Webinar: DER Transmission Study Overview and Findings	
Question	**Answer**
please explain how we should think about a "GW-mile" in terms of scale i.e. "230kV line at 2400 Amps" or another analogy?	The candidate lines in the model were created in the study process by looking in a WECC powerflow case and identifying a reasonable set of upgrades that would increase the transfer capability between the two regions. We used geospatical data paired with substation locations to determine the "miles" of conductor added. So GW-Miles is the "GW Increase in Transfer Capability x Miles of Conductor" for each of our 80 transmission upgrade candidates.
what is the generation nameplate capacity in the distributed scenario? I thought that model couldn't add utility-scale generation?	The distributed scenario only adds distributed generation (solar and storage) from 2031 onwards. So all utility-scale generators in that case are held at their 2030 levels (unless units were specified to be retired after that date). The DG nameplate capacity in the distributed scenario is shown in slide 10 and totaled about 230GW nameplate.
Could we substitute the phrase "non-dispatchable" for "distributed" throughout this study? If DG is misaligned with grid need, need more capacity (T&Gen)	Do not see any instances in the slides of "non-dispatchable", but in general, distributed resources are not necessary non-dispatchable, nor vice versa.
Do the scenarios assume a constant buildout of DG solar, hybrid, and storage? Or does the concentration vary across the study area?	I think this was answered verbally. The Centralized & Hybrid cases built the same relative capacities of DG to one another. But the Distributed scenario could build wherever was most cost-effective from the model's cost-minimization standpoint.
Would the takeaway be significantly different if looking at at low wind / high (central) solar instead of the distributed scenario?	Yes, so the results of our study are "non-linear". At small levels, there seems to be a benefit to transmission, but if taken too far DG requires more GW-miles of transmission. So these two comparisons need to be separated.
Did the study estimate the cost difference including Transmission and production cost between the different scenarios	Yes; the capacity expansion model considers capital (gen & transmission) and operating costs (fuel, O&M, cycling costs, etc.) and seeks to minimize all of it together.
Is the analysis in PLEXOS for one year or a particular day?	There were two parts of the analysis: the long-term capacity expansion ran from 2030 - 2040. Then we took the build decision outputs of that and modeled it in a more sophisticated representation of the system in 2035. This "2035 production cost model" was an hourly representation of one year: Jan 1 2035 to Dec 31 2035.
Why is nuclear shown as load following on slide 21?	It is not (or at least not much). It just looks that way because that graph is showing "stacked" generation. If you look at Nuclear alone it has a flat output.
Why was the time range of 2030-2040 considered? Why not buildout from present day to 2040?	We did consider years between 2030 in our "Reference". So all models start from the same 2030 reference point (all generators and transmission is the same) and then diverge from there. 2030 was seleced because it's a reasonable point out in the future after which futures could diverge.

A system with more DG is less visible and controlable for system operators, which could require more reserves. Was this included in the model?	Not directly, and in fact I think our model is optimistic about these assumptions -- but these were what was required to model the Distributed future: our study assumes that DGs could be curatiled as necessary by the system dispatcher, that solar could provide down reserves (if there is power available to be curtailed), and finally that solar could provide up-reserves from headroom.
How would you expect results to change if RPS goals do not constrain all WECC regions?	We initially attempted to model state-level clean energy goals by splitting states up into PLEXOS zones using EIA data. It did change things: it build more resources in those Zones (roughly balancing authority areas) where they could contribute to a state's clean energy goal. However, upon further review of the state-to-zone mapping used to model these constraints, we felt they were inaccurate and decided to relax the constraint to a single West-wide constraint instead.
Presumably adding a massive amount of distributed load (e.g. EVs) would change the balance by sucking up all the local generation?	Yes, and that dynamic is captured in our load shapes.
How was the locational breakdown of DGR (PV + storage) deployment determined?	Consistent with NREL Standard Scenarios' state-level forecasts. We created a mapping between states and our PLEXOS zones and split it out using that.
Assuming storage will always be less capital cost, do you think it would outweigh the cost of maintaining system reliability? ie. ongoing paid response services	I'm not quite sure what's being asked in this question. In our model, storage was allowed to contribute to the operating reserve needs of a region/reserve-sharing group. And I think the right answer here is just that storage has it's limitations just like any other technology (cost-effectiveness being one).
wouldn't that much more storage in dist. mean smaller load profile at some point? that is a lot of back up in comparison	I should've made this more clear in the presentation: DGRs are modeled as Generator objects in PLEXOS, which are by default assumed to be front-of-the-meter.