IURC Implementation re: FERC Order 2222
August 16, 2023 Roundtable Discussion at IGCS, Conference Room A

Discussion topic: Distribution System Operations and Impacts

SUMMARY NOTES:

Attendees (alphabetical by organization and names):

AES Indiana
- Matt Fields
- Joshua Spalding
- Brandon Stuckey
- Rob Whitworth
- Xuan Wu

Citizens Action Coalition of Indiana (CAC)
- Ben Inskeep
- Jennifer Washburn

Collaborative Utility Solutions
- Chris Hickman

Duke Energy Indiana, LLC
- Nancy Connelly
- J.D. Cox
- Andrew Wells

Hendricks Power
- Levi McNeely

Hoosier Energy
- Ryan Henderson
- Blake Kleaving

Hoosier Environmental Council
- Delaney Barber

Indiana Michigan Power Company (I&M, AEP)
- Dan Coleman
- Subin Mathew
- Denzil Welsh

Indiana Office of Utility Consumer Counselor
- Scott Jones

Indiana Utility Regulatory Commission staff:
- Brad Borum
- Rich Brunt
- Steve Davies
- Beth Heline
- Ren Norman
- Dale Thomas

Johnson County REMC
- Kevin Shelley
- John Sturm

Northern Indiana Public Service Company, LLC (NIPSCO/Nisource)
- Tiffany Murray

Southern Indiana Gas and Electric Company (dba CenterPoint Energy Indiana South)
- Chris Akin
- Jeff Earl

State Utility Forecast Group
- Doug Gotham, Purdue University

Tipmont REMC
- Ron Holcomb
- Jeremy Konkle

Voltus, Inc.
- Yinka Ajibade

Wabash Valley Power Alliance (WVPA)
- Rebecca Moor Davrich
- Dan Phillips

Acronyms used:
- 2222 – FERC Order 2222
- DER – distributed energy resource
- DR – demand response
- EDC – electric distribution company; term used by ISOs/RTOs
- EDG – excess distributed generation (see Indian Code chapter 8-1-40)
- EE – energy efficiency
- EPRI – Electric Power Research Institute
- EV – electric vehicle
- FERC – Federal Energy Regulatory Commission
- IAC – Indiana Administrative Code
- ISO – independent system operator (aka RTO)
- IURC – Indiana Utility Regulatory Commission
- MISO – Mid-continent Independent System Operator
- NERC – National Electric Reliability Corporation; sets standards to be approved and enforced by FERC
- OUCC – Indiana Office of Utility Consumer Counselor
- PJM – PJM Interconnection LLC
- RDER – DER that is connected and mixed in with load, such as at a house
- REMC – rural electric membership corporation – Indiana's electric cooperatives
- RERRA – relevant electric retail regulatory authority; in Indiana, this is the IURC and can also be the boards of municipal utilities and of REMCs.
- RTO – regional transmission organization – Indiana has electric utilities in two RTOs – MISO and PJM
- UDER – DER that is connected to a dedicated utility facility.

Introductions:

Sign in sheet; request to be added to email distribution list.

NOTE: I&M provided a handout, "Engineering Impacts from Distributed Energy Resources Aggregation", which is also posted on the IURC website at: https://www.in.gov/iurc/home/implementation-re-ferc-order-2222/.

Discussion:

Initial question – should the IURC adopt IEEE 1547 (2018)?
- I&M/AEP is currently drafting interconnection and interoperability requirements; recommend adopting IEEE 1547 (2018).

Are there any downsides to adopting IEEE 1547?

- Some may want "walled gardens"; but everyone supports it, particularly for new DERs and DERs wanting to participate at wholesale.

The performance categories in IEEE 1547 (2018) – should they be the same throughout the state? Or can they be different for each utility?

- They should be different for each utility, because the utilities have different levels of DER penetration and distribution system differences.
- EPRI recommends the performance categories be by utility, but have a general format and settings readily accessible.

