Implementation Plan for Distributed System Platform REV Demonstration Project

Case 14-M-0101

Niagara Mohawk Power Corporation d/b/a National Grid
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Executive Summary

The Reforming the Energy Vision ("REV") Distributed System Platform ("DSP") Demonstration Project (the "Project") described herein was initially filed with the Public Service Commission ("Commission") by Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") with the Buffalo Niagara Medical Campus Inc. ("BNMC") as its customer partner on July 1, 2015. A revised Pscope for the Project was filed with the Commission on June 15, 2016. This Implementation Plan has been prepared in consultation with New York State Department of Public Service Staff ("Staff") and in accordance with the REV Demonstration Project Assessment Report filed by Staff with the Commission on July 15, 2016 which requires the Implementation Plan to be filed by the Company no later than August 15, 2016.

The Project seeks to develop and test services based on a local, small-scale, but centralized Distributed System Platform ("DSP") that will communicate with network-connected points of control ("POCs") associated with BNMC distributed energy resources ("DERs"). DSP was defined in the Commission's REV Track One Policy Order using the definition developed by the Platform Technology Working Group 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."[1] The POC will take the form of an application hosted on a server at a customer's site, with communications capabilities to control DER assets based on requested events on the electric power system (*e.g.*, local generation to meet peak demand or voltage support needs) and the terms of contractual agreements in place with the local DSP provider.

The Project team consists of National Grid, BNMC, and Opus One Solutions ("Opus One"). Opus One will provide contracted services to National Grid. All Project partners will be engaged throughout the duration of the Project.

BNMC, consisting of thirteen (13) member institutions and nearly 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. The BNMC serves as the umbrella organization of the anchor institutions that make up the Buffalo Niagara Medical Campus located within the 120-acre footprint bordering the areas of Allentown, the Fruit Belt, and downtown Buffalo. The BNMC (depicted in Figure 1) fosters conversation and collaboration among its member institutions, its partners, and the community to address various critical issues; including energy, entrepreneurship, access and transportation, workforce and procurement, neighborhood conditions, and healthy communities.

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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), ("REV Track One Policy Order"), p. 31.

Figure 1: Part of the Buffalo Niagara Medical Campus

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 and Project planning and execution.

National Grid's Elm Street substation provides power to the BNMC and the majority of downtown Buffalo through local distribution stations via underground 23 kV circuits. The Elm Street substation steps down the voltage from 230 kV to 23 kV and acts as the central distribution point for most of the BNMC buildings. BNMC's annual electricity demand was 153 GWh and peak demand was 30 MW in 2015. BNMC's current DER capacity is over 34 MW with about 28 MW coming from the three major entities; Roswell Park Cancer Institute, University at Buffalo, and Kaleida Health. The 28 MW of DER capacity currently consists of twenty-four (24) diesel engine gensets and numerous buildings equipped with building energy management systems ("BEMS") wherein load shedding schemes can be implemented. BNMC is currently evaluating an increase in DER capacity through the addition of a combination of 19 MW of natural gas engine and turbine generators, 1 MW of solar photovoltaic ("PV"), and 150 kW (600 kWh) of battery energy storage. These additional DERs were identified in a feasibility study partially funded by the New York State Energy Research and Development Authority ("NYSERDA") Smart Grid Electric Power Transmission and Distribution ("EPTD") Program Opportunity Notice ("PON") 2715 and the NYSERDA RFP 3044 New York Prize Community Grid Competition.[2]

The proposed local DSP will communicate the electric distribution system needs of the Elm Street substation and local feeders and send dynamic price signal events to the POCs. The POCs will communicate with the DSP as to the availability of BNMC DERs to respond to local electric system needs and the willingness to accept price signal events. Within the market of the BNMC, the Project will evaluate what price signal events and/or other revenue opportunities motivate BNMC member institutions with DER capabilities to provide the DSP with local electric distribution system services at the POC level. The Project will also evaluate what revenue opportunities are needed to encourage further DER investment.

[2] *See, BMNC Community Microgrid, Stage 1-Feasibility Study Report*, prepared by BMNC, National Grid, the Electric Power Research Institute ("EPRI"), CDH Energy Corp., Navigant Consulting, Inc., and National Fuel Gas Company, March 2016.

The Project recognizes that opt-in bid-based events and bilateral contracts directly with the DER owner/operator or aggregator are additional options. However, until sufficient data is collected and analyzed, it will not be known if bid-based events will generate enough certainty to enable forecasting of responses, or if bilateral contracts will improve planning capabilities.

A high-level schematic of the key components of the Project (*i.e.*, DSP, POCs, and DERs) is presented in Figure 2 below. National Grid will license and operate the DSP.

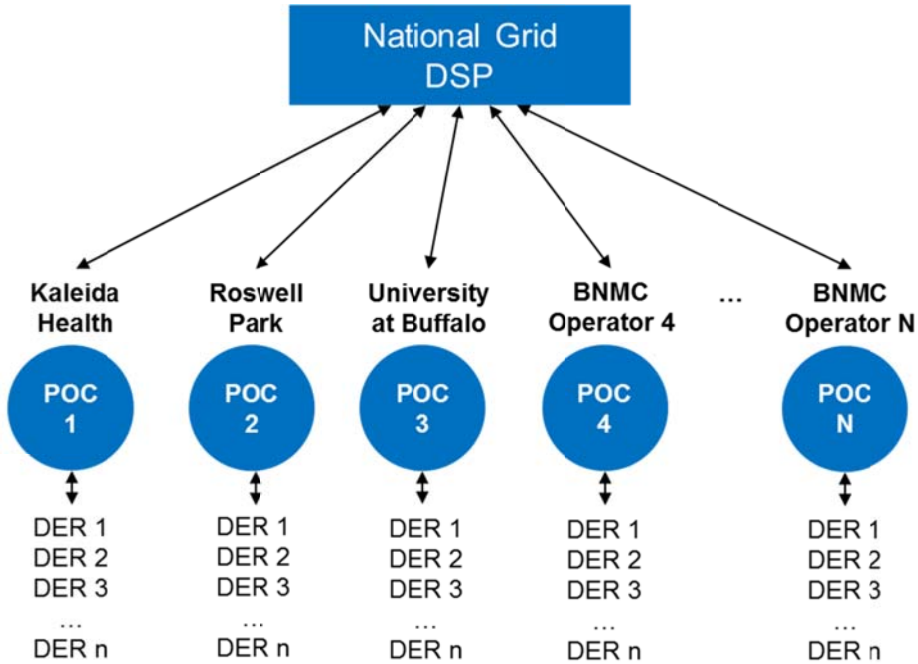

Figure 2: Schematic of DSP's Components

The Project will inform how best to engage current DER owners and operators with revenue opportunities that unlock their DER assets,[3] via investment and return on investment ("ROI"), while considering operating constraints that may impede the utilization of those DER assets. An example of an operating constraint that may impede the utilization of diesel engine-based DERs in the Project is the current small-scale generation emissions regulations. The Project team anticipates the need to retrofit BNMC's existing Tier 2-compliant diesel engine gensets with Tier 4-compliant emissions control technology in order to be able to operate in non-emergency

[3] The term "unlock" refers to the ability to use the DER assets for supplying power/energy and/or supporting the electric distribution system.

situations as required by the U.S. Environment Protection Agency (EPA).[4] However, even after retrofitting existing diesel engine gensets, these DERs may face additional operating constraints depending on local or state-level emissions goals and/or additional operational constraints within the health services sector. Given the large number of Tier 2 diesel engine-based DER assets at BNMC and across New York State that are required for emergency backup power (but sit idle most of the year due to emissions regulations), overcoming these operating constraints will be necessary so that early adopters can engage in the DSP.

