Maryland
Public Service Commission

Small Generator Facility Interconnection

PC44 Interconnection Workgroup
Phase III Final Report

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PC44 Interconnection Workgroup

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I. Introduction

On September 26, 2016, the Public Service Commission ("Commission") issued a notice initiating Public Conference 44 ("PC44") "for the purpose of commencing a targeted review to ensure that electric distribution systems in Maryland are customer-centered, affordable, reliable and environmentally sustainable".[1] The Commission received written comments from nearly 50 parties in response to its notice, and held public hearings on December 8 and 9, 2016. A second notice was issued on January 31, 2017 that, among other things, set forth guiding principles for the proceeding, amended the list of topics to be considered, and established several work groups, including the PC44 Interconnection Workgroup ("Workgroup").[2] In the second notice forming the Workgroup, the Commission expressed an objective that "Interconnecting to the electric grid should be as smooth as possible for both residential and commercial solar generating systems". Specifically the Commission listed the following objectives on pages 11-12:

"In this proceeding, we will consider the following possible actions[3]:

1. Completing a rulemaking applying residential solar interconnection standards statewide to ensure that the interconnect process is timely, electronic and customer-friendly, using Condition 16[4] of the Exelon-PHI merger decision as the starting point of discussions;
2. Exploring whether it should [be] required or encouraged that each newly interconnected solar generating system connect to the electric grid with a smart inverter[5];
3. Ensuring that the interconnection application process for non-residential solar projects is timely, electronic and customer-friendly;
4. Developing a specified plan and timeline for each utility to publish feasible and useful hosting capacity maps similar to those produced by PHI in its December 9, 2016 comments; and
5. Reviewing whether cost allocation and system capacity issues regarding interconnection of large and mid-size solar facilities that use a significant amount of a distribution system component's remaining capacity restrict other projects from grid access or unfairly burden them with system upgrade costs."

[1] Maryland Public Service Commission, Notice, September 26, 2016, PC44 p. 1.
[2] Maryland Public Service Commission, Notice, January 31, 2017 PC44.
[3] PC44 Interconnection Workgroup Requested Actions 1 – 5.
[4] Case No. 9361, Order No. 86990 dated May 15, 2015, Appendix A, pages A20 - A23, Enhancements to Interconnection Process for Behind-the-Meter Small Distributed Generation in Maryland.
[5] "Smart Inverter" means any inverter hardware system certified to be compliant with Institute of Electrical and Electronic Engineers ("IEEE") 1547-2018 or subsequent revisions to these standards.

The Workgroup has made good progress in Phases I and II of the Workgroup's efforts and these requested actions continue to be the focus of the Workgroup in Phase III. Phase I of the Workgroup's efforts was completed with a final RM61[6] rulemaking session that was held on September 5, 2018. Phase II was completed with a final RM68[7] rulemaking session that was held on March 31, 2020. A full list of key changes to the Maryland regulations from Phase I and II is listed in Appendix A. These proposed changes in Phase III will continue to make it easier, more automated, more cost-effective and more transparent for interconnection applicants to connect clean energy to the electric grid. The Workgroup's Phase III efforts considered the following topics:

- **Interconnection Jurisdiction** - The Workgroup proposes a regulation change in an attempt to clarify regulations on state versus federal jurisdiction for cases where an electric distribution circuit crosses state lines. Furthermore, in its Final Rule in Order No. 2222 and Amendment No. 2222-A the Federal Energy Regulatory Commission ("FERC") clarified jurisdiction with respect to federal, state, and local jurisdictional boundaries. Distributed Energy Resource ("DERs")[8] that participate in markets through an aggregator, including those that "make wholesale sales of electric energy in interstate commerce", are interconnected under state authority. This applies to all interconnections of DERs participating exclusively through a DER aggregation, even when there is a preexisting "first use"[9] on the applicable distribution facility, and even when the DER aggregation consists of only a single DER. These topics are further discussed in Section II of this report.

- **Interconnection Facility Costs** - The Workgroup evaluated alternatives to Maryland's existing "Causer Pays" model for an interconnection facility cost sharing**[10]** mechanism and proposes further study of an alternative model to allocate the cost of electric distribution hosting capacity proportional to the

[6] *See* RM61 "Revisions to COMAR 20.50.02 and 20.50.09 - Small Generator Facility Interconnection Standards".
[7] *See* RM68 "Revisions to COMAR 20.50.02.02 and COMAR 20.50.09".
[8] "Distributed energy resource" means any geographically dispersed energy resource located on an electric distribution system that produces electricity or offsets electrical demand including small generator facilities, energy storage devices, energy efficiency devices, and demand response devices. *See* COMAR 20.50.09.02B(10).
[9] See PJM Interconnection, L.L.C., 114 FERC ¶ 61,191 (2006) ("GSG LLC Order") that held that distribution facilities become partly FERC jurisdictional once a wholesale transaction occurs on the system. This action would, therefore, render any subsequent interconnections to the relevant distribution facilities FERC jurisdictional after "first use".
[10] "Interconnection facility cost sharing" means the allocation of distribution interconnection facility upgrade costs among multiple small generator facility projects that utilize the hosting capacity created by an interconnection facility upgrade.

hosting capacity used by an interconnection customer ("IC").[11] A hosting capacity fee framework is also proposed, if necessary to balance cost risk between ICs and ratepayers. This topic is further discussed in Section III of this report.

- **Maryland Smart Inverter Settings Standards** – With industry standards now in place, a new generation of smart inverters compliant with Institute of Electrical and Electronic Engineers ("IEEE") 1547-2018 are now becoming available. In order to meet Maryland's January 1, 2022 requirement to use smart inverters in Maryland, the Workgroup proposes a list of IEEE 1547-2018 smart inverter functions and their associated inverter setting policies in a statewide standard to support grid modernization. This topic is further discussed in Section IV of this report.

- **Utility Monitoring and Control Plans[12]** - The Workgroup is monitoring pending IEEE 1547.3 Revisions to promulgate DER cybersecurity standards and also a National Association of Regulatory Utility Commissioners ("NARUC") / National Association of State Energy Officials ("NASEO") Cybersecurity Advisory Team for State Solar that is currently working to develop a state policy framework for DER cybersecurity. FERC Order No. 2222 is an emergent issue that allows DER aggregations to participate directly in Regional Transmission Organization ("RTO")/Independent System Operator ("ISO") markets that has impacts on DER information and data requirements, metering and telemetry requirements and operations coordination that need to be resolved before codifying utility monitoring and control regulation modifications in the Code of Maryland Regulations ("COMAR"). Since these aforementioned initiatives are still in progress, the Workgroup recommends deferring utility monitoring and control regulation proposals to a Phase IV Workgroup effort. This topic is further discussed in Section V of this report.

<u>Scope of Workgroup With Respect to Hosting Capacity</u>

While the Workgroup addressed hosting capacity in Phase II, and recommends extending hosting capacity cost allocation concepts in Phase III, it is important to recognize the scope limits of the Workgroup with respect to hosting capacity. In Phase II the Workgroup previously proposed regulations to codify the concepts of reserve hosting capacity,[13] closed circuits and restricted circuits and hosting capacity upgrade plans.

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[11] "Interconnection customer" means an entity that proposes to interconnect or has interconnected a small generator facility to an electric distribution system. *See* COMAR 20.50.09.02B(24).

[12] "Utility Monitoring and Control Plan" means a plan to monitor and control in the aggregate a set of small generator facilities in multiple locations that includes a cost recovery method, under conditions that are approved by the Commission.

[13] Reserve hosting capacity means the amount of hosting capacity reserved for small generator facilities on an electric distribution system circuit.

Regulations were also codified by the Workgroup to require utilities to annually report by April 1 on their future plans for providing hosting capacity information and maps as part of hosting capacity reporting system for transparency.. In Phase III the Workgroup is further recommending to codify concepts such as requiring hosting capacity calculation validation checks, reporting of reserve hosting capacity in hosting capacity reporting systems and new reporting metrics related to hosting capacity utilization and cost allocation. Although some of these present and past efforts to develop, extend, and codify hosting capacity related concepts touch on electric distribution planning, the Workgroup is not a planning initiative. Therefore, the Workgroup is pleased with the Commission's decision to investigate the potential for launching a distribution planning initiative with its March 25, 2021 Technical Conference on the National Association of Regulatory Utility Commissioners (NARUC) / National Association of State Energy Officials (NASEO) Distribution Planning Task Force Report. If launched, this initiative should further consider hosting capacity calculation methods, use cases and DER forecasting and also build off our Workgroup's current and past hosting capacity efforts to help meet Maryland's energy goals.

II. Interconnection Jurisdiction

During Phase II of the Workgroup's efforts, the COMAR 20.50.09.01 Scope section was significantly enhanced in an attempt to provide "bright line" regulations to guide interconnection applicants and utilities on interconnection situations under Maryland jurisdiction as opposed to FERC jurisdiction.

Recently in Case No. 9408,[14] Commission Staff ("Staff") noted that an application for Certificate of Public Convenience and Necessity ("CPCN") to construct an 8.0 MW solar photovoltaic generator facility in Washington County, Maryland was deemed to be under FERC jurisdiction. Therefore, this applicant and the host utility, Potomac Edison, utilized the PJM Interconnection LLC ("PJM") interconnection processes requiring a PJM Interconnection Services Agreement ("ISA"), as opposed to the normally expected Maryland Interconnection Agreement ("IA") and a PJM Wholesale Market Participation Agreement ("WMPA"). This generating facility tapped the Halfway–Milnor 34.5 kV line at a point of interconnection in Maryland between Halfway substation in Maryland and Milnor substation in Pennsylvania. Staff also considered that there are many other situations in Maryland where electric distribution lines cross into Pennsylvania, Delaware, Virginia, West Virginia, and the District of Columbia. Staff also observed that COMAR 20.50.09.01 is presently silent on interconnection jurisdiction when electric distribution crosses state lines and decided to research this further.

After research, it was determined that Section 201 of the Federal Power Act ("FPA") confers jurisdiction upon the FERC over the transmission of electric energy for resale in interstate commerce. The FPA states that electric energy is deemed to be transmitted in interstate commerce if it is "transmitted from a State and consumed at any point outside thereof." Court cases have found that due to the interconnectedness of the electric transmission electricity network, all electricity transactions are in interstate commerce, regardless of their contractual origin or destination, with the exception of transactions wholly within Alaska, Hawaii and Texas.[15] Electric distribution in Maryland consists of predominantly radial circuits with limited interconnectedness, except through normally open switching devices with no reasonable expectation that energy can be transmitted across state lines for resale in interstate commerce. FPA Section 201(b) denies the FERC jurisdiction over "local" distribution. "[The] FERC has found that the transportation of wholesale power over a distribution system is non-"local" distribution. This situation arises when a generator is connected to a distribution system and its wholesale customer is not the electric distribution owner."[16] This implies that even if an electric distribution

[14] Case No. 9408, In the Matter of the Application of Perennial Solar, LLC for a Certificate of Public Convenience and Necessity to Construct an 8.0 MW Solar Photovoltaic Generating Facility in Washington County, Maryland.
[15] *See Florida Power & Light Co. v. Federal Power Commission*, 404 U.S. 453 (1972).
[16] *See* https://www.scotthemplinglaw.com/files/attachments/elec_jurisdiction_hempling_020514.pdf , page 2.

circuit crosses state lines but the energy is not intended to be consumed except by the electric distribution owner's customers, it is not electric energy for resale in interstate commerce.

Furthermore, in its Final Rule in Order No. 2222 the FERC clarified jurisdiction with respect to federal, state, and local jurisdictional boundaries. FERC Order No. 2222 in Paragraphs 43 and 44 of page 35 states:

> 43. We further clarify that we are only exercising jurisdiction in this final rule over the sales by distributed energy resource aggregators[17] into the RTO/ISO markets. Hence, an individual distributed energy resource's participation in a distributed energy resource aggregation would not cause that individual resource to become subject to requirements applicable to Commission-jurisdictional public utilities.
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> 44. As the Commission [FERC] stated in Order Nos. 841 and 841-A, the Commission recognizes a vital role for state and local regulators with respect to retail services and matters related to the distribution system, including design, operations, power quality, reliability, and system costs. As in Order No. 841, we reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements.

Furthermore, in FERC Order No. 2222-A issued on March 18, 2021, FERC affirmed its decision not to exercise jurisdiction over the interconnection of DERs that participate in RTO markets exclusively through a DER aggregation. This applies to all interconnections of DERs participating exclusively through a DER aggregation, even when there is a preexisting "first use" on the applicable distribution facility, and even when the DER aggregation consists of only a single DER. Specifically FERC stated on pages 42-43 of FERC Order No. 2222-A that, "we reiterate that the Commission will not exercise jurisdiction over the interconnection to a distribution facility of a distributed energy resource for the purpose of participating in RTO/ISO markets exclusively through a distributed energy resource aggregation, even after first-use has been triggered."

Therefore, except for the limited cases codified presently in COMAR 20.50.09.01, electric distribution interconnection jurisdiction is under Maryland, not FERC jurisdiction. To codify these aforementioned requirements to further enhance our "bright line" regulations, the Workgroup proposes that following regulation (*See* Appendix C – COMAR 20.50.09.01B) be added for a small generator facility seeking to interconnect under Maryland jurisdiction:

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[17] DER Aggregators bundle distributed energy resources to engage as a single entity in wholesale markets.

(4) The small generator facility intends to make sales of wholesale electric energy through the PJM Interconnection, LLC at an electric distribution interconnection facility only through participation in a distributed energy resource aggregation.

(5) The small generator facility will be interconnected to an electric distribution circuit and its energy will not be transmitted across state lines for a wholesale customer other than the electric distribution owner.

III. Interconnection Facility Costs

Interconnection Regulations Should Support State Policy

The 2019 Maryland General Assembly enacted new legislative Renewable Portfolio Standard ("RPS") goals by Senate Bill 516 / House Bill 1158, titled the Clean Energy Jobs Act, for the State to obtain 50 percent of its electricity via renewable energy by 2030. The Act also required the Power Plant Research Program to study the economic impacts upon the State if the RPS goal were to be increased to obtaining 100 percent of its electricity from renewable energy by 2040, and to issue its report to the Governor by January 1, 2024. Maryland's RPS target includes 14.5 percent being supplied by solar generation in Maryland. This Act will require a further escalation of distributed energy resources on Maryland's electric grid resulting in an increased need to accommodate and interconnect small generator facilities in Maryland.

A solution to the allocation of interconnection facility costs should support State policy.

"Causer Pays" Cost Allocation Model

Interconnection Customer ("IC") (or "small generator facility" or Distributed Generator ("DG")) projects[18] in Maryland are currently required to pay for the full cost of utility electric distribution hosting capacity upgrades ("HC upgrades") required to facilitate interconnection of the project.[19] This is known in the industry as "Causer Pays."

> Causer Pays reflects a narrowly tailored "*but for*" test. Under this test, if, *but for* the requested interconnection, an upgrade to the network would not be initiated, then the requesting party must pay for all of the upgrade costs, irrespective of any other uses of the network.[20]
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> Causer Pays works best where there is a single beneficiary of upgrade costs that fully utilizes the hosting capacity created by the upgrade. Causer Pays can also result in an additional hosting capacity buffer or

[18] Although used interchangeably, IC is used in this report as opposed to small generator facility or DG where the context of the report section is focused on customer aspects of a DG project such as agreements instead of the generator aspects such as operations.
[19] COMAR 20.50.09.12E(3)(d) states that "Upon completion of the interconnection facilities study, and with the agreement of the applicant to pay for the interconnection facilities and distribution upgrades identified in the interconnection facilities study, the utility shall provide the applicant with an interconnection agreement within 5 business days."
[20] See https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11895878 for the Northeast Clean Energy Council Inc.'s Alternative Cost Allocation Proposal, February 28, 2020, Page 1

> “headroom” that may over time be consumed by additional DG projects that did not contribute to the cost of the upgrade. [Future] DG projects will share in the benefits provided by the upgrade, but not the cost. In some cases, the cost of these upgrades can be a significant portion of total project costs and can lead to delays in interconnection queues and imperil project viability and lead to sunk costs due to canceled projects. “[While this] cost causation principle may historically have been a sensible approach when there was an unambiguous single beneficiary and the incremental uses of the network was relatively static, it is no longer appropriate nor reflective of the dynamic nature of the electricity system because it is no longer aligned with the manners in which electricity is currently generated, distributed and consumed.”[21]

Proposed Hosting Capacity Cost Allocation Guiding Principles

During the RM68 Hearing on September 18, 2019, the Commission requested that the Workgroup further evaluate alternatives to Maryland’s existing Causer Pays principle to further remove obstacles to interconnecting clean energy to the grid in support of Maryland Renewable Portfolio Standard (“RPS”) policy. Therefore, the Workgroup considered elements that should exist in an ideal cost allocation solution against which various alternatives could be evaluated. To that end, the Workgroup proposes the following interconnection cost allocation guiding principle:

> An ideal cost allocation solution should promote Maryland policy by mitigating cost obstacles to clean energy interconnection, facilitating efficient utilization of existing available hosting capacity and balancing the needs of distributed energy resource developers, utilities and ratepayers.

While it may be self evident that our guiding principles should include promoting Maryland RPS policy and preventing overbuilding of the electric distribution grid through efficient utilization of existing available hosting capacity, it may not be obvious to all stakeholders that balancing the needs of distributed energy resource developers, utilities and ratepayers is desirable. However, when considering the impacts of any cost allocation methodology there are really only two potential payers for hosting capacity to facilitate clean energy interconnection, the IC or ratepayers. Utilities by law are entitled to cost recovery if their investments are deemed prudent. When the Commission directed the Workgroup to consider options to a Causer Pays method, options available included methods where the costs of adding hosting capacity are: (1) paid by ICs, (2) shared by ratepayers and ICs, or (3) paid by ratepayers. The utility role should be to do their fair share in promoting the interconnection cost allocation guiding principles by adopting processes to facilitate safe, reliable and efficient interconnection. Therefore, in consideration of the needs and roles of these three key stakeholders, a guiding principle

[21] *Ibid*.

element is proposed to "balance the needs of distributed energy resource developers, utilities and ratepayers."

Evaluation of Other Industry Cost Allocation Models

In Phase III the Workgroup evaluated cost allocation methods in other states that are testing innovative schemes for distributing HC upgrade costs and categorized these approaches into several cost allocation models, for which we assigned our own labels. It has already been described that Maryland utilizes a Causer Pays cost allocation model. An overview of these other alternative cost allocation models is summarized below:

- *Causer/ Beneficiary Pays Hybrid Model* – The New York Standard Interconnection Requirement ("NYSIR") Cost Allocation Mechanism requires the first project that triggers the system modification is to pay upfront for 100 percent of the upgrade's cost similar to the Causer Pays Model. Following the upgrade, subsequent projects that benefit from the upgrade will reimburse the initial developer so this transitions to a Beneficiaries Pays Model. A Beneficiaries Pays Model would ideally allocate HC upgrade costs proportionally to benefits received. The subsequent ICs pay a prorated portion of the HC upgrade costs based on the fraction of their utilized capacity to the total capacity of projects benefiting from the upgrade. The payment is made to the utility who then distributes it among the necessary developers. The NYSIR cost allocation method provides an alternative to the current paradigm by spreading the cost of system modifications among those who benefit. However, this method still does not address the issue that the IC triggering upgrades must provide the upfront capital and still absorb the full cost of the HC upgrade if no subsequent project arises. Therefore, this method is not a pure Beneficiaries Pays Model but a combination of the Causer Pays and Beneficiaries Pays Models. The NYSIR may also impede interconnection of clean energy resources to the grid in some situations due to high upfront cost obstacles. This cost allocation method does promote IC location on areas of the electric distribution system that has spare hosting capacity since upgrade costs are avoided if the project locates where no upgrade is needed; therefore, this method is deemed to provide locational incentives.

- *Field of Dreams Model* - In the 1989 film, "Field of Dreams", while wandering in a corn field the main character hears a strange whisper: "If you build it, he will come." Although the movie certainly is not about building hosting capacity, the Workgroup chose this label nonetheless to describe a cost allocation model were the utility preemptively produces the upfront capital required and installs the network upgrade in targeted areas with the expectation of recovering the costs through future IC applications. In other words, if the utility builds the hosting capacity the ICs will come; hence the inspiration for the Field of Dreams Model label. After completing the HC upgrade, the IC projects connecting to the upgraded network reimburse the utility through a pro-rated fee based on the cost of the upgrade, network capacity, and project capacity. National Grid tested this methodology by preemptively installing network upgrades in targeted areas with the expectation of recovering the costs through future IC applications similar to the NYSIR model.[22] The biggest drawback to this model is the utility will have to recover the cost differential from ratepayers. This method, however, would appear to mitigate cost obstacles to clean energy interconnection, but not entirely remove them. This process would also promote efficient utilization of existing available hosting capacity through locational incentives since no upgrade cost would be incurred if a project locates where no upgrade is needed. This method also appears to balance the needs of distributed energy resource developers, utilities and ratepayers since both IC projects and ratepayers share in expanding hosting capacity and utilities recover their costs.

- *Ratepayer Pays Model* – In California hosting capacity upgrades made for customers under the former NEM tariff ("NEM 1.0")[23] are allowed in rate base, thereby socializing upgrade costs across all customers. This model certainly mitigates cost obstacles to clean energy interconnection. However, this model may not promote efficient utilization of existing available hosting capacity through locational incentives nor does it balance the needs of distributed energy resource developers, utilities, and ratepayers since ratepayers pay for HC upgrades.

- *Tariff Incentive Model* - Hawaii has a non-export tariff that seeks to avoid hosting capacity degradation that is enabled by energy storage and allows a BESS interconnection customer to earn an additional revenue stream from their solar output if they install a non-export[24] system. This model mitigates cost obstacles to clean energy interconnection through efficient utilization of existing available hosting capacity through locational incentives. The model also balances costs in some degree between IC developers and ratepayers. However, this method appears to be a niche application that is required due to the high DER penetration levels that exist in Hawaii such that it appears to have limited applicability in Maryland at this time.

- *Tariff Fee Model* – Massachusetts allows utilities to collect fees from IC s when projects are installed and those fees are used to pay for the needed upgrades on the feeder/substation transformer at the time the grid reaches an operating limit. Arizona Public Service has a variation on this model with a net energy metering Tariff that increases fixed charges to collect funds for needed utility upgrades to increase hosting capacity. In California, under the current NEM tariff ("NEM 2.0"), any customer-generator applying for NEM will pay a one-time

[22] Massachusetts DER Interconnection Cost Allocation Proposal, Massachusetts Department of Utilities, Docket No 19-55, Strategen Consulting. February 28, 2020, pp. 22-23.
[23] Note that fees for are assessed under the current NEM 2.0 tariff.
[24] DGs that do not export power to the electric grid are referred to as "non-export."

interconnection fee ranging from $75 to $145.[25] This Tariff Fee Model appears to mitigate cost obstacles to clean energy interconnection but it does not appear to promote efficient utilization of existing available hosting capacity through locational incentives.

The Workgroup evaluated the pros and cons of these various cost allocation models against the aforementioned guiding principles in an attempt to recommend an alternative cost allocation proposal to the Commission. Table No. 1 below is a high level summary of this evaluation with the Workgroup's evaluation of different cost allocation methods and pros and cons, when compared to our proposed guiding principles. The different elements that are checked in Table No. 1 below align with Maryland's cost allocation guiding principles.

Table No. 1 – Comparison of Various Interconnection Cost Allocation Models

Model	Causer Pays	Causer/ Beneficiary Pays Hybrid	Ratepayer Pays	Field of Dreams	Tariff Fee	Tariff Incentive
State Examples	Maryland	New York Interconnect Standard	California NEM 1.0	New York National Grid Pilot	Arizona, California NEM 2.0, Mass.	Hawaii
Cost to IC Beneficiary for Hosting Capacity?	✓ Yes	✓ Yes	No	✓ Yes	✓ Yes	No
Efficient Hosting Capacity Utilization?	✓ Yes	✓ Yes	No	✓ Yes	No	✓ Yes
Obstacle to Interconnection?	Situational	Situational	✓ No	Situational	Situational	✓ No
Winners & Losers?	1st Mover IC Overpays For Upgrades	Strives for Beneficiary Pays Model, But Falls Short	Ratepayers Pay	✓ Seeks Balance Between ICs and Ratepayers	ICs Pay	✓ Seeks Balance Between ICs and Ratepayers

The Workgroup decided not to pursue the Ratepayer Pays model because the Workgroup concludes that costs should be allocated between ratepayers and ICs because both stakeholders benefit from grid modernization. Also the Ratepayer Pays Model does not promote locational incentives to avoid overbuilding the electric grid.

While the Workgroup is not aligned on the Tariff Incentive Model, it concluded it is a niche tool to address an acute DG penetration saturation scenario that is not needed in Maryland at this time.

25 https://www.cpuc.ca.gov/NEM/

In an ideal scenario, a non-hybrid Beneficiaries Pay model would be most desirable since costs should be allocated in proportion to benefits received, but that objective is very hard to achieve. The NYSIR falls short of a non-hybrid Beneficiary Pays model but still has useful elements of attempting to allocate costs to beneficiaries proportionally after the initial HC upgrade. However, because the NYSIR still uses the Causers Pay Model as a starting point in a Causers Pay/ Beneficiaries Pay Hybrid Model with no assurances that the First Mover DER will ever get repaid for the excess hosting capacity created from its project, it was decided not to pursue this model further in Maryland at this time.

The Field of Dreams model also has attractive elements, especially the ability of utilities to forecast and plan preemptive HC upgrades for DG penetration. These preemptive HC upgrades may also have the benefit of reducing project timelines that previously needed to account for construction time. The Field of Dreams model also improves cost certainty and ensures single projects are not stuck with the full cost of HC upgrades that benefit other projects as well. Lower capital requirements and increased cost certainty reduce financial risk, which may improve a developer's ability to obtain financing. Therefore, the Workgroup concluded some elements of the Field of Dreams Model could be useful in Maryland. This is discussed further in this report.

