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PROJECT NO. 54224

COST RECOVERY FOR SERVICE	**§**	**BEFORE THE**
TO DISTRIBUTED ENERGY	**§**	**PUBLIC UTILITY COMMISSION**
RESOURCES	**§**	**OF TEXAS**

ONCOR ELECTRIC DELIVERY COMPANY LLC'S REPLY COMMENTS ON THE QUESTIONS FOR COMMENT CONCERNING <u>DERS INTERCONNECTION ALLOWANCE</u>

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

Oncor Electric Delivery Company LLC ("Oncor") timely files these reply comments on the questions for comment concerning an interconnection allowance for distributed energy resources ("DERs") and related issues posed by Public Utility Commission of Texas ("Commission") Staff on September 9, 2024, in this Project. Oncor's reply comments focus only on certain recommendations and comments raised by certain commenters. Oncor's silence on a particular party's recommendations does not, however, indicate Oncor's agreement with those recommendations. In support of these reply comments, Oncor respectfully shows the following:

I. REPLIES TO SPECIFIC INITIAL COMMENTS ON <u>COMMISSION STAFF'S QUESTIONS</u>

<u>Question 2</u>**:** What are the advantages and disadvantages of the proposed standard distribution resource interconnection allowance? Is a standard distribution resource interconnection allowance a viable option to move forward? If not, why?

<u>Oncor's Reply Comments</u>**:** First, despite the various comments suggesting that implementation of a DER interconnection allowance will have the benefit of encouraging more DERs to interconnect, Oncor's position continues to be that it is just not appropriate to uplift DSP-incurred costs to ratepayers in order to serve DERs, unless and until the Commission determines that DERs provide enough benefits, including actual resiliency, sufficient to justify shifting those interconnection costs to other ratepayers.

Next, various sets of comments discussed that there appears to be variability among the distribution service providers ("DSPs") when it comes to typical interconnection costs for a DER.[1]

[1] *See, e.g.*, Comments of Texas Advanced Energy Business Alliance at 2 (Sept. 30, 2024) (discussing the variability of contribution in aid of construction ("CIAC") payments among utility districts); Regis Energy Partners, LP's letter to the Commission containing responses to questions at 2 (Sept. 30, 2024) (discussing variation between

AEP Texas Inc. also suggests that setting a specific allowance across all transmission and distribution utilities may not be appropriate and that a standard methodology could be more appropriate than a standard value.[2] HGP Storage, LLC ("HGP Storage") also commented that the typical range of interconnection costs in Oncor's service area of $250,000 to $500,000 includes costs for distribution expenses past the substation breaker, and that if a resource requires a change in substation relays, relay setting, transmission overvoltage protection schemes, transformer LTC/regulatory controllers, lightning arrestors, etc., then these expenses would be charged at full cost but would not be accompanied by a detailed breakdown and would only be "classified vaguely as 'Substation Upgrades.'" As a result, HGP Storage recommends that the allowance breakdown categories should be reviewed, and those costs that are installed to support the benefit of the grid should be allowed (Oncor presumes this means those costs should be allowed to be covered under an interconnection allowance).[3]

In response, Oncor notes that there could be differences in how different DSPs approach the categorization of costs that they deem to be interconnection costs attributable to the interconnecting DER. Oncor, for example, analyzes and separately categorizes (i) the costs to serve an interconnecting DER's charging load such as when battery storage technology is being proposed (for which Oncor already applies an allowance, with costs in excess of the allowance paid for by the DER through a CIAC), and (ii) the additional costs that Oncor will incur as a result of the generation aspect of the interconnecting DER (which Oncor currently charges directly to the interconnecting DER through CIAC). Oncor does not have a categorization that identifies specific utility upgrades as being installed to support the benefit of the grid. Instead, Oncor's pre-interconnection impact studies identify the substation and distribution system upgrades and the estimated costs necessary for safe, reliable interconnection with the DER. Oncor describes these costs in the impact study report conducted for a given DER, and Oncor refers to these costs in the invoice and the interconnection agreement provided to that customer or DER developer.

DSPs with respect to the study process and costs and interconnection costs); and East Point Energy L.L.C. Comments at 2 (Sept. 30, 2024) (discussing variation in connection costs between utilities).

[2] AEP Texas Inc.'s Initial Responses at 2 (Sept. 30, 2024).

