May 24, 2017

VIA ELECTRONIC DELIVERY
Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV)

NATIONAL GRID DISTRIBUTED GENERATION INTERCONNECTION REV DEMONSTRATION PROJECT – IMPLEMENTATION PLAN

Dear Secretary Burgess:

Niagara Mohawk Power Corporation d/b/a National Grid ("Company") submits for filing the Distributed Generation Interconnection REV Demonstration Project (the "Project") Implementation Plan as required by the Department of Public Service Staff's ("Staff") April 24, 2017 letter approving the Project with modifications.

Please direct any questions regarding this filing to:

Allen C. Chieco
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National Grid
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Albany, NY 12204
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The Company looks forward to continuing to work collaboratively with Staff as it proceeds with the implementation of the Project.

Respectfully submitted,

Allen C. Chieco
Allen C. Chieco
Director, Asset Management
National Grid

Enc.

cc: Tammy Mitchell, DPS Staff, w/enclosure (via electronic mail)
Michael Worden, DPS Staff, w/enclosure (via electronic mail)
Denise Gerbsch, DPS Staff, w/enclosure (via electronic mail)
Christian Bonvin, DPS Staff, w/ enclosure (via electronic mail)
Marco Padula, DPS Staff, w/ enclosure (via electronic mail)

Implementation Plan Distributed Generation Interconnection
REV Demonstration Project
Case 14-M-0101
Reforming the Energy Vision

Niagara Mohawk Power Corporation d/b/a National Grid

May 24, 2017

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Executive Summary

On February 14, 2017, Niagara Mohawk Power Corporation d/b/a National Grid ("NMPC" or the "Company") filed a proposal for the Distributed Generation Interconnection REV Demonstration Project (the "Project") in Case 14-M-0101.[1] The Project is designed to test alternative solutions for increasing the pace and scale of interconnecting distributed generation ("DG") systems above 50 kW through upfront investments by the Company coupled with a cost-allocation methodology aimed at removing barriers for DG interconnection applicants. By letter dated April 24, 2017, New York State Department of Public Service Staff ("DPS Staff") directed the Company to file an implementation plan. The purpose of this implementation plan (the "Implementation Plan") is to describe NMPC's execution plan and the core team supporting the Project.

For the Project, the Company will upgrade equipment at the Peterboro and East Golah substations (the "Demonstration Areas") by installing $3V_0$ ground fault protection. These upgrades will effectively make the system "DG-ready," capable of interconnecting current, as well as future, DG projects in the respective Demonstration Areas. To recoup the investment costs, NMPC will charge a pro-rated fee to all applicants (not just the first applicant) with DG systems above 50 kW who connect to the upgraded substation transformer banks in the Demonstration Areas. For accounting purposes, the Company will place the costs of the common-system upgrades as well as fees received from DG applicants in a regulatory asset. To the extent the fees do not equal the costs, the Company will recover or pass back the residual balance in the regulatory asset in a future proceeding.

Design and engineering work is underway with construction anticipated to be completed by December 2017. From the end of common-system upgrade construction, the Project will continue for six months. During that time, the Company will use the Project to test:

- Assumptions that DG developers will respond to shorter construction timelines and known costs;
- Whether upfront investment with post-upgrade cost recovery is a feasible mechanism for DG applicants and the Company; and
- Methods for effectively marketing capacity to DG developers seeking to interconnect with the Company's system.

[1] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), "Proposed Distributed Generation Interconnection REV Demonstration Project" (filed February 14, 2017).

Project Design

Standard Station Upgrade Process

There are two types of distribution system upgrades that may be required before a DG project can be interconnected: common-system upgrades and site-specific upgrades. Site-specific upgrades benefit a single applicant, whether located on private property or in the public way (*e.g.*, new poles, meters, or switches at an applicant's facility). Common-system upgrades provide support to an area of the Company's electric power system and can benefit multiple interconnection customers (*e.g.*, high-side transmission ground fault overvoltage protection equipment, known as $3V_0$ protection, transformer load tap changer, and other substation upgrades) because the upgrades, once made, often allow additional customers to interconnect to the distribution system. The Project addresses common-system upgrade costs for $3V_0$ protection.