Finally, the Workgroup examined the Tariff Fee Model further because it does have the benefit of ensuring that all ICs that benefit from available hosting capacity are paying for that interconnection, not just the projects that require hosting capacity upgrades. Utilization of the Tariff Fee Model could be beneficial depending on a State's cost allocation policy objectives. The objective for setting these Tariff fees should be to balance cost risk between the interconnection customer and ratepayer for hosting capacity upgrades. Therefore, the Workgroup concluded some elements of the Tariff Fee Model could be useful in Maryland. This is discussed further in this report.

Hosting Capacity Cost Allocation Background

Before discussing more fully a Workgroup proposal for a Maryland Cost Allocation Model ("MCAM"), it is helpful to consider how interconnection is accomplished today in Maryland for ICs.

Historically, if an IC locates its Point of Interconnection ("POI") on a part of the electric distribution system that has sufficient hosting capacity, the project can utilize that hosting capacity without a charge other than direct costs needed to physically interconnect the IC since a HC upgrade is not needed. As defined in COMAR 20.50.09.02(B)(17), "Hosting capacity" means the amount of aggregate generation that can be accommodated on the electric distribution system without requiring infrastructure upgrades.

The costs of this hosting capacity have already been embedded in electric rates and the utility seeks no further reimbursement. We will use the term "embedded hosting capacity" to mean existing hosting capacity[26] on an electric distribution system available to an interconnection customer without the need for a hosting capacity upgrade project.

Alternatively, if an interconnection customer locates its POI on a part of the electric distribution system that does not have sufficient embedded hosting capacity the utility can enlarge hosting capacity to meet future needs by a HC upgrade, for which costs will eventually need to be recovered. Examples of possible HC upgrades include reverse fault protection, regulator/load tap changer control upgrades, circuit reconductoring and substation transformer upgrades. Other improvements may also be needed and are site specific. In its simplest form,[27] ICs in Maryland are currently required to pay for the full cost of utility electric distribution system upgrades required to facilitate interconnection of the project as part of the Causer Pays methodology. We will use the term "non-embedded hosting capacity" to mean additional hosting capacity on an electric distribution system that is available to an interconnection customer from a hosting capacity upgrade project.

In summary, existing hosting capacity on the electric distribution system is considered embedded hosting capacity. Similarly, prospective hosting capacity improvements that result from normal utility plans or operational dynamics are also considered embedded hosting capacity. Hosting capacity upgrades triggered by prospective ICs are considered non-embedded hosting capacity and associated costs should be allocated in an MCAM.

Proposed Maryland Cost Allocation Model ("MCAM")

Since there was no perfect cost allocation model that met all of Maryland's needs, the Workgroup pursued a model that captures the best elements of other State models that align with the Workgroup's proposed guiding principles. In its simplest form, it would be ideal to utilize a "Beneficiaries Pays" method to allocate the cost of electric distribution hosting capacity upgrades among the both ICs and ratepayers proportional to the benefits received. However, a purely proportional "Beneficiaries Pays" model is very hard to achieve. Therefore, the Workgroup's proposal for a MCAM is a hybrid model that incorporates their best features of the Field of Dreams Model and the Tariff Fee

[26] Since each utility has different hosting capacity calculation capabilities (e.g., stochastic method or manual power flow), the Workgroup did not prescribe a hosting capacity calculation method except to the extent that it shall account for the utility's experience, good engineering practices, and judgment. Also, hosting capacity limitations will commonly exist at the feeder head but in some cases can exist at other locations such as a substation transformer.

[27] There is also an existing COMAR 20.50.09.12E(3)(e) requirement for Level 4 interconnection requests that addresses the use of hosting capacity where there is more than one small generator facility project in queue. There are also issues that are unaddressed in regulation involving projects that require interconnection facility upgrades and then are cancelled.

Model that are customized to propose a MCAM as consistent as possible with traditional Maryland ratemaking principles.

The Workgroup proposes that the utility would recover its costs of upgraded hosting capacity in a traditional rate case/multi-year plan or via a regulatory asset. This is described in more detail later in the report. The first mover DG project that triggers the need for an upgrade and all subsequent DG interconnections using the upgraded capacity will pay their fair share of the upgrade cost in proportion to their need for hosting capacity. All funds received for the upgrade cost from DG interconnections will serve to reduce amounts needing to be recovered from ratepayers in the future. Since DG projects could modify available hosting capacity due to impacts on distribution load and the resulting changes in power flows, the hosting capacity impact of all DG will be evaluated to determine the appropriate allocation of hosting capacity upgrade costs. After evaluation DG Projects, such as non-export systems dependent on proposed use,[28] that do not reduce hosting capacity should not be allocated hosting capacity upgrade costs.

The Workgroup also concluded that alternative solutions such as smart inverter voltage control capabilities on a site-specific basis and DER management systems, if available, should be employed by the host utility to increase hosting capacity prior to any decision that an HC upgrade project would be needed. However, after these methods to extend hosting capacity have been exhausted, the Workgroup concluded that for any HC upgrade deployed, the MCAM should also allow utilities to consider preemptive HC upgrades under certain conditions based on DER forecasting. However, the Workgroup did not agree with the Field of Dreams Model requiring the utility to produce all of the upfront capital required for the upgrade if a "first mover" DG triggers the need for an upgrade. Instead, the Workgroup concluded that the "first mover" DG that triggers the need for an electric distribution system upgrade should pay their proportional share of the benefits that accrue from the upgrade, not the entire HC upgrade cost. Any subsequent DG interconnections using that hosting capacity should also pay their proportional share of the benefits. Therefore, the MCAM should more fairly treat the "first mover" DG than the Causer Pays method, which in the past required an IC to pay for an HC upgrade that created hosting capacity benefits that exceeded the IC's needs.

The Workgroup also concluded that while preemptive upgrades envisioned in the National Grid pilot can be beneficial, in the MCAM the utility should not preemptively upgrade the hosting capacity to support prospective DGs on circuits that are not restricted circuits. However, the utility should be able to enlarge an existing HC upgrade project triggered by a "first mover" DER preemptively, to support future DER forecasts to avoid

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[28] *See* COMAR 20.50.09.02(42). Proposed use:
(a) "Proposed use" means the operational control modes of a small generator facility upon which the applicant's technical review is based and under which the small generator facility is bound to operate upon the execution of the interconnection agreement.
(b) "Proposed use" for a small generator facility includes a combination of electric generators and energy storage devices operating in specified operational control modes during specified time periods.

performing a second HC upgrade within the near future since the "used and useful" principle does not exclude partially used infrastructure as long as it is driven by an actual need. Traditional Maryland ratemaking principles are more fully discussed later in this report. The only other preemptive upgrades that utilities should undertake should be to open closed circuits[29] or restricted circuits[30] to not block small Level 1 (i.e., $\leq$ 20 kW) residential small generator facility installations based on DER forecasts as part of a hosting capacity upgrade plan[31] as codified in COMAR in Phase II of the Workgroup's efforts.

In this MCAM, a "first mover" DG will only be required to pay for the project's proportional share of an HC upgrade. The unallocated costs would still need to be recovered.

In the proposed MCAM, the upgrades that only benefit a DG project such as dedicated generator lead lines and feeders, metering, communication circuits, protective devices and other facilities required for direct interconnection that have no beneficiary other than the DG project should be fully allocated 100 percent to the interconnection customer. Conversely all electric distribution upgrades, metering, communication circuits, protective devices and other facilities that may benefit other ICs that are included in a HC upgrade can be allocated and shared in proportion to the interconnection customer's percentage utilization of that increased non-embedded hosting capacity.

While these HC upgrade costs will be a derived quantity, the amount of non-embedded hosting capacity created is more dynamic and can vary dependent on many factors as explained later in this report. Therefore, the MCAM will require eligible[32] interconnection customer projects benefiting from an upgrade, to pay a prorated portion of required hosting capacity project upgrade costs based on the fraction of their required interconnection capacity to the total capacity added though the upgrade improvement. The mechanism is not retroactive, so projects that have already provided an upgrade payment are not eligible for reimbursement. The cost sharing cycle is ended when the non-embedded capacity provided by the upgrade is fully allocated or when a new project requires a subsequent HC upgrade and cost sharing is reset.

[29] Closed circuit means an electric distribution system circuit with no available hosting capacity.

[30] Restricted circuit means an electric distribution system circuit with reserve hosting capacity.

[31] A hosting capacity upgrade plan means a plan to open restricted and closed circuits or areas on an electric system in the aggregate that includes a cost recovery method, under conditions that are approved by the Commission.

[32] Since DG projects could modify available hosting capacity due to impacts on distribution load and the resulting changes in power flows, the hosting capacity impact of all DG will be evaluated to determine the appropriate allocation of hosting capacity upgrade costs. After evaluation DG Projects, such as non-export systems dependent on proposed use, that do not reduce hosting capacity should not be allocated hosting capacity upgrade costs..

The Workgroup also proposes that the costs of this HC upgrade be recovered based on a headroom share calculation to allocate costs commensurate with benefits. Three additional definitions are proposed:

- Headroom means the total non-embedded hosting capacity created by an electric distribution system upgrade project at the time the project is installed as measured by the total hosting capacity created from an electric distribution system upgrade project.

- Headroom cost sharing is the process of allocating headroom costs to small generator facilities proportional to headroom share until this process is either ended or reset.

- Headroom Share[33] means the proportional allocation of hosting capacity to interconnection customers based on the fraction of the hosting capacity utilized by the interconnection customer to the total hosting capacity created from an electric distribution system upgrade project.

The goal of the MCAM is to allocate non-embedded hosting capacity upgrade costs triggered by First Mover DGs proportionally between all subsequent eligible interconnecting DGs until the upgrade costs have been fully allocated at which point the cost sharing cycle is ended. The cost sharing cycle is reset and begins again if a subsequent DG interconnection requires a new hosting capacity upgrade. The timing of the cost sharing cycle beginning and end is independent of the timing for when a utility may seek cost recovery of their hosting capacity upgrade costs in a rate case before they have been fully reimbursed from subsequent ICs. This is discussed in more detail later in this report.

As an example, consider that a HC upgrade project creates 20 MW of headroom but the First Mover DG only requires 10 MW. The headroom share in this example is 50 percent because half the headroom has been utilized.

If a Second Mover DG is 5 MW the headroom share in this example is 25 percent because a quarter of the upgrade capacity has been utilized.

Therefore, 5 MW of the headroom remains to be allocated in this example until the cost sharing cycle is ended.

[33] See https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11895878. The Workgroup credits the Northeast Clean Energy Council Inc.'s Alternative Cost Allocation Proposal, February 28, 2020 for developing the headroom share concept although this concept has been customized by the Workgroup to be workable in Maryland.

The cost sharing cycle for the headroom created by the First Mover DG will be ended when all headroom has been fully allocated. The cost sharing cycle is reset and begins again when a subsequent DG interconnects that creates the need for an additional hosting capacity upgrade project.

As an example, consider that 5 MW headroom remains to be allocated from the previous example. If a subsequent 10 MW Third Mover DG interconnects and creates a need for an additional 20 MW hosting capacity upgrade project, the cost sharing cycle will reset. The Third Mover DG will require 10 MW of the new 20 MVA headroom. Therefore, this Third Mover DG's headroom share in this example is 50 percent because half the new Headroom has been utilized. The 5 MWs headroom that is still unallocated will become embedded hosting capacity to avoid complications in mixing costs from multiple projects in the cost allocation. Sometimes for simplicity, it's desirable to avoid using "too fine a pencil" for the calculations. Utilities will need to develop processes to track and allocate non-embedded hosting capacity and associated costs, especially as DG penetration increases in coming years.

The additional regulations needed to implement this cost allocation method are described later in this report.

Once the HC upgrade project is completed, the HC upgrade project will also likely create some excess non-embedded hosting capacity since it is rare that an HC upgrade project size will exactly match the hosting capacity needs of an interconnection customer. Therefore, this excess non-embedded hosting capacity will transition to embedded hosting capacity available to future interconnection customers once the headroom cost sharing process is ended or reset.

The next issue that needs to be addressed is whether all small generator projects should get charged proportional to their headroom share? The Workgroup considered that the Commission previously determined that Level 1 small generator projects less than or equal to 20 kW should not have any interconnection application fees to promote higher penetration of these smaller projects, which in many cases are smaller residential and commercial rooftop solar projects. Therefore, consistent with the Commission decisions in both the RM61 and RM68 proceedings associated with utility fees that socialize these fees to promote small generator interconnection, the Workgroup concludes that Level 1 DG projects should be exempt from being charged for headroom share. This would be true even if a Level 1 DG project requires a shared service transformer upgrade that creates Headroom for additional ICs. This will give the utility the flexibility to install a larger service transformer than the immediate need in anticipation of other future ICs off the same service transformer. Level 1 DG projects that trigger shared service transformer upgrades shall only be responsible for dedicated infrastructure upgrades required and any tariff fees. Utilities are already allowed in COMAR to hold hosting capacity in reserve for Level 1 DG projects less than or equal to 20 kW so this situation should rarely occur where any single Level 1 small generator project would trigger the need for more hosting capacity headroom. However, as with larger DG projects, any Level 1 DG that requires dedicated lead lines and other facilities required for direct interconnection above and beyond a normal service connection covered by Tariff fees that have no beneficiary other than the DG project, these costs should be fully allocated 100 percent to the IC.

MCAM Proposal Solves Other Issues

This proposed MCAM also solves other issues with the existing Causer Pays method. Three of these issues are:

1. The MCAM can enable utilities to properly size an electric distribution system upgrade project to anticipate future DER forecast needs of ICs.

2. The MCAM can be used to create reserve hosting capacity in excess of First Mover DG needs to open closed or restricted circuits for Level 1 ICs.

3. The MCAM can eliminate negative impacts to ICs of speculative small generator facility projects utilizing space in an interconnection queue.

Properly Sizing a HC Upgrade Project Based on DER Forecasts

Regarding the first additional aforementioned benefit with regard to the sizing of electric distribution system upgrade project to anticipate future DER forecast needs, in scoping the electric distribution system upgrade project, a utility should consider both the upgrade needs of the interconnection customers in addition to DER forecasts. This is similar in concept to the way utilities currently plan capacity for load forecasts. Therefore, an upgrade project could potentially be sized larger than the hosting capacity required by the IC without encumbering them with larger costs since they are only paying their proportional share of the benefits from the upgrade. In and of itself, this may also decrease upgrade costs allocated to the IC since a larger project size may have economies of scale that can also help reduce proportionally allocated upgrade costs to ICs.

Using MCAM Reserve Hosting Capacity

Regarding the second additional aforementioned benefit with regard to providing utilities a way to upgrade hosting capacity to open closed or restricted circuits for ICs, when hosting capacity is not available on an electric distribution circuit, utilities may close a circuit (i.e., closed circuit) to all further interconnections, including small residential installations, or they may restrict further interconnections based on small generator facility size (i.e., restricted circuit). Restricted circuits have reserve hosting capacity available. Regulations were adopted in RM68 to codify the concepts of reserve hosting capacity, closed circuits and restricted circuits. To allow for potential future consideration of utility plans to open closed or restricted circuits, COMAR revisions were also adopted in RM68 that require a utility to seek Commission approval for a hosting capacity upgrade plan in the aggregate. Also the Commission may, in some cases, request a utility to submit a hosting capacity upgrade plan in the aggregate if it determines, based on annual small generator facility reports, that it is concerned with the number of restricted or closed circuits in a utility. Aggregate means that utilities would not present a plan for Commission approval for each circuit individually, but for a set of circuits or areas on their electric system. These utility proposals should come forward in a process that allows full notice and opportunity for stakeholders to comment. These hosting capacity plans submitted for Commission approval would propose the conditions under which the utility would increase hosting capacity to support DG installations along with the recommended cost recovery method,[34] the benefits to customers and the cost effectiveness of the plan. The MCAM allows a utility to allocate headroom created in excess of First Mover DG needs to create reserve hosting capacity needed to open closed or restricted circuits for Level 1 ICs. This could allow utilities to defer the need to submit hosting capacity upgrade plans through allocation of headroom created by HC upgrade projects.

Using MCAM for Speculative Small Generator Facility Projects

Regarding the third additional aforementioned benefit with regard to impacts to interconnection customers of speculative projects in interconnection queues, since projects can utilize interconnection queue space and then withdraw or cancel relatively penalty free (except for the interconnection request fees, interconnection study costs and forfeited milestone payments), there are two ways they can complicate the cost requirements for downstream projects in the same interconnection queue.

The first issue involves projects that require interconnection facility upgrades and then are cancelled. In FERC Docket No. ER17-156-000, FERC approved the Midcontinent Independent System Operator ("MISO") second petition for interconnection queue reform. On January 3, 2019, FERC ordered MISO to allow forfeited milestone payments from cancelled projects to be applied to fund network upgrades, thereby lessening the financial burden on other projects that rely on the upgrades. The Workgroup is proposing a similar provision in COMAR to allow forfeited study and milestone payments in excess of utility cost for a cancelled electric distribution upgrade project to be used to off-set future revenue requirements. This is a non-consensus Workgroup proposal.

The non-consensus viewpoint is that given that projects can drop out of the queue for a number of reasons and at different stages, the timing and cause of the forfeiture is important. If a project drops out after the utility has initiated construction on the necessary grid upgrades, a forfeiture would be more reasonable than if the project drops out before upgrades have begun, which would not have as significant an impact on remaining projects in the queue. In addition, projects can drop out for a number of reasons that are outside of the customer's control, including permitting challenges or, in some cases, delays in the interconnection process itself that result in loss of financing. In

[34] A cost recovery method should include a proposal for how the utility will recover its costs, by rate base or other methods, to fund a hosting capacity upgrade plan, including how much cost should be borne by interconnection customers.

order to effectuate the intent of the forfeiture of removing speculative projects, the application of the forfeiture should be designed to avoid penalizing non-speculative projects that drop out of the queue for reasons beyond their control and before grid upgrades have begun.

For speculative small generator facility projects utilizing space in an interconnection queue and then cancelling, there is an existing COMAR 20.50.09.12E(3)(e) requirement for Level 4 interconnection requests that addresses the use of hosting capacity where there is more than one small generator facility project in queue. This regulation addresses a rare case where a second small generator facility project lower in the queue needs to pay for an upgrade because there is a higher small generator facility project in queue using all the available hosting capacity. The regulation allows the second small generator facility project lower in the same interconnection queue to continue with the interconnection process through energization while delaying payment for an upgrade until the time the first higher small generator facility project in queue is ready to interconnect. At that time, the second small generator facility project must then disconnect if they have not paid for an upgrade. Presumably the second small generator facility project responsible for the upgrade costs could monitor the first project to determine if the first higher small generator facility project in queue is a confirmed viable project before they elect to pay for a distribution system upgrade. This regulation addresses a situation where a higher ranking speculative small generator facility project in queue may never materialize thereby forcing lower ranking small generator facility projects in queue to pay for a distribution system upgrade that will never be needed if the first small generator facility project does not materialize.

In some cases, the schedule requirements to complete a distribution system upgrade in a timely manner could be problematic if the small generator facility project responsible for the upgrade costs has not paid the utility in time to begin construction to meet its service date. It is also problematic having the second small generator facility project in queue interconnect without paying and then requiring this project to disconnect when the first small generator facility project in queue is ready to interconnect, if they have not paid the distribution system upgrade. In addition, this situation could get even more complicated with several small generator facility projects in the same interconnection queue. No utility in Maryland has reported having encountered this type of situation to date and they also do not believe it would happen very often. Therefore, the Workgroup is proposing to completely eliminate this existing COMAR 20.50.09.12E(3)(e) requirement since in the MCAM proposal eligible ICs will be charged proportionally for an upgrade based on their headroom share thereby eliminating the need for this regulation.

Maryland Cost Allocation Method (MCAM) Economic Principles Consistency with Traditional Maryland Ratemaking Principles

Maryland ratemaking principles traditionally rely on the principle of "cost causality" that assigns costs to those who cause them for the utility. Furthermore, Maryland ratemaking principles also rely on the "fairness" principle that requires to the extent possible that costs are fairly apportioned among different customers. Another important ratemaking principle is the “used and useful” concept that requires energy assets to be physically used and useful to current ratepayers before those ratepayers can be asked to pay the costs associated with them. Any Maryland cost allocation should be consistent with these three principles, to the extent possible.

The MCAM strives to be consistent with these longstanding Maryland ratemaking principles. The “causer pays” methodology used presently in Maryland for interconnection cost allocation is based on the principle of “cost causality.” In other words, the First Mover DG project that causes the upgrade pays for the cost of the upgrade. However, the “causer pays” method is not necessarily consistent with the “fairness” principle in that costs are fairly apportioned among different customers since the First Mover DG project may create additional non-embedded hosting capacity that can be used free of charge by subsequent interconnecting DGs. The “fairness” principle is important to meeting Maryland's aggressive RPS goals because “cost causality” may make some First Mover DG project proposals uneconomic and therefore, not viable. DG project developers have choices where to locate their projects and it is important to remove entry cost barriers that could impede DG development in Maryland if there are more economically competitive choices in other States.

The “fairness” principle also applies to shifting risk. In other words, any proposed cost allocation principle should not unduly shift risk to a particular set of customers. The MCAM is designed based on the concept of allocating all non-embedded hosting capacity additions to subsequent DG projects that interconnect and utilize this hosting capacity, so in a perfect world this would not shift risk to ratepayers if the utility were able to recoup its costs from interconnection customers before a subsequent rate case. However, it is not a perfect world. It may take many years for non-embedded hosting capacity to be allocated to the subsequent ICs.

The timing of the aforementioned cost sharing cycle beginning and end is independent of the timing for when a utility may seek cost recovery of their hosting capacity upgrade costs in a rate case before they have been fully reimbursed from subsequent ICs. One complicating factor is that a utility may seek cost recovery of their hosting capacity upgrade costs in a rate case before they have been fully reimbursed from subsequent ICs. Utilities make decisions on the timing of their rate cases based on their own internal needs, and generally they seek to recoup costs even if the infrastructure being installed is only partially used. In these cases, facilities that are partially used are still considered “used and useful” since you can never completely match infrastructure usage with capacity. This is further complicated in multi-year rate plans (“MYP”) that are now in use in Maryland since utilities will need to forecast their interconnection hosting capacity upgrade costs out several years in advance with a reconciliation and prudency review occurring at the end of the MYP to determine how well hosting capacity cost projections netted with payment offsets matched the original MYP forecasts.

Therefore, there will always be risks to ratepayers of paying for unallocated hosting capacity because if non-embedded hosting capacity costs are not allocated to ICs, these costs will eventually be allocated to ratepayers. Therefore, the MCAM should have a feedback loop and corrective mechanism to ensure that the traditional Maryland ratemaking principles of cost causality and fairness are applied to the extent possible. Metrics have been added to the Workgroup proposal to track the allocation of hosting capacity and their associated costs to ensure there is transparency on the amount of unallocated headroom costs to manage risk to ratepayers. This will enable a feedback loop and corrective mechanism that could possibly lead to an IC Fee for their use of non-embedded hosting capacity if experience indicates that too much risk is being shifted to ratepayers. An IC fee corrective action will also only be applied prospectively to ICs and cannot be applied retroactively since DG project viability can be dependent on hosting capacity cost assumptions they make at project initiation. Also an IC Fee will apply to all projects except for Level 1 ICs, non-export ICs or ICs that are paying their allocated headroom share for non-embedded hosting capacity.

With an IC Fee, there will be a question about what is considered too much risk and when to apply this fee? The Workgroup recommendation is to have no IC fee at the outset so as to not impede the interconnection of ICs needed to interconnect clean energy to meet Maryland interconnection goals. Experience monitoring trends in the allocation of non-embedded hosting capacity will indicate how much risk is shifting to ratepayers that may result in triggering the need to implement an IC Fee. Different stakeholders will have different opinions on when to trigger an IC fee and these decisions will be utility specific, not a statewide IC fee, because hosting capacity allocation trends may vary from utility to utility. Since different stakeholders will have different opinions on when to trigger an IC fee and these opinions may be fully expressed in rate cases, the Workgroup did not attempt further exploration of this question. The Workgroup is only recommending a regulatory cost allocation framework to enable an IC Fee in electric utility tariffs should a corrective mechanism be needed to properly balance cost risk between ICs and ratepayers.

These IC Fees, if ever deployed, should be calculated on a per kW basis based on projection trends for unallocated non-embedded hosting capacity costs and DER forecasts for applicable DGs (e.g., excludes Level 1 DGs which will not receive IC Fees) in kW to yield an IC Fee. For instance, in its simplest form is a utility trend illustrates that over a multi-year period it is accumulating $1M/ Yr. non-embedded hosting capacity costs on average and annual DER forecasts indicate that, excluding Level 1 DGs, 100,000 kW of applicable DGs are expected to interconnect annually on average, an IC Fee that could mitigate ratepayer risk my be $1,000,000/ 100,000 kW or $10/KW. If any IC Fee is applied in the future, it is recommended to be prospective to not impose past costs on future interconnection customers in alignment with the “fairness” principle.

Of course, the actual IC Fee calculation would be more complex and other factors would need to be considered such as the risk that an IC Fee would have on impeding DG interconnections to meet State policy goals. Therefore, this example is being offered only for illustrative purposes and should not be considered an “order of magnitude” calculation representative of a likely IC Fee. The example does point out, however, the IC Fee could be “fine tuned” between a range of zero fees to place cost risk entirely on the ratepayer to a full fee to place cost risk entirely on the IC, or somewhere in between to balance cost risk between the IC and ratepayer.

The balance of cost risk between the IC and ratepayer is a policy decision for which the Workgroup seeks Commission guidance. The Workgroup is simply proposing a regulation framework to enable the MCAM Method with a feedback loop and a corrective measure tool that can potentially be used to balance cost risk between the IC and the ratepayer.

If an IC Fee is eventually adopted as part of the MCAM, some Workgroup stakeholders recommend laying out more detailed guidelines for the utilities to apply IC Fees consistently. For example, Maryland could model an IC Fee on an approach similar to California's NEM 2.0 which establishes the Fee annually using the prior year's upgrade costs attributable to a particular class of interconnection customer, divided by the number of projects in that class. The fee could also have some corrective mechanisms. For instance, if the prior year's upgrades were higher than the current year's the utility could adjust by lowering the fee accordingly in its annual recalculation. In addition, more guidelines should be developed to determine when an IC Fee would be triggered.

