Jack E. Jirak
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October 15, 2019

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: CPRE Tranche 2 Stakeholder Meeting Report
Docket Nos. E-2, Sub 1159 and E-7, Sub 1156

Dear Ms. Campbell:

Pursuant to Ordering Paragraph No. 3 of the Commission's July 2, 2019 *Order Modifying and Accepting CPRE Program Plan*, please find enclosed the Report of the Independent Administrator pertaining to the CPRE Tranche 2 Stakeholder Meeting that was held October 10, 2019.

Please do not hesitate to let me know if you have any questions.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

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CERTIFICATE OF SERVICE

I certify that a copy of the CPRE Tranche 2 Stakeholder Meeting Report in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 15th day of October, 2019.

Jack E. Jirak
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DUKE ENERGY CAROLINAS, LLC
DUKE ENERGY PROGRESS, LLC

REPORT OF THE INDEPENDENT ADMINISTRATOR
RE:

TRANCHE 2 – October 10, 2019 STAKEHOLDER SESSION

DUKE ENERGY CAROLINAS (DEC)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposal (RFP) – 600 MW

DUKE ENERGY PROGRESS (DEP)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposals (RFP) – 80 MW

October 15, 2019

ACCION GROUP, LLC
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Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP)
CPRE Tranche 2 Stakeholder Meeting Compliance Report

On July 2, 2019, the North Carolina Utility Commission ("NCUC" or "Commission") issued an order Modifying and Accepting CPRE Program Plan in Docket E-2, Sub 1159. That order requires Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (together, Duke) to meet monthly with interested stakeholders to continue discussions with the IA, the Public Staff, and the market participants with the goal of reaching consensus on the documents that will be used in the Tranche 2 CPRE RFP Solicitation and of providing a forum for market participants to gain more detailed information about the solicitation process. Further, Duke shall file reports detailing the status of these discussions on or before July 15, 2019, and every 30 days thereafter until December 15, 2019. Duke hereby submits this report with regards to the stakeholder meeting held on August 7, 2019.

I. Attendance

STAKEHOLDER SESSION PARTICIPATION October 10, 2019	
Total in Person:	
Total on Webinar:	51
Total Identifiable Companies:	25
Total Not Identifiable by Company:	8

Attachment A is a list of the firms with representatives either in person or via the webinar.

II. Subjects Discussed

Attachment B is a copy of the presentation made by Accion Group, LLC, the Independent Administrator and Duke.

III. Areas of Agreement, Disagreement, and Open for Discussion

Attachment C is a list of all questions posed during the Stakeholder session. Written responses to each will be posted on the IA Website. The meeting was conducted as an information session with an open discussion without identified issues to be agreed to by the participants.

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ATTACHMENT A

Attachment A: Firms with Participants – October 10 019 Stakeholders Session	
Accion Group (IA)	Innogy Renewables
Advanced Energy	Invenergy LLC
Carolina Solar Energy	National Renewable Energy Corporation
	NCCEBA
	NCUC Public Staff
	NextEra Energy
	Origis Energy
Crisp Law	Orion Renewables
Cypress Creek Renewables	Parker Poe
	Pine Gate Renewables
Duke Energy	PSNCUC
EDF Renewable Energy	Renewable Energy Services, LLC
Eon	Revoleve Power
Exoplexus	Solterra Partners
First Solar	Southern Current, LLC
ICF	VivoPower

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Attachment B
October 10, 2019 STAKEHOLDER SESSION
Presentation

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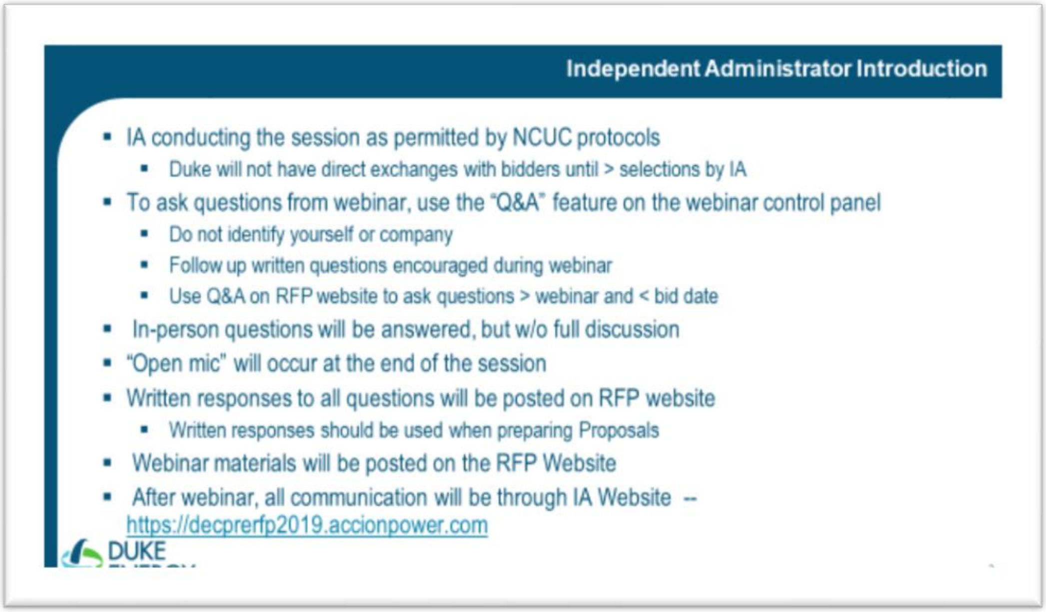

