nationalgrid

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May 1, 2017

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 – Q1 2017 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 January 1, 2017 to March 31, 2017 ("Q1 2017 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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Distributed System Platform

REV Demonstration Project

Buffalo, New York

Q1 2017 Report

May 1, 2017

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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. 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 Kaleida Health (left) and the Roswell Park Cancer Institute (right), members of the BNMC

The Model: LMP+D

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 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 assigned to each of these items. Energy supply, volt-ampere reactive ("VAR") support, voltage

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

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 value of E will most likely be attributable for renewable generation, or current Net Energy Metered (“NEM”) resources as defined in the “Value of D”[4] order (i.e., solar PV, farm fuel, micro-CHP, fuel cell, and micro-hydro DG). While this component was initially left out of scope in 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 key partners in the Project have made substantial progress in the first quarter of 2017, completing Phase I (*i.e.,* Financial Model Development) and planning for the next Phase of the Project. The National Grid Project Team worked closely with Opus One and the BNMC to finalize the Financial Model, refining the different elements that are used to calculate the value of D (*i.e.,* locational value of generation on the distribution system). Initial results were obtained by running the model using the specific feeder information of the BNMC area, historical data, and comparing the results using the Day Ahead and Real Time Clearing Prices for 2012 - 2016 obtained from the NYISO, for Zone A West.

All Project team members have agreed on the Financial Model methodology and results, with all parties continuing to push to deliver the expected outcomes laid out in the Project Implementation Plan. For a reference timeline emphasizing the major milestones and accomplishments, see Figure 2.1 below. Changes and additions are highlighted in yellow and are further described in Section 2.2.

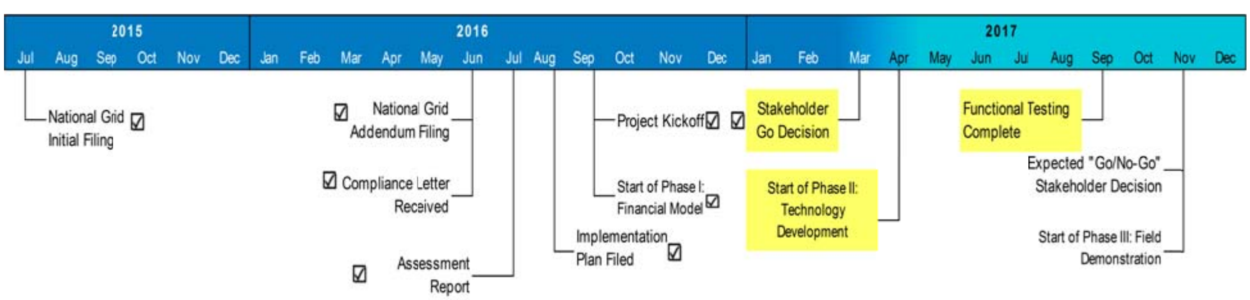

Figure 2.1 – Achievements and Milestones Timeline

[4] Case 15-E-0751 and Case 15-E-0082, *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* (issued March 9. 2017)(“Value of D Order”).
[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. **Financial Model Completion**
The major activity for Q1 of 2017 was refining and finalizing the DSP Financial Model, resulting in a significant evolution and refinement of the methodology. Equations for calculating “LMP+D” as a DSP price signal were developed using National Grid’s BCA Framework as a guideline. The resulting methodology that was developed can be illustrated as:

$$LMP + D = B_1 + B_2 + D_1 + D_2 + D_3 + E_1$$

In particular, the individual values are as follows:

- “B”= Bulk system benefits, with:
    - B1: Avoided Generation Capacity (ICAP); and
    - B2: Avoided Energy (LBMP).
- “D”= Distribution system benefits, with:
    - D1: Avoided Distribution Capacity Infrastructure Costs;
    - D2: Avoided Distribution Operation and Maintenance (“O&M”) Costs; and
    - D3: Avoided Distribution Losses.
- “E”= External and environmental benefits, with:
    - E1: Net Avoided CO_2.

The specific objective for each of the aforementioned elements is set forth below:

- B1 (Avoided Generation Capacity), was constructed to encourage DER owners to reduce National Grid’s load during the NYISO peak loading hours, decreasing the Company’s ICAP requirements for the following year.

- B2 (Avoided Energy), was developed to pass on NYISO Day Ahead or Real Time market LBMP signals to DER owners, accounting for the avoided loss between the bulk system and the retail delivery point.