At a minimum, the following proposed regulation would be needed in COMAR 20.50.09.06 to implement an IC Fee:

> Utilities shall track allocated and unallocated non-embedded hosting capacity upgrade project costs in utility accounts.
>
> Utility hosting capacity fees, if needed to balance non-embedded hosting capacity upgrade project cost risk between interconnection customers and ratepayers, shall be included in utility tariffs.

Additional regulation proposals may be required to address both detailed guidelines for the utilities to apply IC Fees and when IC Fees would be triggered.

<u>Non-Wires Alternatives</u>

Lastly, if the DG provides system planning benefits as a Non-Wires Alternative, the utility will develop a separate agreement with the IC outside of this MCAM. For example, in Case No. 9619 utilities have entered into third party agreements to own and operate energy storage devices for electric system benefit for which they will seek costs recovery in rate cases. Distribution System Planning was the subject of a technical conference held by the Commission on March 25, 2021.

<u>DGs Under FERC Jurisdiction</u>

The MCAM is not applicable to DG projects in Maryland under FERC Jurisdiction that are subject to cost allocation requirements in the PJM Tariff. The PJM Tariff requires interconnection facility cost sharing of upgrades over $5 million for five years after the initial Interconnection Service Agreement. Any subsequent project may take advantage of the additional capacity created by the first interconnection project but will be allocated costs proportional to their impacts on the upgraded interconnection facility as determined by PJM.

<u>Interconnection Scenarios Using MCAM</u>

In summary, Table No. 2 below describes impacts to ICs, Utilities and Ratepayers Workgroup proposals for cost allocation for different interconnection scenarios.

Table No. 2 - Interconnection Scenario Matrix
(The Following Scenarios Assume a Zero IC Fee)

Interconnection Scenario	IC	Utility	Ratepayer
DG Project > 20 kW That Utilizes Available Embedded Hosting Capacity	0% Cost Allocation for HC. IC Pays Direct Interconnection Costs	HC Investment Included in Rate Base. Charges Direct Interconnection Costs to IC.	Current Ratepayer Rates Reflect Previous Additions of Embedded HC to Rate Base
DG Project > 20 kW With Benefits That Only Accrue to The IC	100% Cost Allocation For All Direct Interconnection Costs That Only Benefit IC	Charges IC 100% For All Direct Interconnection Costs That Only Benefit IC	No Impact – Causer Pays
First Mover DG Project > 20 kW That Triggers Upgrade That Creates Headroom	HC Costs Allocated Based on Headroom Share	Creates HC Upgrade Project. Charges Costs Based on Allocated Headroom Share. Recovers costs through a multi-year or traditional rate case, possibly using a regulatory asset. All upgrade funds received from ICs are credited to ratepayers.	Ratepayer Risk is the Costs for Unallocated Headroom Share
Subsequent Second Mover, Third Mover etc. DG Projects > 20 kW That Utilize Existing Non-Embedded Hosting Capacity	HC Costs Allocated Based on Headroom Share	Charges HC Costs Based on Allocated Headroom Share. Recovers costs through a multi-year or traditional rate case, possibly using a regulatory asset. All upgrade funds received from ICs are credited to ratepayers.	Ratepayer Risk is the Costs for Unallocated Headroom Share
DG Project ≤20 KW (i.e., Level 1 DG) That Does Not Require Shared Service Transformer Upgrade	0% Cost Allocation Except for Charges Specified in Utility Tariff Including Dedicated Infrastructure Upgrades Not Covered in Tariff	Interconnects DGs and Charges per Utility Tariff Including Dedicated Infrastructure Upgrades Not Covered in Tariff. Cost Recovery for Unbilled Costs	Ratepayers Absorb Unbilled Costs But Also Benefit in Aggregate

DG Project ≤20 KW (i.e., Level 1 DER) Requiring Shared Service Transformer Upgrades That Create Headroom for Additional DGs	0% Cost Allocation Except for Charges Specified in Utility Tariff Including Dedicated Infrastructure Upgrades Not Covered in Tariff	Interconnects DGs and Charges per Utility Tariff Including Dedicated Infrastructure Upgrades Not Covered in Tariff. Cost Recovery for Unbilled Costs	Ratepayers Absorb Unbilled Costs But Also Benefit in Aggregate
DG Project ≤20 KW (i.e., Level 1 DG) Requiring A Service Transformer Upgrades That is 100% Dedicated to the DG Project	100% Cost Allocation for Transformer, Other Dedicated Infrastructure Upgrades & Charges Specified in the Utility Tariff	Interconnects DERs and Charges per Utility Tariff Including Dedicated Infrastructure Upgrades Not Covered in Tariff. Recovery for Unbilled Costs	No Impact – Causer Pays
Utility Proposed Hosting Capacity Upgrade Plan Based on DER Forecasts	To the Extent that Headroom is Created Above HC Needed for Reserve HC, Costs Allocated Based on Headroom Share	Petitions Commission for HC Upgrade Plan and Proposes Cost Recovery Method	Cost Recovery Method Proposed in HC Upgrade Plan
Utility Enlarges Hosting Capacity Project Beyond HC Needed for First Mover DG Project > 20 kW Based on DER Forecasts	Costs Allocated Based on HC Headroom Share	Creates HC Upgrade Project. Charges HC Costs Based on Allocated HC Headroom Share. Recovers costs through a multi-year or traditional rate case, possibly using a regulatory asset. All upgrade funds received from DGs are credited to ratepayers.	Ratepayer Risk is the Costs for Unallocated HC Headroom Share
Speculative DG Projects > 20 kW in Interconnection Queues That are Cancelled	Forfeits Interconnection Study and Milestone Payments	Forfeited Interconnection Study and Milestone Payments in Excess of Utility Costs Offset Revenue Requirements	Ratepayer Benefit From Reduced Revenue Requirements
DG Projects Utilized in Integrated Distribution Planning	Separate Agreement Between Utility and IC in Accordance With Any Existing Applicable Tariff that Addresses Ongoing Payments & Terms and Interconnection Costs	Separate Agreement Between Utility and IC that Addresses Ongoing Payments & Terms and Interconnection Costs	Normal Cost Recovery of Expenses in Rate Cases Reflected in Rates
Customer Load Reduction that Results in Need for a Hosting Capacity Upgrade (See Further Discussion Later in Report)	N/A	Does Not Involve an Interconnection Request. Normal Cost Recovery of Expenses in Rate Cases.	Normal Cost Recovery of Expenses in Rate Cases Reflected in Rates

Non-Export System that does not Reduce Hosting Capacity or May Improve Hosting Capacity	Pays Charges Specified in Utility Tariff Including Dedicated Infrastructure Upgrades Not Covered in Tariff	Interconnects DERs and Charges DER Fees per Utility Tariff & Dedicated Infrastructure Upgrades Not Covered in Tariff.	Normal Cost Recovery of Expenses in Rate Cases Reflected in Rates
DER Projects in Maryland Under FERC Jurisdiction	Subject to PJM Tariff. Cost Allocation Requirements	DER Project Charges Subject to the PJM Tariff	No Impact – Causer Pays

MCAM Cost Recovery

The Workgroup considered the question of cost recovery.

Utilities may prefer to recover their expenditures for HC upgrade costs using traditional cost recovery methods in a traditional rate case / multi-year plan or a regulatory asset with subsequent reimbursements by ICs for headroom share (and forfeited interconnection study and milestone payments in excess of utility costs) offsetting future revenue requirements.

The regulatory asset mechanism would allow non-embedded hosting capacity costs (including incremental depreciation expense and accrued carrying costs on the associated rate base) to be deferred and tracked into a regulatory asset to be offset by interconnection customer's future payments that will be subsequently allocated according to the IC's usage of Headroom.

In the end, the Workgroup decided that the MCAM model and associated COMAR regulations should be agnostic to the method of cost recovery deployed and makes no further recommendation on the matter. This issue can be decided in future rate case proceedings or when a utility petitions the Commission for approval of a hosting capacity upgrade plan.

Hosting Capacity Calculation Methods, Accuracy & Transparency

For simplicity, the concept of hosting capacity up until this point has assumed that hosting capacity is a relatively static calculation at one point in time. However, this is far from the case as hosting capacity will vary dynamically over time and is also dependent on the calculation method. First hosting capacity can change over time as loads increase and decrease even if no new generators are added that consume hosting capacity. For instance a permanent load reduction due to an energy efficiency project will look like a generator to the electric system and decrease hosting capacity. In some cases a large enough load reduction could even trigger the need for a hosting capacity upgrade. The MCAM does not envision that a customer should be charged for a load reduction since that is counter-intuitive and would also conflict with state policy that encourages energy conservation and de-carbonization. This scenario does not have to be codified to prevent a customer with a load reduction triggering a hosting capacity upgrade since this scenario will not result in an interconnection request.

Furthermore, non-export systems typically do not reduce hosting capacity and may even improve hosting capacity but the current MCAM proposal currently does not envision that an interconnection customer should be incentivized for improving hosting capacity, at least at this time. However, this may be future "use case" study in a distribution planning initiative to provide additional value streams to interconnection customers in high penetration areas similar to the Tariff Incentive Model for non-export systems that currently exists in Hawaii.

Similarly the calculation of hosting capacity results also can vary depending on the methodology used to perform the calculation. The stochastic method models the electric distribution system by adding DGs of varying sizes to a feeder at randomly selected locations producing a hosting capacity range, not a fixed number. Other methods may use manual power flow simulations to yield a fixed number, not a range. Different utilities in Maryland are at different points and it will be counter-productive to prescribe calculation methodologies at this time for interconnection purposes until a distribution planning initiative can consider hosting capacity calculation methods and policies further. The important thing at this point is that utilities have a calculation method and policies that accounts for the utility's experience, good engineering practices, and judgment.

When determining headroom share we decided to utilize equipment capacities as a surrogate for hosting capacity because hosting capacity is too dynamic and would only be accurate for a snapshot of system conditions at the particular time the hosting capacity calculation is made. Therefore, non-embedded hosting capacity created is measured by the total equipment capacity created from an electric distribution upgrade project.

The only objective of the Workgroup's interconnection facility cost proposal is to more fairly allocate hosting capacity upgrade costs to ICs to remove obstacles to interconnection. Therefore, since the primary goal is to allocate HC upgrade costs, the headroom share calculations will be based on the installed equipment capacity in kWs or MWs created by the HC upgrade project and then the goal will be to allocate that non-embedded hosting capacity proportionally to subsequent ICs seeking to interconnect. Subsequent headroom share calculations will also be based on the subsequent IC's hosting capacity use in kWs or MWs. This will continue until the hosting capacity is either fully allocated or vanishes due to aforementioned dynamic reasons. Therefore, there is also risk to ratepayers that hosting capacity upgrade costs may never be fully allocated if hosting capacity vanishes due to dynamic reasons.

Since hosting capacity calculations play such a large part in determining the need for an HC upgrade, the Workgroup determined that hosting capacity calculations utilized by utilities need to be validated for accuracy periodically. Furthermore, there needs to be some metrics to provide transparency to ensure that utilities are not overbuilding hosting capacity with risk to ratepayers. Also, since the amount of reserve hosting capacity factors into the headroom allocation, there needs to be some transparency on the amount of reserve hosting capacity on each applicable restricted circuit. Reserve hosting capacity policies on restricted circuits are usually circuit-based, instead of a single limit for all circuits set by utility policy, since the amount of potential DG penetration is likely influenced by whether the area is urban, suburban or rural.

In the Workgroup's Phase II Final Report, we stated, "More robust DER forecasting methodologies will need to be developed in order to provide greater granularity and accuracy of the HCA [Hosting Capacity Analysis]." Since DER forecasting capabilities will take some effort and time to be developed it is not appropriate for regulations at this time but it is a utility best practice that should eventually be adopted by utilities along with hosting capacity reporting systems that include HCA maps.

The Workgroup concludes it is also desirable to address the concerns about hosting capacity accuracy and transparency expressed by some stakeholders by specifically requiring that utilities address accuracy by performing a representative sample of hosting capacity calculation validation checks at least annually, or more frequently in areas experiencing significant growth or DG penetration. The hosting capacity calculation validation check frequency shall account for the utility's experience, good engineering practices, and judgment. The Workgroup will not prescribe a percentage for sampling since some of these hosting capacity calculations are likely manually calculated by smaller utilities whereas some calculations are likely automated for larger utilities. The only requirement proposed is that the utility have a procedure for calculating hosting capacity and perform a representative sample of hosting capacity calculation validation checks at least annually. The results of these validation checks can be subject to inspection by Commission Staff during periodic compliance inspections per current practice.

Furthermore, any improvements made to hosting capacity calculations or a goal to add reserve hosting capacity for each circuit should be reported in the utility progress reports in implementing or improving their hosting capacity reporting systems in their small generator facility reports currently required by COMAR 20.50.09.14C(9) annually on April 1 without any additional regulation change.

In order to address the concern of providing more transparency to ensure that utilities are not overbuilding hosting capacity, the Workgroup is recommending that a utility shall also report annually for the previous year and cumulatively the total headroom created and headroom allocated to ICs. As previously mentioned, cost allocation tracking is proposed to be required by utilities in associated cost accounts and this data can be made available in rate cases or other relevant proceedings and is not recommended to be tracked in annual interconnection reports.

These headroom and headroom allocated metrics will provide a good indication of the utilization of new hosting capacity created by ICs. These new MCAM concepts are projected to take some time to implement associated Information Technology ("IT") and process changes after codification, with the implementation date subject to a Commission rulemaking proceeding.

In addition, Workgroup stakeholders proposed that the amount of embedded and non-embedded hosting capacity be made available in hosting capacity reporting systems such as hosting capacity maps. The Workgroup felt that would be challenging to implement this requirement in hosting capacity reporting systems but did agree that that the amount of embedded and non-embedded hosting capacity should be made available in pre-application reports. This will enable a prospective interconnection customer to determine if they will need to pay for an HC upgrade or to utilize non-embedded hosting capacity. Therefore, a change is proposed to COMAR 20.50.09.06C(4)(c) for pre-application reports.

COMAR Interconnection Facility Costs and Hosting Capacity Allocation Regulations

To codify the Workgroup's interconnection facility cost proposals, the following COMAR regulation additions, as discussed earlier in this report, would be required. However, the Workgroup recommends further study of our interconnection facility cost in a future Phase IV Workgroup effort as discussed in the Conclusions and Recommendations Sections of this report.

Definitions (*See* Appendix C - COMAR 20.50.09.02)

- Embedded hosting capacity means existing hosting capacity on an electric distribution system available to an interconnection customers utilize without the need for a hosting capacity upgrade project.

- Non-embedded hosting capacity means additional hosting capacity on an electric distribution system that is available to interconnection customers from a hosting capacity upgrade project.

- Headroom means the total non-embedded hosting capacity created by an electric distribution system upgrade project at the time the project is installed as measured by the total hosting capacity created from an electric distribution system upgrade project.

- Headroom cost sharing is the process of allocating headroom costs to small generator facilities proportional to headroom share until this process is either ended or reset

- Headroom Share means the proportional allocation of hosting capacity to interconnection customers based on the fraction of the hosting capacity utilized by the interconnection customer to the total hosting capacity created from an electric distribution system upgrade project.

Regulations (See Appendix C - COMAR 20.50.09.06C(4)(c))

- (c) Amount of embedded and non-embedded hosting capacity available on the closest feeder, if this information is in possession of or easily obtainable by the utility; and

Regulations (*See* Appendix C - COMAR 20.50.09.06Q)

- A Level 1 small generator facility shall not be charged for hosting capacity.

- A small generator facility interconnection that triggers an electric distribution system upgrade will be charged 100 percent for costs that only benefit the small generator facility.

- A small generator facility interconnection that utilizes non-embedded hosting capacity will be charged for headroom proportional to its headroom share, except for a Level 1 small generator facility.

- Headroom cost sharing is ended when headroom has been fully allocated.

- Headroom cost sharing is reset when additional hosting capacity exceeding unallocated headroom is required by a small generator facility thereby triggering a new electric distribution system upgrade.

- A utility can create additional headroom above the needs of an interconnection customer request for a hosting capacity upgrade based on distributed energy resource forecasts according to the utility's experience, good engineering practices, and judgment.

- Utilities shall track allocated and unallocated non-embedded hosting capacity project costs in utility accounts.

- Utility hosting capacity fees, if needed to balance non-embedded hosting capacity upgrade project cost risk between interconnection customers and ratepayers, shall be included in utility tariffs.

- A small generator facility shall not be charged for both non-embedded hosting capacity and a utility hosting capacity fee.

- A small generator facility will forfeit interconnection study and milestone payments for cancelled projects which will be allocated to reducing utility revenue requirements for increasing hosting capacity.

Despite a decision to not pursue new interconnection facility cost regulations in Phase III, the Workgroup recommends the following regulation be added to existing hosting capacity regulations in COMAR 20.50.09.06P.

Regulation (See Appendix C - COMAR 20.50.09.06P(3))

- A utility shall have a procedure for calculating hosting capacity. The utility shall perform a representative sample of hosting capacity calculation validation checks at least annually, or more frequently in areas experiencing significant growth or distributed energy resource penetration. The hosting capacity calculation method and validation check frequency shall account for the utility's experience, good engineering practices, and judgment.

Annual Reporting Regulations (*See* Appendix C - COMAR 20.50.09.14)

- A utility shall also report for the electric distribution system annually for the previous year and cumulatively from the beginning of To Be Determined ("TBD"):
    - Total reserve hosting capacity available in kWs
    - Total Headroom created in kWs; and
    - Headroom allocated to interconnection customers in kWs

There are also several deletions of existing regulations (*See* Appendix C - COMAR 20.50.09.12E(3)(e)) that will no longer applicable if this new regulation proposal is eventually codified.

IV. Maryland Smart Inverter Settings Standards

Background

A smart inverter is not only capable of performing traditional inverter functions (i.e., converting DC power to AC power) but also has the capability of providing advanced features that support grid reliability and stability for grid modernization. A smart inverter is considered as an inverter hardware system certified to be compliant with IEEE 1547-2018 or subsequent revisions to these standards.

Among the tasks assigned by the Commission to the PC44 Interconnection Work Group were to:

> "assess … whether each newly interconnected solar generating system should be required or encouraged to connect to the electric grid with a smart inverter"[35] and "develop proposed regulations for Commission consideration instituting … if appropriate, a requirement that newly interconnected solar generating systems connect with a smart inverter."[36]

Smart inverters are needed for grid modernization. It is important for Maryland to develop a smart inverter state-wide standard to ensure that all smart inverters installed utilize settings that support grid modernization. Smaller electric cooperative and municipal utilities in Maryland may not have the engineering capabilities to develop their own smart inverter setting standards but will benefit from a state-wide standard that supports grid modernization. A smart inverter state-wide standard will also enable smart inverter manufacturers to provide inverters to Maryland customers with these standardized default settings directly from the factory, if no other direction is provided.

Feasibility of Maryland's January 1, 2022 Smart Inverter Requirement

The Workgroup proposed a smart inverter state-wide standard to be effective January 1, 2022, in Maryland in our Phase II recommendation to the Commission. This requirement was codified in COMAR with the RM68 rulemaking proceeding. The Workgroup did not recommend making the use of any particular smart inverter features mandatory at that time. IEEE and Underwriters Laboratory ("UL") were in the process of making major revisions to inverter standards, and the use of new features would be considered after those revisions are complete. IEEE 1547.1 was published on May 21, 2020 and UL-1741 was published on September 16, 2020. With the publication of IEEE 1547-2018 and the companion IEEE 1547.1 and UL 1741 standards,[37] it will be possible to move toward the

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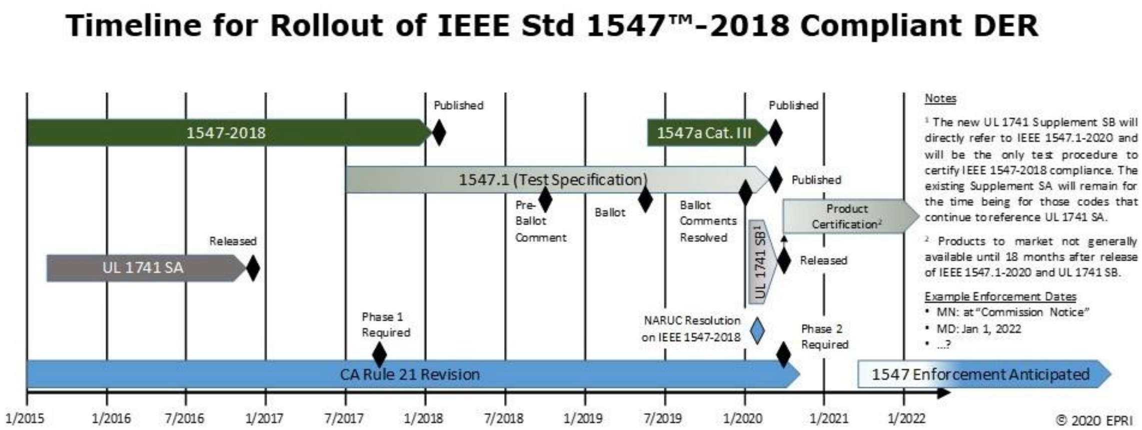
[35] Maryland Public Service Commission, PC44 Notice, January 31, 2017, p. 15.
[36] *Ibid*., p. 16.
[37] Updating the COMAR 20.50.02.02E, 20.50.02.02F and 20.50.02.02G references to the latest IEEE 1547-2018, IEEE 1547.1 and UL 1741 is not appropriate at the present time. Hardware compliant with the IEEE 1547-2018 standard is not yet available. Once this occurs, references in COMAR will need to be updated.

realization of the Commission's objectives for the Workgroup to ensure that Maryland's electric distribution systems can handle increasing DG penetration, help achieve reliability for both the distribution system and the bulk power system, help achieve cost-effectiveness by minimizing interconnection costs for solar generators and the distribution system upgrades needed to accommodate them and helps enhance environmental sustainability by increasing hosting capacity on distribution feeders.[38] This timeline is captured in Figure No.1[39] below.

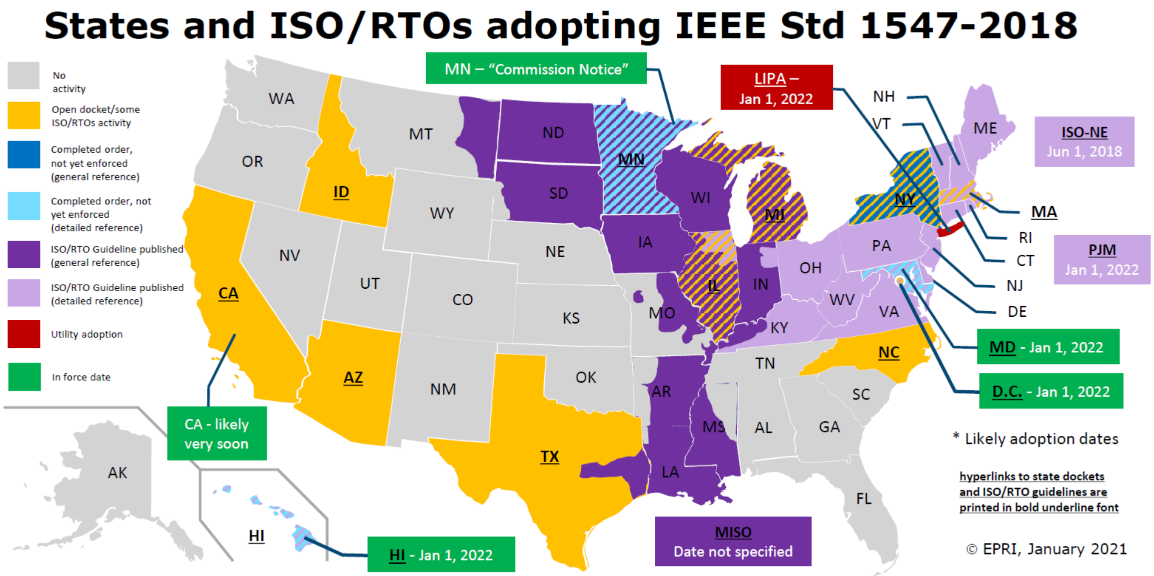
Figure No. 1 – IEEE 1547-2018 Rollout Timeline



Now that these IEEE and UL precursor efforts are complete, manufacturers are now in the process of certifying smart inverters to these standards making the Maryland January 1, 2022 smart inverter requirement feasible. Several other States and Regional Transmission Operators ("RTOs")/ Independent System Operators ("ISOs") have also adopted or are in the process of considering a smart inverter requirement as illustrated in Figure No. 2[40] below. PJM has also set a January 1, 2022 target for utilization of their prescribed Voltage and Frequency Ride-Through settings.

[38] *See* Maryland Public Service Commission, PC44 Notice, January 31, 2017, p. 3.
[39] *See* https://sagroups.ieee.org/scc21/standards/1547rev/
[40] *See* https://sagroups.ieee.org/scc21/wp-content/uploads/sites/285/2021/01/IEEE-1547-2018_States-and-ISOs-RTOs-Adoption_IEEE-Format.pdf, Slide 8.

Figure No. 2 – IEEE 1547-2018 Adoption Status (January 2021)



On March 15, 2021 the California Solar & Storage Association ("CALSSA") sent a letter[41] to the California Public Utilities ("CPUC") Energy Division citing several manufacturer obstacles to meeting the compliance date for of January 1, 2022, for smart inverters in California to be certified to IEEE 1547.1. The CALSSA recommended a compliance date of March 1, 2022, to the CPUC. Industry stakeholders involved both in Maryland and California indicate the California utilities assume the CPUC will approve an extension to at least March 1, 2022. Apparently, there are emergent problems with the UL 1741 SB testing standard and it is quite possible the corrections will not be published until August or September, 2021. Given that it will take months for a single inverter manufacturer to get certification for all models, even a smart inverter requirement for the first quarter of 2022 may be unrealistic. On March 30, 2021, a notification was sent out that Hawaiian Electric changed their smart inverter requirement from January 1, 2022, to April 1, 2022, after having further discussions with inverter industry members about the status of inverter certifications.