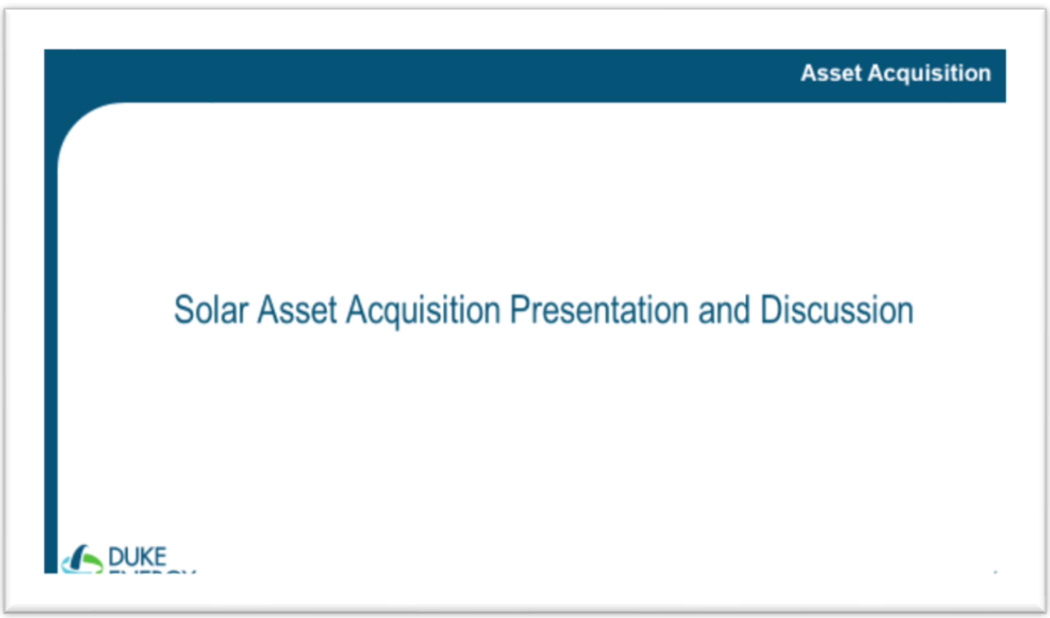

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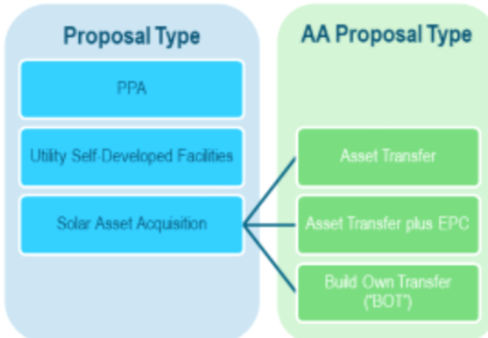
Proposal Categories

- Three types of Proposal categories
- Three types of Asset Acquisition ("AA") Proposal structures
  - **Duke is soliciting only solar asset acquisitions**
- MP's can submit separate Proposals for PPA and AA for the same project



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Asset Acquisition Proposal Structures

Asset Transfer[1] – Facility siting, land control, design, permitting, and interconnect studies completed by the MP and fully-developed project offered into the RFP. Facility ownership will be transferred to DEC or DEP prior to construction and DEC or DEP will be responsible for construction.

- *Parties would enter an Asset Purchase Agreement ("APA")*
- *MP is responsible for full development of the project*
- *Developed project assigns/transfers all assets, rights, etc. to DEC/DEP upon APA closing (all closing conditions met)*
- *DEC/DEP is responsible for all financing, construction, procurement and operation of solar facility (unless parties agreed to otherwise)*
- *DEC/DEP is the responsible party for Transmission Interconnection Facilities (Agreements, schedule, cost, funding, etc.)*
- *DEC/DEP is responsible for operation of the solar facility*

1- as defined in Tranche 2 RFP Guidelines.

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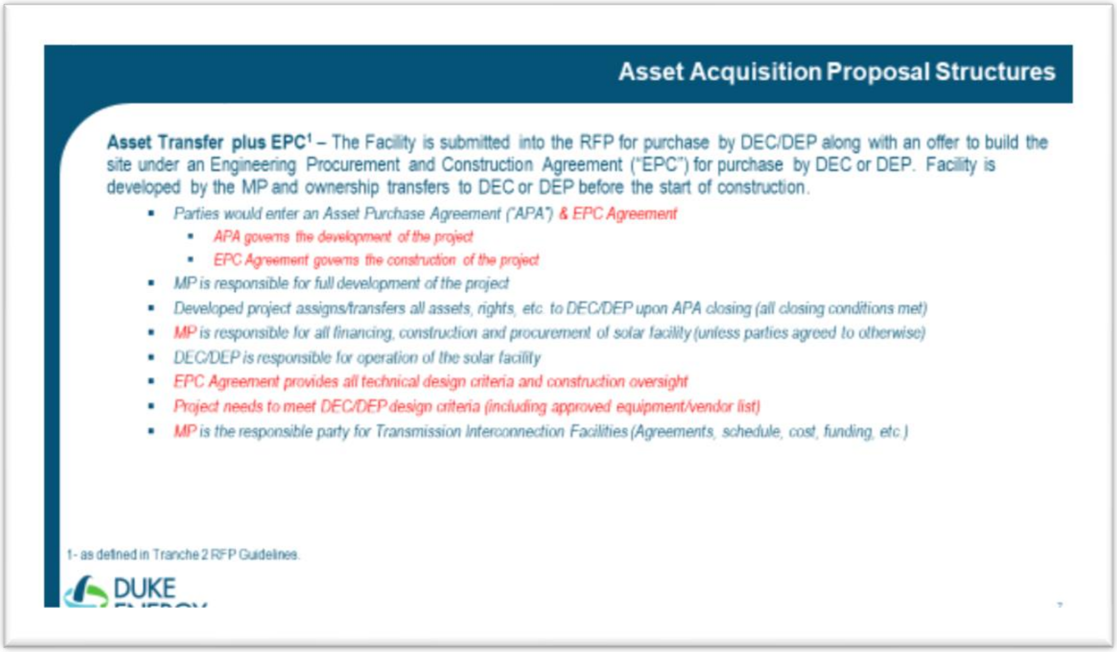

