Karla M. Corpus
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July 31, 2018

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 – Q2 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 April 1, 2018 to June 30, 2018 ("Q2 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

Karla M. Corpus
Senior Counsel

Enc.

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Distributed System Platform
REV Demonstration Project
Buffalo, New York

Q2 2018 Report

July 31, 2018

nationalgrid

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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 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. 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 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]

Image 1.1 – Part of the Buffalo Niagara Medical Campus

The Project team consists of National Grid, BNMC (*depicted in Image 1.1*), 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

[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

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.

The BNMC, 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.

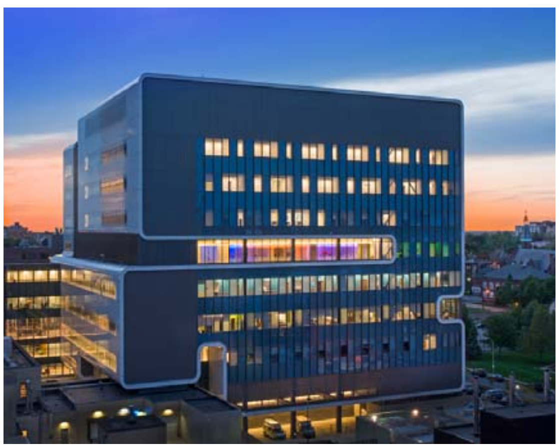


Image 1.2 – Images of Kaleida Health (left) and the Roswell Park Cancer Institute (right), members of the BNMC

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" 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") Zone-A West 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

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

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 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.

"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

National Grid and the Project team continued to make progress in the second quarter of 2018, which led to the DSP second release Go Live. At the same time, National Grid worked closely with the BNMC in the design for the installation of the Measurement and Verification ("M&V") equipment. Additionally, the Project team collaborated with National Grid's Distribution Planning and Asset Management ("DPAM") team in order to identify potential new locations and participants to continue the DSP field test.

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

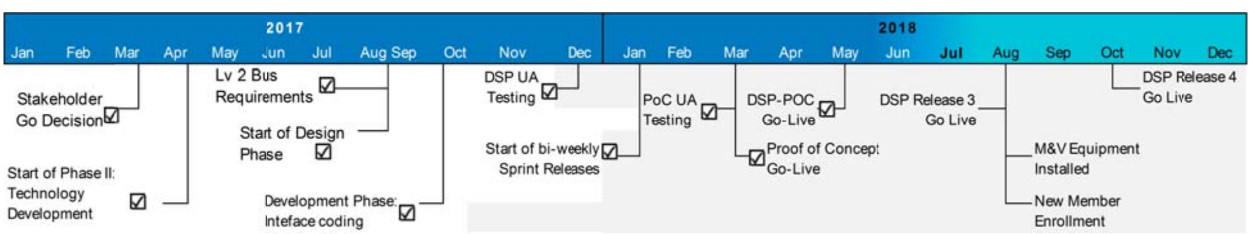

Figure 2.1 – Achievements and Milestones Timeline

[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").

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 Project team performed seven (7) sprints, each with two (2) week duration. This effort resulted in the development of over thirty-five (35) product features. The first four (4) sprints were used to develop the key features of the POC (*e.g.,* the customer portal). The subsequent sprints were focused on the functionality necessary to test the DSP in different geographical locations.

2. DSP End-to-End Testing

After the first four (4) sprints were completed, the Project team performed User Acceptance Testing ("UAT") for the second release of the DSP.

Based on the Testing Scenarios used in the testing of Release 1, the Project team expanded the tests to include the features of the POC. This release of the software met the requirements for the DSP – POC key functionalities, and was given the stakeholder approval for Go-Live.

The main features developed in this release were:

- The Customer Portal User Interface ("UI"), key features and integrations with the DSP;
- DSP automatic settlement calculations using meter data;
- Improvements in DSP reporting; and
- Complete redesign and improvement of the DSP UI.

Two (2) additional releases, each with additional functionality to the platform, are planned for Q3 and Q4 2018.

