WHITNEY BELL: Hello, and welcome to the National Transmission Planning Study Updates webinar. I am Whitney Bell with ICF and I will be your host today. I first have a few housekeeping items for today's webinar. This Webex meeting is being recorded and may be used by the U.S. Department of Energy. If you do not wish to have your voice recorded, please do not speak during the call. If you do not wish to have your image recorded, please turn off your camera or participate by phone.

If you speak during the call or use a video connection, you are presumed consent to recording and use of your voice or image. Luckily for you, all of our participants are in listen-only mode. If you have any technical issues or questions throughout today's webinar, feel free to use the chat box and select send to host and we'll be able to help you out. We will be taking questions today, so you may submit them throughout the entire presentation using the chat function. We will then have a Q&A session at the end of this presentation.

If you need to view the live captioning, please refer to the link that will appear in the chat now. Finally, we will post a copy of today's presentation on the National Transmission Planning Study Updates Webinar webpage by Friday. The recording of today's webinar will be available in about two weeks, and we will notify you when it is available. Alright, so let's go ahead and get started. Today you'll hear from Jeffery Dennis, the Deputy Director for Transmission Development with the Grid Deployment Office. Jeff, I'm going to go ahead and turn this over to you. Are you there?

JEFFERY DENNIS: I'm here – thank you, Whitney. Good afternoon and good morning, depending on where you are. Thanks for joining us today for this update on the National Transmission Planning Study. I'm excited to dig in. But first I want to provide a brief introduction to the Grid Deployment Office. Here in GDO we work to provide electricity to everyone everywhere by maintaining and investing in critical generation facilities, expanding transmission and distribution systems to ensure all communities have access to reliable, affordable electricity and conducting analysis and technical assistance on these topics.

We have three divisions that are doing this work – the Generation Credits Division, which works with existing nuclear power and hydroelectric generation facilities to ensure reliability and resilience, and works to improve electricity markets at the wholesale and distribution level and works with entities on technical assistance in those areas.

The Transmission Division, which I'm proud to lead, supports innovative efforts in examining transmission reliability, conducting planning, clean energy analysis and programs, and looking at energy infrastructure and risk analysis in support of the Administration's priorities to enhance grid resilience. And finally, the Grid Modernization Division oversees activities that help prevent outages and enhance the resilience of the electric grid, including grants for resilience programs, grants to state and tribal energy programs, and related technical assistance efforts.

Next slide, please? So today we're going to talk about one pillar of our three-pronged strategy for enhancing the transmission grid and building out the national transmission system at a scale we need to meet our national clean energy and climate goals, ensure reliability, continued reliability and reduce consumer cost. Those three prongs include commercial facilitation, that bar in the middle right there.

We have a number of tools to help support transmission projects commercially including the Bipartisan Infrastructure Laws Transmission Facilitation Program. The Transmission Facility Financing Program adopted in the Inflation Reduction Act, and the Grid Resilience and Innovation Partnership Programs, all enacted in the Bipartisan Infrastructure Law. In addition, we are working on transmission permitting and siting programs to improve transmission siting and permitting outcomes at every level, be it federal permitting, state permitting, and to address impacts on local communities. But today we're going to focus on one part of our third prong there, which is enhanced transmission planning.

The National – and I want to differentiate between a couple of these things. You see the National Transmission Planning Study there, which is one part of our enhanced transmission planning work. You're also going to hear an update on our offshore wind, our Atlantic and west coast offshore wind transmission studies, but our focus today is on the National Transmission Planning study. But let me also explain why it's a little bit different than our National Transmission Needs Study.

The National Transmission Needs Study, a draft of which you saw in February in which we received comments on in April and we're finalizing now, is DOE's triennial look at the state of the transmission grid. And in accordance with the directives of Congress, including most recently in the Bipartisan Infrastructure Law, that study assesses where current and expected future transmission system constraints and congestion are negatively impacting consumers. To do that, the study assesses existing data to identify constraints and congestion, including a wide variety of industry studies, wholesale market pricing data, widely available capacity expansion models.

By contrast, the National Transmission Planning Study that we will discuss today is a wider aperture look at future transmission needs over a longer time period and with a wider set of potential future scenarios of demand in clean energy growth. Unlike the Transmission Needs Study, which assesses existing data, the National Transmission Planning Study is conducting new modeling to identify not just needs, but also high value solutions for customer across a wide range of potential future scenarios. I'm looking forward to today's update from our team on this work, on this scenario development and on how this work really will demonstrate the value of multi-factor long-term planning to our overall efforts to build a grid that meets our future needs. Next slide, please?

So you can learn more about all of the Grid Deployment Office's activities on our website. I want to point you in particular to the Grid and Transmission Programs Conductor where this is a clearinghouse for all our transmission and grid-related financing programs. And here you can learn more about programs within the Bipartisan Infrastructure Law, the Inflation Reduction Act, and other existing DOE transmission and grid programs. And with that, I think that's my last slide and I'm going to turn it back over to you, Whitney, to introduce the real smart folks who are going to walk you through the National Transmission Planning Study. Thanks.

WHITNEY BELL: Thank you, Jeff. We really appreciate it, appreciate you clarifying all those differences there. It was really helpful. We now get to welcome Carl Mas and Hamody Hindi from the Grid Deployment Office to provide updates on the National Transmission Planning Study. Hamody, I will go ahead and hand this over to you.

HAMODY HINDI: Alright, great Whitney. I'm going to go ahead and share my screen so that we can get that video playing later. Hope everyone is seeing that alright. So I'm going to go through the first half of our presentation here that we have on the National Planning Study, and thank you, Jeff, for that introduction and background. So we'll first do a project overview. Of course, we did our takeoff webinar all the way back in March of 2022, but we'll give you all a reminder.

WHITNEY BELL: I'm sorry, I don't think you're actually sharing the screen yet. We're not seeing anything different.

HAMODY HINDI: Oh, let me try that one more time. How's that look?

WHITNEY BELL: Perfect – now we see it.

HAMODY HINDY: Perfect, thank you. So yeah, we'll go over a project overview and then we're going to focus in today on our multi-model approach. We're using six or so different models to measure the multi-value of transmission and so we're going to do a deep dive into those different types of models that we're looking at. And then we'll talk a little bit about timeline and next steps, and then as Jeff just mentioned, we're going to pass it off to Alissa Baker to give us a little update on how we're coordinating with the two offshore wind studies that are ongoing. And then, of course, we'll have about 15 minutes or so at the end for some Q&A.

Alright, so project overview. So this is a collaboration between the Department of Energy Grid Deployment Office and the National Renewable Energy Lab and the Pacific Northwest National Lab. And we're trying to leverage work from previous studies, including the Seam study that you see a picture in the lower left, NREL's 100 Percent Clean Electricity by 2035 which was published last year. And then other creative efforts including the North American Energy Resilience Model that multiple labs, including PNNL, have been involved in.

Okay, and we really have three main objectives with this National Transmission Planning Study. First one, identify interregional and national strategies to accelerate cost-effective de-carbonization while maintaining reliability. So the emphasis really is there on identifying, as Jeff said, high value interregional transmission expansion options and we want to identify interregional expansions that perform well over a broad range of possible power system futures. So that's really our focus in this study.

The second objective here is well, how are we going to do that? So DOE, of course, is not going to go out and build transmission themselves. And so to actually catalyze the building of interregional transmission, we need to have deep engagement with the public and the industry as a whole. And we feel like by doing this deep engagement and getting buy-in from all the right folk, that we can then catalyze the building of these high volume interregional transmission. And so we've put a lot of energy into engaging a broad range of groups across the energy sector, as well as the public at large.

And thirdly, but not least important certainly, is we want to help inform where some of the DOE funding for transmission infrastructure support goes. Now there of course are independent efforts due to the Transmission Facilitation Program, and all that, they have their own independent efforts, but hopefully the results from this study will help inform decisions where some of the funding might be guided to. So that's an important piece of the study.