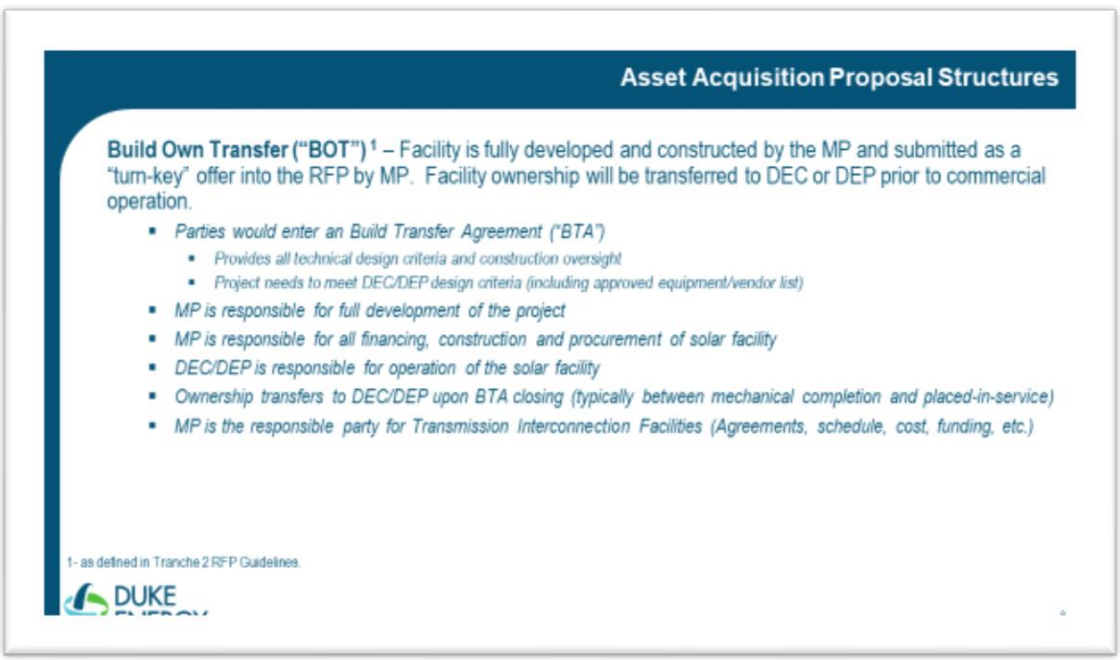

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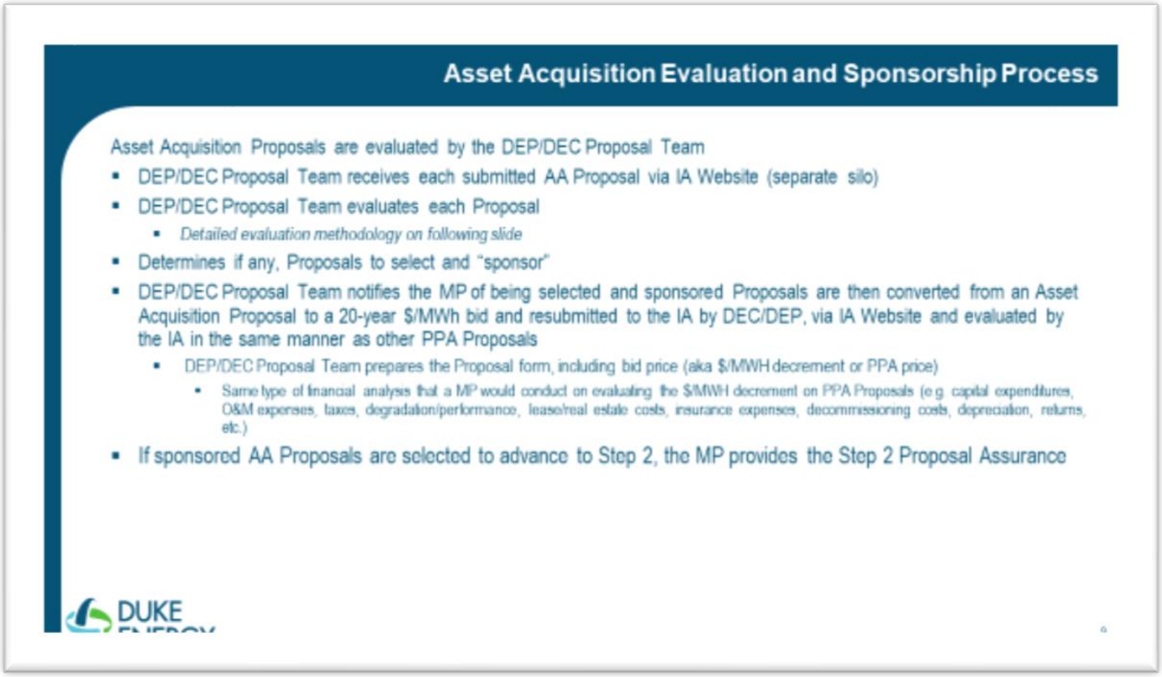

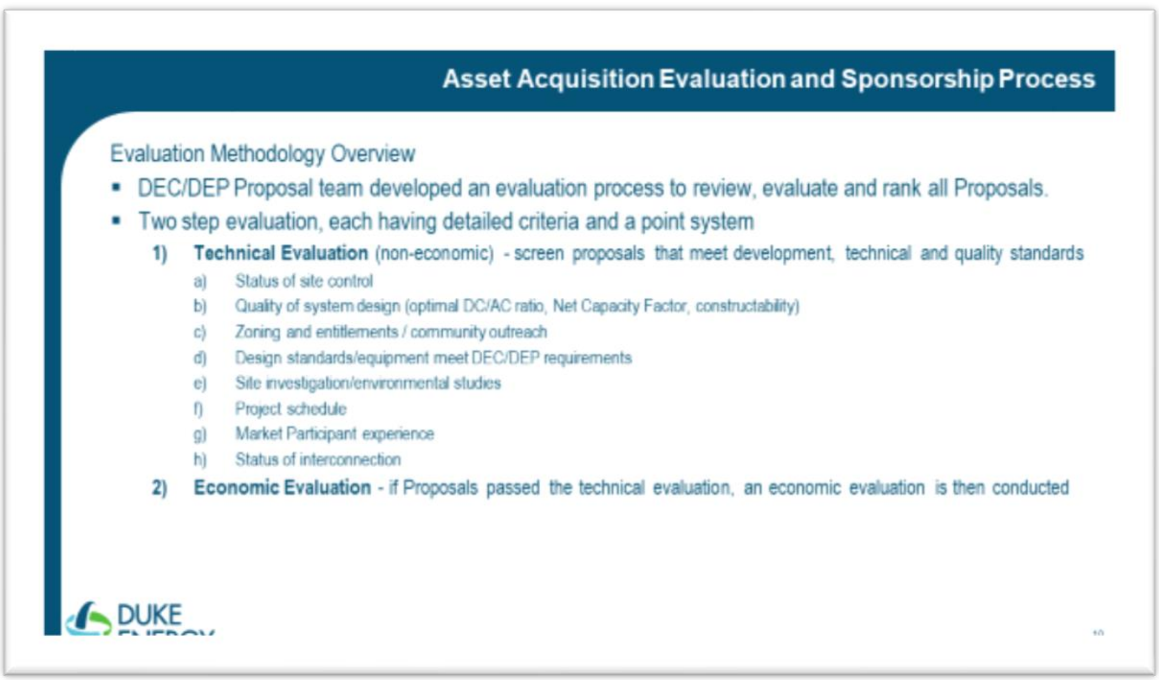

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Asset Acquisition Evaluation and Sponsorship Process

