nationalgrid

Proposed REV Demonstration Project Revised Scope

Distributed System Platform

Case 14-M-0101

Niagara Mohawk Power Corporation d/b/a National Grid
Revised 6/17/2016

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Executive Summary

The Reforming the Energy Vision ("REV") Distributed System Platform ("DSP") Demonstration Project (the "Project") 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. The Project was subsequently revised as to scope following a series of discussions with the Department of Public Service Staff ("Staff"). The Project as described herein reflects the outcome of those discussions and additional considerations by the National Grid and BNMC. This document replaces the Company's July 1, 2015 filing.

The Project team consists of National Grid, BNMC, and Opus One Solutions ("Opus One"), who will subcontract with National Grid. All Project partners will be engaged throughout the Project.

BNMC, consisting of 13 member institutions and nearly100 public and private companies that are a dynamic mix of health care, life sciences, medical education, and private enterprise, is a significant growth engine of Western New York. At 7 million square feet of infrastructure today with 2 million square feet of new construction currently underway, the BNMC has its sights set on accommodating an additional 5.3 million square feet by 2030 to achieve its long-term vision as a comprehensive Community Engaged Academic Health Center in downtown Buffalo. BNMC is a self-sustaining social enterprise successfully combining innovation, job creation, and urban revitalization. The BNMC serves as the umbrella organization of the anchor institutions that make up the Buffalo Niagara Medical Campus located within the 120-acre campus bordering Allentown, the Fruit Belt and downtown Buffalo. The BNMC fosters conversation and collaboration among its member institutions, its partners, and the community to address critical issues impacting them including energy, entrepreneurship, access and transportation, workforce and procurement, neighborhoods, and healthy communities.

Opus One is a software engineering company who shares the vision for the Project to develop and deploy one platform that can accommodate a complete range of business models as an active partner. This partnership would include not only software development but also thought leadership, 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. 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 distributed energy resource ("DER") capacity is over 34 MW with about 28 MW of that from diesel engine generators and approximately 1 MW from demand response/load reduction capacity available from Building Energy Management Systems ("BEMS") throughout the BNMC. BNMC is currently evaluating increasing its DER capacity by adding 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's ("NYSERDA") Smart Grid Program Opportunity Notice ("PON") 2715 and the New York Prize Community Micro-grid Competition.[1] The BNMC

[1] NYSERDA, "BNMC Community Micro-grid, Stage 1 - Feasibility Study Report", March 2016.

aspires to optimize both revenues and energy savings opportunities from their growing and evolving inventory of DERs. The willingness of the BNMC member institutions, both individually and collectively, to collaborate with National Grid on the Project is based on their respective priorities as they relate to reliability, cost, and sustainability objectives.

The Project seeks to develop and test services based on a local, small-scale, but centralized DSP that would communicate with network-connected points of control ("POC") associated with BNMC 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."[2] The POC would be a head-end type of application that would be hosted on a server at a customer's site with communications capabilities to control DER assets based on events on the electric power system and contractual agreements in place with the local DSP provider.

The proposed local DSP would communicate the electric distribution system needs of the Elm Street substation and local feeders and send dynamic pricing signals to the POCs. The POCs would communicate with the DSP as to the availability of BNMC DERs to respond to local electric system needs and the willingness to accept pricing signals. Within the market of the BNMC, the Project will evaluate what price signals 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, and what revenue opportunities would encourage additional DER investment. A high-level schematic of the key components of the Project (*i.e.*, DSP, Communications, POCs and DERs) is presented in Figure 1 below. For the Project National Grid would license and operate the DSP.

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[2] 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.

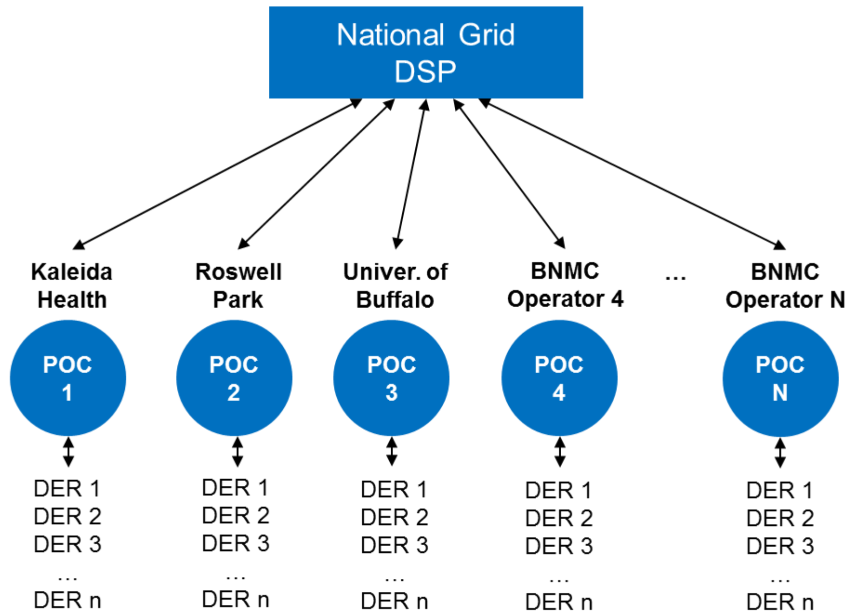

Figure 1: Schematic of Project Components

The Project will inform how best to engage current DER market participants with revenue opportunities that unlock their DER assets, including considering regulatory constraints that impede their utilization, and what revenue opportunities would encourage additional DER investment. These outcomes can lead to optimization of the electric distribution system relative to the desired objectives of the larger, system-wide DSP as noted in the REV Track One Policy Order.[3] Successful deployment of the small-scale DSP developed and tested through this 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 in New York.

Business Model Overview

Market Opportunity

The BNMC approached National Grid in 2011 seeking its expertise in meeting their anticipated energy needs and transportation challenges as outlined in BNMC's 2010 Master Plan.[4] As a result, the *energizeBNMC* Partnership was formed and an Energy Innovation Plan for the BNMC and Surrounding Neighborhoods (the "Plan") was drafted to integrate energy efficiency, grid modernization, alternative transportation, and renewable energy to foster a sustainable, growing community that would generate jobs and foster local economic growth. The Project will test the ability of the DSP to facilitate participation of existing DERs in various DSP opportunities (*e.g.*, energy supply, peak load modification), as well as inform BNMC's decisions to invest in additional DER assets. Additional investment opportunities include both new DER assets (*e.g.*, natural gas or solar PV generation, battery energy storage) and retrofits to existing DER assets (*e.g.*, emissions reduction technologies for diesel generators). BNMC's existing DER assets,

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[3] *Id*., pp. 31-35.
[4] Buffalo Niagara Medical Campus, "MASTER PLAN UPDATE - A Scoping Document for the Future", Dec 2010 (available at: http://www.bnmc.org/wp-content/uploads/BNMC-Master-Plan-Update-FINAL_12-3-10.pdf).

potential future DER assets, and future micro-grid capabilities are presented in the attached Appendix.