- D1(Avoided Distribution Capacity Infrastructure Costs), was constructed to encourage DER owners to reduce load on specific feeders during the feeder or substation peak hours, so that National Grid may defer traditional distribution capital expenditures (*e.g.,* poles and wires).

- D2 (Avoided Distribution O&M Costs), was developed to track any increase or decrease in O&M expenses due to DER operation, which would then be used to either compensate or charge DER owners for such changes.

- D3 (Avoided Distribution Losses), was developed to track any increase or decrease in distribution losses due to DER operation, which would then be used to either compensate or charge DER owners for such changes.

- E1(Net Avoided CO2), was developed to pass on prices reflecting the value of Renewable Energy Credits (“REC”) or the Social Cost of Carbon (“SCC”) to owners of renewable DG assets (*e.g.,* Solar PV).

While the external or environmental components were originally left out of scope in the DSP Implementation Plan, the Project Team followed the "Value of D"[6] order released by Staff on March 9 to provide an additional value for all renewable DG assets.

For illustrative purposes, in Figure 2.2 the light blue area represents the NYISO Load (in MW) for every hour of the year in 2016, the red lines represent the magnitude of the B2 price signal based on the NYISO Zone A West Real Time LBMP, and the dark blue lines represent the magnitude of the B1 price signal based on National Grid's Avoided Generation Capacity Cost ("AGCC") at the bulk system level. The graph shows how B1 would only be offered during selected NYISO Load peak hours in order to reduce National Grid's ICAP requirements for the following year by utilizing local DER assets to reduce the load.

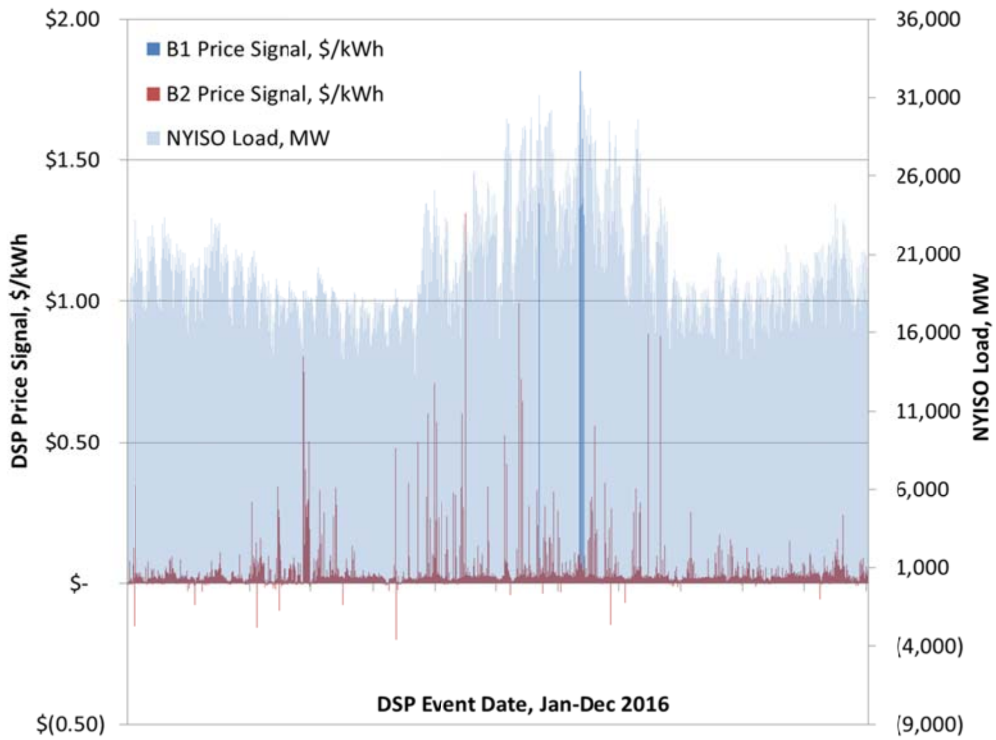

Figure 2.2 – B1 & B2 vs. NYISO Load – 2016 RT Market

Similarly, in Figure 2.3 the light gray area represents a feeder load in a highly congested area (not the BNMC area) for every hour of a particular week in 2016, and the green lines represent the magnitude of the D1 price signal based on National Grid's Marginal Distribution Cost ("MDC") at the distribution system level. The graph effectively shows how the D1 price signal would only be offered during the selected feeder peak hours, which may or may not coincide with the B1 and the bulk system peak hours.