3. DSP-POC Go Live

On May 29th the second release of the DSP was successfully migrated to the production environment hosted in Amazon Web Services ("AWS"). The major feature of this release is the Customer Portal. The newly released POC provides access and management of events for DSP participants. For reference, Figure 2.3 displays four (4) screenshots of the current version of the DSP and POC,

The key functionalities of the POC are:

- Ability to view/accept/reject both Day-Ahead ("DA") and Same-Day ("SD") events;
- Ability to counter the amount of energy requested in an event, and rearrange the total energy requested among several assets; and
- Ability to enroll and change user/asset information.

The release also added some improvements on the DSP UI and functionality, mainly:

- Ability to use interval meter data to perform automatic settlement calculations;
- Complete redesign, improvement and branding of the DSP UI;
- Ability to check PI, weather and NYISO feeds statuses; and
- Improved reporting capability.

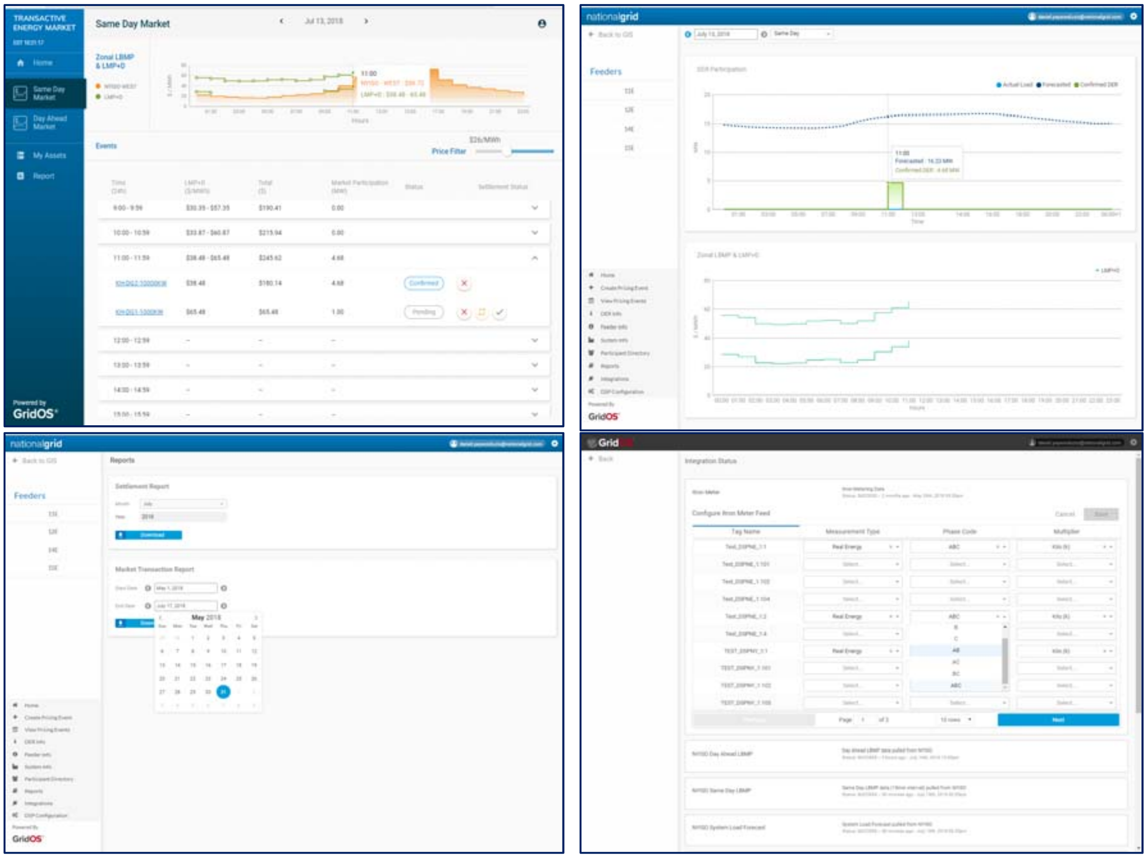

Figure 2.2 – POC and DSP User Interface Screenshots

4. Customer M&V Equipment Design

The Project team worked with Kaleida Health and its contractors, in conjunction with National Grid's Control and Integration ("C&I") and Meter Engineering teams, to design a solution to install AMI meters to perform the Measurement & Verification ("M&V") functionalities for the DSP settlement.