AES is going through similar process as I&M/AEP, to define categories and settings, depending on penetration.

Duke is also working on the interconnection and interoperability requirements in an enterprise-wide document with local variations. All ride through categories does have a minimum ride through.

What is specific concern with ride through? All DERs will have to meet minimum requirements. What's driving the question?

The industry has raised the question. Two of the primary benefits of adopting IEEE 1547-2018 is ride-through and open communication standards. Unlike the 'dumb energy bricks' in Australia that all trip off for any grid anomaly and then all come back on simultaneously, IEEE 1547-2018 allows these units to ride through these smaller events on the grid and can also stage how they come back onto the grid. The open communication standards allow any aggregator or utility the ability to communicate with the inverters to download appropriate settings and execute any type of utility program or market events. However, all of this is new and live line work must always be a consideration when thinking about concepts like 'ride-through'. This should be an area of discussion moving forward to ensure the safety of utility workers. The suggestion to date has been that a utility has the ability to communicate with applicable inverters on the line in question to be able to disable this functionality if they are doing live line work.

Does anyone feel that we shouldn't adopt IEEE 1547 (2018)?

Categories and settings depends on penetration but also on the individual system characteristics; therefore, adoption of IEEE 1547 (2018) shouldn't mandate one specific category.

All new inverters moving into the direction of IEEE 1547 (2018). More than half of inverter manufacturers meet the new UL 1741 SB testing criteria for 1547-2018 and are listed on the CEC website. Certified inverters – the new ones will meet the standards.

The old (non-IEEE 1547 compliant) converters trip off, cascade, and create problems. This is happening every day in Australia right now. This problem depends on penetration; Indiana is not at that level of penetration; however, every day that 1547-2018 is not in place, more sub-standard equipment is put into the system. As long as 1547-2018 is adopted in the near future, there does not need to be a requirement to go back and require existing customers/DERs to put in new inverters, as it's not an immediate issue for most utilities, due to the small level of penetration. In addition, there can also be upgrades to the firmware of existing inverters. Many inverters are four-quadrant and have the ability to meet the requirements of 1547-2018, they were just not set up for this functionality, so the assumption should not be that an inverter would have to be replaced, it could be upgraded and meet necessary requirements for a lot of the inverters in the field right now. (Anything 1-5 years old for sure)

Regarding ride through, Texas and California, with higher levels of penetration, are having some issues with larger renewables. This is detailed in a recent NERC report.

Current interconnection rule – allow, require, or compatible with IEEE 1547 (2018)?.

Categorical options – does it give the utility more tools?

Settings have nothing to do with penetration; it involves grid requirements; EPRI is working on this and has provided industry use cases and example set points.

Aggregator perspective – support IEEE 1547 (2018) because it creates standards and does not allow any manufacturer to create 'walled gardens' where only the manufacturer can aggregate the resource.

DERs that participate in wholesale markets will need to be upgraded to an IEEE 1547 (2018) compliant inverter or firmware.

Who has the authority to place requirements on non-wholesale aggregators? In Indiana, any retail (i.e., non-wholesale) aggregation would have to be part of an existing electric utility's tariff, which would need approval by the IURC.

Existing DER that is not participating in wholesale markets would not need to upgrade to IEEE 1547 (2018). If they want to switch and participate at wholesale, then they'll need to upgrade.

Interconnection rule or new rule? Current interconnection rule doesn't refer to ride through; can it just refer to IEEE 1547 (2018) or does there need to be more clarification?

Generically, the ISOs will have view of the settings; EDCs have capability of setting own parameters. IEEE 1547 (2018) takes care of everything, as long as everyone follows the standard. It's best to get in front of it before we get to a higher penetration level. Once you have the settings, settings may be different for different feeders. Once a DER makes the decision to enter into a wholesale market program, then the DER will need to upgrade its equipment to the IEEE 1547 (2018) standard.