The BNMC area is an excellent early DSP opportunity 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 the learnings from the Project to inform National Grid's larger, system-wide DSP and DSPs for other utilities in the state.

Proposed Solution

This Project seeks to test and develop services based on a DSP that would communicate with network-connected POCs associated with BNMC DERs. The DSP would communicate the electric distribution system needs of the local Elm Street electrical substation and send pricing signals to the POCs. The POCs would communicate with the DSP as to the availability of individual BNMC DERs to respond to local electric system needs and the willingness to accept pricing signals. The DSP would also communicate to the POCs similar electric distribution system needs based on contractual arrangements with the POC owners. A schematic of the DSP component interactions for a price signal event is presented in Figure 2 below. When the Project is successfully deployed, National Grid and BNMC anticipate up to 33 BNMC DERs could be controlled by multiple POCs where the POCs will communicate with the DSP via secure internet connection. Through the course of the Project, the Project team will evaluate this approach and determine if other approaches are more effective.

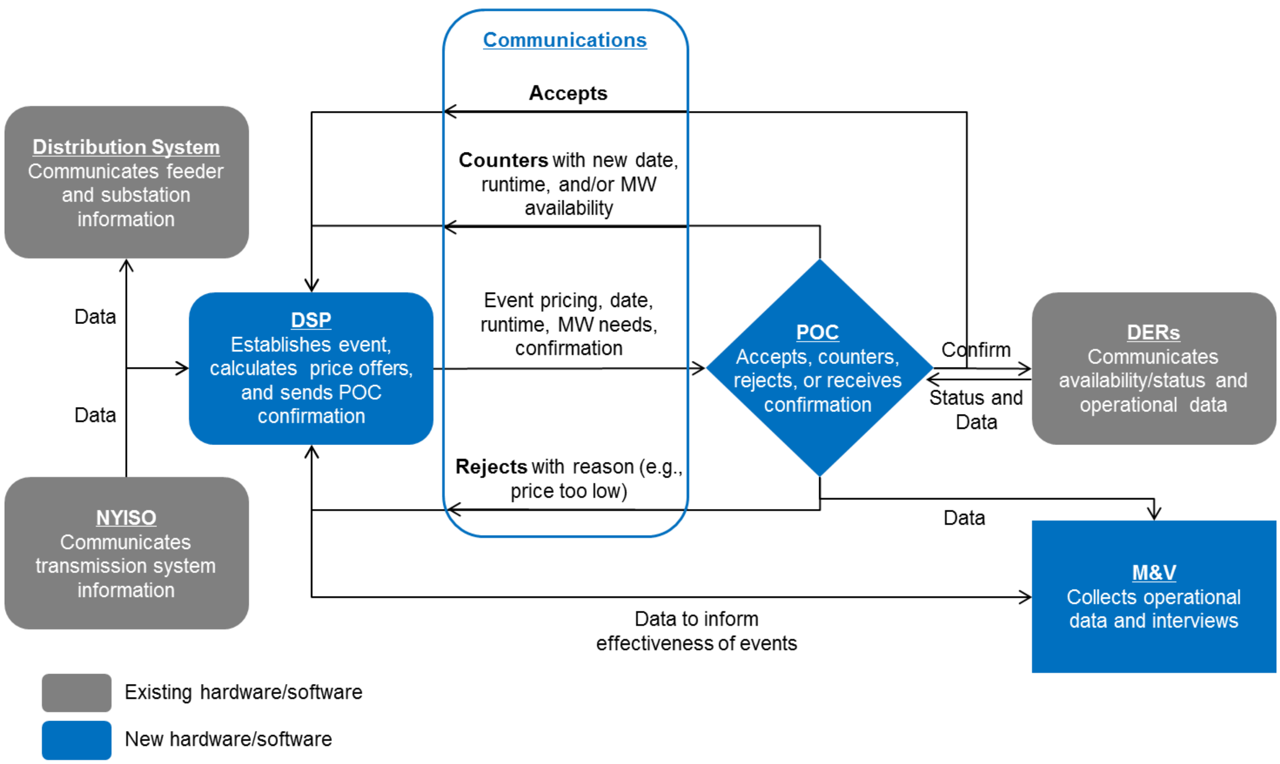

Figure 2: Schematic of DSP Component Interactions for a Price Signal Event

Hypothesis Being Tested

The Project will demonstrate how customers with DER capabilities can be motivated to provide them to 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 would 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.
2. Customer participation will increase as the offered electricity prices increase or other revenue opportunities are made available.
3. Prevailing electricity prices or other revenue opportunities can provide sufficient financial motivation for customer investment in new DER 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 technology
- Constraints and/or limitations of the DER customer
- Operation of the technology when providing the service requested
- 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 the assessment of each DER capability to assist in the efficient operation of the local electric distribution system based upon the current and future needs for the provision of safe and reliable service at reasonable prices. This evaluation will lead to development of potential infrastructure improvements to provide information to help customers evaluate their risks and tolerance for investment.

While the DSP market structure, the services it transacts, and its transactional mechanisms will evolve over time, a successful DSP will provide an animated market with day-ahead or contractual price signals to customers with DERs such that those customers will choose to actively participate in market activities for the reason that it is cost beneficial for them to do so. As such, initial development of the DSP framework will require standardized planning, market functionality, operations, and customer interfaces to 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 that enable the potential for the

[5] *See* Case 15-E-0751 – *In the Matter of the Value of Distributed Energy Resources*, Notice Soliciting Comments and Proposals on Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015), Attachment A, at 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* 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."

customer to optimize their capabilities in a manner 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") load zone prices and any constraints that may be priced into the local area, if it can be determined. The evaluation of potential local NYISO issues will be performed in consultation with NYISO staff. If possible, a dollar value may be added to the LMP as the +D component for any local constraints that could be addressed more economically through DER operated by the BNMC member institutions.

"D" refers to distribution delivery value, which is the value that DERs can provide to the distribution system, including load relief to help alleviate substation constraints, feeder constraints, voltage issues, etc. Energy supply, 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 this Project. This component takes into consideration potential issues along the distribution grid such as substation and feeder constraints. This 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 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 focus the effort and provide a solid basis and framework for the DSP approach, the Project will focus on the annual and day-ahead planning timescales for DERs, but will also consider intra-day timescales as appropriate. These timescales should provide significant opportunity for DERs and the DSP provider, as well as distribution system benefit in the context of the Project. Figure 3 below summarizes some of the DSP services and timescales that will be evaluated in the Project. The Project may consider other services/products beyond what is presented in Figure 3 that might 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 3: Example DSP Services and Applicability to Annual and Day-Ahead Timescales

Specific Use Cases will be outlined in the Project's Implementation Plan, but will include:

- Capacity-based energy supply: 24 hour advance notification for long duration (4-6 hrs.), infrequent events although year round capability
- Synchronized reserves for Peak Load Modification: 24 hour advance notification for short duration (15 -30 minute) but much more frequent events

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

REV Demonstration Principles Being Addressed

The Project will test several of the stated goals and objectives of the REV Proceeding including:

- Market animation and leverage of utility customer contributions;
- Improvements in local system efficiency;
- Cost-effectiveness;
- Power quality;
- Fuel and resource diversity;
- Customer empowerment and;
- System reliability and resiliency.