- Each of the eight technical evaluation criteria have a ten-point scoring system
  - 0 being the lowest, 10 being the highest
- Each criteria has a multiplier of five, with a total of 400 points available
- Established a minimum score requirement of 200 points
- If the resulting score was less than 200 points, the AA Proposal was eliminated
- If the resulting score was greater than 200 points, a detailed economic evaluation was conducted

Sample Technical Evaluation Scoring Sheet:

	Non-Economic Criteria	Weighting	Proposal Score
1	Full site control required to build and operate the proposed facility is secure (including any easements).	10	
2	Quality of system design/layout, including optimal DC/AC ratio, constructability and serviceability of layout and system's production performance (capacity factor).	10	
3	Proposal has secured proper zoning and permit entitlements required to construct and operate the facility. MP has further engaged local stakeholders (neighbors, community, permitting authorities, etc) and identified potential opposition and development issues.	10	
4	Proposed facility complies with DEC/DEP design standards and approved equipment.	10	
5	MP has conducted sufficient site investigation in order to ascertain the quality of site and lack of constructability and operational risk.	10	
6	Proposed project schedule enables the project to be in-service as required under the RFP.	10	
7	Experience of MP as project developer, EPC (if applicable), financial stability, etc.	10	
8	Status of interconnection studies and quality of interconnection costs/results. Does the project have a fully executed Interconnection Agreement and network upgrade costs are cost-effective.	10	
		Minimum Criteria Score:	200
		Proposal Score:	-

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11

Asset Acquisition Evaluation and Sponsorship Process

- Economic analysis and scoring:
  - The DEP/DEC team conducts financial modeling (very similar to how a MP determines their decrement pricing) using inputs such as:
    - project capex, project production estimates, and project operations and maintenance cost, etc.
  - Economic evaluation is assigned a maximum point score of 600 points
- AA Proposal selection:
  - Proposals are ranked based on the combined noneconomic and economic scores
  - DEP/DEC team considers project risk, including but not limited to environmental, development, construction, cost and schedule
- Following an audit by the IA in Tranche 1, the IA determined:
  - *"The Duke AA Evaluation Methodology was comprehensive and balanced."* [2]

2- Source- CPRE Tranche 1 Final Independent Administrator Report, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.

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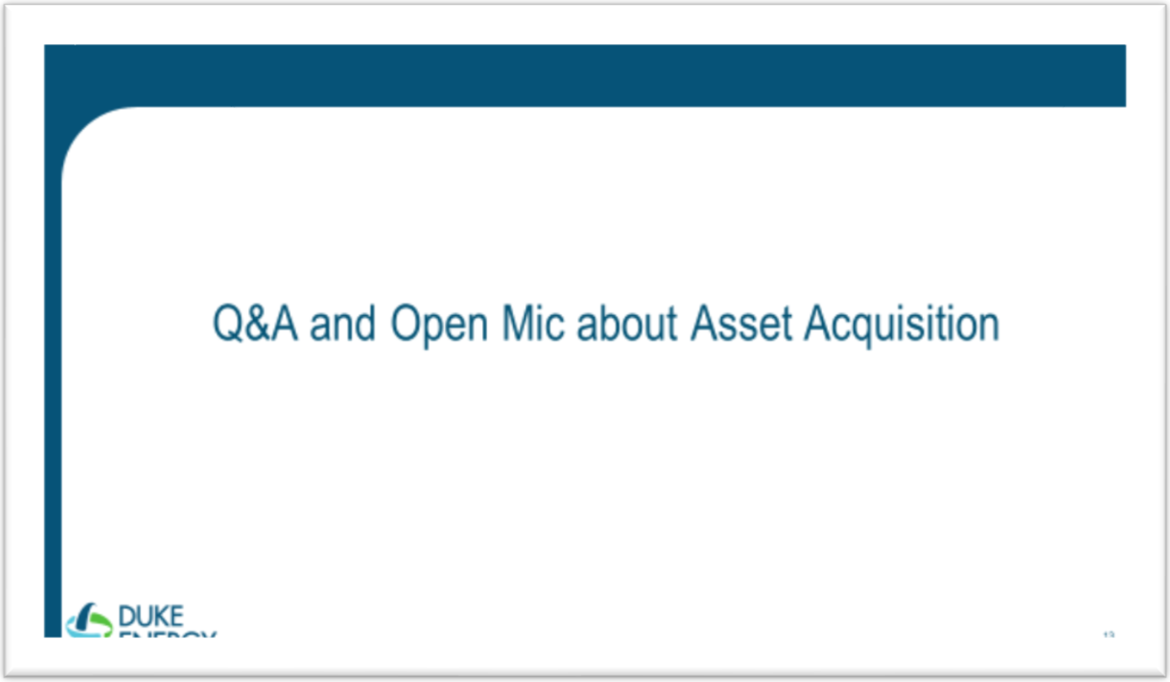