For distribution system interconnections, start with the interconnection rule, and then the additional layered rule of what you need to participate in wholesale market. There may be additional requirements for aggregations. There is some diversity in individual DERS, but, in theory, when having a large number acting in unison, that requires different study and requirements.

If a DER wants to participate at wholesale, they need to comply first with the customer generator interconnection and then with the (to-be-developed) market participant rules. Should those processes be in serial or can they be parallel, so don't discourage DERs?

The processes and studies can't be done in parallel unless the utility/DER know the details of the aggregation. The processes need to be serial initially, as you don't know what the rest of the pieces are that you have to study. However, this should not slow any customer down in permitting a DER and getting it installed. Participation in a utility program or market program would come after that process.

Standard interconnection rule as step one, before a 2222 process. Then, once that's done, then additional process, then 2222 process. State needs to have its rules and its timeline, and, once everything is approved, then can access RTO market.

Step two would be for a single DER/aggregator, for those who want to participate at wholesale.

Important to remember that each aggregation is a different analysis.

We will need a pre-registration process.

Keep step one, then do wholesale analysis process, including safety and reliability of the aggregation. This could include distribution system upgrades.

For the 60 day review period that's in 2222, the utility lets the RTO know if additional time needed to distribution system upgrades. There's a burden shift.

Looking at potential upgrades in step two will depend on the scale/size of the DER; upgrades are more common with the larger DERs or large aggregations on a single facility (such as a single feeder or substation).

PJM did not ask for any exceptions in the 60 day 2222 review period.

We need to clarify the difference between review and work. The 2222 review period is 60 days. However, if the utility identifies issues that need upgrades or other work done, it doesn't have to complete the work needed to resolve the issue within the 60 days.

Limit aggregations to single node – to walk before you run – to make analysis done within the 60 days.

If not aggregations are not at a single node, then it makes settlements very difficult. If breaking by node, it could prevent aggregator from making minimum, then PJM may work with them on settlements. In the on-going process to define all rules with the RTO, this concept of different settlements based on node connection, and also the RTO dispatch of of different products on different nodes at the same time must be addressed. It could create significant difficulties on day one for an aggregator or utility to try and have half of an aggregation respond to a dispatch on one node and then try to settle that, not to mention two different dispatches on two nodes that an aggregation crosses.

Nodal decision won't be the IURC's decision; that will be an RTO decision; we will have to deal with it. RTO process will help to define that; if you do an aggregation and can meet 100 kw across two nodes, PJM may allow and work with them.

What do we need to add in our interconnection/aggregation rule/process to make sure distribution is reliable? What do we need to add to step two?

The utility will have to look at the models and make sure the aggregation meets the model. There needs to be a requirement for some kind of communications, and the utility will need to make sure it has controllability regarding the DER(s) and aggregation. 1547-2018 required open communication standards to allow this, but for safety, reliability and execution, the utility will have to have a system to communicate with the DERs.

The utility must be able to override a dispatch from aggregator; for a level 3 resource, the utility would have the override and disconnection points.

For large interconnections, there must have an override that utility has control of; utility developing control systems. Anything smaller than 2 MW, the utilities don't currently have the ability to control, so the utility will need the aggregator to respond or have other equipment. If there are voltage violations, then utility must need to be able to take action to resolve. The utility must be able to meter the DER separately, so the utility can control. It is difficult to project generation and usage that behind the meter. Solar generation can mask load. The utility will need to know all of the components. The utility needs to have good insight of what's happening and what's available. A DER going out can overstress that part of system. It is currently suggested in the PJM implementation plan that any curtailment or override by the DSO will go to the ISO and the ISO executes.

There are very few DERs currently. PJM said no new equipment needed, but that is probably not correct.

One option is to have active resources behind one meter and demand response usage behind another meter – California is requiring two meters.