Further, the Company anticipates the Project will meet all of the following REV demonstration project criteria:

- Participation of third-party partners
- New utility business model
- Customer-community engagement
- Identify economic value
- Pricing and rate design
- Transactive grid
- Scalability
- Market rules and standards
- Cost effective
- Timeframe

Market Attractiveness

The Project provides New York State, National Grid, and the BNMC a controlled, "real life" DSP test bed. The Project will enable National Grid and the BNMC to model the operation and functionality of a DSP, while leveraging funding previously awarded to the BNMC through NYSERDA's Smart Grid PON 2715 and the New York Prize Community Micro-grid Competition, for which the BNMC was awarded funding to study feasibility. The study identified the necessary micro-grid capabilities that would allow the BNMC to meet almost 90% of their energy needs with on-site generation. The envisioned BNMC micro-grid would operate multiple sources of power generation and include the pipes and wires needed to deliver the energy produced. As a grid-connected resource, the micro-grid has the ability to operate in parallel (connected) to the grid or in a stand-alone isolated (*i.e.*, island) fashion. Central to the operation of a robust BNMC micro-grid is sophisticated software and controllers. This advanced intelligence manages the DERs in various configurations against constraints depending on what offers the most economic or operational value. This is typically done autonomously – without human intervention. The key elements of the BNMC micro-grid are listed in the attached Appendix.

The Project will develop and test the necessary software to present market opportunities and pricing models for customers. The pricing models will test the economic effectiveness of the use of existing and new DER capabilities in improving the performance and efficiency of the electric distribution system. The software will provide the following:

- Identify and address current and anticipated electric distribution system requirements;
- Facilitate DER/load deployment;
- Enable the exchange of historical and real-time event information;
- Enable the exchange of demand response provider data; and
- Provide market information to aid customers' decision making on investment in DERs.

Customer Segmentation and Demographics

The BNMC, consisting of 13 member institutions and close to 100 public and private companies that are a dynamic mix of health care, life sciences, medical education, and private enterprise, is a significant growth engine of Western New York. At 7 million square feet of infrastructure today with 2 million square feet of new construction currently underway, the BNMC has its sights set on accommodating an additional 5.3 million square feet by 2030 to achieve its long-term vision as a comprehensive Community Engaged Academic Health Center in Downtown Buffalo.

The Project will impact all member institutions of the BNMC (see Participation Section herein for details) but the Project expects to interface primarily with the BNMC's three major entities, Roswell Park Cancer Institute, University at Buffalo, and Kaleida Health, most frequently because these have the largest number of potential DERs. See attached Appendix for a complete list of all available and potential future DERs within the BNMC.

Channels

The BNMC acts as an umbrella organization for the member institutions and helps to provide a single point of contact and administration for the Project. The BNMC's member institutions and the BNMC recently completed a Stage 1 Feasibility Study under the NY Prize Competition[6] and are in the process of conducting several other studies in Stage 2 to outline possible strategies to accomplish the objectives of the competition and compare the economic and non-economic (*e.g.*, resiliency) costs and benefits of each. Upon conclusion of Stage 2, the BNMC plans to present the team's findings and recommendations to the executive teams of its member institutions. It should be noted that Stage 1 and Stage 2 of the NY Prize financial award is valuable to the Project in that it will enable quantifiable feasibility (technically & economically), which is most important.

For the member institutions of the BNMC, the test of a DSP marketplace will provide the opportunity to consider potential investments in capabilities to manage current DERs to benefit from the marketplace and to consider additional investments to expand DER capabilities. The

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[6] The NY Prize Community Micro-grid Competition ("NY Prize") is administered by NYSERDA"), with support from the Governor's Office of Storm Recovery, to promote the design and build of community micro-grids that will improve local electrical distribution system performance and resiliency in both a normal operating configuration as well as during times of grid outages. NY Prize offers financial support for feasibility studies (Stage 1), audit-grade engineering design and business planning (Stage 2), and project build-out and post-operational monitoring (Stage 3).

DSP marketplace is expected to provide opportunities to member institutions through potential new revenue streams.

Given that the Project is an extension of National Grid's collaboration with the BNMC member institutions in the development of their Energy Innovation Plan in 2011/2012, as well as its current engagement with the BNMC in the implementation of the Plan's energy initiatives through its campus-wide Energy Innovation Council, no additional communication, sales and/or promotion channel needs have been identified relative to the BNMC at this time.

Scalability

There is also the potential for the BNMC POCs to serve as a common platform for other regional DERs whose operator(s) lack the financial resources and/or motivation to invest in their own POC to interface with the DSP. Providing other DER customers this option will not only create an avenue for their market participation, but could ultimately lead to the creation of regional dispatch capabilities with resulting efficient and cost-effective demand elasticity. In acting as the DSP's single point of contact for multiple DER assets, customers will benefit from the monetization of additional electric distribution system efficiencies. This will allow the DSP to improve the overall efficiency of the electric distribution system. The Project will provide a better understanding of DSP market dynamics that can be applied to more locations within National Grid's New York service territory.

Demonstration Plan

Statement of Work

The Project will be conducted in three phases by National Grid and its partners. Phase 1 will develop the financial model that will provide the opportunity for customers to consider use of potential DER assets. This work will develop event-driven pricing for day-ahead peak periods and contractual pricing for blue sky periods and test that model using historical data to help determine the prices applicable to each service requested from the DERs. Phase 2 will utilize the financial model developed in the first phase to develop the technology functionalities of the DSP and POCs. Phase 3 will be the field demonstration that will include deployment of the DSP and POCs with those DER assets owned by members of BNMC, measurement and valuation ("M&V") tasks, and evaluation of results. Throughout the Project, Go-No/Go decision points will be used to solicit feedback from DER and POC operators and additional scenarios and pricing models will be developed if necessary. Figure 4 below summarizes the interactions within and between each phase.