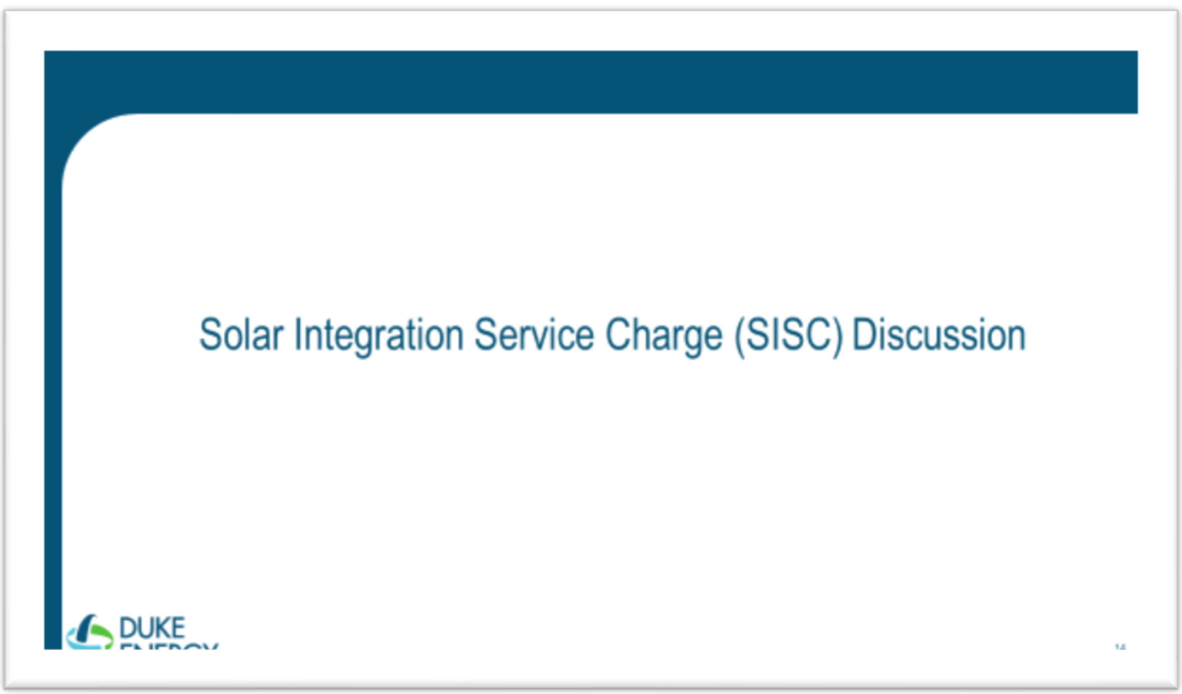

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SISC Update

- By an order dated October 7, 2019, the NCUC has requested comments regarding the applicability of SISC to CPRE.
  - Applicability of SISC to CPRE Tranche 2 will be determined by the NCUC sometime after the October 25th close of period for comments to NCUC.
  - Therefore, when CPRE Tranche 2 RFP goes live on October 15, we will not have a final answer on this issue.
    - Once issue is resolved by NCUC, any necessary changes to RFP and/or PPA will be made

SISC

Duke Draft Proposal

- Required with storage
- Solar Site Volatility Metric
  - 5-minute interval
  - Volatility less than or equal to 12%: Partial reduction in SISC of 50%
  - Volatility less than or equal to 6%: Full reduction in SISC of 100%
  - Volatility greater than 12% shall receive a zero-percent (0%) reduction in SISC

Observations via Comments

- Redundant to curtailment rights
- Clarify how dispatch rights can mitigate SISC
- Should not be included in CPRE absent NCUC Order
- Would make PPA impossible to finance
- MP should be able to bid with technology to limit output
- Allow 10 business days to submit data

T&D

Transmission & Distribution

T&D

T&D System Upgrade Cost Evaluation

- Same Step 2 analysis process as Tranche 1
- Move from Step 1 to Step 2 in rank order
  - Proposal Assurance required
- Estimated system upgrade costs imputed to Proposal as $/MWh
  - System upgrade costs include:
    - Network upgrades
    - Distribution upgrades
- Interconnection costs not included in system upgrade costs
- MP has cost responsibility for transfer trip scheme in DEC
  - Cost guidance to be posted on IA Website
- Competitive tier re-ranked iteratively with imputed costs
- Bids added to competitive tier from reserve list as needed

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Treatment of Projects with Fully Executed Interconnection Agreements

Updated RFP

- A MP that
  - has a fully executed Interconnection Agreement with the Companies as of the Proposal submission date (whether under the NCIP, SC GIP or the Companies' Joint Open Access Transmission Tariff) and
  - is not in default under the Interconnection Agreement

  Shall have the option to elect to participate as an "Advanced Stage Proposal."
- Advanced Stage Proposal will not be evaluated as part of the System Impact Grouping Study.
- Advanced Stage Proposal shall be solely responsible for the cost of any System Upgrades assigned to it under its Interconnection Agreement and should bid accordingly.
- A MP sponsoring an Advanced Stage Proposal must perform all obligations (including satisfying any applicable payment or financial security obligations) arising under the Interconnection Agreement.

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Updated RFP

- In the event that, during the Tranche 2 evaluation process, a default on the part of the Interconnection Customer occurs under the relevant Interconnection Agreement or the relevant Interconnection Agreement is terminated, the Advanced Stage Proposal shall be removed from the evaluation process and, if applicable, forfeit the Step 2 Proposal Assurance.
- An Advanced Stage Proposal does not forfeit its queue position by participating in CPRE Tranche 2
  - The outcome of CPRE Tranche 2 shall have no impact on the applicable Interconnection Agreement, which shall continue to be administered in accordance with the terms thereof both during and after CPRE Tranche 2.
- If a Facility satisfies the eligibility criteria for an Advanced Stage Proposal but elects not to participate in CPRE as an Advanced Stage Proposal, then: (1) such Facility will be included in the System Impact Grouping Study and studied based on the Queue Number established by the Companies and (2) the applicable Interconnection Agreement will be terminated by the Companies.

Miscellaneous RFP Updates

- Fixed percentage decrement changed to fixed dollar decrement for bidding.
- Pending SC approval of CPRE grouping study.

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Tranche 2 Proposal Form & Process

Tranche 2 Proposal Form

- Tranche 2 Proposal Form
  - Form will be released on October 15, 2019
    - Most data fields expected to be unchanged by NCUC – use form to get started
    - Indicative avoided cost will be on Proposal Form
      - Will be updated per NCUC Order re Avoided Cost
    - Submission option available *only* after NCUC Order re Avoided Cost
    - Submission date will be established by NCUC

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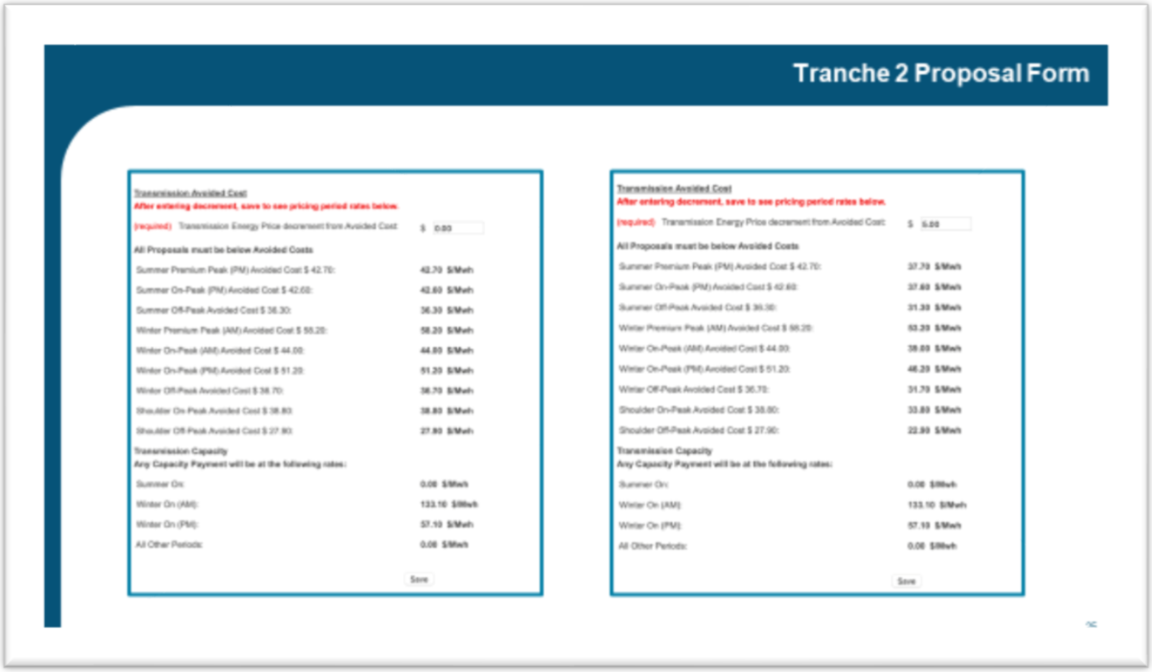