The expected Project outcomes can lead to optimization of the local electric distribution system and the desired objectives of the larger, system-wide DSP as noted in the REV Track One Policy Order. Successful deployment of a small-scale DSP, as developed and tested through the Project, is expected to result in a better understanding of DSP market dynamics that can be applied to a full-scale DSP rollout across the National Grid electric service territory.

Business Model Overview

The Project will test the ability of the DSP to facilitate participation of existing DERs in various electric distribution system opportunities (*e.g.*, energy supply and peak load modification), as well as provide informed decision-making as to whether BNMC member institutions should invest in additional DER assets. Additional investment opportunities include both new DER assets (*e.g.*, natural gas, solar PV generation, and/or battery energy storage) and retrofits to existing DER assets (*e.g.*, emissions reduction technologies for diesel generators). BNMC's existing DER assets, potential future DER assets, and future microgrid capabilities were presented in the revised scope filed for the Project.

The BNMC provides an excellent DSP test bed due to the willingness of the BNMC to participate and the existing and potential future DER assets available for the Project. National Grid and other stakeholders can use lessons learned from the Project to inform National Grid's larger, system-wide DSP.

Proposed Solution

The Project seeks to test and develop services based on a DSP that would communicate with network-connected POCs associated with BNMC DERs. A schematic of the DSP component interactions for a price signal event is presented in Figure 3 below. Throughout the course of the Project, the Project team will evaluate the effectiveness of this communications platform. When the DSP for BNMC is successfully deployed, National Grid and BNMC anticipate up to thirty-three (33) BNMC DERs could be controlled by multiple POCs, where the POCs will communicate with the DSP via secure internet connections.

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[4] U.S. EPA emissions standards for nonroad engines were structured as a 4-tiered progression with increasingly stringent emissions requirements (*i.e.*, Tier 1 phased-in from 1996 to 2000, Tier 2 phased-in from 2001 to 2006, Tier 3 phased-in from 2006 to 2008, and Tier 4 phased-in from 2008 to 2015). The Tier 1-3 standards were met through advanced engine design, with no or only limited use of exhaust gas aftertreatment systems. Tier 4 emission standards introduced substantial reductions of nitrogen oxides ("NOx") and particulate matter ("PM"), as well as more stringent hydrocarbon ("HC") emissions limits. Such emission reductions can only be achieved through the use of advanced aftertreatment control technologies (*e.g.*, selective catalytic reduction, diesel particulate filters) similar to those required by the 2007-2010 standards for highway engines. However, unlike highway engines, the stationary engine owner/operator is responsible for emission compliance for Model Year 2008 and earlier engines. Note that stationary diesel engines used only for emergencies (*e.g.*as stand-by generator sets) are exempted from Tier 4 emission requirements. Source: DieselNet (https://www.dieselnet.com/standards/us/stationary_nsps_ci.php)

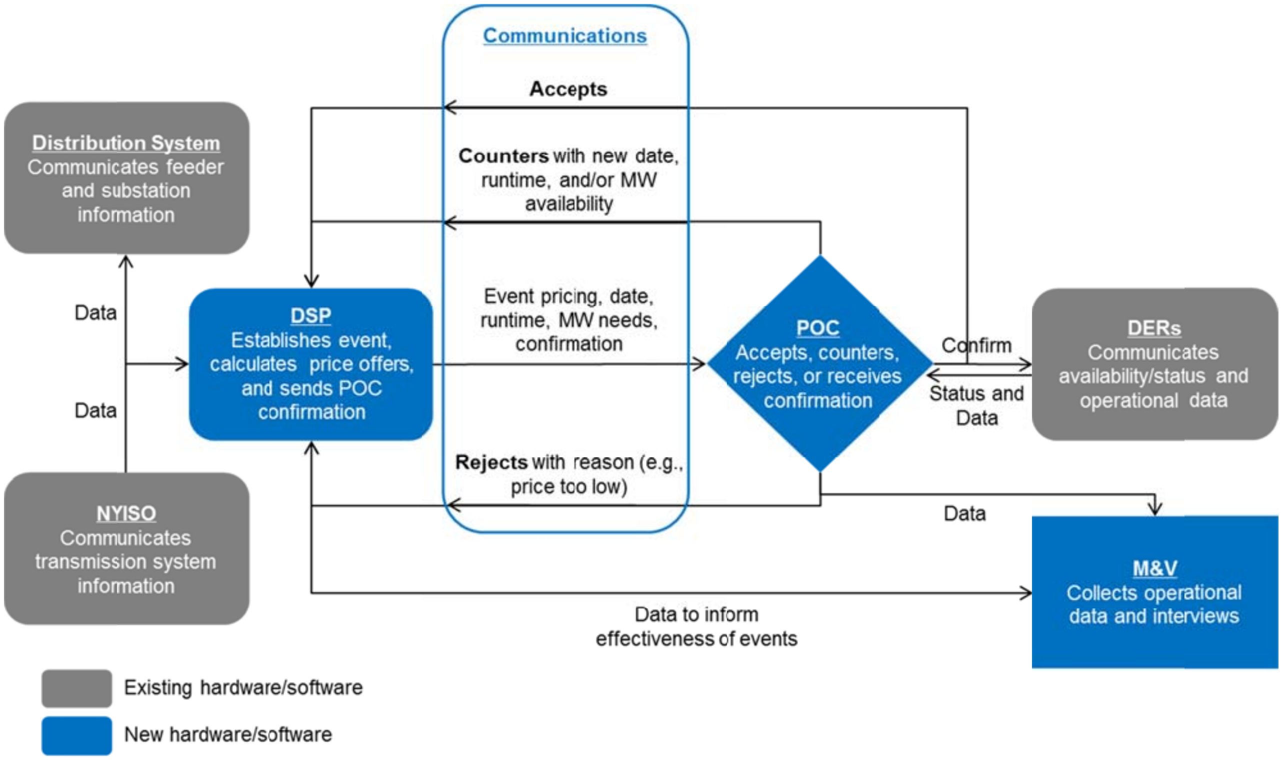

Figure 3: Schematic of DSP Component Interactions for a Price Signal Event

Hypotheses Being Tested

The Project will demonstrate how customers with DER capabilities can be motivated to operate those DERs for the benefit of the overall electric distribution system during unconstrained ("blue sky") or constrained ("peak period") electric distribution system operations. Specifically, the Project will evaluate what price signals and/or other revenue opportunities will motivate BNMC member institutions with DER capabilities to provide the National Grid DSP with local electric distribution system services at the POC level. In addition, the Project will provide insight into the types of revenue opportunities that could encourage additional DER investment.