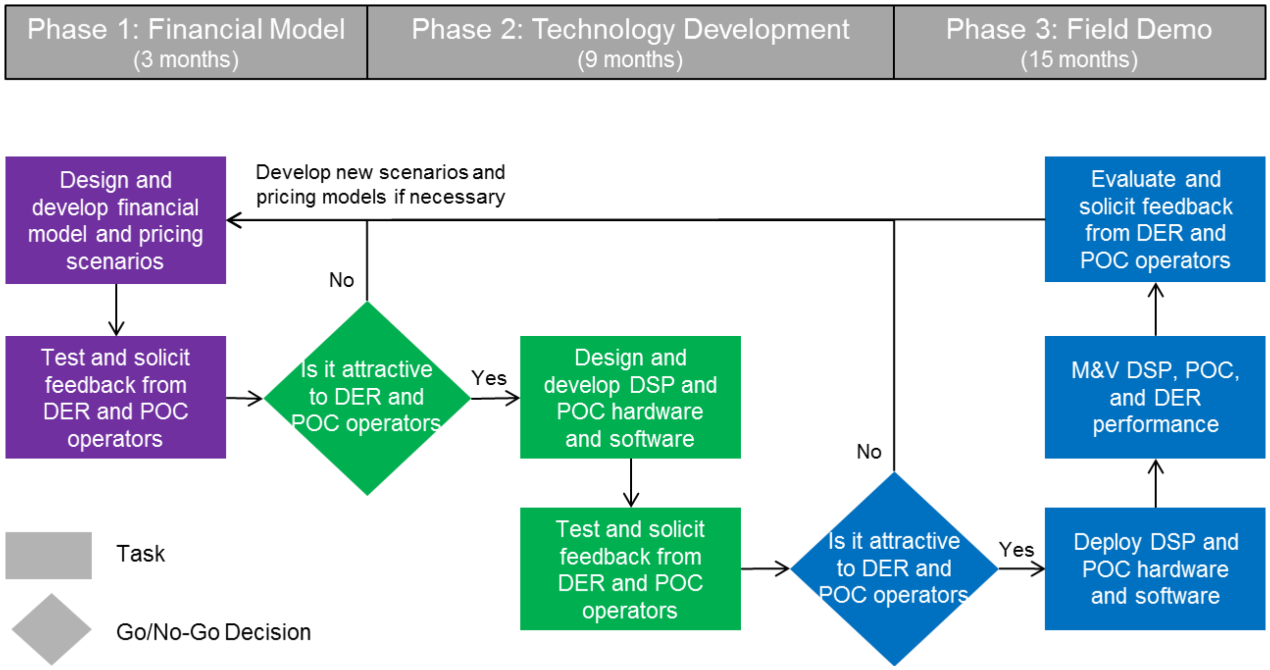

Figure 4: Project Phase Interactions

Phase 1 - Financial Model

Phase 1 will develop a detailed financial model that can be used to test which DER capabilities are most cost effective and the willingness of customers to participate in the DSP market activities. The LMP+D+E approach described earlier will be used as a basis for the proposed financial model.

This phase of the Project will start by understanding the inputs an asset owner would require to determine if operating their DER would be feasible and economical. This information will consist of items such as the required customer operation lead time, frequency of requests for the customer's operation, duration of each requested event, time of day, and season of the year. Additional types of information that will also be considered include options for event engagement, penalty conditions, regulatory constraints, and audit processes.

Based on this understanding, the Company will develop a detailed financial model for the services within the scope of the Project based on the DER assets that BNMC member institutions currently have, National Grid's historical and forecasted load information, and the NYISO day-ahead hourly pricing data. National Grid will develop test cases that will utilize these various components and the varying seasonal impacts for refinement and validation of the model.

This model will then be used in two ways. First, the model will be populated with historical data so DER owners can make investment decisions to help them determine how their existing DER inventory – and how potential additions to that inventory - can be leveraged in the market. Second, the model output will drive events and prices that DER operators can accept, counter, or decline.

Determination of LMP

The model will use the NYISO Day Ahead Market Zonal LBMP Zone-A West as the base (*i.e.*, "LMP") price adjusted for losses in delivery to the customer. The NYISO day-ahead hourly price reflects projected market conditions and prices for the next day. The use of the day-ahead price allows the customer time to take appropriate actions with their DERs. Customers will receive this value for the export of power onto the grid. Thus, if the customer reduces use or increases generation output, reduction or generation will be paid this value.

In addition, the Company will investigate as part of the Project how to map the installed capacity ("ICAP") values as compensation for generation during peak times. The Project will develop two options. The first option will be to pay for generation or demand reduction during the hours projected day-ahead to have a high probability of being the system peak. The second option will be by contract for blue sky periods of operation. The Project will assess customer favorability to each approach and then develop a final offerings based upon these assessments.

Determination of +D

The second component of the financial model is distribution system optimization compensation (*i.e*., value of D). The Project will test how the DER capabilities (*e.g*., energy supply, VAR support, voltage management, peak load modifications, and dynamic load management) can be integrated into the operations of the electric distribution system to alleviate issues such as substation constraints, feeder constraints, voltage issues, etc. This component of the Project will evaluate the capabilities of customers to allow DER integration, potential savings from DER integration, and administrative costs to manage DER integration. The Project will take into consideration items such as substation constraints, voltage support, and feeder constraints. It also will consider average demand, peak demand, day-ahead load forecast, and historical demand at both the feeder and substation levels. Also, expected future growth and proposed new DER installations within the BNMC area will also be considered. Historical, current and forecasted information will be utilized to understand current and future needs. These items will be used to establish the values for the value of D.

To limit the scope of the Project and reduce overlap with other projects, the value of "E" will not be evaluated in the Project. However, the Project could use values of "E" determined by other means to see what impact it would have on encouraging new DER assets.

Phase 2 – Technology Development

The work completed in Phase 1 will be utilized to inform the development, customization and integration of a successful DSP platform and a POC platform as many of the requirements will be defined during the Phase 1 work. Development will be conducted by National Grid and its partners for the Project. The DSP will be licensed and operated by National Grid and developed with its partners. Various POC ownership models will be evaluated during the course of the Project. For the purposes of the Project the POC will be licensed by National Grid, operated by the participating BNMC members, and developed with National Grid and its partners on this Project including Opus One.

Distributed System Platform

Based on the results from Phase 1, work will begin to develop the DSP. The DSP will define schedules and events with pricing, monitor participating DERs, and feed and generate the necessary data to run the financial model built during Phase 1. The resulting output will be used to create events, schedules, and prices that DER owners can utilize to make decisions as to whether or not to participate. These generated events would maximize distribution system operational performance and monetary benefits and would come solely from the DSP. There would also be additional feeds for scheduled demand response events or load reduction requests from the NYISO, National Grid Distribution Control, and/or demand response operations. The output of the DSP will be twofold:

- Events that optimize electric distribution system performance; and
- Events that are triggered from price signals in the NYISO market.

In addition to required hardware and software, the delivery of the DSP will include, at a minimum, the analytics and algorithms to provide the following outputs:

- Development of the automated financial model
- Generation of events at the customer, branch, feeder, and substation level that will process requests for load reduction and demand response from National Grid, NYISO, and/or other entities
- Development of day-ahead pricing model for peak demand reduction that considers:
    - Transmission and distribution ("T&D") deferrals
    - Area distribution congestion at the feeder, substation, and NYISO zone levels
    - Projected peak demand periods
- Process and manage the scheduling of generated events including:
    - Creation of scheduled events
    - Communication of events
    - Acceptance or decline of events by the participant's POC
    - Execution of events
    - Settlement of events
- Real-time monitoring and inventories of customer-owned DER availability
- An Optimization Platform that maximizes economic value (*i.e.*, savings, avoided costs, etc.) through the efficient use of the existing and future portfolio of DERs, including co-generation, renewables, storage, alternative fuels, alternative generation, energy efficiency, demand response, and demand management capabilities.
- Development of a Command and Control model of customer-owned DERs through a POC framework
- 2-way communications with POCs
- Provisioning of data flows from such sources as:
    - Load forecast estimates
    - Real-time electric distribution load information
    - Geographic information systems ("GIS") data
    - Availability of customer-owned DERs
    - Meter information
    - Customer information
    - Day-ahead pricing resources
- Development of an approach and logic that will provide analysis of the electric distribution system at the customer, branch, feeder, substation, and zonal levels to determine different types of DER resources that would be beneficial to the electric distribution system, third parties and customers
- DERs that not only respond to market prices but also to market opportunities to enhance the electric distribution system
- Development of a web portal(s) that would provide access to this information as a DSP service to potential third parties while observing customer confidentiality requirements

The common interface between the DSP and the POC can be utilized by any other third-party developer for use by DER asset owners or aggregators. The interface would, at a minimum, have the capabilities to securely send and receive any:

- DER information to/from the DSP
- Real-time run information

- Scheduled, unscheduled, accepted and/or declined events
- Pricing information

The very nature of the data and connections requires a very robust and secure environment to be developed in strict accordance with National Grid's cybersecurity standards.

