Ameren Illinois Flexible Interconnection and DER Orchestration Report

Phase 1

September 2025

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Key Contributing Organizations

Ameren Illinois

Electric Power Engineers (EPE)

Eclipse Energy Partners

CHARGED Initiative, which includes:

- GridLab
- RMI
- Advanced Energy United

Joint Non-Governmental Organizations (JNGOs) and Joint Solar Parties (JSPs)[1]

[1] The Joint Non-Government Organizations (JNGOs) and the Joint Solar Parties (JSPs) intervened and participated in the Dockets 22-0487/23-0082/24-0238 (consl.), which included flexible interconnection and related topics. JNGOs includes Environmental Law and Policy Center, Natural Resource Defense Council, Union of Concerned Scientists, and Vote Solar. JSPs includes Solar Energy Industries Association, The Coalition for Community Solar Access, and The Illinois Solar Energy Association.

Executive Summary

Flexible interconnection, broadly speaking, incorporates new techniques and technologies into the interconnection process to utilize the flexibility of a customer's load or DER in order to improve outcomes for that customer during the connection process. While there are several specific methods (which will be explored in detail within this report), the common thread is exploring new techniques and technologies to reduce interconnection costs and timelines by avoiding distribution constraints and the need for subsequent system upgrades.

To investigate the potential of flexible interconnection, Ameren Illinois, along with technical experts from Electric Power Engineers (EPE), collaborated with the Joint Non-Governmental Organizations (JNGOs) and their consultant Eclipse Energy Partners, and explored the feasibility, process impacts, customer use cases, and other potential impacts of several different methods of Flexible Interconnection (see below).

Ameren Illinois, as part of the Refiled Multi-Year Integrated Grid Plan, committed to engaging stakeholders to explore flexible interconnection approaches and potential pathways and timelines for implementation. As part of this effort, Ameren Illinois collaborated with the CHARGED Initiative[2] to host a series of facilitated stakeholder engagement sessions for stakeholders representing both load and DER connectors. Feedback from stakeholders in these sessions was extremely valuable to understanding the value proposition for various flexible interconnection methods, approaches to implementing and making each method available, as well as how to communicate new connection options effectively. While this report documents individual feedback provided for each specific method, other feedback regarding more holistic concerns and ideas was also shared and has been incorporated throughout this report. Ameren Illinois also presented monthly updates and summaries of technical content and stakeholder feedback to the DER Subcommittee, which included Staff as well as representatives of many advocacy and DER development organizations. More information about the stakeholder engagement process, feedback, and participants is available in Appendix A.

As a result of this investigation and stakeholder engagement activities, Ameren Illinois intends to pursue or expand the offering of connections with volt/watt settings, staggered connections, and limited import/export connections during Phase 1 of the Ameren Illinois Flexible Interconnection

[2] https://gridlab.org/chargedinitiative/

Plan. These methods were selected because of their potential benefits for both applicants and other Ameren customers, available mitigations for potential negative reliability impacts, and ability to be implemented without major structural or technology modifications or the development of new study capabilities. These methods will create additional complexity within the interconnection process, and Ameren Illinois will continue to make appropriate investments in the people, tools, and infrastructure necessary to implement them effectively.

Table 1 – Flexible Interconnection Methods Summary

Connection Method	Description	Proposed Path Forward Summary
Volt/Watt	Enable Volt/watt to resolve overvoltage conditions	Enable for Level 1 DER connections which fail the 20kVA shared secondary screening
Limited Import/Export	Utilize a single maximum import or export value (rather than equipment nameplates) during screening and study processes	Develop updated technical requirements and enable use for load connections
Scheduled	Utilize a range of pre-determined seasonal or time-varying maximum import or export values	Further development during Phase 2
Staggered	Allow for a portion of applicant load or DER facilities to be energized prior to the completion of system upgrades needed to support the full planned facility	Enable for applicants which would require upgrades with long lead times. Enable for Level 1 DER temporarily utilizing Volt/Watt
Dynamically Managed	Dynamically modify resource operating limits in real time based on actual system conditions or forecasted operating limits	Further development during Phase 2

Ameren Illinois also explored some methods that, while highly promising, will require additional investigation refinement before they can potentially be offered to customers. Schedule-based connections show significant potential value for maximizing the use of existing infrastructure and were highly desired by stakeholders. However, there are key decisions regarding the granularity of proposed schedules as well as the technological requirements for their implementation that will require additional exploration. Dynamic managed connections were also of significant interest to stakeholders but will require similar development for key decisions as well as the deployment of communications and management infrastructure such as a DER Management System (DERMS) to support implementation. Further refinement of static scheduled connections and dynamic managed connections will occur during Phase 2 of this effort, which is expected to begin in September 2025.

This report also explores how flexible interconnection fits within the broader landscape of DER initiatives in Illinois as part of DER Orchestration efforts. DER Orchestration considers the concurrent operation of DER for a variety of purposes including avoiding distribution system constraints (flexible interconnection), potentially positively impacting the distribution system by providing additional capacity or other benefits (Value of DER or Distribution Services), and enabling the participation of DER in bulk power services markets (Virtual Power Plants). While DER can potentially participate in each of these three activities, the combined operation of a single DER for multiple purposes is operationally complex, which can create challenges and requires a coordinated approach. This coordination, for each method individually and in combination, is explored for feasibility and potential challenges, as well as the role of DERMS in coordinating DER dispatch and operations. Additional refinement of these concepts and DERMS requirements and implementation will be conducted during Phase 2.

Finally, this report identifies activities, concepts, initiatives, and programs that have been developed using the best available information and is subject to refinement, revision and change by Ameren Illinois, as appropriate.

Flexible Interconnection Overview

Flexible Interconnections are perhaps most easily defined in contrast to the existing standard utility process. The traditional process primarily utilizes equipment nameplate information to assess the alignment of "worst case" outcomes, where the maximum impact of the resource occurs during the local distribution system's most constrained time. Flexible connections still use the same fundamental approach to identify grid constraints and potential system upgrade needs but allow for the performance of the resources (or the connection process itself) to be modified to better reflect the operational capabilities of the resource. As a result, flexible connections create significant new complexity within the interconnection process but can enable more efficient connections that make better use of existing infrastructure. The different flexible interconnection methods explored in this report will consider different types of performance modifications and their impact on the connection process and the need for grid upgrades.

Flexible interconnection, where implemented effectively, can be beneficial for new connectors of both load and DER, as well as other Ameren customers, while still maintaining grid safety and reliability. For new connectors, flexible connection methods can be used to adjust resource performance to avoid otherwise necessary distribution system upgrades. Where practical, this allows applicants to reduce their interconnection cost and speed up their timeline for operation. Flexible connections can benefit other Ameren customers by maximizing the use of existing infrastructure. They enable new loads to connect and increase energy delivery with less capacity investments, helping to control costs and put downward pressure on customer rates. Specific benefits and use cases will vary by flexible connection method, resource type, and customer size.

The following flexible connection methods were to be explored for potential implementation by Ameren Illinois:

Table 2 - Flexible Interconnection Methods and Examples

Connection Method	Description	Demonstrative Example
Volt/Watt	Enable Volt/watt to resolve overvoltage conditions	10kW Solar PV that fails the Level 1 20kVA shared secondary screening
Limited Import/Export	Utilize a single maximum import or export value (rather than equipment nameplates) during screening and study processes	10kW solar PV installation with a 10kW battery storage system with a maximum export of 10kW
Scheduled	Utilize a range of pre-determined seasonal or time-varying maximum import or export values	5 MW solar facility with a maximum export of 2.5 MW during Spring/Fall and 5 MW during Summer/Winter
Staggered	Allow for a portion of applicant load or DER facilities to be energized prior to the completion of system upgrades needed to support the full planned facility	5 MW solar facility that connects 2 MW immediately and the remaining 3 MW after the completion of necessary system upgrades
Dynamically Managed	Dynamically modify resource operating limits in real time based on actual system conditions or forecasted operating limits	5 MW solar facility that has its maximum export limited during periods of distribution constraint

When assessing whether, when, and how to proceed with developing connection offerings associated with each method, key factors that will be a part of the assessment include:

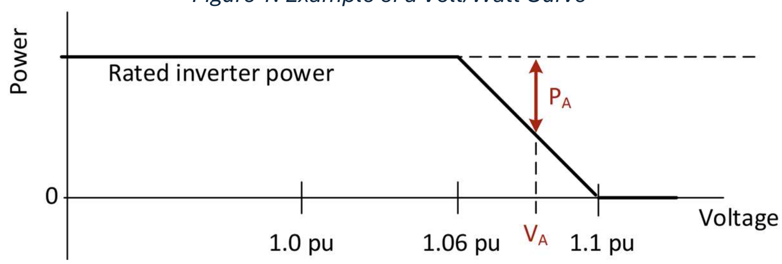
- Risk Management – Can the method be enabled without compromising the safety and reliability of the distribution system?
- Implementation Speed – Can the method be enabled using existing connection processes, tools, and supporting infrastructure? Are the supporting technologies relatively mature and available?
- Impacts to Non-Participants – What additional costs or investments will be necessary to implement the method? Are there benefits for customers other than the direct applicant?
- Benefits to Participating Customers – How likely is the method to be utilized by applicants to improve connection speed or reduce connection costs? To what extent?

Static Flexible Interconnection Approaches

Volt/Watt

A volt/watt curve is utilized to manage voltage at the DER inverter by reducing the resource's real power output based on the measured voltage. Currently, volt/watt curves are a standard inverter function available to applicants under the existing IEEE 1547 and UL 1741 SA and SB standards but are disabled by default. These curves have preprogrammed set points that determine how the inverter should curtail the resource's real power injection to mitigate high voltage. When DERs are connected to the system, the voltage at the point of connection will tend to increase due to the real power injection, making volt/watt curves a potential tool to mitigate high voltage. These curves can be utilized alongside volt/var curves, which function similarly but will inject or absorb reactive power based on measured voltage. Figure 1 below provides an example volt/watt curve from NREL, where P_A is the maximum real power output based on measured voltage V_A. In this example, the highest voltage level the inverter can export power without curtailment is 1.06 per unit.

Figure 1: Example of a Volt/Watt Curve[3]



Within the existing screening process for new DER connections in Illinois (as defined within the Illinois Administrative Code Part 466), small DER applicants within the Level 1 process are screened for whether the additional DER will cause the total amount of DER within a shared secondary district to exceed 20kVA. The primary condition that this screening criteria is intended to prevent is excessively high voltage. Volt/watt curves, which act in response to excessive high voltage, could be used in lieu of this screening criteria (or added in response to a failure of this screening criteria) to maintain customer voltage levels.

[3] NREL Estimating Customer Impact of Volt-Watt Using Only Smart Meter Voltage Data Presentation, Slide 9, (NREL, 2019), Link: Source

Similarly, for larger DER within the Level 2 or Level 4 interconnection process, volt/watt could be used to prevent the new DER from creating or exacerbating excessive overvoltage conditions if such conditions are identified during the study process.

Risks and Challenges

One primary concern with using volt/watt curves to prevent overvoltage conditions is the potential for customer non-compliance. For small systems, inadvertent or intentional removal of the volt/watt curve could lead to localized overvoltage impacting other customers on the same service transformer. For larger DER, this could cause more widespread high voltage conditions on primary voltage equipment, impacting a larger number of customers.

There are some potential mechanisms that could be used to prevent non-compliance or respond to any issues caused by non-compliance. First, prior to receiving permission to operate, the volt/watt curve's activation and settings can be verified (during, for instance, the witness test). Some equipment manufacturers require a special administrative password or access through an admin profile to modify smart inverter settings (though this is not required by the IEEE or UL equipment standards)[4].

For compliance monitoring at larger DER sites with SCADA-enabled on-site reclosers, time-series data for site voltage and real power could be used to monitor compliance by identifying overvoltage conditions at the DER and verifying the associated level of real power output. This could occur either during live system operation (in response to reports or measurements of overvoltage conditions) or by reviewing historical data. In practice, this approach can help identify and response to non-compliance conditions, but it does not prevent such conditions (and the resulting overvoltage conditions) from occurring.

For smaller DER, direct detection via SCADA is unlikely to be available. AMI data may provide some insights via voltage and real power data collection, but the specific DER performance may be obscured by on-site loads. For smaller DER, the impact of potential non-compliance is more limited, likely only impacting other customers served by the same service transformer. Where overvoltage issues would be caused by non-compliance, existing processes for voltage violation

[4] https://service.sungrowpower.com.au/files/Web_Files/FAQ/IT_20200423_C%26I_Power%20Quality%20Response%20Mode%20Settings%20Guide_V1.1.pdf

identification and customer voltage issue resolution can be used to detect and respond to such cases.

Direct utility communication to DER to monitor volt/watt curve points is also an option for ensuring ongoing compliance. Because this requires establishing communications and data exchange with the DER, implementation of this approach for settings compliance is unlikely to be cost-effective in the short term. If DER communications are already being pursued or established for other purposes (e.g., via DERMS), direct enablement of settings monitoring could be considered as an additional benefit of such efforts.

Another key challenge area for volt/watt curves is addressing real power curtailment and the subsequent loss of energy production by the DER owner. The magnitude of annual curtailment is a significant factor in the economics of considering adoption but is difficult to estimate at the time of interconnection (and its estimation is not part of the existing study process). Because the customer's project economics may be negatively impacted by curtailment risk, they may be hesitant to adopt volt/watt as a mitigation measure to avoid system upgrades. In other jurisdictions where volt/watt has been required, it has been accompanied by mechanisms such as utility reporting of estimated customer curtailment or requirements for the utility to resolve excess curtailment through system modifications. Such approaches shift the risk from the individual customer to the utility (and, consequently, to other utility customers). Both mechanisms come with associated utility costs for data analysis, administration, and potentially construction. With volt/watt as an optional mitigation measure, mandatory reporting or upgrade approaches are not necessary to protect customers from curtailment risk, so long as the customer has a reasonable path to resolution if they experience a level of curtailment that is uneconomic for them.

