Information Request EDC-1

Request:

Identify whether a group or groups of interconnecting customers in the Company's service territory are likely to be presented with interconnection costs in the next 1-1.5 years that are significantly higher than have been historically presented. Include in the Company's response:

a. Detailed information on the group(s), including: geographical region, number of distributed generation ("DG") facilities, capacity in megawatt ("MW"), and estimated timing for conclusion of associated distribution and transmission impact studies;

b. High-level planning estimates of expected interconnection costs for the group(s). Provide data in dollar-amount-per-kilowatt ("$/kW") and by group, where possible;

c. High-level planning estimates of timeline for construction of anticipated EPS upgrades that will be required due to interconnection impacts of the group(s). Provide data by group, where possible;

d. High-level estimates of how much DG capacity will be enabled by the anticipated EPS upgrades for the group(s); and

e. Whether additional DG capacity could be enabled in coordination with anticipated EPS upgrades for the group(s), and if so, high-level estimates of costs and timelines for any additional EPS upgrades required to enable additional DG capacity.

f. Will the anticipated EPS upgrades for the group(s) provide benefits to ratepayers and the Commonwealth beyond enabling renewable energy to interconnect to the EPS?

Response:

With respect to subparagraphs a through d, please see the Attachments to this Response, in addition to the narrative and tables below:

- Attachment EDC-1-1, Supporting workpapers and calculations in the form of a working Microsoft Excel spreadsheet with all cell references and formulae intact
- Attachment EDC-1-2, Group Study Outreach, March 4, 2021
- Attachment EDC-1-3, Central & Western MA Study Update, October 20, 2020
- Attachment EDC-1-4, Central & Western MA ASO Cluster Study Update, March 19, 2020

The groups of interconnecting customers in Group Studies[1] in Central and Western MA identified below are likely to be presented with interconnection costs in the next 1-1.5 years that are significantly higher than have been historically presented, continuing the recent trend of increasing interconnection costs.

a. The following table provides the geographical region of each Group Study in the Central/Western MA area of National Grid's service territory, number of distributed generation ("DG") facilities, capacity in megawatt ("MW") of the facilities applying for interconnection, and estimated timing for conclusion of associated distribution and transmission impact studies:

Group Study Region	Number of DG Facilities	DG Capacity (MW)	Estimated T & D Studies Completion
Ayer-Clinton	3	23	Spring 2022
Barre-Athol	9	41	Spring 2022
Gardner-Winchendon	8	54	Summer 2022
Millbury-Grafton	3	16	Spring 2022
MPL-East*	9	35	Summer 2022

[1] "Group Study" is defined in Section 3.4.1 of the Standards for Interconnection of Distributed Generation, D.P.U. 19-55 and D.P.U. 20-63 EDC Compliance Tariff (Revised 11.12.20) ("Compliance Tariff"). Capitalized terms that are not defined in this Response are defined in the Standards for Interconnection of Distributed Generation, M.D.P.U. No. 1320.

MPL-Northwest	1	5	Spring 2022
Spencer-Rutland	12	62	Spring 2022
Webster-Southbridge-Charlton	12	75	Spring 2022
Shutesbury	5	20	Winter 2021
Total	**62**	**331**	

**MPL stands for Monson-Palmer-Longmeadow.*

Transmission

The preferred distribution infrastructure solutions for a Group Study must be sufficiently developed to identify DG and load injection points to the transmission system. This stage establishes the transmission study start milestone, which will be the point where the distribution system Group Study outputs become inputs to the transmission analysis. New England Power Company ("NEP"), the Company's transmission provider and operator, will initially scope the Affected System Operator ("ASO") studies in a way that may enable parallel studies to be undertaken simultaneously. National Grid anticipates that this approach will help move some DG projects forward for review by the NEPOOL Reliability Committee sooner than otherwise would occur; however, this approach will be subject to the Group Study inputs, the magnitude of MW at each injection point and ISO-NE approval of this ASO study approach. See Attachment EDC-1-2, slide 9. The ASO study timeframe is 6 to 9 months and is accounted for in the above table. See Attachment EDC-1-2, slide 8. Group Study timeframes have been determined in accordance with the Group Study provisions of the Compliance Tariff and are accounted for in the above table. National Grid has advised Group Study members that each Group Study timeframe is 160 Business Days, exclusive of any ASO holds, which will be applied to the Group Studies until the ASO study is completed. See Attachment EDC-1-2, slides 7 and 9.[2] (The Company may exceed the 160 Business Day timeframe if a Group elects the Extended Group Study.)