Figure 5 below shows a very high level conceptual view of what types of components, universal data sources, and data flows that would potentially be required as inputs and outputs of a highly effective DSP.

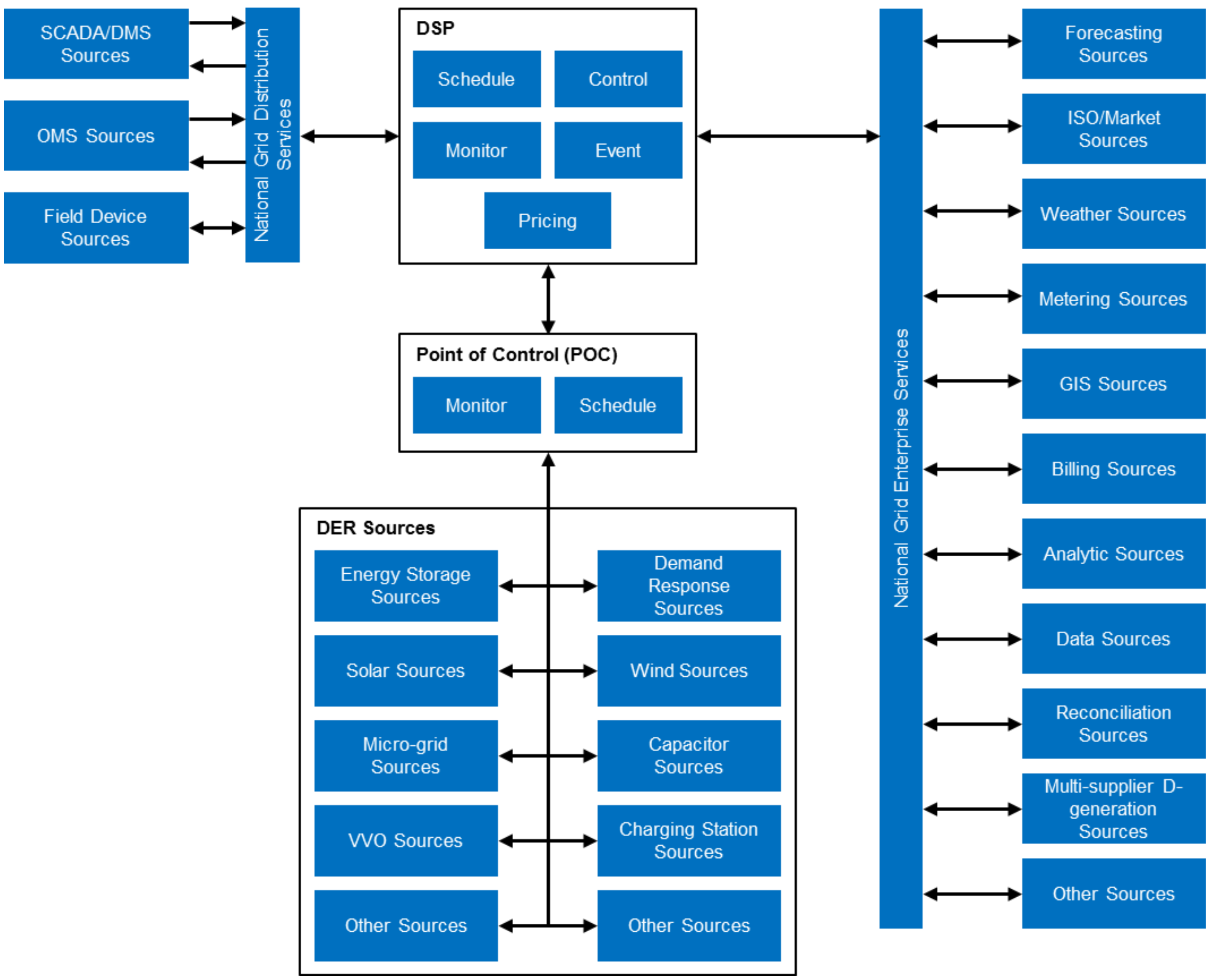

Figure 5: High-level DSP Flow Chart

Point of Control

The POC would be the central communications portal between the DSP and associated customer-owned DERs with a common, re-usable interface(s). The various BNMC POCs would communicate with the DSP as to the system availability of individual and aggregate customer-owned DERs. The various POCs would include all of the member institutions' available DERs and would dispatch them according to received scheduled events and respective of agreements between member institutions and the DSP.

The POCs would have, at a minimum, the capability to transmit to/from the DSP:

- All DER availability
- Real-time run information
- Receipt of scheduled events
- Accept/Counter-offer/Decline of events

All of which would be through a secure, command/control functionality across the BNMC POCs.

The POC would be developed so that it is scalable. While initially developed for the Project, it would be designed for use by any customer or third party seeking a platform to utilize the services and market opportunities provided through the DSP. As it is currently scoped, National Grid will develop the POC software in collaboration with its partners. All DSP interfaces would be developed as a standard services package so that any entity would be able to develop or customize their own POC software, which would add to market development of software. Additionally this will allow National Grid to replicate this model for different services in different areas.

The POC will utilize a combination of:

- Command and Control Functionality that serves to interface command and control capabilities with the local electric distribution grid infrastructure to enable the customer portfolio of DER capability to serve as an asset to the benefit of the electric distribution system
    - Customers would have the opportunity to choose whether to maintain control over their DER capability or allow National Grid to control the DER capability.
    - The model will need to also recognize that customers could choose not to participate in events.
- DERs that not only respond to market prices but also to market opportunities to enhance the electric distribution system
- A data display to enable analysis and real-time visualization for the purposes of POC and DSP operations.

