Transmission Planning and Interconnection for Offshore Wind
December 2, 2014

Coordinator: Welcome and thank you for standing by. At this time all participants will be in a listen only mode for the duration of today's conference. This call is being recorded, if you have any objections you may disconnect at this time. I would now like to turn the call over to Charlton Clark. Sir, you may begin.

Charlton Clark: Thanks. Well thanks everybody, for taking the time to call in for today's WINDExchange webinar. Today's webinar is going to be dealing with some topics related to our offshore wind strategy. In particular we're going to be talking about transmission planning and interconnection for offshore wind.

And we have a variety of different speakers that are going to be going through a handful of studies that they've connected—or that they've conducted for the department over the last couple of years, as part of our ongoing strategy to try to address and bring more—bring offshore wind to the U.S.

So the next—the slide that hopefully everyone sees up on their screen is the agenda for today. My name is Charlton Clark. I'm the Program Manager for Grid Integration here at the Wind and Water Power Program within the Department of Energy's Office of Energy Efficiency and Renewable Energy.

Just a quick note for everybody, if you do have any questions that pop up, please type them in to the Q&A Session on the webinar and we're going to take questions at the very end. And we'll go through and select questions depending on—based on how much time we have available. And hopefully you have the chance to try to answer everybody's questions.

A couple of quick notes that the webinar recordings and presentations will be posted on the WINDExchange website. Usually takes about a week for that to

happen. We want to let you guys know that we may run over and if folks have to drop off the call please go back and check on to that—to the recording that'll be up on the website. And hopefully we'll able—we're able to address your questions, if we can't get to it by the time you have to get off the phone.

So next slide up is a little teaser for some of the upcoming webinars that are coming out in the next few weeks. The—we tend to have WINDExchange webinars on the third Wednesday of each month. Due to the Thanksgiving holiday we ended up moving this webinar to the first week in December.

Upcoming webinars are going to deal with small and distributed wind turbine updates; wind turbine recycling and repowering; national development siting considerations; and in another offshore related webinar on design conditions for hurricane and mid-ocean environment.

So the studies that we're about to hear on are related to removing market barriers. We issued a—the National Offshore Wind Strategy in conjunction with the Department of Interior back in 2011 basically to promote and accelerate responsible commercial offshore wind development in the U.S.

And as part of that we issued a FOA or Funding Opportunity Announcement. This was a multipart funding opportunity announcement. And the studies that you're going to hear about were related to Topic Area 4 which dealt with transmission planning and interconnection studies.

Specifically that topic are kind of had two different sub areas, one dealing with trying to develop a National Offshore Wind Energy Grid Interconnection Study, or NOWEGIS study. The results and information about that will be presented by John Daniel from ABB shortly.

The other studies were centered on utility interconnection and integration situations. We have studies from Kenneth Loparo from Case Western Reserve University, as well as from—Dr. Willett Kempton from the University of Delaware, and finally from Bob Burner from Duke Energy.

Just a quick note, if anybody does have any follow-up questions or wants to contact any of us, here is a list of the variety of folks who are associated with the WINDExchange Program, and would be more than happy to try to answer any questions that aren't—that we aren't able to field during today's webinar. So with that I think that we are about ready to go ahead and turn control over to John Daniel.

John Daniel is the—is an Executive Consultant with ABB (unintelligible) Consulting. He's been with ABB since 1998 where he's been involved with a wide variety of projects, ranging from the development of medium voltage power electronic converters, to wind farm and HVDC substation design, to wind integration studies for developers and utilities, and most recently has been the principle investigator for DOE's National Offshore Wind Energy Interconnection Study.

So with that, John you have the control, and please move forward.

John Daniel: Great, thank you Charlton. And welcome to everyone. So today I'll talk very briefly, provide an overview of the results from the NOWEGIS, the study that we conducted. That was completed earlier this year, about July, and is available for folks to download and look at. We've had a very positive response from the industry and we're very pleased with that.