b. The following table provides high-level planning estimates of expected interconnection costs for each of the Group Studies in dollar-amount-per-kilowatt ("$/kW"):

[2] Group Study members may unanimously consent to proceed with their distribution system impact study in parallel with the ASO study, at their risk. Attachment EDC-1-2, slide 9. (A Group Study is a distribution system impact study, carried out in accordance with the Group Study process, including the Group Study timeframes.)

Group Study Region	Number of DG Facilities	DG Capacity (MW)	Estimated Interconnection Costs	$/kW
Ayer-Clinton	3	23	$ 54,100,000	$ 2,359
Barre-Athol	9	41	$ 116,800,000	$ 2,868
Gardner-Winchendon	8	54	$ 76,800,000	$ 1,412
Millbury-Grafton	3	16	$ 38,300,000	$ 2,359
MPL-East	9	35	$ 81,800,000	$ 2,352
MPL-Northwest	1	5	$ 4,200,000	$ 848
Spencer-Rutland	12	62	$ 284,400,000	$ 4,608
Webster-Southbridge-Charlton	12	75	$ 77,600,000	$ 1,029
Shutesbury	5	20	$ 26,700,000	$ 1,342
Total	**62**	**331**	**$ 760,700,000**	**$ 2,298**

The high-level planning estimates of the interconnection costs for each Group Study region were derived by scaling the estimated costs of distribution system modifications and associated transmission upgrade costs required by previously completed studies in these areas. See Attachment EDC-1-3, slides 7 and 10-11. The above high level estimated interconnection and $/kW costs should not be used to inform project specific financial decisions. These previously completed studies in the area provided the best available basis at this time for deriving the high level planning estimates of the interconnection costs ahead of the more accurate estimates that will be determined by the Company through the course of the Group Studies, which are in the very early stages of engineering. The costs and $/kW values include transmission interconnection costs driven by the previous distribution system impact studies ("DSIS") in these areas but do not include transmission upgrade costs driven by the previous transmission system impact studies ("TSIS") in these areas, which are described below.

<u>Transmission</u>

National Grid conducted several iterations of an ASO study, that is, a TSIS, in Central and Western MA. National Grid advised stakeholders that it had evaluated the interconnection of 391MW in the region, which prompted approximately $50M of transmission system upgrade costs. See Attachment EDC-1-4, slides 6 and 9. Although subsequently there was significant attrition, other applications in the region moved forward, including into the Group Studies. Based on the preliminary review of where the distributed generation in the Group Studies will interconnect to the transmission system, National Grid anticipates that the transmission system upgrades determined to be necessary by the TSIS for the previously proposed the 391MW in this region are a credible indicator of the magnitude of costs associated with the transmission upgrades that will be required for the 331MW in applications currently in the Group Studies. See Attachment EDC-1-3, slide 7. As discussed below in subparagraph e, if the Department determines that additional distribution system capacity should be enabled for future DG, National Grid anticipates that additional engineering solutions would be required for the transmission system.

c. The following table provides a high-level planning estimates of timeline for construction of anticipated EPS upgrades that will be required due to interconnection impacts of the Group Studies:

Region	Number of DG Facilities	DG MW Capacity	Estimated Construction Completion
Ayer-Clinton	3	23	2027 (5 Years)
Barre-Athol	9	41	2027 (5 Years)
Gardner-Winchendon	8	54	2027 (5 Years)
Millbury-Grafton	3	16	2027 (5 Years)
MPL-East	9	35	2027 (5 Years)
MPL-Northwest	1	5	2027 (5 Years)
Spencer-Rutland	12	62	2027 (5 Years)
Webster-Southbridge-Charlton	12	75	2027 (5 Years)
Shutesbury	5	20	2027 (5 Years)

