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January 31, 2019

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)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID: DISTRIBUTED SYSTEM PLATFORM REV DEMONSTRATION PROJECT – Q4 2018 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 Plan covering the period of September 30, 2018 to December 31, 2018 ("Q4 2018 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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Enc.

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Distributed System Platform
REV Demonstration Project
Buffalo, New York

Q4 2018 Report

January 31, 2019

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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 a simple, small-scale DSP that will communicate with network-connected Points of Control ("POCs") associated with the Buffalo Niagara Medical Campus Inc. ("BNMC") DERs. Additionally, the project will evaluate and test the DSP in additional locations that may present different distribution-level constraints and DER types. The DSP is "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]

Image 1.1 – Part of the Buffalo Niagara Medical Campus

The Project team currently consists of National Grid, BNMC (*depicted in Image 1.1*), and Opus One Solutions ("Opus One"). Opus One provides contracted services to National Grid. Opus One is a software engineering company. Their role in the Project encompasses not only software development, but also thought leadership, planning, and execution.

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[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 consists 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; it 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 Kaleida Health (left) and the Roswell Park Cancer Institute (right), members of the BNMC

The Financial Model for DER Value Streams: LMP+D+E

In the near term, services transacted and purchased through the DSP will test the implementation of a "LMP+D+E" financial model approach for electric services. The value of "LMP+D+E" will be evaluated in the Project and is expected to generate sufficient financial incentives for existing DERs to participate in the DSP market. For LMP, the Project will consider New York Independent System Operator ("NYISO") locational-based marginal prices ("LBMP") for Day-Ahead ("DA") 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, *available at*: http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp.

assigned to each of these items. 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.

"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 value of E will most likely be attributable to those renewable generation, or current Net Energy Metered ("NEM") resources eligible to participate in the Value of DER Phase One NEM or Value Stack compensation as set out in the Commission's Value of DER ("VDER") Order[4] (*i.e.*, solar PV, farm waste, micro-CHP, fuel cell, and micro-hydro DG). While this component was initially omitted from the DSP Implementation Plan,[5] the Project Team has developed a first component in order to incentivize the use of renewable energy.

2.0 Highlights Since Previous Quarter

The project continued to have positive progress the last quarter of 2018. The team focused on developing and testing the features for the fourth DSP release, which went live in December. At the same time, National Grid continued to look for potential new customers and locations to test the DSP.

For a reference timeline emphasizing the major milestones and accomplishments, see Figure 2.1 below.

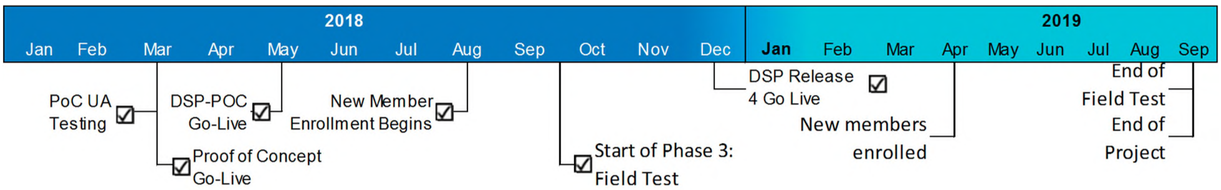

Figure 2.1 – Achievements and Milestones Timeline

2.1 Major Task Activities

1. DSP Sprint Releases

National Grid and Opus One maintained focus on the technology development of the DSP platform and POC features in this quarter, continuing to work with agile methodologies. The agile method is an approach to project management that is used in software development. This approach assists teams in responding to the unpredictability of constructing software. It uses incremental, iterative work sequences that are commonly known as sprints.

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[4] Case 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources* ("VDER Proceeding") *et al.*, *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* (issued March 9, 2017).
[5] REV Proceeding, National Grid: Distributed System Platform REV Demonstration Project-Implementation Plan (filed August 15, 2016) ("DSP Implementation Plan").

Opus One continued to develop and add features to the DSP platform, mainly focusing on improving the User Experience ("UX") in the customer portal and for the DSP operator, implementing a short-term weather-adjusted load forecast capability, and expanding the DSP's DER catalog.

2. DSP Release User Acceptance Testing ("UAT") & Go Live

After the features planned for the Release were developed and passed integration testing, the Project team held several workshops for UAT. During this effort, the team tested the performance of the DSP platform and Customer Portal through several test scenarios, confirming the new features and functionality.