[6] Value of D Order, supra.

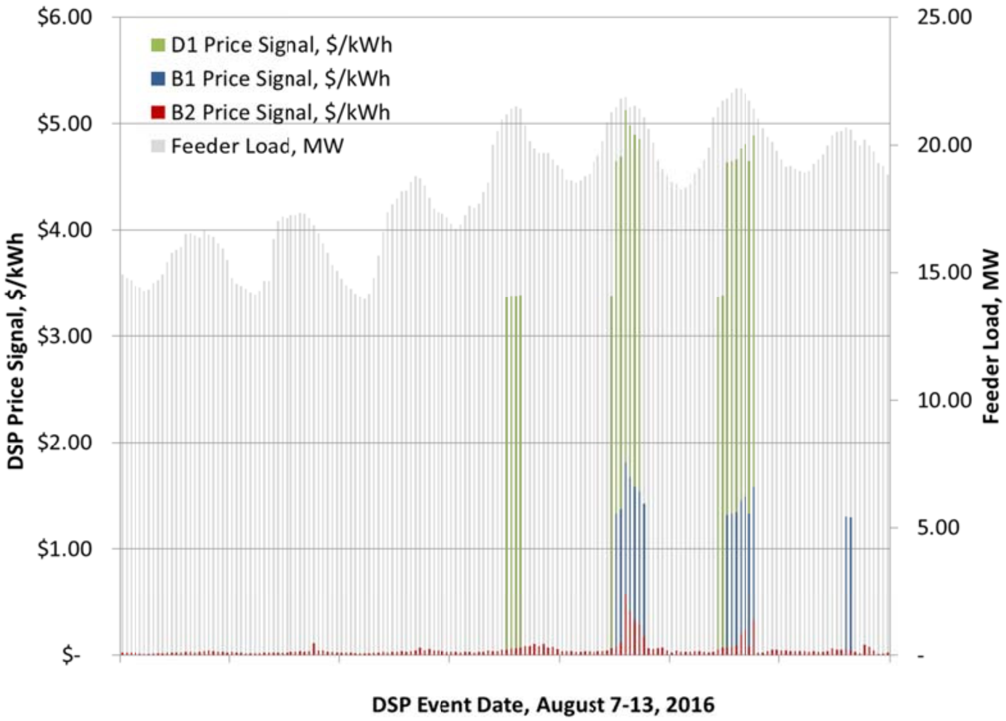

Figure 2.3 – D1, B1 & B2 vs. Feeder Load – 2016 RT Market

2. **Financial Model Simulation**
   A functional interactive spreadsheet model was created in order to simulate DER owners' financial feasibility in the BNMC area. The model calculates the DSP price signal and resulting potential annual DER revenue for every hour of the year based on historic load and price (*e.g.*, LBMP, ICAP) data. Some of the main inputs to the model are:
   - DER type, cost to operate, and performance specifications;
   - AGCC at the bulk system level based on ICAP price forecasts;
   - NYISO load data and LBMP Historical prices (Day Ahead and/or Real Time);
   - MDC based on an annual levelized revenue ("ALR") requirement for deferring a capital distribution project in a Non-Wires Alternative ("NWA") opportunity area;
   - Feeder load data;
   - Tier 1 REC price per kWh generated injected; and
   - Percent of Transmission and Distribution ("T&D") variable loss.

Simulations were run to compare the expected DSP event prices during the 2012-2016 time periods using NYISO Zone A West LBMP for the Day Ahead and Real Time markets. As criteria, it was assumed that the BNMC would accept any DSP event price as long as that price would be above their estimated cost to run their DER assets (including fuel and O&M costs).

The initial results indicated that there would have been considerably more opportunities for the DER owners based on Real Time operations in terms of number of hours of operations and potential revenue.