IEEE 1547 (2018) should be incorporated into interconnection standard. An additional rule for DERs participating in a wholesale market should be adopted in advance of 2222. EDCs must have absolute control over of settings for DERs on their system; UDER – connected to a dedicated utility facility; RDER – any home or whatever mixed in with load. Governance should be determined, including on the aggregator side, and regarding modeling responsibilities.

FERC RM 22-12 is telling NERC to figure how to collect modeling data for all DERs via a rulemaking.

[BREAK]

Appreciation expressed for the I&M handout/comments, but the requirements should not include unnecessary equipment or be too cost prohibitive. We don't need to design for a California-like situation when we're not at that level of penetration. Existing DERs should not be required to upgrade, as long as they choose not to participate in the wholesale market or in a wholesale aggregation.

AEP Texas had most DERs on the AEP system; some AMI meters have the ability to do disconnections when the load is below a certain threshold.

It's important to discern the difference between what's needed and what's ideal.

We should make provision for revisiting this as things change in the future.

2222 places an additional burden on utilities and customers – but what if no one is interested in participating?

What do we have to have in place? Some items may be necessary, but at a later date.

There's no intent to make wholesale participation onerous for customers. It's important for the utility to understand what's happening on its system in real time. This depends on level of DER penetration – what do we need to be prepared for and not be blind to the possibilities?

We should set up what we need now and then touch base on a periodic basis.

Are cost recovery and cost allocation future agenda items?

There will be people/process/system changes required at the utilities and the RTOs.

If a hurricane comes, then the community works together versus everyone does their own thing. DERs are coming – not if, when – $4 billion worth. It's better to deal with this in mass; it could save us money if we do this together. DER registry is an option. We know this is coming, so best not to do this ad hoc. DERs are coming, regardless of 2222 and much of this work needs to be done regardless of 2222 to ensure safe and reliable operation of the system. In fact, it could be seen as an opportunity to lower the cost to utilities and customers by allowing everyone to work on the problem together, with common solutions, to lower the overall cost/burden. It's important to get the structure in place, with the ability to revisit as things change.

How big of a challenge is bi-directional flow? System is not designed for bi-directional flow; it requires a much more complex analysis; distribution systems were built 50-80 years ago.

If there's reverse flow into the substation, and that substation is not set up for reverse flow, then the utility must change out that equipment. If you have a large DER or multiple DERs that are causing reverse flow into the transmission, then they are wheeling power across distribution system to transmission and wholesale. If there's no wheeling tariff, how to you decide to allow reverse flow, so you have enough load, and so reverse doesn't occur.

One key issue to be discussed in the 2222 implementation process in each state is the concept of a 'open access distribution wheeling charge'. As with FERC 888/889, new tariffs had to be created for people that wanted to wheel power across the transmission system. With 2222, new 'generators' are asking to wheel power across the distribution network. Tariffs or a new wheeling charge should be a discussion point with the implementation of 2222.

There's distribution interconnection plus transmission interconnection at a certain level. A developer looking at large solar farm seeking to interconnect on distribution can cause reverse flow. Do current interconnection processes deal with that?

Neighborhood transformer can do both flows, but it may need some upgrades.

Planning criteria are changing.

Standard level 1 would be an EV driving 31 miles/day and coming home with 85% of their charge. But size and scale matter. Level 2-3 with Ford Lightning will destroy the system, as it can draw 1.5 times more energy than the house. If you want an EV to participate in a market program, then it must be part of the interconnection process. List EVs as an option – future with injection, not just load.

The utility also needs to know information about the DER for safety reasons.

Having a wheeling tariff on the distribution system is an option under 2222, like open access tariff. State decision about such a tariff needs to be undertaken as part of this process.

Utilities need to get a list of two-way capable EV chargers.

There is a responsibility for the customer to make sure the utility is aware of the customer's DER components and to do an interconnection process. Customer often find out what's needed when they are working with an installer.

AMI helps with information and potentially disconnecting a DER if necessary to protect the distribution system. However, with 1547-2018 in place, the utility should be able to signal any inverter in their system to disconnect.

