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PROJECT NO. 54233

TECHNICAL REQUIREMENTS AND INTERCONNECTION PROCESSES FOR DISTRIBUTED ENERGY RESOURCES (DERS)	**§ § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF ENPHASE ENERGY AND TESLA ON STAFF DISCUSSION DRAFT DOCUMENTS

I. Introduction

Enphase Energy, Inc. (Enphase) and Tesla, Inc. (Tesla) (Joint Original Equipment Manufacturers [OEMs]) appreciate the opportunity to submit these comments in response to the Public Utility Commission of Texas (Commission) Staff's March 14, 2025, request for feedback on its discussion draft. In its draft, Staff has proposed changes to the interconnection rules as applied to Distributed Energy Resources (DERs). In these comments, the Joint OEMs address the following issues:

- Recognizing Power Control Systems as a legitimate means of mitigating DER grid impacts and reducing interconnection costs.
- Establishing a more streamlined interconnection process for smaller DERs.
- Ensuring that DSPs authorize use of meter socket adapters, a key enabling technology to streamline the deployment of DERs.
- Clarifying and modifying the interconnection rules as necessary to ensure they support the ability to interconnect vehicle-to-grid systems.
- Clarify or substantially modify the proposed requirements for legacy DERs to comply with new smart inverter settings.

Per the request from staff, an executive summary providing an overview of our specific recommendations is included at the end of this document.

II. Utilities Should Recognize and Permit Power Control Systems in DER Interconnections.

The Joint OEMs strongly recommend that the Commission's interconnection rules expressly direct DSPs to recognize and permit the use of Power Control Systems (PCS) to limit exports from behind-the-meter (BTM) DERs such as solar and storage. Interconnection studies and the need for any upgrades or other mitigations should be based on the level of exports allowed and controlled by the PCS operating mode and specified on the interconnection application.

Export-limiting PCS can avoid upstream upgrades to a customer's service connection, service transformer, and / or distribution circuit, that DSPs may otherwise require as an outcome of the interconnection study due to the DER installation's nameplate capacity rating and / or projected grid exports under "worst-case" assumptions. Avoiding such upgrades reduces both the time and cost to interconnect and provides benefits to adopting customers, ratepayers, and utilities. This solution is substantially similar to ERCOT protocols that allow generation to interconnect and operate so long as it curtails output to remain within the rated capacity of a constrained interconnection.[1]

PCS is recognized in the interconnection procedures in several other states, including Arizona, California,[2] Colorado, Hawaii, Illinois, Maryland, Minnesota, and Nevada.[3] PCS is also allowed via the National Electrical Code (NEC) Sec. 705.13 to

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[1] See ERCOT Protocol Section 3.8.7, *Self-Limiting Facility*.

[2] See California Rule 21, Section Mm., e.g., at p. 260: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf.

[3] See, e.g., https://www.dsireinsight.com/blog/2024/9/26/interconnecting-non-exporting-systems-how-do-states-and-utilities-interconnect-dg-customers-that-dont-export-electricity; IREC "Toolkit and Guidance for

limit current and loading on busbars and conductors, as to avoid upgrades to a customer's main panel. PCS is a software overlay to onsite hardware that autonomously adjusts the power flows of controllable devices to stay within pre-programmed limits. This is accomplished by an onsite system controller sending device commands via local (i.e., site-level, and not cloud-based) communications based on real-time current readings from current transformers (CTs) that monitor solar production and battery charge / discharge and overall site-level consumption downstream of the utility meter.

PCS functionality has heretofore been tested and certified for safe operations under UL 1741 PCS-CRD, originally issued in March 2019. PCS is thus a relatively mature technology that has become a standard feature across the DER industry, as evidenced by 48 manufacturers having UL-certified PCS products listed on a solar equipment list that is relied upon by utilities across the US.[4] Going forward, UL has developed a new, standalone standard to cover PCS functionality, UL 3141, that covers both export and import limitations. UL 3141 is currently an Outline of Investigation with full approval expected by end-of-year 2025 but is available for product testing today. The UL standards include fail-safes that ensure systems revert to their most conservative limits in the instance of malfunction or local communication loss.