Okay, and then quickly, what is this study doing, and what is it not doing? So on the left there, what we are doing, we're looking at several different types of models together to demonstrate the value of interregional transmission. As I said, we'll go through about six different types of modeling that we're doing to date. And we want to inform existing processes. Now this is important. We're not looking to replace existing regional planning processes here.

We see national planning as complimentary to existing regional processes. And again, that's why that engagement piece with regional planners, as well as others, is so important, to make sure we compliment and we add value to existing planning efforts and not trying to replace them. We want to test transmission options that lie outside the typical, say, ten year planning horizon.

So in this study we're going all the way up unto the year 2050 and we're exploring a broad range of futures, about 200 or so different futures, and we'll talk more about that. As well as looking at the resilience, cold waves and heat maps. And lastly, we want to measure the value of transmission with a number of different indicators, including economic indicators, liability indicators, and resilience indicators to again, demonstrate that multi-value.

And then some things, importantly, that we’re not doing. Again, we’re not trying to replace existing planning processes; we want to compliment. Also, we’re not going to get to the granularity of siting individual transmission line routes or get to the granularity of doing detailed environmental impact studies that you would have to do as you develop detailed final plan service, say. And we’re not generally getting as granular as the planning done by regional and utilities.

For example, we’re not doing the full suite of America TPL reliability standards. [unclear], although we will do some contingency analysis and I’ll talk a little bit about that later. And then lastly, importantly, we’re not here to develop detailed plans of service. Again, our goal is to catalyze the building of transmission as we get engagement with the public and industry, and then have them take the concepts that we see as high value to do that development of more detailed plans. Alright, so themes from public engagement. As I said, deep engagement is an important piece of the study and we've heard a lot of feedback from the public and we appreciate you all's attention and effort in supporting us in the study as we work together. So we kind of have bucketed them here in three categories of things we've heard over the last year and a half or so.

On the modeling front, you know, we've heard recommendations to review existing industry reports to help support our study. For example, the California 20 Year Transmission Plan Study has helped inform where and how much offshore wind we're locating some of our scenarios in the west there. We've also heard from many folks to make sure we account for the impact of climate change, and so Carl will talk a little bit later about how climate is informing some of the future resilience scenarios we're looking at.

Developing actionable tools and methods and maintaining a feasible scope. Of course, this is a very broad scoped project and so we appreciate that feedback, that there’s always more to do, more follow-on work. Engaging with regional planners – so this was a big one for this study as well. We’ve had great engagement from the public at large, as well as the technical review committee. We’ve had several deep dive regional planning meetings where we’ve met with groups of regional planners.

We did several rounds of that, actually. First we did it last September, and then again last December and most recently this May we’ve had direct feedback from regional planners and we appreciate their time and efforts there, so thank you. On the policy front, we’ve received a lot of feedback from states to help us implement the latest and greatest state policies that are enshrined in law. So we’re not modeling policies that are our goal or non-binding policies.

So we want to acknowledge that those goals exist and drive de-carbonization and in some cases states may go further than what’s shown in our model. And we’re just modeling what’s been enshrined in law, de-carbonization targets and so forth that are enshrined in law. And on the land use and environmental piece, we’ve heard frequently that permitting and siting is one of the biggest challenges in transmission planning and transmission development.

And certainly we hear there, and as Jeff had pointed out, another part of our office is focused pretty heavily on permitting and siting and doing more than just studies or trying to really facilitate that. And so you’ll see large infrastructure buildout in some of what we’re going to share today. And we acknowledge that such large infrastructure build outs are challenging in terms of just meeting permitting and siting challenges. And so we do acknowledge that and then see that also as an important place to make progress.

And then lastly, equity considerations. We’re looking at those and seeing how we can fold it into the study. Looking at things like energy justice and how that can fit into sort of national level transmission planning. All right. So these are the six models that we're going to go through today. And so first we've got capacity expansion modeling. That's really the hardest to study and that's where it all starts.

And so what we're doing there is, it's a zonal model, so 134 zones across the whole country. And it basically co-optimizes both transmission expansion and generation expansion together as we simulate the buildout of the power system from present day all the way out until 2050. And based on different input assumptions into the model you'll arrive at a different future power system by the time you get to the year 2050. So we'll vary things like the cost of wind and solar, as well as how much load growth you have. We have a low demand and a high demand growth in our first round there. And also how much de-carbonization you might have.

We do want better rounds where we're looking at say achieving 90 percent de-carbonization on the power system by 2035, and another where we're looking at 100 percent by then, as well as looking at just current policies which can potentially be a lower level. And so by varying all those different inputs as you co-optimize the generational transmission buildout, you arrive at different power systems with different resources and different transmission expansions. So we did that in the first round about 200 times and then we'll take that and apply more detailed modeling, and so that's what these other five models are.

So we'll do production cost modeling, and that's at the nodal level using industry models, as well as we'll do Power Flow of both DC Power Flow and AC Power Flow, and then Resource Adequacy. So the goal of a Resource Adequacy there is to check and make sure like you have enough generation to serve the loads at all times. And we're including the traditional probabilistic based approach, as well as some other approaches looking at the extreme types of events there.

And then a Stress Analysis and that's really synonymous with Resilience Analysis, and we worked a little bit with the North American Transmission Forum looking at sort of definition of resilience. There we're looking, and Carl will talk a little bit more about that, that heat waves and cold snaps and droughts to again try and characterize the value of interregional transmission. And then lastly, Economic Analysis. So while production cost modeling has an economic piece to it, you're looking at the cost of what it takes to operate the system over the course of a year, the Economic Analysis ties in not only that operating cost, but also with that capital cost of those different power system futures.

So how much do you invest in transmission versus generation, and what are the tradeoffs, and what happens when you build into your regional transmission and how it impacts all of that together. So that economic analysis is an important piece of what we're doing and it's ultimately getting to things like cost/benefit ratios.

Okay, so those are the six models and we'll dive into them here. So this picture here kind of shows again all these models together, but just as a flow chart. So on the left you have all of our different input modeling pieces. On the Resource side as well as Assumptions on the low side using full transportation, building electrification, as well as the network itself. Then that blue piece is the capacity expansion piece. And there again we’re simulating about 200 or so future scenarios in the first round. And then this green piece is where we go to these other detailed models.

So what’s kind of new about this slide that I’ll point to you is that when we do that down selection from the 200 or so futures of the capacity expansion model, we’re going to down select to about 3 to 5 nodal models or nodal future systems. And it’s pretty labor intensive to do those conversions, so that’s why we’re only aiming for three to five, and we’ll talk more about that.

But ultimately the main goal is, from all this analysis, both the zonal analysis and the detailed nodal analysis, we want to identify, as Jeff was saying, high value transmission expansion options that perform well over a broad range of futures. So again for the capacity expansion model, this is kind of four different outputs of the model shown on this map, from our round one of analysis. And Carl is going to talk a little bit about our round two analysis that we're going to do later. But again, we're looking at about 200 different futures. So here's four of them shown, each a different map.

So first of all, all four of these are looking at the high demand set of futures. So that's consistent with the net zero economy by the year 2050. And it's looking at a 90 percent de-carbonization for the entire electric system by 2035, and 100 percent by 2050 and the maps are showing the year 2050. So for these four different maps, what you're looking at that's changing is the transmission buildout paradigm.

So the first one in the upper left there assumes, what if the power system develops and we really only have within region transmission that is intraregional. So no new interregional transmission between the third quarter 1,000 regions. How does the resource and transmission buildout happen in that case? And so what you see is the blue dots are new wind, and the red dots are new solar, and the purple dots are new offshore wind. And then those little gray lines are the new transmission expansions that happen. So the thicker the gray line is, the more new transmission there is, and you can see that reference point in the lower left that shows the thickness of a ten gigawatt line to get a feel for it, or I should say a ten gigawatt pipe right here.