The design resulted in four (4) meters, each assigned to one of the 2MW participating assets. Due to the unusual high voltage, additional safety devices are also required in the facility to install a shared set of 20:1 Potential Transformers ("PT") in order to step down the 4.16kV of voltage to the meters.

The unplanned requirement has also delayed the completion of the meter installation to Q3. To reduce the impact on field operations, the Project team is looking for potential alternatives to perform M&V and settlement while the cabinet and meters are in the process of being installed.

5. Analysis for New DSP Test Locations

The Project team worked closely with National Grid's DPAM group, which oversees all of the Company's Non-Wires Alternatives ("NWA") and DER interconnection initiatives, in order to find potential locations that could present a distribution level constrain, and therefore additional value for DSP participants.

The key criteria selected to classify the potential new areas are:

- Areas that present distribution level constraints;
- Existing or potential NWA areas with capacity constraints at the feeder or substation level (*e.g.*, feeder loading levels above seventy percent (70%) of capacity);
- Areas that are part of the Commercial System Relief Program ("CSRP"), and/or have Locational System Relief Value ("LSRV")[6];
- Areas with potential for microgrids; and
- Areas that have an existing and installed mix of dispatchable and renewable DERs with a maximum capacity of 5MW.

The analysis resulted in a shortlist with nine (9) top locations, constraints and existing DER assets (See Table 2.1).

Substation	Region	Number of DER Assets	Total DER Assets (kW)	Total DER Pending (kW)
OAKFIELD	Batavia	18	770	-
BURGOYNE 337	Glens Falls	194	2,279	19,292
DEBALSO 684	Utica	24	4,371	325
FRONT ST 360	Schenectady	113	4,741	345
LAWRENCE AVE 976	Potsdam	155	9,705	6
NILES 294	Syracuse	21	409	5,006
ONEIDA 501	Oneida	94	5,818	5,043
SHELBY 76	Albion	34	1,033	51
W. ADAMS 875	Watertown	57	907	3,391

Table 2.1 – Top DSP Test Locations and DER Information

Using this analysis as a baseline, the Project team proceeded to prioritize the potential participants given the type of asset, location, interconnection status and current Power Purchase Agreement ("PPA"). Subsequently, the Project team began approaching the highest ranked potential participants (See Figure 2.4 for DSP New Participant Guide and FAQs). Priority will be given to new DER types in these locations, particularly emerging technologies. The Company hopes to learn about the characteristics and operational protocols of different asset technologies and their suitability for automated participation in future using potential POC features of the DSP.

[6] See, *Case 15-E-0751*, *In the Matter of the Value of Distributed Energy Resources*, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

Figure 2.3 – DSP New Participant Guide and FAQs.

2.2 Challenges, Changes, and Lessons Learned this Quarter

2018	Issue or Change	Resulting Change to Project Scope/Timeline	Strategies to Resolve	Lessons Learned
Q2	The unusually high nameplate voltage on the BNMC's DERs, coupled with space limitations at the facility, have required additional safety hardware, effort and time to install M&V equipment.	M&V Equipment Installation will be completed in Q3 of 2018.	To minimize the impact on the field test phase, the Project team will work closely with the BNMC and use their generator logs or building management system's outputs for M&V while the necessary equipment for the meters is being installed.	An efficient plan for a DSP expansion would require standardization guidelines specific for DERs depending on size, type and nameplate ratings.
Q2	The Project team and Opus One will continue the use of agile methodology for the rest of the Project, conducting several additional releases.	During the field demonstration phase, the DSP will continue to add functionality and use customer feedback for continuous improvement.	None.	Using agile and Design Thinking[7] methodologies can improve customer experience.