Implementation Pathways

To implement volt/watt as a resolution for screening or study criteria failure requires additional interaction between the customer and the utility within the process. For level 1 applicants, this interaction can be relatively easily woven into the existing process during the results communication phase. If the customer is amenable to using a volt/watt curve to cure the failure of the 20kVA shared secondary screen, they can proceed with the typical interconnection process. Because customers are already incorporating volt/var functionality as a result of the smart inverter rebate, it is anticipated that volt/watt function could be enabled within this process without triggering “material modification” provisions that would require application withdrawal or resubmission.

For larger applicants, modifications in response to study criteria failure are already anticipated and enshrined within the Level 2 and Level 4 process within Part 466. However, because additional DER projects may be queued behind the applicant considering volt/watt, it is much more difficult for the applicant to modify their installation to remove volt/watt if they experience elevated levels of curtailment. In addition, the wider-reach impacts of non-compliance for large systems and higher likelihood of curtailment for large projects using volt/watt to avoid overvoltage conditions create hurdles to utilizing volt/watt for large systems.

Another factor to consider for enabling the use of volt/watt curves is the existing smart inverter rebate in Illinois. Default settings associated with the smart inverter rebate include volt/var and ride-through performance requirements, but do not include volt/watt settings. Language within the Climate and Equitable Jobs Act (CEJA), which established the current rebate, contemplates “additional compensation” for additional benefits realized by the distribution system as a result modifications to the default settings (such as use of volt/watt curves). However, when volt/watt curves are provided to the customer as an option to avoid interconnection cost they would otherwise incur, no significant benefits accrue to the wider distribution system from that choice. Due to the prevalence of voltage optimization in Illinois, system-level overvoltage is expected to be minimal, and thus no significant benefit to other customers is anticipated.

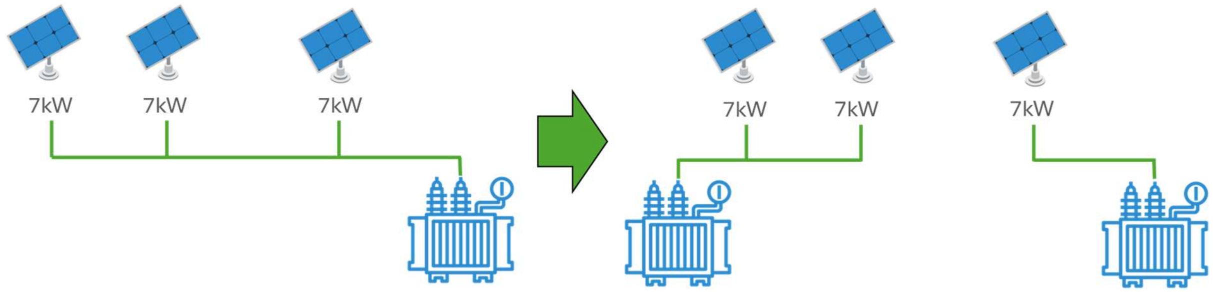
Impacts on Customers, Applicants, Developers, and Users

For small DER applicants within the Level 1 process, interconnection costs for applicants are capped at $200 by Part 466[5], with any necessary system modification costs in excess of $200 recovered from utility customers through base rates. When applicants fail the 20kVA shared secondary screening, system upgrades to relieve the condition, such as splitting secondary districts by installing a new service transformer (see below), are significantly in excess of $200, which results in increases to customer rates. If DER applicants were to utilize volt/watt curves instead of pursuing such upgrades, the applicant customer would save $200 and the rate impact

[5] See Illinois Administrative Code Part 466.90(c)

from the costs in excess of $200 would be avoided. Thus, there are potential benefits directly to customers that choose volt/watt curves as well as significant benefits to other utility customers.

Figure 2: Example of Splitting Secondaries to Mitigate High Voltage



For larger applicants using the Level 2 or Level 4 process, all costs associated with system upgrades are the responsibility of the applicant. Consequently, if the applicant were to utilize volt/watt to resolve an overvoltage condition that occurred within the study, that applicant could avoid the cost of the system modification that would otherwise be necessary to resolve the condition. Because this approach would be used to avoid specific conditions identified in the study, the potential for curtailment is significantly higher. Uncertainty around the degree of curtailment could negatively impact the ability of the applicant to secure project financing, which further hinders the effectiveness and level of benefit of volt/watt for large systems. Unfortunately, estimating annual curtailment due to volt/watt is difficult. Historical voltage information at the point of connection is unlikely to be a reliable indicator of potential voltage-driven curtailment, as the historical data does not account for changes resulting from the DER interconnection.

Applicants considering volt/watt as a means of avoiding interconnection costs must also consider the potential for real power curtailment due to the operation of the curve and the subsequent impact on their project economics. Where curtailment is minimal, there is effectively no downside, as the volt/watt curve serves as an insurance mechanism against unexpected conditions and only rarely operates. Because of the broad deployment of voltage optimization within Ameren Illinois' service territory, this is expected to be the case for most DER. Individual large DER applicants may be more likely to experience such conditions, depending on the size and location of their proposed facilities.

Stakeholder Feedback & Discussion Focus Areas

Utilization of volt/watt for Level 1 DER was previously discussed with stakeholders and detailed within Ameren Illinois' Revised Multi-Year Integrated Grid Plan. During stakeholder discussions within Phase 1, it was determined that customer choice was a key element to successful implementation. Stakeholders recommended that customers be given the option to use a volt/watt curve or incur the otherwise necessary upgrade costs. Stakeholders also suggested the option for small DER to temporarily use of a volt/watt curve while waiting for infrastructure upgrades to be completed, enabling DER owners to begin generating sooner, while still eventually being able maximize their system's output. Stakeholders indicated that interconnection cost reduction would be valuable, so long as customers have a means of addressing any curtailment-related issues that occur during operation.

For larger DER projects within the Level 2 and 4 processes, stakeholders indicated it may be difficult to finance projects utilizing volt/watt curves due to the unknown degree of project curtailment. Additional historical voltage data was requested to help mitigate such concerns.

Other Jurisdiction Examples

The table below provides a summary of how other jurisdictions have treated volt/watt curves.

Jurisdiction	Summary
California[6]	• Volt/watt is enabled by default. • A voltage complaint process is used to monitor voltage issues. • Utilities are required to report estimated curtailment.
Hawaii[7]	• Volt/watt is enabled by default. • Utilities are responsible for identifying and investigating voltage issues and making upgrades to relieve issues.
Massachusetts[8]	• Volt/watt is disabled by default.
Minnesota[9]	• Volt/watt is enabled by default.

[6] 2021, PG&E Advice Letter, ELEC_5832-E.pdf

[7] 2022, Rymsha, Steven; Hawaii's Pathway to Leveraging Smart Inverters New York Interconnection Technical Working Group 9/15/2022

[8] 2022, Default IEEE 1547-2018 Setting Requirements, download

[9] 2020, State of Minnesota Technical Interconnection and Interoperability Requirements, TIIR w CORRECTED Interim Implementation Guidance_tcm14-431321.pdf

	• DER operators can notify the utility when experiencing excess curtailment and the utility will modify equipment if the excess curtailment is utility-caused.

Proposed Path Forward

In August 2025, Ameren Illinois began a pilot offering allowing for the optional use of volt/watt curves to customers within the Level 1 interconnection process who fail the 20kVA shared secondary screen to allow them to avoid otherwise necessary system modifications and be subject to other system requirements. Customers who elect to opt-in and are eligible will be able to avoid the $200 cost contribution, as an upgrade will no longer be necessary. Such customers can also connect faster, since they do not have to wait for the completion of upgrade construction. When customers choose to opt in to using volt/watt curves for this purpose, other Ameren Illinois customers should also benefit because the construction costs in excess of $200 would no longer be recovered through rates. Because this is a customer choice, customers may still elect to pursue the system upgrade instead of choosing the volt/watt curve and will still have their cost contribution capped at the rate set by the Illinois Commerce Commission. Customers may also choose to temporarily utilize volt/watt while any corresponding construction occurs, with the volt/watt settings able to be removed after the completion of construction (though this may require additional interaction with their project installer or equipment manufacturer).

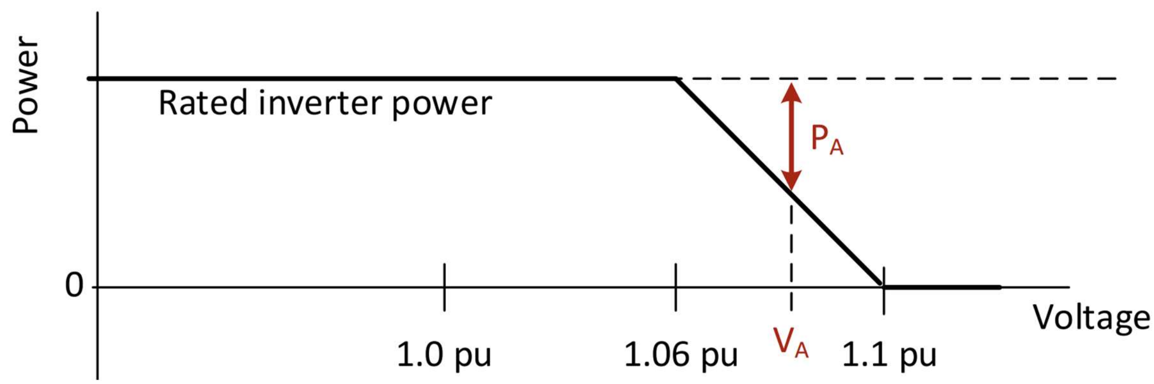
Since Level 1 application customers opting in to volt/watt reduces the cost of facilities recovered through rates, removing potential barriers to utilization of volt/watt curves is critical. Consequently, Ameren Illinois intends to allow Level 1 application customers, at any point after energization, to change their mind risk-free and opt out of utilizing the volt/watt curve, instead paying the $200 contribution to enable upgrade construction. Allowing customers this option helps to reduce the potential for customer regret by allowing them to modify their choice risk-free after seeing the actual level of curtailment experienced. Lowering customer's perceived risk for volt/watt will encourage the customer to use this approach and, subsequently, maximize the benefits to Ameren Illinois customers.

Since volt/watt curve adoption is optional for customers, utility curtailment reporting is not necessary and would result in unnecessary expense. Customers and their service providers will have the best access to their system performance data to make decisions about whether to continue with the volt/watt curve enabled. Additionally, since the volt/watt curve is intended to benefit the applicant directly, no additional compensation via a smart inverter rebate is anticipated.

To address voltage impacts in cases of non-compliance, the existing customer voltage issue resolution processes can be used to identify and respond to potential small-scale local voltage issues that may arise.

Figure 3 below shows the recommended volt/watt curve for use by Level 1 applicants seeking to avoid modifications due to failure of the screening criteria. This curve begins curtailing real power at 106% of nominal voltage, at which point the Illinois standard volt-var curve will have already exhausted reactive power support capabilities.

Figure 3 Recommended Volt/Watt Curve



For DER systems too large for the Level 1 process, Ameren Illinois is still evaluating the potential impacts of non-compliance and the processes for detecting and responding to related voltage issues effectively. There are also complications relating to the data that applicants may request to secure project financing and the process for removing the volt/watt curve if elevated levels of curtailment occur. As a result, the potential use of volt/watt to resolve overvoltage conditions within the Level 2 and Level 4 study processes will continue to be investigated during Phase 2.

Limited Import / Export

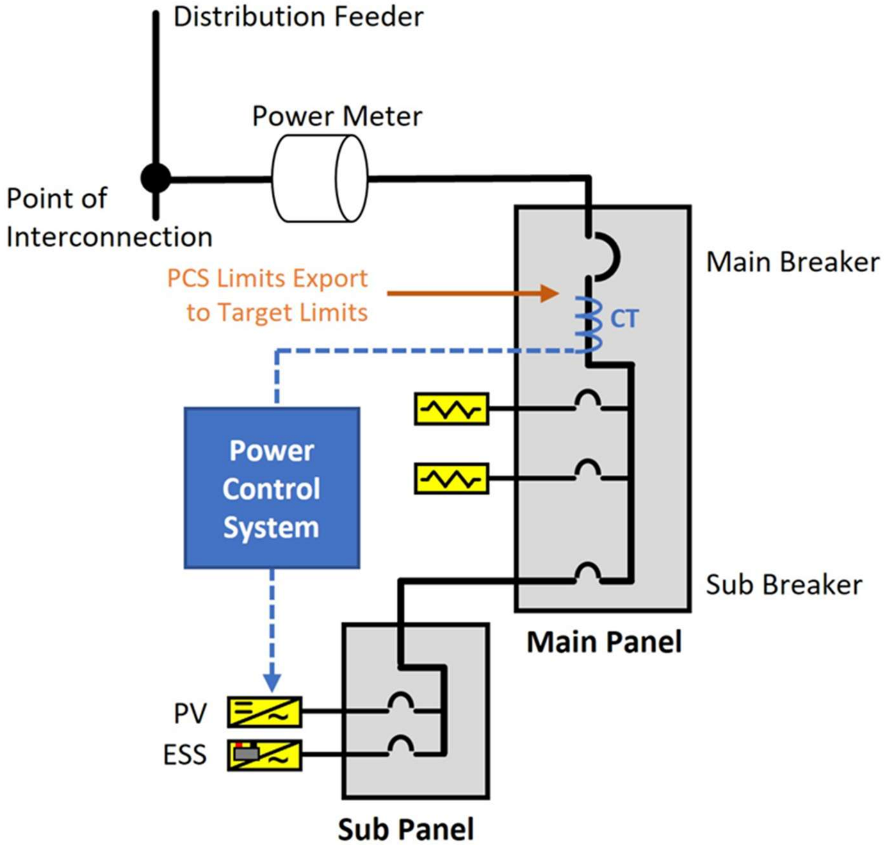
The limited import / export method can be utilized to set specific maximum continuous import power or export power limits rather than solely equipment's nameplate rating for interconnection screenings and studies. This allows for the connecting resources to be modelled and studied in a manner reflecting how they will actually be operated, rather than relying on more conservative assumptions. This, in turn, can expedite interconnection screenings and potentially avoid otherwise necessary distribution upgrades. Limited import/export connections are already available for DER applicants in Illinois, as defined under Admin Code Part 466.75.

This interconnection method can be applied at the site level (i.e., import or exports through the utility meter) or to a specific subset of resources (i.e., solar and storage self-charging). Several different tools, technologies, and methods can be utilized to implement limited import/export connections including Power Control Systems (PCS), protective relaying, or the relative rating approach.