This is a pipe and bubble model - we're not showing individual transmission lines. Anyways, that's the upper left. It is assuming you don't have any new interregional transmission, only local new transmission. Then the upper right, what if we do have new interregional transmission, but no new HVDC transmission so you don't have any new expansions across the Eastern to Western interconnect boundary or into Texas.

So in that case you see different transmission developments and slightly different resource developments across the country in terms of wind, solar, and offshore wind. And then the lower left is if you allow not only for both of those types of expansions but also point to point HVDC. So there you do have new ties between the Eastern and Western interconnect and also into Texas. As you can see there, thicker gray lines across the country.

And then lastly in the lower right that's the most progressive of our transmission expansion futures where you have not only AC expansion and point to point HVDC, but also multi-terminal HVDC. And so you can see how that affects both the resource amounts and locations as well as where the transmission expansions are happening. But this is really just to show you how the different systems can evolve based on input assumptions.

Okay, so that was the capacity expansion model, an example of four of those outputs. Now I'm going to dive into a couple other types of modeling, production cost modeling and the Power Flow modeling. So for production cost modeling there we've transited over from the zonal model which is the role the capacity expansion model was in. And what we're talking about is about 134 zones through the whole country, connected by a pipe and bubble model of the transmission system. Transiting over to the nodal level, which is really the industry model.

So here we're talking about, instead of 134 zones, we're talking about tens of thousands of nodes where each node can represent either a substation or even busses within a substation, as well as representation of individual transmission lines and individual transformers. And so it's a much more spatially granular model, and it's also a much more temporally granule as we'll talk about. But this is quite a labor intensive process to do this transition to the nodal model and that's why we've only done it for the few scenarios.

But why are we doing this transition to the nodal model? What do you gain? Well as I said, by modeling those individual elements you can get closer to reality in terms of modeling actual limits and actual constraints of the system and so there's value there. And also we can gain insights into grid balancing using more granular spatial and temporal models. And for the temporal granularity what we're talking about, you know, the capacity expansion zonal model has got roughly 17 time steps per year, and then we simulate every three years going out to 2050.

On the other hand this nodal model, right, we're doing simulations in the production costs of 8,760 hours in a single year so you can really see within that single year, what are your challenges during different seasons. And then even within seasons, what are different challenges in different weeks, or even across the course of a day.

For example, say a sunset in California where you've got that [unclear]. You can really see the challenges and constraints that the system might face there. And then of course on the spatial side when we've got individual lines modeled we can see in much more detail where are the local constraints, right? If you're adding one or two gigawatts of wind to an area, how does that impact not only the intraregional system, but the local system? What are local reinforcements that you need to be able to get that power out of there to where it needs to go? And so we've gained a lot of insight there by having these more spatially granular models.

And then lastly, I'll point out in terms of the generator interconnection, we have actually two interconnection points that are specific to, if we want to put it at a 230 kV substation versus a 500 kV substation. And so that's just another piece that you get when you look at these more detailed nodal models with that higher spatial granularity.

And so I think I've covered basically these points on the previous slides, but we're going to post these slides, so you all can feel free to read back through these points here, about the benefits of the nodal model. And the grid balancing insights, I think I covered most of these there and that's a couple slides ago.

The one thing I'll point out on this grid balancing insights, and here the picture you're seeing is a production cost modeling simulation zoomed into a particular week in the month of January. And it’s an hourly granularity, but you can see sort of each day with the load peak. That black line is the load, and then wind and solar in blue and yellow. And then you can also see when we have this more temporal granularity where exactly curtailment is happening. And that’s the gray piece of the graph, that sort of the highest pieces of the graph towards the beginning and end of the week.

And by having that temporal granularity, we can see more, how often the curtailment is happening, and what’s causing it. And of course with the spatial granularity, individual line models, you can see well, there’s a local constraint that might be driving curtailment. In that case, intraregional isn’t going to help you until you fix that local constraint. And so by having these detailed nodal models, we can see that.

Actually, one of the adjustments that we’ve made to our models as we go into round two analysis is we saw that there are a lot of local constraints impacting some wind integration, and so we decided to increase the cost assumption for local network reinforcement for wind integration as we move to round two in this analysis. And so those are some of the insights we gained with these more detailed models.

Okay, so here's a nice video that the very smart folks at our labs have put together for us. What you're looking at is a particular month in August, a particular day in August, I should say. So it's a 24 hour period that keeps re-planning over and over in hourly granularity. And this is the power system out in the year 2035 where what you're seeing here is new resources and new transmission added.

And so on the resource side, the yellow dots you see up here in our solar, so the brighter yellow dot is the more solar generation that is happening over the course of the day. So it disappears at night, and appears strongly in yellow in the day. And then the blue dots are new wind resources that we've added. And again, the stronger the blue dot is, or the darker it is, the more wind generation is happening at that particular hour.

And then the last thing you can see in the resource side are pink dots that are batteries that we've mostly co-located with solar. So you can see as the solar goes away, it sort of, the battery lighten up and spread that solar energy up into the evening. And then on the transmission lines you're seeing, those are the new transmission expansions. And the darker the line is, the more heavily it's loaded.

So you can see as the lines change color how their loading changes over the course of the 24 hour period. And what you see nicely here is the complementarity of – some of the complementary, I should say, between the solar in the east and the wind more in the center of the country and how the resources shift, those transmission line loading change over the course of a 24 hour period.

Alright, so diving a little bit more into the zonal to nodal translation. There's really our two pieces of it. So again, we're starting with the capacity expansion model. We're looking at these 200 different futures and it’s 134 zones. So how do we map that to a model that has tens of thousands of nodes and thousands of hours of simulation per year? So first we take the load and the generation, and we try and, as best we can, do a one-to-one mapping. So whatever resource makes the capacity expansion model predicted, we try and map those to magnitude and location as best we can to the nodal model. And then on the load side as well, we do this similar mapping, of course, trying to spread the loads out over those thousands of nodes [unclear].

And then there’s the transmission mapping. So there we’re not trying to do a one-to-one mapping of the expansion that the capacity expansion model predicted. There we’re doing a lot more analysis and sort of engineering judgments, and using capacity expansion partly as a guide to inform what we’re doing, but also there’s a lot more analysis that goes into how much transmission expansion and where to do it at the nodal level.

We’re not just mapping the capacity expansion model transmission expansion. And so really how we do that is we start by running an unbounded production cost model flow. So we don't enforce line limits; we let the power flow where it wants to flow, to be an economical optimum. In that case, you're going to have transmission lines overloading, of course, in the model, but we ignore that just to get a feel of where the power would flow if it weren't constrained by transmission.

We look at that, and try to make decisions about okay, well based on that, it makes the [unclear] transmission, this much over here, maybe this much over here. And then we'll do what we call a semi-bounded production cost model run. There we're just enforcing certain parts of the system to help gain more insight into where expansions are needed and to also get a sense of potentially impactive [phonetic] resource curtailment and how those could be potentially fixed by expanding the system in certain places.

And then lastly, we try to do what's a fully constrained production cost model run where we're enforcing iterative transmission limits for the whole high voltage system 230 and above and seeing how the system performs there. And then, of course, that entire process is repeated, and I'm going to talk a little bit more about that. So here's kind of in words what I was saying. So I'm not going to read through all of these. Again, the slides will be posted, so feel free to go to this level of detail.

The last thing I want to say about the nodal transmission expansion approach is, it's iterative, as I said, but also there's an important piece where we actually are doing some DC contingency analysis. So I really want to highlight that, because so many national studies kind of overlook contingency analysis just because of the scope of it. And so we are, as part of this nodal transmission expansion planning process doing not only the N line to 0 runs where fewer constraints are, but also DC contingency analysis. And it gets on the order of magnitude of about 1,000 or so contingency looking at 50 to 100 different production cost model snapshots. So that gives you the sense of the magnitude. And then we're using that to help inform where we expand the system at a nodal level. So it's quite involved.

All that is to say though, right, we're still not doing the level of granularity that a utility would do in an expansion process. We're not running all the near contingencies. So we're not here to define a final plan of service. And also, these particular implementations that we're doing is one of many possible implementations of the sort of higher level interregional expansion concept for a particular future. Might want to caveat that.