Therefore, the Workgroup may need to recommend a later effective date for Maryland's smart inverter requirement. However, for the purposes of this report, the Workgroup will continue to refer to the Maryland Smart Inverter requirement effective date of January 1, 2022, until a change is approved by the Commission. The Workgroup will continue to monitor manufacturer progress in certifying smart inverters in 2021 and will be prepared to provide an update and implementation date recommendation to the Commission prior to any rulemaking initiated associated with this report.

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[41] *See* https://sunspec.org/wp-content/uploads/2021/03/CALSSA-protest-PGE-6093-SCE-4422-SDGE-3702-R21-WG2-WG-3-Feb-2021.pdf

Workgroup Recommendation for Maryland's Smart Inverter Settings Statewide Standard

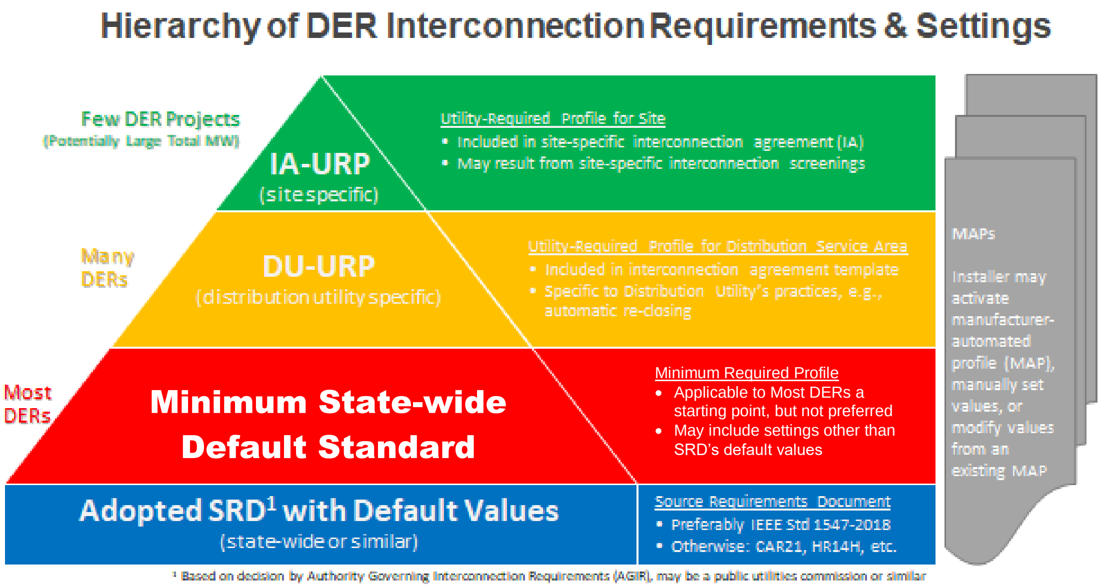
The Workgroup previously codified the following goals of smart inverter settings in RM68:

> Maryland will leverage smart inverter capabilities to optimize the safe and reliable operation of the electric distribution and transmission system.
>
> > A primary "do no harm" objective is for a small generator facility to incur no involuntary real power inverter curtailments during normal operating conditions to the extent reasonable and minimal involuntary real power curtailments during abnormal operating conditions to the extent reasonable.
> >
> > A secondary "provide benefits" objective is to increase utility electric distribution system hosting capacity and to optimize the provision of grid support services[42] to the extent reasonable.

The Hierarchy of Distributed Energy Resource ("DER") Interconnection Requirements & Settings ("EPRI Hierarchy") graphic in Figure No. 3 below is supplied from the October 2018 PJM Ride-Through Workshop materials with the approval of EPRI, but has been customized for use in Maryland.

[42] Grid support services are compensated or uncompensated services unrelated to wholesale markets provided by a small generator facility that support the safety, stability, reliability or economics of the electric grid. These services may include but are not limited to load management, backup services, non-wires alternatives for capacity, voltage support, back-tie, etc.

Figure No. 3 – Maryland Customized DER Setting Hierarchy



At its core, the EPRI Hierarchy is based on Source Requirements Documents that rely on default inverter settings values from IEEE Standard 1547-2018. The EPRI Hierarchy also describes an ideal situation where most state DGs have inverters that utilize inverter settings using a preferred Utility Required [Inverter Setting] Profile[43] ("Preferred URP"). However, in practice the Workgroup determined that a Preferred URP was not recommended to apply state-wide. While most of the Preferred URP functions and settings could be standardized across Maryland, a very narrow band of inverter functions and settings related to voltage control could not be standardized state-wide at this time. Therefore, the Workgroup customized the EPRI Hierarchy in Figure No. 3 above to replace the Preferred URP with a minimum state-wide default standard ("MSDS"). From a least common denominator perspective, a MSDS is a starting point that can apply to every unique electric utility distribution system in the state for both normal and emergency operations for every inverter spanning the wide range from small residential installations less than 20 kW to larger utility scale installations exceeding several MWs. However, the MSDS is not necessarily preferred since larger utilities in Maryland will prefer to build off these minimal requirements to customize inverter settings that optimally support their design and operations philosophies, particularly with respect to voltage regulation. The MSDS will also be particularly valuable to enable smaller Maryland utilities to interconnect smart inverters with desired minimum settings, including PJM Ride-Through settings that may not have the engineering Staff to develop their own function requirements and associated settings. Otherwise, a Maryland January 1, 2022, smart inverter requirement would not be possible.

[43] Utility required inverter setting profile means the smart inverter settings for a small generator facility that are established by a utility.

The EPRI Hierarchy also recognizes the need for a distribution utility specific default profile ("DU-URP") for inverter settings based on specific utility practices. The EPRI Hierarchy also allows for distribution utility site specific profile ("IA-URP") based on site specific interconnection studies. The EPRI Hierarchy also indicates that the DU-URP should be documented in the standard template for a utility's interconnection agreement. Where an IA-URP is needed, the utility will customize the standard interconnection agreement to reflect site-specific requirements. Maryland's interconnection regulations for adopting smart inverters and related inverter settings are based on Maryland's customization of this EPRI Hierarchy.

Furthermore, within a utility there may be a need for smart inverter settings that are site-customized depending on local considerations such as high penetrations of DGs in an area or on a feeder or if the DG will provide grid support services as a non-wires alternative. Therefore, although some DGs have inverters that will utilize the Maryland MSDS, COMAR also recognizes the need for a distribution utility specific default inverter settings profile ("DU-URP") for inverter settings based on specific utility practices and a distribution utility site specific inverter settings profile ("IA-URP") based on site specific interconnection studies. The DU-URP should be documented in a utility's interconnection agreement. Where an IA-URP is needed, the utility will customize the standard interconnection agreement to reflect site-specific requirements.

The IEEE 1547-2018 standard also defines three categories related to the response of DERs to abnormal voltage and frequency conditions that govern the DER ride-through performance. Each category has different general performance requirements:

- Category I (Ride-Through) - Based on minimal bulk electric system reliability needs and is reasonably attainable by all DER technologies, including rotating machines.

- Category II (Ride-Through) - Covers all bulk electric system reliability needs to avoid widespread DER tripping for disturbances for which the bulk system generators are expected to remain connected. Aligns with North American Electric Reliability Corporation ("NERC") Standard PRC-024-2 for Generator Frequency and Voltage Protective Relay Settings.

- Category III (Ride-Through) - Provides the highest ride-through capabilities and is designed to meet the needs of low-inertia or highly-penetrated grids.

Furthermore, the IEEE 1547- 2018 standard requires that all DERs have certain levels of voltage regulation capability. DERs are separated into two normal Operating Performance Categories, designated A and B.

- Category A (Voltage Regulation) - DERs have a set of voltage regulation capabilities that provide a minimum range of voltage regulation capabilities.

- Category B (Voltage Regulation) - DERs have an extended set of voltage capabilities designed to offset the impacts of high local penetrations of DERs or individual DERs that have outputs that are time-varying, such as DERs that provide PJM regulation market services.

The IEEE 1547- 2018 standard defines the Authority Governing Interconnection Requirements ("AGIR") as the agency that has authority for setting the requirements for interconnection to the Area Electric Power System ("EPS"). In the case of the State of Maryland, the AGIR is the Commission for approval of the Maryland MSDS. In accordance with its AGIR responsibilities, during the RM68 rulemaking proceeding the Commission codified smart inverter regulations in COMAR 20.50.09.06N that allows utilities to utilize DU-URPs and IA-URPs in lieu of a Maryland MSDS based on local design and operating needs. The functions of the AGIR that are defined in IEEE 1547-2018 are policy-oriented, including the decision regarding whether Voltage Regulation Categories A/B or Ride-Through Categories I/II/III will be required of DGs in a specific system. For the Maryland Preferred URP, the Commission will set the Voltage Regulation Categories and Ride-Through Categories. For utility DU-URPs and IA-URPs, the utility will set the Voltage Regulation Categories and Ride-Through Categories.

To guide the Commission in setting the Voltage Regulation Categories and Ride-Through Categories for the Maryland MSDS, there are some important considerations described in IEEE 1547-2018:

- "The inherent abilities of various [DG] types to achieve these performance attributes differ. In situations where [DG] penetration is high, basic levels of performance that can be readily achieved by all [DG] technologies may be insufficient to meet bulk power system ("BPS") reliability or localized power quality needs."[44]

- "[U]niversally requiring high levels of performance that are sufficient to meet BPS reliability and power quality needs in all reasonable situations would, in practice, exclude certain types of [DG] from interconnection, which is not the intent of this standard."[45]

[44] IEEE 1547-2018 Standard, p. 98.
[45] *Ibid*., p. 98.

- “However, for consistency in the levels of performance and capability, it is strongly recommended to pair [Ride-Through] Category I with [Voltage Regulation] Category A and to pair [Ride-Through] Category II and [Ride-Through] Category III with [Voltage Regulation] Category B.”[46]

Therefore, since the Maryland MSDS is a default standard that must satisfy the least common denominator, Maryland’s MSDS should require a default level of performance that should be achievable by all smart inverter based DGs in Maryland. Ride-Through Category I generally applies to synchronous and induction generators and will not be considered further for smart inverter based DERs. Therefore, the state-wide standard for all smart inverter based DGs will require a Ride-Through Category II level of performance that should be achievable by all smart inverter based DGs in Maryland. As mentioned earlier, Voltage Regulation Category B should be used with Ride-Through Category II.

When should Ride-Through Category III be utilized for DG smart inverters in Maryland? Fortunately IEEE 1547-2018 provides further guidance. “[T]he Area EPS operator [i.e., the local electric distribution utility] would perform a DER impact assessment based on anticipated [DG] deployment for the future. This assessment would consider technical conditions such as future [DG] penetration levels, [DG] power output variability, distribution system characteristics, e.g., fault-induced delayed voltage recovery (“FIDVR”) issues, feeder configuration and protection, as well as bulk system characteristics, e.g., power reserves or future system inertia.”[47] In view of the increasing DG penetration forecast in Maryland in the future to achieve RPS goals, if a DG can achieve Ride-Through Category III performance, this will be desirable as long as the DG project’s smart inverter can meet this level of performance. The large investor owned utilities in Maryland have expressed a desire to utilize Ride-Through Category III to support bulk power system reliability primarily because Category III utilities momentary cessation during abnormal voltage and frequency events, whereas Category II does not. Momentary cessation is the cessation of energization without physically disconnecting from the grid for the duration of a disturbance thereby allowing a DG smart inverter to ride-through the event with more rapid energy recovery than Ride-Through Category II when voltage or frequency return to a defined range.

This begs the question, why does Maryland not utilize Ride-Through Category III in the MSDS? As mentioned earlier, Maryland’s default standard that must satisfy the least common denominator. Since over 2.3 million of Maryland’s approximately 2.6 million electric customers are investor owned utility customers, approximately 90 percent of the State's inverters will likely use Category III even if Maryland’s co-operative and municipal utilities did not develop their own DU-URPs. The larger utilities have more access to engineering staff and resources to evaluate inverter models for acceptability than the State’s smaller utilities. Category II performance will be achievable by all

[46] *Ibid*., p. 100.
[47] *Ibid*., p. 99.

certified smart inverter based DGs thereby requiring less intervention and allowing the Maryland MSDS to essentially be "plug and play." On the other hand there may be some cheaper certified smart inverters on the market that cannot achieve Category III performance, which will require more intervention and analysis by utility engineers for approval. Therefore, despite a utility specifying Category III in their MSDS, a DG smart inverter's inability to utilize Ride-Through Category III performance should not be a reason to automatically deny an interconnection request unless a utility's impact assessment in the interconnection request approval process requires this level of DG performance. In other words, utilities with DU-URPs should set their standard as Category III, but allow exceptions. If a utility uses a DU-URP, the utility shall determine whether the smart inverter model is approved for Category II or Category III frequency ride-through performance requirements, with Category III as the default. COMAR 20.50.09.09N currently requires a list of acceptable smart inverter models to be published on a utility's website. Utilities feel this regulation will be cumbersome to manage due to the plethora of manufacturers and models expected in the future. Therefore, the Workgroup proposes that the existing regulation be modified to only require utilities to publish a list of smart inverters that are not approved.

Table No. 3 below describes the Workgroup's vision for applying IEEE 1547-2018 Ride-Through and Voltage Regulation Performance Categories in Maryland in different scenarios.

Table No. 3 – Maryland Performance Category Scenarios

Scenario	Ride-Through Performance Category	Voltage Regulation Performance Category	Comments
Not Applicable to Smart Inverter Based DGs in MD	Category I	Category A	Generally applicable to synchronous and induction generators, not smart inverters
MD MSDS	Category II	Category B	Default level of performance that should be achievable by all smart inverter based DGs in Maryland
DU-URP Performance	Category III[48]	Category B	Default level of performance unless the DG smart inverter is acceptable, but incapable of Category III performance.

[48] COMAR 20.50.09.09N requires a list of acceptable smart inverter models to be published on a utility's website. Any smart inverter models that are approved exceptions to the Category III requirement should also be listed.

IA-URP Performance	Category III[37]	Category B	Default level of performance unless the DG smart inverter is acceptable, but incapable of Category III performance.

A list of IEEE 1547-2018 smart inverter functions that were deemed important for Maryland utilities and their associated inverter setting policies and defaults in a state-wide standard agreed by the Workgroup are listed in Table No. 4 below:

Table No. 4 – Maryland MSDS

Function	Description	Default Activation Status	Settings
Anti-Islanding	Refers to the ability to detect loss of utility source and cease to energize	Activated	Trip within 2 seconds of the formation of an unintentional island.
Constant Power Factor Mode	Refers to power factor set to a fixed value.	Activated, if no other voltage control mode is Activated	Unity Power Factor The "Do No Harm" objective supports unity power factor as a default for normal COMAR 20.50.07.02 voltage levels (i.e., +/- 5% of nominal voltage).
Voltage / Reactive Power Mode (Volt - Var)	Refers to control of reactive power output as a function of voltage.	Deactivated	Not applicable to MSDS but the DU-URP and IA-URPs may include this mode as needed.
Enter Service Criteria	Refers to applicable system voltage, frequency and synchronization parameters when entering service and performance (i.e., ramp rate) during entering service	Activated	Adopt IEEE 1547-2018 Enter Service Ramp Rate Default Settings in Section 4.10 of IEEE 1547-2018. When entering service, the DER shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in the defaults on Table 4 on page 33 of IEEE 1547-2018. The DG performance (i.e., ramp rate) defaults during entering service are specified in Section 4.10.3 of IEEE 1547-2018 on pages 33-34. The synchronization parameter limits for synchronous interconnection when entering service are specified in Table 5 of IEEE 1547-2018 on page 35.

Voltage Ride Through	Refers to ability of smart inverter to ride through a certain range of voltages before tripping off.	Activated	See Attachment B - PJM Guideline for Ride Through Performance of Distribution-Connected Generators (Revision 2, Q4, 2019) - Requirements embedded in the Over-voltage ("OV"), Under-voltage ("UV"), Over-frequency ("OF") and Under-frequency ("UF") settings. Momentary Cessation is an inverter operating state where both active current and reactive current go to zero output. Momentary Cessation is required for Category III equipment.
Frequency Ride Through	Refers to ability of smart inverter to ride through a certain range of frequencies before tripping off.	Activated	
Voltage - Active Power Mode (Volt - Watt)	Refers to control of real power output as a function of voltage.	Deactivated	Not applicable to MSDS but the DU-URP and IA-URPs may include this mode as needed.
Constant Reactive Power Mode	Refers to reactive power set to a fixed value.	Deactivated	Not applicable to MSDS but the DU-URP and IA-URPs may include this mode as needed.
Frequency - Droop (Frequency - Power)	Refers to control of real power as a function of frequency.	Activated	Adopt IEEE 1547-2018 default settings in Table 24 on page 60. This function is mandatory for Category II and Category III Ride-Through Performance in IEEE 1547-2018.
Active Power / Reactive Power Mode (Watt -Var)	Refers to the control of reactive power as a function of real power.	Deactivated	Not applicable to MSDS but the DU-URP and IA-URPs may include this mode as needed.
All Other Inverter Settings	Refers to any inverter settings/ activation status not covered in Table No. 4	N/A	See applicable defaults in IEEE 1547-2018

Alternatives Evaluated for the Maryland MSDS

On March 23, 2021 the Workgroup held a workshop to consider the Exelon and FirstEnergy ("Maryland IOU") recommendations for a Maryland Preferred URP. Consensus was achieved for several of the settings recommendations except for the Maryland IOU recommendations regarding voltage control, particularly the Maryland IOU's recommendations for the use of the Constant Power Factor Mode at unity power factor for normal conditions with activation of the Voltage - Active Power Mode (Volt - Watt) at 1.06 per unit (i.e., 127.2 volts on a 120 volt system) when high voltages above COMAR limits are present to help control abnormal voltages and protect the inverters. The Maryland IOU rationale behind the recommendations were to utilize unity power factor in normal voltage ranges which essentially means that the DGs are not providing any reactive power and therefore voltage support to the grid. This is essentially the situation today for a majority of existing DGs with "dumb inverters." Utility voltage planning does not benefit from these DGs and also since hosting capacity can be increased by reactive power support to the grid, there are no hosting capacity benefits to help accommodate larger DG grid interconnections without upgrades. While increasing hosting capacity is Maryland's secondary "provide benefits" objective mentioned earlier, the Maryland IOU recommendation was based on Maryland's primary "do no harm" objective for a small generator facility to incur no involuntary real power inverter curtailments during normal operating conditions to the extent reasonable and minimal involuntary real power curtailments during abnormal operating conditions to the extent reasonable.

The Maryland IOUs are currently engaged with EPRI in collaboration with other EPRI member utilities in an EPRI Model Based Analysis of DER Functions and Settings ("MBADFS") ongoing research project that will further inform their recommendations for voltage control inverter settings, both for the Maryland MSDS and for their own DU-URPs. Although the Maryland IOUs have not committed to a schedule when they will have a recommendation based on the EPRI study, it is like at least six months to a year away. Therefore, the Maryland IOU recommendation essentially extends today's "dumb inverter" mode for normal voltage control until they can make more informed recommendations. While in a perfect world, the Maryland IOUs would have an EPRI informed decision for normal voltage control at this time, in the spirit of the primary "Do No Harm" objective the utilities Constant Power Factor Mode at unity power factor recommendation extends today's "dumb inverter" a little further into the future. This will enable Maryland to still achieve other smart inverter benefits such as implementing PJM's voltage and frequency ride-through settings which will improve grid reliability. In summary, for normal voltage ranges the utility recommendation is no worse than the situation that exists today but with the added benefit of implementing other smart inverter features.

While the previous discussion has been centered on voltage control during normal operations within normal voltage ranges, there was even less consensus regarding the Maryland IOU's recommendations for voltage control during abnormal operations, particularly during high voltage scenarios. The IEEE Standard defines normal operating conditions as the continuous operation region when the voltage is between 0.88 and 1.1 times the nominal voltage, or between 0.88 and 1.1 per unit. In North America, the nominal distribution voltage is 120 volts. Applying the definition of the IEEE Standard means normal operating conditions in North America are when the voltage is between 105.6 and 132 volts in order to account to behind the meter voltage drop. During abnormal high voltages above 1.06 per unit the Maryland IOUs recommended that Volt – Watt mode kick-in to both protect the smart inverters and also provide some support to lower system voltages. The measurement accuracy required by IEEE 1547-2018 is 1 percent, so in the worst case an inverter could go into Volt-Watt reduction at 1.05 per unit. Inverter self-protection will trip most inverters before reaching 1.10 per unit (i.e., 132 volts on a 120 volt system). However, some other workshop participants did not favor using Volt-Watt mode, particularly because this could result in an energy reduction from the DER since the Volt-Watt mode will reduce DG output when activated at high voltage likely due to a behind the meter voltage drop. The Workgroup entertained different discussions and anecdotal scenarios about the trade-offs and the pros and cons, but no conclusive evidence or studies were immediately available to support either side of the debate. Some stakeholders argued that inverters tripping due to high voltage in the industry was rare whereas energy curtailments were more frequent in states like California[49] that have already implemented inverters with some smart inverter features, including Volt-Watt. Other stakeholders argued that while Volt-Watt mode was fine in certain situations to help accommodate larger DGs, it should be an exception and not as state-wide standard. Other stakeholders argued that we should rely on the Voltage / Reactive Power Mode (Volt-Var) for normal and abnormal voltage ranges to provide better voltage support for both normal and emergency operations. Other stakeholders countered that Volt–Var mode was not as aggressive as Volt – Watt mode in an emergency situation. The utility opinion is that wide-spread Volt-Var deployment is inconclusive at best, and at worst causes grid problems in certain situations. Therefore, utilities advocate taking a cautious approach now. The utilities maintain that research in this area does not provide definitive results, while other stakeholders disagree.

Some stakeholders have advocated that given that there is no research on the utilization of Volt-Watt without Volt-Var activated, Maryland should consider following the pathway required by Hawaiian Electric[50] to develop a pilot testing program of the Volt-Watt function to ensure consumer protection and utility learnings on the benefits of advanced inverter functions as interconnection mitigation alternative available to customers during the interconnection process. California is the first state to require the use of the Volt-Watt function for all distributed solar customers. However, stakeholders in California petitioned to ensure there is a system in place to monitor curtailments for customers as a result of this function. These reporting requirements took place in February 2021. To this end, these stakeholders propose that if a utility utilizes Volt-Watt in the future without Volt–VAR activated, that there be reporting requirement to provide the number of DER curtailments it has investigated, resolved and are still pending due to high voltage in annual small generator interconnection reports filed with the Commission to determine if this issue needs corrective action. Some utility stakeholders opposed the burden of this additional reporting requirement. In the end, additional reporting requirements to capture DG curtailments were included in the Workgroup proposal that is described later in this report. This is a non-consensus Workgroup proposal.

In the end, there was no consensus in the Workgroup on the Maryland IOU's recommendations for voltage control settings. So where does that leave us with respect to the Maryland MSDS which is needed to meet our January 1, 2022 smart inverter requirement? Essentially there are four options, but only three are realistic to implement in time to meet our January 1, 2022, smart inverter requirement.

1. Implement the Maryland IOU recommendation for Maryland's MSDS;

[49] *See* https://library.sce.com/content/dam/sce-doclib/public/regulatory/filings/pending/electric/ELECTRIC_4445-E.pdf
[50] https://www.nrel.gov/docs/fy19osti/72298.pdf

2. Implement the Maryland IOU recommendation for Maryland's MSDS without Volt-Watt Mode Activated;
3. Implement the Maryland IOU recommendation for Maryland's MSDS with another voltage control settings recommendation (e.g., Volt-Var); or
4. Delay Maryland's January 1, 2022 smart inverter requirement until January 1, 2023 to allow time for the Maryland IOUs to incorporate the impacts of the EPRI MBADFS project into their MSDS settings recommendations and their DU-URP.

Option No. 3 is not practical because the Maryland IOU's do not feel comfortable making a Volt–Var mode recommendation until the EPRI MBADFS Project is further along. Option No. 4 is not desired because this will delay Maryland's implementation of other smart inverter features. Option No. 1 does not have consensus due to the consumer protection concerns highlighted in the aforementioned discussion.

The Workgroup concludes that implementing Option No. 2 which is the Maryland IOU recommendation without Volt-Watt mode for Maryland's MSDS is the preferred alternative since it defers the controversy associated with the pros and cons of Volt-Watt and allows the Workgroup to reach near-consensus on Maryland's MSDS, which is a vital prerequisite to achieving our January 1, 2022 smart inverter requirement.

Several Workgroup stakeholders also desire that the utilities establish their DU-URPs by January 1, 2022. However, the utilities cannot commit to establish their DU-URPs by a specific deadline and will likely utilize the MSDS in the interim. Also some utilities indicate that they may still pursue Volt-Watt as a DU-URP at least until they can develop an EPRI research informed voltage control methodology in their DU-URPs. Several Workgroup stakeholders indicate they will likely oppose use of Volt-Watt in a DU-URP, unless paired with other voltage control functions that benefit system active voltage control, namely Volt-Var mode. These stakeholders have requested that the Commission should approve DU-URPs, as in other States like Hawaii and California, in the Commission's Administrative Docket. Therefore regulations will be proposed in COMAR 20.50.09.06N to require DU-URPs be included in utility electric service tariffs if the utility is not utilizing the MSDS. These DU-URPs should be documented at a high level similar to Table No. 4 in this report. Since there are well over 100 different inverter settings in IEEE-1547-2018, these electric service tariffs should specify where DU-URP functions and associated settings differ from defaults. Utilities are required by regulation to publicly file their proposed tariff changes. These changes will then be approved by the Commission as part of the Administrative Docket, where Staff and intervenors are afforded the opportunity to comment and provide alternative recommendations. The utilities oppose this proposal and maintain it is their right to determine specific technical parameters for their design and operations.

Therefore, the issue of requiring the utilities to establish their DU-URPs by January 1, 2022, and publishing these DU-URPs in electric service tariffs are a non-consensus policy question for which the Workgroup seeks Commission direction.

