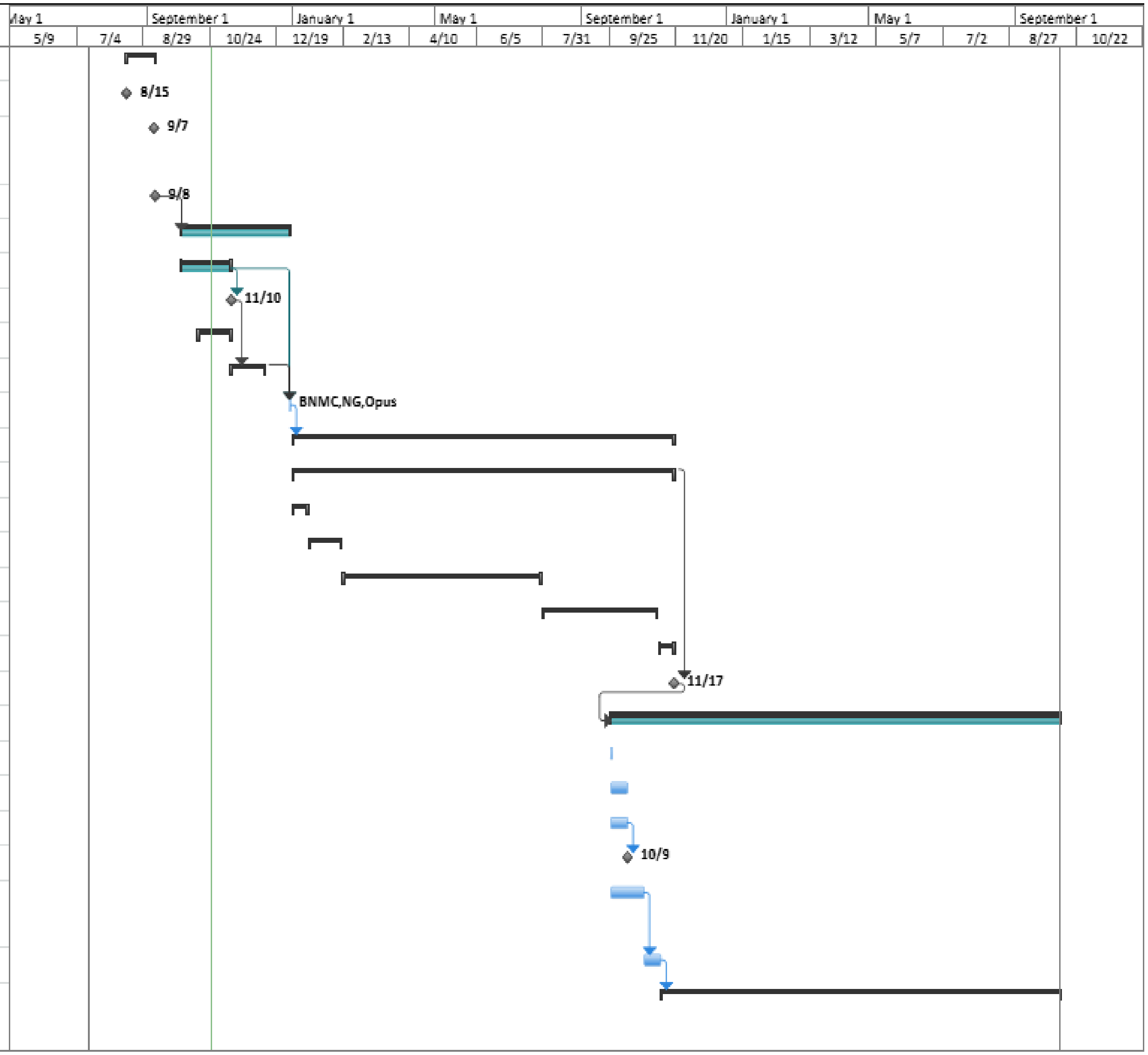

Figure 4.1 – Update of original Gantt Chart found in DSP Project Implementation Plan

4.2 Updated Budget

There are no changes to date for the forecasted budget set forth in the filed DSP Implementation Plan.

Project Budget Requirement		Phase 1		Phase 2		Phase 3		Total Project	
		CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
Opus One	Software License - 50% start of phase 2			$500,000				$500,000	
	Software License - 50% start of phase 3					$500,000		$500,000	
	Program management	$250,000		$750,000		$1,000,000		$2,000,000	
	Software development			$2,000,000				$2,000,000	
National Grid	Resources	$250,000		$750,000		$125,000	$125,000	$1,125,000	$125,000
	IT Integration Services			$200,000				$200,000	
	IT Hardware/Software			$25,000				$25,000	
	IT Network and communications			$75,000				$75,000	
	Subtotal	**$500,000**	**$0**	**$4,300,000**	**$0**	**$1,625,000**	**$125,000**	**$6,425,000**	**$125,000**
	Cost Share (in-kind software development)			$2,000,000				$2,000,000	$0
	Annual operational costs				$30,000		$230,000	$0	$260,000
	Total Funding Request	**$500,000**	**$0**	**$2,300,000**	**$30,000**	**$1,625,000**	**$355,000**	**$4,425,000**	**$385,000**

Ongoing Annual Operational Costs		Year 1		Year 2	
		CAPEX	OPEX	CAPEX	OPEX
Opus One	Annual license maintenance 20%		$0		$200,000
National Grid	Integration Services		$20,000		$20,000
	Hardware 10%		$2,500		$2,500
	Network and communications 10%		$7,500		$7,500
	Total Annual Operational Costs	**$0**	**$30,000**	**$0**	**$230,000**

Table 4.1 – Updated Budget

The incremental costs associated with the Project as of September 30, 2016 total $21,208. Continued monitoring and reporting of incremental costs will be included in subsequent quarterly reports.