It varies by utility whether they require a physical disconnect or if that can be handled by the meter.

Do inverter standards prevent backfeed? Inverters allow it, but older inverters will disconnect and cause other issues. That's why IEEE1547 (2018) is important.

Meters are meant to provide data analytics; remote disconnects in a meter are not designed for safety, they are typically not rated to interrupt full load and are used primarily for move in/move out and cutting off service. The disconnect can wait until the load of the home is below it's rating and interrupt service. As such, they should not be considered a safety device for disconnect.

Where is the signal going for the inverter not to inject? Utility and/or aggregator may generate the signal but the signal should be sent directly to the inverter.

IEEE 1547 (2018) has the communication standard.

If the aggregator fails to disconnect the DER and a utility employee gets injured, who has the liability?

This opens up a risk that utility is not in control of. An aggregator should never be able to stop a disconnect signal or a signal that is generated for system or personnel safety.

If zero voltage, then inverter opens up.

Even with an IEEE1547 (2018) inverter, cease to energize or cease to power does not mean a physical disconnect. The utility crew needs to see that the disconnect is open. If anyone's interconnection standard does not require this disconnect, it should be added.

Under the IURC's current interconnect rule, the utility has the option to require physical disconnect.

Under FERC 2222, the EDC can override the dispatch. Currently planned for the utility to tell ISO and the ISO overrides/curtails the dispatch or the aggregation.

The inverter does not count as a control safety, the disconnect must be in place.

California and New York don't require external physical disconnect switches. This is not universally true, they do require this in some cases, but their states made the decision to further incent adoption by eliminating this requirement in some cases. Ultimately, if you were to speak with utility system engineers, they do not like this decision and the incremental cost of an external disconnect in comparison with a solar or solar+battery install is marginal and ensure utility system and personnel safety.

Do the utilities have the analytical tools to do the 60-day review?

Utilities are just starting to get experience and figure out processes for 2222. It's hard to know everything you need to look at. Utilities are starting to draft processes and looking at what additional information they need to know. Some utilities are in the process of implementing ADMS. The systems are changing, and the tools the utilities have weren't designed to analyze the grid, so utilities are working to develop tools and models. The ability to look at every hour and flows is not there yet. System upgrades need to be made to do this analysis.

We need to create different review levels for different wholesale DER, DR, and aggregations.

What should the differentiations in the analysis be? Separate circuits? What should the levels of review should be?

One option is geographic; for instance, more than 500 kw on a single feeder could require a higher study process.

We also need to consider ramping – simultaneous action of all of the resources. Example: you can't activate more than X kW within Y amount of time. As with ramping of a scale generator, the system needs time to adapt to changes and if appropriate 'ratchets' for increasing or decreasing load are in place, it will significantly enhance system reliability.

Economic vs. reliability – keep both in mind. Regulations should allow for dual participation and registration, just get rules right for compensation (look at New York and California). Everything for the RTOs is almost always going to be economic while a utility might have a program focused on reliability.

Safety is above both of those. Safety of the workers and the public, then reliability, then economics.

Ramping is an important consideration, with DERs turning on and off. Voltage regulations can take time to respond, and you can end up with flicker and voltage violations.

The utilities need to have visibility of system.

Utilities study what can happen in the future. Customers can have equipment that can be impacted by voltage variation.

If ramping takes 5 minutes, it can be simple to resolve, but must be thoughtful.

Analytic tools for 60-day review – single node aggregation, high side of substation feeder, solar modeled as electronic connected generator, battery modeled as generator or load, DR as negative load if software has ability to do that; are we looking at all of the DERS in aggregation and non-wholesale DERs on the feeder? What is the 60-day review? Looking at the aggregation of those DERs together and looking at the impact on the system. Initial screening questions. But if all the DERs in an aggregation are on a single circuit, the utility needs to have the ability to model that and see the impact(s) within 60 days.

All of the current DERs are not in the system or with the technical details needed to do the analysis if they choose to be aggregated.