[3] HGP Storage raised these comments in its initial September 30, 2024 response to Question No. 3, but Oncor is responding to them as part of its response to similar comments submitted for Question No. 2.

Attachment 1 hereto is a redacted copy of a Utility System Impact Study that Oncor conducted for the requested interconnection of a DESR in Oncor's service territory. Pages 7 and 9 of the attachment provide an example of the types of required work to the distribution system that Oncor may identify as being necessary to interconnect a DER, with the estimated costs for that work provided on page 10 (reflecting a standard allowance applied to the load-serving costs).

Other DSPs, however, may categorize the costs differently, such as categorizing both the costs to the serve the load and the costs to serve the generation portion of the DER all as costs to be paid directly by the DER. Thus, if the Commission determines that there should not be a one-size-fits-all standard amount for a DER interconnection allowance that applies to all DERs and all DSPs, then the Commission may alternatively want to consider adopting a DER interconnection allowance of an unspecified amount that will instead uniformly cover the same categories of costs for all interconnecting DERs. By specifying the categories of costs/equipment that should always be covered by an interconnection allowance, the Commission could provide for use of a more uniform methodology for calculating interconnection costs by the various DSPs, and the Commission would avoid having to calculate a specific interconnection allowance amount based on the capacity size of the interconnecting DER, as other comments have suggested. By requiring all DSPs to use the same methodology and approach for categorizing (i) the types of costs to be covered by an interconnection allowance, and (ii) the costs to be paid directly by the DER, the Commission could minimize the potential for "DSP shopping" by interconnecting DERs.

The categories of costs that should be covered by a DER interconnection allowance include reasonable upgrades in the substation, meaning only costs for equipment or work that are required, under the DSP's least-cost design standard, to interconnect the resource and to allow for provision of safe and reliable service. The scope of the allowance should not be so broad that it would include the addition of a transformer, as energy storage resources connected at either transmission voltage or distribution voltage should be responsible for step-up transformation cost (as illustrated on the one-line diagram attached to Oncor's initial comments). Specifically, the allowance should cover costs associated with the following: distribution system interconnection costs based on the utility's least-cost design standards, the modification of the substation (minus transformers), costs associated with the transmission system protection impact, and standard metering.

Oncor also notes that the higher the dollar amount the Commission considers adopting for a DER interconnection allowance, the less need there is to consider distinctions in interconnection costs among different regions of the state or among different interconnecting DSPs. As discussed in Oncor's initial responses to Commission Staff's questions, a large interconnection allowance amount (e.g., $1.5 million) is likely to entirely cover the costs of many, if not most, interconnecting DERs, regardless of the region of the state in which they seek to interconnect or how the particular interconnecting DSP categories and assigns costs to the DER. Even if the Commission ultimately adopts a standardized, specified dollar amount for the allowance, the Commission may still want to specify that the allowance amount will not cover certain categories of equipment (like a transformer addition) in order to encourage some level of site discipline by the DER owners. Additionally, any standard, specific interconnection allowance amount should be determined through a similar data analysis process the Commission used for transmission-interconnected generation resources in Project No. 55566, *Generation Interconnection Allowance*.

> ***Question 3***: At what amount should a standard distribution resource interconnection allowance be set? Should the applicability or amount of the allowance vary based on the size of the resource?

Oncor's Reply Comments: In the joint comments filed by the Texas Solar Power Association and the Solar Energy Industries Association ("TSPA/SEIA"), and in comments filed by the Texas Advanced Energy Business Alliance ("TAEBA") and the Texas Solar Energy Society, these commenters have recommended that for smaller-scale residential or small commercial DERs, the Commission should, instead of applying a standard interconnection allowance, require the interconnecting DSP to charge those smaller DER customers a "uniform administrative fee," a "uniform, minimal fee," or a "marginal interconnection allowance standard of no more than $300" to cover the costs of the interconnection. Oncor does not necessarily have an objection to this concept of a uniform fee for these smaller-scale DERs, although Oncor does not currently charge any application fee for residential DERs, and only rarely are transformer upgrades required for which such a customer would have to pay. For clarity, as discussed in Oncor's initial response filed on September 30, 2024, if the Commission decides to adopt a standard DER interconnection allowance, any such allowance should only apply to DERs like distribution generation resources ("DGRs") and distribution energy storage resources ("DESRs") that provide ancillary services in the Electric Reliability Council of Texas, Inc. ("ERCOT") wholesale market and/or are security constrained economic dispatch ("SCED") dispatchable by ERCOT. No interconnection allowance of any amount should be provided to any smaller-scale