Transmission

As communicated in stakeholder meetings in 2020, any applications seeking to interconnect to the A1/B2 circuits will need to wait until the A1/B2 planned transmission asset condition work has been completed, currently estimated to be 2027, before interconnecting. Relative to the distribution upgrades, the reconductoring of these lines will be the critical path to interconnection in this area. National Grid currently estimates that other transmission upgrades will take approximately 2 to 5 years to complete and may not be critical path activities to the interconnection of the projects in the Group Studies. See Attachment EDC-1-4, slides 9 and 10; Attachment EDC-1-3, slide 7.

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The above table provides high level estimates of construction timelines and does not take into consideration any external factors outside of National Grid's control or other non-EPS limiting factors that could affect those timelines, such as available land suitable for DG development in the area and permitting issues (see D.P.U 20-75 National Grid Comments on Straw Proposal at 50-52), supply chain constraints and customer delays.

d. The following table provides high-level estimates of how much DG capacity will be enabled by the anticipated EPS upgrades for the Group Studies, including the 331MW of DG currently in the Group Studies and excluding any incremental capacity from connected DG in these regions:

Region	**DG MW Enabled Capacity**
Ayer-Clinton	100
Barre-Athol	240
Gardner-Winchendon	165
Millbury-Grafton	50
MPL-East	155
MPL-Northwest	15
Spencer-Rutland	300
Webster-Southbridge-Charlton	180
Shutesbury	30
Total	**1235**

The high level planning estimates of how much DG capacity will be enabled by the anticipated EPS modifications for the Group Studies were derived by scaling the amount of DG capacity that previously completed detailed distribution studies and TSIS identified in these areas. These previously completed studies in the area provided the best available basis at this time for deriving the high level planning estimates of how much capacity will be enabled by the Group Studies, which are in the very early stages of engineering. The values represent substation enabled capacity and do not consider the distribution system feeder level enabled capacity, which is very dependent on the location of the DG that would use this enabled capacity. The distribution system enabled capacity could be greater than or less than these substation-based values but is unable to be quantified without specific DG location analysis. These estimates of enabled DG capacity also do not take into consideration any factors outside of National Grid's control or other non-EPS limiting factors that could affect enablement of additional capacity, such as available land suitable for DG development in the area and permitting issues (see D.P.U. 20-75 National Grid Comments on Straw Proposal at 50-52).

e. With regard to whether additional distribution system feeder level DG capacity could be enabled in coordination with anticipated EPS upgrades for the Group Studies, National Grid is unable to quantify further incremental capacity beyond the values presented in response to subparagraph d above, at this time, because the Group Studies are in the very early stages of engineering.

Transmission

Based on the 1235MW of enabled capacity by the projected upgrades referenced in the table above, National Grid anticipates that the 69Kv loop in Western MA will be converted and operated at 115kV to make sure the transmission system does not become the enabled capacity constraint.

With consideration to anticipated EPS upgrades, four out of the five main circuits in this 69kV loop in Western MA are planned to be rebuilt to a 115kV standard and reconductored over the next five to ten years based on an asset condition need. As a result, the cost of upgrading all of the other associated infrastructure in this area and operating at 115kV is significantly offset by the asset condition replacement projects forecasted by the Company. The total cost forecast for these four EPS circuits is $583M, with two of the EPS circuits planned to come into service in 2027 and the other two in 2031. The 2031 schedule could be re-baselined as necessary, depending on a number of different factors, including coordination and outage planning, which are under evaluation.

69kV Loop Upgrade Need:
As an output of the integrated planning efforts between distribution and transmission system planning at National Grid, as large volumes of distributed generation continue to saturate this area, attempting to interconnect as much as possible to the 115kV system is seen as preferred, as typically there is more margin in what the system can absorb prior to the presentation of adverse impacts. In the continued application of this principle, the distribution enabled capacity was evaluated and produced the following findings.

