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Grid Services Provided by Distributed Energy Resources

Volume 2: Interconnection of Distributed Energy Resources Providing Grid Services

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ABSTRACT

Distributed energy resources (DER)—including battery energy storage, solar photovoltaics, small diesel, combined heat and power, demand response, and associated controls and technologies connected to the distribution network—are increasingly being explored for their ability to provide energy and grid services to distribution and/or bulk system operators.

This report is the second volume of a two-part series:

- Volume 1 (3002031320) summarizes findings from a jurisdictional scan conducted by EPRI of efforts that leverage DER for grid services. This canvasing activity spans across seven geographical areas: in the United States, the states of New York and California; in Europe, the United Kingdom, France, the Netherlands, Germany, and Sweden. Content distills insights and identifies approaches being considered in these regions for enabling more DER, either individually or aggregated, to offer services to the distribution and transmission grids.
- Volume 2 (this report) presents key considerations related to the interconnection of DER providing grid services. This includes assessing whether additional interconnection analysis may be necessary, and examining whether flexible interconnection agreements can be compatible with, or even aid in, the provision of grid services by DER.

These two volumes aim to complement the *DER Scenarios and Modelling Study* focusing on Ontario, Canada, which EPRI completed for the Independent Electricity System Operator (IESO) and Alectra Utilities Corporation (3002028579, 3002028580, and 3002028581).

This report series does not intend to make policy or market design recommendations; rather, its goal is to inform grid stakeholders tasked with assessing the potential development of DER-provided grid services.

Keywords

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Flexibility services
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EXECUTIVE SUMMARY

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KEY RESEARCH QUESTION

Distributed energy resources (DER) are increasingly being explored for their ability to provide energy and grid services to distribution and/or bulk system operators. This report presents considerations related to the interconnection of DER intending to provide grid services.

RESEARCH OVERVIEW

This report presents key considerations related to DER interconnection. This includes assessing whether additional interconnection analysis might be necessary for DER providing grid services, and examining whether flexible interconnection agreements could be compatible with, or even aid in, the provision of grid services by DER.

KEY FINDINGS

- All individual DER seeking to grid connect must first go through an interconnection process managed by the distribution system operator, irrespective of whether they intend to provide grid services. Most jurisdictions have well documented DER interconnection procedures.
- Existing interconnection screens and studies have been developed prior to the introduction of grid services. For this reason, industry stakeholders are considering potential changes to the interconnection process, to better capture distribution impacts directly resulting from DER-provided grid services.
- Flexible interconnection, a new type of connection solution recently introduced in certain jurisdictions, aims to connect DER assets faster and/or at a lower cost.
- If sufficient visibility on interconnection limits is provided ahead of the deadline to submit grid service bids, DER assets connected under a flexible interconnection agreement may be able to provide grid services.

WHY THIS MATTERS

DER-provided grid services are an emerging approach explored at early-adopter utilities and wholesale markets, with limited practical experience to date. This research summarizes insights on the interconnection of DER intending to provide grid services, with the goal of informing stakeholders worldwide.

HOW TO APPLY RESULTS

This research summarizes industry experience related to the interconnection of DER; it can serve as a reference guide for industry stakeholders tasked with learning about and evaluating possible approaches intending to enable more DER to provide grid services to the distribution and/or bulk power systems.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- EPRI Distribution Services Working Group (DSWG)
- EPRI DER Bulk Service Power Working Group (DERBSP WG)

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1 INTRODUCTION

Background

Distributed energy resources[1] (DER) connected to the distribution network are increasingly being considered for their capabilities to provide energy and grid services. Such services may be provided to the electric utility operating the distribution system, and/or to the wholesale market operator operating the bulk transmission system[2].

Grid services provided by DER have the potential to cost-efficiently replace (or enhance) conventional resources, network reinforcements, or solutions otherwise required to maintain reliable operations. For this reason, electric regulators in several jurisdictions are now encouraging (and sometimes requiring) distribution utilities to fully consider DER-provided distribution services as part of their standard planning practices, along with traditional capital investments. In addition, several recent regulatory initiatives, including the Federal Energy Regulatory Commission's (FERC) Order No. 2222 in the U.S., require that wholesale market operators allow and enable DER to provide energy, capacity, and ancillary services in the wholesale electricity markets if they are technically capable of providing those services.

EPRI, in collaboration with the Independent Electricity System Operator (IESO) and Alectra Utilities Corporation, recently explored the opportunities and challenges related to DER-provided grid services in the context of the Ontario power system[3]. This study considered a range of topics, including possible grid service definitions, whether DER can potentially provide multiple grid services, and the needs for enhanced coordination between distribution and transmission actors when procuring grid services from DER. As part of this effort, EPRI also conducted distribution simulations to analyze technical and market offer impacts of DER providing grid services.

[1] This report intentionally adopts a broad working definition of DER, which includes solar PV, other form of distributed generation, battery storage, demand response, electric vehicles and their supply equipment, and other types of distribution-connected technologies. This approach is consistent with the recent Framework for Energy Innovation (FEI) developed by the Ontario Energy Board (OEB), which states that the definition of DER "is context specific and different definitions may be warranted in different regulatory instruments serving different purposes".

[2] While DER can also provide economic or reliability services to the *customer*, the scope of this report is limited to services DER provide to the *grid*.

[3] Key findings from this initial effort can be found in a three-part series of Technical Briefs published by EPRI: *Part 1–Foundational Topics: Grid Services, Coordination Frameworks, Value Stacking Scenarios (3002028579)*; *Part 2–Structuring the Coordination between ISO, DSO and DER to Enable DER-Provided Grid Services (3002028580)*; and *Part 3–Distribution Feeder Simulations to Analyze Technical and Market Offer Impacts of DER Grid Services (3002028581)*.

While this initial work focused on Ontario, Canada, EPRI conducted a follow-up effort to offer broader perspectives on DER-provided grid services. Findings are summarized in a two-volume series:

- Volume 1, titled *Jurisdictional Scan and Analysis* (3002031320), presents approaches being considered in multiple geographic regions for enabling a greater number of DER, either individually or aggregated, to offer services to the grid[4]. Seven geographical areas are considered: in the United States, the states of New York and California; and in Europe, the United Kingdom, France, the Netherlands, Germany, and Sweden. These regions are often recognized as early adopters of grid service solutions, with several pilots and utility programs intending to support a greater adoption of service-based alternatives to conventional network investments.
- Separately, Volume 2 (this report), describes key considerations related to the interconnection of DER, including resources intending to provide grid services.

Organization of this Report

Chapter 2 introduces the fundamentals of the interconnection process. Next, it discusses some of the new complexities introduced by DER-provided grid services and possible steps to update current interconnection practices.

Chapter 3 focuses on flexible interconnection, and examines whether flexible interconnection agreements can be compatible with, or even aid in, the provision of grid services by DER.

This report does not intend to make policy or market design recommendations; rather, its goal is to inform grid stakeholders tasked with assessing the potential development of DER-provided grid services.