So that's the method, now let me get to some examples here of actual output. So we're going to zoom in on a particular scenario that assumed interregional expansion, but only AC interregional expansion, so no new ties across the interconnects. And we're going to focus on the year 2035 and again, that's high demand future, so it consistently zero economy by 2050 and then 90 percent de-carbonization by 2035. So that's kind of the power system we're going to look at here for some illustrative output.

So first let’s look at the capacity expansion model, what happens when you go from the present day power system to this particular high demand 90 percent decarbonized system in the year 2035? Well, first of all, the generation capacity increases and you can see that in the upper right, the bar charts. 2020, today, we have about 1100 gigawatts of name plate capacity installed.

Once you get to this high decarb 2035 system, the model is saying well, we need to more than double that and get to about 2,400 gigawatts, so it’s quite a large infrastructure buildout in terms of resource capacity. You can see in the blue and yellow a large portion of that is wind and solar. Of course, it still has the purple, quite a bit of gas there, you can see. So that’s the resource capacity.

And then in terms of energy, what’s happening, so that’s lower right bar graph. Today we’re about at 4,000 terawatt hours per year in terms of energy. And this high demand feature, by 2035, you know, we’re getting to about a 50 percent increase in terms of annual energy demand. They're going up to close to 6,000 terawatt hours. And then lastly the transmission system itself on the left side, you know, today's system, about 160 terawatt miles. And we see it going up to 2035 here about 40 percent increase, and that's just in the interregional transmission buildout. That's not accounting for radial lines to connect generation, or local network reinforcements.

And as I said we found, especially in this nodal analysis, that you do need a significant amount of local reinforcement to accommodate these transformative features that have a large amount of resource addition and of course a large amount of load growth as well. Okay, so that's kind of the system we're looking at. Now what does the zonal to nodal translation look like?

So first I want to focus on the Eastern interconnection, which you see shown here. On the left there's our capacity expansion model that I was talking about. Again, 134 zones for the whole country and connected by a pipe and bubble transmission model. So first the green you're seeing there are new transmission expansions that the model is saying that we should have. So the thicker the green line, the more transmission expansion there is. You can see, especially connecting sort of the center of the country to the eastern load centers is where most of the transmission expansion is happening. And then on the resource piece for the capacity expansion model on the left, the yellow dots are solar, the blue dots are new wind and the larger the circle, of course, the larger the power plant is or the larger the number of power plants are in a particular area. So you can sort of see the resource location across the country there for this particular feature in the capacity expansion model.

Now when we map this over to the nodal model, which is shown on the right, you see, again, the resources are in the same locations and same magnitude because we're doing as best we can on one-to-one mapping there. But the transmission, you still see a lot of transmission going sort of, connecting the center of the country to the eastern load center there. But here what you're seeing is the different colors of lines represented for voltage classes of 345, 500, and 765 kV. And the solid red lines, for example, represent new double circuit 500 kV lines and the dash lines are single 500 kV lines, new lines we've put in as one particular nodal implementation.

And again, we have to do some sort of particular nodal implementation in order to get the models to run, to do the production cost analysis and other detailed nodal analysis. But we want to caveat, we're not saying that this is the, quote/unquote, "correct" implementation. It's one of many possible nodal implementations for the particular system shown there on the left. It's harder to see, but the purple you see sort of expansion sort of in the PJM area, 765 kV system as well. So this, the eastern interconnection. And then lastly, here's the western interconnection.

Again, on the left you see a particular capacity expansion model of the system in the year 2035 for this 90 percent decarb system with a high demand. And then on the left, excuse me, on the right you see the nodal implementation of that, where the resources are located. Again, the yellow solar and the blue wind dots, the new resources. As well as the mostly red and green lines you can see is near 500 kV and 345 kV expansion happening. So that kind of gives you a flavor for what happens when we do these zonal to nodal translations.

And I'll just cover a couple of quick take-aways, and then pass it over to Carl here. You know, so firstly, as I was saying before, these nodal implementations aren't intended to be your final plan of service. They're just one particular implementation of many possible nodal implementations for a particular power system future. What we've seen in these, though, is that there are robust trends in resource and transmission expansions observed across a broad range of future scenarios, particularly for the capacity expansion model over the 200 or so futures of simulated we see.

Continuing trends of need to expand transmission, for example, from the center of the country towards the eastern load center is one of the trends we saw. But also continued trends and really large amount of wind and solar growth that point to earlier webinars. But even as we vary assumptions and availability of technology and cost of different technology, we see these trends continue. So that's encouraging.

The third takeaway there, you know, we were able to successfully transfer over these really transformative changes to the system and get them to run on industry-grade detailed model. So that's also encouraging. It is possible to successfully model really transformative power system futures in a very detailed model.

And then the last point here on this slide is just a brief scene. Of course, if you have a broader interregional view of transmission expansion, that those types of expansions really can have significant impacts on what type of regional, local planning you do, as we see both the need for local reinforcement to accommodate large local resources that might be driven in part by interregional connections, as well as just changes in resources just generally, and transmission just generally, depending on whether or not you have a lot of new interregional transmission.

And then kind of this last slide or takeaway here, through these nodal models, as we've seen also how much curtailment can happen in various places. And again, we've seen these for local reinforcements to help prevent some of that curtailment so that we can deliver the energy up to the main grid so it can get to where it needs to go.

For example, one thing you saw, a picture of the western interconnection, there was a new background buildout in Montana to collect all the wind that's going in there. And so we've seen that often and we collect your backbone [phonetic] as needed to help deliver new renewable energy to the main grid. And then this third thing here, so nodal modeling, one of the things it helps us do is learn how to improve our zonal model.

So, for example, I made that point of, we saw really there were a lot of local network reinforcements needed and so we've made adjustments to the local wind integration cost and our zonal model to account for that. Let's see, new insights for technical feasibility using these multiple models. So again, this is getting to this idea of these nodal models have both more spatial granularity, and more temporal granularity and they better model the physical limits on the system. And we can also gain critical balance and insights there with these more granular temporal models.

And then the last piece I'll leave you all with is really we're trying to build tools that can be leveraged by industry. Again, DOE is not looking to build transmissions exactly themselves. We want you all to be able to leverage these tools and do more detailed studies that hopefully will lead to transmission expansions that get put in the ground.

So with that, I will go ahead and pass it to Carl. Oh no, one more slide before I pass it to Carl. This is an important piece. AC power flow – so as I said, we're doing DC power flow contingency analysis to help inform our nodal transmission expansion that we're doing.

We're also doing some AC power flow analysis. So Pacific Northwest National Lab has developed a tool called C-PAGE, the chronological AC power flow automation, automated generation tool. And that takes basically a power flow snapshot, excuse me, a production cost modeling snapshot and can automatically convert it over to an AC power flow snapshot.

And why is that important? Well, when you have an AC power flow, you're representing reactive power flows which has an impact on line loading and also has an impact on allowing you to analyze voltage stability, see how the system performs there. And so we've been able to convert over hundreds of cases from hundreds of production cost model snapshots and see some analysis there. So just want to point to that. Here we go. So now I'll pass it over to Carl, and I'm going to stop sharing my screen, give control back and he'll talk about a few other models here.

CARL MAS: Great, so I'll advance to that point. Hopefully I'm not making people too seasick. So again, it's a pleasure to be with all of you. Again, my name is Carl Mas, I'm a Senior Advisor with GDO. I'm really pleased to be back with you all for this third series of our webinars. Back in October we touched on many of the themes that we're talking about today. So this will serve partly as a reminder, but also to give you all an update on some of the key outcomes that we've seen along the way, and give you an update on what tools we are using.