Figure 2.4 shows potential revenue opportunities for different types of DER assets, including dispatchable DG (*i.e.*, Diesel and Natural Gas reciprocating engines) and non-dispatchable DG (*i.e.*, Solar PV), on a highly loaded feeder that was identified by National Grid as a NWA opportunity area. The model results assume 1 MW (nameplate) DER assets with a cost to operate of $0.220/kWh for Diesel-based DG, $0.106/kWh for Natural Gas-based DG, and $15/kW for Solar PV-based DG. The main takeaways are:

- D1 revenue could dominate for dispatchable DERs in NWA opportunity areas;
- D1 and B1 revenue could be harder to capture for renewable DERs due to lower power output during certain NYISO and feeder peaks; and
- E1 revenue can provide significant revenue for renewable DERs assuming a $24.24/MWh REC price according the Value of D Order.[7]

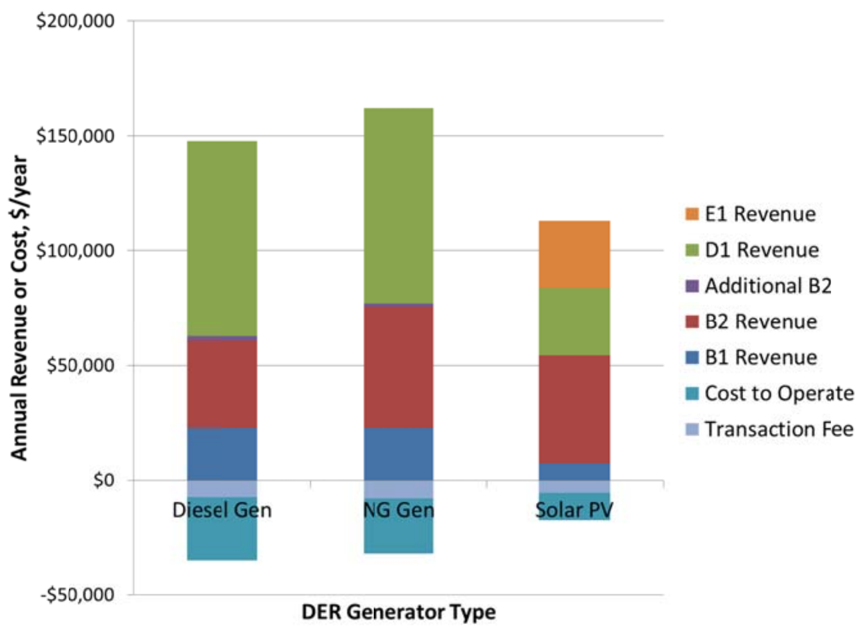

Figure 2.4 – Revenue Comparison for 1MW DER – 2016 RT Market

3. Stakeholder Go Decision

In order to continue with Phase II of the DSP REV Project, an important milestone was obtaining the approval of the main stakeholders in the Project. Individual meetings were set with the BNMC members and National Grid's Leadership team to present the Financial Model results and seek feedback.

On March 28, 2017 the Project Team met with Roswell Park Cancer Institute and Kaleida Health, the two (2) largest members of the BNMC. After presenting the modeling results, both parties showed interest in the potential benefits and expressed their desire to continue to be part of the Project. At the same time, the University of Buffalo decline to proceed further, as the timing of its construction does not align with the Project schedule.

National Grid and Opus One Solutions have agreed on the Financial Model methodology and will continue to work together to develop the technology needed for the DSP.

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[7] *Id.*

2.2 Challenges, Changes, and Lessons Learned this Quarter

2017	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q1	Carlos Nouel appointed as new Executive Project Sponsor.	None.	None.	None.
Q1	The initial developed Financial Model methodology intended to provide a clear hourly price signal to DER owners needed additional refining.	The Project timeline was negatively impacted, as the Project Team needed to devote significant time and effort to refine the model. The Phase I Go/No Go checkpoint was therefore 3 months behind schedule.	The Project Team has created a revised schedule to develop the DSP and POC technology that is intended to minimize and/or eliminate any delays for the end of Phase II milestone.	Creating a first of its kind Financial valuation model requires a level of effort, complexity and buy-in that should not be underestimated.
Q1	The initial Financial Model results showed insufficient value for the BNMC when running the DSP on Day Ahead Market operations.	The results from the Financial Model simulations using Real Time market conditions did however show sufficient value for the BNMC. Therefore the DSP will have more emphasis on Real Time market operations.	The DSP will require additional and faster communication and forecasting capabilities in order to integrate local DER with Real Time market information. All partners will work on addressing those issues in Phase II.	Real Time NYISO prices are considerably more sensitive to market forces than Day Ahead prices, thus providing greater benefits for DER owners. However, it will also increase the complexity and require additional work by the Project Team.

Q1	Given the guidelines released by DPS Staff in the Value of D Order, an External ("E") component was added to the Financial Model.	The value of E was originally left out of scope in the Implementation Plan. However, the Project Team has determined that it is important to devote extra effort to include a value specific to renewable DG.	The guidelines in the Value of D Order[8] were used to develop the E component.	None.