[4] *Grid Services Provided by Distributed Energy Resources. Volume 1: Jurisdictional Scan and Analysis*. (3002031320)

2 REVISITING THE INTERCONNECTION PROCESS WHEN DER PROVIDE GRID SERVICES

Chapter Overview

DER technologies connecting to the distribution system have the potential to interfere with grid reliability and service quality. For this reason, all individual DER seeking to grid connect must first go through an interconnection process managed by the distribution system operator. This requirement applies irrespective of the objectives pursued by DER owners, and whether they include customer services (e.g., self-consumption), grid services, operating as a standalone asset, or possibly joining a DER aggregation.

Yet, existing interconnection screens and studies have been developed prior to the introduction of grid services. For this reason, industry stakeholders are increasingly considering whether existing interconnection practices are sufficient to detect potential system impacts associated with the delivery of grid services by DER.

This Chapter discusses some of the new complexities introduced by DER-provided grid services as well as possible steps to revise current interconnection practices.[5]

Fundamentals of DER Interconnection

While exact interconnection steps can vary widely across jurisdictions, the goal of the interconnection process is always to **detect and mitigate upfront any potential issues** that may result from new proposed DER connections. Specifically, interconnection engineers aim to identify potential DER contributions to distribution system constraints. When potential system violations are detected, corrective measures may be required, including modifying the project design and/or operation modes, and/or upgrading the distribution system infrastructure. The end goal is to uphold standards of grid reliability and service quality.

The interconnection process is managed by distribution system operators. Utility staff review interconnection applications and may conduct analysis to determine possible risks and remediations as needed. Upon successful completion of the interconnection process, an agreement is executed between the DER customer and the utility. In addition, DER customers intending to provide wholesale market services may need to complete additional steps managed by the ISO (e.g., installation of additional telemetry equipment, registration, collateral posting, etc.) before they can start submitting bids in wholesale electricity markets.

[5] Certain sections in this Chapter are adapted from the following EPRI publications: *Evolving DER Interconnection Technical Review and Studies to Meet Changing Grid Dynamics* (3002021972); *Planning for Impacts from DER Aggregations Providing Bulk Grid Services* (3002024201); *Considering the Interconnection of DER Aggregations* (3002027451).

Current DER Interconnection Philosophy

The completion of detailed interconnection studies requires engineering resources, time, and can come at a significant cost. For this reason, distribution utilities have progressively **structured interconnection as a *tiered process*, with increasing levels of scrutiny**. The tiered approach recognizes that not all DER interconnection requests have the same potential to interfere with distribution operations. Further, certain parameters intrinsic to the DER project itself and/or to the circuit the project intends to connect to can help determine the appropriate level of analysis, or tier, required for each DER project. The goal is to maintain grid reliability while maximizing interconnection efficiency.

The *Small Generation Interconnection Procedures* (SGIP), developed by the Federal Energy Regulatory Commission (FERC) in the U.S., outline the technical procedures that both the small generator and the utility must adhere to when connecting the generator to the utility's lines. This includes a tiered interconnection process structured around four levels, shown in Figure 1 as illustrative example.

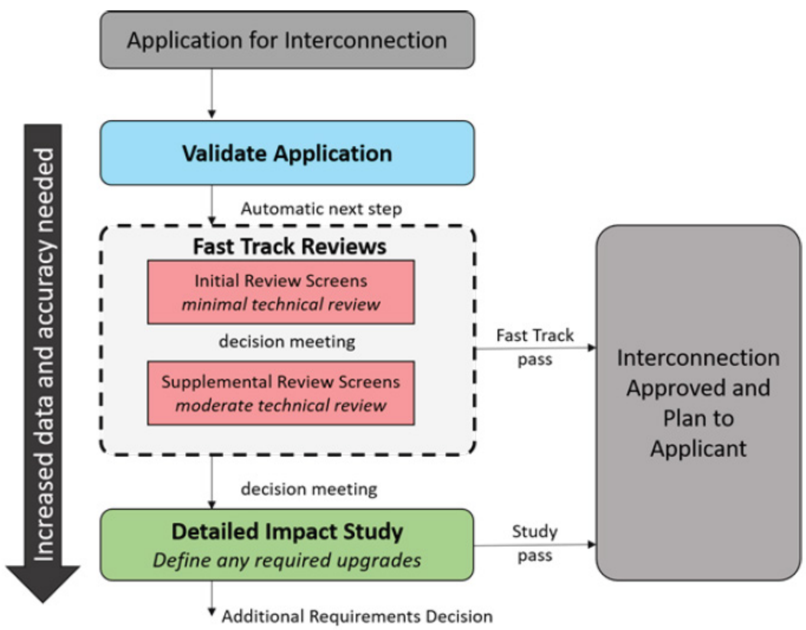

Figure 1. High-level flow diagram of the utility interconnection review process modeled after the FERC SGIP. Source: EPRI.

1. **Validate Application (Expedited Connection)**: The initial level is limited to an application completeness check, with some basic one-line diagram review. Certain DER of relatively small size may be allowed to connect upon competition of this step without any further analysis required.
2. **Initial Screening**: The second level applies a series of pass/fail screens to the DER project seeking to connect, with technical considerations spanning protection, thermal and voltage limits, and potential backfeed issues. Table 1 provides a high-level summary of these first-

order SGIP screens. DER projects passing all these screens may be allowed to connect without any further analysis. Failing one or multiple screens sends the project to the next level of scrutiny.

3. **Supplemental Review**: The third level applies a second level of pass/fail screens, further probing potential DER impacts related to protection, voltage, power quality, and system reliability. Table 1 also provides a high-level summary of these second-order SGIP screens. DER applications failing to pass all the screens typically require a detailed interconnection study.
4. **Detailed Studies**: The fourth tier provides the highest level of technical scrutiny, and may involve advanced modeling and analysis to determine potential system impacts and remediation measures.

Table 1. High level summary of the SGIP screening process.

FERC SGIP	Screen Type/ Level	Technical Considerations	Specific Technical Issue	Typical Limits or Criteria
2.2.1.2	Initial/Fast-track	Protection	15% of peak load (islanding)	15-30%
2.2.1.3	Initial/Fast-track	Export Limit	If secondary network	5% or 50 kW
2.2.1.3	Initial/Fast-track	Export Limit	Separate spot network	5% or 50 kW
2.2.1.4	Initial/Fast-track	Protection	Short circuit contribution	90%/10%
2.2.1.5	Initial/Fast-track	Protection	Interrupting capability	88%
2.2.1.6	Initial/Fast-track	Protection	Feeder GFO/ineffective grounding	Ng or Δ
2.2.1.7	Initial/Fast-track	Thermal	Shared secondary ratings exceeded	20 kW 65%
2.2.1.8	Initial/Fast-track	Voltage	Secondary imbalance	20%
2.2.1.9	Initial/Fast-track	Backfeed	Transient stability limits	10 MW/weak grid
2.2.1.10	Initial/Fast-track	Thermal	No construction required	Yes/No
2.4.4.1	Supplemental	Protection	100% of minimum load	100%
2.4.4.2	Supplemental	Voltage/PQ	Within ANSI limits?	Load flow
2.4.4.2	Supplemental	PQ	Flicker	Pst < 0.35
2.4.4.2	Supplemental	PQ	Harmonics	ITHD < 5%
2.4.4.2	Supplemental	PQ	Rapid Voltage Change (RVC)	MV-3%, LV-5%
2.4.4.3	Supplemental	Safety-Reliability	Safety	1547

DER nameplate (in kW) is one of the key parameters influencing the level of scrutiny triggered by the tiered interconnection process. In practice, **DER of relatively small size** (i.e., 0-50kW) connected behind-the-meter (BTM) often require **little to no interconnection analysis** prior to grid connection. On the other end of the spectrum, **larger DER** connected front-of-the-meter (FTM) often require the **most detailed analysis**.