As was mentioned, the heart of this effort is our scenario analysis and the core tool for this analysis is the capacity expansion model. So I'm going to be speaking briefly about our next round of our capacity expansion modeling to give you a sense of where we're headed this fall. Our Center of Analysis asks, what are the different ways the grid might evolve? So as was mentioned, we have co-optimized generation storage and transmission given a series of input assumptions and constraints such as carbon system constraints and goals.

For all of these future systems we'll be looking at the interaction across great sensitivities and then picking some of them to perform more detailed production cost modeling, power flow which you just heard about, and resource adequacy analysis which I'll speak to briefly, and then we'll be doing some economic analysis on that work. So let's jump into it. So for the capacity expansion modeling round two, we have a number of updates that we've done as compared to the work that we shared with you last October. Let's highlight a few.

So for the temporal work, while the previous model looked at 17 time slices, what we found through the work that we did this winter, we would really benefit from a more granular modeling approach. But what we saw from the more detailed [unclear] modeling is that we could benefit, get better insights, if our capacity expansion modeling could be more granular. So we now have 33 representative days, and 30 stress period days at four hour resolution. So that increases our time sets to 378. So it's a considerably more detailed modeling effort that we're doing, requiring more computing power, but we think we're going to get a lot from that.

Also just to highlight our transmission network reinforcement costs, which was already mentioned a little bit earlier today, we just have a more uniform network reinforcement cost assumption. Based on what we’ve seen both from literature, from looking at the results from this winter, we felt that we would benefit from having a spatially varying reinforcement costs. And so in some cases that will raise the costs for certain wind generators for getting into the system that we think would more accurately represent what we’re going to see in the future.

The last one I’ll highlight is our demand projections. And so we’ve been working with states and getting input from various states around the country to learn better about what demand forecasts they are assuming and how does their being used both within PUCs and within the various planners in the state and we’ve been doing updates to that information. And then we’ve also, while we did a preview in October of the impact of the federal IRA, of the Inflation Reduction Act, it’s now incorporated into all of our scenario work.

So now I’m moving on to the next slide 34. I want to talk a little bit about our transmission paradigms, then we have a couple of slides here. These are the same paradigms that we shared with you last October. We have a limited case, which is really our counterfactual and it’s focused on only allowing intraregional. So looking at expansion within each of our main regions. And what we’ve done in limiting it, and the blue text highlights some of the small changes that we’ve made versus October.

We’re looking at annual transmission additions of less than 1.1 terawatt mile per year and that’s really based on the historical data that we’ve seen looking at large transmission buildouts in the country. So it both serves to teach us of what could be considered a flat business as usual, but also gives us a counterfactual to be able to compare against our other three paradigms. Our so-called AC transmission case is largely unchanged. And this is where we focused on intra-interconnect.

So we have three interconnects, West, East, and ERCOT and we focus on looking at AC expansion within each of those. And so that leverage is the work of our capacity expansion model which is 134 zones and looks out how we might see AC expansion within those interconnects. And then the next two paradigms allow for high voltage direct current, HVDC upgrades and we look at two different examples of that. And again, these are illustrative paradigms. We’re not forecasting that the system will evolve in any of these, but what we hope to gain is insights from each of them to help inform where are the best opportunities.

And so the first one we’ve now called P to P, which is point to point. We’re looking at allowing inter-interconnect. So allowing us to connect East and West and connect ERCOT with East and West and to be able to use those high voltage DC lines. And what we’ve done is we’ve looked at over or roughly 200 candidate interregional lines of how HVDC could run.

And we’ve been limiting it to less than a thousand miles, so we’ve been looking at fairly long lines and looked at a large opportunity space to help map out how we might model those P to P scenarios. And then the last one is really looking even more expansive at a multi-terminal HVDC platform. And so this is where we allow for a not simple point to point, but allow for off-ramps and onramps within that HVDC platform. So we've taken those four paradigms and then we've layered onto them, as we did in the fall, different assumptions around how load will grow, and to what degree will we, we will de-carbonize the grid. And so for those two variables we now have a three by three matrix.

So we've added an additional set of load growth. And before we had a high low bounding and now we have a low, medium, and high. And so there've been some changes to those assumptions as well. For the high demand we're still framing that around a net zero economy by 2050. So that includes a significant amount of electrification to get these full economies to a zero net emissions.

For the low it's still focused on a business as usual load growth. And the medium, by its name, is a less aggressive than the high growth scenario but does include the impacts of the IRA. And so with that we have our four transmission paradigms, and then we multiply that by our three by three matrix to develop these 36 core scenarios. And just as we presented it again in the fall, we're then going to do additional sensitivities on those.

And so what we've done is looked at this diagonal of the three demand and emission scenarios. And so we take our four transmission paradigms and focus on three of the, again the current policy low demand, the 90 percent and medium demand, and then the 100 percent and high demand. And look at those and multiply them by 12 different sensitivities to give us 144 different views of what the future might be. And we highlighted some of these previously, but just to run you through them quickly.

We're looking at sensitivities around lower wind costs. We're also looking at lower solar and battery costs. We also want to pressure test the cost of carbon capture and storage. We've been looking also at variables that may hinder the growth. So looking at limited wind and CD siting. So we put additional constraints on where we can site wind and solar and see what those impacts are.

We also want to test out, what if we have more limited options in terms of technologies? So what if we don't have carbon capture and storage? What if we don't have hydrogen available? What if we don't have new nuclear available? So this will give us additional insights into how the future might play out and then we layer some of them in what we call our many challenges.

So if we have a more difficult time siting solar and wind, combined with an inability to have new nuclear carbon capture and hydrogen, and combined with climate change impacts, what does that more challenging future look like and what is the benefit of transmission that we see in those circumstances? So that's the quick overview of our round two. And again, we'll be embarking in that work towards the end of summer and we'll be looking to come back in the fall to share some of the results.

So now I want to do a very quick view in the time left on a couple of the other parts of this multi-model approach. So first I want to give you an overview on our resource adequacy work. So this slide just gives you some high level definitions. For those who don't know the term, resource adequacy is a process in which we look at the supply of electrical demand and how it's being met at all times, taking into account system outages. So how are we able to meet our demand needs even when we have a contingency that's being applied to the system? And the traditional method is we look at a prediction of when will the system peak. That's our most stringent time.

As we think about other futures, there will be other hours that we need to also look at, when might we have lower wind and lower sun. But a traditional first approach is to look at system peak. And then we use specialized tools to help estimate the amount of extra capacities a system will need above that peak. So we call it our planning reserve margin. And it's that reserve margin that we need that allows the system to deal with system outages that might occur. And then we build our system around those needs, and that's what this illustrative graph shows you.

That we have in the dark gray what the actual peak is. There's a planning reserve margin above it and then we build resources to help us meet those needs. So in our National Transmission Planning Study we have our capacity expansion model ReEDS. And it builds the required firm resources to equal or exceed that peak demand plus the planning reserve margin. And ReEDS doesn't just base this on nameplate capacity, but looks at how will each resource be available in the hour when we need it.

And so we then verify the work of this capacity expansion model ReEDS using other tools that are able to model the system and verify that we are indeed adequate. And one tool is called PRAS or Probabilistic Resource Adequacy Suite. And we also a number of different production cost models to help us verify that we have an adequate system. And we found that for futures of low carbon power systems and we demonstrated it in the fall, and reaffirming it now, including those with greater than 75 percent variable or renewable shares, we can meet resource adequacy needs with proper planning.

We've evaluated adequacy in a more complex way as well. And what we found is that we need to carefully examine stressful periods given the fact that we'll have a system which has a much higher degree of variability and uncertainty in our supply. And supply impact adequacy, still there is a change in the demand shape, as we see from increased electrification. And a changing climate must also be considered to understand the impacts on our resources and the shape of that demand.

So what we've done for round two is we'll be using an updated approach based on what we've learned from our round one, in which we'll integrate PRAS, our probabilistic tool, that dynamically in the capacity expansion model ReEDS. And so that's what we are able to incorporate now in a more thorough way looking at stressful periods to identify when we'll have key periods of hourly dispatch, PRAS, that are going to be challenging for the system. We directly model network flows and storage operation during those stress periods and can identify period of inadequacy due to energy limitations. And so these are significant upgrades that the labs have been working on over this year, and we will be implementing as part of our round two.