DERs who are neither providing ancillary services nor are SCED dispatchable, because such DERs do not provide enough (or perhaps any) benefit to the grid such that it would deserve an allowance. Thus, the smaller-scale DERs that the commenters reference (e.g., small resources at or below 500 kW) should not receive any interconnection allowance. Finally, the determination of whether a particular DER is of the type of resource that qualifies for an interconnection allowance should be made at the initial time of interconnection to the distribution grid and that determination should not be revisited later. Specifically, to determine a DER's eligibility for the interconnection allowance, the interconnecting DSP should be instructed to rely on the DER's identification of itself as either a DGR or DESR in the executed interconnection agreement with the DSP.

Regis Energy Partners, LP[4] and Hunt Energy Network, L.L.C. ("HEN")[5] suggest that once the Commission adopts a DER interconnection allowance, those DESRs that have already signed interconnection agreements should receive a retroactive application of the interconnection allowance, so that any interconnection costs they have previously paid would be partially or wholly refunded. The Commission should reject these suggested refunds or credits because Oncor simply cannot practically or legally accommodate this refund concept. Issuing refunds to DERs covered by previously-signed interconnection agreements predating the adoption of any interconnection allowance would constitute illegal retroactive ratemaking. It would also require the interconnecting DSP to perform a host of accounting work and would risk requiring a DSP to refund a large amount of money in the aggregate among multiple DERs that would then have to be socialized, all at once, and paid by the other ratepayers. There is no reason to retroactively violate a signed interconnection agreement and force other ratepayers to subsidize existing DERs. Further, if the Commission were to adopt a requirement that interconnecting DER owners must directly pay the costs of certain categories of equipment or work necessitated by the interconnection that should not be covered by the interconnection allowance, would the Commission instruct the DSPs to retroactively *charge* any DERs covered by previously-signed interconnection agreements to now pay those charges after the fact if they haven't already? Oncor

[4] Regis Energy Partners, LP's letter to the Commission containing responses to questions at 2 (Sept. 30, 2024).

[5] HEN raised these comments in its initial September 30, 2024 response to Question No. 8, but Oncor is responding to it as part of its response to similar comments submitted for Question No. 3.

suspects the answer would be "no." Both retroactive charges and retroactive credits/refunds create havoc in terms of accounting for the utility, and retroactive refunds would ultimately penalize ratepayers as they would be forced to further subsidize DERs at a higher level.

TAEBA,[6] the Office of Public Utility Counsel ("OPUC"),[7] East Point Energy, L.L.C.,[8] and SMT Energy LLC[9] have recommended that the Commission require the interconnecting DSP to provide either a detailed account, a detailed cost estimate, or a detailed cost breakdown of the costs necessary to interconnect the DER, especially with respect to costs that exceed the interconnection allowance amount. As Oncor has commented at an earlier juncture in Project No. 54233,[10] Oncor is not opposed to providing a description of required substation upgrades and equipment, a description of distribution feeder upgrades and equipment, and an overall estimated cost associated with those required upgrades and equipment. For example, Oncor could give a price estimate (broken down by the Oncor internally loaded price, any additional operations and maintenance costs, the tax adjustment factor, and the franchise fee adder, for a total estimated cost) for (i) distribution work and equipment to serve the energy storage resource, and (ii) distribution work and equipment to serve the DER as a load only with the applicable standard allowance for load-serving costs in accordance with Oncor's Commission-approved tariff.

Oncor, however, is concerned with any suggestion that DSPs should be required to provide more granular cost details than that. Such a requirement would pose concerns on a number of fronts. First, this information could prove difficult if not impossible to provide in many instances, given the way Oncor procures equipment in bulk for use in multiple different projects, as well as the manner in which labor costs are embedded in project costs through a blended rate that

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[6] Comments of Texas Advanced Energy Business Alliance at 3 (Sept. 30, 2024).

[7] OPUC's suggestion that DSPs should be required to provide a detailed estimate of interconnection costs was made in OPUC's preliminary comments on page 2 of its September 30, 2024 comments, not specifically in response to Question 2.