New Complexities Introduced by DER-Provided Grid Services

The tiered interconnection process developed by the utility industry and the associated list of pass/fail screens were developed prior to the introduction of DER-provided grid services. For this reason, there is an industry concern that **changes introduced by grid services may render existing DER interconnection screens and studies insufficient** to properly detect and mitigate potential grid impacts.

In particular, some of the key changes to consider, all introduced by grid services, relate to modified DER behavior, the possibility for DER to aggregate, new utility needs for upfront data collection and ongoing operational visibility, and potential cross-domain impacts. Table 2 summarizes the changes to except across each of these areas, which the rest of this section further discusses.

Table 2. Key changes introduced by DER-provided grid services

Area of Change	Today: Few DER Providing Grid Services	Tomorrow: DER Providing Grid Services at Scale
DER Behavior	Most DER are non-dispatchable and/or uncontrolled. Interconnection process focuses on impacts from DER intermittency.	DER behavior driven by service requirements / economic opportunities. Loss of "natural" diversity and intermittency.
DER Aggregation	Most DER are operated individually, no aggregated dispatch.	DER aggregation: multiple individual DER are dispatched in concert.
Upfront Data Collection and Operational Visibility	Limited information collected upfront. Utility has no oversight over DER dispatch.	Additional information collected: grid services; individual vs. aggregated operations. Enhanced operational visibility and control.
Cross-Domain Impacts	Most DER do not actively respond to bulk level needs in a way that could impact distribution operations.	Wholesale services provided by DER have potential to impact distribution operations.

DER Behavior

Most DER today are non-dispatchable and/or uncontrolled. As a result, the interconnection process typically focuses on potential impacts resulting from DER intermittency.

By contrast, the behavior of DER providing grid services may be driven primarily by service requirements and/or economic opportunities. Each service may lead to a specific type of behavior, and DER may also choose to switch between services over time. The behavior of already-connected DER may also change, should they choose to start providing services either as an individual resource, or as part of a DER aggregation.

Further, the **emergence of DER-provided grid services may also result in a loss of "natural" diversity and/or intermittency currently exhibited by unmanaged assets**. Customer load and generation profiles may no longer behave non-uniformly (i.e., according to differing operating characteristics, use cases, etc.), but instead follow the same service dispatch signals, or be orchestrated as part of the same aggregation.

DER Aggregation

Most DER today are operated individually: their dispatch is not coordinated with any other DER, except sometimes for those DER co-located at the same customer site. Still, most of the *existing* interconnection screens give some consideration to the aggregated DER capacity already connected to the feeder, as illustrated in Table 3 for the SGIP screens.

By contrast, with the advent of DER aggregation, **large numbers of individual DER, possibly spread across multiple distribution circuits, may increasingly be dispatched in concert to provide grid services**. This development poses the question of whether existing screens or other interconnection study practices are properly capturing all the relevant physical impacts that may result from a DER group operated in a coordinated manner.

Table 3. Consideration of aggregated DER capacity in existing SGIP screening process.

FERC SGIP	Screen Type/ Level	Technical Considerations	Applies To
2.2.1.2	Initial/Fast-track	Protection	Aggregate
2.2.1.3	Initial/Fast-track	Export Limit	Aggregate
2.2.1.3	Initial/Fast-track	Export Limit	Aggregate
2.2.1.4	Initial/Fast-track	Protection	Aggregate
2.2.1.5	Initial/Fast-track	Protection	Aggregate
2.2.1.6	Initial/Fast-track	Protection	Individual
2.2.1.7	Initial/Fast-track	Thermal	Aggregate
2.2.1.8	Initial/Fast-track	Voltage	Individual
2.2.1.9	Initial/Fast-track	Backfeed	Aggregate
2.2.1.10	Initial/Fast-track	Thermal	Aggregate
2.4.4.1	Supplemental	Protection	Aggregate
2.4.4.2	Supplemental	Voltage/PQ	Aggregate
2.4.4.2	Supplemental	PQ	Aggregate
2.4.4.2	Supplemental	PQ	Aggregate
2.4.4.2	Supplemental	PQ	Aggregate
2.4.4.3	Supplemental	Safety-Reliability	Aggregate

Upfront Data Collection and Operational Visibility

Under existing interconnection practices, for most DER applicants, only a limited amount of information is collected upfront. In particular, no information is typically collected on intended applications (e.g., whether the customer intends to provide grid services). Further, most distribution utilities still lack a centralized repository to archive all data collected from DER applicants. In operational time, the utility typically has no oversight over DER dispatch as long as DER customers stay within the interconnection limits approved during interconnection process. Abnormal circuit conditions are one exception where utilities generally reserve the right to disconnect DER (especially larger DER) if required to maintain or restore normal distribution system operations.

With the emergence of DER-provided grid services, **utilities may need to collect additional information from DER applicants** as part of the interconnection process, including the number and type of applications being considered (such as a list of grid services the resource intends to provide), or whether the applicant intends to operate the resource individually, or as part of a DER aggregation. In operational time, distribution system operators may require enhanced operational visibility and/or control over DER customers, especially for customers connecting under a flexible interconnection agreement (as further described below).

Cross-Domain Impacts

While bulk system operators have investigated bulk-level stability concerns over the past years due to a continued growth in distribution-connected inverter-based resources (e.g., loss of inertia, etc.), most DER today do not actively respond to bulk-level needs in a way that could potentially affect distribution system operations.

This may change with the advent of DER-provided grid services. From the perspective of distribution grid operators, distribution services may present a lower level of risk, since the associated service requirements are developed by distribution planning engineers who have visibility into potential distribution impacts. Further, in operational time, distribution operators can evaluate system conditions prior to dispatching distribution services to address system needs.

By contrast, **wholesale services provided by DER to the bulk system have the potential to significantly affect distribution system operations.** Distribution planning engineers may have limited to no advance knowledge of the potential impacts of wholesale services on the distribution grid, which may also vary depending on the market participation model and/or grid service(s). Further, in operational time, since wholesale service dispatch is not initiated by the utility but by the ISO, unless proper mechanisms are in place to manage impacts proactively, distribution operators may be limited to react to distribution constraints created by the delivery of wholesale services after the fact.

Revisiting the Interconnection Process

Overarching Concerns

Are existing interconnection screens sufficient to identify and address potential distribution constraints when DER start providing grid services? Concerns expressed by industry stakeholders are generally twofold:

First, **many of the existing DER connected behind-the-meter were <u>not</u> individually screened or studied**, consistent with the tiered interconnection approach, and current assumptions on DER behavior. In this context:

- The individual behavior of existing DER that were not screened or studied could change (driven by services instead of natural intermittency) and start causing grid impacts.
- The aggregated behavior of existing DER connected behind-the-meter could cause impacts, and utility may be blind to these potential impacts since most of these resources were not individually screened or studied.