So with that transition, I want to talk a little bit about additional work we'll be doing to look at stress analysis. And so there are a lot of different ways that studies have defined stress. For this particular study, we're focusing on weather patterns and weather impacts. That we can look at global climate models, which I described last October. And what we see is there will be increasing heat waves.

I think many people in the country right now are experiencing some of those impacts already, so we do think it's really important for us to explore and expand on, not just what we've seen in the past, but how these heat waves will become more intense in the future. We'll also be looking at cold waves. We've seen some more extreme cold move its way through the country, and we want to understand that. And then also drought. And so the types of impacts that we'll be seeing from heat and cold, they will have a direct impact on load.

So, for example, heat waves will increase our needs for cooling in buildings and we'll see higher peak loads during those time periods. We'll also see impact on our supply. So what we've seen from heat waves is that it could have an impact on air density and that can affect wind resources and wind generation. It also, hotter air temperatures will affect our conventional thermal generation fleet, and those will decrease our supply. The heat also has an impact on transmission capabilities, and we will be explicitly modeling that as part of our stress case.

And so just to give you a quick overview of kind of how we want to split this up and test out some new tools. As I mentioned, we have very detailed atmospheric simulations that allow us to look at what might a future climate look like. And we have that stacked, both load modeling, as well as our resource, think about the impacts on wind and solar generation and our hydropower plants. And then we translate that into two different levels of our modeling suite. So we'll be looking at the zonal level, at a probabilistic resource adequacy, using PRAS. We'll also be looking at the nodal level using our production cost modeling platforms.

So some of the outcomes that we expect to see are analyzing loss of load probability for the entire U.S., and looking also at specific regions, as we see heat waves coming through. And this considers a broad set of combined weather and infrastructure of time uncertainties. And so through our zonal analysis we will be able to combine in kind of an annual look over time different levels of heat waves and cold waves and see those impacts.

We're also going to be looking at more fine grained, so looking at individual days and weeks through our nodal analysis and really demonstrating some brand new methods. We'll be starting by looking at certain regions to demonstrate that we're able to gain actionable and useful insights. And then we'll be able to, over time and into the future, expand these tools to look at other regions. So we'll be looking at unserved energy at the nodal level with this higher spatial resolution. And we'll be able to really see how the system is coping and what the value of this extra transmission is going to provide us as we face some of these hotter and colder extremes.

And so this just walks you through a quick example looking at our nodal work and some of the methodologies. So what we've done is we've looked at historical heat waves. So this is an example of, of course, a year where we see peak in the middle of the summer, during that heat wave. So we expand that and look at that full week and see what the peak load is on the system, and we can model that in our production cost tools.

But we won't stop there. We won't just look at our historical peak data. But then we'll layer on climate scenarios, and that's what these additional colored lines show. That as you look at different probabilities of outcomes of different climate impacts, we see in many cases they will be increasing the heat and therefore the level of our peak load. And just to give you a breakdown of that, what this final graph shows you is the percent difference in load between our climate impact scenarios and our business as usual heat wave.

And so you can see, we have certain periods where we could see 20 percent increase in our peak load simply because our future climate is going to more than likely than not give us more extreme heat to have to contend with. So that’s a quick overview of our stress analysis.

What I’ll now pivot to is talk a little bit about what we’re going to do with some of that work on economic analysis, and this is still underway. We don't have any output to share with you today, so this will be a little bit of a refresher of what I described for you all in October. So our approach here, again, is multi-faceted. We want to leverage our multi-model platform.

So we'll be leveraging our capacity expansion work, our production cost work, and our resource adequacy work.

You see we've culled out zonal production costs. We will be also doing economic analysis based on some of our nodal date, but the core of our economic analysis will leverage our zonal PCM work, and that's because that gives us a much broader set of data to be able to look at. More scenarios to analyze over many more years. And so we leverage those three different modeling platforms to help us draw out data around capital costs.

So what are the avoided generation and transmission investments that might be made? We look at operating cost changes. How are we avoiding using fuel and what is the value of that? How are we avoiding the costs of unit cycling in the more detailed PCM work? We look at the reliability impacts when it comes to the economics. So what's the reduced costs of ancillary services, and what do we look at the reduced loss of load probability that will come from the different paradigms of our transmission expansion?

And then finally looking at resilience which is really new work in the literature that our labs are beginning to dig into, is if we see a reduced duration of outages what is the economic value of that? And if we see again reduced outages during those extreme events, how can we look at, at least at the first stage qualitatively describing it, and then exploring methodologies for how we can quantify those benefits.

So with that, that's the very quick run-through our multi-model approach. I did want to close out this part of the presentation with a refresh on our timeline. We have shared this slide with you all before. So as was mentioned previously we kicked this off over a year ago and we have completed our initial round of scenario modeling and we've brought that work forward to you all in October. We've been doing much more detailed analysis over the winter and have learned quite a bit to refine and build into our round two.

And then what we see in the box is our meeting with you now today. We will have a meeting with our TRC who's our Technical Review Committee and they will be reviewing, getting us feedback in the fall and then our plan is to come back at the end of year and share with you the results of our round two findings. So we're really looking forward to that. We hope that you all will be able to come back and help to learn with us as we see what we've found from our round two work. So with that I will close out and turn over the mic to my colleague. Thank you, Alissa, for joining us.

WHITNEY BELL: Thank you, Carl, I really appreciate it. Thank you Hamody. So I did want to jump in here and just introduce Alissa Baker. She's a Senior Technical Advisor for Offshore Transmission with the Grid Deployment Office. Alissa, I can see you, can we hear you?

ALISSA BAKER: Yeah, I think so.

WHITNEY BELL: All right, great, the floor is yours.

ALISSA BAKER: Absolutely. Well, thank you all for having me today. I know Offshore doesn't always get talked about with the NTP and all of the National Transmission work onshore that's going on, but I'm here to assure you that those pieces absolutely do fit together. They absolutely are working together behind the scenes. And in case you haven't been involved in some of our offshore work, I'm going to give a quick summary of that today just to fill you in a little bit and then we'll see how the pieces fit together. Next slide. So, the offshore work that we've been doing has been in partnership with BOEM. So unlike the Onshore Transmission Study, this has really been a joint agency effort. We've been tasked to look at both the Atlantic and the West Coast and we'll be shifting to the Gulf pretty soon.

But we're looking at not only the transmission analysis that we have going on the Atlantic, and have just started on the West Coast, but we're trying to look at all of the policy and the economic questions, things that the analysis may not tell us or may not tell us definitively. As well as hosting conversations to bring relevant stakeholders, state leadership, tribal nations, impacted parties, ocean co-users, everybody to the table to have a voice to talk about these important issues because transmission has a huge impact on us though we don't always see it in our daily lives and it has an impact on the power prices that we pay as well.

So we’ve been doing a lot of convening work. For the Atlantic in particular we ran a huge series of workshops last year, bringing together a bunch of experts to talk through these various topics and then bringing in the preliminary information from the transmission studies that were happening concurrently. Those have been packaged together into an action plan that I’m really excited about.

If you’ve heard me talk earlier, I’ve probably told you it would be published in the spring or early summer because it turns out that getting multi-agency concurrence on a series of actions as broad and detailed as these are takes just about as much time as getting the good ideas to begin with. But I promise we are nearing the end and I’m excited that we’re going to have publication pretty soon and more information there.

But enough of just the offshore; let’s look at how it kind of fits into that national planning work. Next slide. So I like to say that the West Coast Study and the Atlantic Coast Study are siblings. They're not identical twins, but they're very closely related. And the National Transmission Study has got to be like a cousin because they're definitely familiar, but they're not exactly the same. So some of the things that are absolutely shared, you know, the study teams have a lot of overlap.