The Project seeks to test three key hypotheses:

1. The functional and operational benefits flowing from the POC, based on the capabilities of customer-to-grid DER, can be successfully monetized by sending a price signal that is reasonably close to the benefit seen by the distribution system;
2. Customer participation will increase as the offered electricity prices increase, risks decrease, and/or other revenue opportunities are made available; and
3. Prevailing electricity prices or other revenue opportunities can provide sufficient financial motivation for customer investment in new DERs and participation in animated markets.

There are many factors to evaluate when considering the financial model that will provide potential opportunities for customers in the DSP marketplace, including:

- Capabilities of each DER technology;
- Constraints and/or limitations of the DER technology;
- Constraints and/or limitations of the DER participant;

- Operation of the DER technology when providing the service requested; and
- Information that will help customers assess risk when considering potential investment in DER capability or provision of services with existing DER capability.

These factors require a capability assessment of each DER to assist in the efficient operation of the local electric distribution system without compromising the provision of safe and reliable service. This evaluation will additionally provide information to help customers evaluate their risks and tolerance for investment and may lead to development of potential infrastructure improvements.

While the DSP market structure, the services it transacts, and its transactional mechanisms will evolve over time, a successful DSP will provide day-ahead or contractual price signals to customers with DERs such that those customers will choose to actively participate in market activities. As such, initial development of the DSP framework will require standardization in planning, market functionality, operations, and customer interfaces to efficiently and effectively attract market participants.

Approach

In the near term, services transacted and purchased by the DSP will test the implementation of a "LMP+D+E"[5] financial model approach for electric services. This model will evaluate the potential for the customer to optimize their capabilities in order to improve the operation of the electric distribution system. In the LMP+D+E model, "LMP" refers to location-based marginal price, which includes the wholesale price of energy, transmission congestion charges, and transmission line losses. 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[6] 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 peak power constraints, reduction of line losses, and alleviation of voltage issues. Energy supply, volt-ampere reactive ("VAR") support, voltage management, peak load modifications, and dynamic load management are some service examples 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 distribution grid such as substation and

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[5] *See* Case 15-E-0751 – *In the Matter of the Value of Distributed Energy Resources* ("Value of D Proceeding"), Notice Soliciting Comments and Proposals on Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015), Attachment A, p. 2, where "'LMP' represents the location-based marginal price of energy, and 'D' represents the full range of additional values provided by the distribution-level resource" and where "[i]n the NEM Ceilings Order, the Commission further elaborated that "[t]he 'value of D' can include load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational values as well as values not directly related to delivery service such as installed capacity and emission avoidance." *See also*, Value of D Proceeding, Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering, p. 7, where "E" represents 'externalities' or "social benefits that may be provided by DER but which are not captured in current markets."

[6] New York Independent System Operator LBMP and real-time pricing information. Source: http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp

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.

“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.

Scope

In order to provide a solid basis and framework for the DSP approach, the Project will focus on the annual and day-ahead planning timescales for DERs. These timescales should provide significant opportunity for DERs and the DSP provider, as well as distribution system benefits, in the context of the Project. Distribution system benefits may include operational savings (*e.g.*, loss minimization, power quality management), capital deferral (*e.g.*, load relief and other non-wires alternatives), and revenue generation (*e.g.*, DSP access fees, DSP revenue sharing, and DSP services such as analytics). Figure 4 below summarizes some of the DSP services and timescales that will be evaluated in the Project. The Project may also identify other services/products beyond what is presented in Figure 4 that could provide greater benefits, including those that are not currently being offered by the NYISO or other markets.

DSP Service	Annual	Day-Ahead	DER Response Examples
Energy Supply	X	X	Generation, energy storage, demand response
Volt-Ampere Reactive (VAR) Support	X	X	Power electronics (energy storage, solar PV inverter) power factor setting
Voltage Management		X	Power electronics (energy storage) voltage control, VAR control (indirect)
Peak Load Modification	X	X	Generation, energy storage, demand response
Dynamic Load Management		X	Demand response

Figure 4: Examples of DSP Services and Applicability to Annual and Day-Ahead Timescales

The DSP for the Project will provide revenue-generating (and revenue savings) opportunities, predominantly during blue sky and grid-constrained days. Additional efforts can build on this work to extend the DSP operation to intraday planning timescales (*e.g.*, hour-ahead, minute-ahead, near real-time) to address immediate (*i.e.*, emergency) distribution system events.

Demonstration Design

Project Overview

The Project will be conducted in three (3) phases by National Grid and its partners. Phase 1 involves development of a DSP financial model that will provide the opportunity for BNMC member institutions to consider use of potential DER assets. To build the DSP financial model, event-driven pricing will be generated for day-ahead peak periods and contractual pricing will be used for blue sky periods. Thereafter, the model will be tested using historical data to determine the prices for each service requested from BNMC DERs. In Phase 2, the DSP financial model implemented in Phase 1 will be used to develop the technical functionality of the DSP and the POCs. In Phase 3, a field demonstration will be conducted which will include: deployment of the DSP and POCs with BNMC DER assets; measurement and verification ("M&V") tasks; and evaluation of results. Throughout the Project, go/no-go decision points will be used to solicit feedback from DER participants and the Company and, if necessary, to explore the development of additional scenarios and pricing models. Figure 5 below summarizes the interactions within and between each phase.