A PCS can be used by the customer to measure and control the energy imported and exported from the resource at defined limits. PCS can currently be certified to the UL 1741 PCS Certification Requirement Decision (CRD), which is in the process of being expanded and formalized into a consensus standard under UL 3141.

Figure *4* below provides an example of how a PCS can be connected to limit exports for a residential customer with solar and storage.

Figure 4: Local Power Control System Diagram (EPRI)[10]



A relay-based approach uses a protective relay to trip at defined limits, which can be set to enforce import/export limitations by tripping if prescribed limits are violated, disconnecting the customer's equipment. As a means of implementing limited import/export connections, relaying does not directly control equipment but rather acts as a backstop in case the conditions are violated. Consequently, it is generally paired with other techniques.

Another approach is the relative rating method, which considers the size of the DER compared to the size of the on-site load. If the DER is small enough, relative to the customer's minimum load, the export risk is minimal but may still be present during certain conditions. For sites with large loads that occasionally shut down (e.g., industrial production facilities on a holiday), the relative

[10] BATRIES, "D. Certification Requirement Decision (CRD)", Link: Source

rating method can be used in conjunction with a PCS to ensure that export limits are not violated during the shut-down conditions.

In the past, Ameren has enabled several large behind-the-meter projects to utilize export controls to reduce interconnection costs and increase the amount of allowable generation. Historically, Ameren has preferred utilization of PCS with relays as backup for limited export connections, particularly for large DER.

Risks and Challenges

Depending on the size of the facilities, PCS malfunction or other customer non-compliance with import/export restrictions may create reliability issues such as thermal overload conditions on the distribution system. Fortunately, there are utility mechanisms and customer equipment design features available to mitigate such risks.

For larger sites with SCADA-enabled metering or SCADA-capable on-site reclosers, direct telemetry is available to detect violations of site-level import or export restrictions. Sites where utility reclosers are deployed, such as large DER facilities, can also utilize relaying as a back-up method for ensuring compliance without adding significant additional costs. Where limited import/export facilities are embedded behind customer meters with other loads, non-compliance may be more difficult to detect using site-level equipment.

For smaller sites without operational visibility via SCADA, AMI meter data can provide similar visibility, although generally not fast enough to be available for operational purposes. Still, monitoring historical data can detect potential non-compliance, similar to existing mechanisms for detecting unauthorized customer solar installations. Non-compliance for smaller systems is less likely to cause damage to large primary voltage facilities but can impact local service transformer loading. Redundancy mechanisms such as relaying are not generally viable for small customers due to cost.

For PCS-based approaches to limited import/export connections, design features within the UL 1741 PCS CRD provide protection against violations due to PCS misoperation. Recent updates to the National Electrical Code have allowed for PCS-based approaches to be utilized by customers when sizing home electrical equipment, demonstrating the relative maturity and reliability of the technology and limiting the potential for negative grid impacts from misoperation. In addition, some PCS manufacturers can lock PCS limits so customers cannot change them without a manufacturer override[11].

Short-duration violations of steady-state import or export limitations (i.e., inadvertent export) can occur, particularly with PCS-based approaches, and should be expected due to limitations in the response time when changing resource behavior following changes in load or generation. Performance requirements for the allowable duration and magnitude of these conditions and related parameters such as open loop response time are defined within applicable standards, as well as within the Admin Code Part 466.75. Potential impacts from inadvertent export should be assessed during the interconnection process, where applicable.

Finally, while DER are frequently modelled as stand-alone additions to existing customer facilities within utility systems of record (i.e., GIS databases), customer load information is often not directly documented due to a combination of complexity and the availability of other load data sources such as metered consumption. When considering limited import connections for load customers, documenting import limits and making them available to planning models (i.e., Synergi Electric) and operational power flow modeling tools (i.e., ADMS) is important to ensuring model accuracy. This may require modifications to existing practices and capabilities related to mapping customer load additions and new customer facilities in GIS.

Implementation Pathways

As mentioned previously, limited import/export connections are already available for use in Ameren Illinois' service territory, as described within Admin Code Part 466.75. This includes the addition of limited import/export capabilities in response to screening criteria failure or to avoid system reinforcements identified during the study process.

Extending the same concept to new load additions or new connections could be implemented with some modifications to existing processes and documents. Information on size and characteristics of the load is already required by Ameren's Standards and Qualifications for Electric Service[12]. It also requires Ameren to be notified of modifications that would impact utility

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[11] 2025, SolarEdge, Setting the PCS ESS Export Only Mode, page 3: https://knowledge-center.solaredge.com/sites/kc/files/se-setting-pcs-ess-export-only-application-note-na.pdf?_gl=1*1n9wed4*_up*MQ..*_ga*MzQwMjE5NzgzLjE3NTQ1ODU4NzE.*_ga_WHZZFQTD8B*czE3NTQ1ODU4NzAkbzEkZzAkdDE3NTQ1ODU4NzAkajYwJGwwJGgw

[12] Standards and Qualifications for Electric Service

facilities, which could be interpreted to include any PCS or other equipment for import and export. However, there are no specific performance terms for on-site equipment. In addition, customer non-compliance with notification requirements for load additions is a known issue, particularly where new load can be connected without modifying the size of the service transformer. In order to ensure these existing mechanisms can function for limited import connections for load additions, formal documentation of the associated import limits, along with documentation of customer agreement with the limit, is recommended. There may also be impacts to revenue offset calculations within the System Expansion Guarantee Agreement process due to changes in expected load characteristics and energy use.

While limited import/export connections are already available, the specific options and performance requirements enshrined within the Admin Code Part 466.75 are relatively limited and do not necessarily account for improvements in the technology or capabilities within the forthcoming UL 3141 standard. Through the “by mutual agreement” language within the Admin Code, additional compliance mechanisms or less restrictive requirements could be allowed, where doing so does not create new risk of negative reliability impacts to the distribution system. By developing and publishing an updated set of requirements to define what the utility will accept under “mutual agreement”, both DER and load applicants could potentially better utilize limited import/export connections.

One potential implementation of limited import/export connections for consideration is the use of customized, non-certified control hardware in lieu of PCS equipment certified under UL 1741 PCS CRD or UL 3141. Customized automation controllers (such as SEL’s RTAC Real-Time Automation Controller) may be capable of performing the same control actions and meeting the associated performance requirements but will not be certified due to the customized nature of the implementation. Use of such hardware, especially where the applicant already plans to incorporate it into the design of their facilities, could reduce customer costs or provide additional on-site design options. Due to the lack of certification, it may be necessary to utilize redundant compliance mechanisms, more extensive testing and documentation, or other measures to ensure the acceptable operation of the system. Publishing specific requirements for import/export performance and utilization can also be used to enable this type of implementation and inform customers on impacts to facility design.

Impacts on Customers, Applicants, Developers, and Users

Limited import/export connections can be used by a variety of customer types and resource types to achieve a variety of different goals within or separate from the utility interconnection process.

As mentioned previously, recent revisions to the National Electrical Code (NEC) have allowed for control-based methods to be used to limit power flow to comply with requirements related to component sizing. This can help customers avoid otherwise necessary upgrades to home electrical equipment when adding new solar, storage, or loads. While such methods are generally outside the utility connection process, utility adoption of PCS-based approaches can increase awareness of similar options for behind-the-meter applications, expanding their use or improving adoption of associated NEC revisions.

For DER interconnections, customers can already utilize limited import/export connections to prevent or resolve screening criteria failures or in response to grid constraints identified in the study process that would result in the need for system reinforcement.

Large loads, particularly controllable loads such as an EV charging hub, could also utilize limited import/export connections to reduce their capacity impact on the distribution system in two ways. First, they can adjust the maximum power draw from on-site equipment in order to limit the maximum coincident site demand. This reduces the capacity impact on the distribution system, which may allow for faster or lower-cost connection while also managing demand charges on the customer’s bill (where applicable). In addition, customers can incorporate on-site DER within the limited import/export scheme, which can increase the amount of charging capability available or reduce the capacity impact on the distribution system. Large load customers adding relatively small DER can also utilize limited export during hours when on-site load is minimal to maintain non-export conditions (as explained previously).

Stakeholder Feedback & Discussion Focus Areas

Stakeholders stated that, while this method is already allowable for DER interconnections, technology has changed since PCS specifics around response times were enshrined within Part 466. Utilizing new standards or less limiting performance requirements under the “other acceptable methods” element of part 466 import and export limits was recommended for consideration. Participants indicated they would want specific information available regarding technical requirements and site design impacts so that the method could be used effectively. Customized controller implementations using, for example, an SEL RTAC, were also of interest.

For load customers, stakeholders identified that different types of customers will have very different levels of sophistication when it comes to estimating demand, which will impact the extent to which limited import/export connections could be used effectively by some customers.

Stakeholders indicated that they would need to be able to estimate the long-term impacts of import and export limitations and that they may require data from the utility to do so. It was communicated that, since the import/export limits are fixed at the time of connection, customers could assess the impact of such constraints on their own systems without additional utility data.

Other Jurisdiction Examples

Jurisdiction	Summary
New York[13]	• Can use limited export for DERs.
New Mexico[14]	• Allow for limited export for DERs.

Proposed Path Forward

Limited import/export options made available through Illinois Administrative Code Part 466 will continue to be available to new DER applicants. To better enable customers to utilize limited import/export connections and account for technology developments, Ameren Illinois will develop updated technical and site equipment requirements, detailing what options are available to customers within Part 466 or are otherwise acceptable to Ameren Illinois and could thus be utilized under "mutual agreement".

Ameren Illinois also proposes allowing new load customers (or load additions by existing customers) to utilize limited import/export connections where they choose to do so. Updated technical and site equipment requirements will also capture considerations for load customers. Where system upgrades are identified during a load addition study, customers will be able to modify their proposed facilities to utilize import/export limits, similar to existing DER interconnection processes for DER using the Level 2 or Level 4 processes. Where the applicant chooses to utilize limited import/export connection, corresponding site performance

[13] 2024, New York State Public Service Commission, New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution System, sir-effective-february-1-2024.pdf

[14] 2023, New Mexico Public Utilities and Utility Services, *Interconnection of Generating Facilities with a Nameplate Rating Up to and Including 10 MW Connecting to a Utility System*, 17.9.568 NMAC

requirements must be approved in writing by the customer and documented as part of the load connection process.

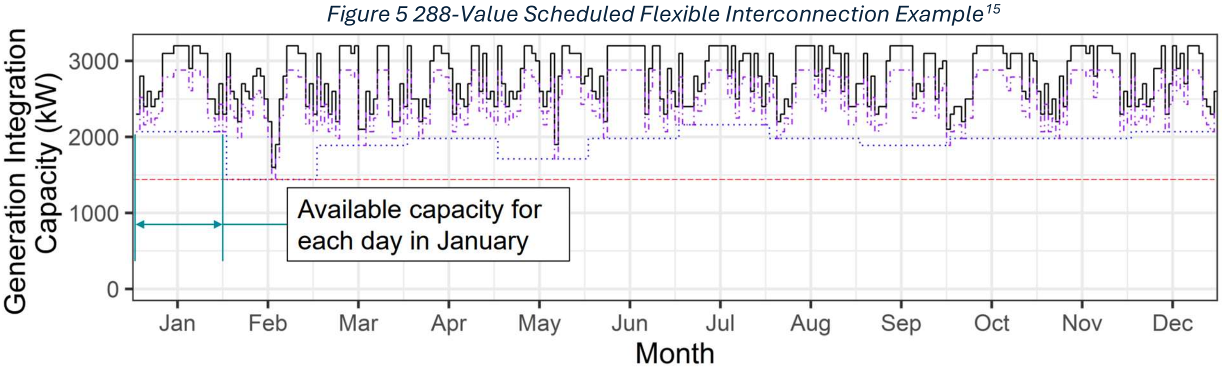
Scheduled

The schedule method expands upon the single-value import/export limit concept explored previously by allowing for different import or export limits during specified time periods. For example, a DER customer may be allowed full export during peak seasons but may need to limit their export during minimum load conditions in the Spring and Fall. Similarly, a flexible load using a scheduled connection may need to limit their power import during peak load periods but may be able to operate without restrictions during off-peak seasons.

Scheduled operating limits may also incorporate variation by time-of-day. Time granularity can vary significantly with scheduled flexible interconnections, with the simplest schedule using just a two-point schedule with peak and off-peak seasonal values. A much more complex schedule may include a different 24-hour profile for each month (a total of 288 schedule points). There are a variety of options of varying complexities that can be considered, with more granular schedules generally being significantly more difficult to produce but providing a relatively higher degree of operational freedom and capacity utilization.

Figure 1Figure 5 below shows the more complex example of a 288-point monthly 24-hour limited export schedule to avoid system violations based on available capacity.

Figure 5 288-Value Scheduled Flexible Interconnection Example[15]



A static scheduled flexible interconnection can help applicants avoid interconnection costs and reduce connection timelines by limiting their import and export during constrained periods to avoid system upgrades. It also helps maximize the use of existing infrastructure by allowing for a higher degree of resource operation than other fixed-limit conventional or flexible approaches. Because the schedules are pre-determined in advance, they cannot achieve the same extent of

[15] 2023, California PUC, 288-Value Limited Generation Profiles, [R.17-07-007 Limited Generation Profiles]

utilization and operational freedom as dynamic methods, but they do not require significant operational control system deployments to implement and also provided a clearer picture of operating limits to customers considering a scheduled connection.

The UL 3141 Power Control System standard is a key enabling technology for scheduled connections. The early outlines of the standard establish capabilities for on-site controllers that allow for schedules for specific months and hours to be pre-programmed, with granularity up to a 288-point schedule covering 24-hour time periods for each month. Other methods of implementing scheduled-based import and export limits, such as custom programming of automation controllers such as SEL's RTAC, are available, but may require additional technical specifications, testing, and oversight for effective implementation and compliance.