Currently, the DG applicant whose proposed service would result in the need for the Company to upgrade its system is responsible for 100 percent of the common-system upgrade costs.[2] Subsequent DG applicants who benefit from the common-system upgrades reimburse the earlier applicant who paid the upgrade costs.[3] The Commission and DG applicants have indicated that common-system upgrade costs create economic barriers to siting more DG projects.[4] Even with the new cost-allocation mechanism recently adopted by the Commission,[5] the timing and uncertainty of reimbursement likely remains a difficult hurdle for developers to overcome, as does the fact that the initial applicant still has to pay the total upfront costs for its project to move forward. Recognizing that other cost allocation methodologies may exist, the SIR Queue Management and Cost Allocation Order indicated that stakeholders may propose alternatives to the current cost allocation mechanism.[6] This Project seeks to test an alternative method to attract more DG projects in the Company's service territory.

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[2] Standardized Interconnection Requirements (issued February 2017) ("SIR"), Appendix E ("[T]he first project triggering an eligible upgrade will initially bear 100% of the cost, while subsequent projects benefitting from those upgrade [sic] will reimburse the first project developer").

[3] SIR, Appendix E.

[4] *See* Case 16-E-0560, *Joint Petition for Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems* (the "SIR Queue Management and Cost Allocation Proceeding"), Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings (issued January 25, 2017) (the "SIR Queue Management and Cost Allocation Order"), p. 29; *see generally*, Case 16-E-0560, the Queue Management and Cost Allocation Proceeding, Comments of SolarCity Corporation on the Petition of the Interconnection Policy Working Group (December 5, 2016), p. 3 ("SolarCity Cost Allocation Comments") ("As the Commission is aware, there are two major factors causing the queue backlog problem – uneconomic barriers to entry and extreme delays in the interconnection process.").

[5] SIR, Appendix E.

[6] *See* SIR Queue Management and Cost Allocation Order, p. 29.

Project Component Details

NMPC proposes to upgrade the distribution system in the Demonstration Areas, making the Peterboro and East Golah substations ready for future DG applicants to interconnect. The investment will include the installation of $3V_0$ protection at four transformer banks: two at the Peterboro substation and two at the East Golah substation. These $3V_0$ installations are considered to be common-system upgrades, enabling DG applicants to interconnect to the upgraded substations, essentially making the substation transformer banks "DG-ready." To recover its costs, National Grid will charge a pro-rated fee to all applicants (not just the first applicant) with DG systems above 50 kW who connect to the upgraded substation transformer banks in the Demonstration Areas.

The Project will test the concept: if the Company builds $3V_0$ protection where needed to enhance capacity, will DG developers come to these stations to build and interconnect their projects? Moreover, once built, does the proposed cost-allocation mechanism provide greater certainty and lower financing costs for developers than has traditionally been available for such projects? Finally, is the Company able to market the available capacity and recoup its investment at the upgraded sites? More specifically, these three concepts include the following elements:

1. **Pre-build $3V_0$ Protection** – As part of the Project, NMPC will pre-build $3V_0$ protection at four substation banks. The Company estimates it will take three months per substation bank to design and engineer the $3V_0$ protection. For the Peterboro substation, design and engineering is underway. Based on that early work, the Company adjusted the completion date by a month to accommodate design changes that will save approximately $50,000 and two weeks of construction time. With those changes, the Company anticipates completing the Peterboro substation upgrade design by the end of July. The Company has also started design and engineering work for the East Golah substation, and anticipates completing that work by the end of August. Once the design and engineering is complete, NMPC expects construction at the four substation banks to finish by the end of December 2017 (subject to the availability of mobile substations and/or outages). The term of the Project will be six months from the date the common system upgrades are completed in each of the respective Demonstration Areas.