The key features added to the platform in this release were:
- Improved UX for both the market participant and the DSP operator;
- Added user-enabled setting for DER availability;
- A revenue estimator for new DERs in all NYISO zones;
- Incorporated a short-term weather-adjusted load forecast;
- Improved management and coordination of multiple transactive energy markets;
- Added notifications and system alerts for the DSP operator and market participant; and
- General bug fixes.

After the UAT was completed, the production environment was updated in mid-December with the new functionality.

3. Enrollment of New DSP Participants

The Project team continued the effort to enroll new participants to the Project, focusing on customers that could provide the most interesting case studies based on existing distribution needs, and DER technology.

The team successfully enrolled a 2.2MW Combined Heat and Power ("CHP") DER in Utica and continues to work to integrate the DSP's Application Program Interfaces to the DER's newly deployed Pacific Northwest National Laboratory's ("PNNL") VOLTTRON protocol.

Additionally, the Project team continued to have conversations with potential customers and participants, DER aggregators, and energy storage developers.

2.2 Challenges, Changes, and Lessons Learned this Quarter

2018	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q4	After further analysis, it is unclear if the current functionality of OpenADR 2.0 aligns with the DSP needs for DER communication.	The team may need to choose another open standard for DSP and DER communication.	The Project team is currently evaluating all options for open standard DER protocols.	The lack of standardization between DER providers in communication protocols and automation capabilities is a barrier to expanding the Project.
Q4	There were some delays and issues developing features for Releases 3 and 4.	After reprioritizing, the Project team decided to combine Release 3 and 4 into one big release in December.	None.	None.

3.0 Next Quarter Forecast

The focus in Q1 of 2019 will be in expanding the DSP platform with more participants and locations. Starting with the DSP-VOLTTRON integration for the Utica CHP DER, the Project team will also continue to engage potential DSP participants, with the goal of enrolling them before the spring/summer season.

Meanwhile, while the main functionality of the DSP platform has been completed, the Project team will continue to improve and develop its features.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	SLA Sprint Development	1/1/19 – 5/31/19		● (green)
2	Enroll new DSP participants	7/1/18 – 10/25/18	7/1/18 –4/1/19	● (yellow)

Key

● On-Track

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

● Terminated/abandoned checkpoint

1. SLA Sprint Development

Status: [●]
Start Date: 1/1/19
End Date: 5/31/19

National Grid and Opus One will continue using an agile process, having continuous two (2) weeks sprint development cadence, adding additional features, functionalities and customization abilities to the DSP and Customer Portal.

The Project team will continue to work directly with Opus One's development team in multi-week sessions, looking at mockups and using quick prototyping to quickly gather customer and end-user feedback.

Some of the key features that will be developed during the Software License Agreement ("SLA") phase are:

- Evaluation and Integration of VOLTTRON and/or OpenADR 2.0 for DER control;
- Optimal Power Flow ("OPF") integrated with event generation; and
- Development of additional DSP & POC user roles.

As these and other features are completed, there will be several updates to the DSP and POC software.

2. Enrollment of New DSP Participants

Status: [●]
Start Date: 7/1/18
End Date: 4/1/19

The Project team will continue to address some of the gaps found after the initial conversations with potential new participants. Mainly, most of the development will be focused in allowing for a deeper integration with more automated and advanced controllers.

First, the team will focus on finalizing the integration with PNNL's VOLTTRON protocol and the DSP's APIs to enable the participation of the 2.2MW CHP DER in Utica.

At the same time, the Project team will target adding up to three (3) new participants, continuing conversations with potential customers and participants, DER aggregators, and energy storage developers. For a complete enrollment into the DSP, each new participant will require:

- CYME feeder models from National Grid's Advanced Data & Analytics group;
- PI historian tags and feeds for each feeder from National Grid's Energy Management Systems ("EMS") group; and
- Metering from National Grid's Distribution Critical Network Infrastructure ("CNI") group.

Subsequently, the information will be imported and integrated into the DSP, and each participant will be provided their POC log-in information.

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.