[7] Design thinking is a human-centered approach to innovation that uses customer insights and rapid prototyping to design and develop products and solutions. *See* https://www.ideou.com/pages/design-thinking

3.0 Next Quarter Forecast

During the 3rd Quarter of 2018 the Project team will continue to work on the technology development of the DSP software. The effort will result in a third release at the end of July, adding advanced features to the current platform.

At the same time, the Field Demonstration phase will officially start with the BNMC. The Project team will train Kaleida Health in the use of the Customer Portal, with the first events to occur in July.

Finally, the Project team will continue the selection, engagement and enrollment of new DSP participants into the platform, targeting to have new member participation commence by the end of Q3.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	DSP Sprint Releases	10/27/17 – 4/9/18	1/10/18 – 10/31/18	● (green)
2	DSP Release 3 UAT & Go Live	N/A	7/31/18 – 8/3/18	● (green)
3	Phase 3 – Field Demonstration	1/10/18 – 9/30/19	7/1/18 – 9/30/19	● (yellow)
4	Customer M&V Equipment Installation	1/10/18 – 6/1/18	1/10/18 –8/15/18	● (yellow)
5	Enroll new DSP participants	N/A	7/1/18 – 10/25/18	● (green)

Key

- ● (green) On-Track
- ● (yellow) Delayed start, at risk of missing on-time completion, or over-budget
- ● (red) Terminated/abandoned checkpoint

1. DSP Sprint Releases

Status: [●]
Start Date: 1/10/17
End Date: 10/31/18

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.

2. DSP Release 3 UAT & Go Live
Status: [●]
Start Date: 7/31/18
End Date: 8/3/18

The last three (3) sprints of Q2, and the first two (2) sprints of Q3 will focus improving the DSP-POC functionalities, and more importantly, adding the ability for the DSP to work with participants in different geographical areas in National Grid's electric service territory. After these features are developed, the Project team will perform an in depth review of all features and functionalities to ensure accurate and safe DSP operations.

After UAT is complete, and with National Grid approval, Opus One will have the green light to proceed with the push to the production environment of the Release 3 software.

3. Phase 3 – Field Demonstration
Status: [●]
Start Date: 7/1/18
End Date: 9/30/19

Starting in July, the BNMC will start active participation in the DSP platform. The Project Team will provide two (2) training sessions on the Customer Portal for Kaleida Health, and assist in the initial configuration and settings of the platform.

Kaleida Health will be able to receive, manage and counter both DA and SD events. The DSP will track the utilization of the platform, and response to different types and times of events to develop key performance indicators ("KPIs") that will help to evaluate the solution.

At the same time, the Project team will work closely with the BNMC to identify any problems or pain points using the platform. This effort will create a continuous feedback loop that can be used to tweak and improve the platform, as well as informing future releases.

4. Customer M&V Equipment Installation
Status: [●]
Start Date: 1/10/18
End Date: 8/15/18

National Grid's Control and Integration ("C&I"), Meter Data Services and Meter Data Engineering teams will continue to work closely with the BNMC to install the M&V equipment for the DSP. These teams will install a set of four (4) advanced revenue grade meter using a Verizon Wireless Network to gather data at fifteen (15) minute intervals, which will then be sent daily to the DSP via the Itron cloud.

Additionally, the teams will install a set of PTs in a dedicated cabinet that will step down the voltage from 4.16kV to the meters.

5. Enrollment of New DSP Participants
Status: [●]
Start Date: 7/1/18
End Date: 10/25/18

With the shortlist of potential assets and locations developed in Q2, the Project team will now move to engage and potentially enroll new participants to the DSP.

Initially, the Project team will target two (2) to five (5) potential new participants that were given the highest priority ranking during the analysis phase. For a complete enrollment into the DSP, for each new participant will require:

- CYME feeder models from National Grid's Advanced Data & Analytics group;
- PI historians tags and feeds for each feeder from National Grid's Energy Management Systems ("EMS") group; and
- Metering from National Grid's Distribution C&I 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.