The POCs would have, at a minimum, the capability to:

- Send and receive all customer-owned DER information to the DSP such as:
    - Real-time run information
    - Resource availability (*i.e.*, available, not available, out of service, running)
    - Acceptance, counter-offer, or declination of events from the DSP
- Perform real-time monitoring and command/control of all customer-owned DER
- Determine scheduling of customer-owned DER based on agreements between the members, and/or agreements between the BNMC POC and the DSP
- Create requests to operate customer-owned DERs outside the real-time operational requirements of the DSP based on agreements between the parties
- Perform two-way, real-time communication between the DSP and POC, and between the POC and customer-owned DERs
- Communicate events to appropriate customer-owned DERs
- Interface with web portals to perform minimally all functionality described above

Development of a common set of re-usable services that will provide any:

- Customer-owned DER information to the DSP
- Real-time run information

- Scheduled, accepted, countered, declined events
- Command/control information
- Approved customer information for use by third-party aggregators per customer confidentiality provisions

The Application Program Interfaces ("APIs") and other common interfaces developed during the Project could be utilized by any other POC that may subsequently be developed by a third party. The APIs and other interfaces would, at a minimum, have the capabilities to securely send and receive any and all data needed for successful operation with the DSP. A POC deployment document and a DER asset deployment document will be created for use in Phase 3 of the Project to ensure fast, proper and consistent installation at member sites.

Phase 3 – Field Demonstration

Phase 3 will be the deployment and operation of the local DSP at National Grid, standing up the network and communications to each POC at the participating members, the deployment and operational readiness of a POC at participating members, and getting the participating members' DERs ready for operation to participate in DSP events.

Once all of these components are operationally ready, the DSP will start to generate and send the pricing signals and/or contractual events to the POC. The POC operator will be able to address the pricing signals and/or events and confirm the participation of the DER(s). All participation types (accept, counter-offer, and decline) will be recorded by the DSP for reconciliation and reporting purposes. The participation by DERs based on the initial financial model and their overall impact to the improvement to the electric distribution system optimization are key findings for this project.

The details of this phase, including the M&V process, will be further described in the Project's Implementation Plan.

Metrics for Success

The success of the Project will be measured by its ability to support and inform the multiple functions of the DSP as described within the REV Track One Policy Order. The Project will develop insights regarding what can and cannot be used successfully from an economic and operational perspective. These learnings will improve the ability to support and inform future development and operation of the DSP. The Project success will be evaluated using the following metrics.

1. Transparent Integrated System Planning for Current and Future Needs
    - Assess ability and willingness of BNMC POC's to help address projected electric distribution system issues
        - Key DSP-related challenges and benefits for each type of DER technology and operator
        - Range of price points and relative magnitude of other revenue opportunities sufficient to engage current DER operators and encourage new DER investment
    - Provide the above and other critical information to National Grid's larger, system-wide DSP

2. Electric Distribution System Benefits
    - Evaluate the potential to use the BNMC POCs (*i.e.*, model POC interface) to accomplish short-cycle load relief to alleviate forecasted electric system issues, including:

    - Voltage and frequency regulation
    - Maintain power quality
    - Reduce annual peak loads
- Maintain resiliency in the area during weather and system events that threaten the integrity of the electric distribution system
- Evaluate the potential to defer future infrastructure spending, including:
    - Reduce LTC operations
    - Reduce peak load
    - Reduce feeder peak capacity requirements

3. Market Operations
- Establish market mechanisms that enable increase rate of DER penetration
- Establish a M&V methodology to ultimately inform electric system efficiency

Timelines, Milestones, and Data Collection

The timeline for each Phase of the Project is summarized below and graphically presented in Figure 6.

- Phase 1: Financial Model (3 months): completed 3 months from the Project start date
- Phase 2: DSP and POC (9 months): completed 12 months from the Project start date
- Phase 3: Field Demonstration (15 months): completed 24 months from the Project start date (note that the Project will likely continue beyond the 15-month period if the Project is successful)

Prior to the start of each subsequent phase of the Project, there would 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.

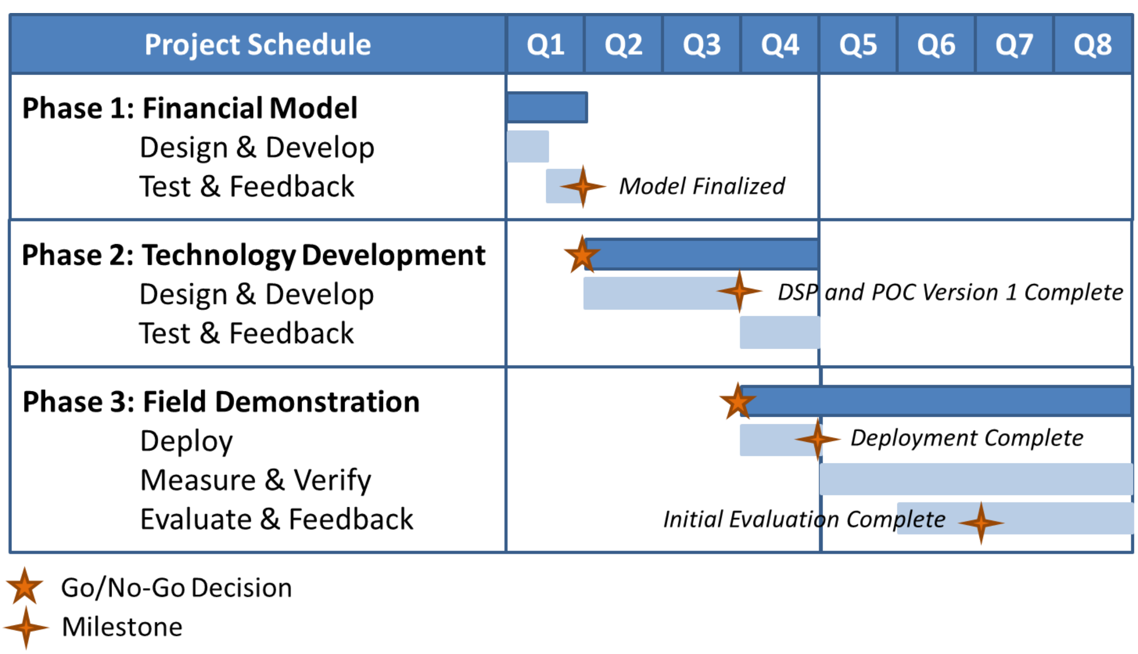

Figure 6: Project Timeline

National Grid anticipates the following short-term schedule (week of):

06/17/2016	Refiling filing
06/20/2016	Approval Letter
06/27/2016	Assessment Report
07/04/2016	Implementation Plan
07/11/2016	Project Kickoff

Participation

Third-Party Partners
The BNMC and National Grid conducted an extensive review of software vendors and selected Opus One as the vendor partner to develop the software-based operating system for the Project. Opus One has developed a real-time operating system for the smart grid that integrates DERs such as generation, storage and demand, with information resources such as SCADA, sensors, meters and analytics, to optimize the grid including reliability, power quality, asset utilization, and cost of operation. Opus One will subcontract with and report to National Grid, but will work with all project partners, and will be an important part of all three phases of work.