Second, **existing screens or studies may not be sufficient** to properly capture all distribution impacts resulting from the **orchestrated dispatch of DER** managed under the same aggregation. For example, existing interconnection studies often rely on the analysis of worst-case scenarios. The goal is to limit the evaluation of DER impacts to a small set of boundary conditions for efficiency purposes. Worst-case scenarios often lie at the intersection of grid-side and asset-side conditions. Relevant grid-side conditions are typically minimum or peak load conditions. Relevant asset-side conditions entail DER operating at maximum capacity, and/or transitioning between minimum and maximum capacity. But while existing screens do consider operations at maximum DER capacity, they give limited consideration to minimum-to-maximum transitions. This highlights several limitations of current screening and analysis approaches.

Possible Steps to Progressively Revise the Interconnection Analysis Process

The primary challenge utilities face as they consider potential additional screens or studies for DER providing grid services is the **lack of field experience**. While existing screening practices for individual DER have been refined over the years from field experience, there is currently little to no field experience related to dispatchable DER providing grid services, either individually or as part of DER aggregations.

Focusing on the potential cross-domain impacts of wholesale services, one approach to develop an initial understanding consists of **translating the requirements of these services into a list of potential distribution system impacts**, and then develop a list of technical studies and/or screens that could detect these adverse impacts, whether related to safety, power quality, or reliability.

Table 4 highlights possible distribution analysis approaches for a selection of bulk system services.

Table 4. Possible distribution analysis approaches for selected bulk services

Bulk Services	Response Time	Primary Distribution System Impact	Planning Analysis Approach
• Inertia Response • Fast Frequency Response	Sub-second to seconds	• Control instability • Short-term voltage fluctuations (Rapid Voltage Change (RVC), flicker, etc.)	• Dynamic simulation (necessary for stability analysis and useful for voltage fluctuation assessment) • Snapshot power flow simulation (to identify the worst-case voltage variation, ramp rate, and occurrence frequency with pre-screening the regulation signal)
• Primary Frequency Response • Regulating Reserves • Voltage Support and Reactive Power Control	Seconds to minutes	• Sustained voltage deviation (over-voltage, under-voltage out of operational limit) • Voltage imbalance between phases • Excessive operation of feeder regulating devices due to fighting and chasing • Ill-conditioned power factor or higher feeder loss due to increased reactive power flow	• Long-term dynamic simulation (to capture the interaction with feeder regulating devices) • Snapshot power flow simulation (for worst-case analysis)
• Energy • Contingency reserves (activated in minutes) • Flexibility Reserve	Minutes to hours	• Thermal	• Snapshot power flow simulation (for worst-case analysis)

With respect to DER aggregations intending to provide grid services, distribution utilities should perform more detailed analysis initially, until sufficient field experience validates the transition to a more simplified analysis approach. As highlighted in Table 4, tools may include power flow and/or short circuit analysis, and possibly dynamic studies to capture sub-second range, especially when DER aggregations intend to participate in frequency regulation service products.

The industry end goal should be to develop a **tiered process with increasing levels of scrutiny to maximize efficiency,** similar to the existing interconnection process for individual DER. The new process could possibly re-use elements of the existing tiered process for individual DER, and/or develop new elements accounts for technical characteristics defined at the DER aggregation level.

In the short term, utilities approving DER aggregations after completing a full interconnection study should consider whether the aggregation application would have been approved if it has been assess only using the existing individual DER screens (if needed, the aggregation should be segment into per-circuit sub-aggregations to appropriately leverage the traditional fast track eligibility process and screens).

Cost Recovery of Additional Analysis Specific to DER Aggregations

The exact scope and prevalence of any additional interconnection analysis distribution utilities may need to conduct for DER aggregations intending to provide grid services is still being determined. Yet, such analysis would come at an extra cost. How should such cost be allocated?

Traditional cost allocations options for individual DER interconnection can typically be broken down into two buckets. Interconnection costs are either directly charged to the DER customers (typical for larger individual DER), or socialized across ratepayers (more typical for small DER customers).

The same cost allocation approaches could be considered for any analysis specific to DER aggregations (when such analysis is warranted). The additional analysis costs could be directly charged to the DER aggregations minimizing cost impacts on ratepayers. This first approach could be justified by the fact that providing grid services is *voluntary*; therefore, DER aggregators should factor any additional analysis costs when considering such business opportunity. On the other end, an argument could be made to socialize the additional analysis costs across all ratepayers when DER aggregations, by providing grid services, deliver value to the grid and generate cost savings for all ratepayers.

Very few jurisdictions to date have started to debate these cost allocation alternatives considering the limited number of DER aggregations currently providing grid services.

An Early Example: AEP's Tiered Approach for DER Aggregation Analysis

Following common interconnection screening frameworks, AEP has developed a tiered method in Texas to determine where a prospective DER aggregation might present risks to system reliability and require a closer look.[6] This process, developed in response to the ADER pilot, has not yet been fully utilized, as no ADER applications in AEP's service territory have required escalation to an Aggregation Study. The flow chart presented in Figure 2 illustrates the step-by-step process.

[6] *Considering the Interconnection of DER Aggregations: Industry Developments & Screening Guidance*. EPRI, Palo Alto, CA: 2023. 3002027451.

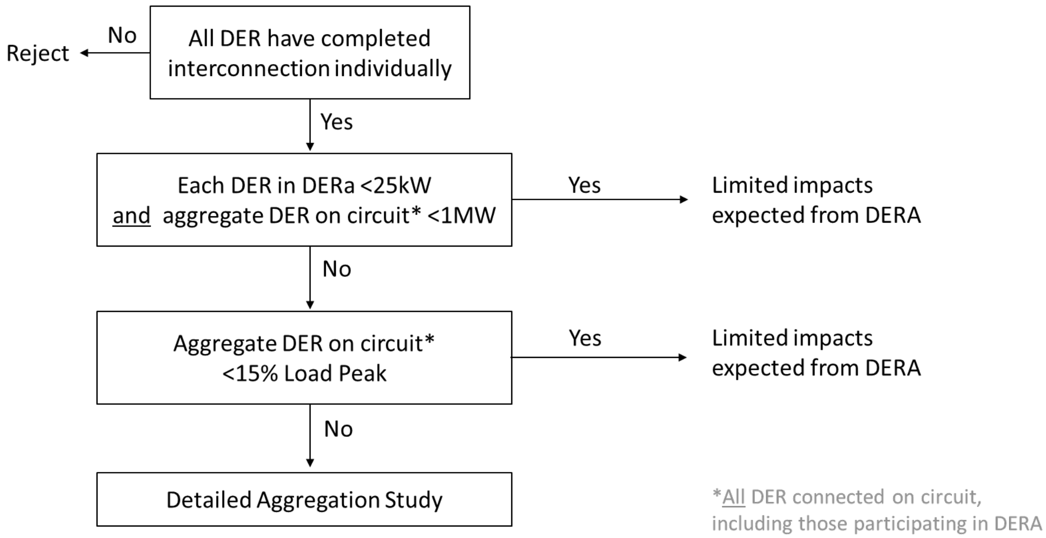

Figure 2. AEP's tiered approach for DER aggregation analysis developed in response to the ADER pilot.