3.0 Next Quarter Forecast

During the 2nd Quarter of 2017 the Project team will officially kickoff the second part of the DSP project, where Opus One and National Grid will work in the technology development of the DSP and POC software and architecture.

The Project Team will work in a fast-paced approach to the critical path tasks that are a pre-requisite to the timely commencement of Phase 3 – Field Demonstration.

3.1 Checkpoints/Milestone Progress

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1	Phase II Kickoff Meeting	1/2/17	4/18/17	🟡
2	Phase 2: Technology Development	1/2/17 – 11/17/17	4/19/17– 11/17/17	🟡

Key
- 🟢 On-Track
- 🟡 Delayed start, at risk of on-time completion, or over-budget
- 🔴 Terminated/abandoned checkpoint

1. Phase II Kickoff Meeting

Status: [🟡]
Start Date: 4/18/2017
End Date: 4/18/2017

The Project Team has scheduled a meeting for 4/18 to officially Kickoff Phase II of the Project. This meeting will have the participation of the main Project partners, and the leads for each of

[8] *Id.*

the different groups in National Grid that will play a role in the DSP development and operations. The National Grid teams participating in the meeting and in Phase II are:

- New Energy Solutions;
- Regulatory Compliance;
- Electric Operations;
- Network Strategy;
- Distribution Control and Integration ("C&I");
- Distribution Planning;
- Wholesale Electric Supply;
- New York Pricing, Electric;
- Digital Risk & Security
- Interconnections;
- Meter Data Services;
- Regional Control Room;
- Information Services; and
- Advanced Data and Analytics ("ADA").

2. Phase 2: Technology Development

Status: [🟡]
Start Date: 4/19/2017
End Date: 11/17/2017

Phase II will focus on designing, developing and testing the DSP and POC architecture and software. The first step will be to gather the business and technical requirements for the DSP and POC. This will include the development of detailed business requirements, logical, physical and technical models, a detailed application design, test plans and training plans that will all lead to a technology solution that is consistent and viable with the needs of the Project.

To accomplish this, the Project Team has developed a series of cross-functional workshops where the different teams will gather to quantify and qualify the requirements. Additional, detailed network and communication processes will be identified to safely and accurately transmit data between National Grid's server and Supervisory Control and Data Acquisition ("SCADA") system, the DSP and ultimately, the POCs located at the BNMC site.

The workshops will be classified as:

- DSP operations;
- DSP event creation;
- Event coordination;
- Market operation and coordination; and
- DSP Communications and Network.

The Project Team will also conduct workshops with the BNMC members to gather the main features, requirements and user interface in order to develop a POC with a costumer centric approach.

While the Project Team has developed a fast-paced and aggressive approach in order to compensate for the timeline delays in Phase I and finalize the Technology Development Phase within the timeline set forth in the Implementation Plan, the Team also recognizes that there is a significant risk of not being able to reach that milestone in the allotted time.

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**
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**
7	**LMP+D**	**Fri 9/30/16**	**Thu 11/10/16**
14	**Settlement - wholesale**	**Fri 9/30/16**	**Tue 10/25/16**
17	**Settlement - financial**	**Fri 10/14/16**	**Thu 10/27/16**
20	**New Revenue streams**	**Fri 10/14/16**	**Tue 11/8/16**
24	Initial model stakeholder GO/NOGO	Thu 11/10/16	Thu 11/10/16
25	**Financial Model Simulation**	**Fri 11/11/16**	**Thu 12/8/16**
29	Phase 1 Stakeholder GO/NOGO	Fri 12/30/16	Fri 12/30/16
30	**Phase 2 - Technology Development**	**Tue 4/18/17**	**Mon 11/20/17**
31	**DSP & POC**	**Tue 4/18/17**	**Mon 11/20/17**
32	**Requirements definition**	**Tue 4/18/17**	**Mon 5/1/17**
35	**Solution Design**	**Tue 5/2/17**	**Mon 5/29/17**
38	**Solution Development**	**Tue 5/30/17**	**Mon 8/14/17**
45	**Solution Testing**	**Tue 8/15/17**	**Mon 11/6/17**
52	**Implemention**	**Tue 11/7/17**	**Mon 11/20/17**
56	Phase 2 stakeholder GO/NOGO	Mon 11/20/17	Mon 11/20/17
57	**Phase 3 - Field demonstration**	**Tue 11/21/17**	**Mon 12/3/18**
58	Phase 3 Kick off	Tue 11/21/17	Tue 11/21/17
59	Market Structure and Economics	Tue 11/21/17	Mon 12/4/17
60	Market Deployment	Tue 11/21/17	Mon 12/4/17
61	Market Deployment complete	Mon 12/4/17	Mon 12/4/17
62	Market Integration into DSP and POC Build I	Tue 11/21/17	Mon 12/18/17
63	Testing and Op Demonstration	Tue 12/19/17	Mon 1/1/18
64	**DSP, POC and Market Monitoring and Measurement**	**Tue 1/2/18**	**Mon 12/3/18**