Various studies have demonstrated that the use of PCS avoids thermal overloading of distribution circuit and customer interconnection facilities and can increase overall system hosting capacity. For instance, Section V of the IREC "Toolkit"

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the Interconnection of Energy Storage and Solar-Plus-Storage," March 2022, at p. 49, whitepaper accessible at https://energystorageinterconnection.org/resources/batries-toolkit/

[4] https://solarequipment.energy.ca.gov/Home/PowerControlSystem

(see footnote 3) evaluated the impact of a PCS with an "open loop response time" (OLRT) of no greater than 30 seconds (characterized as "Inadvertent Export") on example rural and urban feeders. PNNL also concluded that using a PCS with sub-30 second OLRT to control "Inadvertent Exports" results in negligible thermal impacts on service transformers.[5]

Finally, while perhaps not germane to this proceeding due to the focus on interconnection of generating or discharging DERs (rather than energization of new loads), the Joint OEMs would like to highlight that UL 3141 includes a power import limiting (PIL) PCS function that will become increasingly necessary as EV adoption and electrification continue to proliferate. PIL PCS can similarly be deployed on an optional basis to defer or avoid upgrades to service transformers due to EV or storage charging or other building electrification measures and is notably also applicable to larger EV charging facilities such as fleet charging or public fast charging. Enabling the use of PCS within both the interconnection and energization contexts would provide significant benefits to customers, ratepayers, and utilities at little to no added cost.

Both Tesla and Enphase products offer PCS functionality that has been effectively used to reduce system impacts on the grid across the country. We encourage the Commission to modify the interconnection rules to ensure that Texans served by the DSPs have access to and can utilize this capability.

III. SEIA and TSSA's Recommendation to Establish a Streamlined Interconnection Process for Smaller DERs Should Be Adopted.

[5] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-36933.pdf

The Joint OEMs agree with SEIA and TSSA's recommendations to establish a streamlined interconnection process for DERs under 50 kW in size. These systems have relatively lower potential impacts on the grid and evaluating them pursuant to the same framework as much larger systems subjects them to a level of review and scrutiny that in many cases is unnecessary. Joint OEMs support the various recommendations SEIA and TSSA provide to both streamline the review process for smaller projects subject to specified conditions (e.g. enabling smart invert functions and utilizing PCS to mitigate grid impacts), in addition to establishing firm timelines and other accountability measures to ensure the utilities complete upgrades and grant permission to operate in a timely way.

IV. The Interconnection Rules Should Require Distribution Service Providers to Authorize Use of Meter Socket Adapters.

The Joint OEMs respectfully request that the draft interconnection rules be updated to expressly allow for deployment of customer or third-party owned meter socket adapters (MSAs). Also known as meter collar adapters, these devices represent a suite of technologies produced by several manufacturers including Enphase[6] and Tesla[7] that take advantage of the standardized form factor and location of the primary utility meter socket to streamline the deployment of distributed energy resources. MSAs can serve a variety of purposes, but regardless of their specific application, these technologies allow customers to avoid the extensive rewiring work, associated costs

[6] https://enphase.com/store/storage/gen4/iq-meter-collar

[7] https://www.tesla.com/support/energy/powerwall/learn/tesla-backup-switch

and installation complexity that would otherwise be required when installing and interconnecting a DER system.

Key applications of MSAs include interconnecting a solar PV system that would, in the absence of an MSA, require a main panel upgrade, and to establish a point of disconnection to allow battery systems to safely isolate from the grid and provide whole-home backup power in the event of a grid outage. In short, use of MSAs lowers costs and saves customers hundreds to thousands of dollars per project in avoided labor and material costs, while also substantially reducing project timelines and installation complexity. MSAs represent a critical means of expanding access to DERs to a broader cross section of customers by significantly reducing project soft costs.