Task Name	Start	Finish
Phase 0	**Mon 8/15/16**	**Mon 8/29/16**
Project Kickoff	Thu 9/8/16	Thu 9/8/16
Phase 1 - Financial Model	**Thu 9/8/16**	**Wed 3/29/17**
Phase 2 - Technology Development	**Mon 4/17/17**	**Wed 11/28/18**
Phase 2 Kickoff	Mon 4/17/17	Mon 4/17/17
DSP & POC	**Tue 4/18/17**	**Wed 11/28/18**
Requirements definition	**Tue 4/18/17**	**Mon 8/7/17**
Solution Design	**Tue 8/8/17**	**Mon 10/16/17**
Solution Development	**Tue 10/10/17**	**Wed 11/28/18**
Software Development	Tue 10/10/17	Mon 6/4/18
PoC UAT	Wed 3/21/18	Tue 3/27/18
PoC Go Live	Wed 3/28/18	Fri 3/30/18
DSP-POC UAT	Thu 5/17/18	Wed 5/30/18
DSP-POC Go Live	Thu 5/31/18	Fri 6/1/18
Go/No Go Decision	Mon 6/4/18	Tue 6/5/18
Release 3 Go Live	Mon 6/4/18	Wed 11/28/18
Release 4 Go Live	Mon 7/30/18	Wed 11/28/18
Phase 3 - Field demonstration	**Wed 3/21/18**	**Fri 10/25/19**
Phase 3 Kickoff	Fri 3/30/18	Fri 3/30/18
M&V Equipment Installation	Sun 4/1/18	Tue 8/21/18
Evaluate New Customer Enrollment	Wed 3/21/18	Thu 6/28/18
Enroll New Customers	Fri 6/29/18	Mon 4/1/19
DSP, POC and Market Monitoring and Measurement	**Mon 4/2/18**	**Fri 10/25/19**
Evaluate new revenue streams	Mon 4/2/18	Fri 5/24/19
Scenario and Sensitivity Testing and Analysis	Mon 4/2/18	Fri 5/24/19
Continuous Improvement and Updates	Mon 4/2/18	Fri 9/27/19
Project Clousure (Reporting, etc)	Mon 9/30/19	Fri 10/25/19