Foundationally, if all individual DERs in an aggregation have a nameplate capacity less than 25 kW, and the aggregate DER penetration on the circuit is less than 1 MW, then the DER aggregation is assumed to have limited system impacts per the utility's traditional DER interconnection process (which all individual DER are required to individually complete). Any subgroup of DER participating in an aggregation that do not meet these criteria must undergo a 15% penetration screen in the context of the affected circuit. Failing the 15% screen escalates the subgroup of DER systems to an Aggregation Study, which assesses all DER capacity and multiple feeders served from each substation.

3 FLEXIBLE INTERCONNECTION: APPROACH AND INTERACTIONS WITH GRID SERVICES

Chapter Overview

Flexible interconnection, a new type of connection solution recently introduced in certain jurisdictions, aims to connect DER assets faster and/or at a lower cost. Flexible interconnection was developed independently of the concept of grid services.

This Chapter introduces the concept of flexible interconnection, considerations on cost allocation, and discusses potential synergies or incompatibilities between flexible interconnection agreements and DER-provided grid services.[7]

What is Flexible Interconnection?

Flexible interconnection[8] is a DER control strategy used to defer or avoid system upgrades and/or increase distribution system utilization. In general, this may involve defining operating constraints on the DER active and/or reactive power at key times when transmission and/or distribution system constraints are binding. In practice, most early-adopter utilities have focused on using flexible interconnection to limit (i.e. curtail) *active* power exports from DER units in order to avoid grid congestions. However, the concept of flexible interconnection can also be applied to load customers, especially in areas where the system operators may have difficulties to construct network upgrades fast enough to keep up with significant load growth.

When focusing on export customers, the amount of DER power export that can be accommodated on the distribution system is inherently time varying because the underlying load, generation, temperature, control settings, circuit configuration and other system parameters fluctuate over time. Traditionally, export customers are connected under a fixed capacity agreement; this fixed export capacity is granted based on "worst case" grid conditions, such that the grid can absorb the full power generated by the DERs whenever it appears while ensuring grid reliability and power quality. By contrast, the flexible interconnection approach aims to grant higher export capacity to DER units, provided that their operation can be reliability managed if grid congestions appear. The approach aims to increase grid utilization, supporting greater energy exports from DER units and larger DER sizes in more locations (see Figure 3).

[7] Certain sections in this Chapter are adapted from the following EPRI publications: *Principles of Access for Flexible Interconnection Solutions: Rules of Curtailment* (3002018506); *Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management* (3002019635).

[8] *Flexible interconnection* is sometimes called *flexible capacity* or *non-firm interconnection*. By contrast, *traditional interconnection agreements* are sometimes called *fixed capacity* or *firm agreements*. In Europe, flexible interconnection solutions are commonly referred to as *Active Network Management* (ANM); in the U.S., the term *Flexible Interconnection Capacity Solution* (FICS) is used. In multiple regions, while more generic, the term *dynamic operating envelope* is also used.

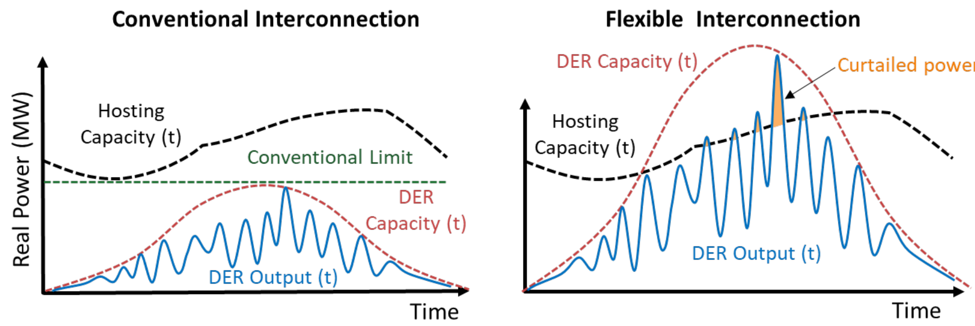

Figure 3. Conventional (fixed capacity) vs. flexible interconnection

Adoption Drivers

While it is common practice for bulk system operators to manage transmission constraints by re-dispatching generation in the presence of transmission system congestion, it is a relatively new practice for distribution system operators to do so. To date, early adopters of flexible interconnection solutions are predominately located in Europe and Australia, while interest appears to be growing in the U.S. Table 5 summarizes potential benefits of flexible interconnection solutions, drawing on early-adopter experiences.

Table 5. Potential benefits of flexible interconnection solutions

Benefit	Description
Lower interconnection costs	Adding controls and curtailing available generation can be cheaper than conventional network reinforcements. In many cases, conventional upgrades may be prohibitively expensive, constraining DER project development. Flexible interconnection may provide a less costly interconnection option by instituting limited curtailment in lieu of grid upgrades.
Faster interconnection times	Adding controls can be a faster solution than many conventional upgrades (e.g. constructing a dedicated feeder). Flexible interconnection can also be used as a temporary solution for customers who want a firm connection; it allows them to grid connect while they wait for the network reinforcement to occur.
Increased network utilization	Flexible interconnection allows for more DER generation per unit of distribution network capacity available; this maximizes use of existing grid assets and increases DER hosting capacity.
Facilitated renewable generation growth	Flexible interconnection can expand renewable generation and meet renewable portfolio standards by using existing network infrastructure, as opposed to building out additional network capacity.

Although there are many potential benefits, not every situation is suitable for flexible interconnection arrangements. For example, some areas may not have sufficient variability in net loads to yield enough flexibility in a feeder’s time-varying hosting capacity to limit the expected amount of curtailment in a flexible interconnection arrangement. Insights from early-adopter utilities[9] also reveal several key factors denoting an area's suitability for flexible interconnection, including:

- Areas where conventional reinforcements would be slow or cost prohibitive
- Areas with enough DER penetration to approach the grid's existing DER accommodation limits
- Areas with DER growth (i.e., cheap and available land, good resource potential, and favorable economic conditions)

Rules of Curtailment

When applied to exporting customers, each flexible interconnection agreement explicitly defines (1) the *grid conditions* that may trigger curtailment, and (2) the *curtailment logic* used to calculate the active power export limit applicable to each participating DER when such grid conditions occur. Since curtailing power exports results in reduced revenues for DER customers, curtailment rules must be clearly defined upfront so that each DER project can adequately compare the flexible interconnection alternative against traditional fixed-capacity arrangements.

Grid conditions triggering curtailment are characterized by one or several specific network constraints defined by a binding limit. Curtailment may be triggered when at least one of these constraints gets "too close" to its binding limit in order to avoid violations that compromise reliability or power quality. Network constraints can be of several types (e.g. thermal, voltage), and of various levels of complexity, as illustrated in Figure 4:

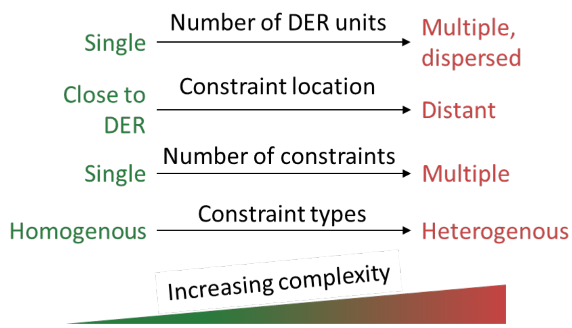

Figure 4. Network constraint complexity factors

Simple scenarios may involve a single network constraint either localized close to a DER site or at a distance. Examples of single constraints include thermal operating limits constraining the operation of a specific distribution line or substation transformer. In more complex scenarios,

[9] *Flexible Interconnection for Distributed Energy Resources: Emerging Practices at Early-Adopter Utilities.* EPRI. Palo Alto, CA: 2018. 3002012964.

multiple network constraints, possibly intertwined, may simultaneously trigger active power curtailment at multiple, geographically-dispersed DER sites owned by different customers. In all cases, constraint status is monitored and logged in real-time so that customers involved can verify grid conditions when curtailment was triggered.