ID	Tas Mo	Task Name	Start
1		**Phase 0**	**Mon 8/15/1**
4		Project Kickoff	Thu 9/8/16
5		**Phase 1 - Financial Model**	**Thu 9/8/16**
18		**Phase 2 - Technology Development**	**Mon 4/17/1**
19		Phase 2 Kickoff	Mon 4/17/1
20		**DSP & POC**	**Tue 4/18/17**
21		**Requirements definition**	**Tue 4/18/17**
24		**Solution Design**	**Tue 8/8/17**
29		**Solution Development**	**Tue 10/10/1**
30		Software Development	Tue 10/10/1
31		PoC UAT	Wed 3/21/1
32		PoC Go Live	Wed 3/28/1
33		DSP-POC UAT	Thu 5/17/18
34		DSP-POC Go Live	Thu 5/31/18
35		Go/No Go Decision	Mon 6/4/18
36		Release 3 Go Live	Mon 6/4/18
37		Release 4 Go Live	Mon 7/30/1
38		**Phase 3 - Field demonstration**	**Wed 3/21/1**
39		Phase 3 Kickoff	Fri 3/30/18
40		M&V Equipment Installation	Sun 4/1/18
41		Evaluate New Customer Enrollment	Wed 3/21/1
42		Enroll New Customers	Fri 6/29/18
43		**DSP, POC and Market Monitoring and Measurement**	**Mon 4/2/18**
44		Evaluate new revenue streams	Mon 4/2/18
45		Scenario and Sensitivity Testing and Analysis	Mon 4/2/18
46		Continuous Improvement and Upda	Mon 4/2/18
47		Project Clousure (Reporting, etc)	Mon 9/30/1