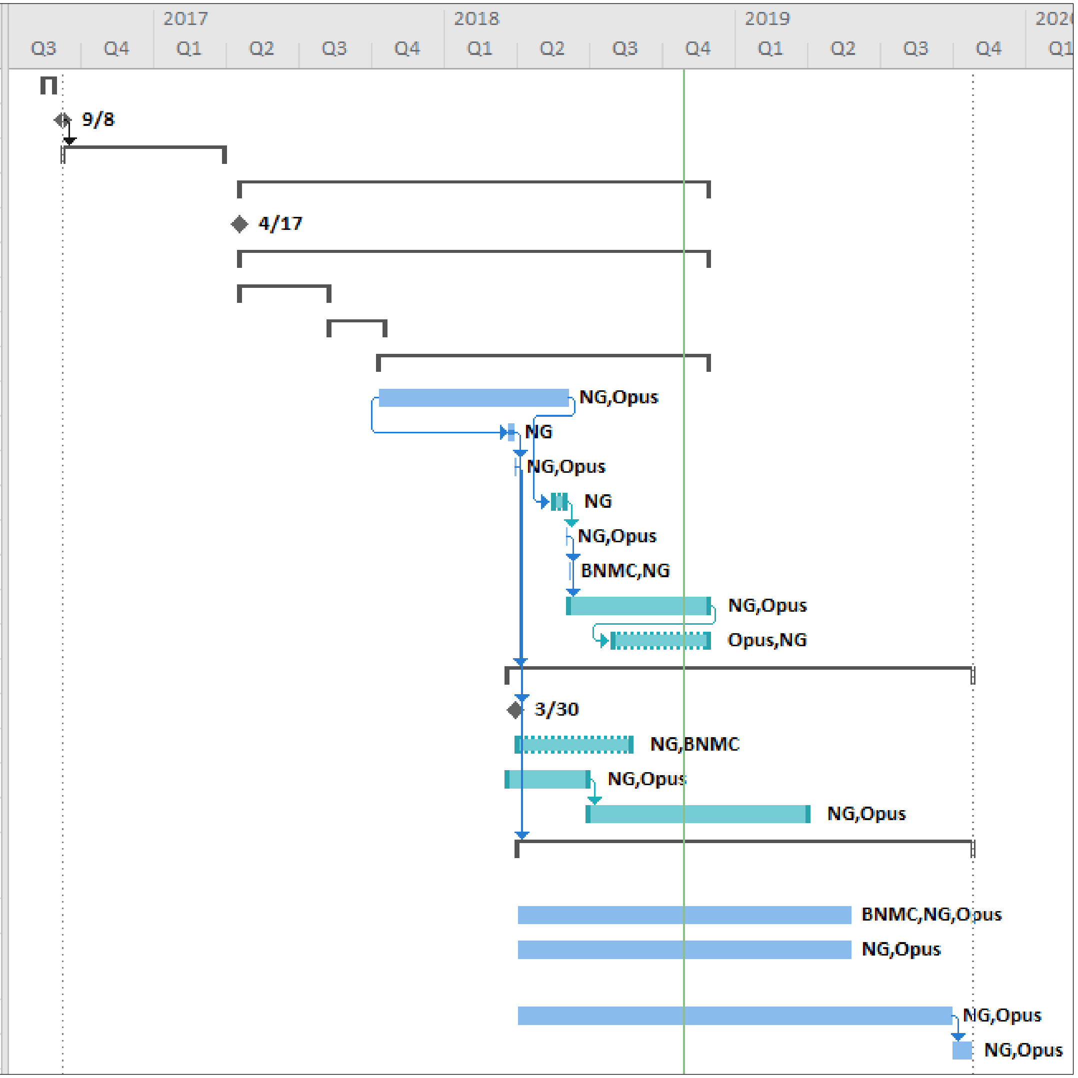

Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

4.2 Updated Budget

There are updates to the estimated budget set forth in the filed DSP Implementation Plan. The updated budget information is displayed in the table below.

Project Task	4th Quarter Actual Spend	Project Total Spend to Date	Project Budget[6]	Remaining Balance
CapEx				
	$ -	$ -	$ -	$ -
OpEx				
NG Resources	$ 7,383	$ 847,223	$ 915,000	$ 67,777
IT Integration Services	$ 21,186	$ 567,405	$ 586,000	$ 18,595
Program Management	$ 185,843	$ 1,512,925	$ 2,000,000	$ 487,075
Software License	$ 350,000	$ 850,000	$ 1,000,000	$ 150,000
Software Development ($2M in kind)	$ -	$ -	$ -	$ -
DER Payments	$ -	$ -	$ 859,000	$ 859,000
Annual License Maintenance (est.)	$ -	$ -	$ 150,000	$ 150,000
Total	**$ 564,412**	**$ 3,777,553**	**$ 5,510,000**	**$ 1,732,447**

Table 4.1 – Updated Budget

The incremental costs associated with the Project as of December 31, 2018 total $1,347,030.31 Continued monitoring and reporting of incremental costs will be included in subsequent quarterly reports.

5.0 Tracking Metrics

The Project team continues to monitor prices at the BNMC location (NYISO Zone A West) for both Day Ahead ("DA") and Same Day ("SD") events and monitor any peak events that may have occurred at the bulk or feeder level.

Table 5.1 presents the average and maximum DSP prices for DA and SD from April to December in $/MWh. Additionally, it estimates the number of events and revenue opportunity for a 1MW DER that has an estimated $100/MWh cost to operate[7]

[6] The Company updated the Project budget to reflect incremental costs, and to account for costs that may have originally been characterized as capital or operating expenses, but now, because of changed circumstances (*e.g.*, licensing instead of owning software), should be categorized differently.
[7] The analysis assumes that a DER would accept an event any time when the DSP price is above the cost to operate.

Month	Event Type	Average DSP Price	Max DSP Price	Events Above $100/MWh	Revenue Potential (est)
April	DA	$29.76	$68.88	0	$-
	SD	$26.19	$189.33	14	$1,920
May	DA	$30.00	$210.55	29	$3,917
	SD	$37.82	$2,515.38	33	$15,326
June	DA	$31.90	$196.04	16	$2,199
	SD	$32.77	$2,959.36	20	$7,418
July	DA	$42.69	$519.89	26	$6,770
	SD	$38.34	$488.04	34	$7,328
August	DA	$61.59	$567.62	42	$21,446
	SD	$58.52	$593.98	51	$21,853
September	DA	$38.75	$574.28	10	$5,029
	SD	$37.46	$824.48	26	$7,654
October	DA	$31.43	$63.58	0	$-
	SD	$28.68	$208.09	14	$2,291
November	DA	$31.43	$63.58	0	$-
	SD	$44.76	$4,369.55	15	$10,623
December	DA	$34.32	$127.27	2	$241
	SD	$34.32	$469.37	22	$3,666