While the MSDS is fully developed with respect to other IEEE 1547-2018 functions and settings, the MSDS is an interim standard for voltage control functions until further EPRI MBADFS research concludes. To assist the Commission fulfill its AGIR responsibilities to move the MSDS from an interim standard to a final standard, the Workgroup will revisit the MSDS recommendation after the utilities have further developed their DU-URPs at the conclusion of the EPRI MBADFS. There is no need to codify MSDS approval regulations that are similar to proposed DU-URP approvals in COMAR, because by definition in IEEE 1547-2018, the AGIR sets the MSDS requirements.

In Phase II the Workgroup did not recommend codifying the Maryland MSDS in COMAR since regulations are not the appropriate place to maintain detailed technical requirements which may change time to time. For instance, an amendment to IEEE 1547-2018 has already been approved on April 15, 2020.[51] The Workgroup also notes that since the Maryland MSDS individual settings are not codified directly in COMAR, this does not affect other regulation changes proposed by the Workgroup.

The Workgroup will continue to work to move the Maryland MSDS proposal from interim to final state after the EPRI MBADFS Project concludes. It is also anticipated that over time there will always be a need to modify the statewide standard due to standard amendments at the national level or utility, customer and other stakeholder experiences with smart inverters. The Workgroup will need to develop a "living process" to enable stakeholder engagement to communicate and change MSDS changes over time.

Implementing Maryland's January 1, 2022 Smart Inverter Requirement - Next Steps

The Workgroup proposed new smart inverters state-wide settings to be used to interconnect with Maryland utility distribution systems after January 1, 2022. Therefore, ideally Maryland's MSDS should be approved well in advance of January 1, 2022 to allow the Maryland MSDS to be implemented by smart inverter manufacturers for Maryland interconnection customers before the Maryland smart inverter requirement goes into effect. As mentioned earlier, the Workgroup will continue to monitor manufacturer progress in certifying smart inverters in 2021 to ensure that Maryland's January 1, 2022, smart inverter requirement can be implemented on-time. Otherwise the Workgroup may need to petition the Commission for a temporary waiver of COMAR 20.50.09.06N[52] or, alternatively, adjust the January 1, 2022, smart inverter requirement in a rulemaking to reflect the new date.

[51] IEEE 1547a-2020 revises the ranges of allowable trip clearing time settings for DERs in abnormal operating performance category III to allow wider ranges to broaden and simplify the adoption of the standard by adopting Category III ride-through capability with Category II default trip settings.

[52] *See* COMAR 20.50.09.06N(1): After January 1, 2022, any small generator facility requiring an inverter that submits an interconnection request shall use a smart inverter with either a default or a site-specific utility required inverter settings profile, as determined by a utility.

While current Maryland regulations are adequate with regard to requirements for lab-certified and field-approved equipment in COMAR 20.50.09.07, utilities should also publish a list of unapproved smart inverters on their interconnection webpages per a proposed change to COMAR 20.50.09.06N(9).

The Workgroup is still exploring how to ensure that inverter manufacturers and DER developers / installers will be notified of the Maryland MSDS. Utilities are also encouraged to perform outreach to educate DG developers / installers of the new requirements. Manufacturers and installers today have to interpret inverter trip/functional settings listed in rules or technical documents.

Concomitant with determining a Maryland MSDS will be a need to determine both where default inverter settings profiles will be stored and also a protocol for utility to installer inverter settings communication going forward. Representatives on our Workgroup from the Maryland IOUs are enthusiastic about the role that the EPRI Smart Inverter Configuration and Settings Tool Project can play in solving this issue. This EPRI initiative will standardize file structures for IEEE 1547.1. A standardized file structure format in a comma-separated-values ("CSV") file will allow manufacturers to easily translate the state-wide and utility specific inverter settings profiles into programmed settings in the future. These inverters ideally would be able to download the settings directly in the standardized format, eliminating errors and speeding commissioning. Since this is an EPRI Smart Inverter Configuration and Settings Tool funded by the EPRI participants, there are still some questions EPRI needs to resolve to make this tool available to non-EPRI members.

After a Maryland MSDS has been established, the Workgroup proposes that a settings file in the EPRI standardized format be posted and maintained by the Commission's Engineering Division on the Commission's website. The Maryland MSDS should also be available in the EPRI Inverter Settings Database. Utilities should also post their utility specific inverter settings profiles (i.e., DU-URP) profile on their websites and electric service tariffs per the proposed COMAR 20.50.09.06N(8). In some cases, especially for smaller Maryland utilities as mentioned earlier, the Maryland MSDS may be the same as their DU-URP.

There is also utility change management needed to incorporate smart inverters requirements into the utility interconnection request and technical review process. COMAR 20.50.09.04B specifies that "an interconnection request shall be in the form and format specified by the utility that owns the electric distribution system to which interconnection is sought and shall include the following information and any additional information that may be reasonably requested by the utility." Utilities will need to modify their interconnection request templates to collect additional smart inverter information. The applicant will need to verify that the inverter to be used is a smart inverter. There is no need to further modify the COMAR 20.50.09.04 Interconnection Request section to add this additional template information since this requirement is covered by the existing 20.50.09.04B(8) requirement that the interconnection request contain "Technical information regarding the interconnection components and system or systems."

If utilities use inverter settings, such as Volt-Watt, that are capable of curtailing DERs, they should provide the interconnection customer information during the interconnection request process about the potential for curtailing DGs during emergency high voltage situations, along with a process for communicating with the utility if there are repeated occurrences. While a DG curtailment can occur occasionally happen for an unusual event, repeated occurrences need to be investigated. Utilities should develop processes to for problem investigation and mitigation, leveraging Advanced Meter Infrastructure ("AMI") data if available.

Utilities should also consider adding wording in their Interconnection Agreements to reference the initial inverter settings and clauses to allow these settings to be changes periodically, if necessary. Utilities also need to verify that the correct settings have been used. This could be a utility employee during the witness test or they may use an IEEE certified commissioning agent to submit a commissioning report to the utility. IEEE is working on this certification process now to provide protocols for standardized commissioning reports and qualified agents. Utilities note that it will be very challenging to roll a truck to every smart inverter to verify and change the settings in the future unless utilities have ways of doing this remotely through communication links with DGs and this issue needs to be considered as a "use case" in Phase IV of the Workgroup's efforts for monitoring and control.

The utility's technical review and study process will also need to identify the inverter settings profile that should be used per COMAR 20.50.09.06N(1). If the utility does not have a DU-URP established, the Maryland MSDS should be used unless there is a reason that a utility site-specific (i.e., IA-URP) inverter settings profile should be used per COMAR 20.50.09.06N(6). The Interconnection Agreement between the utility and interconnection customer should also incorporate references to the inverter settings profile utilized per COMAR 20.50.09.06N(8). The utility commissioning and witness testing process and "Permission to Operate" ("PTO") approval should incorporate a review of the inverter settings profile. Therefore, COMAR 20.50.09.06K Witness Test of Small Generator Facility should be amended to require this satisfactory review for a PTO.

<u>Smart Inverter Proposed Regulation Modifications</u>

The Workgroup is proposing the following regulation update to COMAR 20.50.02.02 (*see* Appendix C) to adopt the latest applicable IEEE and UL standards:

- Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, IEEE 1547-2018 and Amendment 1547a-2020;

- IEEE 1547.1-2020, Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces; and

- UL Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, UL Standard 1741, Edition Date: September 16, 2020.

The Workgroup is proposing the following regulation update to COMAR 20.50.09.06K (*see* Appendix C) to require that DG inverters meet Maryland's smart inverter requirements after January 1, 2022:

- The applicant shall demonstrate that it meets the smart inverter requirements of §N of this regulation, if applicable.

The Workgroup is proposing the following regulation update to COMAR 20.50.09.06N(8) (*see* Appendix C) to require utility DU-URPs be described in utility electric service tariffs.

- A default utility required inverter settings profile shall be published on the utility's website. If the default utility required inverter settings profile is different from the statewide utility required inverter settings profile it shall be published in the utility's electric service tariff.

The Workgroup is proposing the following regulation update to COMAR 20.50.09.06N(9) (*see* Appendix C) to clarify utility smart inverter approval requirements for Category II and Category III frequency ride-through performance requirements.

- A list of unacceptable smart inverters shall be published on a utility's website.

The Workgroup is proposing the following regulation update to COMAR 20.50.09.14 (*see* Appendix C) to add reporting requirements for DG smart inverter related curtailment complaints.

- Beginning April 1, 2023, a utility shall also report for the electric distribution system annually for the previous year:
    - Number of total interconnection customer complaints about smart inverter related curtailments
    - Number of smart inverter related curtailment interconnection customer complaints resolved by utility
    - Number of smart inverter related curtailment interconnection customer complaints resolved by customer
    - Number of smart inverter related interconnection customer curtailment complaints unresolved

V. Utility Monitoring and Control Plans

IEEE 1547-2018 compliant smart inverters are capable of two-way communication. This provides the opportunity for monitoring or active control of an inverter by a utility or by DER aggregators that can further optimize the operation of the electric distribution system and provide market services, respectively. Realizing that this opportunity requires the development of utility control system and strategy by the utility (such systems are often called Distributed Energy Resource Management Systems ("DERMS") and requires the development of a secure, low-cost communication channel between utilities and inverters. Secure, low-cost communications offer the possibility of self-joining and self-identification capabilities with future DGs. Another benefit of secure, low-cost communications is to speed part of the initialization process for a new inverter, when it first communicates with a utility to download any MSDS, DU-URP or IA-URP smart inverter settings directly. This would allow the utility the ability to confirm that the correct smart inverter settings have been applied to the smart inverter in a process sometimes called DG registration. In addition, communication with these smart inverters will allow the exchange of real-time or near-real-time DG information that may benefit future utility operations and DER aggregator's participation in PJM markets as envisioned in FERC Order No. 2222.

Utility monitoring and control of a jurisdictional DG in Maryland is only required for small generator facilities 2 MWs or greater, unless agreed by the generator. Existing COMAR 20.50.09.06J regulations also now allow the Commission to request utilities to submit a utility monitoring or control plan for Commission approval addressing facilities under 2 MW in the aggregate. Aggregate means that utilities will not present a plan for Commission approval for each small generator facility individually, but for a set of small generator facilities in multiple locations. These utility proposals should come forward in a process that allows full notice and opportunity for stakeholders to comment. These plans submitted to the Commission would presumably propose the applicable generator size ranges, the conditions under which utility monitoring and control plans would apply, the range of potential per-site costs to pre-existing and new small generator facilities, a cost recovery method,[53] the benefits to customers and the cost effectiveness of the plan.

During the RM68 hearing for Phase II, the following concerns were expressed:

1. Should utilities be allowed to install control/ communication cards in customer inverters as part of a utility monitoring and control plan versus other communication solutions, such as the internet, in accordance with IEEE 1547-2018?

[53] A cost recovery method should include a proposal for how the utility will recover its costs, by rate base or other methods, to fund a utility monitoring and control plan, including how much cost should be borne by interconnection customers. While a utility can present a plan for future DERs, a cost recovery plan must also address who pays for pre-existing installations.

2. How is customer permission for a utility monitoring and control plan envisioned?

3. How is cyber-security for DG monitoring and control handled?

These questions are still be considered by the Workgroup. Several emergent initiatives will delay our utility monitoring and control regulation proposal to the Commission.

First, IEEE 1547-2018 does not define requirements for cybersecurity. Various standard development organizations like UL, the International Organization for Standardization and the International Electro-technical Commission have developed standards for cybersecurity for "smart energy" systems, but not explicitly for DGs meeting the IEEE 1547-2018 requirements. The industry is also learning from field and lab experiences. New vulnerabilities and potential threats are being discovered as more DGs are evaluated. Therefore, IEEE 1547.3-2007 is being updated to provide guidance by referring to the cybersecurity features available in existing protocols along with new cybersecurity concepts and technologies that have been developed over recent years. The Project Title is "Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems." The expected date of submission of the Draft for Initial Ballot is July 2021. The projected completion date for submittal to the IEEE Standards Board Review Committee ("REVCOM") is December 2021. There is also a NARUC/ NASEO Cybersecurity Advisory Team for State Solar ("CATSS") that is currently working to develop a state policy framework for DER cybersecurity. Maryland interconnection regulations should require DER compliance with the IEEE 1547.3 Revision once it is updated and also consider any state policy framework recommendations from CATSS.

Second, FERC Order No. 2222 allows DER aggregations to participate directly in Regional Transmission Operator ("RTO") / Independent System operator ("ISO") markets. FERC Order No. 2222 does not preempt state regulation of safety and reliability of the distribution systems. Also state jurisdiction over retail rates, distribution system planning and operations, DG siting and interconnection remain. While FERC Order No. 2222 recognizes state authority over DG interconnections for DER aggregations, there are some complex issues involving DER information and data requirements, metering and telemetry requirements and operations coordination between the RTO/ISO, the DER aggregator, the electric distribution utility and the relevant electric retail regulatory authorities that need to be resolved. Maryland may need to update interconnection processes to assess impacts of aggregations on the distribution system at the initial interconnection stage and for distribution system impact studies when a DG joins an aggregation. The Workgroup will need to reconsider our monitoring and control regulations to reflect PJM and utility metering and telemetry requirements for

DERs in aggregations. PJM is currently evaluating internet based SCADA[54] solutions as opposed to proprietary utility control and monitoring solutions.

In its initial strawman proposal discussed on March 31, 2021, PJM proposes to dispatch and monitor operations data from DER aggregators directly. DGs will need to have communications with the DER aggregator to be monitored and dispatched by PJM through the aggregator. For instance, if a residential solar customer was included in a DER aggregation, this would be summed with other smaller systems to form one aggregated DER for purposes of market participation. In their initial strawman proposal, PJM is not prescriptive about communications beyond their requirements for communicating with the DER aggregators. PJM will require aggregators to communicate with them using an internet SCADA software product such as “Jetstream”, which PJM currently uses for load management aggregator communication, or the PJM Inter-Control Center Communications Protocol (“ICCP”) link at scan rates prescribed based on the market they participate in (e.g., 2 seconds, 10 seconds or 1 minute). The strawman proposal is not prescriptive on the method of communication between a DER or aggregator and a utility. The PJM strawman proposes this be defined on a utility-by-utility basis. Therefore, this PJM strawman proposal leaves unanswered other questions regarding utility to aggregator communications, utility to DG communications, DG to aggregator communications and individual customer communications required to be considered part of an aggregated DER. Some of these requirements could potentially be codified in COMAR.

The goal of the Workgroup is to work on these and other aforementioned open questions to ensure that Maryland control and monitoring regulations facilitate DER aggregation, or at least do not impede it. PJM has recently petitioned FERC for an extension for a required compliance filing for FERC Order No. 2222. On April 9, 2021 FERC granted PJM's extension request and accordingly the new due date of PJM’s Order No. 2222 compliance filing is February 1, 2022.

In summary, resolution of these DER cybersecurity and FERC Order No. 2222 issues will need to be considered for impacts to our utility monitoring and control regulations in COMAR. Since these efforts are still underway, the Workgroup will need to defer any utility monitoring and control regulation proposal to a Phase IV, should the Commission approve to extend the Workgroup.

[54] SCADA is an acronym for supervisory control and data acquisition. SCADA systems are used to monitor and control equipment in industries such as electric, gas, telecommunications, water, etc.

VI. Conclusions

In the notice forming the Workgroup, the Commission stated that "Interconnecting to the electric grid should be as smooth as possible for both residential and commercial solar generating systems." Specifically, the Commission listed the following Workgroup objectives:

1. Completing a rulemaking applying residential solar interconnection standards statewide to ensure that the interconnect process is timely, electronic and customer-friendly, using Condition 16[55] of the Exelon-PHI merger decision as the starting point of discussions [Commission Action No. 1];
2. Exploring whether it should [be] required or encouraged that each newly interconnected solar generating system connect to the electric grid with a smart inverter [Commission Action No. 2];
3. Ensuring that the interconnection application process for non-residential solar projects is timely, electronic and customer-friendly [Commission Action No. 3];
4. Developing a specified plan and timeline for each utility to publish feasible and useful hosting capacity maps similar to those produced by PHI in its December 9, 2016 comments [Commission Action No. 4]; and
5. Reviewing whether cost allocation and system capacity issues regarding interconnection of large and mid-size solar facilities that use a significant amount of a distribution system component's remaining capacity restrict other projects from grid access or unfairly burden them with system upgrade costs [Commission Action No. 5].

The regulations adopted in Phase I for energy storage integration into interconnection regulations, interconnection application process automation, small generator facility size applicable to a streamlined application process, closing the interconnection process "donut hole," pre-application interconnection reports and interconnection queues have already resulted in an interconnection process that is more timely, electronic and customer-friendly [Commission Action No. 1 and No. 3]. Phase II also includes proposals for hosting capacity and flexible interconnection options for energy storage that will provide further value to interconnection customers. A smart inverter implementation vision and plan for Maryland has been proposed in Phase II and Phase III with a further study effort recommended in Phase IV effort [Commission Action No. 2]. Regulations addressing hosting capacity and useful maps are also proposed in Phase II [Commission Action No. 4]. Also, cost allocation and system capacity issues regarding interconnection

[55] Case No. 9361, Order No. 86990 dated May 15, 2015, Appendix A, pages A20 - A23, Enhancements to Interconnection Process for Behind-the-Meter Small Distributed Generation in Maryland. This requirement includes hosting capacity maps and acceptable inverters and various reporting requirements.

have been addressed [Commission Action No. 5] with interconnection cost and hosting capacity proposals in Phase II and Phase III with a further study effort recommended in Phase IV effort. In addition, several other interconnection topics such as interconnection jurisdiction, interconnection fees and other miscellaneous regulation modifications have also been addressed. A list of Phase I, II and III topics addressed by the Workgroup is highlighted below:

1. Energy Storage Integration into Interconnection Regulations (Phase I)
2. Interconnection Application Process Automation (Phase I)
3. Small Generator Facility Size Applicable to Streamlined Application Process (Phase I)
4. Interconnection Process Jurisdiction "Donut Hole" (Phase I)
5. Pre-Application Interconnection Report Requirements (Phase I)
6. Interconnection Queue Requirements (Phase I)
7. Interconnection Jurisdiction (Phase II & Phase III)
8. Interconnection Application Fees (Phase II)
9. Interconnection Facility Cost Allocation (Phase II & III)
10. Flexible Interconnection Options for Energy Storage (Phase II)
11. Hosting Capacity (Phase II and Phase III)
12. Smart Inverters (Phase I, II and III)
13. Utility Monitoring & Control (Phase I, II and III)
14. Miscellaneous Regulation Modifications (Phase II)
15. Interconnection Process Reporting (Phase I , II and III)

The Workgroup achieved broad consensus or near-consensus on many issues in Phase III. Notwithstanding any areas of non-consensus that may be raised further by stakeholders before or during a prospective rulemaking session on Phase III, there are several non-consensus policy questions for which the Workgroup seeks Commission direction.

The Workgroup's Interconnection Jurisdiction proposed regulations are a consensus recommendation. The Workgroup also has consensus that our utility monitoring and control efforts need to be extended to consider the future impacts of the FERC Order No. 2222 implementation, IEEE cybersecurity standards and the NARUC/NASEO State Policy framework initiative for DER cybersecurity.

The Workgroup's Interconnection Facility Cost proposal and associated regulations are a non-consensus recommendation.

The Workgroup's proposal for upgrade cost allocation using a MCAM is a hybrid model that incorporates features of the aforementioned Field of Dreams Model and the Tariff Fee Model that are customized to as consistent as possible with traditional Maryland ratemaking principles.

The MCAM will require eligible interconnection customer projects benefiting from an upgrade, to pay a prorated portion of required hosting capacity project upgrade costs based on the fraction of their equipment capacity to the total equipment capacity of the project. The cost sharing cycle is ended when the non-embedded capacity provided by the upgrade is fully allocated or when a new project requires a subsequent HC upgrade and cost sharing is reset.

The MCAM also implements a regulation framework for hosting capacity fees in utility tariffs, if needed, to balance non-embedded hosting capacity upgrade project cost risk between interconnection customers and ratepayers.

The Workgroup ratepayer advocate stakeholders have expressed concerns about rate recovery being left unaddressed in the MCAM framework and the process for developing and triggering IC Fees not being more defined in the MCAM framework. DG advocates while in favor of the MCAM cost allocation to reduce upfront cost impacts on first Mover DGs, are wary about potential cost impacts to other ICs through IC Fees and subsequent cost allocation. The utilities have expressed concerns about the complexity of MCAM process implementation, the associated reporting and the ability to implement their preferred method for cost recovery. The Workgroup is also proposing a non-consensus provision in COMAR to allow forfeited study and milestone payments in excess of utility cost for a cancelled electric distribution upgrade project to be used to off-set future utility revenue requirements.

The Workgroup leader notes that while no stakeholder has indicated the MCAM proposal is a non-starter, several of these stakeholders feel that this effort would benefit from collecting more information before implementation and providing more detailed answers to potential questions regarding IC Fees.

Specifically, more information could be compiled by utilities going forward on how frequently the MCAM would potentially be used and how many interconnection projects were abandoned due to upgrade costs. Other information could potentially be tracked by utilities on future upgrade capacity and associated costs in excess of interconnection customer needs and how long it takes for this upgrade capacity to be used annually. This information could be utilized to set cost and time boundaries on accumulating unallocated upgrade costs to study the potential IC Fees. Other information could be collected on situations where a utility would desire to increase upgrade capacity beyond the needs of an interconnection customer based on DER forecasts, but is limited to right-sizing a HC upgrade, to determine the number of missed opportunities to preemptively increase upgrade capacity. More information could also be collected on forfeited study and milestone payments in excess of utility cost for a cancelled electric distribution upgrade projects to determine the frequency of this occurrence.

In short, a continuing study effort would ensure that the implementation of Interconnection Facility Cost regulations and associated process changes by utilities would not be a “solution in search of a problem” since the utilities have indicated anecdotally that cost allocation has not been a significant problem to date. However, as DG penetrations increase in the future this could become a larger obstacle in the future.

The MSDS is the "Statewide utility required inverter settings profile" defined in COMAR 20.50.09.06N(3) .[56] The initial Workgroup MSDS proposal as described in Table No. 4 of the Workgroup's report is an interim proposal until superseded but still can be used by utilities to satisfy their COMAR 20.50.09.06N(3) default utility required inverter settings profile requirements.

There is consensus in the Workgroup to adopt our interim MSDS proposal to be effective on a future date to be proposed by the Workgroup. The Workgroup will continue to monitor manufacturer progress in certifying smart inverters in 2021 and will be prepared to provide an update and implementation date recommendation to the Commission prior to any rulemaking initiated associated with this report. This interim MSDS will be beneficial to incorporate PJM's ride-through recommendations to protect the bulk power system, and other settings valuable to system performance and safety (e.g., anti-islanding, enter service and frequency droop). The Workgroup's Smart Inverter proposals, however, contain non-consensus elements. Various Workgroup stakeholders request the Commission to order the utilities to establish their DU-URPs by January 1, 2022, or file requests with the Commission to extend the due date for establishing their DU-URPs and publishing these DU-URPs in electric service tariffs in order that subsequent changes will be filed publicly and considered in a public hearing in the Commission's Administrative Docket. The Workgroup Leader concludes that a utility's DU-URPs are operational settings for which the utility should have a final determination as they are directly accountable for the safe, reliable and economic operation of their electric distribution systems. Having final determination does not imply that utilities will not be judged by the Commission on their efforts to eventually establish more advanced DU-URPs to further grid modernization.

The Workgroup Leader also concludes that it is reasonable to expect the utilities to inform the Workgroup and Commission of a DU-URP target deadline or their intent to use the MSDS indefinitely. The Workgroup leader also concludes that it is reasonable for utilities to publish their DU-URPs or MSDS, as applicable, at a high level as exemplified in Table No. 4, in addition to any additional settings details that may be needed in their electric service Tariffs to allow for public discourse on related Tariff changes.

Some stakeholders are also concerned that smart inverter settings could result in DG curtailments, especially if a utility utilizes Volt-Watt mode in the future. These stakeholders requested that there be reporting requirement to provide the number of DG curtailments a utility has investigated, resolved and are still pending due in annual small

[56] *See* COMAR 20.50.09.06N(3): Prior to January 1, 2022, all utilities will establish default utility required inverter settings profiles for smart inverters pursuant to §N(5) of this regulation. A utility may use a Statewide utility required inverter settings profile as their default utility required inverter settings profile.

generator interconnection reports filed with the Commission to determine if this is an issue that needs corrective action. Some utility stakeholders view this additional reporting requirement as burdensome and oppose its inclusion in regulations proposed in Phase III. The Workgroup leader concludes that it is reasonable to include a high level reporting requirement on the number of DG curtailments investigated, resolved and still pending to determine if this is an issue that needs corrective action.

VII. Recommendations

The Workgroup recommends that the Commission accept our interim Maryland MSDS proposal as described in Table No. 4 of the Workgroup's report and officially note its acceptance in a motion that is captured in the minutes from the rulemaking since the MSDS is not proposed to be codified in COMAR.

The Workgroup will continue to monitor manufacturer progress in certifying smart inverters in 2021 and will be prepared to provide an update and interim MSDS implementation date recommendation, if different than January 1, 2022, to the Commission prior to any rulemaking initiated associated with this report. Concomitant with this recommendation, the Workgroup will also discuss with the Commission the whether a temporary waiver of COMAR 20.50.09.06N should be pursued or alternatively, whether it is more desirable to adjust the COMAR 20.50.09.06N smart inverter requirements to reflect any new date proposed by the Workgroup.

The Workgroup also recommends that the Commission approve our Phase III regulation proposals for interconnection jurisdiction, and smart inverters and schedule an associated rulemaking proceeding. The Workgroup Leader makes the following recommendations on two non-consensus regulations associated with smart inverters proposed in the Workgroup's report:

1. Utilities shall publish their DU-URPs or MSDS, as applicable, at a high level in their electric service tariffs prior to implementation of Maryland's smart inverter requirement unless they plan on utilizing the MSDS.

2. Utilities shall have a high level reporting requirement to annually to capture the number of DG curtailments investigated, resolved and still pending to determine if this is an issue that needs corrective action.

The Workgroup Leader recommends the utilities inform the Workgroup and the Commission of a DU-URP target deadline or their intent to use the MSDS indefinitely at our requested rulemaking proceeding.