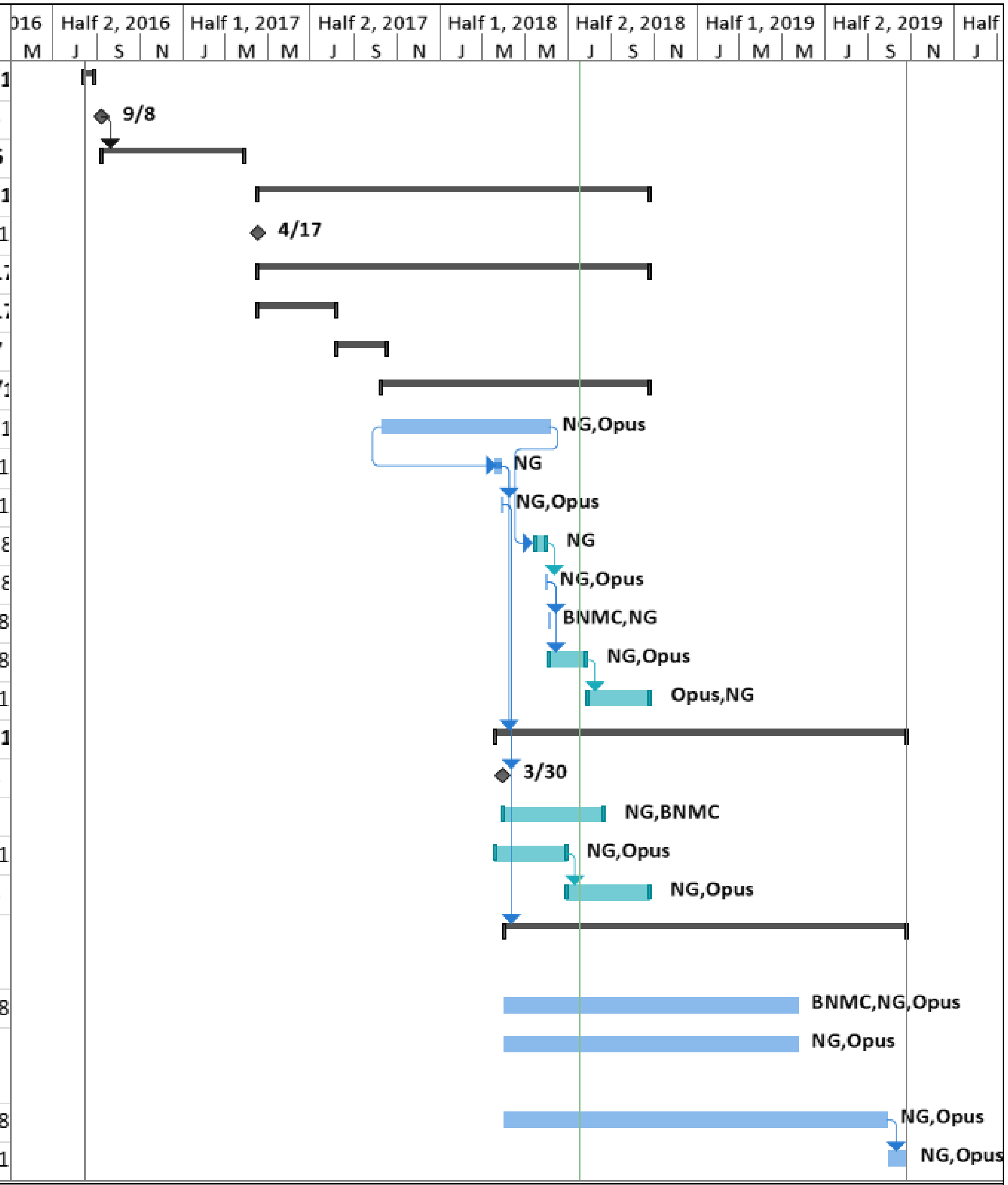

Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

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	2nd Quarter Actual Spend	Project Total Spend to Date	Project Budget[8]	Remaining Balance
CapEx				
	$ -	$ -	$ -	$ -
OpEx				
NG Resources	$ 39,725	$ 814,348	$ 1,350,000	$ 535,652
IT Integration Services	$ (98,151)	$ 414,310	$ 700,000	$ 285,690
Program Management	$ 25,392	$ 1,109,907	$ 2,000,000	$ 890,093
Software License	$ 500,000	$ 500,000	$ 1,000,000	$ 500,000
Software Development ($2M in kind)	$ -	$ -	$ -	$ -
Annual License Maintenance (est)	$ -	$ -	$ 150,000	$ 150,000
Total	**$ 466,966**	**$ 2,838,565**	**$ 5,200,000**	**$ 2,361,435**

Table 4.1 – Updated Budget

The incremental costs associated with the Project as of June 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

With the Go Live of the Release 1 in Q1, the Project team created two Virtual DERs at the BNMC location in order to start tracking prices for Day Ahead and Same Day events, and monitoring if any peak events have occurred at the bulk or feeder level. The graphs in Figure 5.1 display the price variation trend for both types of events.

Table 5.1 presents the average and maximum DSP prices for DA and SD in the months of April, May and June 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[9]

[8] 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.

[9] The analysis assumes that a DER would accept an event any time when the DSP price is above the cost to operate.

	April		May		June	
	DA	SD	DA	SD	DA	SD
Average DSP Price	$ 29.76	$ 26.19	$ 30.00	$ 37.82	$ 31.90	$ 32.77
Max DSP Price	$ 68.88	$ 189.33	$ 210.55	$ 2,515.38	$ 196.04	$ 2,959.36
Events Above $100/MWh	-	14	29	33	16	20
Revenue Potential (est)	$ -	$ 1,920	$ 3,917	$ 15,326	$ 2,199	$ 7,418

