Ari Peskoe:

Welcome to Clean Law from Harvard Law School's Environmental and Energy Law Program. Today's episode is about the future of our energy system. Electric transmission delivers energy from power plants to consumers. We need more for clean energy and to ensure our energy is reliable and affordable. We discuss how the industry thinks about building new transmission and what FERC is doing to push the industry to build more high-energy transmission lines. Thank you for listening.

This is Ari Peskoe, director of the Electricity Law Initiative, and I'm so pleased to be joined today by Claire Wayner, senior associate at RMI's Carbon-Free Electricity program, and with Casey Baker senior program manager at GridLab. And our topic today is transmission planning and FERC's new rule order number 1920 about regional transmission planning. So let's just kick it off.

Claire, tell us a little bit about what is transmission planning?

Claire Wayner:

Well, thanks, Ari, for having me. Excited to be on this podcast. Transmission planning is a process that every regional grid operator in the US undergoes, and also each utility, to prepare for various future outcomes. And that includes load growth and maybe new generation coming online, so solar, wind, also resource retirement. So we're seeing a lot of fossil plant retirements now. And so transmission planning takes all of those inputs and looks at what upgrades to the grid are required to maintain a reliable and affordable energy supply.

Ari Peskoe:

Yeah. So the basic goal of the planning process to make sure the system continues to work. And I want to highlight one thing you said there, which is that we basically have two types of entities that are doing this. Is that right? We have the regional transmission organizations and the utilities. Maybe you could just distinguish between who those two parties are.

Claire Wayner:

Sure. The utilities do their own local planning for their systems, but then the Federal Energy Regulatory Commission, or FERC, has established what are known as what you call regional transmission organizations, or RTOs, in most of the US. There are some regions of the US that do not have RTOs, but they still have regional planning entities. And these organizations are responsible for doing that higher level regional system planning. And they take inputs from the local utility plans and look at whether there are more efficient regional solutions to maybe enable more power-sharing or enable a more reliable system.

Ari Peskoe:

Yeah. And we'll get into FERC's role here and the role that FERC's new rule is going to play in all this. And I would point out that FERC itself is a rate regulator. Primarily, one of its main jobs is to protect consumers, make sure rates are not unjustly too high. And there's a connection here between that role and transmission planning, and that is that if a utility is going to build a new transmission line and it's going to be financed through utility rates, then it has to be in a transmission plan. So ultimately, there's some consumer protection function to transmission planning. And we'll also get into some issues about, I think, utility incentives. And so if we're going to be talking about how utilities make money by building new transmission, that's also going to connect to this planning process as well.

Casey, I want to go to you because you actually did transmission planning. You once were at a Western utility. And what were you and your colleagues trying to achieve through the utility's planning process?

Casey Baker:

Thanks, Ari, and really honored to be on this podcast. Transmission planning used to be the small windowless office where PhDs practice the dark arts of power flow modeling and that kind of thing. When I started, I had a mentor explain that transmission planning was a two-project career. Every 15 years, you would build a project. So that's what transmission planning used to be. It was really focused on reliability and taking a really deep dive look into the electrical functioning of the grid. And so NERC reliability, NERC being the North American Electric Reliability Corporation, has reliability standards that transmission planners try to focus on and make sure that the system can withstand certain disturbances to the grid. We call them contingencies. And that was really what transmission planning was focused on 10 plus years ago.

When I started solar in Nevada was it was $120 a megawatt hour and now it's a fifth of that cost. And so these renewable interconnections that are getting a lot of press weren't even really on the radar. We moved from maybe three to four interconnection requests a year to what today is probably 30 to 40 interconnection requests today and moving from a serial interconnection process to a cluster interconnection process. So there was a big evolution over the last 10 to 15 years in transmission planning, going away from just reliability, very strict conservative approach, to trying to integrate clean energy projects. And in that, regional planning was barely a conversation. At the highest conceptual levels, there was discussion happening within those FERC order 1,000 regions. So these are the regional planning regions outside of the RTOs in the West. But I think it comes as no surprise to many listeners that no project has ever come out of that process. And so regional planning from outside of the utilities was not a main focus. The main focus was that reliability, that deep dive into that.

Ari Peskoe:

You mentioned power flow modeling.

Casey Baker:

Yeah.

Ari Peskoe:

Can you tell us a little bit about what that is?

Casey Baker:

Yeah, yeah, absolutely. The grid is modeled by transmission planners as a series of buses, and buses being electrical nodes that you can determine what the voltage and current flowing through these entities are. And not to get too much into the weeds, but basically, the problem is a giant matrix of each bus has two knowns and two unknowns, and you use numerical methods to then solve the entire network of electrical equipment as a giant matrix. And so what I'm getting at is that it's a very robust but also very detailed model of the entire system.