The study process for a scheduled flexible interconnection will be significantly more complex than that traditional process, requiring studying a fixed number of static snapshot cases that capture boundary conditions within each scheduled interval. The more granular a schedule is, the more data granularity and engineering work will go into creating the resulting static schedules. Simplistic, two-point peak/off-peak schedules could be determined by using existing study processes for peak load seasons for load and adding one additional case for the most constrained time within the off-peak period. Time-varying profiles will add an order of magnitude of additional complexity, requiring time-series data and analysis capabilities to efficiently study dozens or hundreds of snapshot cases. In addition, historical time-series load profiles may require additional processing before use in such studies. Using just a single previous year of data may not capture year-to-year variations in seasonal conditions (such as temperature). For instance, variations in Illinois in September due to the severity of heat and the timing of agricultural loads can lead to very different levels of available capacity in different years. Because of these challenges, highly granular operating schedules are likely to require significant new capabilities and additional engineering study labor.

Another important aspect is determining who will propose the schedule. One option is to allow applicants to propose their own schedule, with the utility then reviewing the customer's system under the proposed schedule to identify any potential violations. This is ideal, as it allows applicants to be studied in a way that aligns most closely with the actual operation of the new load or DER addition. Ameren Illinois' planned 2026 deployment of Dynamic Hosting Capacity can help provide applicants with information to facilitate this approach.

In practice, there are a few challenges that limit the effectiveness of applicant-proposed schedules even after granular data is made available. First, applicants must be sophisticated enough to develop an operating schedule detailing their planned maximum import and export levels at as granular of a level as is practical. If their proposed schedule is too restrictive, relative to their actual business needs, it will negatively impact the customer's operation after connecting. Second, the customer's proposed schedule would also need to be compared against distribution system constraints during each time period, requiring complex analysis from the customer to consider both their operating needs and the complex, time-varying capacity information from the utility (depending on the schedule granularity).

A second option is to have the utility propose a schedule for specific applicants as a remedy to avoid a system upgrade after their initial study (which would follow the existing process) by modifying import or export limits during specific constrained periods. The applicant would then need to determine whether their operations and project economics are viable if operating within the proposed limits. This approach also comes with challenges. The utility would have to perform the additional work of developing a schedule, which would be tailored to avoid grid constraints, rather than the customer's actual operational needs. As a result, the utility-proposed schedule is likely to reserve more operational capacity for the customer than they may need during some intervals (resulting in inefficient capacity allocation) and may not meet their operational needs during others (which may result in applicant withdrawal or other modifications).

Ideally, applicant-specific schedules would be the result of dialogue between the utility and the applicant, leveraging an iterative approach that would allow for customization to maximize customer operations, avoid overallocation of capacity in unneeded intervals, and limiting operation during constrained periods that would trigger system upgrades. In practice, this approach may significantly extend the duration of the study process and the amount of engineering labor necessary from both the customer and the utility to develop and assess proposed schedules. In addition, such a dialogue is unlikely to be feasible for DER projects, given the timelines and process steps defined within the Admin Code Part 466.

A third option is for the utility to pre-calculate operating schedules based on specific feeder or substation limitations in advance of any specific applications. Because this approach frontloads the utility analysis work, it is best suited to areas of known interest for new connections. One high-potential application would be pre-calculating an operating profile for new solar PV connectors that would reduce production during constrained daytime minimum load periods but allow production during other periods. To pre-determine a schedule, a specific total amount of anticipated PV or an acceptable maximum level of PV curtailment would need to be established ahead of time. In addition, such an approach may be difficult to deploy under existing Admin Code Part 466 rules, as earlier applicants would generally prefer to opt for firm service using existing capacity under the existing process, reducing the effectiveness of the schedule-based sharing of capacity.

Risks and Challenges

As discussed previously, the process of designing the operating schedule is a significant challenge that must be addressed. This includes the granularity of the schedule, the party who identifies and proposes the schedule, and the execution of the resulting study.

There is also risk for both participating customers and the utility that future changes may make previously determined schedules impractical. For customers, this may include changes in operational needs, increasing utilization of assets such as EV chargers, or deviations between estimated needs and actual needs. From the utility perspective, there is already risk within the existing process that new customer load or DER additions will negatively impact the ability to perform switching, maintenance, load transfers, or other desirable operational or planning solutions. Adding a schedule does not fundamentally alter that presence of that risk, but it does significantly increase the number of time periods during which planning and operational capabilities may be constrained as a result. Because customers expect to be able to operate under agreed-upon terms in perpetuity, the increased number of constrained time periods increases the likelihood that this risk becomes a reality in future years, reducing system flexibility and potentially requiring additional utility investment to maintain the agreed upon level of service.

Another risk to consider is the potential for customer non-compliance. Because schedule-based connections push the distribution system closer to its limits more often, there is relatively higher risk of non-compliance than for methods such as limited import/export. For PCS-based implementations, early outlines of the UL 3141 PCS standard allow for vendor password-protected access for modifying import and export limits, which prevents customers from modifying on-site limits (inadvertently or otherwise) once the system is operational. Alternative means of ensuring compliance, such as monitoring and relaying, are much more challenging to utilize effectively for scheduled connections. Because maximum allowable import and export values change in different periods, existing single-value SCADA alarms and pre-set relay trip values cannot effectively identify or prevent misoperation. Analysis of historical data also becomes more complex, as each time period must be compared to its allowable limit, rather than a single maximum value.

Once a schedule is created and applicants have connected, utility recordkeeping of the schedule will be critical for both planning and operations. Distribution planners will need to understand how to correctly model and study scheduled interconnections in future studies. Existing recordkeeping systems such as GIS may not be readily adaptable to document customer operating schedules, especially more complex schedules with many time intervals.

Implementation Pathways

Because the UL 3141 standard is so central to scheduled connections, its progress toward consensus approval and the availability of certified equipment will be key considerations for implementation. Some equipment, certified to early outlines of the standard, is already available[16], but may not meet the full set of needs for all types of customers considering such connections.

For DER interconnections, the regulatory impacts for scheduled connections are similar to those for limited import and export. Existing rules in Part 466 allow for limited export as part of the DER interconnection process, with methods for using a PCS and a catch-all within "Limited Export Using Agreed-Upon Means[17]" that would allow for an operating schedule to be used with mutual agreement from the utility.

For load connections, Ameren's Standards and Qualifications for Electric Service[18] already require load characteristics to be provided prior to interconnection. While there are no specific requirements related to operating schedule or PCS utilization, there are requirements to notify the utility of any relevant modifications, which could be interpreted to include changes to a pre-determined operating schedule. Some means of documenting the operating schedule and the customer's acceptance of the schedule and requirements for on-site hardware should be incorporated within this process.

[16] See California Rule 21 Approved PCS List: https://solarequipment.energy.ca.gov/Home/PowerControlSystem
[17] 466.75, subsection C (7), Limited Export Using Agreed-Upon Means
[18] AIC Standards and Qualifications for Electric Service Standards and Qualifications for Electric Service

Impacts on Customers, Applicants, Users, and Developers

Because operating schedules will generally be intended to avoid specific grid upgrades and their associated costs and timelines, it is expected that scheduled connections will be primarily utilized by larger load customers and larger DER applicants for such purposes. Where load customers utilize scheduled connections in lieu of system upgrades, the additional bill contributions from the operation of new customer loads, without requirements for new capacity expansion investments, will tend to put downward pressure on customer rates.

Stakeholder Feedback & Discussion Focus Areas

Schedule connections received the highest degree of interest for implementation during stakeholder discussions. These connections were generally seen as a way to increase value for interconnections, potentially synergize with concepts such as time-of-use rates, and help to unlock meaningful capacity without the complexity of DERMS. However, some stakeholders were concerned with the complexity of more granular schedules. To be comfortable with scheduled connections, stakeholders indicated a need for the utility to be willing to share data during the interconnection process to understand costs, timelines, expected curtailment, and circuit conditions.

For the interconnection agreement, it was recommended that the operating schedule and defined limits be included and documented, as well as language for how schedule changes and updates will be addressed. Stakeholders also recommended that the agreement specify that the schedule will not be updated to further limit customer system operations. Penalties and enforcement mechanisms for customer non-compliance were also identified as necessary to enshrine within the agreement, with indications that overly severe penalties or liability may inhibit utilization.

Other Jurisdiction Examples

Jurisdiction	Summary
California[19]	• Utilize limited generation profiles (LGP). Customers can download a file with a pre-generated limited generation profile based on the node closest to their interconnection site. The

[19] 2020, California Public Utilities Commission, *Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup*. Link

	file includes generation profiles to choose from. Require a 10% buffer in addition to existing limits[20].

Proposed Path Forward

Scheduled connections show significant potential to improve utilization of existing infrastructure when connecting new loads or new DERs. This was further illustrated through the high degree of interest and support for scheduled connections from multiple stakeholders. Consequently, Ameren Illinois recognizes that it is important to pursue scheduled connection offerings as a way of improving outcomes for both existing customers and new load and DER applicants.

At the same time, scheduled connections are significantly more complex than both existing, standard connections and the other static flexible connection methods being explored. Key elements of the process design for scheduled connections are not yet conclusively established, including:

- Which party proposes the schedule?
- What level of schedule granularity is reasonable?
- What level of schedule customization is reasonable for applicants or distribution system locations?
- What requirements are necessary to ensure compliance with the relevant operating schedule?

Given the degree of interest, Ameren Illinois plans to further refine scheduled connections by performing additional analysis and stakeholder engagement in Phase 2. The goal of the work to be performed in Phase 2 is to establish an initial offering for scheduled connections that is feasible to implement, enables new applicants to connect efficiently, and maintains distribution system reliability. Refining the scheduled concept into an effective offering will be prioritized for early focus during Phase 2.

[20] 2025, Southern California Edison, *Interconnection Process for Limited Generation Profile Projects, Interconnection Process for Limited Generation Profile Projects*

Staggered Connections

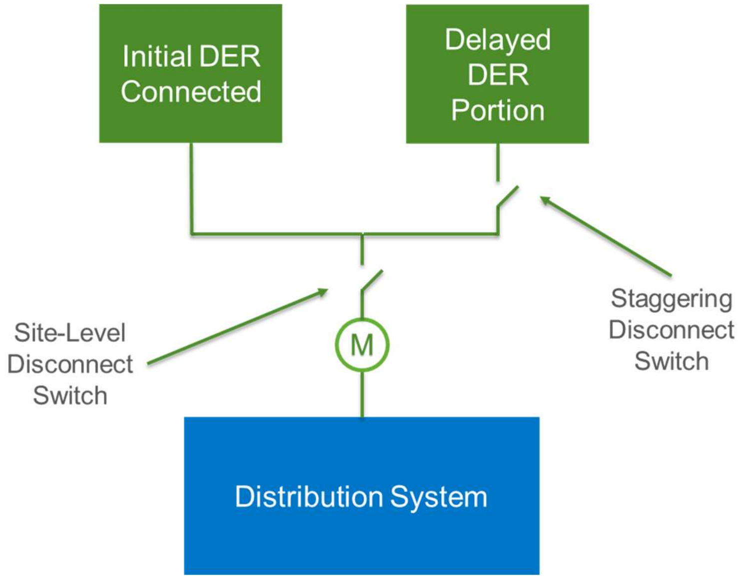
Staggered connections allow applicants to connect and operate a portion of their total proposed load or DER addition before the system upgrades to accommodate the full system are completed. This contrasts with existing practices, which do not allow customers to connect or operate any portion of their proposed facilities until after necessary system upgrades are completed. Under the staggered approach, customers could physically connect or construct only a portion of their facilities or could temporarily utilize other approved flexible connection methods (i.e., import/export limits, volt/watt, etc.) up to determined limits to avoid violating constraint conditions. For customers' sites requiring line extensions or other on-site facilities to serve them, construction of such facilities must still be completed before the initial portion can be energized.

The goal of implementing a staggered connection is to reduce the wait time between a customer's application and their ability to energize their load or DERs. This allows applicants who move forwards with system modifications to begin operating sooner. If the applicant does not wish to move forward with the system upgrade, there is no potential for staggered connection, though the customer could still connect at the reduced size.

The key element necessary to enable staggered connections is a mechanism for ensuring that no more than the allowable portion of the customer's proposed capacity impact is connected prior to the completion of the upgrade. Violations of these temporary limit conditions can cause equipment overloads, which can lead to equipment damage or negative reliability impacts for other customers. While even existing interconnection agreements contain provisions for responding to non-compliance, such provisions are inherently responsive and do not, on their own, enable the prevention or detection of potentially damaging non-compliance conditions.

The simplest method of implementing staggered connections is to physically separate the initial portion of the customers' facilities from the portion that must wait to be energized. When using this connection approach, customers may wish to construct their entire planned facility up-front and wait for energization, or they may wish to wait to begin construction of the delayed portion until closer to the completion of the system upgrade. For both options, it is important to ensure that the site design incorporates a mechanism to prevent inadvertent energization of the delayed portion. One such method would be to require a separate lockable disconnect to prevent on-site personnel from accidentally energizing the facilities. *Figure 6* below shows an example of how a lockable switch could be utilized when implementing a staggered connection.

Figure 6 - Example of Staggering Connection Implementation with Utility-Lockable Disconnect



Similarly, rather than a dedicated disconnecting means, an intentional air gap in the facilities (by, for example, not installing a set of jumper wires) could be left until the time of energization. Other means of protecting against inadvertent energization may also be acceptable, so long as they prevent on-site personnel from accidentally energizing the equipment.

Staggered connections can also involve the temporary utilization of other flexible connection methods or temporary settings within such methods. For instance, an applicant could temporarily opt for dynamic management as a means of avoiding a constraint violation, transitioning back to an unmanaged connection after the upgrade is completed. Similarly, customers utilizing import/export connections could temporarily utilize a more restrictive import/export limit, with limits increasing following the system upgrade.

Implementing staggered connections requires some modifications to the existing study process. Critically, the utility would be responsible for determining and communicating the maximum allowable temporary operating conditions for the applicant. Adding this layer requires additional engineering labor within the study process. In addition, an extra communications step is required with the customer. Once a system upgrade is identified from the study, a staggered connection could be offered as a means of expediting connection, provided the customer wishes to proceed with the upgrade. Because temporary operating capabilities may impact the customer's decision of whether to move forward, the details of the staggered connection capability should be determined before the customer's final decision of whether or not to proceed.

Because the site energization for such connections is occurring in two phases, it may be necessary to conduct two site visits to verify that the site facilities match those proposed in the application, including any modifications needed to enable the use of the staggered connection. This may also involve additional costs for the applicant as a result of multiple deployments of utility testing personnel.