2. **Cost Mechanism** - To recover the common-system upgrade costs, NMPC will charge a one-time pro-rated fee to each applicant with DG systems above 50 kW that interconnects its DG project in the Demonstration Areas. The fee will be based on the estimated common-system upgrade costs (subject to true up once actual costs are known) in each of the respective Demonstration Areas divided by a factor that represents the substation transformer bank's capacity. An illustrative example of how the fee will be calculated is included in Appendix 1 to the Company's February 14, 2017. In the case of the Peterboro and East Golah substations, the factor is assumed to be 80 percent of the smaller of the respective substation transformer bank's capacity at the highest bank rating. This assumption ensures that each bank is protected in case of a bank failure or outage by enabling the Company to restore customers fed by the substation during the bank outage using the second substation bank as originally designed. This also allows for up to 20 percent of the respective substation transformer bank's capacity to be used by DG projects of 50 kW or less (free of charge), which are primarily residential and small

commercial projects. The total common-system upgrade costs would be recovered from those applicants with DG systems above 50 kW in the Demonstration Areas. For the Project to be successful, the Company's cost-allocation methodology should be utilized in the Demonstration Areas.

3. **Utility Marketing of Capacity –** The Company's Customer Energy Integration ("CEI") department will proactively seek participants for the Project. CEI provides DG customers a single point of contact to assist in navigating the interconnection process, and it regularly conducts outreach sessions to educate potential and existing DG applicants on topical DG issues. Marketing initiatives associated with the Project include:

   - CEI will email over 700 DG installers and developers in its database, notifying them of the Project and inviting them to a webinar to learn more;
   - An initial webinar on a date to be determined and subsequent monthly webinars (as needed) based on interest and participation/enrollment in the Project;
   - CEI will have direct conversations with developers to explain the Project, gauge interest and facilitate participation accordingly;
   - CEI will post a link to the Project filing, participation information and webinar logistics on its DG website;
   - A potential joint effort with the New York State Energy Research and Development Authority ("NYSERDA") to assist in marketing the Project in the Demonstration Areas; and
   - A one-page handout with the Project's highlights, including substation location and an explanation of cost-allocation methodologies.

   These activities mark a shift from traditional DG interconnection requests, where developers or customers typically initiate the interconnection request with the Company. This proactive Company-led effort will be supported by existing personnel, and the Project marketing expenses are projected to be *de minimus* at this point.

Billing

For the DG applicant to receive credits upon interconnection and for witness testing once permission to operate is granted, the Company must set the appropriate metering. Additionally, the Company must adjust billing for DG applicants based on the specifics of their respective projects. The Company is currently working to implement a system change to automate this process. By the time interconnections begin under this Project, the automated system should be operational.

"Go/No-Go" Test

The Company will proceed with the installation of the $3V_0$ protection in the Demonstration Areas to ensure internal processes are appropriate and to develop actual timelines for delivering the protection in the field. At the conclusion of the existing queue management and marketing effort, the Company will determine whether to undertake further marketing in the Demonstration Areas for this Project.

Infrastructure

NMPC will install the required site-specific materials for $3V_0$ protection at the four Peterboro and East Golah substation banks. The modifications are required to prepare the substations for reverse power flows and transmission line ground-fault protection from anticipated source additions. To accomplish this, the Company will install $3V_0$ protection relays, associated voltage transformers, relay racking and associated hardware, foundations, support structures, grounding, and 115 kV bus modifications. In addition to these upgrades, NMPC will upgrade the load tap changer ("LTC") controllers to handle reverse power flow and allow for proper voltage regulation. Communications processors and ancillary control and integration equipment will also be installed to aid in protection event recording and monitoring system conditions.

The Company estimates $850,146 in total costs (including taxes) at the Peterboro substation. The estimated cost for each Peterboro bank is as follows: transformer bank ("TB") 1 is the smaller of the two banks which is utilized in this calculation in case there is a loss of the larger bank. If a loss of TB2 occurs, TB1 is sized appropriately at its highest rating of 25MVA to support the generation on TB1 without damaging TB1 (assume further that 1 MVA equals 1 MW). The capacity to utilize the bank for DG is determined by 80 percent of the 25MVA, or 20MVA to be utilized by both banks. TB1 is 38 percent (7.7MW) of the overall station capacity and TB2 is 62 percent (12.4MW). The cost for each bank is then divided by 2. The cost per kW is then calculated by dividing the bank cost by bank MW capacity calculated to determine cost per kW, including taxes. The cost to upgrade TB1 is $55.26/kW and TB2 is $34.54/kW.