And typically, each interconnection, so Western Interconnection, ERCOT and the Eastern Interconnection are their own model and each model will have about 60,000 nodes, each with five to 20 different characteristics between those nodes, whether it's a transmission line or a transformer or a generator. So it's a very intricate, very detailed robust model. But because of that, transmission planning is primarily focused on the snapshot modeling of the system. There's very little work done in the temporal domain looking at the transmission system over time. Transmission planners have to really focus on a single instance in time or within a few seconds of time to evaluate the reliability of the system. And that's become a limiting factor for the connection of renewable resources, which, as you know, change their output in response to the weather, and that is impacting how transmission planning has to be done in the future.

Ari Peskoe:

So just to go back to this power flow modeling for a second, from the perspective of a planner, someone who's actually doing this planning work, this looks like a big math problem. And from the planner's perspective, is it up to somebody else in the department to tell you what to put into that math problem, what are the inputs into this process and then the planner runs the software?

Casey Baker:

Yeah, a big math problem is a great way to describe it. And there's a couple different inputs. So you would have the integrated resource plan, which would direct what generation you're going to model. You're going to have your load forecasting group, which is going to provide you a load forecast for the various nodes on your system. And then you're going to have a capital projects group that's going to tell you which capital projects, meaning new transmission lines, new substations, are going to need to be modeled in the futures for this particular instance you're looking at. So let's say you're looking at a system 10 years from now, all of those inputs are going to go into that mathematical model and then it's going to output a model of the transmission system in that specific instance. And then you run disturbances or contingencies on that system to make sure that it's reliable enough to withstand that scenario.

Ari Peskoe:

Okay, great. So I think that gives us some technical grounding in what's going on here without getting too much into the weeds.

You've both mentioned regional planning processes and this is where basically utilities form alliances that are either through RTOs or just run by the utilities themselves. And the goal of these regional planning processes is to find beneficial transmission projects. That is projects that can provide some kind of benefit to more than one utility. And this word "benefits" is a very loaded term in transmission planning. So Claire, you've been very involved in PJM's regional transmission planning process. Can you give us a flavor of what benefits means, maybe in general, but also how has PJM historically looked at the benefits of new transmission?

Claire Wayner:

There are many different benefits with transmission as you acknowledged. And within a region, it can be difficult to agree on what those benefits are. At least in PJM to date, the benefits' calculation has really just been a part of what they call their market efficiency planning, and those are the transmission lines that are built to reduce congestion on the system. And the reason why PJM quantifies benefits for those comes back to FERC Order 1000, which has been around for a little over a decade now. And Order 1000 required each planning region in the US to be doing regional planning around three main types of transmission projects.

So the first was reliability projects, and these are, as Casey mentioned, to maintain NERC standards and again, maintain reliability of the grid. Reliability transmission projects, we typically don't see benefits quantified for necessarily because the alternative to not building a reliability-based project is to have an unreliable grid and to be in violation of NERC standards, which is not legally permissible. So that's one type of project under order 1000.

Then the second type is market efficiency or you'll also hear them called economic projects. And for these projects, these are, again, to reduce congestion on the system, reduce cost to consumers. But in order to justify the case for these projects, FERC required each region to use benefit calculation. So PJM has in Order 1000 established, this idea of a 1.25 benefit to cost ratio. So what sort of benefits does PJM look at for market efficiency projects? They look at the benefits of, again, reduced congestion, reduced cost to consumers, reduced clearing prices in the electricity markets that they run, basically like reduced generation costs. And they compare that to the cost of building the project. And if that ratio exceeds 1.25, then the project is approved and gets built. And this is to ensure that consumers aren't being held responsible for paying for transmission projects that aren't benefiting them more than the cost of building those projects.

Ari Peskoe:

Now, Claire, you've also done some research on transmission spending in the PJM region and specifically looking at the breakdown between projects planned by each individual utility going it alone as compared to projects planned by PJM either for these reliability or economic benefits. And what did you find in that research?

Claire Wayner:

The research revealed that since Order 1000, PJM utilities have been increasingly investing in what we call supplemental projects at PJM. And this is a category of project that are locally planned by the utility. They do not undergo any real scrutiny by PJM in terms of making sure there's maybe a more efficient regional solution. The supplemental projects essentially just get green lighted by PJM as long as they don't have any adverse reliability impacts on the grid. PJM does what they call a do no harm test. And the downside of this local planning is it doesn't look at those regional efficiencies that you can get through more regional planning.

And one hypothesis behind why we've seen this shift since Order 1000 is Order 1000 removed what was known as the Federal Right of First Refusal, or ROFR, which prior to Order 1000, each utility had the ability to basically build any transmission project that PJM said was needed in their territory. And Order 1000, by removing the ROFR, introduced competition to the transmission space, which definitely has posed a challenge for utilities who are seeking project opportunities where maybe they don't have to compete because as soon as there's competition introduced, they might not win the bid, they might not get to build that project. And so we've potentially seen this shift to supplemental projects simply as a competition avoidance because supplemental projects are exempt from competition.