BNMC Resources
The BNMC, while consisting of 13 member institutions and close to 100 public and private companies, will interface primarily with the following member institutions on the Project:

- Buffalo Niagara Medical Campus, Inc.
    - Innovation Center
    - Cleveland BioLabs
- Hauptman-Woodward Medical Research Institute
- Kaleida Health
    - Buffalo General Medical Center
    - Gates Vascular Institute
    - HighPointe on Michigan
    - Oishei Children's Hospital (opening 2016)
- Roswell Park
    - Cancer Institute
    - Center for Genetics & Pharmacology
    - Clinical Sciences Center
- University at Buffalo, State University of New York
    - School of Medicine (opening 2017)
    - Clinical and Translational Research Center
    - NYS Center of Excellence in Bioinformatics and Life Sciences
    - Research Institute on Addictions

The BNMC's three major entities, Roswell Park Cancer Institute, University at Buffalo, and Kaleida Health, have the largest number of potential DERs. See attached Appendix for a summary of related BNMC work and a complete list of all available and potential future DERs within the BNMC.

Utility Resources
The Project will leverage the knowledge and expertise of the following National Grid departments:

- Asset Management
- Customer Organization

- Electric Operations – New York
- Network Asset Strategy
- Advanced Data & Analytics
- Network Strategy
- New Energy Solutions (includes DSIP team)
- New York Pricing
- Western Region Control Center Operations
- Western New York Jurisdiction Team, and
- Wholesale Electric Supply

Customer Outreach/Community Engagement

Motivating Customers/Communities

In 2012 National Grid and BNMC forged a unique partnership, known as energizeBNMC to develop an Energy Innovation Plan. Under the guidance and direction of the BNMC Energy Innovation Council, the plan represents a new approach to energy innovation that integrates energy efficiency, grid modernization, alternative transportation and renewable energy in the context of a growing medical and life science campus. Additionally, the BNMC community, which includes the Campus proper, the adjacent Fruit Belt and Allentown neighborhoods, and downtown Buffalo, is bound together by a common *Four Neighborhoods, One Community* vision. While each distinct neighborhood has unique strengths and issues to confront, an effective interrelationship of the four areas creates a very powerful and vital urban setting.

The Energy Innovation Plan took shape when campus leadership, in speaking with leaders in the energy field, realized that as the campus grew, its energy needs, coupled with a desire to demonstrate leadership and innovation, would evolve as well. The campus needed to think differently and to think of energy in new ways to secure the capacity necessary for their expected growth. Formation of the Plan began by identifying key stakeholders and partners, including on campus, such as BNMC institutions; within the community; regulatory and business. Through extensive stakeholder engagement, including one-on-one interviews, listening sessions, and workshops, the partnership was able to understand the various needs and priorities of all stakeholders. Based on those sessions and the feedback received, the partnership was able to identify and develop the Energy Innovation Plan Vision, as well as the supporting pillars, necessary to achieve that vision:

> *The National Grid partnership with the Buffalo Niagara Medical Campus will define and implement the global standard for an efficient, modern, high-quality and customer driven platform. National Grid will provide a world class customer experience while enabling BNMC plans for economic growth and innovation both on campus and in the broader Buffalo-Niagara region.*

Building on the vision, feedback from the stakeholder engagement sessions were synthesized into five opportunity areas; cost-cutting energy efficiency, foster local economic growth, alternative energy & transportation, ability to serve as a hub for learning and health+energy innovation. Numerous initiatives, including REV and NY Prize activities, have been integrated under each opportunity area as these initiatives have unfolded with the expectation that those opportunities would evolve as the Energy Innovation Plan progressed over time.

The willingness of the BNMC member institutions, both individually and collectively, to collaborate with National Grid on the Project is based on their respective priorities as they relate to reliability, cost, and sustainability objectives. National Grid and BNMC plan to continue their strong partnership and motivate active participation from the BNMC member institutions using frequent reporting, meetings, and hands-on demonstrations.

Outside of regularly scheduled BNMC Energy Innovation Council meetings, which include the member institutions and occur monthly from January to June and September to December, the Project team will meet quarterly to prepare an update report for Staff and the Commission.

In step with the Project Schedule (see page 16), each phase of the project will require ad hoc meetings with member institutions individually. These meetings are necessary to capture the many unique factors needed to build out the financial / functionality models. For instance, since existing and scoped DER technology differs from location to location, capabilities of those technologies will also differ as will the constraints and/or limitations of those assets and the constraints and/or limitations of the DER owner.

Conditions / Barriers

The BNMC aspires to optimize both revenues and energy savings opportunities from their growing and evolving inventory of DERs. As discussed earlier in the "Hypothesis Being Tested" section, the Project seeks to determine which financial incentives (*e.g*., the value of D) will engage and motive BNMC and other customers to participate in the DSP market and invest further in DERs. The specific questions to be answered are:

1. What are the functional, operational, and monetary benefits to the electric distribution system and the DSP operator that flow from the POC based on the capabilities of customer-to-grid DER?
2. What is the customer participation rate at offered electricity prices or other revenue opportunities?
3. Would prevailing electricity prices or other revenue opportunities provide sufficient financial motivation for customer investment in new DER and participation in animated markets?

The key Project barriers are listed below. The scope of work outlined previously includes Go/No-Go decision points and other elements to mitigate each barrier as much as is feasible.

- 28 MW of diesel generation presents regulatory barriers for use
- Price signals and/or other DSP revenue need to be capable of attracting current DER assets
- Price signals and/or other DSP revenue opportunities need to be able to attract new DER assets
- National Grid will need experience and comfort integrating DERs versus traditional assets

Financial Elements / Revenue Model

New Utility Revenue Streams

National Grid has multiple options to attain new revenue streams through the DSP operation. The options presented below will be evaluated and quantified in Phase 1 and tested in Phases 2 and 3.

1. Provide one-time data as a service about distribution optimization opportunities to help BNMC members make decisions on their potential investments in DER assets.
    a. One-time fee
    b. Monthly or annual fee

2. Access to DSP only
    a. Monthly or annual fee
    b. License agreement
    c. X% of KW added/removed
    d. Contractual agreement
    e. Data as a service
    f. Customer owned POC
    g. Any combination of 2a - 2f

3. Access to DSP and POC
    a. Monthly or annual fee
    b. License agreement
    c. X% of KW added/removed
    d. Contractual agreement
    e. Data as a service
    f. Any combination of 3a - 3e

Investments

Details and Timing of Spending

The Project will require an initial investment in equipment and software, as well as operational and maintenance resources, to complete Phases 1, 2, and 3. Prior to the start of each phase, there would 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.

The total budget requirement for the Project is $6.81 million, of which $2.00 million will be provided as in-kind cost-sharing by the Project partners. Therefore, the total funding request is $4.81 million. Budget requirements and timing for each phase of the Project are provided below and budget details are provided in Figure 7. Once the final revenue and incentive numbers have been defined, they will be factored in.

- Phase 1: Financial Model (3 months): $0.5 million CAPEX completed 3 months from the Project start date
- Phase 2: Technology Development (9 months): $4.3 million CAPEX, $2.0 million cost share, and $30,000 OPEX completed 12 months from the Project start date
- Phase 3: Field Demonstration (15 months): $1.625 million CAPEX and $335,000 OPEX completed 24 months from the Project start date. Note that the operation of the DSP will likely continue beyond the 15-month period if the Project is successful. The continued operation would need to be paid for by ongoing revenue or similar means.