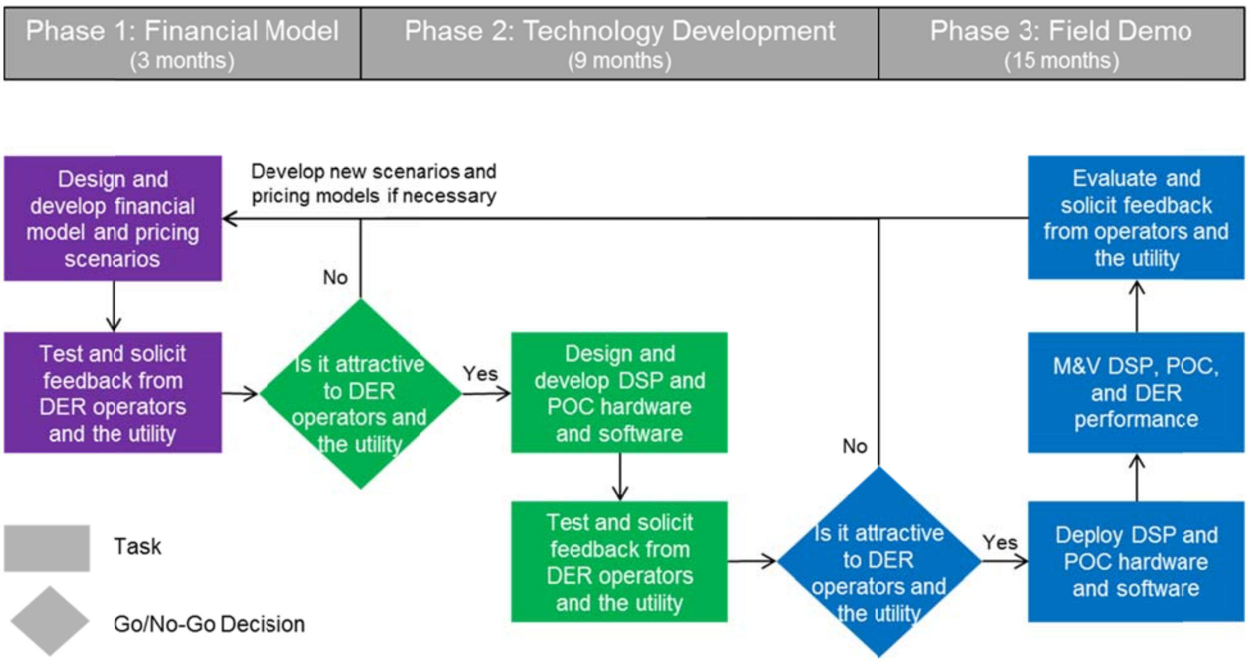


Figure 5: Project Phase Interactions

Phase 1: Financial Model

In Phase 1, a detailed DSP financial model will be developed that can be used to test which DER capabilities are most cost-effective, and the willingness of customers to participate in DSP market activities. The LMP+D approach described above will be used as a basis for the proposed DSP financial model. NYISO LBMP and ICAP values will be used as the LMP base price. National Grid planning and operational data will be used to determine the value of D portion of the LMP+D price (which includes kWh loss minimized, voltage events mitigated, kWh conserved from voltage reduction, kW peak load reduced, and kW peak supply generated). The DSP financial model will be populated with historical data so DER participants can determine how existing DERs, as well as potential new DERs, can be leveraged in the market. In Phase 1, options will also be developed for National Grid to generate new revenue streams, such as providing: one-time data as a service for distribution optimization opportunities; pricing options for access to the DSP only; and pricing options for access to the DSP and POCs. These options will be evaluated and developed to provide DER participants with flexibility for products and services provided by the Company. At the end of Phase 1, a go/no-go decision will be made, based on whether the DSP is financially attractive to both DER participants and National Grid.

Phase 2: Technology Development

The DSP financial model and other work completed in Phase 1 will inform the development, customization, and integration of a successful DSP-POC platform in Phase 2 of the Project. The DSP will be licensed and operated by National Grid and developed with the Project's partners. Various POC ownership models will be evaluated, but for the purposes of the Project, the POC will be licensed by National Grid and operated by the participating BNMC members. At the end of Phase 2, a go/no-go decision will be made based on whether the DSP is financially attractive and a successful solution platform for both DER participants and the Company.

Phase 3: Field Demonstration

In Phase 3, the Project partners will: determine the operational readiness of a POC at participating members' sites; stand up the network and communications with each POC; prepare the participating members' DERs for participation in DSP events; and deploy and operate the local DSP at National Grid. Once all of these tasks have been completed, the DSP will start to generate and send price signal events to the POCs. The POC operators will be able to respond to the price signal events and confirm the participation of the DERs. All participation types (accept / counter-offer / decline) will be recorded by the DSP for reconciliation and reporting purposes. The participation rate of BNMC DERs, and the degree to which the local electric distribution system is optimized, will be key findings for the Project.

Test Statements

Phase 1: Financial Model

Test Statement	Hypothesis "If" Statement	"Then" Statement
1. The locational marginal value of DERs can be financially modeled as LMP+D.	A. If the NYISO LBMP and ICAP values are representative of the wholesale value…	Then these components can comprise the LMP portion of the DSP financial model.
	B. If the quantification of DERs' capabilities for voltage management, VAR support, peak load management, and dynamic load management can be incorporated in the DSP financial model as the distribution system operational value…	Then these components can comprise the value of D portion of the DSP financial model.
2. The DSP financial model can demonstrate sufficient value for DER and utility participation.	A. If the DSP financial model can be populated with historical data for the different test scenarios and generate a range of values for DER participation…	Then DER participants will accept the functionality of the DSP financial model for development of the DSP market.
	B. If the DSP financial model can be populated with real-time and forecasted data and generate price signal events with a range of values for DER participation…	Then DER participants can effectively evaluate the price signal events that will be generated from the DSP financial model in field operation.
	C. If DER participants can expect sufficient financial returns for existing or new DERs under historical, real-time, and forecasted scenarios…	Then DER participants will be willing to participate in the DSP market and potentially invest in new DERs.
	D. If National Grid can generate positive financial returns from the DSP via new revenue streams…	Then National Grid should be able to experience similar positive results as the DSP is rolled out across the Company's service territory.

Phase 2: Technology Development

Test Statement	Hypothesis "If" Statement	"Then" Statement
3. The DSP can create a technical and financial platform for DERs, with NYISO integration for market-based services.	A. If the DSP is integrated with planning and operational systems at National Grid, and with POCs for automated DER management and financial modeling…	Then the DSP can transmit price signal events for POC response to optimize electric distribution system performance.
	B. If the DSP is integrated with the NYISO for scheduled demand response or load reduction requests…	Then the DSP can trigger POC price signal events using price signals from the NYISO for load reduction requests..
4. POCs can become a central communication portal between the DSP and participating DERs.	A. If DER participants, whether individually or in aggregate, can be modeled technically and financially via POCs…	Then the POCs can represent DER participants and interface with the DSP to trigger price signal events and transactions.
	B. If the POCs and the DSP maintain a common, re-usable application programming interface ("API")[7]…	Then the POCs and the DSP can establish seamless interoperability for implementing a DSP market.

[7] An application programming interface ("API") is a language and message format comprised of routines, protocols, and tools to communicate with the operating system or some other control program or communications protocol.

Phase 3: Field Demonstration

Test Statement	Hypothesis "If" Statement	"Then" Statement
5. The DSP with POC model can enable an attractive and vibrant market for DER participation under both unconstrained and grid-constrained operations.	A. If the DSP provides the price signal events, manages transactions, provides platform services (*e.g.*, data analytics, scheduling), and manages interoperability with the POCs…	Then DER participants will have efficient access and transparency to DSP information, services, and potential revenue streams via the POCs.
	B. If the DSP provides the market price signal events representing the dynamic locational marginal value of DERs on the distribution system (and these signals/revenue opportunities are attractive to the DER participants)…	Then DER participants will be able to extract financial and operational value from the DSP.
	C. If the market signals and other revenue opportunities developed by the DSP are sufficiently attractive to current DER participants and to the marketplace…	Then there will be financial motivation for investment in new DERs.
6. The DSP with POC model can enable significant electric distribution system benefits (operational and financial) under both unconstrained and grid-constrained operations.	A. If DERs can provide predictable operational capabilities, objectives, and constraints to the DSP, such as kW and kVAR capacity, energy duration, and dispatch frequency…	Then the DSP can rely on DERs with relative certainty in integrated distribution system planning.
	B. If the DSP can use price signal events to encourage DER participants to consistently engage with the market on a long-term basis…	Then the DSP can rely on DER participants to provide grid support to optimize day-to-day grid operations (such as reducing line loss and power quality management).
	C. If the DSP can use price signals to encourage DER participants to consistently engage with the market during short-cycle grid-constrained events…	Then the DSP can rely on DER participants to provide grid support to mitigate short-cycle grid constraints (such as load relief), which enables deferral of future distribution system infrastructure spending (similar to non-wires alternative projects).
	D. If the DSP can provide a financially attractive and reliable DSP market for the DER participants…	Then National Grid will have the opportunity to realize new revenue streams via the DSP operation (*e.g.*, DSP access fees, DSP revenue sharing, and DSP services such as analytics).