Ari Peskoe:

Yeah, I mean, this issue is definitely a thicket. As you mentioned, those supplemental projects don't undergo the benefit analysis, and so utilities don't have to justify them in the same way. I think your research also showed that locally planned the supplemental projects are faster to execute and can therefore provide quicker profits for utilities?

Claire Wayner:

Yes. They're more locally planned, so they're generally smaller scale, maybe less risky financially, maybe less risky from a permitting perspective. So those could also be reasons why we've seen that increase in spending on supplemental projects. There's just not as much of an incentive these days after Order 1000 for regional planning to be top down and to look at those more efficient regional solutions. Loopholes like supplemental projects can undermine the potential efficiencies you can get from regional planning.

Ari Peskoe:

Yeah. And Casey, you mentioned earlier that we actually haven't seen any regional projects outside of the RTOs. And what that means is that each utility is building transmission by itself rather than collaborating with neighboring utilities or somehow inviting other developers to participate. What do you think is going on there? Why haven't we seen any projects at all in the West?

Casey Baker:

Yeah, you're right. So the stat I tell people is that FERC Order 1000 came out when the first Captain America movie came out, and there's been 28 Marvel movies since then, and yet not a single regional project has been developed under the FERC Order 1000 regions outside of the ISOs. So it's a pretty stark reality that the rule did not enable the transmission build that it was intended to develop.

And in the West, what I believe is going on is that both the non-ISO West region, so the regions outside of California, California being part of the CAISO, they outsource that regional planning and each of the independent utilities then sign on to that study. And the problem is is they're using models that come directly from the utilities. And when utilities and transmission planning entities within those utilities are submitting those models, they make sure that those models are already very balanced. And what I mean by balanced is load is equal to generation and that the transmission system that's being modeled is very reliable already.

So as you can imagine, when all 38 of the Western transmission models are put together, if they're already independently reliable in and of themselves, when a third party comes in to study what additional reliability benefits could be gathered by regional planning, it's not going to find any real reliability problems because all of those transmission models have been tuned to already be reliable in and of themselves.

That said, there's certainly reliability problems. There's outages that have occurred in the West over the last 15 years, and that speaks to a need for greater regional planning to address those reliability issues, especially as things like load growth continues. But I think that's really what's happening, is that the various utilities in the West are submitting data for a system that is already balanced. And when you put those together, you don't see very many benefits through regional planning.

And the same is true with the other benefits that FERC Order 1000 identified beyond reliability. So economics, which typically means congestion, so economic analysis is at the transmission level is evaluating transmission congestion, but again, those models are balanced out so when you put them all together, you're not going to see very much congestion in the model. But meanwhile, we see about $20 billion in congestion costs across the US. So something is going on where the model is not showing the real value of transmission because it's assuming these perfectly modeled worlds 10 years out. And that's what I think is really limiting identification of needs as well as solutions from a regional perspective in the non-ISO regions.

Ari Peskoe:

So we have basically no regional planning outside of the RTOs. In the RTOs, we've seen, for the most part, investment concentrated outside of regional planning in each individual utility's own planning processes. So this brings us to FERC's latest efforts to improve regional planning. On May 13th, FERC issued Order number 1920 and that requires RTOs and the utilities outside of the RTOs to conduct long-term regional planning. So FERC is requiring, I believe it's looking 20 years out if I'm remembering that correctly. And it specifies that planning should be done based on three scenarios that consider the following seven factors in each scenario. So I'll just read off the factors and then we'll get into it a little bit.

Factor one, laws and regulations affecting supply and demand. Two, laws and regulations on decarbonization and electrification. Three, state approved utility integrated resource plans. Four, trends and fuel costs and generator technology performance, as well as electrification technologies. Five is generation retirements. Six is generation interconnection requests. And seven is purchasing commitments from utilities and corporations or other transmission customers about primarily clean energy preferences, although I suppose it could be other preferences as well.

And so, again, what FERC wants to do is, based on these seven factors, use them in different to come up with three plausible future scenarios as a starting point for your planning exercise.

Casey, let me start with you here. Do these seem like the right factors to you? Is there something missing here? Is this what, in your role as a planner at utility, you would've been thinking about anyway?

Casey Baker:

Yes. These seven factors are not new. I think they're reasonable, and in today's world, they're really considered locally. It's just the devil's in the details. And this is a place where regulators or staff can step in to make questions about those specific factors. So things like fuel cost assumptions, load growth, generator retirements, that's where you start to see those assumptions have outsize impact on the transmission system that you end up with.

I'll give you a quick example. NorthernGrid is the FERC Order 1000 region in the Pacific Northwest and surrounding region. And their most recent FERC Order 1000 study found that load was forecasted to grow about 3% over the next five years, which seemed a little low. Then, in February, in the Pacific Northwest Utilities conference said that load in the region is actually going to increase 20% over the next five years.