[8] East Point Energy L.L.C. Comments at 2, 5 (Sept. 30, 2024) (specifically in responses to Questions 2 and 8).

[9] SMT Energy LLC Comments (Sept. 30, 2024) (specifically in response to Question 8).

[10] *See Technical Requirements and Interconnection Processes for Distributed Energy Resources (DERs)*, Project No. 54233, Oncor's Initial Comments on Staff Discussion Draft Proposed Changes to §§ 25.211 and 25.212 at 14 (Jan. 6, 2023).

represents a mix of direct labor, contract labor and loadings. Second, to the extent such information is available, the disclosure of this pricing information could be a violation of confidentiality agreements with contract labor resources and materials suppliers. Thus, it is highly unlikely that DSPs could comply with any requirement to itemize each and every element comprising the total estimated cost to interconnect a DER to the distribution system.

Question 4: How should the interconnection costs covered by such an allowance be reallocated? What effects would this have on other customers?

Oncor's Reply Comments: SMT Energy LLC suggests that the Commission could consider a cost-of-service recovery approach, which would handle the DER interconnection allowance similar to the existing allowance for large load interconnections. SMT Energy LLC comments that this approach would localize costs to the utility's service area where the resource is interconnecting. Grid Resilience in Texas ("GRIT") similarly commented that it is appropriate to allocate cost recovery across the loads on the utility's distribution system because all neighboring distribution customers of the utility will benefit from improved reliability and resiliency. Oncor, however, is unpersuaded that this would be a good outcome for ratepayers, for the reasons set forth on page 8 of Oncor's initial comments filed on September 30, 2024 (specifically in response to Question No. 4). As discussed in those initial comments, if the Commission bases its adoption of a DER interconnection allowance on a determination that DERs are providing a sufficient benefit to the ERCOT grid to justify the socialization of the costs to interconnect the DERs, then all those who use the grid (i.e., *all* ratepayers across ERCOT) should pay for that system-wide benefit. There is no logical reason why only a small subset of end-use customers within the interconnecting DSP's service area should have to fully bear such costs for system-wide benefits enjoyed by others.

While HEN suggests DESRs can provide various benefits including resiliency benefits that transmission resources are unable to provide,[11] Oncor questions how this would be the case. If HEN is suggesting that DESRs could be dual-purposed and provide backup support to a particular distribution customer while also being registered as a resource with ERCOT, then Oncor questions whether such a dual-purposed DESR would ever actually inject power back into the distribution grid. Any time there are problems with the distribution grid, such a resource would default to

[11] Hunt Energy Network L.L.C. Comments at 7 (Sept. 30, 2024).

providing backup support to that single, associated distribution customer, at the exact time the distribution grid (and other customers) could benefit from the DESR. The resource would never discharge power to the grid at the times when power is really needed.

> ***Question 7*:** What disparities exist between distributed generation and energy storage resources interconnecting at transmission and distribution voltages?
>
> ***Question 8:*** What, if any, action should the Commission take to address these disparities in a uniform fashion?

***Oncor's Reply Comments*:** In their initial comments in response to Question No. 7 and/or Question No. 8, TAEBA, HEN, SMT Energy LLC, Shell Energy North America (US) LP ("Shell Energy"), East Point Energy, L.L.C., and TSPA/SEIA argue that DERs should not have to pay monthly utility charges for wholesale transmission service provided at distribution voltage, basing this argument on the claim that generators interconnected on the transmission grid are not subject to charges for comparable wholesale transmission service. Thus, these commentors suggest there is a disparity in the way that energy storage resources connected at transmission voltage and those connected at distribution voltage are charged. As Oncor thoroughly discusses on pages 9-10 of its initial September 30, 2024 comments, no such disparity exists. Resources connected at distribution voltage use the DSP's system in a different way than resources connected at transmission voltage do. First, it should be clarified that neither distribution-connected nor transmission-connected resources are charged for the use of the transmission system, as those costs are included in the transmission cost of service (as shown in the one-line diagram attached to Oncor's initial comments as Attachment 1). Next, as Oncor explains in its initial comments (and as also depicted in the aforementioned one-line diagram attached to Oncor's initial comments as Attachment 1), transmission energy storage resources do not use Oncor's distribution system because they own their own distribution facilities at their own cost; as a result of their non-use of Oncor's distribution system, they are not charged by Oncor for the use of the distribution system. Conversely, batteries on the distribution system do use the DSP's distribution system and do not own their own distribution facilities; thus, they are appropriately charged for their use of the DSP's distribution system. Yes, this is a distinction, but the distinction lies in how the resources use the DSP's infrastructure, and all resources should pay for their respective use of that infrastructure.