For East Golah, the Company estimates $731,206 in total costs (including taxes). As mentioned, 80 percent of the rating of the East Golah substation transformer would be used as the base kW value (allowing 20 percent to be used by residential and small commercial projects). The rating of the smallest East Golah substation transformer bank two is 25 MVA (assume further that 1 MVA equals 1 MW). TB1 is 57 percent (11.4MW) of station capacity and TB2 is 43 percent (8.6MW) of capacity. The cost estimate for TB1 is $32.13/kW and TB2 is $42.41/kW, including taxes. The overall cost for the substation upgrades is divided by two for the calculations as with the Peterboro example.

These numbers are revised from the illustrative estimates in the Company's February 14, 2017 filing to account for the addition of a fourth substation bank. Company crews will complete the electrical construction work at the substations.

Metrics for Success

The Company will measure the success of the Project by the extent to which the pace and scale of interconnections are increased in the Demonstration Areas. As the Project progresses, the Company will notify DG developers of the upgrades to the Peterboro and East Golah substation banks and solicit DG interconnection applications in the Demonstration Areas. The Company will solicit feedback from DG developers during the initial and late stages of the Project. This will include a survey of DG applicants who participated in the Project, as well as those who opted not to pursue interconnections in the Demonstration Areas. This feedback will help the Company identify lessons learned and incorporate suggestions for improvement, where appropriate, into future offerings. The Company will also share its experience and opportunities for improvement with the Interconnection Policy Working Group ("IPWG") to use in proposing refinements and improvements to the interconnection process and the current cost-allocation mechanism.

Because the success of the Project is dependent on use of the Company's proposed cost-allocation methodology, the Company will actively market the circuits with solar developers. Interconnections are allowed to utilize the SIR process, outside of the Company's cost allocation method, if desired. If a developer chooses to utilize the existing cost mechanism in the SIR rather than the Company's cost allocation mechanism, the Project will be determined a failure in regards to cost recovery.

DG applicants in the Demonstration Areas would still bear full responsibility for their respective site-specific and any other distribution line upgrade costs that are outside of the common system upgrade charge under this Project. The pro-rated common system upgrade fee would be due at the same time as payment of site-specific and any other distribution line upgrade costs.

Participation

NMPC proposes a targeted site selection process as part of the Project, focusing on the two substations mentioned above: Peterboro and East Golah. DG applicants will be able to participate in the Project if the applicant:

- Has a DG project above 50 kW in the Demonstration Areas (applicants are not allowed to break up their projects to avoid paying the common upgrade costs);
- Executes an interconnection agreement and pays its share of the common-system upgrade costs as determined by the Company's methodology or the existing Queue Management cost sharing methodology; and
- Complies with all other existing interconnection requirements, such as payment of site-specific and any other distribution line upgrade costs that are outside of the common-system upgrade charge under the Project.

Outreach

The Company discussed the Project at the April 18th IPWG meeting and the Company intends to pursue the aforementioned marketing strategy through its CEI department – targeted contact with DG developers, webinars, and website updates. The Company also intends to continue answering questions and soliciting feedback to inform potential future offerings by participating in the IPWG, the Interconnection Technical Working Group, the DG Ombudsman Group, and maintaining its own internally driven stakeholder outreach. In addition, the Company will provide updates to Staff on the results of its efforts. So far, initial feedback from DG developers has been very positive.

Test Statements

The Company will test the validity of the prebuild $3V_0$ concept as shown below. The results of the testing will be tracked and documented and then used to inform and modify any subsequent programs where applicable.

Test Statement	If…	Then…
Prebuilt $3V_0$ system upgrades will lead to increased DG interconnections in the Demonstration Areas.	A. NMPC prebuilds $3V_0$ protection at selected station banks; B. The Company's cost-allocation mechanism allows greater certainty and less upfront cash payment for DG developers; C. Provides the Company with acceptable cost recovery.	Developers will look to build at these sites as defined by participation and/or queue increase and utilities will continue to scale this approach in future filings.
Can a utility effectively market capacity to solar developers for DG interconnection without additional price reductions?	NMPC markets interconnections in the Demonstration Areas using the proposed cost-allocation mechanism.	Developers will be aware of the opportunity and seek to interconnect DG projects.