69kV System:

(A1/B2/E5/F6/D4) Adverse impacts were identified even considering the new upgraded conductor rating assumed by the asset condition projects on the A1/B2/E5/F6, assuming the circuits are operated at 69kV. This is consistent with the findings referenced in Attachment EDC1-4, slides 6-7, where stakeholders were informed of the presentation of significant adverse impacts on the 69kV system where was only 391MW under review.

115kV System:
(A127/B128/I135): Adverse impacts were identified on these circuits, even when some of the circuits have the typical maximum rated conductor used at 115 kV.

345kV System:
(Carpenter Hill): Adverse impacts were even identified where the volume of distributed generation is so large on some circuits, it is triggering overloads on the 345kV system.

When there are problems presenting on the 115kV system and cascading up to the 345kV system, this means that while the 69kV system cannot accommodate this level of DG, neither can the 115kV system in the same area. As a result, the most prudent solution is to enhance the capacity in this area by selecting to convert and the 69kV system to 115kV. This would enable more DG to be interconnected into this system and remove the burden from the current 115kV system. From a transmission standpoint, this is the more technically advantageous and cost-effective long-term solution to enable the large amounts of DG anticipated in this area over the next 10 to 15 years, considering the planned asset condition work in Western MA.

Study Assumptions/Costs:
The screening study completed to conclude the above observations was based on a range of assumptions and may change given more accurate scopes and sufficient time to undertake all of the typical study components, including steady state, stability, short circuit, and PSCAD analysis.

The incremental proposed cost, added to the transmission EPS anticipated project work in the area, is approximately $380M. This is a good faith estimate including all of the circuit and substation work on this 69kV loop, and dynamic devices on the 115kV system. This estimate assumes a range of scopes that would need to be re-evaluated and validated for accuracy if this proposal moves forward.

f. National Grid has considered the state's clean energy and climate change policies during its evaluation of potential customer and Commonwealth benefits. This evaluation considers benefit allocation concepts as compared to the traditional cost causation concept. The Company has explored ideas such as shared capacity across load and generation customers and DG availability as a reliability requirement.

National Grid has considered these potential benefits to customers and the Commonwealth only at a conceptual level and therefore provides the following qualitative benefits that may result from the types of upgrades described in subparagraphs a through d above:

1. Voltage control technology used to mitigate potential DG overvoltage events will be used to prevent load based under voltage events.
2. Reclosers and protective devices remote to the point of interconnection ("POI"), will be used to protect, isolate, and restore a system event regardless of load and generation served.
3. Substation redundancy will be utilized for faster restoration, reducing duration for transformer contingency events.
4. Increasing the Commonwealth's future capability to host new, un-forecasted load growth (e.g., a large warehouse, data center, other C&I customer, electric vehicles, and beneficial heat electrification) in regions that historically have seen low demand and/or low load growth.
5. Other ancillary benefits to the Company's EPS that accompany any new construction (e.g., refreshed tree-trimming clearances, newer poles) that might not otherwise occur until a later planning cycle or when a failure occurs during a storm.

Such shared system uses increase at higher levels within the electric system. Substation equipment will be used in a mutual benefit manner, more so than other distribution assets, and transmission equipment more so than substation assets.

Additionally, the facilities will be vital to creating a resilient system enabling renewable generation to be transmitted and distributed without limitations to regional areas that need the energy. In order to reliably utilize these resources in a matter that will enable the state's clean energy and climate change policies, DG availability will need to be considered and become a fundamental purpose of the electric system. Utilities need to think beyond historical standard interconnection requirement concepts, as these resources will become critical factors in the stability and reliability of the future distribution and transmission electric systems.

In recognition of all these mutual benefits, National Grid believes up to 40% of the DG interconnection costs should be allocated as system benefits to all customers, and recovered through the Reconciling Charge discussed in the Department's Straw Proposal.

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