Once interconnection studies are complete and the first portion of an applicant's system is connected, ensuring compliance with temporary requirements will be critical, as non-compliance can damage utility equipment and create safety hazards. Where a physical disconnect is used, this disconnect could be locked with a utility lock (as identified previously), to be removed by the utility after the completion of the system upgrade. On-site telemetry, via SCADA or AMI, can also be used to verify site compliance for large loads or DERs utilizing staggered connections. When staggered connections involve the temporary use of other flexible connection methods, compliance assurance mechanisms for those methods can be utilized.

For customers with large load additions, using staggered connections may complicate the calculations for their cost contribution to system upgrades within the System Expansion Guarantee Agreement. Under existing practices, system expansion costs to enable a new large load can be offset by the additional bill contributions from that customer over a preset number of years (currently seven years for Ameren Illinois). If this period starts with the initial energization, the customer's energy use during the initial period will be relatively lower than if they had waited until the completion of the upgrade, which would tend to reduce the amount of upgrade cost that is able to be offset. If the period starts after full energization, the customer's additional bill amounts during the interim period will not be counted towards the upgrade cost at all.

Risks and Challenges

Staggered connections, even more than other types of flexible connection, require a foundational change in the goals and methods of the interconnection study process. In the existing process, the utility's role is to determine whether a specific application can be accommodated by the distribution system and which distribution system modifications, if any, are necessary to do so. Under the staggered process, this role shifts from a "pass/fail" reviewer approach to actively proposing a specific aspect of site performance. This approach can also require additional study iterations to identify specific failure points, increasing the associated engineering labor.

In addition, since the goal of staggered connections is to connect as much of the load or DER as practical before completing upgrades, the resulting connections will necessarily operate distribution equipment as close to its operating limits as possible. To ensure that unexpected changes in conditions do not result in constraint violations or equipment damage, a safety margin should be established. Determining this safety margin should evaluate risks such as year-to-year temperature fluctuations, local load or DER growth, or fault response conditions to ensure that, during upgrade construction, constraint conditions are not exceeded.

Implementation Pathways

For DER applicants at being processed at Level 1, Level 2 or Level 4, the application process is not expected to require significant modification to allow for staggered connections. Because these conditions do not result in an increase in overall capacity or otherwise trigger “material modification” provisions, temporary requirements can be added during the existing connection process. These requirements can also be documented within the existing standard interconnection agreement without changes to the Admin Code.

Impacts on Customers, Applicants, Users, and Developers

Staggered connections are expected to primarily be useful for larger load and DER interconnections, as they are much more likely to trigger and be responsible for system upgrades. For such customers, accelerating the commercial operation of the facilities can significantly improve the viability of the project. Improving flexibility by allowing for the temporary use of other flexible connection methods can further improve outcomes for such customers by further maximizing the use of available capacity.

. Small, level 1 DER customers whose application fails the 20kVA shared secondary screening may also be able to benefit from the staggered approach. These customers could temporarily utilize volt/watt functionality to connect their DER while awaiting a permanent upgrade to split the secondary conductors (as explained in the Volt/Watt section). This does come with some additional work for the customer, as they may need to coordinate with their project developer and the equipment manufacturer in order to modify the volt/watt settings after the initial energization. This may also involve coordination with the utility, as many inverters require a manufacturer password to adjust smart inverter settings following energization, and the manufacturer may require assurance from the utility prior to modifying inverter settings.

Stakeholder Feedback & Discussion Focus Areas

Staggered connections were generally seen as beneficial by stakeholders, as they allow for faster energization with effectively no downside. It was recommended that interconnection agreements include any technical requirements and information on the nature of the flexible interconnection. Stakeholders were interested in having definitive timelines for the associated system upgrades, which is applicable for both existing connections and the potential use of staggered connections. It was communicated that staggered connections would tend to reduce any negative impact of construction timelines and potential delays, relative to the existing process.

Allowing for temporary use of other flexible methods was recommended by several stakeholders, especially temporary import/export restrictions, temporary schedules, and temporary volt/watt utilization to speed energization of load and DER.

Other Jurisdiction Examples

Jurisdiction	Summary
California[21]	• Southern California Edison developed a load control management system enabling customers to energize to a certain point before capacity upgrades have been completed.

Proposed Path Forward

Ameren Illinois plans to allow staggered connections to be used by new load and DER applicants 2MW and above where system upgrades with lead times in excess of 12 months are identified during the study process. For applicants requiring site-servicing construction such as line extensions or the installation of on-site equipment (e.g., primary metering), eligibility will be contingent on the ability of site-serving construction to be completed sufficiently far in advance of the system upgrade to enable benefits from the staggered connection. Ameren Illinois will identify candidate applicants for staggered connections during the study process and will communicate the availability of this option when providing study results for qualifying applicants.

[21] 2024, Southern California Edison Company's (U 338-E) Plan and Compliance Report on Bridging Strategies and Solutions, page 6, [Microsoft Word - R2106017 Cover Page - SCE Bridging Strategies Plan.docx]

Partial energization and temporary import/export limits will be available to applicants initially. When other flexible connection offerings such as scheduled or dynamically managed connections become available, they may be offered on a temporary basis as part of a staggered connection.

Customers connecting DER through the level 1 process will also be able to utilize volt/watt as a means of staggered connection to enable connection while any corresponding transformer or secondary conductor changes (resulting from failure of the 20kVA screening) are completed by Ameren Illinois. Customers will be informed that they may need to contact their project developer or equipment manufacturer to enable the necessary volt/watt modifications once construction is completed.

Where large DER customers elect to connect using staggered connections, Ameren Illinois may choose to require separate witness tests for the initial energization and the final energization (once the system upgrade is completed). Where multiple witness tests are required, Ameren Illinois anticipates recovery of the additional costs of such tests.

For large load customers utilizing staggered connections, cost contributions within the System Extension or Modification Agreement (SEGA) process will be calculated starting from the date of full energization (after the completion of the system upgrade). This approach allows the customer to maintain the maximum revenue offset and does not penalize them for energizing a portion of their facilities early.

Dynamic Flexible Interconnection Approaches

The previous sections outlined several static flexible interconnection methods, such as staggered connections, limited import/export, schedule-based connections, and volt-watt curves. While these approaches can be very effective, they depend on pre-set, study-driven constraint identification for loads and DERs. Historically, the interconnection study process relies upon assumptions about anticipated peak and/or minimum load conditions that only occur during a relatively small percentage of the year. Even when static flexible methods are used, these assumptions often lead to relatively conservative limits, resulting in underutilization of both DER and load-serving capacity.

Dynamically managed connections, on the other hand, aim to replace static limits with real-time or short-term forecast-based constraint management, allowing flexible loads or DERs to operate with lesser restrictions when the system has available capacity while still enforcing restrictions when necessary to maintain reliability. This not only allows for greater operational flexibility but also improves the utilization of existing distribution infrastructure, potentially deferring or avoiding the need for costly upgrades. The dynamically flexible connections are addressed by two primary approaches: Real Time Dynamic Management and Dynamic Operating Envelopes. These are explored in more detail in subsequent sections.

When considering implementing dynamic flexible connections, it is necessary to decide how available capacity will be allocated if multiple loads or DER are impacted by the same capacity limitation and there is insufficient capacity to allow all resources to operate unconstrained. Multiple strategies have been developed for allocating capacity to participant resources, each with unique benefits and challenges.

Regardless of how capacity is allocated, resources interested in participating in dynamic flexible connections may still experience interconnection costs. Facilities such as line extensions and on-site metering or protective equipment may be required and cannot be avoided by dynamic management. In addition, some utility study criteria may not be mitigated by dynamic management or may depend on the specific location of individual participant loads or DER within the distribution system.

In addition, under existing interconnection rules, new DER applicants would only be incentivized to utilize dynamic connections once the existing hosting capacity in an area is already exhausted.

This may artificially limit total size of DER that can be accommodated by existing infrastructure, as early connectors absorb existing capacity that could otherwise be shared across a wider set of DER participants using dynamic methods.

Dynamic Flexible Connection Capacity Allocation Strategies

The most common methods for determining curtailment are the pro-rata method and the last-in-first-out (LIFO) method. The pro-rata method curtails resources proportionally to each resource's contribution to the network's constraints, generally determined using equipment nameplate values or import/export capacity limits. Under this method, each new resource that connects stretches the available capacity over a larger total resource pool, which tends to increase the extent to which each participating resource is constrained.

The LIFO method mimics the traditional queue approach to connection, allocating capacity based on the order in which customers applied for connection[22]. This effectively places a higher priority on capacity for older connections, with more recent connections potentially being fully limited before earlier connectors experience any change in their available capacity.

In practice, more complex approaches considering other factors or utilizing a combination of pro-rata and LIFO can be utilized. Three strategies will be explored for consideration in future implementations of dynamic flexible connections: Pure Pro-Rata, Pro-Rata Tranches, and Pure LIFO.

Table 3 - Capacity Allocation Approaches

Approach	Description
Pure Pro-Rata	Capacity is allocated proportionally based on the relative size of participant resources and their contributions to the constraint condition.
Pro-Rata Tranches	Capacity is allocated proportionally for participants up to a pre-determined total size at a given location
Pure LIFO	Capacity is allocated based on the order of interconnection, with earlier connectors having higher priority access and later connectors being curtailed first.

[22] 2020, EPRI, *Principles of Access for Flexible Interconnection Solutions,* Link

Pure Pro-Rata

Under a pure pro-rata approach, all participating customer resources are treated effectively the same, having their available capacity curtailed proportionally to the size of their facilities. Because each new resource that connects tends to increase the degree of curtailment experienced by existing participants, this approach can expose early participants to higher-than-expected curtailment over time as new resources are added. If not addressed through other mechanisms, this can create hesitancy for potential participants, as they could be exposed to a degree of curtailment that makes future operation of their project uneconomical. This risk is somewhat mitigated by likelihood that new connectors will also experience a similar level of curtailment (and may thus themselves be uneconomical), but there may still be hesitancy for early applicants considering dynamic connections.

One option to protect early dynamic connectors using the pro-rata method is to enable the utility to make capacity investments to relieve the constraint, enabling new connectors to connect and preventing excess curtailment for participating resources. This approach is relatively straightforward where upgrades are driven by participating load customers, as utility investments in load-serving capacity are already common practice, but may come with additional regulatory and cost allocation challenges for investments in DER capacity.

Many jurisdictions, including Ameren Illinois, are exploring proactive investment opportunities for load and DER capacity, which allow utilities to construct additional load or DER capacity in advance of specific project-driven needs. The goal of such methods is generally to speed the connection process and support the adoption of clean energy technologies. Pairing pro-rata dynamic connections with proactive investments can be very effective for targeting cost-effective proactive investments, as those investments can provide assurance for relief of participant curtailment in addition to providing capacity for future growth.

Another potential avenue for relieving high curtailment is to incorporate cost-sharing mechanisms to spread upgrade costs among participating customers who would experience curtailment relief as a result of the upgrade. Mechanisms such as “Market-Initiated Upgrades” within New York’s Cost Share 2.0[23], for instance, allow for the costs of some hosting capacity upgrade projects to be shared across multiple DER. When paired with pro-rata dynamic flexible

[23] https://www.psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/-/media/B63F65D2682E4669844F4D18965612E6.ashx

connection, this would allow for projects to connect and operate while sufficient cost-share participation is established to fund the upgrade, rather than having to wait until the upgrade was funded and constructed. While this approach is promising, designing and implementing such a program is likely to be a time-consuming endeavor, as there are significant questions to be answered and no such implementations have yet been attempted at scale at the distribution level.

Benefits

- Treats all participating customers equally when determining capacity allocation.
- In combination with other modifications, can provide a pathway to economically efficient system upgrades to relieve curtailment and expand available capacity.

Challenges

- Potential for early connectors to experience increasing curtailment over time, possibly reducing future economic viability and, as a result, driving adoption hesitancy if not addressed through other means.
- Likely requires development of supporting mechanisms or requirement to protect early participants.

Pro-rata Tranches

Another method for implementing pro-rata is to calculate pre-set amounts of DER (tranches) that can be accommodated with no more than a specific target amount of curtailment. For instance, a study may be performed to determine how much DER (by nameplate or export capacity) can be accommodated on a specific substation transformer with no more than 5% curtailment. Tranches could be calculated and established using all available capacity or could be established to accommodate new connections after existing hosting capacity has already been exhausted. Once the study results identify the appropriate total DER size, DER up to that total size (potentially including any de-rating for operating margins, study error margin, or future growth) could be connected without significant risk to future economic viability of participants.

Once the tranche is fully subscribed, subsequent applicants may be required to pay for capacity upgrades (similar to the existing process) or may be connected utilizing a LIFO dynamic connection (where their access to available capacity is lower priority than those participating in the pro-rata tranche). Because the curtailment of additional LIFO-managed facilities will be higher than the amount of curtailment experienced by participants within the tranche, it may be infeasible for new applicants to actually connect after the initial tranche is filled.

Because the tranche approach does not result in uniform treatment for all DER applicants, there may be some regulatory engagement necessary for implementation. In particular, if a tranche-based approach was offered at substations that still have available hosting capacity, new applicants would have no reason to utilize such an approach and would instead connect using the traditional firm capacity process unless pro-rata dynamic connection for a pre-set tranche of DER was required for all new applicants at that substation.

Benefits

- Enables equal capacity allocation across participant resources (up to a pre-set cap)
- Maximizes use of existing infrastructure.

Challenges

- Optimal implementation that best utilizes existing capacity may require regulatory engagement for implementation.

Pure Last In, First Out (LIFO)

A pure LIFO deployment of dynamic connections is perhaps the most straightforward approach, as it does not require any structural change in how capacity is allocated to new connectors. As a result, it can also be accommodated without major changes to the existing interconnection process, as customers will still have access to the same options as under the static methods: move forward with a system upgrade or use a flexible connection instead, with the expected curtailment based on the distribution system configuration at the time of study.

This approach does come with a few drawbacks that must be considered. First, prioritizing capacity access for some customers over others enshrines unequal treatment into utility operations. Implementing this prioritization and maintaining it over a period of years can significantly increase the complexity of implementing and maintaining the operational systems that enable dynamic connections.