So you have a wide gap in that specific assumption. And as you can imagine, that assumption on how much your load is going to grow is a huge driver in what the model is going to tell you. The model only is as good as the inputs. And if the utilities are inputting or the third parties that are doing the study are inputting assumptions that are either too conservative or too optimistic, you're going to end up with a transmission solution that really doesn't reflect reality.

Another good example there is generator retirements. So at a local level, you may have transmission planners that are thinking about it, but what we've seen especially in PJM and other areas is that in some cases they're not even allowed to really study these scenarios assuming generators are going to retire because that can be viewed as non-competitive because you're planning for a generator to retire before it has actually announced its retirement. But meanwhile, when you zoom out, you can see that certain generators are going to retire, we need to start planning now for the transmission system to support that. So again, it just comes down to how those various dials are tuned to go into the model.

Ari Peskoe:

Yes. Casey, you mentioned that regulators might get involved here in scrutinizing these factors, and that might happen at a state-level planning process, but for these FERC regional processes, FERC has historically not gotten involved. Instead, what it requires is that the utilities or the RTOs let state regulators, market participants, other stakeholders participate in these scenario development processes.

And Claire, you've been on the ground in some recent PJM discussions about transmission planning and maybe you could tell us a little bit about how market participants and various interests have different perspectives on some of these factors and how you could imagine some of these debates playing out between state regulators or clean energy advocates or owners of natural gas plants and other parties that are going to be involved in these processes.

Claire Wayner:

Absolutely. I mean, I think what Casey said about the West very clearly applies to PJM as well where I do a lot of work. Some of the disagreements come up in terms of, for instance, generator retirements, so more clean energy advocates or just economics-based arguments could be made that more resources are going to retire, but then, obviously, owners of that generation would not want their generation to be modeled as retiring. And so that's one potential point of contention. I think another point of contention we've seen in PJM is the role of state and local policy requirements.

There's a difference between policy requirements and policy goals. Policy goals might be, well, this city or this state aspires to electrify all vehicles by a certain date, but it's not legally binding. And so there can definitely be some disagreement on policy goals and whether they will materialize. But we've even seen in PJM disagreement over policy requirements which are legally binding statutes, for instance renewable portfolio standards or clean energy standards. And we've seen other actors in PJM, whether that be other states or generation owners or just other stakeholders disagree fundamentally with the idea that these legally binding statutes that the transmission required to meet those statutes should be regionally cost allocated. And we've definitely seen that disagreement play out in the media coverage around Order 1920.

And I think what I would emphasize here is while Order 1920 requires the consideration of seven factors, it does not say that you're only going to consider certain types of policies, right? All policies need to be considered. And so maybe one state in PJM chooses to have an RPS policy supporting wind and solar growth. Maybe another state chooses to subsidize its coal plants to keep them online. Regardless of what type of generation the policy is supporting, what Order 1920 says is that the regional planning needs to consider all of these policies and look at the transmission needed to meet those policies and then assign costs based on the benefits.

So the order is not requiring states to subsidize other state's policies, it's just requiring the grid operator to respond to what is written in law to ensure that the grid maintains reliability and that costs are assigned only commensurate with benefits.

Ari Peskoe:

Yeah. And it seems that sometimes the interest may be advocating for scenarios that directly align with their own financial goals. So just to give you a for example, an incumbent generator that owns, say a fleet of fossil fuel plants around a particular region may not want more transmission because it may allow potential competitors to connect more cheaply to the system, whether those new competitors are wind, solar, natural gas or whatever. And so they may want a scenario that intentionally leads to underbuilding. But sometimes the interests are less direct. So maybe, I don't know, a rate payer advocate may just want to reduce short-term transmission costs because that could lead to higher bills in the immediate future regardless of any long-term projections about that. And so it seems like this is just a messy process to build these scenarios. And at the end of the day, at least in PJM, it's going to be the PJM staff, I think, that make these final decisions here, right?

Claire Wayner:

Yes. And I don't envy their job in making those final decisions, but what I will say is that's where the power of scenario-based planning comes into play. And so FERC mandates that every long-term regional plan include at least three scenarios. And so maybe your legal mandates go in that least ambitious scenario because you know that those are going to happen. But then these other factors... And FERC even says that factors four through seven that you listed, Ari, can be probabilistically discounted for the future.

So for instance, maybe a corporation has a goal to meet all of its data center load growth with clean energy, but it's a goal. Who's to say it's going to happen, right? And so you can put that in maybe the second scenario or the third scenario, and then you can use the scenarios together to look at where there are common solutions, or maybe there's a solution to the least ambitious scenario that you could then increase in size. So maybe it's 230 kilovolts, but the next ambitious scenario says, "Well, what if you built that line to be 345 kilovolts," and then there is an opportunity through Order 1920 for state entities or interconnection customers to voluntarily pay the cost of increasing the size of that solution between that least ambitious scenario and the next one. And so that's where this holistic scenario-based planning can really help build bridges between these diverse interests.