Tranche 2 Proposal Form

Transmission Avoided Cost
After entering decrement, save to see pricing period rates below.

(required) Transmission Energy Price decrement from Avoided Cost: $ 0.00

All Proposals must be below Avoided Costs

Summer Premium Peak (PM) Avoided Cost $ 42.70:	42.70 $/Mwh
Summer On-Peak (PM) Avoided Cost $ 42.60:	42.60 $/Mwh
Summer Off-Peak Avoided Cost $ 36.30:	36.30 $/Mwh
Winter Premium Peak (AM) Avoided Cost $ 58.20:	58.20 $/Mwh
Winter On-Peak (AM) Avoided Cost $ 44.00:	44.00 $/Mwh
Winter On-Peak (PM) Avoided Cost $ 51.20:	51.20 $/Mwh
Winter Off-Peak Avoided Cost $ 36.70:	36.70 $/Mwh
Shoulder On-Peak Avoided Cost $ 38.80:	38.80 $/Mwh
Shoulder Off-Peak Avoided Cost $ 27.80:	27.80 $/Mwh

Transmission Capacity
Any Capacity Payment will be at the following rates:

Summer On:	0.00 $/Mwh
Winter On (AM):	133.10 $/Mwh
Winter On (PM):	57.10 $/Mwh
All Other Periods:	0.00 $/Mwh

Save

Transmission Avoided Cost
After entering decrement, save to see pricing period rates below.

(required) Transmission Energy Price decrement from Avoided Cost: $ 5.00

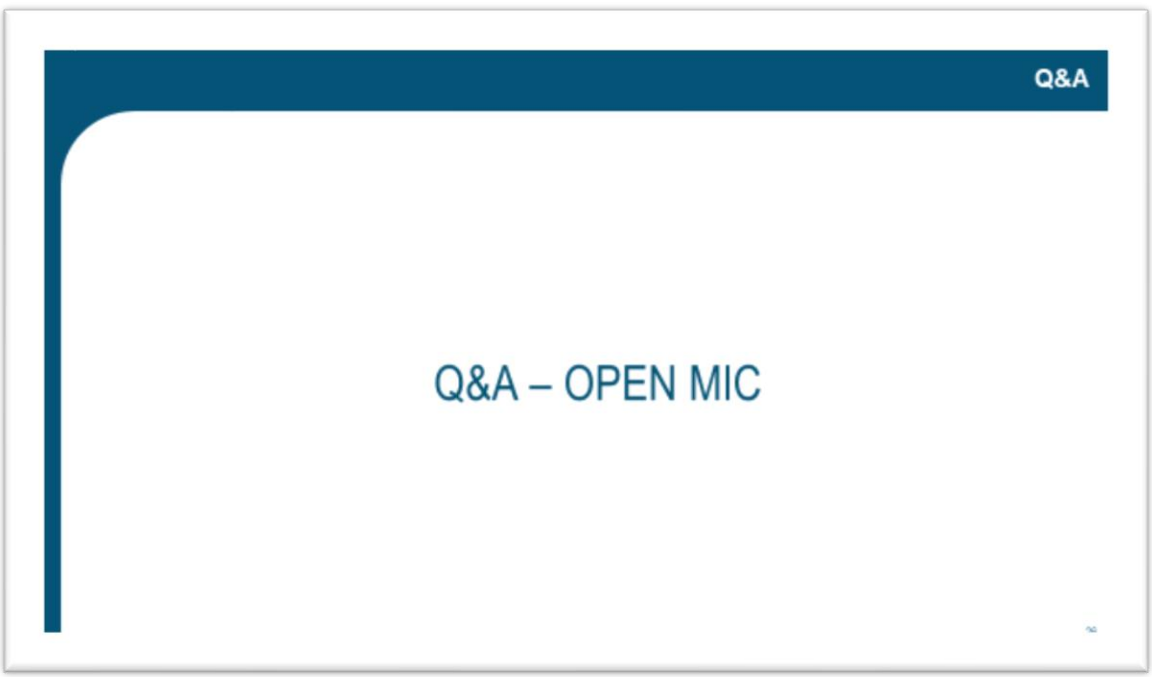
All Proposals must be below Avoided Costs

Summer Premium Peak (PM) Avoided Cost $ 42.70:	37.70 $/Mwh
Summer On-Peak (PM) Avoided Cost $ 42.60:	37.60 $/Mwh
Summer Off-Peak Avoided Cost $ 36.30:	31.30 $/Mwh
Winter Premium Peak (AM) Avoided Cost $ 58.20:	53.20 $/Mwh
Winter On-Peak (AM) Avoided Cost $ 44.00:	39.00 $/Mwh
Winter On-Peak (PM) Avoided Cost $ 51.20:	46.20 $/Mwh
Winter Off-Peak Avoided Cost $ 36.70:	31.70 $/Mwh
Shoulder On-Peak Avoided Cost $ 38.80:	33.80 $/Mwh
Shoulder Off-Peak Avoided Cost $ 27.90:	22.90 $/Mwh

Transmission Capacity
Any Capacity Payment will be at the following rates:

Summer On:	0.00 $/Mwh
Winter On (AM):	133.10 $/Mwh
Winter On (PM):	57.10 $/Mwh
All Other Periods:	0.00 $/Mwh

Save



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Q&A

- You may continue to submit written questions through the IA Website
- Written answers to questions will be posted to the IA Website
- Responses provided during this webinar are preliminary only
  - Written responses posted on the RFP Website are to be used in preparing bids

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ATTACHMENT C
October 10, 2019 STAKEHOLDER SESSION
SUBJECTS DISCUSSED