A growing number of policy makers and utilities across the US have recognized the value of MSAs in facilitating customer access to DERs and have formally approved their use by customers. Table 1 below reflects the utilities that have authorized use of the Tesla Backup Switch. While this list is not comprehensive of all utilities that authorize MSAs broadly, since it does not include those utilities that may not have approved the Back-Up Switch but have approved other MSAs, it demonstrates that utility acceptance of MSAs is widespread. Indeed, with tens of thousands of MSAs deployed across dozens of utility service territories across the US, there is a proven track record and demand for these solutions, notably including in Texas itself.

Table 1: Utilities that authorize use of the Tesla Backup Switch

- Arizona
  - Arizona Public Service Company
  - Hohokam Irrigation & Drainage District
  - Salt River Project
  - Sulphur Springs Valley Electric Coop
  - Tucson Electric Power
- California

    - Lathrop Irrigation District
    - Pacific Gas and Electric Company
    - Pacific Power
    - Sacramento Municipal Utility District (SMUD)
    - San Diego Gas & Electric (SDG&E)
    - Southern California Edison (SCE)
- Colorado
    - Black Hills Energy
    - Fort Collins Light and Power (FCLP)
    - Xcel Energy-Colorado
- Hawaii
    - Hawaiian Electric Company
- Illinois
    - Commonwealth Edison
- Kansas
    - Evergy
- Maine
    - Versant Power
- Michigan
    - Traverse City Light and Power
- Missouri
    - Evergy
- Montana
    - Black Hills Energy
- Nevada
    - NV Energy (South and North)
- New Jersey
    - Jersey Central Power & Light
- Oregon
    - Central Electric Cooperative
    - Pacific Power
- Pennsylvania
    - PPL Electric Utilities
- South Dakota
    - Black Hills Energy
    - West River Electric Association
- Texas
    - Austin Energy (City of Austin)
    - Bluebonnet Electric Coop (BB)
    - CoServ Electric Cooperative
    - Grayson-Collin Electric Cooperative (GCEC)
- Utah

- Kaysville City Power
    - Rocky Mountain Power (RMP)
- Vermont
    - Green Mountain Power (GMP)
    - Lyndonville Electric
    - Vermont Electric Cooperative
    - Washington Electric Coop
- Washington
    - Pacific Power
    - Tacoma Public Utilities
- Wisconsin
    - Eau Claire Energy Coop
    - Sturgeon Bay Utilities
- Wyoming
    - Black Hills Energy

To ensure that any MSAs that are authorized to be deployed are safe and reliable, the Joint OEMs support a criteria-based approach that identifies the specific technical requirements that MSAs must meet. This approach ensures a level playing field across manufacturers and provides an objective standard for purposes of device approval across DSPs. This recommendation is based on the approach taken in Arizona in the service territories of Arizona Public Service (APS) and Tucson Electric Power (TEP), as approved by the Arizona Corporation Commission.

In TEP's case, the relevant language is establishing these criteria can be found in the utility's Interconnection Manual for Distributed Generation[8], Section 9.2.1.i:

> *"A customer-owned meter collar for the purpose of interconnecting power production or whole home electric isolation, shall be allowed where that device does not impede access to the sealed meter socket compartment or pull section of the SES. The meter collar shall be UL 414 Certified and rated adequately for the connected equipment."*

[8] https://docs.tep.com/wp-content/uploads/TEP-Interconnection-Manual-for-Distributed-Generation.pdf

In APS's case, the relevant language can be found in its Interconnection Requirements for Distributed Generation, Section[9] 8.1(F)(2) and 8.1(H):