Flexible interconnection agreements must specify the curtailment logic which defines how curtailment requests are calculated when triggering conditions occur. The logic considered can have various levels of complexity. A basic approach may consist of time-differentiated maximum export schedules, based on historical local network conditions. This approach can be implemented through a local controller and may not require any real-time communications. Infrequent manual schedule updates, for example seasonal, may be considered. Another relatively simple approach may consider a binary logic where a "no-export" command is issued in real time to one or several DER units, based on actual grid conditions.

Many early-adopter utilities have considered more advanced curtailment approaches that seek to minimize curtailment in complex scenarios when simple approaches may lead to levels of curtailment that are not economically viable. These more refined strategies can distribute curtailment requests across multiple participating DERs in a given area, based on actual grid conditions and other factors specific to each DER. The two curtailment approaches most commonly implemented by early-adopter utilities are "last-in-first-out" (LIFO) and "pro-rata".

Last-In-First-Out

The LIFO approach curtails DER customers contributing to a specified constraint in the reverse order in which they applied for network connection. The term "LIFO stack" is sometimes used to refer to this ordered list of flexible DER customers. An example of curtailment under LIFO is shown in Figure 5 (at left) for a group of five DER units. Under LIFO, DER-5, the DER customer most recently connected ("last in"), gets curtailed first ("first out"). For this example, grid conditions triggered a full curtailment of DER units 5, 4, and 3, while DER unit 2 was only partially curtailed. DER unit 1, the first to connect, was permitted to continue to fully export (100% of active power available for export).

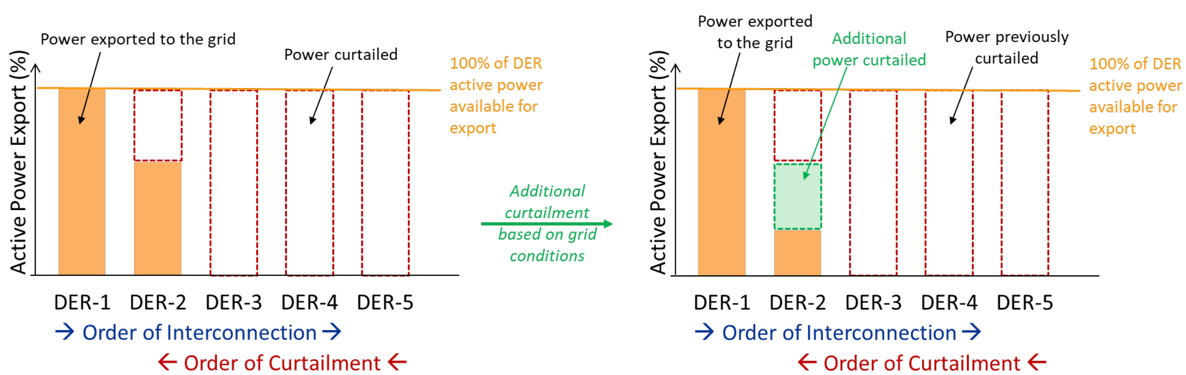

Figure 5. Curtailment under LIFO

Grid conditions are intrinsically dynamic, as both load and DER power production constantly change over time. Evolving grid conditions require to regularly adjust the curtailment levels[10]. Figure 5 (at right) illustrates, for the same group of five DER units, a curtailment update requiring additional active power curtailment on DER-2. Grid conditions eventually return to a state where curtailment of DER power exports can be progressively relaxed thanks to increased load demand and/or decreased DER power production.

Curtailment as depicted in Figure 5 may occur multiple times a year, with different levels of severity based on grid conditions. Some grid conditions may require all flexible DER units to be fully curtailed, while less severe grid conditions may only require a single DER unit to be partially curtailed.

Pro-Rata

Under the pro-rata approach, active power curtailment is shared across DER customers contributing to a specified constraint in proportion to a reference parameter, such as the amount of active power available for export. Figure 6 (at left) provides a basic example for a group of three DER units located in the same geographical area and contributing to the same constraint. It is assumed that all DER units were exporting 100% of their active power available for export prior to curtailment. As a result of evolving grid conditions, active power exports are reduced across all DERs by the same proportion factor.

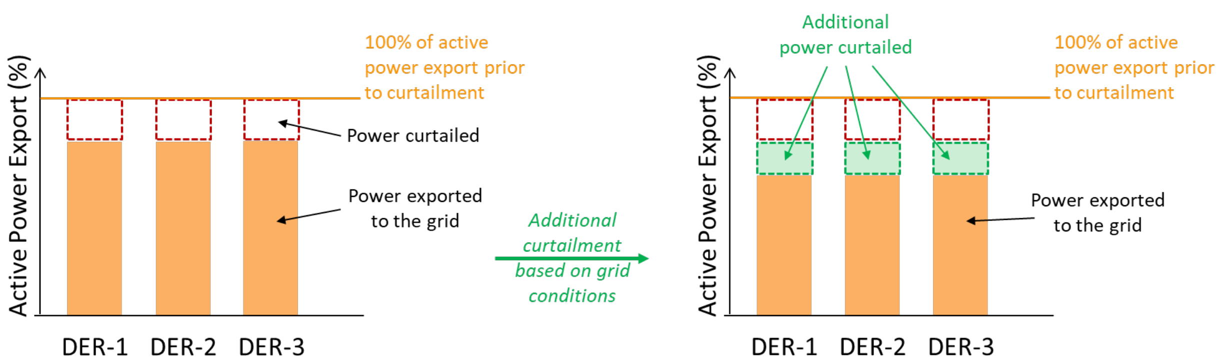

Figure 6. Curtailment under pro-rata using "DER active power available for export" as allocation key.

Evolving grid conditions, reflecting changes in generation and/or demand, may trigger updates in curtailment levels as illustrated in Figure 6 (at right). Such updates may involve an increase or decrease of the total amount of DER power exports curtailed in a given geographical area. Of course, each DER unit can only curtail *up to* its amount of active power available for export (then equivalent to a "no-export" command). Therefore, while Figure 6 provides a simplified

[10] The frequency at which curtailment levels are updated depends on the type of the control and communication technology used, among other factors.

overview of the curtailment process, the actual process may be much more involved in practice to ensure that DER units are never asked to curtail *more* than their active power available for export.

Comparing LIFO to Pro-Rata

Capacity Factors and Network Utilization. DER customers who connect early under LIFO tend to get curtailed less often[11], while the pro-rata approach aims to spread curtailment more evenly across participating DER units. For this reason, a greater number of DER units may be able to reach a capacity factor above the minimum economic capacity factor under pro-rata (Figure 7). This may result in more DER projects being financially viable, and therefore more projects connecting to the grid. A greater number of interconnected DER units can potentially enable better network utilization, especially with a diverse DER technology mix.