October 10, 2019 Stakeholder's Meeting Questions Asked	
Q1	Can you talk about how you will determine the EPC price that you'll attach to development asset bid?
Q2	How will Duke evaluate the total system price?
Q3	Could you highlight what's different about Tranche 2's evaluation process for these types of bids compared to Tranche 1: what's changed?
Q4	Can you say in Tranche 1, so there's three different asset acquisition bid types. Can you say in Tranche 1 how the for the asset acquisition bids that went through Tranche 1 and got selected how they split up between those three categories?
Q5	One thing you mentioned about the approved vendor list; did you say that that includes a list of EPC providers as well?
Q6	My other question is around the proposals that include batteries. Are you also receiving asset bids that include batteries and if so, how are you evaluating their ability to reduce or eliminate any of the integration charges? And as you were converting them into your energy bids.
Q7	I'm assuming there's going to be more guidance on this organization service charge, but it's part of your proposal if there's guidance in how the batteries designed to mitigate the volatility that information would certainly be appreciated.
Q8	Can you explain whether the term sheet is binding; second part of that is if not, how is the third party obligated to post the bid bond?
Q9	Since you mentioned that security agreement, so I understood the if withdrawal for convenience, then essentially the penalty if you will would be on Duke for that but if the bond is drawn on by Duke, how is--trying to understand where the penalty is for Duke for drawing on your for withdrawing of convenience the events.
Q10	When you were going through the asset transfer slide, you mentioned a 2021 COD and I thought Tranche 2 was going towards the 2022 COD pending Commission approval it. Could you let me know the latest status on that?
Q11	I think in its original order establishing CPRE the Commission may have provided that the utilities assumptions on its first PPA evaluations for its own bids would be made transparent just because of course they have substantially advantageous… information on that front and I think they may have since changed their mind on that but I was wondering if we could just clarify if that was the case and even if it is the case if the utility may be willing to voluntarily offer up some of that information just because I think the original notion was that it would provide more transparency to Market Participants.
Q12	Are Duke owned solar facilities required to mitigate integration costs and if not, how is requiring third-party facilities to mitigate such cost non-discriminatory and consistent with the statutory requirement that third-party facilities be operating the same fashion as utility own facilities?

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October 10, 2019 Stakeholder's Meeting Questions Asked	
Q13	My reading of the Commission's October 7th Order is that the Commission has concerns about whether the Solar Integration Services Charge is permitted in the first place by House Bill 589. What is Duke's I guess it's a two-fold question in light of the Commission's order for filing of the PPA. Are you planning to include Exhibit 11 and that PPA before the Commission issues its Order and then can you provide a little bit more information about if the Commission were to determine that this whole integration Services charge should be applied to CPRE how you would implement those necessary changes that you referred to and what the timeframe for doing so would be?
Q14	The major problem with this charge seems like you're cherry-picking, you know, something that storage can do and putting a value to it. And so my question is: How do you put other values to storage if it operates in this manner to avoid the charge? What are the other benefits of storage doing that and shouldn't that be added back in your evaluation? For example, power quality or operations the benefits of storage on those fronts? It seems like you're going to put a value to ancillary services for storage. You should include the values of the other things in this process. So have you guys started that?
Q15	And another question is if storage is providing the ancillary services for the solar facility, presumably you're taking off a resource from the grid that you're providing ancillary services for and is that included in the calculation that you all are doing? Here's one more specific example with an issue with the calculation. So say all you did with the storage was capture solar during the day and you shift it into the peak periods during those Peak periods. It would be a huge benefit for the utility to get power on the grid as fast as possible considering the ramp rate you guys have outlined. According to this calculation you'll actually get dinged for ramping up to provide energy in the peak periods because your volatility is going to be high as you ramp up to provide that into the peak period if you guys account for that, yeah, so why should we be penalized for providing storage into a peak period as fast as possible when it actually benefits utility.
Q16	I think the first question on the chat was maybe put another way and maybe Matt or Justin might offer clarity, but I think it's for those Duke sponsored projects, you know, are they going to be subject to the same charges? And how are those charges actually going to get paid from Duke?
Q17	My other question was just can you can anyone provide clarity on how the charges would be adjusted after the initial two-year period and is there a formula is there a philosophy behind calculating the what those charges would be in the future?
Q18	When will Exhibit 11 be available on the IA website?
Q19	Do projects with earlier COD have an advantage over projects with the later COD?
Q20	Following up on an earlier question regarding the adjustment. Am I correct in understanding that that proposal that's in the Duke public staff settlement is that any upward adjust any adjustment is upward adjustment in the charge would be capped based on the caps that have been proposed for the full life of the CPRE PPA.
Q21	The process that the Commission laid out in its July 2nd order which was the series of stakeholder meetings that we've been participating in with the idea that any unresolved issues would be brought to the Commission for decision. What is the plan for that?

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October 10, 2019 Stakeholder's Meeting Questions Asked	
Q22	If there is a charge that's approved how it ends is a decision that it should apply to CPRE. I think we've made this point in comments on the website, but you know if the options are so I think if they basically two options one is that it's a charge that is paid by the by the market participant just as it would be paid by a purpose QF in which case that supplier has to make an assumption about the upward adjustments over the life of the contract and is a rational party is going to assume the worst case and it's financier financing parties are going to assume the worst case scenario. And so you have a situation where you may have built into bids a higher charge than is actually required based on the costs that are evaluated the time and if that happens ratepayers are then going to be paying more for energy delivered under this program than they would otherwise pay but in the larger point is that either way whether there's a charge or the costs continue to be absorbed directly by ratepayers. The ratepayers are going to pay for these integration costs. It has it as they may be incurred by CPRE participants. So it seems to me to be a much more efficient approach if there is to be a charge that large that it be treated like Network upgrades and attributed to a bid but not actually paid by The bidder and so because they're going to be socialized either way. So I be interested in getting some reaction that.
Q23	I've got a question on the use of curtailment for avoiding the negation charge. I think you know, we all share the same concern here. It's getting the best deal for rate payers and you know, if they're already paying the maximum cap on the integration charge because they'll be baked into the bid then they're also inherently paying for all the full curtailment rights. If 5% DEC 10% DEP, you know, it seems the behoove us all to figure out if there is any way in which those particular rights could reasonably be used to mitigate any of those charges and hear what you're saying. Of course, you know, it's a dispatch down right but it seems to me that you know, the primary concern with volatility that we're all talking about here is largely with respect an intermittent cloud cover and so today. I mean it looks like largely consistent cloud cover. So you're not talking about as much volatility and especially when we're talking about these large scale solar Farms of 500 to 1,000 acres, you know, it seems like the volatility is very much in this range that we're kind of talking about if you know say 5 to 10% and so it seems like, you know open approach here and of course needs to be flushed out and we should probably put more working group around it. But you know on days that you're projecting significant intermittent cloud cover what you could do is utilize an approach similar to what Chico and First Solar proposed where you essentially place a cap on the facilities production to provide headroom in a way that would accommodate some of that volatility and it's not simple so definitely understand. This is a little bit complex and we're all working through this together for the first time but it does seem like there's something there and definitely is value that we can all provide the ratepayers by figuring it out. And so we would love to work with you all the to explore its warm up working group of possible and see what we can do. And so I just want to put that out there and, you know, maybe we can maybe we can circle back on it together.
Q24	So given that reducing volatility to less than 6% per this calculation that y'all have come up with, would completely mitigate the solar integration service charge. Is it fair to assume that the solar integration service charge as you propose it as in place, exclusively to address volatility?