We have a lot of the same technical experts looking at both studies. They're communicating regularly. They've got check-ins scheduled to talk through things, work stuff out. They're sharing a lot of the same assumptions, a lot of the same underlying assumptions. They go into both studies, are common so that we can have a common frame of reference when we're talking about results and are using a lot of the same modeling tools. So, they're not asking the exact same question. Not every scenario matches between the two, but we are making sure that these studies exist in the same universe of plausibility so that they can be useful.

One of the most, one of the things I think is most interesting to pull away from that is the use of the points of interconnection data. So a lot of the coastal work we have been doing in the offshore space involves identifying optimal onshore tie-insurance and those points of interconnections on the shore is something that can be used into the NTP for the nodal modeling. I think there's also, you know, there's been some talk about using the interregional topology that came from the Atlantic study as one of the nodal scenarios for the NTP.

I think the team is still working on that, but rest assured that these are very well-coordinated. But they are answering slightly different questions so they're not redundant. So I think that's kind of the basics. Stay tuned absolutely for more from our offshore stuff. That'll be coming pretty soon with the publication of the action plan. And of course the NTP has another public webinar that Carl just mentioned coming at the end of the year where we'll have even more information to share. Back to you, Whitney.

WHITNEY BELL: Great, thank you so much. All right this brings us to our Q&A portion. So we are going to be bringing all the different people who have spoken today up here to answer some questions. And while we're doing that, I want to make sure that you know you can ask questions. Please put them in the chat and we will try to get to them as best we can. So as we're bringing up the speakers I am going to go ahead and get started here. So I am going to get started here with a question first for Hamody. Hamody can you hear us?

HAMODY HINDI: Yeah.

WHITNEY BELL: Okay, great. So, does DOE intend to incorporate large interstate independent transmission projects that are under development? If so, how and with what criteria?

HAMODY HINDI: Yeah, good question. So, first of all, as we said sort of during the presentation, right, that these particular nodal implementations that we're building of these future power systems, they're just one of many particular implementations. And so, certainly we don't want to choose winners and losers in terms of actual individual transmission line developments. There are many possible futures there.

So that's, as we do these nodal implementations, we have surveyed sort of which projects are in development and in more advanced stages of development. And as certain proposed projects that are in advanced stages of development are lining up with some of the transmission expansions that we're seeing as part of our modeling effort, we may potentially use those in some of the implementations of the models. And so we've discussed in previous meetings, I think, different criteria that we use to potentially look at those.

So when we are looking at those, and potentially using some of them in some of our implementations, I want to emphasize that any of the implementations that we're doing here are not intended to be final plans. They're just one of many possible implementations. We want to identify high value interregional transmission at sort of a higher level, so with many possible different future implementations that can be decided by industry and as part of other processes that DOE has in terms of the valuation of projects.

WHITNEY BELL: Thank you. So I do have another question here, and this one's for NREL. And it's a couple of questions that are kind of related so I'm going to ask both of them. And just so our attendees know, we do have some staffers from NREL and from PNNL that will be joining us here on the screen to answer some questions here. So this question is, with the resource capacity I assume the study is looking at nameplate capacity. How would the analysis change if accredited capacity levels were studied? And a related question is what capacity accreditation for wind and solar are you applying for 2035?

TRIEU MAI: Yeah, thanks, Whitney, and hi everybody. It’s Trieu Mai with the National Renewable Energy Lab and I’m kind of representing a large technical team here I’m on for the labs in this question. So first, in terms of the question, resource adequacy, Carl touched on this a bit. It’s obviously a key component of reliability. And so we obviously need to analyze it and make sure the systems and the portfolios that we’re putting out there are truly resource adequate.

So in fact the modeling, the full suite of models but especially the front end where you have the capacity expansion models that generates your portfolios, does consider resource adequacy by looking at different accreditation for different technologies that vary by region depending on the characteristics of the underlying resource, as well as with scenario and over time. So that's a dynamic part of the model that's calculated.

For the final version of the scenarios we are incorporating the probabilistic resource adequacy suite or that PRAS model, which does draw on outages and does a Monte Carlo analysis within that portfolio-designed framework. So we are calculating that. And within the model, to answer the second part of the question, in many of these high renewable scenarios with lots of wind, solar, and battery storage, we do see the marginal contributions from these resources going down to near zero. However, the interplay with transmission and the fact that the first sets of technologies that are deployed still does contribute to firm capacity or resource adequacy needs. I hope that helps. Back to you, Whitney.

WHITNEY BELL: Thank you so much. This next question is actually for Carl, and so as we're bringing him up here. Carl, this study seems to depend on development of certain generation resources. How useful would this study be if different kinds of generation are actually built, nuclear instead of land-based wind? What if new forms of generation are developed?

CARL MAS: Yes, so that’s a great question. So I’ll maybe reemphasize some of the importance of the work of doing sensitivity analyses. So we all know that making assumptions for 30 years is incredibly challenging. And so given that uncertainty, what we’ve asked the labs to do, and they’ve been able to gather quite an extreme amount of stakeholder input over these months, is to test out different technology assumptions.

So at the core they’ve made a number of technologies available and allowed the model to look at what is the least cost-optimized outcome? While we recognize that those assumptions may not be right, we may get the costs of wind in the next 30 years wrong, we may get availability of nuclear wrong. So we’ve tested, pressure-tested availability through our scenarios and that’s where we have the nearly 200 different sensitivities that we’ll be running this fall to give us insights into what are the implications if certain technologies are or aren’t available. What if it’s harder to site wind? And as the end result how does that affect these outcomes around our interregional and transmission builds.

So one of the core questions for us at DOE is, when we look at all of these sensitivities, which transmission opportunities continue to be beneficial? So we're not just looking at one particular generation profile and saying let's build transmission around that. What we want to be able to do is understand which transmission opportunities are robust to a suite of different future outcomes. And so it's through this different multi-model approach that we'll be able to answer that question, looking at different generation outcomes.

And clearly, there will be new breakthroughs into the future and so that's why this process can't be once and done. We really are looking for this type of national transmission effort, this national planning effort to continue into the future. And so this is about engaging with our various public entities and private entities and moving forward and learning from what we do this round and then doing it again as we see new technologies coming forward. So thanks for the question.

WHITNEY BELL: Thank you, Carl. This next question, there's two of them that are related and this is going to be for PNNL. Are there any considerations of the stability need of such high penetration of IBRs and the moving of generation further away from the load centers? The related question then is, has system stability been assessed or considered?

JEFF DAGLE: Yeah, thank you, Whitney. Excellent questions. As everybody is familiar, the Inverter Based Resources, or IBRs, do behave a little bit differently than synchronous generators and can contribute to stability questions that need to be addressed. The first step is really looking at the power flow analysis. And so when we're done with the capacity expansion and the production cost modeling and looking at the resource adequacy and the hourly profiles, we'll take some specific cases, some stress cases, run some power flow analysis, do a contingency analysis on those. And really what the power flow analysis can reveal are things like reactive power and voltage support and some of those steady state types of considerations that we can model in the power flow and look for whether or not these resources are providing those types of ancillary services.

Really to fully answer that question we need to get into the dynamic analysis to look at things like voltage stability, transient response, inertial response, those types of things. Those are currently outside the scope of what we're doing on the transmission planning study. So some of the analysis we're doing; some of it's out of scope.

WHITNEY BELL: Great, thank you. All right, so this one is for NREL. What criteria is being used to site the new generation and new transmission? How is the existing grid limitations being accounted for, overloads, et cetera? Is the impact of the circuit capability impact to protection systems, system inertia, and essential reliability services being considered?

TRIEU MAI: Yeah, thanks, Whitney. It's a great question, and we probably don't have time to go through all the details, but I'll try to provide a high level summary right now. Which is, in terms of determining which resource mix and where to put the technologies, the model tries to account for as many characteristics of the technologies and needs of the system simultaneously and balance those. So, for example, back to the resource adequacy question. If a technology isn't able to contribute as much to the system needs during its stress periods, either other technologies might become more economical or you'd have to build more of that technology or connect it with storage or with transmission to other systems. So it's doing this holistic approach for system planning all together. And that applies regionally as well.