Ari Peskoe:

So I want to get into how we go from these scenarios to actual transmission projects. So let's say we have our three scenarios. Casey, how are transmission planners going to translate scenarios into a set of transmission expansion projects? I assume this has something to do with power flow models, but help us understand what actually is happening here.

Casey Baker:

Yeah, absolutely. This is what gets at the art of transmission planning because the universe of solutions is so broad. Once you identify a transmission problem, let's say it's under certain conditions, a line could be overloaded or under certain conditions, transmission congestion is significant enough that it merits a project. So the way you solve that is often difficult to nail down to a specific order of operations. It often falls to heuristics or evaluation of solutions that have been proposed before. So transmission planning departments will have lists of projects that they have evaluated previously and they'll apply those projects to the model to see if those projects help alleviate whatever grid problem or economic issue you might be trying to address.

So from a mechanics perspective, I think it's important to note that there's really different departments at utilities that are going to look at things differently, and they all have to start working together to do this long-range integrated planning that really hasn't been done before.

So the first example of that resource planning, these are the folks that are looking at the economic models of generation and they say, "We really need a thousand megawatts more of this generation and we need it in this region." But they typically don't talk directly to the transmission planners. Where that shows up in is in the IRP process. The transmission planners will say, "Oh, we need to build some transmission to allocate to these new resources that our resource planning group is starting to do." And in fact, both groups use different models that don't communicate to each other. So the economic model doesn't directly communicate to the transmission model.

And so I guess what I'm getting at is that it's not a clean one-to-one of the resource planner saying, "Hey, in 15 years, we need 10,000 more megawatts of wind in this region" and transmission planners just hit a button and the model spits out the three transmission projects you need to support that growth. Instead, what it's going to be is an iterative communication between these groups. And that's going to happen at the regional level as well, where you have all these stakeholders, the states, the public interest organizations are all going to be feeding their desired assumptions to the transmission planner. And then the transmission planner is going to have to come up with bespoke solutions to those problems. And now, under 1920, you're going to have to be able to defend those against a variety of scenarios. So I think it's a good thing, it's just it's going to be a long road.

Ari Peskoe:

Just want to test to see if I'm understanding what's going to happen here. So let's say we have these scenarios, and let's say under a scenario we're projecting more demand over here because of data centers and we're projecting more demand in another region because of electric vehicles and the scenario's telling us that state A is going to mandate a gigawatt of new wind and solar and state B is going to also mandate five gigawatts of new wind and solar. And is the idea that we add that supply and demand in the power flow model to the existing network and then search for violations? Is that this first part of this process?

Casey Baker:

Exactly. And then you adjust those inputs as the scenario would dictate. So if you have a high load scenario where we assume a very aggressive electrification, very aggressive data center load growth, you would increase that load, that demand in the model. And then an alternative scenario might be some lower version of that growth rate. And then you can test those various transmission solutions between those scenarios to see which ones maybe operate best under many scenarios. Or like Claire was saying, if the augmentation to a transmission project is pretty low incremental cost and it covers all of your scenarios, it might be best, be a very cheap insurance policy to go after those low cost additive projects that work across a variety of scenarios as opposed to just going with the absolute low cost, low build solution.

Ari Peskoe:

And the transmission solutions, again, just to make sure I have this, is that they're not being developed by the model.

Casey Baker:

Correct.

Ari Peskoe:

The transmission solutions have to be plugged in by a person based on either some project that has already been considered or potentially based on some new project that somebody, whether it's a utility or some other developer, inputs into this model.

Casey Baker:

Yep, that's correct. Yeah.

Ari Peskoe:

Great. That was helpful.

Claire, any observations on that or any questions on that before we move on to the next phase of this? That was a helpful explanation for me.

Claire Wayner:

No, I think the only thing I'll add is some regional planning entities will identify the solutions. So they'll go forward and say, "We need to build lines or do these things in these locations on the grid," and then they'll put those out to bid under Order 1000 competitive bidding requirements. Other RTOs, including PJM, use what they call a sponsorship model or a solicitation model where they just post the violations on the grid and then it's up to each transmission provider to propose a solution. And so there's some nuance in who proposes the solutions, but ultimately, the Order 1000 competitive solicitation requirement will apply to a large chunk at least of the projects identified by this long-term planning process.

Ari Peskoe:

Yeah, no, thank you. That's a great addition. One of the huge controversies around this whole regional planning process is whether utilities should build all the projects by default or whether these opportunities should be opened up to competition. And some of the debate, I think, focuses myopically on a project-by-project cost evaluation, which is who can build it, this one particular project, cheaper, a utility or somebody else. But perhaps the real value of competition is trying to get the best ideas, these best solutions input into the model, and who cares whether those solutions come from a utility or some other developer. We just want the best solutions. And the only way we'll bring more ideas to the table is to make this process open these development opportunities open to everyone, not just utilities.