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October 10, 2019 Stakeholder's Meeting Questions Asked	
Q25	[Regarding the charge] when you review it by annually in two years, are you proposing to change the formulas or just the charge itself the dollar figure because if someone is designed and implemented a system that can hit your 6% reduction. Or 6% measure and then two years later that changes to 4% and I think you've got a tricky situation.
Q26	Would the upgrades triggered by a late-stage projects with an LGIAD modeled in the base case evaluation process?
Q27	Would substation upgrades required to interconnect the project or added a breaker or half scheme also be considered a direct cost borne by the MP?
Q28	We have a question of asking whether these are screen captures put into the PowerPoint or is it actually interactive website
Q29	So if you've got an existing IA and you're going to enter it into CPRE. What's the process for submitting that if it doesn't win? So if you're not a winner what happens to that project after? And if it's not selected in the CPRE I thought I heard you say something like it would forfeit if I agreement did I hear that correctly or incorrectly down? But in terms of payments regardless of whether it's a network upgrade or facilities charge the expectation is that market participant would continue to perform under the interconnection agreement. So it would make those payments regardless just as the IA milestone schedule asked for?
Q30	When will the updated interconnection cost guidance be provided?
Q31	Even if the interconnection costs are the same as the provided cost guidance, there is a significant difference between cost guidance and the actual cost established with the three payment options provided in the interconnection agreement. Will the IA take that into account when reviewing the MP's pro-forma? If not, can that information be added to the interconnection cost guidance to make sure MPS are clear on the actual costs.
Q32	So two things- one is again with this issue of identifying any issues any matters on which consensus has not been achieved. There are obviously a lot of comments that have come to the IA website many of the those, or at least some of those. I mean, I don't think we've discussed any stakeholder meetings. What's the process for being sure that all issues have been resolved in consensus fashion so that you can know what might need to be put to the Commission?

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October 10, 2019 Stakeholder's Meeting Questions Asked	
Q33	I think that the move back to $6 decrements is probably a good thing. But the question that I've asked I asked about Tranche 1 is if you have a fixed dollar decrement it would seem that the economic evaluation would simply be based on the decrement. That is since you've got the same dollar reduction across all megawatt-hours delivered the ratepayers get the same benefit regardless of when the power is being delivered and you could simply do the economic ranking based on the decrement without more, but it's has appeared from things that you…This response and from your Tranche 1 report if there was something more that went on in Tranche 1 and maybe is contemplate the Tranche 2 in which you would take the decrement to run the 8760s for different projects and somehow assess the relative value to rate payers of projects in some way that gets beyond purely just looking at the decrement and so I'm trying to determine if that in fact is what it is contemplated and if so how it would work? And I particularly asked it because if there were some waiting that would being provided to on Peak delivery that would be really important for Market participants to know because and understand how it would work because that would affect the potential economic to the adding storage to projects.
Q34	There will be a question about will you be able to be able to share that evaluation process the details of it?
Q35	Okay on slide 22. I think Dave Ball was taking us through the effect of the decrement using the $5 example and if we could just follow that through a little further so assume someone bids a $5 decrement. This is related to what we were just talking about then the different delivery periods for energy would be discounted by $5 is shown in the model. But then if the shape or the 8760 production for that project delivers in the winter mornings AM with the capacity to how would the capacity component be treated in the evaluation? I understand the energy component that's very clear. The capacity components less clear and in Tranche 1 the rates were blended energy and capacity but in Tranche 2 now they're separated so he could provide some color on that either you were Dave or someone else had be great. Yes, again Tranche 1 there was three rates and they were Blended energy and capacity Tranche 2 now has more energy rates and a couple of capacity rates. And when you apply the decrement to the energy rates, which is somewhat similar to try each one, but I'm just trying to understand how the capacity rates get factored into that analysis. When you look at the shape of the project and you look at when the energy is being delivered and again the energy portions clear the capacity portion…. I'd like to hear how it's actually being done just to see them thinking about it correctly. And then in in the PPA and exhibit to that would that reflect one price or is it going to reflect a number of prices that line up with these Energy Delivery periods as we see? Just to clarify the so that whole structure would translate into the exhibit two table in the PPA and would reflect the same price?
Q36	The question is after we hear the debrief and to understand what the issues were on the project—when it did not win it becomes a business decision of whether to re-enter that into the next Tranche of CPRE or what to do with it. And this was one of the questions that I had out to the Duke team. And I think the answer was on Tranche 1 but I'm curious in Tranche 2 how it would work if the market participants request the study models to review to understand maybe some of the network upgrades are things that were associated with the project. How do we go about that process to kind of validate and understand, you know the economics of this project moving forward at all in any type of scenario outside of CPRE or not.

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October 10, 2019 Stakeholder's Meeting Questions Asked	
Q37	I think the question is still valid in terms of if you are a market participant in you make it through to step two, but you still aren't selected. Is there going to be any, are you going to be able to share any of those study models I mean that is the question right is to be able to see the study models, that were looked at and we're talking about queue reform as well, I'm just curious about what the position is for Tranche 2.
Q38	So everything that is in the queue is assumed in Baseline, including the multiple gigawatts of the utilities proposed facilities? So projects to get into Stage 2 evaluation that go through the study for Network upgrades and then they are not selected is the current standpoint of the utility and the IA that there will be no feedback with respect to the results of that study to the interconnection customer?
Q39	I guess is it Duke's understanding that the Commission directed Duke to not remove any projects deemed speculative from the base case when doing the impact studies not even for contingency analysis or other and if so, I kind of some kind of wondered where in the Commission's orders do they specifically I guess disallow you from removing speculative the projects for certain T&D analysis.

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