"*Interconnection equipment, such as a Utility- or Customer-owned Meter Socket Adapter (MSA), which is used to interconnect power production, Energy Storage, or whole-home electric isolation and (intentional or unintentional) Islanding of a Generating Facility, shall be allowed where that MSA device does not impede access to the sealed meter socket compartment or pull section of the sealed compartment of the Service Entrance Section (SES). The following requirements apply to the use of an MSA for Interconnection:*

(1) MSAs must be UL 414 certified, and rated adequately for the connected equipment.
(2) The MSA must be installed, either by APS or by a certified licensed and qualified professional electric contractor with an active electrical contractor license, R-11 or CR-11, including any subcontractors.
(3) APS residential Customers shall be eligible to install an MSA if all of the following requirements are met:
  a. A self-contained electric meter panel not exceeding a 200 amp rating, as determined by APS, and a single phase 120/240 volt Electric Service is installed.
  b. Subject to exceptions approved by APS, the main breaker and meter socket are contained in the same electrical panel.
  c. An electric meter panel that meets all APS requirements and passes an initial review before the installation. The panel must also pass an evaluation by APS personnel or an APS-approved contractor.
  d. The Customer's solar generating system, including an Energy Storage system if installed, connected to the MSA shall have a rating consistent with the specified Fault Currents in Table 800.2 of the APS Electric Service Requirements Manual (per NEC Art. 110.9 and 110.10). Additionally, if additional conductors are connected to the MSA terminals for the purposes of carrying current to the Utility Distribution System, the service disconnecting means of the MSA shall meet NEC Art. 230.79.
  e. Any existing Customer generation or Energy Storage sources on the property that are interconnected with the APS service are identified on the Interconnection Application and submitted drawings.
  f. The local AHJ has issued a permit for the installation of your [sic] generation system (or Energy Storage system) and the supply (or line) side connection to the MSA.
  g. All Customer-owned electrical equipment, including MSAs, must satisfy the meter Clearances specified in the APS Electric Service Requirements

[9] https://www.aps.com/-/media/APS/APSCOM-PDFs/Residential/Service-Plans/Understanding-Solar/InterconnectReq.ashx

Manual. If additional conductors are connected to the MSA terminals for the purposes of carrying current to the Utility Distribution System, the wire between the fused Disconnect switch and the MSA must be insulated copper wire, and rated for 90° C.

h. *Bond an Equipment Grounding Conductor from the Disconnect Switch and connect to the Service Grounding System; typically, #6 AWG copper, bare."*

While the level of granularity that each of these utilities have incorporated into their respective interconnection manuals is different, both are consistent in their reliance on NRTL standards as the basis for approval and on ensuring deployment of the MSA does not impede access to the meter itself. This framework has proven workable and provides manufacturers a clear understanding of the technical criteria that need to be met by the device itself as well as well as, in the case of APS's rules, clear requirements of the site characteristics that need to be met in order for an approved MSA to be deployed.

The Joint OEMs encourage the Commission to modify the proposed interconnection rules accordingly. Specifically, the interconnection rules should require, by date certain, DSPs to update their interconnection manuals to authorize use of MSAs that have been certified to all relevant and applicable standards (e.g. UL 414) as certified by an NRTL, do not impede access to the sealed meter socket compartment or pull section of the sealed compartment of the Service Entrance Section (SES) and that are rated appropriately for the connected equipment.

V. The Commission Should Clarify that the Interconnection Rules are Intended to Support the Interconnection of V2G Systems, Including V2G AC Configurations.

Vehicle-to-Grid (V2G) technologies, specifically technologies that enable bidirectional-capable electric vehicles to discharge their batteries to meet home loads or to provide grid services represent a potentially significant resource that should be recognized in the interconnection rules. Although the existing rules do not explicitly prohibit interconnection of equipment that would enable this functionality, the absence of any mention of V2G in the rules leaves significant ambiguity that needs to be addressed. In the absence of clear guidance, the Joint OEMs are concerned that DSPs will not allow V2G solutions to interconnect and the vast opportunity to leverage EV batteries to provide a host of services to end use customers and the grid will be missed or significantly delayed.