So then, once we have these potential solutions, we plug them into the model in order to put them in the plan. They have to pass a benefit cost analysis as Claire was describing earlier. And here, FERC is requiring that seven benefits be evaluated. So I'll just run through the seven and then get your reaction.

The first is avoided or deferred transmission investment. Second is reduced loss of load probability. Third is production cost savings. Four, reduced transmission line losses. Five, reduced congestion due to transmission outages. Six, mitigation of extreme weather and unexpected system conditions. And seven is capacity cost benefits from reduced peak energy losses. These are all fairly technical sounding, but they're for the most part designed to measure consumer benefits, cost decreases, due to new transmission investment as well as reduced outage probabilities.

So let me just start with why this all matters, which is, Claire, the clean energy advocates and transmission advocates really pushed FERC to require FERC to order the planners to consider some minimum set of benefits. So this was a really important issue in the rulemaking process. Can you tell us why mandating that planners consider these seven benefits or some set of benefits was really important?

Claire Wayner:

Yeah, we were all very excited when we saw that FERC had mandated that minimum list of seven because as I said earlier, often agreeing on what benefits to calculate can be a really challenging pain point in the stakeholder process in these regional planning entities. And it definitely has been in PJM discussions for instance. And so FERC mandating every region to calculate a minimum set of seven takes away that ambiguity and it helps level the playing field.

And the other thing I'll say is it helps to set the stage for potential progress on interregional transmission planning. So Order 1920 doesn't really get into interregional planning, it just focuses on enhancing long-term planning within each region. But numerous studies and research has shown that the US could benefit from more interregional transmission planning and build out to enable more transfer of power between these planning regions. And one of the challenges that interregional planning efforts face today is each region might use a different set of benefits if they are calculating benefits at all. And so mandating a list of seven for all regions to consider in the same way more or less could make that interregional planning and coordination or rather it will make it much easier to do.

Ari Peskoe:

Casey, FERC doesn't tell utilities how to actually quantify these benefits, which is obviously critical here. Are there standard industry approaches for each of these seven?

Casey Baker:

Largely, yes. And I think, as you point out, that's going to be how each region interprets how to calculate each of these benefits is going to be a critical part of this implementation.

Ari Peskoe:

Yeah, I mean, so I think each region is going to have to come back to FERC and tell FERC how it's going to comply and they'll have to at least, I think, sketch out some high level mathematical formula for calculating it. Is that the end of the story or is there opportunities then when you actually implement that formula to fine tune it, whether is this an outcome-driven calculation where if you want to find transmission you can fine tune the benefits later if you don't want to find transmission solutions, then you fine tune it the other way? Is that something that might happen down the line?

Casey Baker:

I think what you're going to find is that the equations are not going to change much. It takes a long time for industry to update their methodologies. So loss of load probability is a good example of this. There's a variety of ways that you can calculate how likely an outage is and how impactful that outage is. But what's going to change is the actual assumptions that go into that of how valuable is that loss of load. If a factory goes down for two hours, is that a $10,000 impact to the economy or is it a $10 million impact to that economy? And I really think this is why FERC made the decision not to specify how the industry should calculate these benefits specifically because each region is going to have different values for that, for those types of benefits.

So a region that is really concerned about minimum cost levels and production cost savings are going to have different values for lost load than a region that has extreme weather risk or extreme high or low temperatures. If I'm in Minnesota, I want to make sure that in the dead of winter there's a really high cost to that loss of load for residential because you're talking people's lives on the line versus other regions may not have as high of a risk level there. And so they may discount that benefit more so than they may care more about things like reducing congestion or production costs at that point.

Ari Peskoe:

Yeah, and I would say this is a minimum set of benefits. So FERC is not prohibiting regions from considering other benefits.

Claire, are there anything here that you think, let's say PJM, I know I keep picking on them, but that's where you've been very involved, are there other benefits you think might be in the mix in PJM?

Claire Wayner:

Prior to the order, PJM has been workshopping long-term transmission planning proposal that they'll definitely be adapting now in response to the order. But one benefit I know that came out of that initial proposal was the idea of accessing lower cost generation resources and including that as one of the benefits. MISO does that currently as part of its long-range transmission planning process, LRTP. So I could see that also getting added to the mix. And then I'll also note that MISO actually quantifies emissions reductions as a benefit in their planning process. And so you're right that this is only a floor.

And the one other thing I'll say about the benefits that I would hope that planning regions really look at doing is quantifying benefits on a portfolio basis, not just for each individual project. That's what MISO does currently with its long-range planning. And it's a really beneficial approach because it avoids potential conflicts over whether an individual project should get built, which those debates can often flare up in the stakeholder process. So by focusing on a portfolio of projects, basically the total set of solutions at the total set of benefits, they'll confer to the planning region. That can really help to advance as much beneficial transmission infrastructure as possible, recognizing that each project will still need to pass that benefit cost test that you mentioned the order includes.

