Last updated: 6/7/2021

PG&E’s 2021 DIDF RFO

Questions and Answers

A. GENERAL

Question A.1

How many MWs have been awarded under the past 2 DIDF RFO’s?

Answer A.1

We have executed contracts for about 15 MW. Those contracts were executed to defer investments at two locations.

Question A.2

Can you share email addresses and post the slides?

Answer A.2

The slides are posted on PG&E’s RFO webpage (link), but email addresses will not.

Question A.3

You provided the customer composition and load profile for the Willow Pass deferral projects, but not the other projects. Can you provide the customer composition for the other projects?

Answer A.3

Since we have so many locations, we didn’t go over detailed data for every location during the webinar. The information is all available on our website. Please refer to Appendix F1.

Question A.4

Can we redline NDA or do we have to sign it “as is”?

Answer A.4

With respect to the NDA (Attachment C to the Protocol), we will not accept redlines.

B. ELIGIBILITY

Question B.1

Are we obliged to have a site control for the moment of bid submission?

Answer B.1

Site control is not required but it is a qualitative factor that is used in determining project viability, as referenced in Section VI of the Solicitation Protocol.

Question B.2

Is there any bid security upon bid submission?

Answer B.2

No.

C. RFO NEED

Question C.1

When is the next internal load forecast update PG&E is expecting for the areas of this DIDF and when that to be public?

Answer C.1

PG&E expects to have its next internal load forecast in Q2 2021. The new load forecast will be made public in this year's GNA and DDOR (August 2021).

Question C.2

If your new load forecast is different and requires change of the load relief requirements, how that can affect your expected timeline specified in Table I.1. (page 6 of the RFO document)?

Answer C.2

The schedule in the RFO protocol is designed to accommodate CPUC direction to complete the RFO within 6 months of approval of PG&E's AL-6002-E (approved on December 16, 2020) on June 16, 2021. It is possible that a new load forecast could result in changed needs in the

DIDF areas. In anticipation of that possibility, PG&E has sought offers with flexibility in order to increase or decrease the offer size. PG&E would expect to address changes to the local area need as part of the negotiation process, without impacting the RFO schedule.

Question C.3

Is there any probability this RFO is canceled in the next planning cycle or that you will sign a contract even if a new forecast does not show initially expected overload?

Answer C.3

See answer above. The RFO is subject to ongoing change. PG&E will consider updated load forecasts and may adjust the amount it procures during the RFO, either up or down.

D. INCREMENTALITY

Question D.1

If this is a new project, will it be allowed to participate in other programs or tariffs (i.e. SGIP / DR/ EE/ NEM, etc) in addition to load reliefs under this DIDF?

Answer D.1

In order to be considered incremental, and eligible for a DIDF contract, you must demonstrate that you are providing an incremental service over and above what you are being compensated for under existing programs. Please refer to Section IV.C and Table IV.1 of the Solicitation Protocol for additional information on incrementality.

E. DEFERRAL VALUE

Question E.1

Can you walk us through the deferral value, so we have a better understanding of how to value our DER solution? What is the difference between the LNBA values in Advice letter 6002-E and the deferral values shown in the Solicitation Protocol (page 12)?

Answer E.1

The Locational Net Benefits Analysis (LNBA) value is the net present value (NPV) of deferring the annual revenue requirements associated with a planned project, expressed in $/kw-year. The revenue requirement associated with the planned project includes annualized capital costs, including depreciation, taxes and return on investment, and ongoing operations and maintenance (O&M) costs. The deferral value can be expressed in a number of ways – as a total NPV value ($), as an annualized number ($/yr) or, in unit costs ($/kW-year). The deferral values in Advice Letter 6002-E (Refer to Appendix C Table 1) are expressed in terms of total NPV value, and the LNBA values are expressed in $/kw-year, but they are based on the same capital costs and deferral terms. The deferral values in the Solicitation Protocol have been updated to reflect minor changes to the input assumptions such as 2021 cost of capital.

Question E.2

Does the deferral value indicate your willingness to pay for a DER solution?

Answer E.2

The deferral value represents a cost cap. Please note that this a competitive process and just because you are under the cost cap does not mean you will be awarded a contract (e.g. if your offer is under the cost cap but there is another offer at a lower price).

F. <u>TECHNOLOGY</u>

Question F.1

Per the Solicitation document, "PG&E has a preference for selection of renewable resources per Resolution E-4956, Ordering Paragraph 17. In addition, a non-renewable distributed generation project must be able to produce GHG emissions reductions over its lifecycle." Can you explain how you are evaluating the ability to provide emission reductions over the project's lifecycle?

Answer F.1

We will evaluate non-renewable offers on a case by case basis.

G. <u>LOCATION SPECIFIC QUESTIONS</u>

Question G.1

Is it correct, that for Calistoga you simply need a 3 MW solution at feeder 1102 that will provide up to 8 hours of a relief to cover all needs specified in A, B1 and B2?

Answer G.1

Yes.

Question G.2

For Zamora opportunity, would it be acceptable if we put a solution at either of feeders 1105 or 1106 so long it provides require load relief?

Answer G.2

Yes.

Question G.3

Could you provide MWh need per call for Zamora? Through the chart in the Appendix F1 (page 63) it is clear, that 1.1 MW is required not during all 14 hours, but rather fluctuating between 0 MW and 1.1 MW.

Answer G.3

The need per call can be up to 1.1 MW for 15.4 MWh, which is determined on a Day Ahead basis.

Question G.4

Could you provide MWh need per call for Calistoga requirements A and B? Through the chart in the Appendix F1 (page 44) it is clear, that for requirement A a relief of 1.3 MW is not required through full 3 hours, but less. Same is for requirements B1 and B2.

Answer G.4

The needs per call, determined on a Day Ahead basis, are as follows:

- Requirement A: Up to 3.9 MWh
- Requirement B: Up to 18 MWh; Or
    1. Requirement B1: Up to 10 MWh
    2. Requirement B2: Up to 8 MWh

Question G.5

Is the desired project size for utility ownership at Blackwell Bank 1 3 MW / 30 MWh (3 MW with a 10 hour battery)?

Answer G.5

PG&E is seeking 3 MW of distribution capacity for 10 hours, which may be achieved through more than one configuration (e.g. 3 MW 10 hour battery totaling 30 MWh or 7.5 MW 4 hour battery totaling 30 MWh).

Question G.6

Would there be any benefit to being able to discharge at greater than 3 MW nameplate capacity for a shorter duration battery than 10 hour discharge, but then still act as a de-rated battery for 3 MW/30 MWh when charging during the day?

Answer G.6

PG&E is interested in the most cost-effective solution to get 3 MW/30 MWH. PG&E is not attributing any additional value in our selection process to solutions that have higher peak discharge capability.

Question G.7

Is PG&E seeking third-party scheduling services at Blackwell Bank 1 for utility ownership offers?

Answer G.7

PG&E is not seeking third-party scheduling services.

H. <u>COLLATERAL</u>

Question H.1

Could you clarify if we need to post additional security upon COD of the project or we can simply roll over the PDS to DTS since they are the same?

Answer H.1

If there are no damages due after the Initial Delivery Date, you can elect to apply the PDS to the DTS, in accordance with Section 10.4(a)(ii) of the TNPF Contract (Appendix E).