To address this, the Joint OEMs request that the Commission explicitly clarify that V2G systems shall be authorized to interconnect under these rules, to the degree they meet the current definition of a "Distributed Energy Resource" and other relevant requirements within the rules to ensure safe and reliable interconnection.

Related to the above, should the Commission agree that the interconnection rules should support the interconnection of V2G systems, the Joint OEMs seek clarification that the current definition of "Certified Equipment", which states that equipment must "[comply] with the applicable sections of UL-1741 and IEEE 1547 standards as determined by the DSP…" allows bidirectional equipment, specifically V2G AC[10] systems to do so. V2G systems generally, and V2G AC systems in particular, represent a relatively new area that has required the development of new certification frameworks. As discussed below, while these new pathways fall under UL 1741, it

[10] V2G AC systems are those that utilize an onboard vehicle inverter to convert the DC power discharged by the battery to AC power before it is transmitted to the home or the grid. In contrast, V2G DC systems rely on an external inverter to convert DC power to AC power for use by the home or the grid. Because V2G DC relies on an external inverter, the existing certification standards that apply to other inverter-based DER technologies can be readily applied to those systems. However, for V2G AC systems, the existing standards aren't directly applicable as the EV and EVSE "handshake" serves to provide the required smart inverter functionality.

would be helpful to ensure that there is clear guidance and an understanding that V2G systems are eligible for interconnection under the existing rule language, or, if necessary, to augment the language to further clarify this.

From the Joint OEMs' perspective, the V2G AC system architecture is critical to reducing the costs of V2G and it is therefore vitally important to ensure that there is a viable interconnection pathway for this configuration. By utilizing the onboard inverter for DC to AC conversion to power the customer's home or the grid, this configuration materially reduces the equipment and labor needed to deploy V2G systems on a customer's home to access V2G functionality, as compared to a V2G DC system architecture, saving thousands of dollars in deployment costs, streamlining installation, and overall resulting in a better customer experience.

There are two certification pathways the Joint OEMs support, specifically to facilitate the interconnection of bidirectional V2G AC equipment, both of which should be recognized in the interconnection rules. One certification pathway, UL 1741 SC would, in concert with SAE J3072, provide an interoperable approach whereby an EVSE, certified to UL 1741 SC would be able to operate with a bidirectional EV certified to SAE J3072. This certification path is soon to be published. Another approach requires certifying the AC V2G "DER System" to the UL 1741 SB CRD for DER Systems. Pursuant to this approach the EV and EVSE are evaluated as a system to meet the UL 1741 SB requirements at the point of common coupling. This system level approach is published and available for OEM certification today. The Joint OEMs believe that being certified pursuant to either of these pathways by a NRTL should allow a V2G AC system to be deemed "Certified Equipment" and therefore eligible for interconnection. The Joint OEMs note that there is existing precedent for this. The Maryland Public Service Commission recently updated its interconnection requirements to explicitly recognize both of these as legitimate interconnection pathways for V2G AC systems.[11]

Consistent with the above, and to provide additional clarity regarding the applicability of the rule to V2G systems, the Joint OEMs recommend that the definition of "Certified Equipment" be updated to both generally clarify that V2G systems are eligible DERs that may be interconnected pursuant to the rule and to specifically establish that V2G AC equipment that is certified to either UL 1741 SC or pursuant to the UL 1741 SB CRD for DER Systems satisfies the "Certified Equipment" definition:

"Certified equipment - A specific generating and protective equipment system or systems, including V2G systems and equipment, that have been certified by a National Recognized Testing Lab (NRTL) as complying with applicable sections of UL-1741 and IEEE-1547 standards, as determined by the DSP and relating to safety and reliability when paralleling with 2 the grid at the time of interconnection. For V2G AC systems or equipment, certification by an NRTL to UL 1741 SC or certified as a system to UL 1741 SB CRD for DER Systems shall be sufficient for the system to meet this definition."