In addition, this unequal allocation of capacity results in less overall DER that is able to be connected to the system. To demonstrate why, consider a scenario with two 5 MW solar facilities using dynamic connections that would, under a pure pro-rata approach, each experience 5%

curtailment of their total annual production. If these systems were instead connected using LIFO, rather than sharing curtailment equally, the second system to connect would be fully curtailed before any curtailment occurs on the first system. As a result, the first system to connect would experience between 0% and 5% curtailment, while the second system experiences between 5% and 10%. If 5% curtailment is the cutoff for economical project construction, both projects (totaling 10 MW of nameplate capacity) would be able to connect under pro-rata approach, but only the first project (5 MW of nameplate capacity) would be able to connect using LIFO.

Benefits

- Fastest approach to implement due to alignment with serial capacity allocation approach inherent to the existing interconnection process.
- Early adopters have more certainty around future curtailment magnitude due to their inherent prioritization.

Challenges

- Operational complexity and philosophical concerns due to unequal treatment of customer resources.
- Enables relatively fewer resources to connect than pro-rata approaches.

Real-Time Dynamic Management & Dynamic Operating Envelopes

Real Time Dynamic Management and Dynamic Operating Envelopes represent two advanced dynamic flexible interconnection approaches which allow responsive and grid-aware integration and operation of DERs without straining the distribution infrastructure. While both approaches share the core objective of aligning DER operations with system constraints in real time, they differ in the time horizon and method by which the control is executed: one through direct real-time management of constraints and the other through the provision of time-varying operating limits or schedules communicated to DERs, loads, or aggregators.

Real time dynamic management is an approach to actively monitoring and managing DERs based on real time or near real time grid conditions. This approach is characterized by its ability to continuously assess system parameters such as thermal limits, voltage, or transformer loading and dynamically adjusting load or DER performance to maintain system reliability. Participating resources can be managed either directly by the utility through centralized platforms like DERMS or ADMS or indirectly through aggregators and third-party providers who may receive utility signals/commands and coordinate load or DER behavior. The approach typically operates on short time intervals, requiring low-latency control and data acquisition from systems such as SCADA. This approach supports granular dispatch, where the utility actively determines (generally through DERMS/ADMS) which DER or loads to control, when, and by how much, based on criteria such as location, contribution to constraints, resource type, etc.

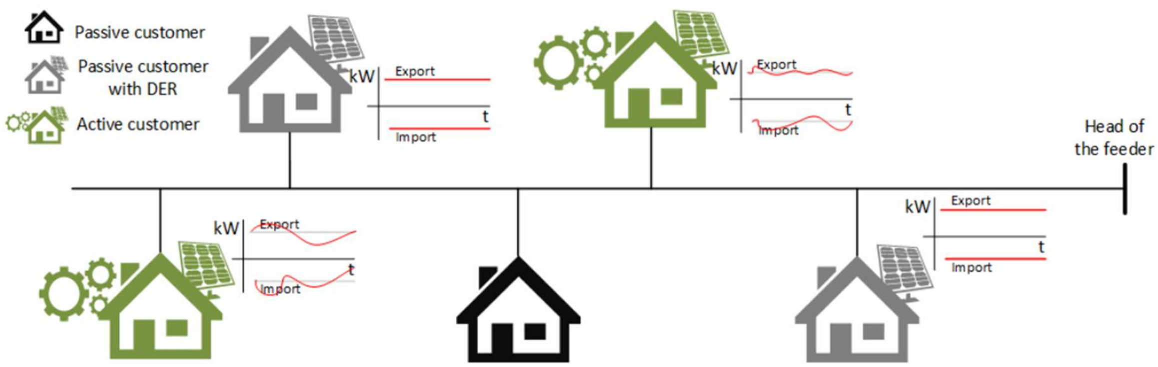
Additionally, real-time dynamic management can complement static methods, rather than replacing them. For instance, static limited-export values can serve as a baseline, with real-time control used to relax pre-set import or export constraints where practical in response to actual grid conditions. This layered approach can maximize grid utilization while also providing customers with specific, well-defined expectations.

Dynamic Operating Envelopes, on the other hand, are a more schedule based and forecast-driven approach to dynamic interconnection. Instead of the utility making real-time dispatch decisions, DOEs define time varying upper and lower bounds on DER/Load import and export as shown in *Figure 7*[24], typically delivered to the DERs/Loads ahead of time (e.g., day ahead or further). These limits are calculated based on predicted system loading, voltage profiles, hosting capacity,

[24] Project Edge Fairness in DOE Objective Function

transformer constraints, and feeder topology, incorporating uncertainty margins and other factors. DOEs are then communicated to resources directly or through aggregators via standardized protocols (such as IEEE 2030.5 or OpenADR), with each DER, load, or combined delivery point (e.g., site PCS) following the prescribed schedule.

Figure 7 - DOE Conceptual Illustration



Regardless of which method is implemented, the necessary modifications to the interconnection process are the same. Customers participating in dynamically managed connections need to be able to understand the degree of curtailment that they should expect and, ideally, the approximate times of day and year, magnitudes, and durations of curtailment actions, in order to make an informed decision about whether to move forward with their project.

For implementations using the Pure Pro-rata approach, determining expected curtailment depends heavily on the amount of additional resources that connect in the future and share in the allocation of available capacity. The level of risk of future curtailment exceeding project economic viability depends heavily on what additional mechanisms, if any, are used to spur system upgrades to expand capacity when curtailment becomes too high. The design and implementation of any such mechanisms depends heavily on associated regulatory constructs, some of which may deviate from the existing “cost causer pays” approach.

For implementations using Pro-Rata Tranches, curtailment amounts are pre-studied and incorporated within the tranche size, which minimizes the risk to participants by eliminating negative effects of future connectors on the amount of curtailment. There is still some potential risk that, due to changes in feeder characteristics over time, that curtailment deviates from the anticipated amount, but that may also be mitigated by incorporating a safety margin between the calculated curtailment amounts (e.g., 2.5% curtailment) and the target amount for the tranche (e.g., 5% curtailment).

For implementations using the Pure LIFO approach, or LIFO connections occurring after a Pro-rata Tranche is fully subscribed, the process of estimating curtailment is highly complex, as each new applicant requires a detailed analysis of existing grid conditions and DER production for DER that will be prioritized ahead of them.

One avenue for estimating project curtailment for LIFO applicants is to have the utility perform the analysis as part of the interconnection study. The utility has the best access to the necessary circuit models and historical data to perform this analysis, which makes this a compelling option. The major sticking point with this approach is the extent to which utility-provided curtailment estimates are sufficiently rigorous or backed by other mechanisms to enable customers to proceed with their project and secure financing. One such mechanism could be a guaranteed maximum curtailment amount, beyond which the utility will take corrective action such as customer compensation or system upgrades. For example, UK Power Networks has established a maximum curtailment threshold beyond which the utility compensates the participant at a set price per kWh for the amount the threshold is exceeded[25]. These types of guarantees or compensation mechanisms can be viable options for connectors but can negatively impact customer rates.

Another option is to have LIFO applicants be responsible for their own curtailment estimates. This can be achieved either by having the applicant (or their representative or consultant) perform the curtailment study themselves or by auditing the results of the utility study to the level necessary to provide appropriate assurances to enable project financing. This approach takes the analytical and risk burdens off the utility (and utility customers) but increases the external costs for applicants and requires significant utility data disclosure to enable. To perform such a study, the applicant would need access to utility equipment data, load and generation profiles, and other applicable data. This requires the utility to either publish the necessary data publicly (via, for example a sufficiently advanced hosting capacity map) or provide access to the party conducting

[25] 2022, The Office of Gas and Electricity Markets, Distribution Connection and Use of System Agreement (DCUSA) DCP404 – Access SCR: Changes to Terms of Connection for Curtailable Customers (DCP404), *DCUSA DCP404 Authority Decision*

the study, both of which may be infeasible for cost or customer privacy reasons, depending on the specific information to be shared, the mechanism used to share it, and any legal agreements or liability mechanisms used to protect it.

Risks and Challenges

For DER developers and installers, dynamic management fundamentally reshapes how projects are designed, evaluated, and financially modeled. If developers are responsible for evaluating curtailment to secure financing, it may present a significant barrier to utilization. Conversely, if the utility is providing assurance regarding the degree of curtailment, it may expose existing utility customers to additional costs or provide insufficient justification for applicants to secure financing. Navigating the roles and responsibilities for curtailment estimation is an essential element of the successful rollout of dynamically managed connections for DER.

For flexible loads, the operational risk is likely to be substantially higher than for DER. Flexible loads are more than just loads. They are equipment that a customer operates as part of their business. Consequently, load customers are much more likely to be negatively impacted by capacity reductions, particularly if capacity is reduced to effectively zero during peak load periods. Pairing dynamic flexible connections with a pre-set schedule can help alleviate these concerns by allowing the customer to bank on a certain level of performance and determine if that meets their business needs. Adding dynamic management to this base operating schedule can relax the pre-set limits, maximizing energy throughput while still maintaining customer confidence.

Another critical challenge in implementing dynamic management is ensuring the performance of communication between the utility, DERs and any third-party aggregators involved. Since the entire process is heavily dependent on communications, fallback options (such as pre-determined maximum safe export levels) in case of a communication failure will be required. As a result, communications uptime can significantly impact the operational capabilities of the resources, as communications failure will restrict import/export capabilities.

Lastly, implementing dynamic management is highly dependent on the accuracy of input data, operational models, and forecasting tools. These methods require the estimation of key distribution system parameters across the system with high spatial and temporal granularity on a constant basis. Model errors or issues with input data quality could artificially limit resource operation or cause utility equipment damage if the resulting import/export limit commands sent to DER are higher than can actually be supported. When considering DOEs, these issues are compounded by the need to forecast future grid conditions to develop the limits for each time point within the interval. Forecast inaccuracy may also create significant frustrations for customers attempting to utilize their resources for bulk power services in day-ahead markets, as inaccuracy will impact the ability of those resources to participate effectively or may result in penalties for underperformance.

Implementation Pathways

As explored previously, determining how to allocate available capacity amongst participating loads and DER is centrally important to designing a dynamic flexible connection offering. Selecting an allocation method and accompanying elements will have broad implications on other aspects of both the study process, operational needs, and system planning.

From the operational perspective, the two dynamic management approaches share the common objective of aligning DER operations dynamically with system constraints. They differ in how the control is executed: one through direct real-time management of constraints, and the other through the provision of time-varying operating limits or schedules communicated to DERs or aggregators. Both of these approaches require significant evolution in utility systems. This operational evolution introduces new requirements across multiple domains, including advanced forecasting, robust communication infrastructure, centralized control systems such as DER Management Systems (DERMS), and compliance frameworks to ensure the DERs abide by the operating envelopes or control commands.

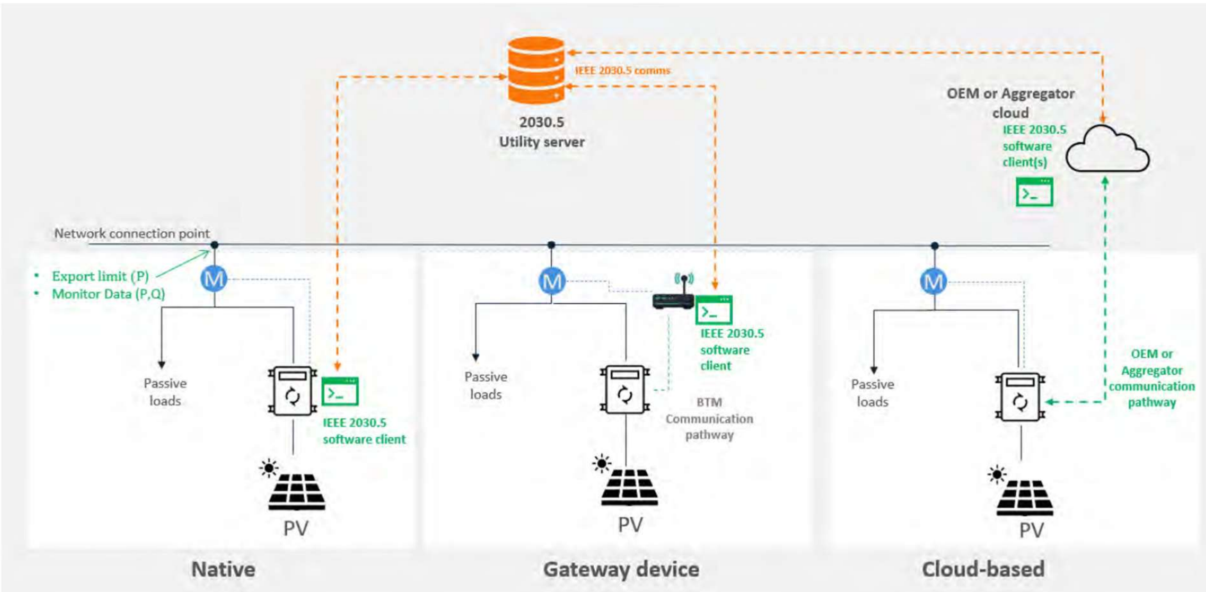
Real time dynamic management relies on active monitoring and direct control of DERs in real time or near real time. In the United States, implementation of dynamically managed connections has primarily been through pilot projects utilizing DERMS to monitor system constraints and modify DER output as needed to prevent the occurrence of reliability problems or negative utility customer impacts. This approach generally utilizes direct communication between the utility operational systems and the DER(s) within the scheme. It has shown significant promise for larger DER, where the cost of the necessary communication and control infrastructure represents a relatively small portion of the total DER deployment cost. For smaller DERs (e.g., rooftop PV, home batteries, EV chargers), a more scalable approach is to interface through aggregator platforms or manufacturer cloud APIs by, for instance, sending controls via an inverter manufacturer's cloud using standard protocols such as IEEE 2030.5. This cloud/aggregator-mediated control avoids the cost of field gateways at every small site while still enabling near-real-time coordination. Interoperability and communication standards are critical in this scheme as well. Utilities and vendors are looking to standards like IEEE 2030.5 (the Common Smart Inverter Profile, originally adopted in California as well as Australia) or OpenADR to ensure different DER and load makes/models can receive controls securely and consistently. Using standardized data structures and protocols will allow signals through aggregators or directly to devices without middleware integrations, improving scalability.