HGP Storage, Regis Energy Partners, LP, GRIT, Texas Industrial Energy Consumers ("TIEC"), and Shell Energy suggest that in addition to adopting a standardized DER interconnection allowance, the Commission should also standardize *in this Project* things like costs associated with the interconnection study process, interconnection standards, interconnection procedures, and interconnection timelines. These other concepts are all being considered and addressed in Project No. 54233, however, and have been thoroughly commented on during workshop discussions within that Project. There is no need to blend those items with this discussion of a DER interconnection allowance; doing so could potentially delay the Commission's consideration of and decision on the potential interconnection allowance.

TIEC also suggests the Commission could develop a pro-forma wholesale distribution tariff. The existing wholesale and retail tariffs, however, are suited to handle DERs with guidance from the Commission from the conclusion of this and other pending projects. Furthermore, several stakeholders have already collaborated on and negotiated a proposed draft of a Standard DESR Interconnection Agreement, which HEN filed with the Commission on October 5, 2022, in Project No. 51603.[12] If the Commission ultimately determines that other aspects of the DER interconnection process should be standardized in Project No. 54233, then this proposed Standard DESR Interconnection Agreement should serve as the logical starting place for developing standardized terms at a later date in Project No. 54233.

East Point Energy, L.L.C. also suggests the Commission should create an exception for when DERs are testing (such as during commissioning), such that DERs would not be charged wholesale rates during that time.[13] Similarly, New Leaf Energy, Inc. supports structuring monthly charges for wholesale transmission service at distribution voltage to exclude off-peak charging from the calculation of monthly demand subject to the distribution charge.[14] These recommendations are essentially asking that the DERs be provided with free energy while testing and daily during off-peak periods. Oncor already waives the billing demand ratchet for DERs while they are testing, which some could argue is an undeserved waiver. This billing demand ratchet waiver is already part of Oncor's tariff. *See* Oncor's Tariff for Transmission Service at Section 4.3.6 - Testing of Customer Equipment. However, it would be wholly inappropriate to

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[12] *See Review of Distributed Energy Resources*, Project No. 51603, Hunt Energy Network's letter to Commissioners at Attachment 1 (Oct. 5, 2022).

[13] East Point Energy L.L.C. Comments at 6 (Sept. 30, 2024).

[14] New Leaf Energy, Inc.'s Initial Comments on Commission Staff's Questions at 7 (Sept. 30, 2024).

provide the DER with completely free energy during testing or during off-peak periods. Energy consumed will ultimately be paid for by ratepayers. If the DER is not charged for the energy it uses, then other customers will have to pick up the bill, which is inappropriate. Not considering "above normal" demand for ratchet purposes during testing periods is appropriate and thus is already included in Oncor's tariff, but there is no justification for DERs not having to pay for their consumed energy and for pushing those costs onto other ratepayers.

II. CONCLUSION

Oncor appreciates the opportunity to provide reply comments in response to Commission Staff's questions posed in this Project. Oncor respectfully requests the Staff's and the Commission's full consideration of the reply comments set forth above.

Respectfully submitted,

Oncor Electric Delivery Company LLC

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ATTORNEYS FOR ONCOR ELECTRIC DELIVERY COMPANY LLC

ONCOR ELECTRIC DELIVERY COMPANY LLC'S REPLY COMMENTS – EXECUTIVE SUMMARY

- It is not appropriate to uplift DSP-incurred costs to ratepayers in order to serve all DERs, unless and until the Commission determines that all DERs provide enough benefits to justify shifting those interconnection costs to other ratepayers. The discussion of grid benefits more appropriately applies to DGRs and DESRs that are registered with, dispatched by, and performance-qualified by ERCOT as a resource dedicated to providing energy and ancillary services support to the grid.

- There could be differences in how different DSPs approach the categorization of costs that they deem to be interconnection costs attributable to the interconnecting DER. The Commission may want to consider adopting a DER interconnection allowance of an unspecified amount that will instead uniformly cover the same categories of costs for all interconnecting DERs. This could provide for use of a more uniform methodology for calculating interconnection costs by the various DSPs.