This change may require adding additional definitions covering various V2G related terms and concepts, including the definition of "Vehicle-to-Grid", "Electric Vehicle Supply Equipment", "V2G DC Systems and Equipment" and "V2G AC Systems and Equipment". The Joint OEMs offer draft definitions below for each of these terms:

Vehicle-to-Grid (V2G) – Vehicle-to-grid means the ability for an EVSE connected to a bidirectional electric vehicle to operate in parallel to the grid and both receive and feed power to the point of interconnection between the EVSE and the grid.

[11] On June 11, 2025, the PSC adopted proposed changes to COMAR 20.50.09 Small Generator Facility Interconnection Standards to incorporate interconnection pathways for V2G DC and V2G AC systems. See Maryland Register dated April 18, 2024, Title 20 for the adopted language. dsd.maryland.gov/MDRIssues/5208/Assembled.aspx

Electric Vehicle Service Equipment (EVSE) - a device or system designed and used specifically to transfer electrical energy between an electric vehicle and the electric grid.

V2G DC Systems and Equipment - a combination of hardware and software in or around the EVSE and EV for the purposes of communication with and programmed flow of energy into and out of the vehicle battery in support of electrical loads or systems offboard the EV, including the electric grid, where the electricity coming out of the vehicle is direct current that must be converted to alternating current by an external inverter.

V2G AC Systems and Equipment - a combination of hardware and software in or around the EVSE and EV for the purposes of communication with and programmed flow of energy into and out of the vehicle battery in support of electrical loads or systems offboard the EV, including the electric grid, where the electricity coming out of the vehicle is alternating current, having been converted in the vehicle through the use of an onboard inverter.

VI. Suggested Revisions to Proposed Smart Inverter Settings.

The Joint OEMs provide the following feedback and suggested revisions to the proposed smart inverter settings in §25.212. Both companies manufacture smart inverters certified by UL 1741 SB to comply with IEEE 1547-2018 functionality.

- **(c) (1) (B) (i - ii)**: We understand the intent of these proposed requirements to mitigate rapid voltage changes through ramp rate controls. While our products indeed support ramp rate control, DERs' ability to adhere to the stated step changes and influence circuit voltage depends on relative location on a circuit and proximity to voltage regulating equipment. For instance, customers at the end of a long rural feeder with high impedance may easily exceed the proposed thresholds because of the voltage rise created by higher impedances. Conversely, customers close to a substation may not be able to effectuate circuit voltage at all. Given these considerations, we recommend additional discussion on this matter.

- **(d) (1):** This section states, "Beginning 90 calendar days after the effective date of this section, any equipment or facilities installed on a legacy DER must comply with the standards under subsection (c)" [which lays out the proposed requirements for IEEE 1547-2018 smart inverter settings]. The subsequent two sections **(d) (2 -3)** go on to describe conditions under which DERs would need to transition to the latest standards within 90 days: changes in energy production mode, equipment replacement, increases in nameplate capacity, DERs registered with ERCOT, and DERs greater than 1 MW in the ERCOT region.

Section (b) (6) defines "Legacy DER" as "A DER interconnected on or before 90 calendar days from the effective date of this section; or a DER for which a completed interconnection application was received by the DSP prior to 90 calendar days after the effective date of this section. A DER that is registered with ERCOT, or is over one MW and interconnected within the ERCOT region, is not a legacy DER."