Test Population

The population of developers currently active in New York State with the Company exceeds 85. Prior to the queue management process, the Company had upwards of 700 DG projects ongoing at some point in the process. The Company believes DG developers doing work in New York State comprise the general universe of companies that will consider interconnecting DG systems above 50 kW in the Demonstration Areas. Specifically, the Demonstration Areas target two substations, Peterboro and East Golah, where the Company anticipates significant DG interconnection interest. Both substations are located in areas where applicants had proposed a number of DG projects and where the Company can quickly deploy and test the efficacy of its proposal. The Peterboro substation is located in the Utica/Rome region near the Town of Lenox. It serves approximately 8,000 customers using one transmission supply line and eight distribution feeders. There is now one DG application in the queue for projects in the area served by the Peterboro substation at approximately 2 MW. The East Golah substation is located south of the City of Rochester, near the Town of Rush. It serves approximately 7,500 customers using a looped transmission supply line and six distribution feeders. There are five DG applications in the queue sized at approximately 2 MW each. The queue has decreased significantly in these areas with developers removing projects from the interconnection process with the implementation of the Queue Management Order. The Company will continue with $3V_0$ build out at these substations to test the cost mechanism and prebuild concept.

Test Scenarios

Essential to a REV demonstration project is the ability to test new proposed business arrangements with customers, stakeholders, and non-utility market participants. The Company envisions that the Project will enable a live "market test" of the concepts outlined in this Implementation Plan by allowing DG developers to compare prebuilt capacity and known costs to the existing process with frontloaded costs and uncertainty. Based on the foregoing, the Company will be able to analyze whether prebuilt common-system upgrades increase the pace and scale of DG projects applying to and ultimately interconnecting with NMPC's system.

Milestones and Checkpoints

The term of the Project is six months, beginning from the date the common-system upgrades are completed in each of the respective Demonstration Areas. As this Implementation Plan is an evolving, working document, refinements to the scope of work for Company personnel are expected throughout the course of the Project. The Company will capture modifications in quarterly reports, as well as through meetings with PSC Staff. Demonstration evaluators should be able to review the Project results, including the following milestones:

General Project Milestones	
Date	**Milestone**
March 2017	Begin general outreach
April 2017	Provide funding numbers
	Begin marketing the Project
	Begin site-specific outreach with developers
May 2017	Order long-term materials
	Develop cost per KW for each bank
June 2018	The Project term ends
Peterboro Substation Milestones	
Date	**Milestone**
February 2017	Complete initial cost estimate
July 2017	Complete $3V_0$ design and engineering
	Determine needs for switching and/or mobile sub
September 2017	Schedule civil work
	Schedule electrical work
	Schedule relay work
December 2017	Anticipated completion date
June 2018	The Project term ends
East Golah Substation Milestones	
Date	**Milestone**
February 2017	Complete initial cost element
June 2017	Determine needs for switching and/or mobile sub
August 2017	Complete $3V_0$ design and engineering
	Schedule civil work
	Schedule electrical work
	Schedule relay work

December 2017	Anticipated completion date
June 2018	The Project term ends

Project Milestones	
Checkpoint	**Description**
Effectiveness of Marketing Capacity	Measure – Amount of kW in respect to capacity at each location to the amount required to equal 80 percent of bank capacity as calculated per substation. How & When – Update by CEI on the last day of each month on status. Continue until a Go/No-Go decision is made with regard to marketing efforts. Resource – CEI Expected Target – Sign up 80 percent of defined bank capacity at each location. Review monthly to see action/increase in queue.
Completion of Final Plan	Measure – Final Go/No-Go determination for completion or continuation of marketing services. How & When – Review six months after completion of construction, or as determined based on lessons learned and market behavior. Resources – CEI Expected Target – Positive decision to proceed (*i.e.*, "Go"). Strategy in Case of Results Below Expectations – Suspend the Project, utilize existing SIR cost-allocation methodology to manage future additional interconnections as requested by DG applicants.