Test Population

Test Population Description	Selection Method
BNMC members with existing or planned DER assets	The Project expects to interface primarily with BNMC's three major members (Roswell Park Cancer Institute, University at Buffalo, and Kaleida Health) because these entities have the largest number of DERs, totaling 28 MW from twenty-four (24) diesel engine gensets and 1 MW from demand response/load reduction capacity available from BEMS.

Test Scenarios

The following test scenarios will be evaluated with the DSP financial model developed in Phase 1 of the Project which includes new utility revenue streams. A subset of these scenarios will be selected for evaluation in Phases 2 and 3 of the Project. The test scenarios are designed to evaluate the level of DER participation on the DSP. Four (4) different services potentially provided by DER participants will be evaluated with the DSP financial model, transacted on the DSP market, and tested under two (2) grid operational environments. The four (4) services provided by the DER participants include: 1) energy services (*e.g.*, kWh generation or conservation); 2) real power[8] services (*e.g.*, kW capacity generation or demand curtailment); 3) reactive power[9] services (*e.g.*, kVAR provided to the grid, either capacitive or inductive); and 4) multiple simultaneous services as a balanced combination of energy, real power, and reactive power services made available by DER participants. The two types of grid operational environments are: a) unconstrained operation (*e.g.*, blue sky days) which represents the normal, everyday scenario where DER may provide lesser incremental value to grid operation but the frequency of price signal events is high; and b) grid-constrained operation (*e.g.*, peak periods), which represents the infrequent but critical scenario where DER may provide significant value to grid operation but the frequency of price signal events is not as high.

[8] Real power is the component of electric power that performs work, typically measured in kilowatts ("kW") or megawatts ("MW") and sometimes referred to as active power. The terms "real" or "active" are often used to modify the base term "power" to differentiate it from reactive power and apparent power. U.S. Energy Information Administration ("EIA") Glossary at: http://www.eia.gov/tools/glossary/index.cfm?id=electricity

[9] Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is a derived value equal to the vector difference between the apparent power and the real power. It is usually expressed as kilovolt-amperes reactive ("kVAR") or megavolt-ampere reactive ("MVAR"). EIA Glossary at: http://www.eia.gov/tools/glossary/index.cfm?id=electricity

Test Scenario Descriptions

Scenario	Description
DER participants providing energy services on the DSP under unconstrained operation (*e.g.*, blue sky days)	Evaluate market structure (*e.g.*, fixed length contracts, day-ahead, event-driven calls) and customer participation for energy products (*e.g.*, kWh generation and consumption) during unconstrained grid operation when the value of D is low for grid support and the number of price signal events for DER participation is high. Energy services will provide distribution value including capacity management and energy conservation.
DER participants providing energy services on the DSP under grid-constrained operation (*e.g.*, peak periods)	Evaluate market structure and customer participation for energy products during constrained grid operation when the value of D is high and the number of events is low. Energy services from DER participants will provide value, including critical capacity management (*e.g.*, during peak capacity periods).
DER participants providing real power services on the DSP under unconstrained operation	Evaluate market structure and customer participation for real power services (*e.g.*, kW generation and demand curtailment) during unconstrained grid operation when the value of D is low and the number of events is high. Real power services will provide distribution value including capacity management, loss minimization, and voltage management.
DER participants providing real power services on the DSP under grid-constrained operation	Evaluate market structure and customer participation for real power services during constrained grid operation when the value of D is high and the number of events is low. Real power services from DER participants will provide value including critical capacity management, transfer capacity management (*i.e.*, feeder load transfer during outage restoration), emergency load shedding/generation dispatch, and voltage management.
DER participants providing reactive power services on the DSP under unconstrained operation	Evaluate market structure and customer participation for reactive power services (*e.g.*, kVAR, both capacitive and inductive) during unconstrained grid operation when the value of D is low and the number of occurrences is high. Reactive power services will provide distribution value including loss minimization, capacity management, and voltage management.
DER participants providing reactive power services on the DSP under grid-constrained operation	Evaluate market structure and customer participation for reactive power services during constrained grid operation when the value of D is high and the number of events is low. Real power services from DER participants will provide value including loss minimization, critical capacity management, and voltage management.
DER participants providing multiple simultaneous services on the DSP under unconstrained operation	Evaluate market structure and customer participation for multiple simultaneous services (*e.g.,* energy, real power, and reactive power) during unconstrained grid operation when the value of D is low and the number of events is high. Assess dependencies, constraints, opportunities and potential outcomes for such multi-product operation for both the DSP and the DER participant (*e.g.*, customer DERs balancing and co-optimizing between kWh, kW and kVAR).
DER participants providing multiple simultaneous services on the DSP under grid-constrained operation	Evaluate market structure and DER participation for multiple simultaneous services (energy, real power, and reactive power) during constrained grid operation when the value of D is high and the number of events is low. Assess dependencies, constraints and opportunities for such multi-product operation for both the DSP and the DER participant.

Check Points

Phase 1: Financial Model

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.

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.

Phase 2: Technology Development

Check Point	Description
3A. The DSP can transmit price signal events for POC response to optimize electric distribution system performance.	Measure: Ability of the DSP to generate and broadcast price signal events at 5-minute intervals (based on the Project's Phase 1 DSP financial model results, but implemented in real-time system operations). How and When: Use industry best practices for program development throughout Phase 2 of the Project, with final acceptance at end of Phase 2. Resources: DSP financial model and software development processes. Expected Target: DSP transmits all designed price signals at 5-minute intervals. Solutions / Strategies in case of results below expectations: Evaluate integration with National Grid's information systems and identify gaps in translating distribution system optimization into price signal events; correct issues causing target shortfall.
3B. The DSP can trigger POC price signal events using price signals from the NYISO for load reduction requests.	Measure: Ability of the DSP to generate and broadcast price signal events at 5-minute intervals (based on the Project's Phase 1 DSP financial model results, but implemented in real-time system operations). How and When: Use industry best practices for program development throughout Phase 2 of the Project, with final acceptance at end of Phase 2. Resources: DSP financial model and software development processes. Expected Target: The DSP can trigger all designed events using load reduction request events from the NYISO at 5-minute intervals. Solutions / Strategies in case of results below expectations: Evaluate integration with NYISO, identify and correct issues causing target shortfall.
4A. The POC can represent DER participants and interface with the DSP to trigger price signal events and transactions.	Measure: Ability of the POC and DER participants to reliably communicate and interoperate via a common, reusable standard set of API protocols and software as defined in Phases 1 and 2 of the Project. How and When: Using industry best practices for program development throughout Phase 2 of the Project, with final acceptance at end of Phase 2. Resources: DSP financial model, software development processes. Expected Target: A working set of open APIs that will provide 100% of the developed requirements for POC/DER interoperation. Solutions / Strategies in case of results below expectations: Evaluate the POC-DER participant integration and the POC-DSP integration and identify and correct issues causing target shortfall.
4B. The POC and the DSP can establish seamless interoperability for implementing a DSP market.	Measure: Ability of the POC and the DSP to communicate and interoperate via a common, reusable standard set of open API protocols and software as defined in Phases 1 and 2 of the Project. How and When: Industry best practices for program development throughout Phase 2 of the Project, with final acceptance at end of Phase 2. Resources: DSP financial model, software development processes. Expected Target: A working set of open APIs that will provide 100% of the developed requirements for DSP/POC interoperation. Solutions / Strategies in case of results below expectations: Evaluate the POC-DSP integration, identify and correct the issues causing target shortfall.