- Costs that should be covered by an interconnection allowance include reasonable upgrades in the substation, meaning only costs for equipment or work that are required, under the DSP's least-cost design standard, to interconnect the resource and to allow for provision of safe, reliable service.

- Even if the Commission adopts a specified dollar amount for the allowance, the Commission may still want to specify that the allowance amount will not cover certain categories of equipment (such as the addition of a transformer) in order to encourage some level of site discipline by the DER owners. Additionally, any standard, specific interconnection allowance amount should be determined through a similar data analysis process the Commission used for transmission-interconnected generation resources in Project No. 55566.

- Oncor does not necessarily have an objection to this concept of a uniform fee for smaller-scale DERs, although Oncor does not currently charge any application fee for residential DERs, and only rarely are transformer upgrades required that such a customer would have to pay for. For clarity, no interconnection allowance of any amount should be provided to any smaller-scale DERs who are neither providing ancillary services nor are SCED dispatchable.

- The determination of whether a particular DER is of the type of resource that qualifies for an interconnection allowance should be made at the initial time of interconnection to the distribution grid, and that determination should not be revisited at a later time. This more appropriately applies to DGRs and DESRs.

- DGRs and DESRs that have already signed interconnection agreements before the implementation of an interconnection allowance should not receive a retroactive application of the allowance through a refund or credit. Oncor cannot accommodate this refund concept, it would constitute illegal retroactive ratemaking, and it would ultimately penalize ratepayers.

- Oncor is not opposed to providing a description of required substation upgrades and equipment, a description of distribution feeder upgrades and equipment, and an overall, estimated cost associated with those required upgrades and equipment. Oncor, however, is concerned with any suggestion that DSPs should be required to provide more granular cost details than that. This information could prove difficult if not impossible to provide in many instances, given the way Oncor procures equipment in bulk and the way labor costs are embedded in project costs. The disclosure of this pricing information could also be a violation of confidentiality agreements with contract labor resources and materials suppliers.

- If the Commission determines that DERs and, more specifically, DGRs and DESRs are providing a sufficient benefit to the ERCOT grid to justify the socialization of the costs to interconnect these types of DERs, then all those who use the grid (i.e., *all* ratepayers across ERCOT) should pay for that system-wide benefit.

- There is no disparity in the way that energy storage resources connected at transmission voltage versus distribution voltage are charged. There is a distinction in how they use the DSP's infrastructure, and all resources should pay for their respective use of that infrastructure.

- The Commission should reject recommendations to standardize things such as costs associated with the interconnection study process, interconnection standards, interconnection procedures, and interconnection timelines in this Project.

- The Commission should reject recommendations that DERs should be exempt from wholesale monthly charges for times when they are testing and daily during off-peak periods. These recommendations are asking that the DERs be provided with free energy. If the DER is not charged for the energy it uses, then other customers will have to pick up the bill.

Attachment No. 1

Oncor Electric Delivery, LLC

Prepared by: Oncor Assets Planning, DG Resource Integration
Substation & Feeder: [redacted]

UTILITY SYSTEM IMPACT STUDY

(FOR INTERCONNECTION OF DISTRIBUTION ENERGY STORAGE RESOURCE)

[redacted]

The following information represents an analysis done around the date indicated above and is specifically for the information detailed in this study. Changes in equipment or modeling parameters will require a new study be performed and could change the results and cost estimates provided.

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1. EXECUTIVE SUMMARY

[redacted] (Customer) has requested interconnection and parallel operation of a proposed Battery Energy Storage System (BESS) [redacted] with registration as a Distribution Energy Storage Resource (DESR). The requested capacities were studied at 9,950 kW of charging and 9,950 kW of discharging. The purpose of this study is to determine the expected impact of this proposed generating system on the Oncor grid and identify upgrades, improvements, or changes needed to support the desired operation. Changes in equipment or modeling parameters will require a new study be performed and could change the results and cost estimates provided.

Customer requests participation in ERCOT ancillary services Non-Spinning Reserve, Regulation Down Service, Fast Responding Regulation Down Service, Regulation Up Service, Fast Responding Regulation Up Service, Responsive Reserve, Fast Frequency Response. Fast Frequency Response ramp up speeds were utilized to [redacted] Charging and discharging operational requirements are shown in Section 4 Distribution System and Metering Impact Results. Due to voltage and substation transformer power flow violations, customer cannot be served from the alternate substation transformer under contingency or maintenance conditions. This means that should the substation transformer serving this facility be taken out of service or is not available, then the BESS system will be required to be taken off-line.