Scalability

This Demonstration Project is highly scalable. As discussed in the Company's February 14, 2017 filing, NMPC's recent rate filing included a similar proposal for up to six banks per rate year.

Conditions/Barriers

As stated earlier, the barriers to increased interconnections are the cost to interconnect and the uncertainty regarding how common upgrade costs will be recovered from subsequent DG applicants. Further, because the Company typically has to perform a Coordinated Eletric System Interconnection Review ("CESIR") every time a DG developer seeks to interconnect with the system, such projects can incur further delays and costs. For NMPC and its customers, the value of the Project is tied to reducing these barriers, thereby increasing access to DG. This, in turn, will create a more transactive grid, improve system resilience, and increase system efficiency.

Project Structure and Governance

Executive Sponsorship

The Company has assigned an executive sponsor for each of its REV Demonstration Projects, recognizing that active sponsorship is a critical factor for successful project management. Executive sponsor responsibilities include:

- Accountability for the ultimate success of the Project;
- Vision and leadership throughout the Project;
- Time commitment and active engagement throughout the Project, and
- Addresses conflicts and ensures senior stakeholders are engaged and supportive.

The executive sponsor for the Project is Carol Sedewitz, Vice President ("VP") Electric Asset Management, Executive Sponsor.

Core Project Team

Name	Title	Contact Information
Carol Sedewitz	VP Electric Asset Management, Executive Sponsor	Tel.: 781-907-2500 Email:carol.sedewitz@nationalgrid.com
Allen Chieco	Director DG Liaison, Ombudsman	Tel.: 518-433-3809 Email:allen.chieco@nationalgrid.com
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	Energy Integration ("CEI") NY	Email:michael.pilawa@nationalgrid.com
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Project governance will include the Core Project Team (as set forth above) and will consist of monthly conference calls and in-person meetings (as needed) at milestone points to report on project schedule, identified risks, project status, and the projected costs and benefits of services under development.

Internal Stakeholders

There are various departments within the Company that are critical to the delivery of the Project. They include:

- Station Engineering
- Protection Engineering
- Distribution Planning and Asset Management ("DPAM")
- Contracting (civil)
- Field Operations
    - Stations
    - PTO
- CEI
- Regional Control Centers ("RCC")
- New York Jurisdiction
- Billing
- New Energy Solutions ("NES")

Roles and Responsibilities

Roles and responsibilities below are for key Project responsibilities. Note that the roles and responsibilities in this document focus on the Project, and do not fully detail related activities.

Role/Responsibility – National Grid	**Description**
Support conceptual and detail design	Provide necessary data and expertise for the design work
Set up 3V0 demonstration project PMO	Create PMO to assist with coordination of REV demonstration
Initial stakeholder outreach	Present demonstration objectives and receive feedback on the project
Develop estimate per kw	Determine proper technical and pricing methodology
Define & implement marketing plan	Develop a marketing plan, staffing, budget, and objectives
Order materials	Provide materials to build project

Field construction	Safely construct all civil and electrical apparatus to the transformer bank
System configuration and switching	Determine outage availability and need for mobiles
Municipal customer outreach	Opportunity for company to provide outreach to municipalities in area on demonstration
Billing	To properly change/develop appropriate billing accounts in project
Interconnection	To provide all required interconnection obligations to customers in regards to the interconnection process

Roles/Responsibility – Developer/Customer	**Description**
Provide proper applications and process participation	Completion of a timely interconnection process
Development in the demonstration area	Participate in demonstration

Department of Public Service Staff, Public Service Commission Role / Responsibility	**Description**
Provide feedback on quarterly reports for Project	Review progress against Project objectives and recommend any corrective actions

Governance

The governance structure for the Project will include the Core Project Team (as set forth above) and will consist of monthly conference calls and in-person meetings at milestone points to report on the Project's status, schedule, risks, lessons learned, as well as projected costs and benefits.