The Workgroup Leader also requests the Commission provide feedback on the Workgroup's MCAM proposal to be considered in a Phase IV effort to further study interconnection facility cost allocation. Pending adjustments that may be required based on this Commission feedback, the Workgroup leader recommends a continuing Phase III study effort to collect data as described earlier that would ensure that the implementation of Interconnection Facility Cost regulations and associated process changes by utilities will exceed the benefits to be obtained.

Also as discussed in Section V of the Phase III Final Report, the Workgroup recommends that a Phase IV effort be launched to further consider utility monitoring and control regulations to consider the future impacts of the FERC Order No. 2222 implementation, IEEE cybersecurity standards and the NARUC/NASEO State Policy framework initiative for DER cybersecurity. A Phase IV effort can also address emergent issues and continue the effort to build consensus on implementing more advanced voltage regulation settings in the Maryland MSDS and DU-URPs.

Appendix A - Summary of Phase I and II Workgroup Accomplishments

Summary of COMAR Regulation Changes in Phase I and Phase II

The following PC44 Interconnection Workgroup Phase I revisions to COMAR went into effect on October 8, 2018:

- **Energy Storage Integration into Interconnection Regulations –** The Workgroup added a new definition for energy storage devices and clarified how energy storage devices are eligible to connect to the grid under the small generator interconnection rules.
- **Interconnection Application Process Automation** - The Workgroup developed regulation changes for the automation of interconnection applications via utility web portals making it easier, streamlined and customer-friendly for applicants.
- **Small Generator Facility Size Applicable to a Streamlined Application Process** – The Workgroup increased the small generator facility Level 1 size limit from 10 kW to 20 kW, which will facilitate more streamlined, timely and customer-friendly interconnection of smaller Level 1 projects that are unlikely to cause any safety or reliability issues or require grid upgrades.
- **Interconnection Process "Donut Hole" -** The Workgroup also improved the interconnection process by removing the previous 10 MW limit on small generator facility projects, such that any project that falls within Maryland jurisdiction connecting to the electric distribution system has a clear process through which their application can be reviewed and studied. Previously a generator greater than 10 MW interconnecting to electric distribution that did not qualify for the PJM Interconnection LLC process also was not eligible for Maryland interconnection processes defined in the Code of Maryland Regulations ("COMAR") 20.50.09. Therefore, an interconnection process "donut hole" existed where some interconnection applications did not fall under any existing regulation.
- **Pre-Application Interconnection Reports** - The Workgroup developed customer-friendly regulations for utilities for pre-application reports for projects over 20 kW, which will enable interconnection applicants to request a report from their utility that improves transparency by providing details on the state of the electric grid at the proposed point of interconnection. This preliminary information allows potential interconnection applicants to get a sense early in the process, before they make a large investment of time and money, whether a given project is likely to integrate into the grid at that location without triggering major upgrades.
- **Interconnection Queues** - The Workgroup developed regulations for utilities to publish a public interconnection queue that enables progress tracking of larger interconnection projects greater than 500 kW that are customer-friendly and improve transparency.

- **Utility Monitoring and Control Plan**[57] – Smart inverters are capable of two-way communication. This provides the opportunity for monitoring or active control of an inverter by a utility or by third-party aggregators that can further optimize the operation of the distribution system. The Workgroup developed regulations enabling utilities to develop utility monitoring and control plans in the aggregate for small generator facilities less than 2 MW and submit them for Commission approval. These aggregate plans do not include site specific utility monitoring and control requirements which should be documented in Interconnection Agreements.[58]

- **Smart Inverters** – The workgroup suggested new language that permits utilities and interconnecting customers, upon mutual agreement, to employ smart inverter capabilities covered under the most recent Institute of Electrical and Electronic Engineers ("IEEE") and Underwriters Laboratory ("UL") standards.

- **Interconnection Process Reporting** - The Workgroup developed additional annual reporting regulations for utilities that will provide more transparency to the Commission and other stakeholders on various aspects of the Maryland interconnection process, especially regarding utility costs for interconnections and reasons for denial and approval delays of interconnection applications.

The following PC44 Interconnection Workgroup Phase II revisions to COMAR went into effect on April 20, 2019:

- **Interconnection Jurisdiction** – The Workgroup further clarified the applicability of FERC interconnection jurisdiction requirements versus Maryland jurisdiction requirements for small generator facility interconnection requests in Maryland regulations.

- **Utility Fees** - The Workgroup recommended regulation modifications to allow utilities to establish fees for interconnection requests greater than 20 kW in their tariffs.

- **Flexible Interconnection Options for Energy Storage –** The Workgroup added provisions in Maryland regulations to improve the efficient utilization of energy storage devices on the electric distribution grid, including evaluating interconnection

[57] "Utility Monitoring and Control Plan" means a plan to monitor and control in the aggregate a set of small generator facilities in multiple locations that includes a cost recovery method, under conditions that are approved by the Commission.
[58] "Interconnection agreement" means an agreement that contains details regarding the proposed interconnection equipment and its operation to ensure the reliability and safety of the grid including schedules, rights, obligations, terms and conditions that become effective on the date the agreement is executed by the utility and the interconnection customer.

applications based on net system capacity[59] instead of the sum total capacities of the energy storage unit and the other generator units at the small generator facility. In addition, inadvertent export[60] is now allowed for small generating facilities to more effectively offset the facility load by being optimally sized to meet its peak demand with load following functionality.

- **Hosting Capacity[61]** - Hosting capacity is of great interest to small generator facility developers seeking to direct their investments in locations in a utility's service territory where interconnection costs are likely to be lower. In addition, the interconnection of large and mid-size small generator facilities that use a significant amount of a distribution system component's remaining capacity may restrict other projects from grid access or unfairly burden them with system upgrade costs. The Workgroup implemented regulations to codify the concepts of reserve hosting capacity, closed circuits and restricted circuits. Regulations were also codified by the Workgroup to require utilities to annually report on their future plans for providing hosting capacity information and maps as part of hosting capacity reporting systems.[62]

- **Smart Inverters** –A new generation of smart inverters compliant with IEEE 1547-2018 will be available before 2022. A requirement was codified to adopt smart inverters and their associated technical capabilities as a foundational technology for future interconnections to improve the safety, reliability and the hosting capacity of Maryland's electric distribution system while still allowing for cost effective installation. The Workgroup codified a January 1, 2022, requirement to use smart inverters in Maryland and several other companion regulations requiring utilities to develop inverter setting policies and also post a list of smart inverters they have approved on their websites.

- **Utility Monitoring and Control Plan** - The Workgroup clarified the definition of utility monitoring and control plans in the aggregate versus site-specific utility monitoring and control plans.

[59] Net system capacity means the total export capacity at a point of common coupling of a small generator facility as measured by the nameplate capacities of all power production units and energy storage devices minus their consumption of electrical power, if applicable, as limited through the use of a control system, power relays, or other similar device settings or adjustments.

[60] Inadvertent export means the unscheduled export of power from a small generating facility, beyond a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

[61] Hosting capacity means the amount of aggregate generation that can be accommodated on the electric distribution system without requiring infrastructure upgrades.

[62] Hosting capacity reporting system means the information available on a utility website providing reports, tabular data, or maps of hosting capacity available on the electric distribution system.

- **Miscellaneous Regulation Modifications** – The Workgroup codified the ability for utilities to be able to customize several interconnection documents to meet evolving interconnection needs as long as these interconnection documents are consistent with COMAR regulations. New regulations will provide interconnection customers more certainty with regard to when they will receive permission to operate their small generator facility.

- **Interconnection Process Reporting** - The Workgroup codified additional annual reporting regulations for utilities that will provide more transparency to the Commission and other stakeholders on various aspects of the Maryland interconnection process, especially regarding utility plans for hosting capacity reporting systems, circuits with hosting capacity restrictions, details regarding inadvertent export and net system capacity approvals and how many utility default and site-specific site inverter settings are being used.

Appendix B – PJM Ride-Through Settings

PJM Guideline for Ride Through Performance of Distribution-Connected Generators

Revision 2
PJM Interconnection
Q4, 2019

I. Summary

This non-binding document provides the PJM guideline for ride through and minimum trip clearing time performance during abnormal frequency and voltage conditions for distribution-connected generators. This guideline is applicable only to distribution-connected generators. For the purposes of this document, distribution-connected generators means all generators connected to radial distribution lines of voltage < 50 kV that are operating in parallel with the grid. This document should not be construed as applying to generators connected to Transmission Facilities.

II. Performance During Abnormal Conditions

Generators generally have contractual obligations to follow the standards referenced in the interconnection agreement with the local Transmission Owner or distribution utility or the Interconnection Service Agreement (ISA) with PJM. These standards may include trip settings and ride-through performance requirements in accordance with IEEE Std 1547™-2018. Current versions of engineering and construction standards for all PJM Transmission Owners are found at:

https://www.pjm.com/planning/design-engineering/to-tech-standards.aspx

III. Ride Through Capability and Trip Settings

Distribution-connected generators installed after January 1, 2022 should have the capability to ride through abnormal frequency and voltage events according to either Category II or Category III of IEEE Std 1547™-2018, as specified by the electric distribution company, except that generators using technology types that are generally incapable of meeting Category II or Category III performance should instead meet the ride through requirements specified by the electric distribution company[1].

Generators that are designed and configured to effectively ride through abnormal low voltage conditions according to the voltages and durations in the following table provide adequate ride through for Bulk Power System stability and reliability needs in PJM[2,3].

Table 1: Minimum Ride Through Capability and Effective Ride Through Time

	Minimum Ride Through Capability	Minimum ride through time	Acceptable ride through modes
Voltages between 65% - 88%	Category II or Category III	1.84 seconds	Mandatory Operation
Voltages between 30% - 65%	Category II or Category III	0.16 seconds	Mandatory Operation, Permissive Operation, or Momentary Cessation

[1] Inverter-based technology is capable of meeting Category II and Category III performance requirements.

[2] Longer trip settings should be considered in areas that may exhibit fault induced delayed voltage recovery of greater than 1.84 seconds, or that utilize transmission fault clearing times of greater than 1.84 seconds.

[3] Note that, under IEEE Std 1547™-2018, where the trip duration settings are equal to or less than the ride through duration, the effective ride-through requirements duration requirement only applies until 160ms prior to the prescribed tripping time. For trip durations of greater than 16 seconds, this "grace period" is extended to equal 1% of the trip time.

Distribution-connected generators configured with trip clearing times greater than or equal to the values in the below table provide effective ride through that meets the above minimum effective ride through need. The following table is provided only as a guide; specific units, or specific individual company practices, may provide for different periods of operation in these specified voltage ranges. However, in considering the possible consequences during a wide area low voltage condition, it is recommended that the following table be used in developing operating practices other than those that apply to specific generating plants or individual units.

Table 2: Minimum Trip Clearing Times to Provide Adequate Effective Ride Through

	Minimum trip clearing time
Voltages between 50% and 88%	2 seconds
Voltages between 0% and 50%	0.32 seconds

For abnormal overvoltage and for abnormal over- or underfrequency, the provisions of IEEE Std 2018 for Category II and Category III ride through capability requirements (including momentary cessation), default trip clearing times, and any other trip clearing times within the allowable range of adjustable settings, generally provide adequate effective ride through for Bulk Power System stability and reliability needs in PJM.

The default abnormal overvoltage trip times and ride through modes are different for Category II and Category III, and are as follows in Table 3.

Table 3. Default Overvoltage Trip Times and Ride Through Modes for Category II and Category III

	Category II		Category III	
	Trip clearing time	Ride through mode	Trip clearing time	Ride through mode
Voltage above 120%	0.16 seconds	None	0.16 seconds	None
Voltage between 110% - 120%	2.0 seconds	Permissive operation	13.0 seconds	Momentary cessation

The default abnormal over- and underfrequency trip clearing times as well as the ride through modes are the same for Category II and Category III, and are as follows in Table 4.

Table 4. Default Abnormal Frequency Trip Times for both Category II and Category III

	Default trip clearing time	Ride through mode
Frequency above 62 Hz	0.16 seconds	None
Frequency between 61.2 Hz and 62 Hz	300.0 seconds	Mandatory operation for frequency below 61.8 Hz
Frequency between 58.5 Hz and 56.5 Hz	300.0 seconds	Mandatory operation for frequency above 57.0 Hz
Frequency below 56.5 Hz	0.16 seconds	None

IV. Voltage Measurement and Reference Point of Applicability

The above voltages should be measured consistent with the provisions in IEEE Std 1547-2018 regarding the reference point of applicability, the applicable voltage, and measurement accuracy, unless otherwise superseded by the interconnection agreement of applicable interconnection laws and regulations.

Appendix C - Proposed COMAR Changes

Title 20 PUBLIC SERVICE COMMISSION

Subtitle 50 SERVICE SUPPLIED BY ELECTRIC COMPANIES

Chapter 02 Engineering

.02 Acceptable Standards.

Unless otherwise specified by the Commission, the utility shall use the applicable provisions in the latest revised version of the incorporated by reference publications listed below as standards of accepted good engineering practice in this subtitle:

A. National Electrical Safety Code, ANSI C2 — 2002;

B. National Electrical Code, ANSI/NFPA 70 — 2005;

C. American National Standard for Electric Meters — Code for Electricity Metering, ANSI C12.1 — 2001;

D. American Standard Requirements, Terminology and Test Code for Instrument Transformers, ANSI/IEEE C57.13 — 1993;

~~E. Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE Standard 1547 — 2003 and Amendment 1-2014;~~

~~F. Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems, IEEE Standard 1547.1 — 2005 and Amendment 1-2015;~~

~~G. UL Standard for Safety for Inverters, Converters, and Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, UL1741 January 28, 2010 edition;~~

E. Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, IEEE 1547-2018 and Amendment 1547a-2020;

F. IEEE 1547.1-2020, Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces;

G. UL Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, UL Standard 1741, Edition Date: September 16, 2020;

H. NEMA Standards Publication TP 1 — 2002; and

I. Guide for Electric Power Distribution Reliability Indices, IEEE Standard 1366 — 2003, 4.5 Major event day classifications.

Title 20 PUBLIC SERVICE COMMISSION

Subtitle 50 SERVICE SUPPLIED BY ELECTRIC COMPANIES

Chapter 09 Small Generator Facility Interconnection Standards

Authority: Public Utilities Article, §§2-113, 2-121, 5-101, 5-303, and 7-306, Annotated Code of Maryland

.01 Scope.

A. This chapter applies to a small generator facility seeking to interconnect and operate in parallel with the electric distribution system. All small generator facilities shall interconnect under requirements in this chapter or under the physical interconnection requirements of the PJM Interconnection, LLC under the authority of FERC.

B. A small generator facility seeking to interconnect and operate in parallel with the electric distribution system under this chapter shall meet one of the following criteria:

(1) The small generator facility is a qualifying facility pursuant to the Public Utility Regulatory Policies Act that intends to make sales at a rate approved by the Maryland Commission;

(2) The small generator facility is not a qualifying facility pursuant to the Public Utility Regulatory Policies Act and does not intend to make sales of wholesale electric energy through the PJM Interconnection, LLC; or

(3) The small generator facility intends to make sales of wholesale electric energy through the PJM Interconnection, LLC at an electric distribution interconnection facility where there has been no prior FERC jurisdictional service

(4) The small generator facility intends to make sales of wholesale electric energy through the PJM Interconnection, LLC only at an electric distribution interconnection facility through participation in a distributed energy resource aggregation.

(5) The small generator facility will be interconnected to an electric distribution circuit and its energy will not be transmitted across state lines for a wholesale customer other than the electric distribution owner.

C. Market processes under FERC jurisdiction that are administered by the PJM Interconnection, LLC may not impede the interconnection timeline requirements in this chapter unless the utility has good cause to believe that equipment upgrades exceeding minor equipment modifications and related modifications to the interconnection agreement will be needed to facilitate these market processes. In these cases, the utility shall notify the interconnection customer in writing of their rationale to delay approval of the interconnection request until the conclusion of the PJM Interconnection, LLC's market process study.

D. In situations where an interconnected small generator facility project intends to change their energy sales strategy from market processes under FERC jurisdiction to retail processes under this chapter, the small generator facility shall submit an interconnection request.

.02 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) “Adverse system impact” means a negative effect, due to technical or operational limits on conductors or equipment being exceeded, that may compromise the safety or reliability of the electric distribution system.

(2) “Affected system” means a utility electric system that is affected by the interconnection of a small generator facility to another utility’s electric distribution system.

(3) “Aggregate generation” means the aggregated net system capacities of all small generator facilities across multiple points of common coupling.

(4) “Applicant” means a person who has submitted an interconnection request to interconnect a small generator facility to a utility's electric distribution system.

(5) “Area network” means a type of electric distribution system served by multiple transformers interconnected in an electrical network circuit, often used in large, densely populated metropolitan areas.

(6) “Certificate of completion” means a certificate provided by a utility to an applicant containing information about the interconnection equipment used, its installation, and local inspections.

(7) “Closed circuit” means an electric distribution system circuit with no available hosting capacity.

(8) “Commissioning test” means one of several tests applied to a small generator facility by the applicant after construction is completed to verify that the small generator facility does not create adverse system impacts, including the test specified in Section 5.4 of IEEE Standard 1547.

(9) “Default utility required inverter settings profile” means a utility set of default smart inverter settings optimized for use across a utility’s service territory.

(10) “Distributed energy resource” means any geographically dispersed energy resource located on an electric distribution system that produces electricity or offsets electrical demand including small generator facilities, energy storage devices, energy efficiency devices, and demand response devices.

(11) “Distribution upgrade” means a required addition or modification to the utility electric distribution system, excluding the interconnection facilities, necessary to accommodate the interconnection of a small generator facility.

(12) “Draw-out type circuit breaker” means a molded case switching device that:

(a) Can be inserted into or removed from its enclosure during no-load conditions; and

(b) Is capable of making, carrying, and breaking currents under normal and abnormal circuit conditions.

(13) Electric Distribution System.

(a) “Electric distribution system” means the facilities and equipment used to transmit electricity generally at less than 69 kV to ultimate usage points such as homes and industries from interchanges with higher voltage transmission networks that transport bulk power over longer distances.

(b) “Electric distribution system” has the same meaning as the term Area EPS as defined in Section 3.1.6.1 of IEEE Standard 1547.

(14) "Energy Storage Device" means a piece of equipment that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity at a future time.

(15) "Fault current" means the electrical current that flows through a circuit during an electrical fault condition, such as when one or more electrical conductors contact ground or each other.

(16) "Grid support services" means compensated or uncompensated services unrelated to wholesale markets provided by a small generator facility that support the safety, stability, reliability, or economics of the electric grid.

(17) "Hosting capacity" means the amount of aggregate generation that can be accommodated on the electric distribution system without requiring infrastructure upgrades.

(18) "Hosting capacity reporting system" means the information available on a utility website providing reports, tabular data, or maps of hosting capacity available on the electric distribution system.

(19) "Hosting capacity upgrade plan" means a plan to open restricted and closed circuits or areas on an electric system in the aggregate that includes a cost recovery method, under conditions that are approved by the Commission.

(20) "IEEE Standard 1547" means the standard incorporated by reference in COMAR 20.50.02.02.

(21) "IEEE Standard 1547.1" means the standard incorporated by reference in COMAR 20.50.02.02.

(22) "Inadvertent export" means the unscheduled export of power from a small generator facility, beyond a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

(23) "Interconnection agreement" means an agreement that contains details regarding the proposed interconnection equipment and its operation to ensure the reliability and safety of the grid, including schedules, rights, obligations, and terms and conditions that become effective on the date the agreement is executed by the utility and the interconnection customer.

(24) "Interconnection customer" means an entity that proposes to interconnect or has interconnected a small generator facility to an electric distribution system.

(25) Interconnection Equipment.

(a) "Interconnection equipment" means a group of components or an integrated system connecting an electric generator with a local electric power system, or an electric distribution system.

(b) "Interconnection equipment" means all interface equipment including switchgear, protective devices, inverters, or other interface devices.

(c) "Interconnection equipment" includes equipment installed as part of an integrated equipment package that includes a generator or other electric source.

(26) Interconnection Facilities.

(a) "Interconnection facilities" means facilities and equipment required by the utility to accommodate the interconnection of a small generator facility.

(b) "Interconnection facilities" includes all facilities and equipment between the small generator facility and the point of interconnection, and modifications, additions, or upgrades that are necessary to physically and electrically interconnect the small generator facility to the electric distribution system.

(c) "Interconnection facilities" includes any distribution upgrade.

(27) “Interconnection facility cost sharing” means the allocation of distribution interconnection facility upgrade costs among multiple small generator facility projects that utilize the hosting capacity created by an interconnection facility upgrade.

(28) “Interconnection request” means an applicant's request for the interconnection of a small generator facility, or to increase the capacity or operating characteristics of a small generator facility that is already interconnected with the utility's electric distribution system.

(29) “Interconnection study” means an interconnection feasibility study, interconnection system impact study, or interconnection facilities study as described in Regulation .12 of this chapter.

(30) “Line section” means that portion of a utility electric distribution system connected to an interconnection customer, bounded by automatic sectionalizing devices, or the end of the distribution line.

(31) Local Electric Power System.

(a) “Local electric power system” means those facilities that deliver electric power to a load that are contained entirely within a single premises or group of premises.

(b) “Local electric power system” has the same meaning as the term local electric power system as defined in Section 3.1.6.2 of IEEE Standard 1547.

(32) “Minor equipment modification” means a change to the proposed small generator facility that does not have a significant impact on safety or reliability of the electric distribution system.

(33) “Minor system modification” means a change to the distribution system:

(a) Located between the service tap on the distribution circuit and the meter serving the applicant; or

(b) That the utility estimates will entail less than 4 hours of work and less than $1,500 in materials.

(34) “Nameplate capacity” means the maximum rated output of a generator at a point of common coupling of all electric power production equipment or energy storage devices under specific conditions designated by the manufacturer that is usually listed on a nameplate physically attached to the equipment.

(35) “Nationally recognized testing laboratory (NRTL)” means a qualified private organization recognized by the Occupational Safety and Health Administration to perform independent safety testing and product certification.

(36) “Net system capacity” means the total export capacity at a point of common coupling of a small generator facility as measured by the nameplate capacities of all power production units and energy storage devices minus their consumption of electrical power, if applicable, as limited through the use of a control system, power relays, or other similar device settings or adjustments.

(37) “Parallel operation” means the sustained state of operation over 100 milliseconds which occurs when a small generator facility is connected electrically to the electric distribution system, and thus has the ability for electricity to flow from the small generator facility to the electric distribution system.

(38) “Permission to operate notice” means the written permission provided by a utility in the form of an email or letter authorizing an interconnection customer to interconnect and operate its small generator interconnection facility.

(39) “Point of common coupling” means the point of interconnection where the small generator facility is electrically connected to the electric distribution system.

(40) “Point of interconnection” has the same meaning as the term “point of common coupling”.

(41) “Primary line” means a distribution line rated at greater than 600 volts.

(42) Proposed Use.

(a) “Proposed use” means the operational control modes of a small generator facility upon which the applicant’s technical review is based and under which the small generator facility is bound to operate upon the execution of the interconnection agreement.

(b) “Proposed use” for a small generator facility includes a combination of electric generators and energy storage devices operating in specified operational control modes during specified time periods.

(43) “Queue position” means the order of a completed interconnection request, relative to all other pending completed interconnection requests, that is established based upon the date and time of receipt of the completed interconnection request by the utility.

(44) “Radial distribution circuit” means a circuit configuration in which independent feeders branch out radially from a common source of supply.

(45) “Reserve hosting capacity” means the amount of hosting capacity reserved for small generator facilities on an electric distribution system circuit.

(46) “Restricted circuit” means an electric system distribution circuit with reserve hosting capacity.

(47) “Scoping meeting” means a meeting between the applicant and utility conducted for the purpose of discussing alternative interconnection options, exchanging information, including any electric distribution system data and earlier study evaluations that would be reasonably expected to impact interconnection options, analyzing information, and determining the potential feasible points of interconnection.

(48) “Secondary line” means a service line subsequent to the primary line that is rated for 600 volts or less, also referred to as the customer's service line.

(49) “Shared transformer" means a transformer that supplies secondary source voltage to more than one customer.

(50) “Site-specific utility required inverter settings profile” means a set of smart inverter settings optimized for use at a specific site on a utility’s electric system.

(51) Small Generator Facility.

(a) “Small generator facility” means the equipment used to generate or store electricity that operates in parallel with the electric distribution system.

(b) “Small generator facility” includes an electric generator, a prime mover, energy storage device, and the interconnection equipment required to safely interconnect with the electric distribution system or local electric power system.

(52) “Smart Inverter” means any inverter hardware system certified to be compliant with IEEE 1547-2018 or subsequent revisions to these standards.

(53) Spot Network.

(a) “Spot network” means a type of electric distribution system that uses two or more inter-tied transformers to supply an electrical network circuit.

(b) “Spot network” is generally used to supply power to a single customer or a small group of customers.

(c) “Spot network” has the same meaning as the term is defined in 4.1.4 of IEEE Standard 1547.

(54) “Statewide utility required inverter settings profile” or “grid code” means a set of smart inverter settings optimized for use Statewide that can be used by utilities and manufacturers in establishing defaults.

(55) “Utility monitoring and control plan” means a plan to monitor and control, in the aggregate, a set of small generator facilities in multiple locations that includes a cost recovery method, under conditions that are approved by the Commission.

(56) “Utility required inverter settings profile” means smart inverter settings for a small generator facility that are established by a utility.

(57) “Witness test” means, for lab-certified or field-approved equipment, verification either by an on-site observation or review of documents by the utility that the interconnection installation evaluation required by Section 5.3 of IEEE Standard 1547 and the commissioning test required by Section 5.4 of IEEE Standard 1547 have been adequately performed.

.03 Acceptable Standards.

The technical standard to be used in evaluating all interconnection requests under Level 1, Level 2, Level 3, and Level 4 reviews, unless otherwise provided for in this chapter, is IEEE Standard 1547.

.05 Interconnection Request Processing Fees.

A. A utility may only charge a small generator interconnection request fee for a Level 2, Level 3, or Level 4 interconnection request.

B. A utility may not charge interconnection request fees for interconnection requests determined to be under PJM Interconnection, LLC jurisdiction pursuant to Regulation .01 of this chapter.