Phase 3: Field Demonstration

Check Point	Description
5A. DER participants will have efficient access and transparency to DSP information, services, and potential revenue streams via the POCs.	Measure: Time requested for roundtrip communication of events between DSP, POCs, and DERs. How and When: Weekly DSP Reports throughout Phase 3 of the Project. Resources: DSP event data files. Expected Target: Time required for roundtrip communication is less than two (2) minutes for greater than 99% of price signal events, transactions, and other services between the DSP and POC, providing sufficient time for DERs to respond.. Solutions/Strategies in case of results below expectations: Identify and correct issue causing the target shortfall.
5B. DER participants will be able to extract financial and operational value from the DSP.	Measure: Risk/benefit metrics (*e.g.*, IRR, payback period, net present value, and capital investment) calculated from projected DER participant annual revenue and cost savings for providing distribution services. How and When: Projections based on DSP financial model results and DER participant interviews throughout Phase 3 of the Project. Resources: Electrical engineering model; DSP financial model, DSP event data files, and DER participant cost data. Expected Target: Risk/benefit metrics (*e.g.*, IRR > 10%, payback period < five (5) years) that will successfully influence DER participant investment necessary to achieve a DER participation rate of 5 MW and/or 10 hours per month (on average). Solutions/Strategies in case of results below expectations: Refine DSP financial model, modify the DSP approach, and/or work with regulatory and policy stakeholders to strengthen benefits and/or reduce risk.
5C. There will be financial motivation for investment in new DERs.	Measure: BNMC DER participants' actual and/or planned investment in DER assets necessary to provide distribution services How and When: DER participant interviews and discussions at the start and end of Phase 3 of the Project. Resources: DSP financial model; DER participant investment plans and activities. Expected Target: Actual or planned investment in upgrading existing DERs (*e.g.*, emissions control, flex fuel technologies, BEMS upgrades) and/or new types of DER assets (*e.g.*, solar PV) necessary to provide an incremental minimum of 5 MW and/or 10 hours of operation per month (on average). Solutions/Strategies in case of results below expectations: Refine DSP financial model or modify DSP approach to strengthen benefits; work internally and with partners to mitigate DER interconnection and participation challenges.
6A. The DSP can rely on DERs with relative certainty in integrated distribution system planning.	Measure: Projected and actual DER supplied power / energy for both constrained and unconstrained opportunities. How and When: Projections based on DSP financial model results; monthly DSP and M&V reports throughout Phase 3 of the Project; meetings with National Grid planning team to determine capabilities needed to consider DERs as non-wires alternatives. Resources: DSP financial model; DSP data files; electrical engineering model; and M&V reporting. Expected Target: Actual MW/MWh received within 25% of targets predicted

	by the financial model. Solutions/Strategies in case of results below expectations: Refine financial model or DSP approach to strengthen benefits; work internally and with partners to mitigate challenges.
6B. The DSP can rely on DER participants to provide grid support to optimize day-to-day grid operations (such as reducing line loss and power quality management).	Measure: Distribution system voltage and frequency, distribution losses, and power quality with and without expected DER participants; estimated operational savings (including reduced wholesale purchases, distributed generation ("DG") interconnection processes, voltage optimization, and loss minimization). How and When: Monthly DSP and M&V reports throughout Phase 3 of the Project. Resources: Electrical engineering model;, DSP data files, and M&V reporting. Expected Target: Case-by-case distribution system optimization using DERs targets (*e.g.,* conservation voltage reduction ("CVR") level, voltage loss), while maintaining voltage and power quality within accepted ANSI C84.1 standards, and estimated operational savings insufficient to pay for DSP incentives to DER participants (when combined with 6C below). Solutions/Strategies in case of results below expectations: Refine financial model or DSP approach to strengthen benefits; work internally and with partners to mitigate DER integration challenges.
6C. The DSP can rely on DER participants to provide grid support to mitigate short-cycle grid constraints (such as load relief), which enables deferral of future distribution system infrastructure spending (similar to non-wires alternative projects).	Measure: Peak load reduction achieved and distribution utility planning current spend projections with and without expected DER participation (*i.e.*, comparing load tap changer operations, peak loads, feeder peak capacity requirements, etc.). How and When: Monthly DSP and M&V reports throughout Phase 3 of the Project; distribution planning annual projections. Resources: Electrical engineering model, DSP data files, financial model, and M&V reporting. Expected Target: Peak load reductions and estimation of capital deferral identified and sufficient to pay for DSP incentives to DER participants (when combined with 6B above). Solutions/Strategies in case of results below expectations: Refine DSP financial model or DSP approach to strengthen benefits; work internally and with partners to mitigate DER integration challenges.
6D. National Grid will have the opportunity to realize new revenue streams via the DSP operation (*e.g.*, DSP access fees, DSP revenue sharing, and DSP services such as analytics).	Measure: Projected National Grid DSP revenue streams. How and When: Extrapolated results of the Project, plus monthly M&V reports throughout Phase 3 of the Project. Resources: Electrical engineering models; DSP financial model; M&V reporting; 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: Refine DSP financial model or DSP to strengthen financial attractiveness.

The information needed to validate each Check Point listed above will be included in regular reports throughout the Project. The table below summarizes the information that National Grid anticipates will be included in each report, as well as the anticipated reporting frequency.

Report	Information	Check Point	Frequency
DER Risk / Benefit Assessment Reports – Phases 1-3	Projected DER participant annual revenue, costs, and cost savings for providing distribution services based on DER participant needs and historical and forecasted data, which can be used by potential participant as a tool for investment decisions.	5B	On request
DSP Reports – Phase 3	Event Details: DER participation; frequency; lag time and type of communication events between the DSP, POCs, and DERs. DER Revenue: Projected DER participant annual revenue for providing distribution services.	5A, 6A, 6B, 6C	Monthly
DER Participant Interviews – Phases 1-3	DER Costs: Projected DER participant annual costs and cost savings for providing distribution services. BNMC interest in new DER investment to provide distribution services.	1A, 1B, 2A, 2B, 5B,5C	Twice per Phase
M&V Reports – Phase 3	Distribution System Operation: Voltage and frequency, distribution losses, and power quality with and without expected DSP operations. Distribution System Planning: Peak load reduction and distribution planning spend projections with and without expected DSP operations (*i.e.*, comparing load tap changer (“LTC”) operations, peak loads, feeder peak capacity requirements, etc.).	6A, 6B, 6C, 6D	Monthly
Utility Cost / Benefit Analysis Reports – Phases 1-3	Distribution System Benefits: Operational savings; capital deferral, and revenue generation.	2D, 6D	Quarterly

Project Structure & Governance

Project Team

National Grid Skill Sets	BNMC Skill Sets	Opus One Skill Sets
Engineering	Program Design	Software Development
Tariff Design	Stakeholder Engagement	Data Analytics
Contracting	DER Operations	DER Management
Information Systems	Asset Management	Microgrid Energy Management
Cybersecurity		Transactive Energy Operations
Data Analytics		User Interface/Experience Design
Stakeholder Engagement		Systems Integration/Interoperability
Communications, Media Relations, and Marketing to the Larger Community		Stakeholder Engagement
Government Relations		Grid/DER/Microgrid Business Models,
Program Management		Financial Modeling
Project Management		Simulation and Testing
		Team/Project Management