Ari Peskoe:

There's one more aspect of project selection I want to briefly touch on. FERC calls it right-sizing. So Claire, can you tell us what right-sizing means and what role it might play in this process?

Claire Wayner:

Right-sizing is the process by which the regional planner can look at proposed either typically replacements to local infrastructure that utilities are planning to do already. So maybe it's an aging local line that they need to replace or some other upgrade to the system on a lower voltage level. And the regional planning entity takes a look at those and sees whether those upgrades can be increased in size or rightsized in order to meet both that local need and a regional need that may have arisen from the regional plan.

To date, I think each planning region has varying degrees of right-sizing going on, but it is really encouraging to see FERC in this order mandate some degree of right-sizing. So every utility now needs to look 10 years into the future, post a list of assets that they are planning to upgrade or replace as part of the local planning process, and then, as part of this long-term planning process under Order 1920, each regional planning entity needs to look at those lists and consider whether right-sizing opportunities exist.

Ari Peskoe:

And I assume these right-sizing projects would still have to pass the benefit cost tests we were talking about.

Claire Wayner:

Yes.

Ari Peskoe:

Casey, I'm going to ask you an unfair question.

Casey Baker:

Go for it.

Ari Peskoe:

You're an engineer. You haven't looked at any of these potential right-sizing projects, but nonetheless, I'll ask you to speculate. Do we think there's a lot of these opportunities out there? Do we see these as potentially just supporting other projects or can these actually displace new greenfield projects by just upgrading existing assets?

Casey Baker:

I wouldn't go so far as to say that right-sizing could displace a lot of greenfield. I think every transmission model that I've seen shows a huge need for transmission capacity, so much so that greenfield transmission is going to be a big part of this puzzle. That said, we've worked with researchers at UC Berkeley and Lawrence Berkeley National Labs and found that reconductering, which is replacing just the wire on the lines with high performance conductors, can double the capacity in many cases of an existing line. And that's a really low hanging fruit for utilities to look at. And our investigation found that the vast majority of lines in the US are eligible for that technology being used. And that's just one of the maybe eight to 10 emerging technologies, things like advanced tower raising, grid-enhancing technologies, HVDC conversion that could be used to rightsize the existing system that we have today.

Another word that I think would be beneficial to use is optionality. And that is the recognition that the right-of-way that system sits on today, what is the optionality to convert what sits there today to something that has a greater transmission capacity potential? And there's a whole suite of technologies that are available today to implement that. And I think that as the long-term regional planning, as well as just the individual local planning starts to really investigate those technologies and start to adopt them, it's going to uncover a lot of potential that hasn't been used today.

That said, just to reiterate though, I do still think that there's a big role for greenfield transmission to play, particularly to access regions with great renewable resources that have no transmission access to speak of today.

Ari Peskoe:

All right, so the next step of this process is figuring out who pays for all these beneficial transmission projects. This is called cost allocation. The overarching principle is that costs are allocated among utilities in a manner roughly commensurate with the benefits each utility is expected to receive. I don't know that FERC has much to say here that's new on cost allocation. Cost allocation, in theory, is an independent process that follows planning. How the costs are divvied up should have no bearing on which projects are actually in the regional plan unless, as Claire mentioned earlier, utilities or other parties can volunteer to pay a disproportionate share of a project's cost. So FERC's allowing parties to essentially overvalue new transmission, meaning it might not pencil out under the benefit cost tests we've talked about, but for whatever reason, a party may really want that project to move forward and can volunteer to pay more for it. But setting that aside, cost allocation is separate from planning and yet a lot of commentary leading up to this rule has blamed cost allocation for lack of transmission expansion.

So Claire, what's your view on whether or how cost allocation influences planning outcomes?

Claire Wayner:

I definitely agree with you that cost allocation is one of the most contentious parts of the planning process. And yes, to date, I think it has stymied transmission investment. One example is what's called the state-agreement approach in PJM, which is PJM's current approach to public policy planning, which requires a state that has public policy that requires grid upgrades. So it could be the most common example is a renewable portfolio standard policy. That state needs to pay 100% of the cost associated with the transmission for that policy, even if that transmission benefits other states and utilities and actors on the grid.

And so because of that potentially unjust cost distribution, we have just seen very few states in PJM take advantage of the state agreement approach. To date, New Jersey is the only state that has used it for its offshore wind commitments. And as a result, in PJM, we've seen increasing interconnection queue backlogs and challenges for renewable resources connecting to the grid.

And so what's really powerful about what Order 1920 does is it requires every planning region to establish an ex ante cost allocation methodology. Ex ante being decided prior to when the planning results come out. And this ex ante approach has to be a default or backstop approach. So this means that even if there are some of those disagreements among stakeholders about how to pay for things, at the end of the day, this default cost allocation methodology will determine how lines are paid for so that lines basically aren't going to drop out of the plan because of disagreements over how to pay for them.