Dynamic Operating Envelopes take a schedule-based approach to flexibility, defining time-varying import/export limits for DERs rather than issuing real-time control commands. Implementation of DOEs centers on two capabilities: (1) a planning and forecasting engine that determines allowable grid capacity for DERs over upcoming intervals, and (2) a communication mechanism to convey those limits to customer's DERs or energy management systems. The calculation engine uses field data (e.g., feeder loads, voltage levels, transformer capacity, etc.), model information and forecasts of load and generation to compute how much headroom or constraint exists on the network at different times and creates import/export limits. Once calculated, these limits need to be delivered to the DERs or site PCS. In South Australia's implementation, DOEs are communicated via the IEEE 2030.5 protocol using the CSIP-AUS profile. This allows the utility's 2030.5 server to interface with either individual inverters or aggregator platforms' 2030.5 clients, providing schedules, as shown in

Figure 8[26]. This method does not require the utility to send continuous real-time control signals or to have a DERMS actively dispatching every few minutes. Instead, the utility's role is to periodically calculate the envelopes and publish them to the server, while the role of the DERs is to self-regulate within the bounds provided by the utility. This architecture can reduce reliance on dedicated end-to-end communications infrastructure and advanced control systems, though it shifts communications responsibility to the DER.

[26] Dynamic Operating Envelopes Working Group – Outcomes Report

Figure 8 - DOE Communication Options



Another key implementation consideration for both approaches is fallback behavior during communication failure. If a DER does not receive an updated envelope (due to, for example, communication failure), it should default to a conservative safe limit until the connection is re-established. For South Australia's DOE implementation, the devices are required to default to conservatively calculated static limits or a fixed maximum export profile. CSIP AUS also has a framework defined to set such fallback controls through IEEE 2030.5 protocols.

Impact on Customers, Applicants, Users, and Developers

Dynamic flexible connections have the highest degree of potential for maximizing the use of existing assets but are the most complex to implement. For larger load and DER applicants, this enables the avoidance of otherwise necessary system upgrades and the associated timelines. Enabling dynamic management of load customers can also help put downward pressure on rates for other customers by increasing the volume of energy sales without requiring additional distribution capacity investments. Load customers, however, may be more hesitant to utilize such connections due to perceived operational risk associated with curtailment during periods of critical business operations.

The impact of risk associated with curtailment assessments, and their subsequent impact on customers, will depend on the specific design decisions withing the dynamic connection offering. If the utility incorporates mechanisms to limit participant risk by facilitating upgrades or through other means, that will tend to maximize utilization by load and DER applicants but potentially at additional costs to utility customers. If the applicant is responsible for determining and managing curtailment risk, this may slow the adoption of dynamic connections.

Stakeholder Feedback & Discussion Focus Areas

Stakeholders understood that dynamic interconnections were more complex but have the benefit of maximizing the available capacity. However, some stakeholders were concerned with the costs of on-site technologies and utility communication and control systems that would be required to participate.

For developers to obtain financial support, they indicated a need to have an estimate of how their system will be curtailed. Depending on the offer, they stated they may require extensive data to finance the project, including historical load and DER data and potential future load and DER growth. They also indicated they would need to understand the cost of alternative options for capacity enhancements such as a system upgrade. In short, they need access to sufficient information to make an informed decision on whether and how to proceed.

It was stated that load customers may be hesitant to utilize dynamic connections without minimum assurances of a base level of capacity to prevent curtailment from impacting business operations. Pairing dynamic connection with a base import/export limit or operating schedule was one option to be considered.

Proposed Path Forward

Ameren Illinois is currently in the process of acquiring a DER Management System, which will enable the implementation of dynamic flexible interconnections (as previously described). In addition, there are several key questions that must be answered before any specific dynamic connection offerings can be made available, including:

- How will available capacity be allocated amongst participating loads and DER?
- Who will be responsible for determining the estimated curtailment, and what supporting tools or data sharing infrastructure needs to be in place to support this analysis?
- What additional mechanisms, if any, are reasonable to protect applicants against higher-than-expected curtailment?
- How will customer site design and equipment be impacted by communications and control requirements?
- What communications architecture, media, and equipment will be necessary to implement dynamic connections effectively?

Ameren Illinois plans to further explore these and other key questions during Phase 2, which is expected to include analysis to demonstrate the feasibility and impact of various design decisions as well as additional stakeholder engagement. Ameren Illinois' goal during Phase 2 will be to refine potential dynamic flexible connection offerings to enable timely progression from concept to pilot program to fully scaled offering once the DERMS is fully operational.

DER Orchestration Plan

DER Orchestration covers a broad set of techniques aimed at optimizing the behavior of distributed energy resources, including flexible loads, to achieve a range of objectives like congestion management, bulk power services, and more. The Department of Energy's report of Distribution Grid Orchestration[27] explores different approaches and mechanisms for DER orchestration in detail, including dispatch signal-based, autonomous and behavioral orchestration methodologies. While Flexible Interconnection is one type of DER Orchestration being pursued by Ameren Illinois, other goals like utilizing DERs for local distribution flexibility services using the Value of DER[28] framework and enabling their participation in bulk power system markets through VPPs (Virtual Power Plants) are also major important elements of DER Orchestration. Rather than treating each use case in isolation, there is a need for developing orchestration strategies and deploying tools such as DER Management Systems (DERMS) to harmonize these use cases. This enables DERs to provide services to both the distribution and bulk power systems while accounting for system constraints, utility objectives, and customer value. Each of these use cases touches many layers of utility process from planning, engineering, and interconnection approvals to market enrollment and operational dispatch. Orchestration mechanisms such as dispatch prioritization, service coordination logic, telemetry integration, and dynamic limit enforcement serve as the glue that binds these processes together.

The goal of this section is to explore how the deployments of flexible Interconnections, Distribution Services, and Virtual Power Plants will impact each other in order to coordinate the design and implementation of each element to enable them to coexist effectively and maximize both the value of DER to the customers and to the entire power system as well as efficient utilization of distribution system infrastructure.

Primary DER Orchestration Use Cases for Ameren Illinois

Because of the broad nature of DER Orchestration, it is necessary to narrow the scope to focus on key areas that will be most impactful to DER within Ameren Illinois' territory. Three primary use

[27] DOE Distribution Grid Orchestration Report: https://www.energy.gov/sites/default/files/2024-12/2024-11-18%20Distribution%20Grid%20Orchestration_Clean.pdf

[28] Illinois Value of DER Investigation: https://www.icc.illinois.gov/programs/climate-and-equitable-jobs-act-implementation-investigation

cases were selected for further exploration based on opportunities identified within Ameren Illinois' Multi-Year Integrated Grid Plan:

- **Flexible Interconnection:** Enable DERs to connect to the distribution system using actual operating capabilities and any agreed-upon restrictions in lieu of traditional study assumptions. For static flexible connection methods, impacts to other potential value streams can be known in advance and incorporated into consideration for other use cases. For dynamically managed flexible connection methods, additional operational coordination may be required to enable other use cases.
- **Distribution Services & Value of DER:** Enable DERs to provide and be compensated for benefits/services provided to the distribution system[29], including increased distribution system capacity. DERs participating in distribution services would require active operational coordination as a condition of participation or compensation in order to ensure that DER operations are aligned with localized grid conditions and constraints. Such coordination is likely to be more extensive and more broadly applied than existing communications requirements for applicants not providing distribution services.
- **Bulk Power System Services via Virtual Power Plant (VPP):** Enables DERs to participate in and be compensated for the benefits/services provided to the bulk power system by individual/aggregated DERs participating in the MISO market. This may be executed by the utility via direct communications or through aggregators or other service providers. It may also be established and directed entirely by an aggregator, with only the required coordination with the utility.

Each of the use cases identified above can be complex on their own. The primary objective of Ameren's DER Orchestration plan is to explore how to integrate these use cases in a coordinated manner that enables DERs to interconnect through flexible methods while maintaining their ability to provide both distribution level and bulk power system services. In practice, this means ensuring that DERs and flexible loads can dynamically respond to system signals and operational priorities as needed. In some instances, multiple use cases may coexist without conflict. In other cases, however, competing service objectives may arise. For example, a DER providing distribution capacity support during a local peak load event may be unable to simultaneously deliver frequency response services to the bulk power system. Hence, developing strategies for

[29] Bulk Power, Distribution and Grid Edge Services Definitions: https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Grid%20Services%20Definitions%20nov%202023_optimized_0.pdf

service stacking (where feasible), conflict resolution mechanisms, and clear dispatch priority protocols between utilities, aggregators, and bulk system operators is a critical component of effective DER orchestration.

The Role of a DER Management System (DERMS) in DER Orchestration

DERMS plays a central role and serves as the intelligent control layer in enabling the real-time orchestration and coordination of DERs. It enables real-time visibility, forecasting, control, and coordination of DERs, ensuring that these assets can provide value without compromising grid reliability. DERMS bridges the operational needs of utilities with the market-facing roles of aggregators and DER operators, unlocking DER potential as a system resource. DERMS' role spans multiple dimensions, some of which are explored below:

- **DER Registration, modelling and visibility:** The foundation of DER orchestration effort is visibility: knowing what DERs exist on the system, where they are, what capabilities they offer, and how they're behaving in real time. A DERMS serves as the central platform for registering DERs by collecting key asset information such as location, type, capacity, inverter settings, and telemetry capabilities. Once registered, these resources are modeled to reflect their operational characteristics, including export limitations, control capabilities, and dynamic behavior. When field communications and/or DER gateways are in place, DERMS can establish real-time visibility by integrating with field devices or aggregator APIs to monitor DER output, state of charge (for batteries), current settings, and overall asset status. This visibility is essential not only for grid situational awareness, but also for enabling effective DER coordination and integration into planning process to develop accurate planning models based on the monitored data.
- **DER Operational control:** DERMS also enables the transition from passive monitoring to active management of DERs. This includes enforcing flexible interconnection rules by sending dynamic import/export limits to prevent thermal, voltage, or other constraint violations on the distribution system. Where configurations and communications infrastructure permit, DERMS can also provide direct control of DER settings, like adjusting Volt-VAR and Volt-Watt curves, enabling remote on/off commands, and managing ride-through parameters. Beyond basic control, DERMS can actively dispatch DERs to support

the distribution system by enabling services such as localized capacity support during peak demand and other grid-support functions.

- **Forecasting and planning assistance**: In addition to monitoring and control, forecasting is another major functionality commonly included within DERMS. DERMS-based forecasting can be conducted at the individual asset level or at the aggregate/group level, and may include load, generation, and capacity forecasting. Forecasts are typically constructed using a combination of historical data, real-time measurements, and external variables such as weather conditions, pricing signals (e.g., TOU or wholesale market prices), and customer usage patterns. This enables utilities to predict DER behavior across time horizons ranging from real-time to day-ahead and seasonal intervals and can potentially assist in enabling accurate predictions of needs and grid services.
- **Market integration:** DERs can provide services beyond the distribution grid, with DERMS playing an important role in maximizing their participation in bulk power markets or distribution service offerings. There are several potential options for how this integration can be structured.
  - **Interface with Aggregators**: DERMS does not necessarily need to directly control DERs for market purposes but can instead act as a coordination agent, sharing critical distribution system data (e.g., import/export constraints from flexible interconnection agreement, system outages, maintenance, etc.) with third-party aggregators. This ensures DER participation in wholesale markets does not create local grid reliability issues.
  - **Acting as Aggregator**: The utility, through DERMS, can aggregate and manage a portfolio of DERs and enable their participation in wholesale markets. In this model, DERMS handles everything from market bidding to dispatch and settlement, acting as the sole aggregator on behalf of customer DERs.
  - **Support both models**: DERMS should be designed to flexibly support both direct utility aggregation and third-party aggregator coordination. This allows DER participation models to evolve over time based on regulatory structures, utility strategy, or customer preferences. This model also requires a clear framework development to ensure the fairness of the bidding process.
  - **Future flexibility**: Recognizing the uncertainty in market rules and regulatory guidance, DERMS should be architected for maximum adaptability, supporting emerging roles and responsibilities such as market frameworks, interoperability

standards, and customer programs continue to evolve. This requires consideration in the functionality and types of DERMS platform being procured.

Utility Process Elements Impacted by DER Orchestration

The three DER orchestration use cases being considered will impact multiple utility processes throughout DER lifecycle, spanning from interconnection to operations. The following breakdown highlights how each use case and its supporting orchestration mechanisms affect utility processes and how they can work together to deliver a cohesive DER orchestration framework:

- **DER Interconnection Evaluation & Approval:** The primary use case which interacts with this stage of DER Orchestration is Flexible Interconnection. At this initial stage, a DER applies to connect to the distribution system and technical studies and screenings are performed to identify any modifications needed to accommodate the new DER. If system limitations are found, a Flexible Interconnection approach may be used to enable the DER to connect without triggering the need for system upgrades, which may include specific operating requirements for the applicant. The outcome is a DER approved for connection under specific operational parameters, establishing a safe and flexible starting point for further participation in distribution and bulk power programs.
- **DER Registration & Configuration:** In order to provide distribution or bulk power services, the DER must be registered in the utility's DER management system or a third-party aggregator platform (or both). This step lays the groundwork for all subsequent orchestration efforts by collecting and configuring essential data such as location, capacity, inverter settings, telemetry capability, and operational characteristics.
- **Distribution Services Compensation Eligibility**: This stage identifies whether the DER qualifies for value-based compensation under mechanisms such as Value of DER incentives or other programs. At this stage, orchestration mechanisms include measurement and verification frameworks, DER performance monitoring tools, and program rules integration within DERMS. The DER receives compensation based on its contributions to the distribution system, provided its operating behavior aligns with defined eligibility criteria. Importantly, enrollment in such programs is separate from flexible interconnection limitations but informed by any limitations established within the flexible interconnection.