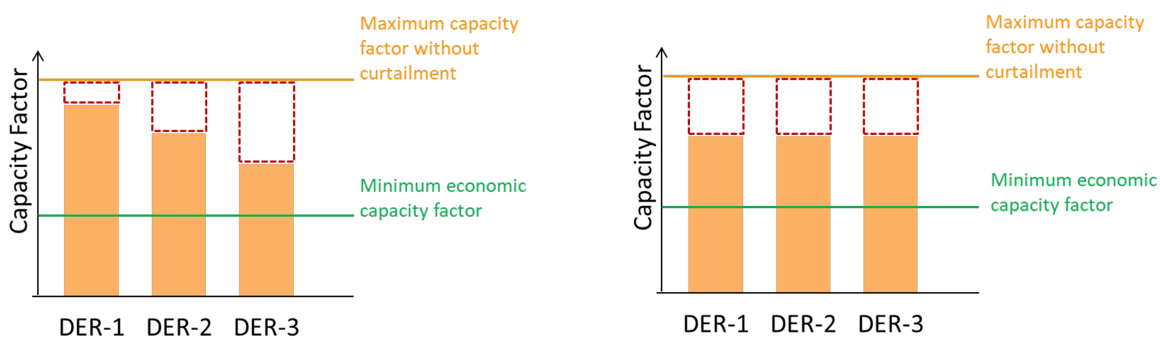

Figure 7. Illustrative annual capacity factors[12] under LIFO (left) and pro-rata (right)

Effect of Additional Flexible DERs on Individual DER Curtailment. Under LIFO, additional DER customers connecting under a flexible agreement do not impact DER customers previously connected from a curtailment standpoint, since customers connecting last get curtailed first[13]. However, under pro-rata, additional DER customers may lead already-connected DER customers to experience increased curtailment: as new DER customers connect, the total active power export capacity increase, potentially leading to more frequent network congestions, in turn leading to more frequent curtailment which increasingly affect *all* DER customers under pro-rata. Consequently, pro-rata may fail to provide DER customers with sufficient confidence that curtailment levels will remain sufficiently low in the long term to ensure financial viability of their DER projects. Backstop measures may include a quota on connected DER capacity, or a maximum curtailment threshold beyond which new DER customers are not allowed to connect under a flexible agreement. For both LIFO and pro-rata, all DER customers may experience increased curtailment as a result of decreasing load in the area.

[11] See also side bar *"LIFO: First connected, lowest curtailment? Not always"* in this paper for further discussion on this topic.

[12] This illustrative example assumes that all three DERs have similar technology and production potential.

[13] This assumes that all additional customers can get *fully* curtailed.

Incentives to Upgrade to Fixed Capacity Agreements. The number of DER customers connected under a flexible agreement in a specific area may reach a critical mass beyond which the total cost of curtailed active power across the group of DER customers may exceed the cost of implementing network reinforcements required to upgrade all DER customers to traditional, fixed capacity interconnection agreements. LIFO and pro-rata rules allocate curtailment requests differently across DER customers, leading to differences in customers' willingness to pay (WTP) for network reinforcements. Under pro-rata, all DER customers are affected by curtailment requests similarly (proportionally to the allocation key used): when DER technologies are similar (e.g. solar PV), all DER customers connected under a flexible agreement have similar incentives to co-finance upgrades when a certain critical mass of DER customers is reached. However, under LIFO, the customers' WTP for upgrades is dependent on their position in the LIFO stack. In general, last-in customers experience more curtailment, and thus would receive greater benefit from network upgrades. This asymmetry in curtailment allocation may require an arrangement where upgrade costs are also allocated asymmetrically (see further discussion on Cost Allocation below).

Gaming of Priority Rules. Since LIFO curtails DERs in the reverse order in which they applied for network connection, some customers may be tempted to apply early to "hold a spot" in the LIFO stack, with no intention to actually connect a DER asset in the short term. Such customers could eventually re-enter the LIFO stack in the mid- to long-term to the detriment of customers who applied at a later date, but effectively connected their DER systems earlier. Backstop measures may include setting a maximum period of time between the interconnection application and effective connection, beyond which the application expires; or using the effective connection date as the reference to establish the priority order in the LIFO stack.

Cost Allocation Considerations

Flexible interconnection solutions intend to integrate rising penetrations of DERs by deferring or avoiding traditional network reinforcements. However, system upgrades may eventually be implemented in areas with flexible interconnection customers, relaxing the very same network constraints that justified the implementation of flexible interconnection solutions in the first place. This, in turn, may alter the frequency and duration of curtailment events, as well as the revenues flexible interconnection customers receive from power exports.

Motivations to Upgrade

There are three primary motivations, summarized below, for upgrading the grid in an area with flexible interconnection customers.

Case 1: Flexible interconnection is a stopgap – Flexible interconnection solutions can be used as a stopgap to more quickly connect DER customers while network reinforcements are being constructed. The aim is for DER customers to first connect under a flexible agreement, and eventually move to a fixed capacity agreement once the upgrade is completed.

Case 2: Upgrades are triggered by the distribution planning process – Network reinforcements may be triggered as part of the standard planning process due to load growth or other reliability considerations that are unrelated to DER growth. These upgrades may relax some of the constraints that drive the implementation of flexible interconnection arrangements in an area.

Case 3: A return to firm connection is economically justified – Flexible interconnection customers may reach a critical mass such that the cost of collectively financing all network reinforcements necessary to upgrade to fixed capacity connections is less, over a given time horizon, than the lost revenues that would result from power export curtailments of flexible capacity connections.[14]

Cost Allocation Implications

Following the principle of cost causation, several cost allocation approaches can be considered for each of the three cases mentioned above where upgrades are performed in areas of pre-existing flexible interconnection agreements.

Table 6. Summary cost allocation considerations for flexible interconnection cases

Case	Motivation	Upgrade Triggered By	Cost Allocation Consideration
#1	End stopgap measure (due to completed upgrade)	Flexible interconnection customers	Apply existing cost allocation rules in place for fixed capacity connections.
#2	Address anticipated load growth/ reliability issues	Distribution System Operator (DSO)	Leverage upgrades triggered by standard planning practices. Challenge: Determining the rules governing how upgrade costs are allocated among utility ratepayers and flexible interconnection customers.
#3a	Revert to firm connection based on favorable economics	Flexible interconnection customers	Allow flexible interconnection customers to decide if they will voluntarily contribute to paying upgrade costs. Challenge: potential for free rider problem.
#3b		DSO	Require flexible customers to upgrade to a fixed capacity connection and share in the associated upgrade costs when an economic threshold is met. Challenge: setting a threshold that is agreeable to all parties.

For **Case 1**, when flexible interconnection is simply a stopgap measure for a firm capacity connection, the DER customer(s) "causing" the needed upgrade is clearly identifiable, and therefore cost allocation based on existing rules is relatively straightforward.

[14] Undergoing partial upgrades to alleviate some (but not all) constraints—for example, reconductoring part of a feeder but not upgrading the substation—may be optimal under some circumstances.