Table 5.1 – DSP Price Comparison for Q2 2018

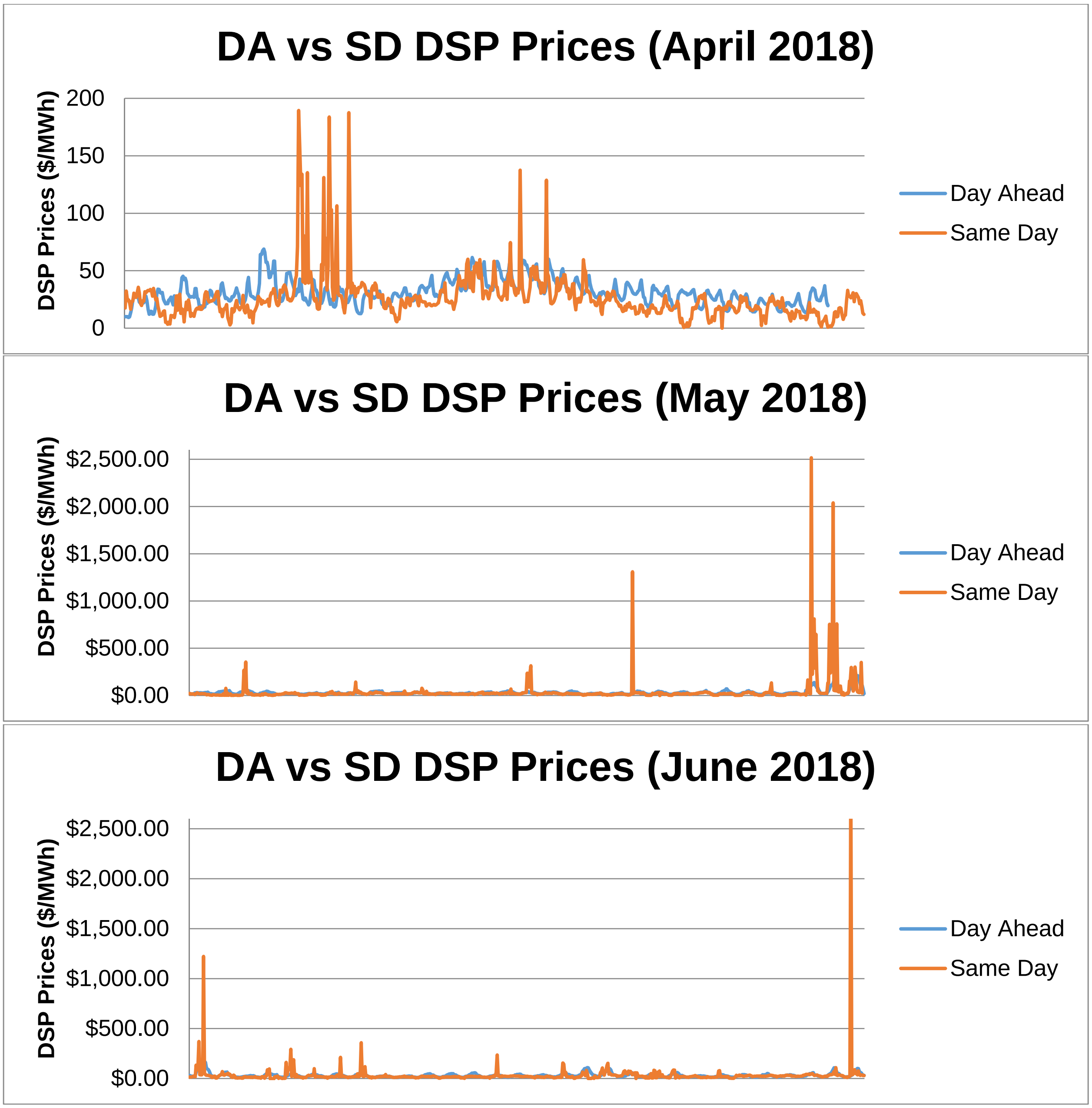

Figure 5.1 – DA vs SD DSP Price trends for May, June and July of 2018

The Project team will continue to gather and monitor several data points on the DSP (*see Table 5.2*), 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 (min, avg, max) for both DA and SD markets. • Monitor values for each component of LMP+D price signal (min, 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 5.2 – Key Project Metrics