Are you able to set up the analytical tools?

Whether a DER is in wholesale market or not, the utilities still need to do analysis.

How does the responsibilities and analysis change when a DER is now in wholesale?

One example, batteries are currently used for when power goes out or solar is not generating. In wholesale, if aggregated, all batteries could discharge at same time. They could also be asked to charge at the same time, even on peak, creating issues for the distribution system.

The utility doesn't presume to have data and information regarding current DERs and what customers want to do. The utilities need to know what customers want to do.

The IURC should draft a rule so utilities can understand what customers want to do. Valid interconnection agreement and more may be needed for the customer to participate at wholesale.

There also needs to be education – customers need to know what the wholesale options are. (Note: If a utility is creating a program, it is their job to educate. If a customer wants to engage an aggregator and engage in a wholesale program, that education is the responsibility of the aggregator/ISO.)

As part of Step two, customers/DERs need to have that information and education, regarding aggregation. The utility needs to know what programs customer is in and what they want. There must be a process for changing between aggregations, driving to another step two process. How will changes be administered or managed? Technical tools are at the distribution level, but not yet at transmission level for RDER.

A national DER registry would allow, and provide for, registration, getting the DER together with the aggregator, state switching rules, and dual participation. The DER registry has the change management built in (people move in and out of houses with solar). If a customer/DER is going to enter into a program, then they need to update and/or upgrade their DER equipment. There needs to be a process for DER switching between programs. No DER can be in more than one aggregation.

Does each change in the components of an aggregation drive another analysis?

The utility needs to know the geographic information of the aggregation, including the specific feeder(s) it is on, as well as the scale (i.e., greater than X kw).

When does an aggregator have to go back through the EDC review process if the aggregation changes? Any change can trigger additional review and analysis.

Utility does not currently make assumptions regarding what the customer wants to do. If a customer moves out, the utility doesn't assume the new customer wants net metering or EDG.

Under MISO process, changes to the aggregation matter.

Utilities and RTOs need to know the effect(s) on the system of any changes.

If EDC can't track what's where, how can it do the analysis? The utility needs to know about any changes.

Any change at all – utility needs to know at some scale – it does matter. That parameter needs to be set.

Is it logical to have change be based on parameters of levels in step two? Reliability yes, but market may want more information.

There's tracking and there's what's needed for the state regulator.

Utility needs to know the changes, but utility doesn't want to study if they don't have to.

Changes do need to be tracked; however, we don't have the experience yet, in order to set thresholds.

There are no limits in 2222 on the size of aggregation – so 2222 and distribution interconnection can be a way of avoiding the RTO interconnection queues. Should there be a limit on size of DER on distribution system? There are limits on feeders and the need for upgrades. Larger sizes are just accommodated with upgrade requirements.

In Texas, there are hundreds of interconnection requests for 10 MW batteries, taking up all of the spare feeder breakers. Batteries participating in market don't help distribution systems, but they are taking up capacity. Texas utilities are trying to figure out how to handle - 150 applications can clog up the distribution queue.

The RTO interconnection process is backed up; that could happen on the distribution side, too.

Hoosier Energy is currently seeing this happen with 50 kw to 20 MW interconnections.

Thanks to everyone for your interest and participation!

<u>Next Steps</u>:

Next roundtable discussion: September 14, 2023; 1:30 p.m. to 4:00 p.m.; in person at IURC Judicial Courtroom 222; and online via YouTube (if watching only) and WebEx (for presenters and to comment and ask questions). Voltus, CPower, and CUS will present and provide the information, including the viewpoint of DER aggregators and a DER registry.

- Comments may be submitted at any time to URCComments@urc.in.gov
- <u>Additional Roundtable discussions:</u>
  - October 12, 2023; 9:30 a.m. to 12:00 p.m.; Conference B
  - November 9, 2023; 9:30 a.m. to 12:00 p.m.; Conference B