So the first question was about siting renewables, and so it does account for the differences in technology costs, resource availability, higher capacity factors in one region and another, proximity to existing transmission, so the cost to interconnect those new renewable power plants in that example to the nearby high voltage substations, for example. It also accounts for the cost of transmission.

So some regions where we assume transmission costs might be higher, it may actually prefer a lower quality of renewable site where the transmission costs and distances may be lower for the whole system as a whole. So the latter part of the question is, obviously some of the issues that were brought up about stability, for example, are outside of the resolution that the model could be able to capture.

So in those cases ideally, as Jeff just noted, we would then evaluate them with higher fidelity models to account for them. We do stop somewhere within the national transmission planning study. We do look at hourly production cost modeling and some of the DC contingency analysis that Hamody referred to, but some of the higher resolution modeling that necessitates a full look at reliability would require more work. Thanks.

WHITNEY BELL: Thank you. There were a lot of questions in there, so I appreciate you covering all of that. This question is for Jeff. Does CPAGE [phonetic] calculate AC power flow as a snapshot or as it continues where generator parameters and transition from one generator state to another is included as a constraint?

JEFF DAGLE: Yeah, thank you for the follow-up question. So the CPAGE tool is basically extracting snapshots from the production cost model. It is in the production cost modeling framework itself that we're looking at the characteristics of the generation constraints. So any sort of ramping issues, if there's a hydro in terms of run river issues. If there's any other things that the hourly production costs model needs to include to make sure that from one hour to the next we're being consistent and reflecting all of the generation constraints. That's handled in the production costs model.

Then what we're doing with CPAGE is we're taking those hourly snapshots and we're extracting that in order to conduct the power flow analysis. It's interesting that in looking at the stress cases and the resilience analysis in the power flow analysis domain, we need to take several different times throughout the year to really look at when the transmission stresses are going to be creating constraints when we do the contingency analysis.

So it's a little bit different than the old days where we would just sort of focus on peak hours and things like that. Because a lot of times peak load isn't necessarily when we have maximum transmission constraints, so we want to use the CPAGE tool to selectively pull out those hours that look like we could have some transmission issues and then we use the results of the production costs model and then pull that out as a snapshot for CPAGE. But we're relying on the production cost model to provide the consistency between the hours and making sure that all the constraints are modeled as it relates to the generation. Thanks, Whitney, for the question.

WHITNEY BELL: Great, thank you. All right our next question is for Carl. Is there specific timing of a specific offshore wind transmission study?

CARL MAS: Great, that's a straightforward one. So, we kicked that effort off at DOE in May of this year and it's a 20 month study. So that gives you a sense of when we think the project is going to be done. So it's an effort, it's another kind of lab-based effort just like we did on the Eastern Seaboard. And with that engagement it will be around 20 months. Thanks.

WHITNEY BELL: Great, thank you. So this one is going to be for Trieu and for Hamody. I believe the first part will be for Trieu and then another part for Hamody. So it seems that these transmission expansion model results focus highly on the implementation of 500 kilovolt lines. Is there a reason why 765 kilovolt and HVDC lines are not considered? Are transmission, voltage, and conducting sizing also considered? And then the part that would be for Hamody is, are advanced conductors being used?

JARRAD WRIGHT: Yes, I'm happy to take this on behalf of Trieu, specifically as it relates to some of those nodal models and nodal modeling efforts that have been underway. Specifically on different voltage levels, we are able to and are expanding at all voltage levels from 230 kV above, so 230, 345, 500, and 765 kV. Specifically on conductor types and assumptions that are being made there, early on during the course of the project timeline we had made some queries with our technical review committees and more specifically the modeling subcommittee, on the types of conductors and conductor arrangements.

So at the different voltage levels we are making very specific assumptions around the conductor bundling and different voltage level thermal transfer capabilities when then translating these zonal capacity expansion outcomes into these nodal models. So in summary, yes, different voltages and various conductor types are being considered. In the maps that were shown specifically today it's one of the scenarios that is an AC expansion scenario, so you will see a lot of AC expansion.

There isn't necessarily a preference between different voltage levels; it's what is the most appropriate voltage level to then transfer the bulk amount of power on the transmission system to the demand hubs as to where it's needed. And in terms of HVDC similarly, some of the further scenarios will start to explore HVDC and we'll hopefully be able to present some of that in the near future, and I think Hamody was alluding to that once the round two capacity expansion model results become available. Hamody, I'm sure maybe you want to then address that, go back to those components, but hopefully that addresses the first two parts of that question.

HAMODY HINDI: Sure, yeah, thank you, Jarrad. So I'll say on that first part again, 500 kV versus 765 kV, I want to emphasize we've done a particular nodal implementation because you have to do something in order to run the models and do the analysis. But what's much more important than any particular implementation we're achieving here is sort of the comparative work between different scenarios.

So how does a system with a lot of interregional transmissions perform compared with systems with little or no interregional expansion, and whether that interregional expansion is implemented with 500 kV lines or 765 kV lines. We would learn the same important lessons and demonstrate the same high value of interregional transmission either way.

So I just want to make sure to emphasize we're not really advocating for one particular implementation in terms of another regarding voltage class. And then also regarding that piece of the question getting to advance conductors. DOE is looking carefully in valuating grid enhancing technologies more broadly, including advanced conductors, as well as other technologies and certainly those are important and we want to see them developed appropriately. For this particular study, given its scope, doing a deep dive into it to where it may be better to do advanced conductors versus traditional, is kind of it's beyond the scope of the study.

So certainly the particular implementations we're showing here, if we move further down the development pipeline into a more detailed plan of service, and it looks like actually this is an appropriate and good application for advanced conductors, then certainly we would support that. Just that's a little bit further along in the more detailed development of plan of service. It's kind of outside of our scope. But again, it gets back to the idea that the particular implementations we're showing here aren't meant by any means to be final and they could certainly be provided.

WHITNEY BELL: Thank you so much, appreciate it. So we have got time for one more question and this is going to be for NREL here. What capacity expansion model was used, and is round two capacity expansion done with ReEDs or a different model and how are these 134 study zones developed? And I'm happy to re-ask any of those because it was three questions in a row.

TRIEU MAI: Nope, I think I've got it, Whitney, thank you. So the ReEEDs model, NREL's Regional Energy Deployment System model, was used for the capacity expansion for both round one and round two. However, round two we've made some fundamental improvements to the model that Carl summarized briefly, including improving its temporal resolution, updating the policies and technology projections, improving our reflection of transmission both of the interconnection, kind of sub-zonal level, as well as kind of our cost in terms of long distance transmission lines, and improving our assumptions about siting renewables, where you could put them, among many other changes that are kind of fundamental. So we are still using the same model. The spatial resolution is the same.

The 134 zones were allocated depending on a bunch of factors, including regulatory factors. We have to conform to state boundaries. We do have a sophisticated method to discuss how we calculate the interface, existing interface transfer limits between zones and whatnot that I'm happy to follow up with those who are interested in those technical details. And in the interest of time, I think I'll stop there, but of course we could go on with many more technical discussion.

WHITNEY BELL: Thank you so much, Trieu. And thank you, Hamody, Carl, Jeff, Jarrod, everyone who was participating there in that great Q&A session. And thank you for all your questions that you all submitted. So that wraps up our questions for today's webinar. So if you have any comments or questions on the National Transmission Planning Study, you can email us at: ntpstudy@hq.doe.gov. That is also there in the chat.

And a copy of today's slides will be available on this webinar's landing page by this Friday and the recording will be available in about two weeks. We will send you an email when all of that is available. And you can find a link to the landing page in the chat now. Again, thank you to Jeff, Hamody, Carl, Alissa, PNNL, and NREL for joining us today and leading us through this wonderful webinar, and thank you to all of our attendees for participating. Take care everyone and we'll see you next time.

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