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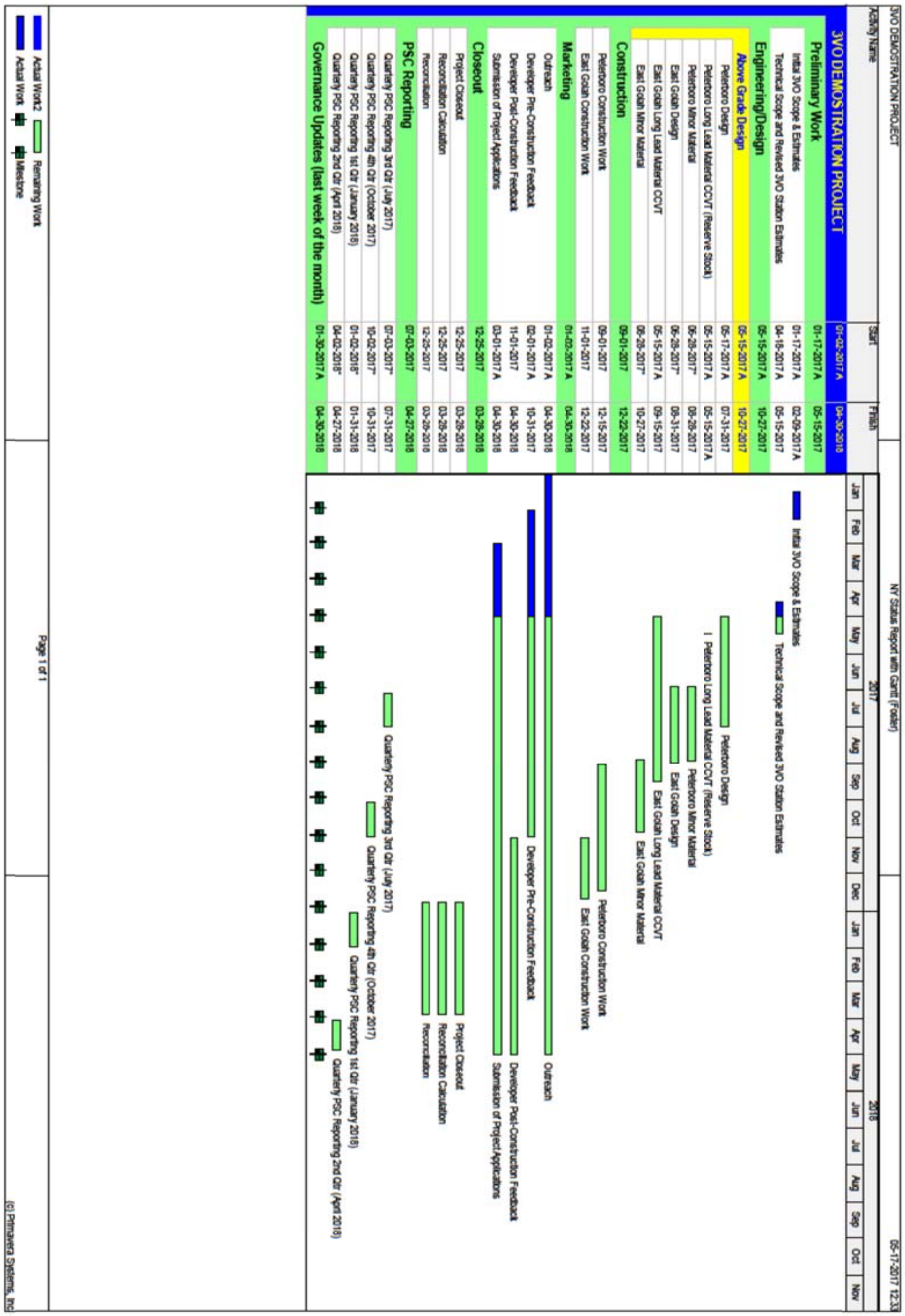
Work Plan