C. The utility shall specify the interconnection [processing] request fees charged under this regulation in its tariff.

.06 General Requirements.

A. For small generator facilities at a site for which the applicant seeks a single point of interconnection, the interconnection request shall be evaluated for total exports on the basis of the net system capacity.

B. An interconnection request is required for the interconnection of a new small generator facility, or to increase the total exports, change the energy sales strategy pursuant to Regulation .01C of this chapter, or change the proposed use of an existing small generator facility. Any time a new interconnection request is processed for an existing small generator facility, the utility will apply any standards in effect at the time of the interconnection request and, if approved, a new interconnection agreement will be required. The interconnection request shall be evaluated on the basis of the total net system capacity of the small generator facility.

C. Utility Provided Information.

(1) A utility shall designate a contact person, and provide contact information on its website and for the Commission's website for submission of all interconnection requests, and from whom information on the interconnection request process and the utility's electric distribution system can be obtained.

(2) The information provided by the utility on its website shall include studies and other materials useful to an understanding of the feasibility of interconnecting a small generator facility on the utility electric distribution system, except to the extent providing the materials would violate security requirements or confidentiality agreements, or be contrary to law.

(3) For projects with a nameplate capacity over 20kW, the utility shall:

(a) Provide the applicant an opportunity to request a pre-application report, which may require payment of a fee listed in the utility’s tariff;

(b) Publicly post the fee amount on the utility’s website; and

(c) Provide the pre-application report within 20 business days, once the fee is paid.

(4) The pre-application report shall rely largely on pre-existing utility data and shall, at a minimum, include the following items:

(a) Initial proposed point of interconnection of the small generator facility, including address or GIS coordinates;

(b) Closest electrical facilities to the initial proposed point of interconnection of the small generator facility, including voltage level, feeder identification, substation, and including distance to that substation;

(c) Amount of generation hosting capacity available on the closest feeder, if this information is in possession of or easily obtainable by the utility; and

(d) Any other items specified by the Commission.

(5) In appropriate circumstances, the utility may require an applicant to execute an appropriate confidentiality agreement prior to release or access to confidential or restricted information.

D. If an interconnection request is determined to be complete, any material modification, other than a minor equipment modification, that is not agreed to in writing by the utility, shall require submission of a new interconnection request.

E. If an applicant is not currently a customer of the utility at the location for the proposed small generator facility, upon request from the utility, the applicant shall provide proof of site control evidenced by a property tax bill, deed, lease agreement, contract, or other acceptable document.

F. Connection of Multiple Small Generator Facilities by Single Interconnection.

(1) To minimize the cost of interconnecting multiple small generator facilities, the utility or the applicant may propose a single point of interconnection for multiple small generator facilities located at a single site.

(2) If an applicant rejects a utility proposal for a single point of interconnection, the applicant shall pay any additional cost of providing separate points of interconnection for each small generator facility.

(3) If a utility unreasonably rejects a customer proposal for a single point of interconnection without providing a written technical explanation, the utility shall pay any additional cost of providing separate points of interconnection for each small generator facility.

G. Electrical Isolation of a Small Generator Facility.

(1) A small generator facility shall be capable of being isolated from the utility electric distribution system.

(2) For a small generator facility interconnecting to a primary or secondary line, the isolation shall be by means of a lockable, visible-break isolation device accessible by the utility.

(3) The isolation device shall be installed, owned, and maintained by the interconnection customer for the small generator facility, and located electrically between the small generator facility and the point of interconnection.

(4) A draw-out type circuit breaker with a provision for padlocking at the draw-out position satisfies the requirement for an isolation device.

H. Use of Lockbox for Access to Isolation Device.

(1) An interconnection customer may elect to provide the utility access to an isolation device that is contained in a building or area that may be unoccupied and locked or not otherwise readily accessible to the utility, by installing a lockbox provided by the utility that shall allow ready access to the isolation device.

(2) The lockbox shall be in a location that is readily accessible by the utility, and the interconnection customer shall permit the utility to affix a placard in a location of its choosing that provides clear instructions to utility operating personnel on access to the isolation device.

(3) In the event the interconnection customer fails to comply with the terms of this section and the utility needs to gain access to the isolation device, the utility may not be held liable for any damages resulting from any necessary utility action to isolate the small generator facility.

I. Metering.

(1) Any metering necessitated by a small generator facility interconnection shall be installed, operated, and maintained in accordance with the applicable utility tariff.

(2) Any small generator facility metering requirements shall be clearly identified as part of the interconnection agreement executed by the interconnection customer and the utility.

J. Utility Monitoring and Control of Small Generator Facility.

(1) Utility monitoring or control of a small generator facility shall be permitted subject to the conditions in §J of this regulation.

(2) Any utility monitoring or control requirements shall be:

(a) Consistent with the utility published requirements, as available on the utility's website; and

(b) Clearly identified in an interconnection agreement executed by the interconnection customer and the utility.

(3) For a small generator facility under a nameplate capacity of 2 MW, utility monitoring or control is not permitted unless:

(a) The Commission approves a utility monitoring and control plan addressing such facilities in the aggregate; or

(b) The interconnection customer consents to utility monitoring or control.

(4) Equipment certified under the latest published editions of IEEE 1547, IEEE 1547.1, and UL 1741 shall be permitted to be used for monitoring or control upon mutual agreement of the utility and the interconnection customer.

K. Witness Test of Small Generator Facility.

(1) The utility shall have the option of performing a witness test after construction of the small generator facility is completed.

(2) The applicant shall provide the utility at least 5 business days notice of the planned commissioning test for the small generator facility.

(3) If the utility elects to perform a witness test, the utility shall contact the applicant to schedule the witness test at a mutually agreeable time within 10 business days of the scheduled commissioning test.

(4) If the utility does not perform the witness test within 10 business days of the commissioning test, the witness test is considered waived unless the utility and applicant agree to extend the time for conducting the witness test.

(5) If the results of the witness test are not acceptable to the utility, the applicant shall address and resolve any deficiencies within 30 calendar days, which may be extended upon the request of the applicant prior to the expiration of the 30-calendar-day period. A request for extension may not be unreasonably denied by the utility.

(6) If the applicant fails to address and resolve the deficiencies to the satisfaction of the utility, the interconnection request shall be considered withdrawn.

(7) If a witness test is not performed by the utility or an entity approved by the utility, the applicant shall satisfy the interconnection test specifications and requirements set forth in Section 5 of IEEE Standard 1547.

(8) For interconnection equipment that has not been lab-certified or field-approved under Regulation .07 of this chapter, the witness test shall also include the verification by the utility of the on-site design tests as required by Section 5.1 of IEEE Standard 1547 and of production tests required by Section 5.2 of IEEE Standard 1547.

(9) All tests verified by the utility shall be performed in accordance with the test procedures specified in IEEE Standard 1547.1.

(10) The applicant shall, if requested by the utility, provide a copy of all documentation in its possession regarding testing conducted under IEEE Standard 1547.1.

(11) The applicant shall demonstrate that it meets the smart inverter requirements of §N of this regulation, if applicable.

L. Interconnection Studies and Applicant Information.

(1) If requested by the applicant, the utility shall provide the applicant copies of any interconnection studies performed in analyzing an interconnection request.

(2) An applicant may provide any other prospective applicant copies of interconnection studies to aid in streamlining a future utility review.

(3) Queue position for all small generator facilities shall be prioritized based on the date the interconnection request is submitted.

(4) Each utility shall publicly and electronically provide an interconnection queue, updated monthly, that includes the following information about each interconnection request for any small generator facility with a nameplate capacity greater than 500 kW:

(a) Size (MW or kW);

(b) Proposed circuit number and substation;

(c) County and zip code;

(d) Interconnection request received date;

(e) Queue position on the system's proposed circuit number and substation;

(f) Review status;

(g) Interconnection request approved date; and

(h) Any other information requested by the Commission.

(5) A small generator facility shall remain on the list for at least 3 years after the interconnection request was approved by the utility, unless subsequently cancelled or removed from the interconnection queue pursuant to §M of this regulation.

(6) A utility may provide any additional information to a prospective applicant if the utility determines that doing so would streamline the utility's review of an interconnection request.

(7) A utility has no obligation to provide any prospective applicant any information regarding prior interconnection requests, including a prior applicant's name, copies of prior interconnection studies performed by the utility, or any other information regarding a prior applicant or request.

M. Validity of Conditional Approval.

(1) The notice of conditional approval shall clearly identify the applicable deadline and the consequences of failing to either deliver the certification of completion or request an extension by the deadline.

(2) Once the utility delivers notice of conditional approval to the applicant, the applicant shall deliver the certification of completion within the following time frames:

(a) For an application for a small generator facility with a nameplate capacity smaller than or equal to 100 kW, the applicant:

(i) Shall deliver the certification of completion within 6 months;

(ii) Shall receive a 6-month extension of the specified deadline, upon request; and

(iii) May receive one or more additional extensions of at least 6 months upon good cause shown after an initial 6-month extension; and

(b) For an application for a small generator facility with a nameplate capacity larger than 100 kW, the applicant:

(i) Shall deliver the certification of completion within 12 months;

(ii) Shall receive a 6-month extension of the specified deadline, upon request; and

(iii) May receive one or more additional extensions of at least 6 months upon good cause shown after an initial 6-month extension.

(3) A project participating in the Community Solar pilot program under COMAR 20.62 is not subject to this section.

N. Smart Inverters.

(1) After January 1, 2022, any small generator facility requiring an inverter that submits an interconnection request shall use a smart inverter with either a default or a site-specific utility required inverter settings profile, as determined by a utility.

(2) Any small generator facility may replace an existing inverter with a similar spare inverter that was purchased prior to January 1, 2022, for use at the small generator facility.

(3) Prior to January 1, 2022, all utilities will establish default utility required inverter settings profiles for smart inverters pursuant to §N(5) of this regulation. A utility may use a Statewide utility required inverter settings profile as their default utility required inverter settings profile.

(4) To the extent reasonable, pursuant to any modifications required by §N(5) of this regulation, all utility required inverter setting profiles shall be consistent with applicable smart inverter recommendations from PJM Interconnection, LLC that are applicable.

(5) A default utility required inverter settings profile shall be established by a utility to optimize the safe and reliable operation of the electric distribution system, and shall serve the following objectives:

(a) The primary objective is to incur no involuntary real power inverter curtailments incurred during normal operating conditions and minimal real power involuntary curtailments during abnormal operating conditions.

(b) The secondary objective is to enhance electric distribution system hosting capacity and to optimize the provision of grid support services.

(6) A site-specific utility required inverter settings profile may be established by a utility as necessary to optimally meet the objectives established in §N(5) of this regulation.

(7) All default and site-specific utility required inverter settings profiles will be documented in interconnection agreements.

(8) A default utility required inverter settings profile ~~will~~ shall be published on the utility's website. If the default utility required inverter settings profile is different from the statewide utility required inverter settings profile it shall be published in the utility's electric service tariff.

(9) A list of unacceptable smart inverters shall be published on a utility's website.

O. Inadvertent Export, Net System Capacity, and Proposed Use for Small Generator Facilities with Energy Storage Devices. Utilities shall approve interconnection requests for inadvertent export, net system capacity, and proposed use for small generator facilities subject to the following requirements:

(1) Small generator facilities using Level 3 interconnection requests are by definition nonexporting systems, and are not allowed to utilize inadvertent exports.

(2) Small generator facilities may inadvertently export power of a magnitude and duration as evaluated and allowed by the utility and as specified in their interconnection agreement. 30 seconds shall be used as a default inadvertent export duration unless the utility determines that this level duration will violate utility evaluation criteria.

(3) There are no limits on the number of times inadvertent exports occur in any given customer billing cycle.

(4) Small generator facilities may not have total inadvertent exports greater than the generating facility nameplate capacity multiplied by 1 hour per customer in each billing cycle.

(5) In the event that a small generator facility exceeds approved inadvertent export magnitude or duration limits, the small generator facility shall immediately cease to export real power to the grid until acceptable output control has been reestablished.

(6) If required by the utility, the small generator facility shall be subject to a verification reporting plan to monitor the small generator facility's compliance with any inadvertent export or net system capacity requirements as documented in the interconnection agreement. A verification reporting plan may include periodic reports, online monitoring, or other verification methods, or it may be waived as agreed by the utility and interconnection customer.

(7) Failure of a small generator facility to demonstrate compliance with the facility's verification reporting plan may result in the suspension of utility approvals in this section until the small generator facility agrees and implements an acceptable corrective action plan with the utility.

P. Hosting Capacity.

(1) Utilities shall establish hosting capacity policies subject to the following requirements:

(a) A utility shall designate a circuit a closed circuit if there is no remaining hosting capacity.

(b) A utility shall designate a circuit a restricted circuit if only reserve hosting capacity is available.

(c) A utility may determine the amount of reserve hosting capacity on a restricted circuit based on distributed energy resource forecasts or other factors including customer density, type of area served, and customer demographics of the circuit.

(d) A utility may determine the aggregate generation of a small generator facility permitted to use an electric distribution circuit's reserve hosting capacity and publish this information on their website.

(e) A utility shall report their closed circuits, restricted circuits, and reserve hosting capacity in their hosting capacity reporting system.

(2) To open multiple closed or restricted circuits in the aggregate, a utility may submit, or the Commission may require a utility to submit, a hosting capacity upgrade plan for the Commission's review and approval.

(3) A utility shall have a procedure for calculating hosting capacity. The utility shall perform a representative sample of hosting capacity calculation validation checks at least annually, or more frequently in areas experiencing significant growth or distributed energy resource penetration. The hosting capacity calculation validation check frequency shall account for the utility's experience, good engineering practices, and judgment.

.07 Lab-Certified and Field-Approved Equipment.

A. An interconnection request may be eligible for expedited interconnection review if the small generator facility uses lab-certified or field-approved interconnection equipment.

B. Interconnection equipment shall be considered to be lab-certified upon establishment of the following:

(1) The interconnection equipment has been tested in accordance IEEE Standard 1547.1 in compliance with the appropriate codes and standards referenced in §B(7) of this regulation by any NRTL recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment under the relevant codes and standards listed in §B(7) of this regulation;

(2) The interconnection equipment has been labeled and is publicly listed by the NRTL at the time of the interconnection request;

(3) The NRTL testing the interconnection equipment makes readily available, such as by posting on its website, copies of all test standards and procedures utilized in performing equipment certification, and, with applicant approval, the test data itself;

(4) The applicant verifies that the intended use of the interconnection equipment falls within the use or uses for which the interconnection equipment was labeled, and listed by the NRTL;

(5) If the interconnection equipment is an integrated equipment package such as an inverter, the applicant shall show that the small generator facility is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment;

(6) If the interconnection equipment includes only interface components such as switchgear, multifunction relays, or other interface devices, the applicant shall show that the small generator facility is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment; and

(7) The interconnection equipment is:

(a) Evaluated by a NRTL in accordance with the following codes and standards:

(i) IEEE Standard 1547, including use of IEEE Standard 1547.1 testing protocols to establish conformity, which are incorporated by reference in COMAR 20.50.02.02; and

(ii) National Electrical Code, which is incorporated by reference in COMAR 20.50.02.02; and

(b) Certified by Underwriters Laboratories under UL Standard 1741.

C. Interconnection equipment manufactured prior to January 1, 2007, does not require testing and listing based on IEEE Standard 1547.1.

D. Interconnection equipment shall be considered to be field approved if within the previous 36 months of the date of the interconnection request, it has been previously approved for use with the proposed small generator facility and the following criteria are met:

(1) The utility has previously approved interconnection equipment identical to that being proposed under the Level 4 study review process described in Regulation .12 of this chapter in a materially identical system application, or the utility has agreed to accept a Level 4 study review conducted for identical interconnection equipment and system application by another utility;

(2) The prior approval process included a successful witness test; and

(3) The applicant provided as part of its interconnection request the following:

(a) A copy of the final certificate of completion from the prior approval process;

(b) A written statement that the proposed interconnection equipment is identical to what was previously approved; and

(c) Documentation or drawings indicating the system interconnection details.

20.50.09.08

.08 Determination of Interconnection Jurisdiction and Level of Utility Review of Interconnection Request.

A. A utility shall determine within 10 business days the interconnection jurisdiction pursuant to Regulation .01 of this chapter and the level of utility review required for an interconnection request based on nameplate capacity.

B. A utility shall use a Level 1 procedure to evaluate an interconnection request to connect an inverter-based small generator facility when the small generator facility, or multiple small generator facilities interconnecting at a point of common coupling, has a nameplate capacity of 20kW or less.

C. A utility shall use a Level 2 procedure to evaluate an interconnection request when:

(1) The following criteria are met:

(a) The small generation facility, or multiple small generator facilities interconnecting at a point of common coupling, has a nameplate capacity of 2 MW or less;

(b) The interconnection equipment is lab-certified or field-approved; and

(c) The proposed interconnection is to a radial distribution circuit, or a spot network limited to serving one customer; or

(2) Alternatively, the small generator facility was reviewed under Level 1 review procedures but not approved, and the applicant has submitted a new interconnection request for consideration.

D. A utility shall use a Level 3 procedure to evaluate an interconnection request to area networks and radial distribution circuits when electric power is not exported to the electric distribution system based on the following criteria:

(1) For interconnection requests to the load side of an area network:

(a) The nameplate capacity of the small generator facility, or multiple small generator facilities interconnecting at a point of common coupling, is less than or equal to 50 kW;

(b) The proposed small generator facility utilizes a lab-certified inverter-based equipment package;

(c) The small generator facility utilizes reverse power relays, other protection functions, or both, that prevent the export of power into the area network;

(d) The aggregate generation on the area network does not exceed the smaller of 5 percent of an area network's maximum load or 50 kW; and

(e) Construction of facilities by the electric distribution company is not required to accommodate the small generator facility; or

(2) For interconnection requests to a radial distribution circuit:

(a) The small generator facility has a nameplate capacity of 10 MW or less;

(b) The aggregate generation on the circuit, including the proposed small generator facility, is 10 MW or less;

(c) The small generator facility will use reverse power relays or other protection functions that prevent power flow onto the electric distribution system;

(d) The small generator facility is not served by a shared transformer; and

(e) Construction of facilities by the utility on its own electric distribution system is not required to accommodate the small generator facility.

E. A utility shall use the Level 4 procedures for evaluating interconnection requests if:

(1) The interconnection request cannot be approved under a Level 1, Level 2, or Level 3 review, and the applicant has submitted an interconnection request for consideration under a Level 4 study review; and

(2) The interconnection request does not meet the criteria for qualifying for a review under Level 1, Level 2, or Level 3 review procedures.

20.50.09.09

.09 Level 1 Review.

A. The utility shall evaluate a Level 1 small generator facility for the potential for adverse system impacts using the following:

(1) For interconnection of a proposed small generator facility:

(a) To a radial distribution circuit, the aggregate generation on the circuit, including the proposed small generator facility, may not exceed 15 percent of the line section annual peak load as most recently measured at the substation or calculated for the line section; or

(b) To a spot network:

(i) On the load side of spot network protectors, the proposed small generator facility shall utilize an inverter-based equipment package;

(ii) The interconnection equipment proposed for the small generator facility is lab-certified; and

(iii) The aggregate generation of all interconnected small generator facilities may not exceed 5 percent of the spot network's maximum load if the spot network serves more than one customer;

(2) When a proposed small generator facility is to be interconnected on a single-phase shared secondary line, the aggregate generation on the shared secondary line, including the proposed small generator facility, may not exceed 20 kW;

(3) When a proposed small generator facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the two sides of the 240 volt service of more than 20 percent of the nameplate rating of the service transformer;

(4) As an alternative method to evaluate the adverse system impacts of a proposed Level 1 small generator facility on the distribution system, as described in §A(1)—(3) of this regulation, a utility may use a power-flow based analysis system if the utility has submitted:

(a) A plan, subject to Commission approval, that describes its methodology for its power-flow based modeling system and includes reasoning for each screen used to evaluate an application; and

(b) Information about the system's results, as required in Regulation .14 of this chapter;

(5) Modification or construction of additional interconnection facilities by the utility on its distribution system, except for metering or a minor system modification, is not required to accommodate the small generator facility; and

(6) If the proposed interconnection requires a minor system modification, the utility shall notify the applicant of that requirement when it provides the Level 1 evaluation result, as follows:

(a) The applicant shall inform the utility within 10 business days if the applicant elects to continue the application;

(b) If the applicant makes such an election, the utility shall provide an interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for those upgrades, to the applicant within 30 calendar days after the utility receives such an election; and

(c) The applicant shall have 30 calendar days, or other mutually agreeable time frame after receipt of the interconnection agreement, to sign and return such agreement.

B. The utility in conducting a Level 1 interconnection review shall:

(1) Within 5 business days after receipt of the interconnection request, inform the applicant that the interconnection request is:

(a) Complete; or

(b) Incomplete and what materials are missing; and

(2) Within 15 business days after the utility notifies the applicant that the application is complete under §B(1) of this regulation, verify that the small generator facility can be interconnected safely and reliably under §A of this regulation.

C. Unless the utility determines and demonstrates that a small generator facility cannot be interconnected safely or reliably to its electric distribution system, the utility shall approve the interconnection request and provide a permission to operate notice within 20 business days of receipt of acceptable documents, subject to the following conditions:

(1) The small generator facility has been approved by local or municipal electric code officials with jurisdiction over the interconnection;

(2) A certificate of completion has been returned to the utility;

(3) The witness test has been successfully completed or waived by the utility; and

(4) The applicant has signed an interconnection agreement.

D. If an applicant does not sign the interconnection agreement within 30 calendar days after receipt from the utility, the interconnection request is considered withdrawn unless the applicant requests to have the deadline extended. A request for extension may not be unreasonably denied by the utility.

E. Level 1 Review Failure.

(1) If the small generator facility is not approved under a Level 1 review, the utility shall provide the applicant a letter explaining its reasons for denying the interconnection request.

(2) If a small generator facility fails a Level 1 review, the utility may approve the interconnection request if the small generator facility can be interconnected safely and reliably to the utility's electric distribution system.

(3) When a small generator facility is not approved under a Level 1 review, the applicant may submit a new interconnection request for consideration under Level 2, Level 3, or Level 4 procedures.

.10 Level 2 Review.

A. The utility shall evaluate a Level 2 small generator facility for the potential for adverse system impacts using the following:

(1) For interconnection of a proposed small generator facility:

(a) To a radial distribution circuit, the aggregate generation on the circuit, including the proposed small generator facility, may not exceed 15 percent of the line section annual peak load most recently measured at the substation or calculated for the line section; or

(b) To a spot network:

(i) When the interconnection of a proposed small generator facility is to the load side of spot network protectors, the proposed small generator facility shall utilize an inverter-based equipment package;

(ii) The applicant's interconnection equipment proposed for the small generator facility shall be lab-certified or field-approved; and

(iii) A small generator facility, when aggregated with other generation, the aggregate generation on the spot network, may not exceed 5 percent of a spot network's maximum load if the spot network serves more than one customer;

(2) For fault current limitations:

(a) The nameplate capacity of the proposed small generator facility, in aggregation with other generation and energy storage devices on the distribution circuit, may not contribute more than 10 percent to the electric distribution circuit's maximum fault current at the point on the primary line nearest the point of interconnection;

(b) The nameplate capacity of the proposed small generator facility, in aggregation with other generation and energy storage devices on the distribution circuit, may not cause any distribution protective devices and equipment including substation breakers, fuse cutouts, and line reclosers, or other customer equipment on the electric distribution system to be exposed to fault currents exceeding 90 percent of the short circuit interrupting capability; and

(c) The interconnection request may not request interconnection on a circuit that already exceeds 90 percent of the short circuit interrupting capability;

(3) The proposed small generator facility's point of interconnection may not be on a transmission line;

(4) When a small generator facility is to be connected to 3-phase, 3-wire primary utility distribution lines, a 3-phase or single-phase generator shall be connected phase-to-phase;

(5) When a small generator facility is to be connected to 3-phase, 4-wire primary utility distribution lines, a 3-phase or single-phase generator will be connected line-to-neutral and will be effectively grounded;

(6) When the proposed small generator facility is to be interconnected on single-phase shared secondary line, the aggregate generation on the shared secondary line, including the proposed small generator facility, may not exceed 20 kW;

(7) When a proposed small generator facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the two sides of the 240 volt service of more than 20 percent of the nameplate rating of the service transformer;

(8) A small generator facility, in aggregate with other generation and energy storage devices interconnected to the distribution side of a substation transformer feeding the circuit where the small generator facility proposes to

interconnect, the aggregate generation may not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity;

(9) As an alternative method to evaluate the adverse system impacts of a proposed Level 2 small generator facility on the distribution system, as described in §A(1)—(8) of this regulation, a utility may use a power-flow based analysis system if the utility has submitted:

(a) A plan, subject to Commission approval, that describes its methodology for its power-flow based modeling system and includes reasoning for each screen used to evaluate an application; and

(b) Information about the system's results, as required in Regulation .14 of this chapter;

(10) Except as permitted by an additional review in §G of this regulation, no modification or construction of additional facilities by a utility of its distribution system, with the exception of metering or a minor system modification, shall be required to accommodate the small generator facility; and

(11) If the proposed interconnection facility requires a minor system modification, the utility shall notify the applicant of that requirement when it provides the Level 2 evaluation result, as follows:

(a) The applicant must inform the utility within 10 business days if the applicant elects to continue the application;

(b) If the applicant makes such an election, the utility shall provide an interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for those upgrades, to the applicant within 30 calendar days after the utility receives such an election; and

(c) The applicant shall have 30 calendar days, or other mutually agreeable time frame after receipt of the interconnection agreement, to sign and return such agreement.

B. A utility shall, within 5 business days after receipt of the interconnection request, inform the applicant that the interconnection request is:

(1) Complete; or

(2) Incomplete and what materials are missing;

C. Queue Position.

(1) When an interconnection request is complete, the utility shall assign a queue position.

(2) The queue position of the interconnection request shall be used to determine the potential adverse system impact of the small generator facility based on the relevant screening criteria.

(3) The utility shall notify the applicant of any other higher queue position applicants on the same line section or spot network for which interconnection is sought.