- **VPP Enrollment**: the DER may also be enrolled in a VPP aggregation to participate in bulk power markets or otherwise provide bulk power services. During this step, utilities coordinate with DER owners or aggregators to validate that the DER meets the requirements for VPP participation. This process involves orchestration protocols such as aggregator-utility communication channels and checks to prevent double-counting between distribution and bulk power services. DERs already receiving distribution-level incentives must be cross-verified to ensure that participation in bulk services does not conflict with existing obligations. If approved, the DER becomes eligible to support the bulk power system through VPP dispatch mechanisms.
- **Operational Dispatch**: The DER actively participates in grid operations and responds to the dispatch signals related to import/export limits, providing distribution services, and fulfilling market dispatch instructions through a VPP. Since all three use cases can be active simultaneously, orchestration becomes critical to avoid conflicts and resource over-commitment. Key orchestration mechanisms include dispatch prioritization framework (e.g., local reliability takes precedence over bulk market services), dynamic constraint monitoring, and bidirectional communication to manage grid outages, system events, or service overrides. The goal is to ensure that DERs operate within safe parameters while delivering maximum value.

Flexible Interconnection Impacts on Distribution Services

Flexible interconnection and distribution services are, on the surface, conceptually similar, but there are key differences that drive them to be considered as separate elements of DER Orchestration. Flexible interconnection is generally attempting to maximize the ability of new load or DER resources to operate while avoiding distribution system constraints that would otherwise require system upgrades. In essence, the goal of flexible interconnection is to “do no harm”. Distribution services, in contrast, consider the positive impacts that new or existing DER or controllable loads can have on the distribution system (most commonly in the form of increasing distribution system capacity). This equates to incentivizing participants to “do good” rather than doing “no harm”. When considering how these two use cases interact, static and dynamic flexible interconnection methods have very different characteristics.

Static Flexible Interconnection Impact on Distribution Services

As highlighted in earlier sections, there are multiple methods of static flexible interconnections methods that can be utilized, including staggered connections, import/export limiting connections, and schedule-based connections. While these methods are valuable for enabling greater DER penetration under existing system constraints, they each carry distinct implications for the DER's ability to provide distribution services.

- Staggered connections allow a portion of the assets to begin operations earlier, which can allow for a portion of distribution services to be provided earlier as well. This may need to be coordinated with relevant compensation mechanisms (i.e., smart inverter rebates), as such mechanisms may not be set up to segment compensation into multiple parts.
- With limited import/export, loads and DERs are approved with fixed maximum limits on how much power they can import from or export to the grid, regardless of real time system conditions. These limits may impact the ability of the participating resource to provide distribution services. For instance, a combined solar and storage system operating using a fixed limited export may not be able to provide full export support from both the solar and storage simultaneously.
- Schedule-based flexible interconnections generally avoid resource operation during constrained periods but may also create limitations on the ability of participating resources to provide distribution services due to import or export limitations. The details of such impacts will depend heavily on the resource's operating schedule.

Dynamic Flexible Interconnection Impact on Distribution Services

Dynamic flexible interconnection allows utilities to modify the behavior of participating resources in real-time to avoid problems that those resources would otherwise cause. This does not inherently include the ability to dispatch those same resources to provide distribution services by relieving constraint conditions caused by other factors. For example, a utility can use dynamic flexible interconnection to curtail a battery's output during a low-load, high-generation period to avoid reverse power flow. However, this does not automatically allow the utility to instruct the battery to discharge during a peak load event for capacity support. To leverage DERs for distribution services like distribution capacity support, a separate mechanism/program is required. This could be a grid services agreement, non-wires alternative procurement, VPP program, or tariff structure that enables dispatchability with added compensation.

When evaluating a resource connected using dynamic flexible interconnection for the ability to provide distribution services, the timing of the resource's constrained operation and the timing of the distribution system need must both be considered. Generally, for power injecting resources such as solar PV, high load conditions on the local distribution system make it less likely that the PV will need to be curtailed, meaning that such resources could still provide a full set of distribution services. This may vary based on specific circuit conditions and the specific constraints being avoided using dynamic flexible interconnection.

For resources capable of absorbing power, this coordination is more complicated. For instance, consider a battery storage system operating under a dynamic flexible connection that has its charging capabilities restricted during distribution peak load conditions. Where that battery is blocked from absorbing more power during peak times, that limit does not constitute distribution services, as the battery is being managed to prevent negative impacts that it would otherwise cause. If the same battery were to be dispatched by the utility to inject power during that distribution peak time window, that could be considered as distribution services, as the battery is changing its behavior to positively impact the distribution system. To navigate this complexity effectively, the underlying reason for the DER dispatch must be considered.

Static Flexible Interconnection Impacts on Bulk Power Services

Static Flexible Interconnection incorporates known import and export constraints on DERs, which can influence their ability to participate in bulk power system services such as energy markets, frequency regulation, or capacity support. These limitations are clearly defined during the interconnection process and are known in advance by the DER owner or aggregator. Consequently, project owners or operators can factor these constraints into their planning, market participation strategies, and bulk power service participation. This may reduce the DER's potential market revenue (relative to unconstrained operation), but since the limits are known, there is sufficient predictability and transparency to enable effective market participation.

Dynamic Flexible Interconnection Impacts on Bulk Power Services

Because dynamic flexible interconnection requires resources to reduce their import or export levels due to operational constraints, it will impact the ability of participating resources to provide bulk power services. The specific impacts to bulk power services will vary based on how dynamic interconnection is executed as well as the bulk services being considered.

Where dynamic operating envelopes are provided, which show forecasted DER operating constraints on a day-ahead basis, participant DER can offer bulk power services more effectively because they have a relatively strong understanding of their expected operating capabilities for real-time and day-ahead participation. Where real-time management is utilized, it may be more difficult for DER to participate due to uncertainty of operating limits.

For real-time bulk power services, DER can use their operating limit to inform bulk power offerings. There is some risk for participants, as operating limits may change in response to changes in distribution system conditions. This would impact the ability of the DER to provide its offered bulk power services if operating limits were reduced just prior to the bulk power service offering window.

For day-ahead bulk power services, dynamic operating envelopes are much more impactful, as they can shape bulk power service offerings based on anticipated distribution constraints. Without such forecasts, bulk power services participation may be more limited or more likely to result in non-performance penalties due to distribution constraints.

When a resource is participating as a capacity resource for the bulk power system, coordination with distribution dynamic flexible connection is necessary. Generally speaking, bulk system capacity constraints are unlikely to align with DER capacity limitations on the distribution system because the additional load would tend to increase the available DER hosting capacity. For instance, solar PV operating constraints are most likely to occur during Spring or Fall, while bulk system peaks tend to occur during hot summer periods. As a result, it will often be practical for dynamically managed DER to provide bulk power capacity support. However, there may be edge cases where individual distribution circuits or substations may experience different constraints which would result in operating restrictions during bulk power peak conditions. As a result, it is important that participating DER be provided with an understanding of both the timing and magnitude of anticipated curtailment events during dynamic operation.

Coordinating Distribution Services and Bulk Power Services

Coordination between distribution and bulk power services is important to consider because, for some services and DER at some locations, bulk power and distribution needs will align, allowing for DER to provide services to both simultaneously. For bulk power capacity and distribution capacity, for example, a large number of distribution substations will experience their peak at the same time as the bulk system peak. This enables a DER to provide services to both without conflict.

In other cases, the timing of distribution and bulk power service needs may not be aligned. Individual distribution circuits or substations may experience peak load conditions at slightly or significantly different times than the bulk system. For resources such as storage, which have a finite amount of stored energy, timing mismatches can be significant. Even if the distribution system and the bulk system peak on the same day, if one occurs earlier in the day than the other, the stored energy may be exhausted and unable to fulfill the needs of both systems.

As a result, it is very important to verify that resources participating in both bulk power and distribution services are able to fully meet the needs of both. If they are not, participating resources may need to select their value streams accordingly. Utilities, aggregators, and bulk power market operators may all play a role in ensuring that resources are capable of providing all the services for which they are compensated.

Appendix A – Stakeholder Engagement Summary

Ameren Illinois collaborated with the CHARGED Initiative[30] to provide stakeholder engagement through a series of facilitated workshops. Participants within these workshops were segmented into DER and EV groups in order to focus on the specific impacts and mechanics of utilization for each flexible connection method. Four workshops were conducted with each group. These workshops explored the overall flexible connection concept, the specific methods being investigated, the process of adopting flexible connection methods, and the overall value proposition.

Ameren Illinois also participated in monthly meetings with a variety of parties during which Ameren presented technical information about the flexible connection methods being pursued as well as provided updates on development progress. Findings and feedback from stakeholder engagement activities were also presented to the group.

General Feedback:

Stakeholders were generally supportive of the concept of flexible connection, indicating that interconnection cost savings from such options would be beneficial and that decreasing the time between application and energization is an important benefit for both loads and DER. Stakeholders also indicated that flexible connection could be paired with proactive planning to enable energization while planned system upgrades were occurring, acting as a "bridge to wires".

When discussing the process for implementing and rolling out flexible connections, stakeholders indicated that having standardized offerings and criteria for implementation would be desirable in order to enable customers to make choices and implement the required infrastructure. Consistency and coordination between methods and throughout the state was also recommended. When designing flexible connection mechanisms, the friction between the complexity of the offering and the workability of solutions was identified as a central tension and that it would be important to strike the correct balance.

From a process perspective, it was recommended that a flexible connection study be triggered when a costly or long-duration system upgrade was identified during the study process. The timing of sharing information about available options was an important consideration, with the

[30] CHARGED Initiative: https://gridlab.org/chargedinitiative/

goal of having customers informed about their options without being overwhelmed or unable to navigate them effectively.

Stakeholders also recommended that utilization of flexible connection methods and an assessment of the benefits achieved through their use be reported. The resulting data could be used to refine flexible connection offerings or further engage customers to ensure awareness.

Feedback on Flexible Interconnection Methods:

Staggered Connections

Staggered connections were generally seen as beneficial by stakeholders, as they allow for faster energization with effectively no downside. It was recommended that interconnection agreements include any technical requirements and information on the nature of the flexible interconnection. Stakeholders were interested in having definitive timelines for the associated system upgrades, which is shared for both existing connections and the potential use of staggered connections. It was identified that staggered connections would tend to reduce any negative impact of construction timelines and potential delays, relative to the existing process.

Allowing for temporary use of other flexible methods was recommended by several stakeholders, especially temporary import/export restrictions, temporary schedules, and temporary volt/watt utilization to speed energization of load and DER.

Capacity Assurance

Stakeholders indicated that mechanisms which allow customers to reserve system capacity are likely to create queue challenges and inefficiencies, quickly becoming unmanageable. Planning-focused customer engagement was identified as potentially beneficial but was generally not considered part of flexible connection because it doesn't change the underlying resource operation or the connection process.

Limited Import/Export

Stakeholders stated that, while this method is already allowable for DER interconnections, technology has changed since PCS specifics around response times were enshrined within Part 466. Utilizing new standards or less restrictive performance under the "other acceptable methods" element of part 466 import and export limits was recommended for consideration.

Participants indicated they would want specific information available regarding technical requirements and site design impacts so that the method could be used effectively. Customized controller implementations using, for example, an SEL RTAC were also of interest.

For load customers, stakeholders identified that different types of customers will have very different levels of sophistication when it comes to estimating demand, which will impact the extent to which limited import/export connections could be used effectively by some customers.

Stakeholders indicated that they would need to be able to estimate the long-term impacts of import and export limitations and that they may require data from the utility to do so. It was indicated that, since the import/export limits are fixed at the time of connection, customers could assess the impact of such constraints on their own systems without additional utility data.

Schedule Based Connections

Schedule connections received the highest degree of interest for implementation. It was generally seen as a way to increase value for interconnections, potentially synergize with concepts such as time-of-use rates, and help to unlock meaningful capacity without the complexity of DERMS. However, some stakeholders were concerned with the complexity of more granular schedules. To be comfortable with scheduled connections, stakeholders indicated a need for the utility to be willing to share data during the interconnection process to understand costs, timelines, expected curtailment, and circuit conditions.

For the interconnection agreement, it was recommended that the operating schedule and defined limits be included and documented, as well as language for how schedule changes and updates will be addressed. Stakeholders also recommended that the agreement specify that the schedule will not be updated to further limit customer system operations. Penalties and enforcement mechanisms for customer non-compliance were also identified as necessary to enshrine within the agreement, with indications that overly severe penalties or liability may inhibit utilization.

Volt-Watt Settings

Utilization of volt/watt for Level 1 DER was previously discussed with stakeholders and detailed within Ameren Illinois' Revised Multi-Year Integrated Grid Plan. During stakeholder discussions within Phase 1, it was determined that customer choice was a key element to successful implementation. Stakeholders recommended that customers be given the option to use a volt/watt curve or incur the otherwise necessary upgrade costs. Stakeholders also suggested the option for small DER to temporarily use of a volt/watt curve while waiting for infrastructure upgrades to be completed, enabling DER owners to begin generating sooner, while still eventually being able maximize their system's output. Stakeholders indicated that interconnection cost reduction would be valuable, so long as customers have a means of addressing any curtailment-related issues that occur during operation.

For larger DER projects within the Level 2 and 4 processes, stakeholders indicated it may be difficult to finance projects utilizing volt/watt curves due to the unknown degree of project curtailment. Additional historical voltage data was requested to help mitigate such concerns.

Dynamic

Stakeholders understood that dynamic interconnections were more complex but have the benefit of maximizing the available capacity. However, some stakeholders were concerned with the costs of on-site technologies and utility communication and control systems that would be required to participate.

For developers to obtain financial support, they indicated a need to have an estimate of how their system will be curtailed. Depending on the offering, they stated they may require extensive data to finance the project, including historical load and DER data and potential future load and DER growth. They would also need to understand the cost of alternative options for capacity enhancements such as a system upgrade. In short, they need access to sufficient information to make an informed decision on whether and how to proceed.

It was stated that load customers may be hesitant to utilize dynamic connections without minimum assurances of a base level of capacity to prevent curtailment from impacting business operations. Pairing dynamic connection with a base import/export limit or operating schedule was one option to be considered.

Stakeholder Engagement Sessions Participating Organizations List:

- BP
- Enphase Energy
- Environmental Defense Fund
- Environmental Law and Policy Center
- Highland Electric Fleets
- Interstate Renewable Energy Council (IREC)
- Mobility House
- Nautilus Solar
- Nexamp
- Pivot Energy
- Soltage
- Sunvest Solar
- Trajectory Energy Partners
- Vehicle Grid Integration Council (VGIC)