5.0 Progress Metrics

Key Progress Metrics have not yet been determined, but will be developed at the end of Stage 1 based on the Check Points identified in pages 15 and 16 of the DSP Implementation Plan.

6.0 Appendices

Appendix A: Press Release (first page)

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A Wood Mackenzie Business

REGULATION & POLICY

National Grid and Opus One Launch a Distributed Service Platform Test for New York REV

Testing how microgrids and distributed energy can integrate with grid operations—and get paid for the service

by Jeff St. John
September 28, 2016

New York's first real-world test of its vision of a platform to connect customer-owned energy assets to a marketplace for grid services has launched in Buffalo, N.Y.

On Tuesday, utility National Grid announced (http://3blmedia.com/News/National-Grid-Announces-Selection-Opus-One-Solutions-Develop-First-Its-Kind-Distributed-System) it's working with startup Opus One Solutions to field-test a distributed system platform (DSP). That's the term created by the state's Reforming the Energy Vision (v) initiative for the combination of technologies and business models it seeks to create for utilities and distributed energy resources to work together in future years.

New York REV has already spawned a host of demonstration projects (http://www.greentechmedia.com/articles/read/New-York-Utilities-Announce-Projects-Aiming-to-Commercialize-the-Grid-Edge) featuring microgrids, community energy projects and third-party efficiency, demand response and virtual power plant rollouts. But this new project is the first to explicitly test a core idea of the state's energy regulatory overhaul -- how these distributed energy resources (DERs) can be compensated for the energy, capacity and resiliency they can provide in lieu of utility-owned assets.

Appendix B: Phase 1 Check Points

Check Point	Description
1A. NYISO LBMP and ICAP values can comprise the LMP portion of the DSP financial model.	**Measure:** Internal stakeholder feedback on the elements of the LMP value. **How and When:** Internal stakeholder discussions and meetings throughout Phase 1 of the Project. **Resources:** NYISO LBMP and ICAP values, DSP financial model inputs for LMP values. **Expected Target:** 100% internal stakeholder acceptance that the LMP component of the DSP financial model accurately reflects NYISO LBMP plus ICAP values. **Solutions / Strategies in case of results below expectations:** Revisit DSP financial model inputs, identify stakeholder concerns and potential solutions to incorporate revised values for the DSP LMP components.
1B. Quantifications of DER capabilities for voltage management, VAR support, peak load management, and dynamic load management can comprise the value of D portion of the DSP financial model.	**Measure:** Internal stakeholder feedback on the elements of the value of D. **How and When:** Internal stakeholder discussions and meetings throughout Phase 1 of the Project. **Resources:** National Grid planning, operations, finance, and rate departments; BNMC DER participant data; quantification of potential DER benefits to the distribution system (*e.g.,* voltage management, peak load management); DSP financial model inputs for the value of D. **Expected Target:** 100% internal stakeholder acceptance that the value of D component of the DSP financial model accurately reflects potential DER benefits to the distribution system. **Solutions / Strategies in case of results below expectations:** Revisit DSP financial model inputs, identify stakeholder concerns, and identify potential solutions to incorporate revised values for the value of D components.
2A. DER participants will accept the functionality of the DSP financial model for development of the DSP market.	**Measure:** Stakeholder feedback on the value of DER participation under the different test scenarios using historical data. **How and When:** Stakeholder interviews and meetings throughout Phase 1 of the Project. **Resources:** Historical data for demonstration feeder, substation, and DER participants; DSP financial model output. **Expected Target:** 100% stakeholder acceptance of the DSP financial model output based on historical data. **Solutions / Strategies in case of results below expectations:** Revisit DSP financial model outputs, identify stakeholder concerns and potential ways to make DER participation and investment more attractive.
2B. DER participants can effectively evaluate the price signal events that will be generated from the DSP financial model in field operation.	**Measure:** Feedback from stakeholders on the value of DER participation under real-time and forecasted price signal event information. **How and When:** Stakeholder interviews and meetings throughout Phase 1 of the Project. **Resources:** DSP financial model output, DER participant financial models and inputs (*e.g.*, internal rate of return ("IRR"), payback period). **Expected Target:** 100% stakeholder acceptance of the DSP financial model output based on real-time and forecasted data. **Solutions / Strategies in case of results below expectations:** Revisit DSP financial model outputs, identify stakeholder concerns and potential ways to make DER participation and investment more attractive.

Check Point (cont)	Description (cont)
2C. DER participants will be willing to participate on the DSP market and potentially invest in new DERs.	**Measure:** Feedback from stakeholders on expected financial returns. **How and When:** Final stakeholder go/no-go meeting at the end of Phase 1 of the Project to review financial returns from historical, real-time, and forecasted scenarios. **Resources:** DSP financial model output; DER participant financial models and inputs. **Expected Target:** A minimum of 5 MW of DER asset participation planned to take part in the DSP market in Phase 2 of the Project. **Solutions / Strategies in case of results below expectations:** Revisit DSP financial model inputs and outputs, identify stakeholder concerns and potential ways to make DER participation and investment more attractive.
2D. National Grid should be able to experience similar positive results as the DSP is rolled out across the Company's service territory.	**Measure:** Projected National Grid DSP revenue streams. **How and When:** Modeled results in Phase 1 of the Project and extrapolated results in Phase 2 of the Project. **Resources:** DSP financial model output, utility financial models and inputs, and Cost - Benefit Analysis Report. **Expected Target:** National Grid DSP revenue and ROI at least equivalent to existing revenue streams and returns. **Solutions / Strategies in case of results below expectations:** Revisit DSP financial model inputs and outputs; identify utility concerns and potential ways to make DER participation and investment more attractive.