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**

Figure 7: Project Budget Requirement Details

Leveraging of Third Party Capital

$2 million will be provided as in-kind cost-share by the Project partners. In addition, the Project will likely benefit from at least some of the current 24 DER assets installed at the BNMC. Potential DER additions for the BNMC, which represent approximately $30.8 million in installed costs have been initially scoped subject to further and more detailed feasibility assessment. This project will benefit as a result of modeling those scoped assets in a simulated manner against and with existing assets. See Appendix for details.

Cost Effectiveness

It should be noted that the Project cannot presuppose qualitative and/or quantitative benefits for National Grid's customers. The cost effectiveness of this Project will be calculated as the Project moves forward and the values (revenues, incentives, etc.) become known. It is expected that the conclusions of the Project will inform cost-effectiveness. The Project is expected to result in significant experiential learning and data that will improve the understanding of how DSPs can enable system-wide benefits due to increased use and integration of DERs. Examples of some of these system-wide benefits are:

- Market Animation and Leverage Customer Contributions (*e.g*., direct price signals and other revenue opportunities to customers with DER assets)
- System-Wide Efficiency (*e.g*., efficient operation of the distribution network)
- Fuel and Resource Diversity (*e.g*., DERs operating on natural gas or solar)
- System Reliability and Resiliency (*e.g*., DERs for reliable, localized, and resilient capacity and energy)
- Reduction of Carbon Emissions (*e.g*., solar PV, demand response via BEMS)

Reporting

Information to be Included in Quarterly Reports to Staff and the Commission

Quarterly progress reports on the stakeholder and business model work will be provided to Staff and the Commission. These reports will include at a minimum an overview of the Project progress against timeline/plan/budget and all stated metrics, and will include results as they become available. Additionally, in order to maintain flexibility and maximize the potential for innovation and learning, the 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 the reports:

- Executive Summary
- Highlights Since Previous Quarter
    - Major Task Completion
    - Challenges, Changes, and Lessons Learned
- Next Quarter Forecast
    - Checkpoints/Milestone Progress
- Work Plan & Budget Review
    - Updated Work Plan
    - Updated Budget
- Progress Metrics
- Appendices

To further ensure alignment, the Company 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 highlighted 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.

Conclusion

In leveraging the POC "test bed" opportunity afforded by the actively engaged and motivated customers within the BNMC, the Project stands to achieve not only a model POC interface with the DSP that can be utilized and/or modified by other customers to enable their participation in the market, but also an evolving test bed to evaluate what price signals can effectively engage customers towards the electric distribution system optimization envisioned by the DSP framework. The Project will proactively create a "living lab" environment that will not only serve to inform the DSP of National Grid and other utilities, but will also serve to further the evolution of the DSP.

The Project seeks to inform and achieve the following DSP functionalities:

- Identify and address current and anticipated electric distribution system needs;
- Facilitate DER/Load visibility, cross-communication, monitoring, control, and coordination;
- Enable the exchange of historical event information and;
- Enable the exchange of DER provider data.

Appendix

BNMC DER Installations and Future Capacity

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,[7] including:

- 28 MW from 24 diesel engine generators
- 1 MW from demand response/load reduction capacity available from BEMS throughout the BNMC

Existing DER Asset	Nameplate Capacity	Owner/Location
8 x Diesel Generator	9.975 MW	Kaleida Health
3 x Boiler	150,000 lb./hr.	Kaleida
13 x Diesel Generator	13.725 MW	Roswell Park Cancer Institute
3 x Boiler	210,000 lb./hr.	Roswell
2 x Diesel Generator	0.825 MW	Cleveland Bio Labs
1 x Diesel Generator	2.5 MW	UB Medical School
Diesel Storage Tank	103,700 gal	(each facility)
9 Chiller	10,000 MW	Roswell
4 Chiller	6000 MW	Kaleida
2 Chiller	170 MW	Cleveland Bio labs
2 Chiller	3500 MW	UB med school
Thermal Distribution System (CHP use possibility in NY Prize)	N/A	Kaleida/Roswell
Electrical Distribution Assets	N/A	National Grid

BNMC is currently evaluating increasing DER capacity by adding 19 MW, including:

- 7.7 MW from one natural gas combustion turbine generator with CHP
- 10 MW from two natural gas engine generators
- 1 MW from three solar PV systems
- 150 kW (600 kWh) from three Li-ion battery energy storage systems

Potential Future DER Asset	Nameplate Capacity	Energy Source	Owner/Location
Gas Combustion Turbine (Combined Heat & Power)	7,692 kW	Natural Gas	Roswell Park Cancer Institute
Internal Combustion Engine #1	5,000 kW	Natural Gas	Kaleida Health
Internal Combustion Engine #2	5,000 kW	Natural Gas	Kaleida Health
BNMC PV System #1	320 kW_{DC}	Solar	Kaleida Health – Children's Hospital
BNMC PV System #2	260 kW_{DC}	Solar	U.B. School of

[7] This current capacity does not include the approximate 25 kW of residential solar PV being installed in the Fruit Belt Neighborhood.

			Medicine
Fruit Belt Distributed PV Systems	500 kW_{DC} – Total	Solar	Fruit Belt Neighborhood
Li-Ion Battery #1	50 kW / 200 kWh	Storage	Fruit Belt Neighborhood
Li-Ion Battery #2	50 kW / 200 kWh	Storage	Kaleida Health – Children's Hospital
Li-Ion Battery #3	50 kW / 200 kWh	Storage	UB School of Medicine

These additional DERs were identified in a feasibility study partially funded by the NYSERDA Smart Grid PON 2715 and the New York Prize Community Micro-grid Competition. The study also identified the necessary micro-grid capabilities that would allow the BNMC to meet almost 90% of their energy needs with on-site generation. These DERs will not be part of the Project as proposed but could be including in ongoing operation of the DSP beyond the Project period of performance. The key elements of the BNMC micro-grid are listed below:

- Smart meters - Enable two-way communication between meters and the central system
- Data display - Enable analysis and visualization.
- Command and control - Integrate campus level command/control capabilities with the distribution grid infrastructure linking customer to utility enabling our collective portfolio to serve as a smart grid asset.
- Generation switch - In response to price or shortage, having a menu of generation options providing base load power, and/or peaking power; will enhance reliability, and generate savings.
- Market interface - Utilize this diverse and flexible set of campus assets monetizing capabilities in existing NYISO market and/or in future distribution level markets to generate a revenue stream.
- Optimization platform - Maximize economic value (*i.e.*, savings, revenue, avoided spend) through the efficient use of DERs such as cogeneration, renewables, storage, alternative fuel / generation resources, and controllable loads. That is a campus centric view. With a well-developed, robust optimization platform you could layer in the topology of campus DER's with forecasted load, generation and constraints to create a dynamic, forward looking dispatch schedule for use by the distribution utility as a system resource.
- Island - Resiliency; protection against catastrophic events and ability to serve as the community safe haven.
- Black Start capabilities, potentially
- Demand response/dynamic load management - Capability of the collective campus portfolio to appear to the market operator (DSP or NYISO) as a single dispatchable load providing load reduction or management services either bid based or via a bi-lateral arrangement with the market operator.