ESIG Webinar: DER Modeling and Distribution System Operations	
Question	**Answer**
Is bypassing cloud and talking direct to DER more affordable for near real time data than via vendor clouds as a result? (edited)	Maybe. Talking directly to the DERs requires them to support a direct comms API (such as OpenADR or OCPP), and you still need a contractual mechanism to gain access to them. Vendor control usually takes care of device health while direct comms may provide more access but also require more care in how they're used, and may require more maintenance (eg, handling asset registration and lifecycle). It's not strictly a cost tradeoff - it's also a question of how much control you want or need and how much complexity you're willing to take on. They're both valid approaches. Direct access to the device should ideally still be internet based rather than placing it onto a special network.
How does forecasting BTM solar vs solar + storage (or other DER) compare?	There are good open source and generally available libraries for insolation forecasting, which is what we're using for both rooftop and utility solar. For rooftop we typically have access to interconnection data, but only some utilities have production meters. For utility solar there is usually a utility production meter with high fidelity real time telemetry, which can inform forecasting. For batteries and other DER the "forecast" is more focused on probable available capacity and impact on net load. For most batteries we touch their activity is controlled rather than passively forecasted.
This seems extremely applicable for modeling hosting capacity for DER interconnection and distribution planning, as well as for realtime distribution operations	Yes - I only touched on it briefly, but visibility into midline and overall grid conditions is very helpful for interconnection use cases, as well as observing the behavior of those connected assets after the fact.
how do you build secondary lines when they are not available ?	Depends on the use case - for transformer loading we can assume the secondary is present and focus on meters which are children of a given point in the graph. PNNL is working on methods to learn/infer impedence and resistance for subsegments of the graph which will support genuinely inferring absent secondaries.

On slide 17 you note "No just stop" for new network protocols. And to use the internet for DERs for comms. Can you please exapnd.	There are plenty of perfectly adequate network protocols already! They're complex to design well, expensive to maintain, and hard to justify in the context of solving grid problems. Domain specific challenges can be solved at the application rather than the protocol level. Using dedicated networks for customer DER comms adds a lot of complexity in terms of setup and network configuration (for both customer and utility), and potentially some risk. In theory they might be more secure, but cybersecurity best practices are evolving to focus on hardening every communication channel individually under a "zero trust" model in which the network layer is assumed to provide no additional protection. The consumer devices should be assumed to be extremely vulnerable to compromise and managed through as narrow and unprivileged an interface as possible.
Hi Astrid--fascinating approach. we need your expertise in DER Australian resources--have you any projects there	Thanks - I'm from Australia and have been closely following grid progress there!
How accurate do the estimates need to be for filling in data gaps?	Depends what we're using the data for. For less sensitive use cases such as peak shaving we operate with a wide margin for error and a lot of advance warning (typically scheduled hours or day ahead), so modeled data within 5-10% of accurate is generally fine. For more critical use cases (such as managing network capacity choke points) we need more accurate and timely data (within minutes ideally). For any place we're modeling we can compare against related data points to guage accuracy - for example, historical gap filling is accurate within 10s-100s of watts because we can compare meter data in aggregate to SCADA points, as well as comparing modeled forecast to actuals over time for model tuning. For insolation forecasting we can compare against modeled actual demand and meter/scada points. And so on.
How to minimize the risk of filling data in situations when there were events like outages for example?	Couple of things - comparing across data sources is very helpful here. One easy one is backchecking against OMS-reported outages. But more generally, there are a lot of additonal signals. If the meter is connected but sending no data the power is probably on. If geographically correlated meters are not answering connection requests there's probably an outage. Outages may also show up in SCADA - either as a data drop or as a loss of connectivity. If the DERs are answering and the meter isn't that is an indicator. And so on.

Why do Coops need to prevent backfeed? In Australia tens of MWs of backfeed is occurring from distribution networks to transmission.	It depends on the specific situation. Sometimes backfeeding across the sub is fine and expected, sometimes it's not. It depends on the relationship with the transmission provider, the contractual specifics (sometimes export is disallowed and there are penalties) and the protection configuration (eg a delta-y transformer in the sub may expose potential grounding issues). The example I'm using here is relevant to any case for actively managing capacity at a point on the distribution grid but definitely acknowledge that conditions vary widely.
What you are proposing require supporting staff to work with the DSO.	This is a good question and I think it will evolve over time. What we see in the field is some cases where people are doing new jobs (eg utility taking forecasting in house and hiring a scheduling coordinator to manage power procurement) and others where current jobs are changing. Sometimes tools make those jobs easier, eg it saves engineering time to avoid manually filling known SCADA gaps for later analysis and simplifies staking workflows to have comprehensive transformer loading data available. In other cases (like shutting off DERs in an outage) operators may need to take on new tasks.
How is Machine Learning handling net meter readings to forecast/project load vs generation, since customer usage and PV generation are not separate?	We forecast PV first and fit that against the AMI data to algorithmically disaggregate load from generation.
How are you collecting the data if a power is flowing to the distribution system from grid and DER connected to a distribution system?	If the power is out DERs usually are not reporting, and that's the desired state in most cases (since they're actually not doing anything). The exception is facilities which have switched to battery backup which will also usually support internet connectivity. This may not work in some cases like public safety power shutoffs where comms infrastructure has lost power, and that will be a future problem condition to address.
how do you remunerate volt/var?	Good question TBD. We have not seen many cases where more is needed beyond what the large DERs provide but I expect we will.
How does Elon Musk's comment about Tesla being a data collection company? I presume he's referring to data collection during and after EV battery charging.	All DERs generate tons of data. Cars report their driving and charging behavior, chargers usually also report charging behavior (in tesla's case I think the smarts are in the car though), and batteries have super comprehensive data about produciton, consumption and flexibility because they're usually fronting both house load and PV generation. That's a lot of data - I can't comment on Tesla's strategic approach to it (because I don't know what that is!) but it's certainly very valuable for product design, grid use cases, and I'm sure other things as well. That's not just tesla, though, that's everyone with DERs.