In consideration of the skill set requirements, the Project will be staffed as follows:

National Grid Team Member	Relevant Skill Sets	Contact Information
Ron Diorio	Program management, information systems (system architecture, Information Technology/Operation Technology ("IT/OT"))	ronald.diorio@nationalgrid.com (781) 907-2597
Dennis Elsenbeck	Stakeholder engagement, government relations	dennis.elsenbeck@nationalgrid.com (716) 831-7748
Stephen Lasher	Engineering (network impacts)	stephen.lasher@NationalGrid.com (401) 525-5640
Dale Kruchten	Advanced data analytics	dale.kruchten@nationalgrid.com (516) 545-2434
Mark Domino	Engineering (distribution and sub-transmission NY)	mark.domino@nationalgrid.com (781) 907-3050
Pamela Dise	Tariff design	pam.dise@nationalgrid.com (315) 428-5172
Muks Ravipaty	Cybersecurity	mukand.ravipaty@nationalgrid.com (781) 907-2992
Brian Cronin	Communications, media relations, marketing to the larger community	brian.cronin@nationalgrid.com (781) 907-1763
Daniel Payares Luzio	Project management, engineering	daniel.payaresluzio@nationalgrid.com (781) 907-3839

BNMC Team Member	Relevant Skill Sets	Contact Information
Paul Tyno	Program design, stakeholder engagement	ptyno@bnmc.org (716) 218-7354

Opus One Team Member	Relevant Skill Sets	Contact Information
Alison Smith	DER management, microgrid energy management, grid/DER/microgrid business models, stakeholder engagement, team/project management	asmith@opusonesolutions.com (917) 612-6416
Joshua Wong	DER management, microgrid energy management, transactive energy operations	jwong@opusonesolutions.com (416) 818-1518
Roger Moore	Software development, data analytics, user interface/user experience ("IU/UX") design, systems integration, interoperability	rmoore@opusonesolutions.com (647) 385-8007
Mark Jaggassar	Software development, data analytics, IU/IX design, systems integration/interoperability	mjaggassar@opusonesolutions.com (647) 639-7930
Wajid Muneer	DER management, microgrid energy management, software development, data analytics, systems integration/ interoperability	wmuneer@opusonesolutions.com (519) 998-7719

Roles & Responsibilities

National Grid Role	Description
Program Management and Design	Design, develop and execute end-to-end Project
Stakeholder Engagement and Government Relations	Continue to develop stakeholder engagement and government relations
Advanced Analytics and Data	Assist in the development of analytical needs
Information Systems	Provide systems, networking, and communications and integration needs for internal components
Engineering Support	Provide information on electric feeders and electric distribution needs, planning, and operations
Tariff Design and Pricing	Partner in the developing of the DSP financial model
Cybersecurity	Ensure all aspects meet National Grid standards
Communications, Media Relations, and Marketing to the Larger Community	Oversee all aspects of communications, media relations and marketing

BNMC Role	Description
Program Design	Facilitate market structure design
Stakeholder Engagement	Serve as portal to multiple commercial customers and asset owners
Operations Insight	Connect current work and other studies into design for efficiency of results

Opus One Role	Description
Financial Modelling	Assist National Grid in financial modelling and pricing scenarios, including DER valuation
Software Development	Code development, UI/UX design, transactive energy process design
Simulation and Testing	Market and technical simulations on DSP and POC interactions, operationalize test case scenarios
Systems Integration	Assist National Grid and BNMC on systems integration of the DSP/POC solution

Governance

Demonstration Steering Committee	
National Grid Participants	**Partner Participants**
Carlos Nouel	Paul Tyno – BNMC
Dennis Elsenbeck	Alison Smith – Opus One
Ron Diorio	Joshua Wong – Opus One

Demonstration Making Logistics	
Meeting Format	**Meeting Frequency**
Short-format tactical conference call with key National Grid and partner workstream owners	Weekly
In-depth tactical conference call with key National Grid and partner workstream owners	Monthly
In-person performance evaluation and strategy setting meeting with workstream owners and senior leadership from National Grid and the Project's partners	Quarterly
In-person performance evaluation and strategy setting meeting with workstream owners, senior leadership from National Grid, and the Project's partners (as appropriate), and as needed with Staff	Quarterly (as appropriate)