Activity Name	Start	Finish
3VO DEMOSTRATION PROJECT	01-02-2017 A	04-30-2018
Preliminary Work	01-17-2017 A	05-15-2017
Initial 3VO Scope & Estimates	01-17-2017 A	02-09-2017 A
Technical Scope and Revised 3VO Station Estimates	04-18-2017 A	05-15-2017
Engineering/Design	05-15-2017 A	10-27-2017
Above Grade Design	05-15-2017 A	10-27-2017
Peterboro Design	05-17-2017 A	07-31-2017
Peterboro Long Lead Material CCVT (Reserve Stock)	05-15-2017 A	05-15-2017 A
Peterboro Minor Material	06-28-2017*	08-28-2017
East Golah Design	06-28-2017*	08-31-2017
East Golah Long Lead Material CCVT	05-15-2017 A	09-15-2017
East Golah Minor Material	08-28-2017*	10-27-2017
Construction	09-01-2017	12-22-2017
Peterboro Construction Work	09-01-2017	12-15-2017
East Golah Construction Work	11-01-2017	12-22-2017
Marketing	01-02-2017 A	04-30-2018
Outreach	01-02-2017 A	04-30-2018
Developer Pre-Construction Feedback	02-01-2017 A	10-31-2017
Developer Post-Construction Feedback	11-01-2017	04-30-2018
Submission of Project Applications	03-01-2017 A	04-30-2018
Closeout	12-25-2017	03-28-2018
Project Closeout	12-25-2017	03-28-2018
Reconciliation Calculation	12-25-2017	03-28-2018
Reconciliation	12-25-2017	03-28-2018
PSC Reporting	07-03-2017	04-27-2018
Quarterly PSC Reporting 3rd Qtr (July 2017)	07-03-2017*	07-31-2017
Quarterly PSC Reporting 4th Qtr (October 2017)	10-02-2017*	10-31-2017
Quarterly PSC Reporting 1st Qtr (January 2018)	01-02-2018*	01-31-2018
Quarterly PSC Reporting 2nd Qtr (April 2018)	04-02-2018*	04-27-2018
Governance Updates (last week of the month)	01-30-2017 A	04-30-2018

Financial Elements/Revenue Model

Project Budget

The Company estimates its initial upfront cost to design, engineer, and construct the common-system upgrades will be $1,581,351 (excluding *de minimus* marketing costs). The preliminary two-year budget with estimated costs for the Project broken down by year is summarized below:

Expense Type	2017	2018
Engineering & Material Procurement	$690,900	
Construction	$546,200	
Marketing	$12,000	$8,000
In Service Liabilities & Closeout	$188,700	$40,000
Total[7]	**$1,437,800**	**$48,000**

The Project consists primarily of engineering, material, marketing, and construction costs.

Cost Recovery/Incentives

As part of the Project, the Company is seeking to recoup investment costs from developers who interconnect DG systems above 50 kW in the Demonstration Areas. The costs of the common system upgrades would be placed in a regulatory asset and recovered through a fee charged to DG applicants (described above). To the extent the fees do not equal the costs, the Company will recover or pass back the net balance in the regulatory asset in a future proceeding. There will be no additional incentives to participate, as the objective of the Project is to determine if DG developers will seek to interconnect in areas with prebuilt capacity and reduced cost uncertainty.

Reporting Structure

The Company will provide quarterly progress reports to Staff. The quarterly reports will include an overview of the Project's progress relative to the timeline set forth in this Implementation Plan, as well as Project results as they become available. The quarterly report template is provided below – the Company will continue to refine the template throughout the duration of the Project.

[7] The total does not include sales taxes.

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Quarterly Report Template	
Milestones:	
Last Project Milestone:	
Next Project Milestone:	
Tasks/Timeline:	
Completed Project Tasks Since Last Quarterly Report:	
Changes or Impacts to Schedule Since Last Quarterly Report:	
Lessons Learned:	
Work Stream Coordination:	
Risks:	
Identified Risks:	
Risk Mitigation Plan:	
Finance:	
Total Incremental Spend to Date:	
Target Incremental Spend:	
Actual Incremental Spend:	
Incremental Spend Variance:	
Non-Incremental Spend:	
In-Kind and Grant Support (Specifically for REV Demo):	
Queue Status Update:	
Additional Notes:	