The estimated cost to customer for interconnecting this facility is $606,963.69 as shown in Section 7. If Customer elects to proceed with this project an Interconnection Agreement and invoice will be developed and provided. Once the project is fully funded, and the Interconnection Agreement is executed, then a project kick-off meeting will be held to develop a working construction schedule and target service date.

2. PROJECT DATA

The following project data includes proposed facility information and proposed Customer generation information for an impact assessment of interconnection and parallel operation.

Proposed Facility Information	
Interconnection Applicant	[redacted]
Service Address, City, State	[redacted]
Latitude/Longitude (Customer proposed POI location)	[redacted]
ESI LOC	[redacted]
Fuel Source	Battery
DSA Executed	[redacted]
Study Fee Received	$4,275.35 and $65,000
Service Desired Date	[redacted]
Type of Operation	Project will participate in the wholesale energy market and have the capability of the following ancillary services: Non-Spinning Reserve (Non-Spin), Fast Responding Regulation Service (FRRS), Regulation Down Service (Reg-Down), Fast Responding Regulation Down Service (FRRS-Down), Regulation Up Service (Reg-Up), Fast Responding Regulation Up Service (FRRS-UP), Responsive Reserve (RRS), and Fast Frequency Response (FFR).
Sequence of Operation & Breaker Failure Logic	Load import / generation export will be controlled by a master distributed control system (DCS). Primary protection for under/over voltage and under/over frequency conditions will be obtained through individual inverter settings and switching at the 480V level. Backup protection will provided by the main recloser at the 12.47 kV level.
Metering	EPS Metering
Requested Exporting Capacity	9,950 kW
Total Connected Generation Capacity	[redacted]
Requested Charging Capacity	9,950 kW
Approved Discharging Capacity	9,950 kW
Approved Charging Capacity	9,950 kW
ONCOR Distribution Voltage	12.47 kV
Delivery Voltage at the PCC	12.47 kV
Oncor Substation Transformer (Existing/Addition/Upgrade)	Existing
Oncor Substation Transformer Number	[redacted]
Oncor Substation Transformer Size (if non- existing)	[redacted]
ONCOR Substation Feeders	[redacted]
Feeder Exit Type (UG or OH)	UG
Securitization Required (Yes/No)	No
Proration Required (Yes/No)	No
Automation	No automation currently on substation
Distance to Substation	6,400 ft.
Up-line Protective Device on Line Section (Past Substation Breaker)	IntelliRupter

Equipment - Totals						
	Qty	Manufacturer	Model Number	Nameplate Capacity	Total Nameplate Capacity	Certification
Inverters*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Batteries	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
				[redacted]	[redacted]	[redacted]
Battery Composition				Total Energy Storage Power (AC) kWh		
[redacted]				[redacted]		

*Each inverter will be software or site controller limited to an amount necessary to limit total export capacity to 9,950 kW at the PCC.

3. DISTRIBUTION SYSTEM IMPACT DATA

Oncor utilizes CYME for modeling conductor and device loadings on their distribution circuits. This model addresses distribution facilities and equipment modifications necessary for interconnection.

Feeder / On-Site and Transformer Data Information	
Transformer Ownership	Customer
Transformer Size/Voltage/Windings	[redacted]
Transformer Impedance Data	[redacted]
ONCOR Main Service Disconnect /Fuse	S&C IntelliRupter
Customer Main Line Disconnect /Relaying	SEL-651RA controlled 12.47 kV recloser
Transfer Trip Communication Method	Not required

Distribution Load Flow Modeling Information	
Steady-state load flow study	Based on balanced three phase load
Modeling tool	CYME (Oncor system model)

4. DISTRIBUTION SYSTEM AND METERING IMPACT RESULTS

Based on model output results, it has been determined that the Oncor system is impacted by this BESS. Required changes in Oncor delivery system to interconnect the proposed Project are as follows:

Identified Changes on Distribution System Including Metering	
✓	Install ~1,250 ft. 3-1000CU UG conductor (feeder exit)
✓	Install ~5,150 ft. 3-795AAC OH conductor with 4/0 neutral
✓	Install service transformer for auxiliary loads
✓	Install Primary Metering Equipment
✓	Install 15kV IntelliRupter at PME

As a result of this study, Oncor requires the following operational requirements:

Charging / Discharging Operational Requirements	
Approved Charging Capacity	9,950 kW
Approved Discharging Capacity	9,950 kW
Energy Market Operations Limitations	
Maximum ramp rate for charging (battery charge rate)	[redacted]
Maximum number of fluctuations[2] between idling[1] to a full discharging ramp rate	[redacted]
Maximum number of fluctuations[2] from idling[1] to maximum charging ramp rate	[redacted]
Maximum number full load cycles[3] in a one hour period.	[redacted]
System Emergency Operations – Ancillary Services	
Maximum charging and discharging ramp rate for Fast Frequency Response (FFR) (five cycle reaction time and ten cycle ramp – 15 cycle requirement from ERCOT)	[redacted]
Maximum charging or discharging response rates: Fast Responding Regulation Down Service (FRRS-Down[4]) Fast Responding Regulation Up Service (FRRS-Up[4]) (forty cycle reaction time and twenty cycle ramp)	[redacted]

1 Idling shall mean a state where the facility is not charging or discharging for 55 seconds or longer at the PCC.
2 A fluctuation is considered a movement from one state of charge of the system to another state of charge.
3 A full load cycle means going from a state of fully charging at maximum rate to a state of fully discharging at the maximum rate or vice versa.
4 FRRS – required to deploy the capacity within 60 cycles of receiving a deployment signal from ERCOT or measuring a frequency deviation in excess of 0.09Hz.

5. TRANSMISSION/DISTRIBUTION SYSTEM SHORT CIRCUIT

Transmission / Distribution Load Flow Modeling Information		
Generation modeled from short circuit study		
Modeling Tool	Aspen OneLiner* (ERCOT system model)	
*Current ERCOT model - (distribution line impedances in per unit on a 100 MVA, 12.47kV base)		
[redacted]	Z_1	Z_0
Line Impedance (P.U) (From Oncor substation to transformer Location)	[redacted]	[redacted]
System Source Impedance at PCC (12.47 kV)* (No generation or Customer transformers at the facility)	[redacted]	[redacted]

Studies were conducted to determine any areas of the system impacted by the proposed generation. The following table shows results at the Point of Common Coupling:

Faults at the Point of Common Coupling (12.47 kV)					
Generators & Transformers Off-line		All Generators & Transformers On-Line			
Three Phase Fault Current (A)	Phase-to-Ground Fault Current (A)	Three Phase Fault Current (A)		Phase-to-Ground Fault Current (A)	
		Total	Generator Contribution	Total	Generator Contribution
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6. TRANSMISSION/SUBSTATION SYSTEM IMPACT RESULTS

Based on model output results, it has been determined that the Oncor system is impacted by this proposed battery energy storage system. Required changes in Oncor delivery system to interconnect the proposed Project are as follows:

Identified Changes on Transmission System	
✓	Add feeder relaying to existing Station 1 Feeder panel for New Feeder (SEL-351S, SEL-551)
✓	Install a new 12.5kV feeder breaker (CB13) for new express feeder to DGR facility
✓	Setting development for New Feeder relays for proper coordination, directional protection, and reclose delay settings
✓	Transformer 1 LTC/regulator controller upgrade for reverse power flow (if applicable)
✓	Transmission Overvoltage Protection Scheme – Installation of an overvoltage relay to trip New Feeder upon transmission over-voltage or under-voltage since New Feeder will be an express feeder to this facility (3 x CCVTs, SEL-351A)
✓	

7. ESTIMATED CUSTOMER COSTS

Costs for system upgrades have been estimated for Distribution and Substation. Completed studies and estimates are valid for two months and are subject to expiration if Customer has not elected to proceed. If the Customer elects to proceed after a two month period, then the project will be subject to a new Impact Study Fee and be re-evaluated.

Estimated Costs for DESR Proposed Interconnection (CIAC)	
System Category	
Distribution Upgrades [Standard Allowance Applied (Credit) = ($786,050.00)]	$286,319.69
Substation Upgrades	$320,644.00
Substation Transformer Proration	N/A
Total	**$606,963.69**