Table 5.1 – DSP Price Comparison for Q2, Q3 and Q4 2018

As expected, the average prices for both DA and SD events declined during the last quarter, by 32% and 20% (respectively) from Q3 to Q4 of 2018 (See Figure 5.1). More importantly, during the last quarter of 2018 there were only two (2) Day Ahead events with prices above $100/kWh, compared to seventy-eight (78)the previous quarter, indicating that the BNMC would need to focus mainly on the SD events to capture the benefits of the DSP during the colder months of the year.

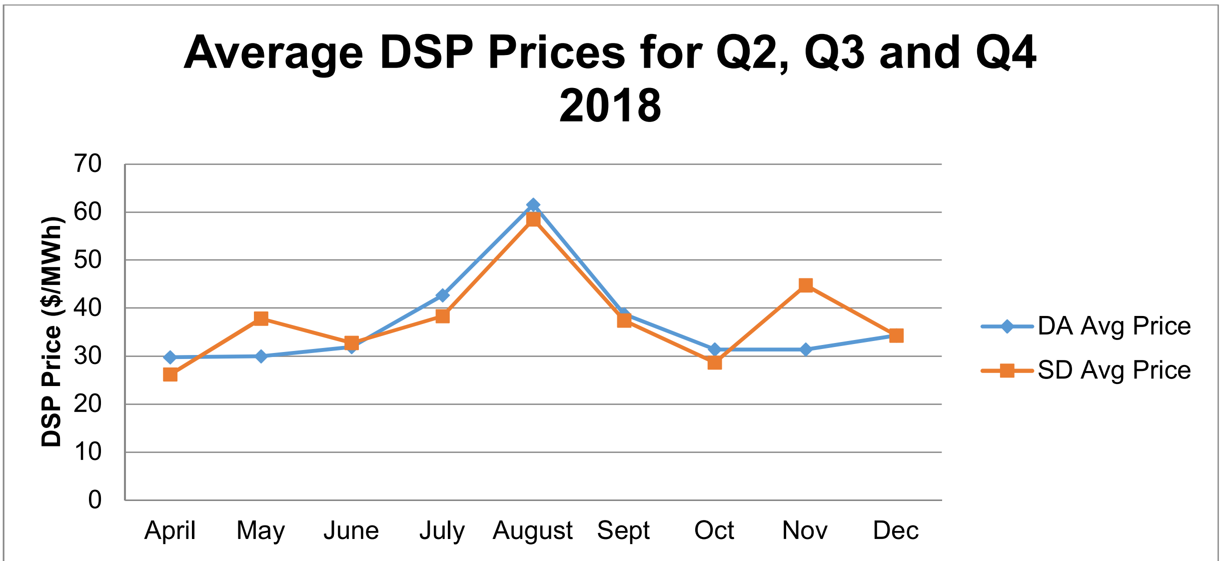

Figure 5.1 – Average DA and SD DSP Prices for Q2 and Q3 of 2018

As expected, there were no B1 events during the last quarter of the year. B1 prices are triggered whenever the forecasted NYISO load is above 85% of the forecasted peak. The main goal is to incentivize DER generation to lower National Grid's load in those peak hours, therefore reducing the Company's 2019 ICAP requirement.

The graphs in Figure 5.2 display the price variation trend for DA and SD events in Q4 of 2018.