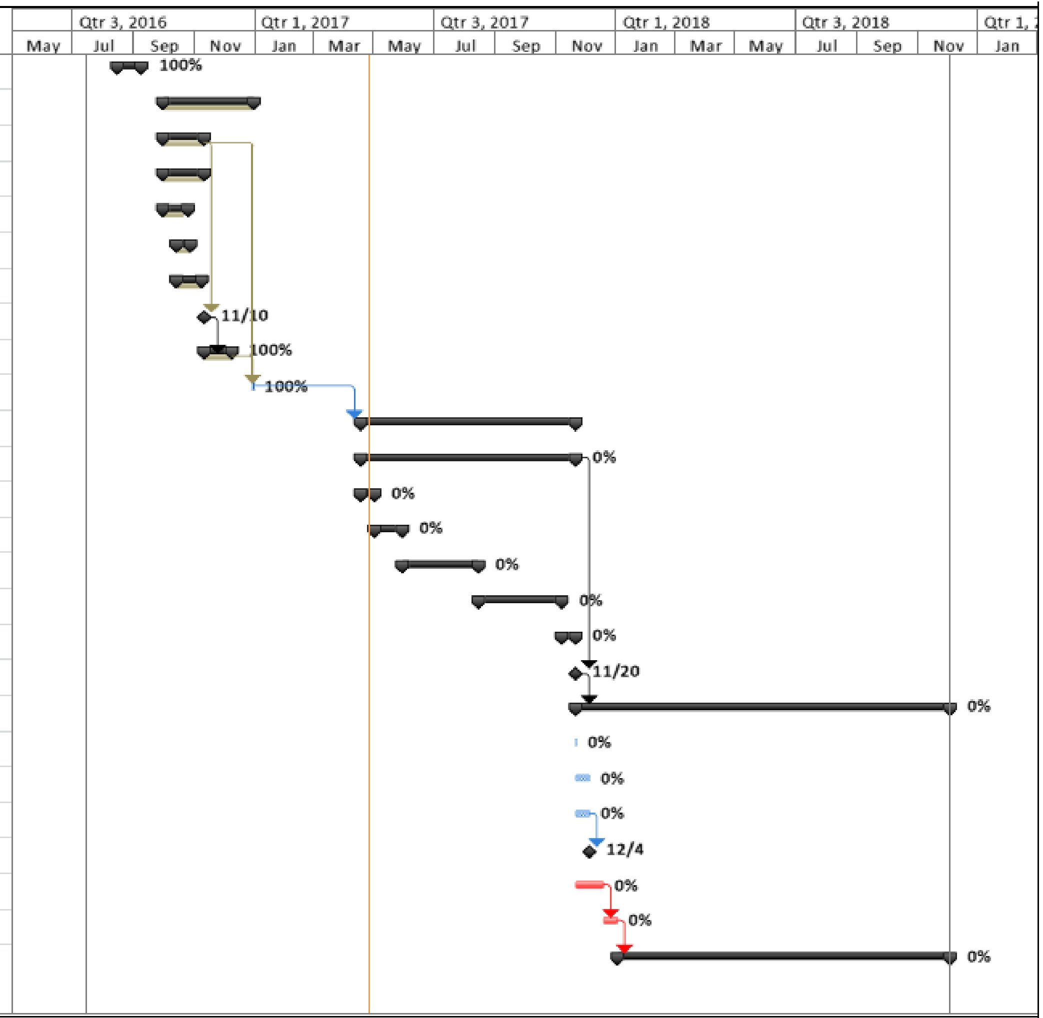

Figure 4.1 – Update of original Gantt Chart found in DSP Implementation Plan

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 March 31, 2017 total $462,942. 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 after the end of Phase 1 based on the Check Points identified in pages 15 and 16 of the DSP Implementation Plan.