Work Plan & Budget

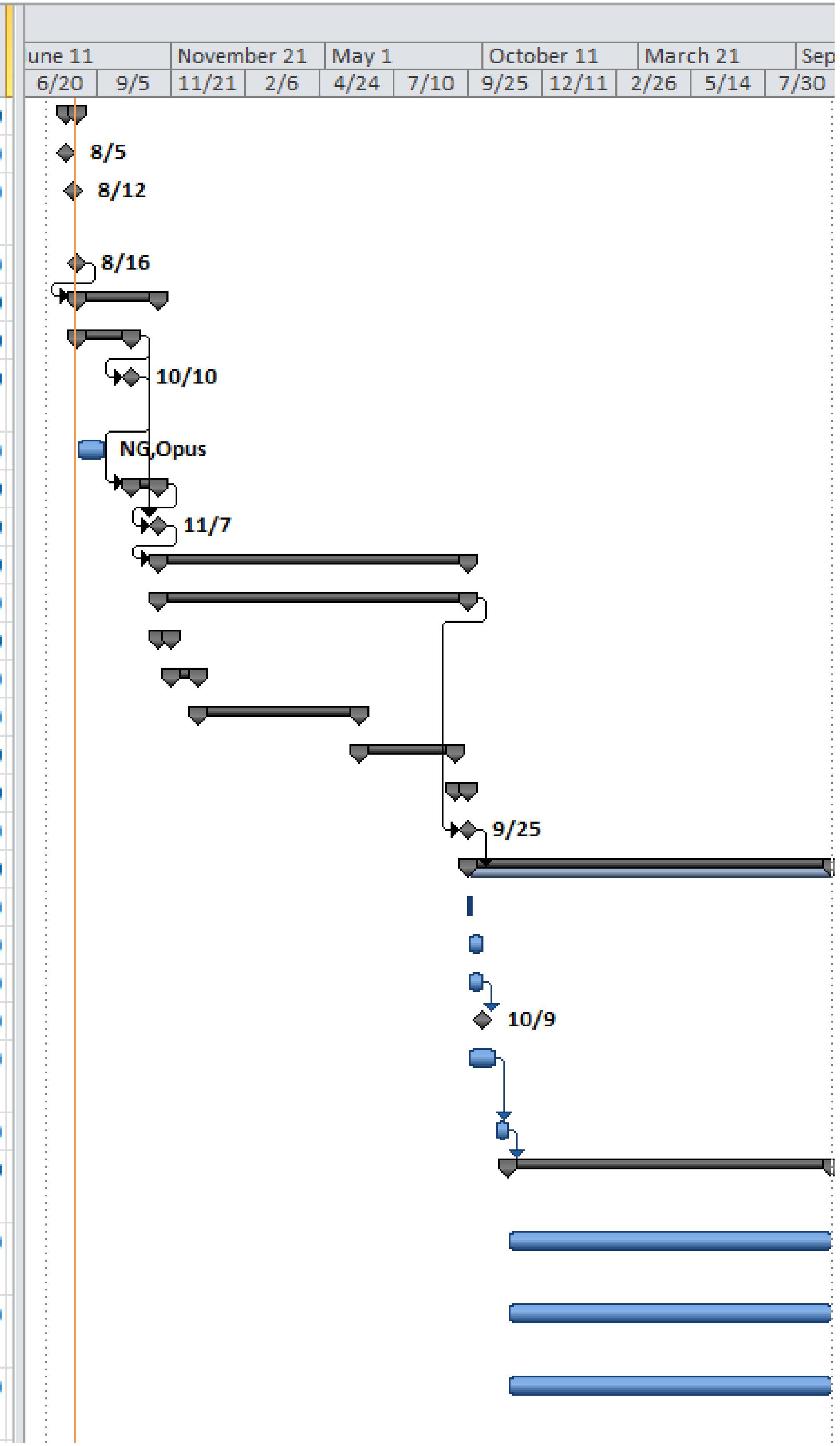
Project Plan

The timeline for each Phase of the Project is summarized below.

- Phase 1: Financial Model (three (3) months): completed three (3) months from the Project start date.
- Phase 2: Technology Development (nine (9) months): completed twelve (12) months from the Project start date.
- Phase 3: Field Demonstration (fifteen (15) months): completed twenty seven (27) months from the Project start date.

Prior to the start of each subsequent phase of the Project, there will be an internal go/no-go review. This will give greater flexibility to refine the scope of work and/or budget requirements as necessary to meet the Project's goals.

	Task Name	Duration	Start	Finish	Pr	Resource Names	Baseline Cost
1	**Phase 0**	**7 days**	**Fri 8/5/16**	**Tue 8/16/16**			**$0.00**
2	Implementation Plan Filed	0 days	Fri 8/5/16	Fri 8/5/16			$0.00
3	Contracts executed, project charter developed	0 days	Fri 8/12/16	Fri 8/12/16			$0.00
4	Project Kickoff	0 days	Tue 8/16/16	Tue 8/16/16			$0.00
5	**Phase 1 - Financial Model**	**60 days**	**Tue 8/16/16**	**Mon 11/7/16**	**4**	**Opus,NG,BNMC**	**$500,000.00**
6	**Design and development**	**40 days**	**Tue 8/16/16**	**Mon 10/10/16**		**BNMC,NG,Opus**	**$0.00**
13	Initial model stakeholder GO/NOGO	0 days	Mon 10/10/16	Mon 10/10/16	6	BNMC,NG,Opus	**$0.00**
14	Startup - infrastructure definition	4 wks	Tue 8/16/16	Mon 9/12/16		NG,Opus	$0.00
15	**Financial Model Simulation**	**20 days**	**Tue 10/11/16**	**Mon 11/7/16**	**13**	**BNMC,NG,Opus**	**$0.00**
19	Phase 1 Stakeholder GO/NOGO	0 days	Mon 11/7/16	Mon 11/7/16	15,6	BNMC,NG,Opus	**$0.00**
20	**Phase 2 - Technology Development**	**230 days**	**Tue 11/8/16**	**Mon 9/25/17**	**19**	**BNMC,NG**	**$2,330,000.00**
21	**DSP & POC**	**230 days**	**Tue 11/8/16**	**Mon 9/25/17**		**BNMC,Opus**	$0.00
22	**Requirements definition**	**10 days**	**Tue 11/8/16**	**Mon 11/21/16**		**BNMC,NG,Opus**	**$0.00**
25	**Solution Design**	**20 days**	**Tue 11/22/16**	**Mon 12/19/16**	**24**	**BNMC,NG,Opus**	$0.00
28	**Solution Development**	**120 days**	**Tue 12/20/16**	**Mon 6/5/17**	**27**	**BNMC,NG,Opus**	$0.00
35	**Solution Testing**	**70 days**	**Tue 6/6/17**	**Mon 9/11/17**	**34**		**$0.00**
42	**Implemention**	**10 days**	**Tue 9/12/17**	**Mon 9/25/17**	**41**	**BNMC,NG,Opus**	**$0.00**
46	Phase 2 stakeholder GO/NOGO	0 days	Mon 9/25/17	Mon 9/25/17	21	BNMC,NG,Opus	$0.00
47	**Phase 3 - Field demostration**	**270 days**	**Tue 9/26/17**	**Mon 10/8/18**	**46**	**BNMC,NG,Opus**	**$1,980,000.00**
48	Phase 3 Kick off	1 day?	Tue 9/26/17	Tue 9/26/17			$0.00
49	Market Structure and Economics	2 wks	Tue 9/26/17	Mon 10/9/17			$0.00
50	Market Deployment	2 wks	Tue 9/26/17	Mon 10/9/17			$0.00
51	Market Deployment complete	0 days	Mon 10/9/17	Mon 10/9/17	50		$0.00
52	Market Integration into DSP and POC Build Environment	1 mon	Tue 9/26/17	Mon 10/23/17			$0.00
53	Testing and Op Demonstration	2 wks	Tue 10/24/17	Mon 11/6/17	52		$0.00
54	**DSP, POC and Market Monitoring and Measurement**	**240 days**	**Tue 11/7/17**	**Mon 10/8/18**	**53**		**$0.00**
55	Scenario and Sensitivity Testing and Analysis	12 mons	Tue 11/7/17	Mon 10/8/18			$0.00
56	Continuous Improvement and Updates	12 mons	Tue 11/7/17	Mon 10/8/18			$0.00
57	Evaluation, Reporting, Information Dissemination	12 mons	Tue 11/7/17	Mon 10/8/18			$0.00



Project Budget

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**

National Grid resources as noted in the table are non-incremental. All other budget items are incremental costs.

Reporting Structure

Reporting Expectations

The Project Management team plans to file quarterly reports in order to showcase the progress made to date, as well as adjustments to schedules/budgets, metrics reporting, and a forecast of the next quarter's activities and milestones. Additionally, in order to maintain flexibility and maximize the potential for innovation and learning, the quarterly reports may contain other updates or deviations from the initial details provided herein. Staff will be consulted as to the specific content required for the quarterly reports, but the following major sections will be included in each report:

1. Executive Summary

2. Highlights Since Previous Quarter
   a. Major Task Completion
      i. Checkpoints, Milestones, Go/No-Go decisions
   b. Challenges, Changes and Lessons Learned

3. Next Quarter Forecast
   a. Checkpoints/Milestones Progress

4. Work Plan & Budget Review
   a. Updated Work Plan

b. Updated Budget

5. Progress Metrics

6. Appendices

To further ensure alignment, National Grid would also like to meet with Staff to discuss the quarterly progress reports. Any changes related to costs shall remain within the overall revenue requirement cap. Furthermore, as set out in Staff's letter dated June 24, 2015, should a situation or activity arise that is not authorized by the Commission, the Company would include a description in the quarterly report and request such authorization through a petition to the Commission. National Grid looks forward to continued collaboration with Staff beyond the formal quarterly reports.