Ari Peskoe:

Yeah, I mean, that was a feature of Order number 1000 as well, the presence of these default cost allocation schemes. Although one criticism there was that regions basically had different cost allocations for different types of projects. So reliability projects could be paid forward one way, different types of economic projects could be paid for in other ways, and maybe that potentially was a barrier to actually finding those economic projects. And here FERC is saying, "No long-term transmission projects all have to have at least one default methodology." So we'll see if that may help things.

I want to close with a couple of bottom line questions for each of you looking forward. So Casey, what makes you think this all might work, particularly outside of the RTOs and that we'll see utilities work together on beneficial projects for our long-term energy future?

Casey Baker:

Yeah. A couple things out of Order 1920 I am really excited about is requiring that 20-year time horizon outlook. In a world where it takes eight to 15 years to build a transmission line, we really need that long range 20 year outlook. And with 1920 requiring that, I think it's going to uncover a lot more opportunities than has been looked at under the previous order, which only required a 10-year outlook. And then, on top of that, evaluating extreme weather and requiring that the transmission planning entities look at extreme weather as a scenario to evaluate transmission solutions, I think is going to also uncover a lot of value.

Lawrence Berkeley National Lab did a study a couple years ago that estimated that only about 5% of hours contribute to about 50% of transmission's value. So when you really start to see transmission shine is under those extreme weather events like winter storm Uri or Elliott, where these regions can lean on each other to trade energy and help support the reliability and cost savings of each individual region. And so requiring that extreme weather analysis is going to go a long way towards identifying those opportunities. So we'll see if those factors get a fair evaluation. I'm optimistic that they will. And hopefully, we'll uncover some new transmission.

Ari Peskoe:

Claire, what about you? For PJM and the other RTOs, what makes you optimistic that this is going to work?

Claire Wayner:

I think the most powerful parts of Order 1920 are the requirements, so the required set of seven factors, the required set of seven benefits, the requirement to come up with a default ante cost allocation method. Often where we see things get stuck in the stakeholder process is disagreement over how to move forward, how to execute. And so when FERC comes in and says, "No, you have to do this, this is required," it, again, removes that ambiguity and makes it easier for planning to progress.

Ari Peskoe:

And so on the flip side then, Claire, what are you really going to be nervous about or what are you going to be looking at carefully and scrutinizing as PJM and all the market participants and everyone else there tries to figure out how to implement this rule?

Claire Wayner:

I think I'm foreseeing two challenges or difficulties with the rule. The first one is while the rule requires each region to develop three scenarios, look at seven factors, quantify seven benefits, it requires each region to come up with a plan, but then it does not require regions to go forward and select and build projects that come out of that plan. That's where it stops short. And so the devil's in the details. It's going to come down to maybe PJM develops this amazing plan, but then what projects are actually going to get built at the end of the day? And that's where we as advocates, I think, are going to have to continue to be monitoring to ensure that the most beneficial upgrades are being built. So that's the first point.

And then I think the second point is agreeing on that default ex ante cost allocation methodology. So just because FERC requires each region to come up with it does not mean that the process to come up with it is going to be easy by any means. And so that's where, I think, careful stakeholder engagement of states and other entities, a lot of education around what the benefits of transmission are, things like that are going to be critical to ensure that what comes out of that process as part of complying with the order is an ex ante cost allocation method that hopefully satisfies as many interests as possible.

Ari Peskoe:

And Casey, what about you? What makes you concerned that this is just going to be more of the same in that non-RTO West and the utilities will continue to basically go it alone on transmission?

Casey Baker:

Yeah, I mean, I think in the vertical states, it bears repeating that it doesn't change the fact that vertical utilities are still incentivized to build a system that protects their generation. That incentive problem has not been fixed by Order 1920. And so advocates and regulators are just going to have to get more sophisticated to ensure, because at the end of the day, the transmission owners are still the ones who control all the dials that go into those factors and how they're going to be represented and how the assumptions that go into those benefits are going to be developed.

And so advocates and those that are interested need to really get a deep understanding of how those assumptions are developed so that they can adequately advocate for a fair playing field because at the end of the day, the incentive structure, the way that the system is today, it does incentivize vertical utilities to tip the scales to the extent that they can to favor their own generation inside their system and build local transmission as opposed to regional or interregional transmission. And the only lever that we really have to combat that is this planning process and really digging into those assumptions so that the studies as they are conducted really show the true value of regional transmission.

Ari Peskoe:

Well, this rule from FERC was the culmination of a three-year effort by FERC to get this out the door. And it's really just the start though of this long process. We'll have to see how each region plans to comply, and then we'll be implementing it from there and hopefully steel in the ground maybe before the end of the decade. So thank you both for sharing your insights into what this rule means and how it might play out over the next several years.

So Casey and Claire, thank you both for being here.

Casey Baker:

Thank you, Ari. This was great.

Claire Wayner:

Yeah, thanks for having us.

Ari Peskoe:

All right. We will leave it there.