In **Case 2**, however, defining cost causers and beneficiaries may be less clear. Although load growth or reliability concerns may impel the Distribution System Operator (DSO) to upgrade the grid for ratepayer benefit, the upgrades may also benefit flexible interconnection customers by reducing their curtailments. Although the reduced curtailments may be temporary if more power exporting customers are added in the future, the existing flexible interconnection customers nevertheless use, and benefit from, the increased grid capacity that they may not have paid for. The issue of DER customers consuming existing headroom for capacity and deferring costs to late comers is an enduring challenge even for conventional firm capacity connections.

Moreover, under special circumstances in Case 2, flexible interconnection customers may seek to leverage the upgrade triggered by the DSO and contribute to oversizing the upgraded capacity beyond conventional planning practices in order to further reduce their curtailments or accommodate firm DER export capacity. These nuances must be addressed in the rules governing how upgrade costs are allocated among utility ratepayers and flexible interconnection customers.

In **Case 3**, where economics justify grid upgrade, additional complexities arise given that multiple flexible interconnection customers contribute to the economic justification of a grid upgrade at varying amounts based on their system size, operating characteristics, and control logic. Case 3 represents an emerging challenge that has yet to be addressed by industry stakeholders. Its circumstances warrant principles that define who triggers the upgrade and how grid upgrade costs should be shared among a group of flexible DER customers.

One option for addressing core challenges presented by Case 3 is to have flexible interconnection customers voluntarily arrange with the DSO to pay for network reinforcements, and upgrade to fixed capacity connections. Each flexible interconnection customer, in theory, has a willingness to pay for upgrades based on the opportunity cost of expected future curtailment. Thus, as more customers connect, eventually the collective willingness to pay may cross the economic threshold to pay for a grid upgrade.

However, complications may arise if some of the existing flexible interconnection customers refuse to voluntarily upgrade to a fixed capacity connection while others decide to proceed. This scenario may create "free riders" wherein some customers elect not to voluntarily contribute to an upgrade, but to stay on a flexible interconnection agreement and thus benefit from the upgrades financed by others in the form of reduced curtailment.

Alternatively, the DSO may require that all flexible interconnection customers in a given area upgrade to a fixed capacity connection once collective curtailment costs outweigh upgrade costs over a given time horizon. This approach would aim to maximize DER production by requiring customers to upgrade to fixed capacity agreements when economic to do so. It would also address the "free rider" problem associated with the voluntary upgrade option. The drawback of requiring upgrades, however, is that each DER customer may have a different individual economic threshold to pay for an upgrade, making it challenging to determine a collective threshold that is agreeable to all parties.

In sum, flexible interconnection arrangements elevate the need for clear-sighted cost-sharing allocation mechanisms. While these arrangements can enable grid connection of a greater number of DER customers (who, in turn, benefit in some way from avoided or deferred grid upgrades), they also add complexity to cost allocation mechanisms. That's because grid upgrades can impact project costs as well as project revenues given expected reductions in curtailment.

Flexible Interconnection and Grid Services: Synergies or Incompatibilities?

The concept of flexible interconnection has emerged independently of the concept of grid services. Specifically, utility engineers considering flexible interconnection alternatives do <u>not</u> typically take into account whether the DER applicant intends to provide grid services. Said differently, as long as one or several of the pre-specified system constraints are binding, DER connected under a flexible agreement are expected to comply with dynamic interconnection limits, even if providing grid services.

In practice, DER applicants electing to connect under a flexible agreement may be guaranteed a certain import and/or export capacity, with additional capacity dynamically allocated based on system conditions. This concept, known as *Time-Varying Operating Envelopes* (TVOE), is illustrated in Figure 8.

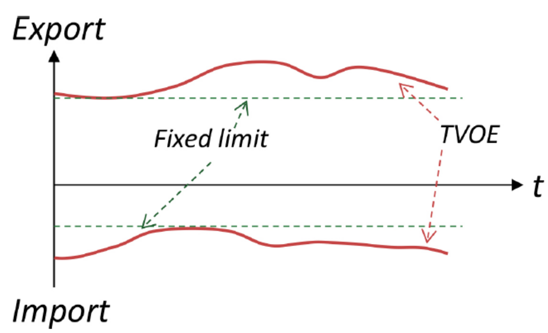

Figure 8. Illustrative example of Time-Varying Operating Envelopes.

Since flexible interconnection aims to connect *more* DER to the grid, faster, and at a lower cost, its wide application could help establish a larger pool of grid-connected DER assets, potentially interested in providing grid services. At the same time, the notion of dynamic interconnection limits inherent to the concept of flexible interconnection could restrict the ability of DER customers to provide services: on one hand, dynamic limits introduce uncertainty around the amount of power that can be effectively exchanged with the grid; on the other end, having visibility into that import and/or export capacity is key for DER interested in providing grid services. DER customers connected under a flexible interconnection agreement may be unable to submit service bids if they lack sufficient certainty that the necessary import and/or export capacity *will* be available to satisfy all service requirements.

In practice, stakeholders should compare two set of timelines to determine potential incompatibilities: 1) how far in advance DER customers connected under a flexible agreement should expect to be notified of potential restrictions affecting their export and/or import capacity due to network conditions; and 2) how far in advance should service bids be submitted to the service requesting entity. For service products where the deadline to place a bid *precedes* the notification of potential import and/or export restrictions due to network conditions, DER customers connected under a flexible agreement would be unlikely to submit bids. On the other hand, if sufficient visibility on interconnection limits is provided ahead of the deadline to submit bids, those same customers could participate in service opportunities based on their available import and/or export capacity.

4 CONCLUSIONS

All individual DER seeking to grid connect must first go through an interconnection process managed by the distribution system operator. The goal is to detect and mitigate upfront potential issues that may result from new proposed DER connections. This requirement applies irrespective of the objectives pursued by DER owners, and whether they include customer services (e.g., self-consumption), grid services, operating as a standalone asset, or possibly joining a DER aggregation.

Existing DER interconnection screens and studies have been developed prior to the introduction of grid services. For this reason, industry stakeholders are increasingly considering whether existing interconnection practices are sufficient to detect potential system impacts associated with the delivery of grid services by DER. Specifically, the delivery of grid services may lead to new DER behaviors and associated grid impacts. This may be reinforced when multiple individual DER are dispatched in concert, as part of a DER aggregation providing grid services.

Concerns expressed by industry stakeholders are generally twofold. First, many of the existing DER connected behind-the-meter were not individually screened or studied; these assets could start causing grid impacts when providing grid services. Second, existing screens or studies, often focused on the analysis of worst-case scenario, may not be sufficient to properly capture all distribution impacts resulting from the orchestrated dispatch of DER managed under the same aggregation.

Possible next steps to revisit existing interconnection analysis processes includes translating grid service requirements into a list of potential distribution system impacts, and then develop a list of technical studies and/or screens that could detect these adverse impacts, whether related to safety, power quality, or reliability. The industry end goal should be to develop a tiered process with increasing levels of scrutiny to maximize efficiency.

Flexible interconnection is a particular type of interconnection agreement recently introduced in certain jurisdictions. In exchange for connecting faster and/or at a lower cost, DER assets connected under a flexible agreement agree to be managed at key times when transmission and/or distribution system constraints are binding.

Flexible interconnection was developed independently of the concept of grid services. However, if DER connected under flexible agreements are provided sufficient visibility on applicable interconnection limits ahead of the deadline to submit grid service bids, they may be able to participate in service opportunities based on their available import and/or export capacity.

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