(4) Queue position may not be forfeited or otherwise impacted by the submission of a dispute under the provisions of Regulation .13 of this chapter.

D. When a utility determines additional information is required to complete an evaluation:

(1) The utility shall request the information;

(2) The time necessary to complete the evaluation may be extended, but only to the extent of the delay required for receipt of the additional information; and

(3) When additional information is required, the utility may not revert to the start of the review process or alter the applicant's queue position.

E. Within 20 business days after the utility notifies the applicant it has received a completed interconnection request, the utility shall:

(1) Evaluate the interconnection request using the Level 2 screening criteria;

(2) Review the applicant's analysis, if provided by applicant, using the same criteria;

(3) Provide the applicant with the utility's evaluation, including a comparison of the results of its own analyses with those of applicant, if applicable; and

(4) When a utility does not have a record of receipt of the interconnection request and the applicant can demonstrate that the original interconnection request was delivered, expedite its review to complete the evaluation of the interconnection request within 20 business days.

F. Failure to Meet Level 2 Criteria.

(1) Additional review may be appropriate when a small generator facility has failed to meet one or more of the Level 2 criteria of §A of this regulation.

(2) A utility shall:

(a) Within 30 calendar days, offer to perform additional review to determine whether minor modifications to the electric distribution system would enable the interconnection to be made consistent with safety, reliability, and power quality criteria; and

(b) Provide the applicant with a nonbinding, good faith estimate of the costs of additional review and minor modifications.

(3) The utility shall undertake the additional review only if the applicant agrees within 10 business days to pay for the cost of the review, which may be extended at the request of the applicant. A request for extension may not be unreasonably denied by the utility.

(4) If the review identifies the need for modifications to the distribution system, the utility shall make the necessary modifications only if the interconnection customer agrees to pay for the cost of the modifications.

G. Interconnection Agreement.

(1) When a utility determines that the interconnection request passes the Level 2 screening criteria, or fails one or more of the Level 2 screening criteria but determines that the small generator facility can be interconnected safely and reliably, the utility shall provide the applicant an interconnection agreement within 5 business days after the determination.

(2) The applicant shall have either 30 calendar days, or another mutually agreeable time frame after receipt of the interconnection agreement, to sign and return the interconnection agreement.

(3) If the applicant does not sign the interconnection agreement within 30 calendar days, the request shall be considered withdrawn unless the applicant and utility mutually agree to extend the time period for executing the interconnection agreement prior to the expiration of the 30-calendar-day calendar period. A request for extension may not be unreasonably denied by the utility.

(4) After the interconnection agreement is signed by the applicant and utility, interconnection of the small generator facility shall proceed according to any milestones agreed to by the applicant and utility in the interconnection agreement.

(5) The utility shall approve the interconnection request and provide a permission to operate notice within 20 business days of receipt of acceptable documents, subject to the following conditions:

(a) All milestones agreed to in the interconnection agreement are satisfied;

(b) The small generator facility is approved by electric code officials with jurisdiction over the interconnection;

(c) The applicant provides a certificate of completion to the utility;

(d) Upon request of the utility, the applicant provides one or more photographs of the small generator facility site location, components, metering equipment, and other related facilities and equipment; and

(e) There is a successful completion of the witness test, if conducted by the utility.

H. Level 2 Review Failure.

(1) If the small generator facility is not approved under a Level 2 review, the utility shall provide the applicant written notification explaining its reasons for denying the interconnection request.

(2) The applicant may submit a new interconnection request for consideration under a Level 3 or Level 4 interconnection review; however, the queue position assigned to the Level 2 interconnection request shall be retained provided the request is made within 15 business days of notification that the current Level 2 interconnection request is denied.

.11 Level 3 Review.

A. The utility shall use the Level 3 review procedure for an interconnection request that meets the Level 3 criteria in Regulation .08 of this chapter.

B. Queue Position.

(1) Once the interconnection request is considered complete by the utility, the utility shall assign a queue position based upon the date and time the interconnection request is determined to be complete.

(2) The queue position of each interconnection request shall be used to determine the potential adverse system impact of the small generator facility based on the relevant screening criteria.

(3) The utility shall notify the applicant of any other higher queue position applicants on the same radial line or area network that the applicant is seeking to interconnect to.

(4) Queue position may not be forfeited or otherwise impacted by any pending dispute submitted under the provisions of Regulation .13 of this chapter.

C. Interconnection requests meeting the requirements set forth in Regulation .08 of this chapter for nonexporting small generator facilities interconnecting to an area network shall be presumed by the utility to be appropriate for interconnection. The utility shall process the interconnection request to area networks using the following procedures:

(1) The utility shall evaluate the interconnection request under Level 2 interconnection review procedures as set forth in Regulation .10 of this chapter, except that the utility shall have 25 business days to conduct an area network impact study to determine any potential adverse system impact of interconnecting to the utility's area network;

(2) If the area network impact study identifies potential adverse system impacts, the utility may determine at its sole discretion that it is inappropriate for the small generator facility to interconnect to the area network, in which case the interconnection request shall be denied; however, the applicant may elect to submit a new interconnection request for consideration under Level 4 procedures, in which case the queue position assigned to the Level 3 interconnection request will be retained provided the request is made within 15 business days of notification that the current application is denied;

(3) The utility shall conduct the area network impact study at its own expense; and

(4) In the event the utility denies the interconnection request, the utility shall provide the applicant with a copy of its area network impact study and written justification for denying the interconnection request.

D. When an interconnection request meets the requirements of Regulation .08 of this chapter for nonexporting small generator facilities interconnecting to a radial distribution circuit, the utility shall:

(1) Evaluate the interconnection request using the Level 2 review in Regulation .10 of this chapter; and

(2) Approve the interconnection request if all of the applicable Level 2 screens are satisfied, except that the peak line section value indicated in Regulation .10A(1)(a) shall be 25 percent instead of 15 percent.

E. Interconnection Agreement.

(1) If a small generator facility satisfies the criteria in §C or D of this regulation, the utility shall approve the interconnection request and provide an interconnection agreement for the applicant to sign.

(2) The applicant shall have 30 calendar days, or other mutually agreeable time frame after receipt of the interconnection agreement, to sign and return the interconnection agreement.

(3) If the applicant does not sign the interconnection agreement within 30 calendar days, the interconnection request shall be considered withdrawn unless the applicant and utility mutually agree to extend the time period for executing the interconnection agreement prior to the expiration of the 30-calendar-day period. A request for extension may not be unreasonably denied by the utility.

(4) After the interconnection agreement is signed by the applicant and utility, interconnection of the small generator facility shall proceed according to any milestones agreed to by the applicant and utility in the interconnection agreement.

(5) The utility shall approve the interconnection request and provide a permission to operate notice within 20 business days of receipt of acceptable documents, subject to the following conditions:

(a) All milestones agreed to in the interconnection agreement are satisfied;

(b) The small generator facility is approved by electric code officials with jurisdiction over the interconnection;

(c) The applicant provides a certificate of completion to the utility;

(d) Upon request of the utility, the applicant provides one or more photographs of the small generator facility site location, components, metering equipment, and other related facilities and equipment; and

(e) There is a successful completion of the witness test, if conducted by the utility.

F. Level 3 Review Failure.

(1) If the small generator facility is not approved under a Level 3 review, the utility shall provide the applicant written notification explaining its reasons for denying the interconnection request.

(2) If the small generator facility is not approved under a Level 3 review, the applicant may submit a new interconnection request for consideration under the Level 4 procedures; however, the queue position assigned to the Level 3 interconnection request shall be retained provided the request is submitted within 15 business days of the notice that the current Level 3 request was not approved.

.12 Level 4 Study Review.

A. A utility shall use the Level 4 study review procedure for an interconnection request that meets the Level 4 criteria in Regulation .08 of this chapter.

B. Interconnection Request.

(1) Within 5 business days from receipt of an interconnection request, the utility shall notify the applicant whether the request is

(a) Complete; or

(b) Incomplete.

(2) If the interconnection request is not complete:

(a) The utility shall provide the applicant a written list detailing information that shall be provided to complete the interconnection request;

(b) The applicant shall have 10 business days, which may be extended at the request of the applicant and not unreasonably denied by the utility, to provide appropriate data in order to complete the interconnection request, or the interconnection request shall be considered withdrawn; and

(c) The interconnection request shall be considered complete:

(i) If the required information has been provided by the applicant; or

(ii) The utility and applicant have agreed that the applicant may provide additional information at a later time.

C. Queue Position.

(1) When an interconnection request is complete, the utility shall assign a queue position.

(2) The utility shall use the queue position of an interconnection request to determine the cost responsibility necessary for the facilities to accommodate the interconnection.

(3) The utility shall notify the applicant of other higher-queued applicants on the same line section of the new interconnection request.

(4) Any required interconnection studies may not begin until the utility has completed its review of all other interconnection requests that have a higher queue position.

(5) Queue position is not forfeited or otherwise impacted by any pending dispute submitted under the provisions of Regulation .13 of this chapter.

D. Scoping Meeting.

(1) By mutual agreement of the utility and applicant, the scoping meeting may be waived and the interconnection feasibility study, interconnection impact study, or interconnection facilities studies provided for in a Level 4 review and discussed in this section may be waived or combined.

(2) If agreed to by the utility and applicant, a scoping meeting shall be held within 10 business days, or other mutually agreed to time, after the utility has notified the applicant that the interconnection request is considered complete, or the applicant has requested that its interconnection request proceed after failing the requirements of a Level 2 review or Level 3 review.

(3) The purpose of the meeting is to review the interconnection request, existing studies relevant to the interconnection request, and the results of the Level 1, Level 2, or Level 3 screening criteria.

(4) If the utility and applicant agree at a scoping meeting that an interconnection feasibility study shall be performed, the utility shall provide to the applicant, not later than 5 business days after the scoping meeting:

(a) An interconnection feasibility study agreement;

(b) An outline of the scope of the study; and

(c) A nonbinding, good faith estimate of the cost to perform the study.

(5) If the applicant and utility agree at a scoping meeting that an interconnection feasibility study is not required, the utility shall provide to the applicant, not later than 5 business days after the scoping meeting:

(a) An interconnection system impact study agreement;

(b) An outline of the scope of the study; and

(c) A nonbinding, good faith estimate of the cost to perform the study.

(6) If the utility and applicant agree at the scoping meeting that an interconnection feasibility study and system impact study are not required, the utility shall provide to the applicant, not later than 5 business days after the scoping meeting:

(a) An interconnection facilities study agreement;

(b) An outline of the scope of the study; and

(c) A nonbinding, good faith estimate of the cost to perform the study.

E. Interconnection Feasibility, Interconnection System Impact, and Interconnection Facilities Studies.

(1) Interconnection Feasibility Study.

(a) An interconnection feasibility study shall include any necessary analyses for the purpose of identifying a potential adverse system impact to the utility's electric distribution system that would result from the interconnection from among the following:

(i) Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

(ii) Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

(iii) Initial review of grounding requirements and system protection; and

(iv) Description and nonbinding estimated cost of facilities required to interconnect the small generator facility to the utility's electric distribution system in a safe and reliable manner.

(b) If an applicant requests that the interconnection feasibility study evaluate multiple potential points of interconnection, additional evaluations may be required. Additional evaluations shall be conducted at the expense of the applicant.

(c) An interconnection system impact study is not required if the interconnection feasibility study concludes there is no adverse system impact, or if the study identifies an adverse system impact and the utility is able to identify a remedy without the need for an interconnection system impact study.

(d) The utility and applicant shall use an interconnection feasibility study agreement form.

(e) The utility shall avoid duplicating previously conducted interconnection studies to the extent possible.

(f) The utility may require a study deposit of the lesser of 100 percent of estimated nonbinding good faith study costs or $1,000.

(g) The interconnection feasibility study shall be completed and the results shall be transmitted to the interconnection customer within 30 calendar days after the interconnection feasibility study agreement is signed by the parties.

(2) Interconnection System Impact Study.

(a) A distribution interconnection system impact study shall be performed when a potential distribution system adverse system impact is identified in the interconnection feasibility study.

(b) Scope of Interconnection System Impact Study.

(i) An interconnection system impact study shall evaluate the impact of the proposed interconnection on both the safety and reliability of the utility's electric distribution system.

(ii) The interconnection system impact study shall identify and detail the system impacts that result when a small generator facility is interconnected without project or system modifications, focusing on the adverse system impacts identified in the interconnection feasibility study, or potential impacts including those identified in the scoping meeting.

(iii) The interconnection system impact study shall consider all small generator facilities that, on the date the interconnection system impact study is commenced, are directly interconnected with the utility's electric distribution system, have a pending higher queue position to interconnect to the system, or have signed an interconnection agreement.

(iv) As part of its impact study, the utility shall agree to evaluate and consider any separate studies prepared by the applicant that evaluate alternatives for interconnecting the small generator facility, including the applicant's assessment of potential impacts of the small generator facility on the electric distribution system.

(v) The utility shall provide the applicant with the utility's final impact study evaluation, including a comparison of the results of its own analyses with those provided by the applicant.

(c) Within 5 business days of transmittal of the interconnection feasibility study report, the utility shall send the applicant:

(i) An interconnection system impact study agreement using a form;

(ii) An outline of the scope of the interconnection system impact study; and

(iii) A good faith estimate of the cost to perform the study.

(d) The interconnection system impact study shall include any necessary elements from among the following:

(i) A load flow study;

(ii) Identification of affected systems;

(iii) An analysis of equipment interrupting ratings;

(iv) A protection coordination study;

(v) Voltage drop and flicker studies;

(vi) Protection and set point coordination studies;

(vii) Grounding reviews; and

(viii) Impact on system operation.

(e) An interconnection system impact study shall consider any necessary criteria from among the following:

(i) A short circuit analysis;

(ii) A stability analysis;

(iii) Alternatives for mitigating adverse system impacts on affected systems;

(iv) Voltage drop and flicker studies;

(v) Protection and set point coordination studies; and

(vi) Grounding reviews.

(f) The final interconnection system impact study shall provide the following:

(i) The underlying assumptions of the study;

(ii) The results of the analyses;

(iii) A list of any potential impediments to providing the requested interconnection service;

(iv) Required distribution upgrades; and

(v) A nonbinding good faith estimate of cost and time to construct any required distribution upgrades.

(g) The utility may require a study deposit of the lesser of 50 percent of estimated nonbinding good faith study costs or $3,000.

(h) The interconnection system impact study, if required, shall be completed and the results transmitted to the interconnection customer within 45 calendar days after the interconnection system impact study agreement is signed by the parties.

(3) Interconnection Facilities Study.

(a) Within 5 business days of completion of the interconnection system impact study, the utility shall provide to the applicant:

(i) A report of the interconnection system impact study;

(ii) An interconnection facilities study agreement;

(iii) An outline of the scope of the interconnection facilities study; and

(iv) A nonbinding good faith estimate of the cost to perform the facilities study.

(b) The interconnection facilities study shall identify:

(i) The electrical switching configuration of the equipment, including transformer, switchgear, meters, and other station equipment;

(ii) The nature and estimated cost of the utility's interconnection facilities and distribution upgrades necessary to accomplish the interconnection, including engineering, procurement, construction, and overhead; and

(iii) An estimate of the time required to complete the construction and installation of the facilities.

(c) Third-Party Design or Construction of Interconnection Facilities.

(i) The applicant and utility may agree to permit an applicant to separately arrange for a third party to design and construct the required interconnection facilities.

(ii) The utility may review and approve the design of the facilities under the interconnection facilities study agreement.

(iii) If the applicant and utility agree to separately arrange for design and construction, the utility, consistent with security and confidentiality requirements, shall make all relevant information and required specifications available to the applicant to permit the applicant to obtain an independent design and cost estimate for the interconnection facilities.

(iv) The interconnection facilities shall be built in accordance with the specifications in the interconnection facilities study.

(d) Upon completion of the interconnection facilities study, and with the agreement of the applicant to pay for the interconnection facilities and distribution upgrades identified in the interconnection facilities study, the utility shall provide the applicant with an interconnection agreement within 5 business days.

(e) The utility may require a study deposit of the lesser of 50 percent of estimated nonbinding good faith study costs or $10,000.

(f) In cases where no interconnection upgrades are required, the interconnection facilities study shall be completed and the results shall be transmitted to the interconnection customer within 30 calendar days after the agreement is signed by the parties.

(g) In cases where interconnection upgrades are required, the interconnection facilities study shall be completed and the results shall be transmitted to the interconnection customer within 45 calendar days after the agreement is signed by the parties.

(e) Delay in Electric Distribution System Upgrades.

(i) In the event that electric distribution system upgrades are identified in the impact study that will be required to be added only in the event that higher queue position customers not yet interconnected eventually will complete and interconnect their small generator facilities, an applicant may elect to interconnect without paying for such upgrades at the time of the interconnection under the condition that the customer shall pay for such upgrades at the time the higher queue position customer is ready to interconnect.

(ii) If the applicant does not pay for the cost of the electric distribution system upgrades at that time, the utility shall require the customer to immediately disconnect its small generator facility so that interconnection of the higher-queued customer can be accommodated.

(f) The utility may require a study deposit of the lesser of 50 percent of estimated nonbinding good faith study costs or $10,000.

(g) In cases where no interconnection upgrades are required, the interconnection facilities study shall be completed and the results shall be transmitted to the interconnection customer within 30 calendar days after the agreement is signed by the parties.

(h) In cases where interconnection upgrades are required, the interconnection facilities study shall be completed and the results shall be transmitted to the interconnection customer within 45 calendar days after the agreement is signed by the parties.

F. Interconnection Agreement.

(1) When a utility determines, as a result of the interconnection studies conducted under a Level 4 review, that it is appropriate to interconnect the small generator facility, the utility shall provide the applicant with an interconnection agreement.

(2) The applicant shall have either 30 calendar days, or another mutually agreeable time frame after receipt of the interconnection agreement, to sign and return the interconnection agreement.

(3) If the applicant does not sign the interconnection agreement within 30 calendar days, the request shall be considered withdrawn unless the applicant and utility mutually agree to extend the time period for executing the interconnection agreement prior to the expiration of the 30-calendar-day period. A request for extension may not be unreasonably denied by the utility.

(4) After the interconnection agreement is signed by the applicant and utility, interconnection of the small generator facility shall proceed according to any milestones agreed to by the applicant and utility in the interconnection agreement.

(5) The utility shall approve the interconnection request and provide a permission to operate notice within 20 business days of receipt of acceptable documents, subject to the following conditions:

(a) All milestones agreed to in the interconnection agreement are satisfied;

(b) The small generator facility is approved by electric code officials with jurisdiction over the interconnection;

(c) The applicant provides a certificate of completion to the utility;

(d) Upon request of the utility, the applicant provides one or more photographs of the small generator facility site location, components, metering equipment, and other related facilities and equipment; and

(e) There is a successful completion of the witness test, if conducted by the utility.

G. Level 4 Review Failure. If the interconnection request is denied, the utility shall provide the applicant a letter explaining the reasons for denying the interconnection request.

20.50.09.13

.13 Dispute Resolution.

A. The applicant and utility shall attempt to resolve all disputes regarding interconnection as provided in this regulation promptly, equitably, and in a good faith manner.

B. Dispute Resolution Before the Commission.

(1) If a dispute arises, the applicant or utility may seek immediate resolution through the procedures of COMAR 20.32.01, or an alternative dispute resolution process approved by the Commission, by providing written notice to the Commission and the other party stating the issues in dispute.

(2) Dispute resolution shall be conducted in an informal, expeditious manner to reach resolution with minimal costs and delay.

(3) If available, dispute resolution may be conducted by phone.

C. Dispute Resolution by Technical Master.

(1) If disputes relate to the technical matters regarding the interconnection process, upon the request of the applicant and utility and at their cost, the Commission may designate a technical master to resolve the dispute.

(2) The Commission may designate a Department of Energy National Laboratory, PJM Interconnection, LLC, a college or university with electric distribution system engineering expertise, or another electric distribution system expert unaffiliated with the interconnection process in dispute as the technical master.

(3) Upon Commission designation, the applicant and utility shall use the technical master to resolve disputes related to interconnection.

(4) Responsibility for the costs for a dispute resolution conducted by the technical master shall be determined either prior to submission of the dispute to the technical master by the applicant and utility, or by the technical master after the resolution of the dispute.

D. Pursuit of dispute resolution may not affect an applicant with regard to consideration of an interconnection request or an applicant's queue position.

E. Any deadline imposed by the regulations in this chapter, which is directly affected by any issue in dispute, shall be suspended until resolution of the dispute.

20.50.09.14

.14 Record Retention and Reporting Requirements.

A. A utility shall retain records of the following for a minimum of 7 years:

(1) The total number nameplate capacity and total fees charged for the interconnection requests received, approved, and denied under Level 1, Level 2, Level 3, and Level 4 reviews;

(2) The number of evaluations of interconnections requests approved and denied using any alternate process under Level 1, Level 2, Level 3, and Level 4 reviews;

(3) The fuel type, if appropriate, total number, and nameplate capacity of small generator facilities approved in each of the following categories:

(a) Net metering;

(b) Emergency standby capable of operating in parallel;

(c) Behind the meter load offset;

(d) Combined heat and power;

(e) Energy storage devices; and

(f) Other;

(4) The number of interconnection requests that were not processed within the deadlines established for Level 1, Level 2, Level 3, and Level 4 reviews in this chapter;

(5) The number of scoping meetings held, the number of feasibility studies, impact studies, and facility studies performed, and the fees charged for these studies;

(6) The justifications for the actions taken to deny interconnection requests;

(7) The number of interconnection requests that were not processed within the deadlines established for Level 1, Level 2, Level 3, and Level 4 reviews in this chapter due to a PJM Interconnection, LLC market process study; and

(8) Any special operating requirements required in interconnection agreements, which are permitted only for generating facilities with a nameplate capacity greater than 2 MW, that are not part of the utility's standard operating procedures applicable to small generator facilities.

B. A utility shall retain records of interconnection studies it performs to determine the feasibility, system impacts, and facilities required by the interconnection of any small generator facility for a minimum of 7 years.

C. A utility shall file not later than April 1 of each year a report entitled "Annual Small Generator Interconnection Report" to the Commission containing the following information for the preceding calendar year:

(1) The total number of and the nameplate capacity of the interconnection requests received, approved, and denied under Level 1, Level 2, Level 3, and Level 4 reviews;

(2) The number of evaluations of interconnections requests approved and denied using any alternate process under Level 1, Level 2, Level 3, and Level 4 reviews;

(3) The fuel type, or energy storage type, total number, and total nameplate capacity of small generator facilities approved in each of the following categories:

(a) Net metering;

(b) Emergency standby capable of operating in parallel;

(c) Behind the meter load offset;

(d) Combined heat and power;

(e) Energy storage devices; and

(f) Other;

(4) The number of interconnection requests that were not processed within the deadlines established for Level 1, Level 2, Level 3, and Level 4 reviews and permission to operate notices in this chapter;

(5) The total number of interconnection requests denied and the reason for each denial;

(6) Each interconnection request for a proposed small generator facility that received a cost estimate or incurred an actual cost of at least $10,000 for interconnection facilities or distribution upgrades and was completed during the reporting year, which shall include:

(a) A list of the nameplate capacity of the proposed small generator facility;

(b) Cost variance;

(c) Variance percentage; and

(d) If required, a summary explanation on why the actual cost of facilities or upgrades was at least 10 percent greater than the cost estimate provided;

(7) The number of scoping meetings held, the number of feasibility studies, impact studies, facility studies, and combined studies performed and the total fees charged for these studies;

(8) For each interconnection request for a proposed small generator facility that failed to meet Level 2 criteria according to Regulation .10F of this chapter, a list of the queue number, reason for failure to meet Level 2 criteria, if the applicant requested additional review, whether the additional review was completed within 30 calendar days, or if the applicant decided to request interconnection under Level 4 criteria;

(9) The current utility status and future plans and schedule for implementation of hosting capacity reporting systems or improvements to existing hosting capacity reporting systems;

(10) Beginning April 1, 2021, a utility shall also report annually for the previous year:

(a) The total number of restricted circuits and the total number of closed circuits;

(b) The number of interconnection requests totaled for Level 1, Level 2, Level 3, and Level 4 that were denied due to restricted circuits and the total number that were denied due to closed circuits;

(c) The number of interconnection requests for inadvertent export totaled for Level 1, Level 2, Level 3, and Level 4 that were approved, denied, or suspended due to non-compliance pursuant to Regulation .06P(1)(g) of this chapter;

(d) The number of interconnection requests for net system capacity totaled for Level 1, Level 2, Level 3, and Level 4 that were approved, denied, or suspended due to non-compliance pursuant to Regulation .06P(1)(g) of this chapter;

(e) The number of cancelled small generator facility projects that result in interconnection costs to subsequent small generator facility projects in the same interconnection queue; and

(f) The number of small generator facility projects that delay payment for a distribution system upgrade until the time a first higher small generator facility project in an interconnection queue is ready to interconnect; and

(11) Beginning April 1, 2023, a utility shall also report for the electric distribution system annually for the previous year:

(a) Number of total interconnection customer complaints about smart inverter related curtailments;

(b) Number of smart inverter related curtailment interconnection customer complaints resolved by utility;

(c) Number of smart inverter related curtailment interconnection customer complaints resolved by customer;

(d) Number of smart inverter related interconnection customer curtailment complaints unresolved

D. The utility shall file a notice with the Commission describing any interconnection equipment the utility has considered field-approved for its distribution system within 90 days after granting approval for the interconnection of a small generator facility using the field-approved interconnection equipment.

E. For any small generator facility receiving an interconnection impact study, the utility shall list and explain any study for which the cost of the actual upgrade exceeded the impact study's estimate by at least 25 percent.

F. For any small generator facility receiving an interconnection facilities study, the utility shall list and explain any study for which the cost of the actual upgrade exceeded the impact study's estimate by at least 10 percent.

G. The utility shall send a weekly electronic confidential report to Commission Staff of all solar facilities successfully interconnected. The weekly electronic confidential report shall:

(1) Be compatible with the format requirements of PSC and MD State IT departments to facilitate the processing of Solar Renewable Energy Credits (SRECs); and

(2) Contain the name of the customer, the address, the size of the facility (kW DC) and the date of final approval (net meter set).