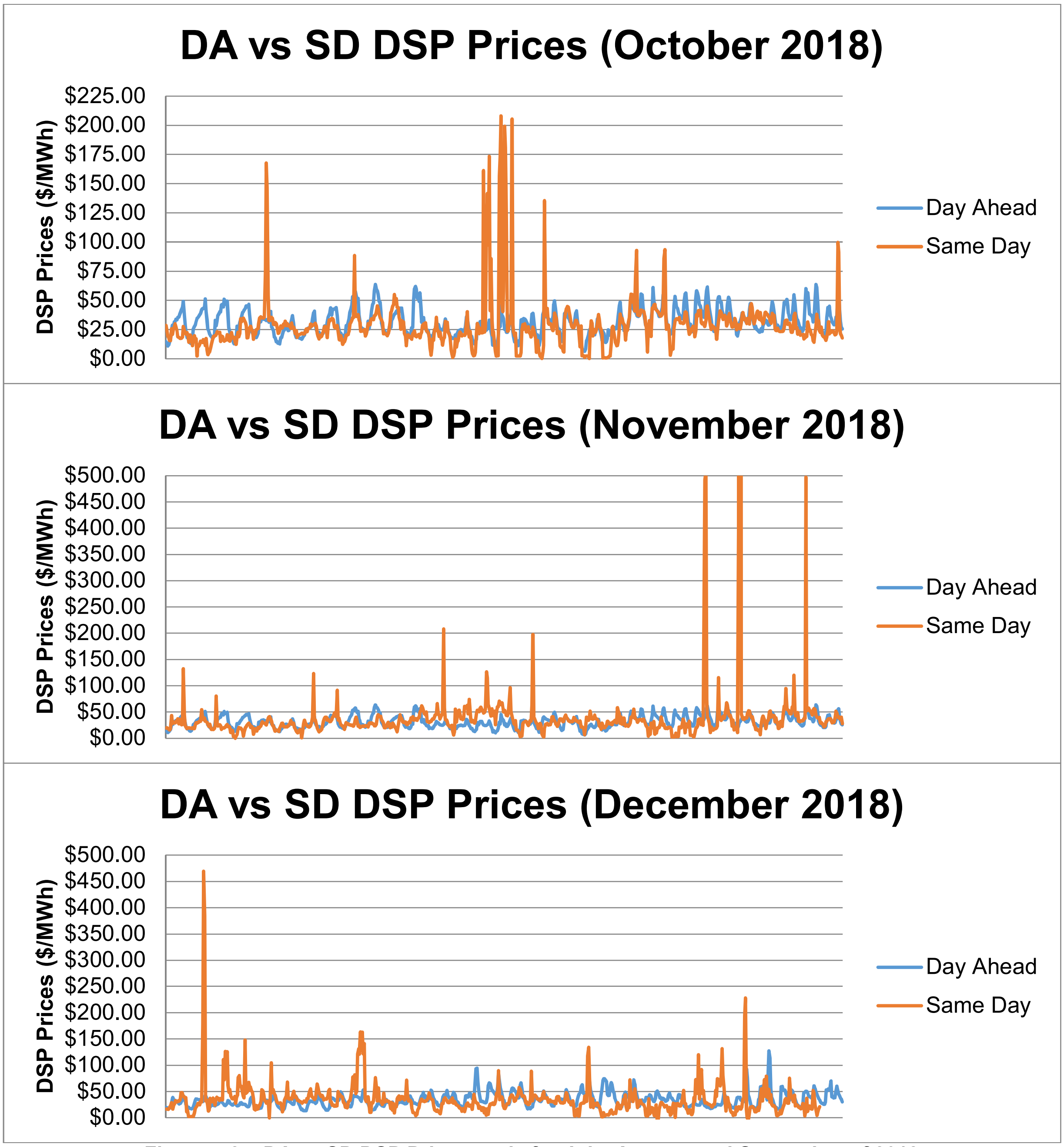

Figure 5.2 – DA vs SD DSP Price trends for July, August, and September of 2018

The Project team will continue to gather and monitor several data points on the DSP (*see Table 5.3*), to measure and evaluate a set Key Performance Indicators ("KPI") that will serve to inform all stakeholders on the potential and feasibility for Distributed System Platforms.

Focus Area	Objectives and KPIs
LMP+D Prices	• Monitor LMP+D prices (avg, max) for both DA and SD markets. • Monitor values for each component of LMP+D price signal (avg, max) for both DA and SD markets.
Event Tracking	• Track the market participant's responses towards events (number of events generated, accepted, rejected, etc.) for both DA and SD markets.
DER Participation	• Total amount of capacity (in MW) enrolled in the DSP. • Number of customers enrolled.
DSP-POC Communication	• Measurement of roundtrip communications for price signals and responses. • Average participant's event response time.
DSP Operations	• Monitor DSP operations (total hours of DER operation, total MW delivered vs MW committed, Number of peak events generated vs accepted vs delivered).
DER Operations	• Monitor and track the participation and effectiveness of different types of DER technology to respond to DSP events.

Table 5.4 – Key Project Metrics