Subsection (d) requires clarification to ensure that, if adopted and implemented, it does not unduly expand the scope of existing systems that must transition to the requirements of subsection (c). The Joint OEMs submit that, to the degree that Legacy DERs are required to transition to the new standards, any such directive needs to be tempered by recognition of the considerable costs that this may entail. For example, Enphase's first microinverter products were available for sale in Texas starting in 2008. Early-generation products such as these cannot adopt these new settings with over-the-air updates and would have to be ripped-and-replaced entirely to comply. More recent product generations also may not be capable of implementing the proposed settings, or would not be able to support, from a balance-of-system perspective, for instance, a single upgraded microinverter that complies with IEEE 1547-2018, deployed among an array of legacy microinverters that were built around prior versions of the standards. .

Furthermore, as drafted, the circumstances that would trigger a transition to the new requirements are not entirely clear, and/or are potentially problematic. For instance, subsection (d)(1) states, "Beginning 90 calendar days after the effective date of this section, any equipment or facilities installed on a legacy DER must comply with the standards under subsection (c) of this section." However, neither the term "equipment" nor "facilities" are defined, leaving ambiguity as to what this applies to. It is also not clear whether the reference to "equipment or facilities installed on a legacy DER" means only *new* equipment or facilities installed at a legacy DER site, or if instead, all existing equipment or facilities would be implicated. It's likely that Commission Staff intended the former, but this should be clearly spelled out as the latter scenario would seemingly require all legacy DER equipment in the state to be replaced within 90 days of enactment.

Subsection (d)(2)(B) also seems problematic, insofar as it does not allow for "like-for-like" replacement of equipment and thus may cause customers to incur significant costs to meet the subsection (c) requirements if they have the misfortune of having to replace a piece of hardware. It is unclear, for instance, if the mere replacement of one or more solar panels, even if the system nameplate capacity remains the same, would trigger an upgrade to subsection (c) requirements and require a complete replacement of the inverter system. The Joint OEMs do not believe circumstances like this, or other like-for-like equipment replacements, such as replacing a single microinverter under a warranty claim, merit upgrading the entire system to comply with the latest standards.

The Commission should duly revise section (d) to primarily focus any system upgrade requirement on relatively major overhauls of a legacy DER system – e.g., fully changing out inverter systems, changing the generation source, or adding a substantial amount of new generation capacity – while enabling like-for-like replacements that don't affect the overall system nameplate rating without needing to upgrade the entire legacy DER system to comply with the latest standards.

VII. Conclusion

The Joint OEMs appreciate the opportunity to submit these comments. As suggested by the issues raised herein and as recognized by Staff, DER technologies are rapidly evolving, providing new and emerging opportunities to streamline the deployment of DER solutions, mitigate grid impacts, and access an entirely new asset class to provide a variety of customer and grid services. The current Commission Staff initiative to revisit the interconnection requirements provides a valuable opportunity to take stock of these changes and ensure that the regulatory framework recognizes and supports these important developments.

Respectfully submitted,

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EXECUTIVE SUMMARY OF THE JOINT OEMS' RECOMMENDATIONS

- The Commission should direct utilities to recognize and permit use of Power Control Systems as a legitimate means to mitigate grid impacts and cost of DER Interconnection.

- The Commission should establish a less onerous interconnection pathway for smaller DERs (< 50 kW).

- The Commission should authorize use of customer- or third-party-owned meter socket adapters that are certified to all relevant and applicable standards as determined by a Nationally Recognized Testing Laboratory and provided the meter socket adapters do not impede access to the sealed meter socket compartment or pull section of the sealed compartment of the Service Entrance Section (SES) are rated appropriately for the connected equipment.

- The Commission should clarify that the interconnection rules applicable to DERs encompass vehicle-to-grid systems, including both V2G DC and V2G AC configurations. Furthermore, the rules should be updated to explicitly and broadly incorporate V2G systems and equipment into relevant definitions, and to recognize relevant certification pathways for V2G AC solutions, specifically including UL 1741 SC and the UL 1741 SB CRD for DER Systems into the definition of "Certified Equipment".

- The Commission should clarify or substantially modify the proposed requirements for legacy DERs to comply with new smart inverter settings.