There we go. I'd like to acknowledge our study team partners. We brought in some expertise from various organizations to make sure that we could address

all of the areas of the study in an appropriate way, from determining wind resources, the expertise of NREL and Duke Energy, as well as support from the University of Pittsburgh.

In addition to that we had a technical review committee that was comprised of utilities, regional operators, wind industry representatives and government industries. So we had a lot of input to be able to direct the efforts of that study.

The project itself consisted of four primary tasks that included such things as the staging projections for the offshore wind, trying to get a feel for how we expected the buildout to be across the United States; the development of wind production profiles, so that we could determine what kind of resources we expected to be available offshore; and to enhance earlier studies in the databases from those earlier studies.

We also had a task to look at the types of integration analyses that are typically done onshore to see if they would be valid offshore or if there was some need to adjust the way that we did those studies because of the offshore environment.

And then we did a fairly extensive technology assessment of the different types of technologies that are available and what they're—the impact of the wind would be, including production cost changes for the utilities.

And then the—we also took a look at some of the regulatory environment to see what sort of recommendations we would make there.

Now just to highlight some of the key results.

One of the things that we noted form the study is that the U.S. does have sufficient offshore resources for at least 54 gigawatts of offshore wind. We're not saying that 54 is all that we can do. This was a target that was selected for the study based on earlier studies, specifically the 20% wind energy by 2030 report that was previously performed by NREL for DOE.

The study methods that are used for terrestrial wind integration are definitely appropriate for offshore wind. We didn't see any need to make any changes in those study methods.

The technologies that are currently existing are generally adequate for large scale offshore wind integration. So there's nothing holding us back there.

We found that at a regional and national level, offshore wind may provide significant value from the standpoint of reduced production costs.

And then, it's necessary for appropriate—to have appropriate state and federal policies and permitting processes to make sure that offshore wind reaches its potential here in the United States.

Digging into that—oh, and then of course, research and development shows promise for reducing the initial capital investment. And so there's still future work to be done that can make this easier for us to do in the U.S. and across the world.

Digging into some of those results in a little more detail.

With the 54 gigawatts of offshore wind, up in the upper left you can see that the northeast area and off the West Coast, the Great Lakes and parts of Texas

tend to have quite significant net capacity factors, good offshore wind resources to be able to utilize.

Based on the information that we have there for the study, we selected 209 low-cost energy sites to arrive at our 54 gigawatts that we used to—that we investigated during this study. And we saw the primary buildout occurring along the East Coast, starting up in the Northeast around New England and then coming down towards the Carolinas as time progressed.

Now with regard to the technologies we looked at a wide variety of the technologies that have been used around the world and that are available; we looked at AC versus DC transmission from the offshore, to bring that onshore; we looked at a number of the cable types and what made sense there; some of the platforms and the availabilities that were there.

Now one of the things in the process of reviewing these technologies that I think became quite important is that we saw that there were some onshore benefits to the power grid that can result with proper selection and combinations of the technologies. You can actually relieve some of the congestion that is existing onshore by properly selecting the offshore technology and using that to control where it's injected into the grid.

The production cost assessment is—has been one of the results that has received the most interest and attention from this study. Basically what we did is created a model of the entire United States, taking a look at the fuel sources, the types of generation, some of the congestion areas and calculated what the expected production cost was for an entire year, with and without offshore wind and with a variety of sensitivities on gas prices and the level of offshore wind that was installed.

The key finding I think is that you basically have about $41 per megawatt hour of savings of—with 54 gigawatts of offshore wind. And that can vary depending on how much penetration there is and what the penalties are, say for co2 production, with the natural gas and the coal plants, and also depending on the gas prices in the different areas.

What we found that was particularly interesting and intriguing was that the production costs dropped across the entire country. As you brought in the offshore wind in the Northeast up in the New England area, that offshore wind offset the demand the—for import of energy from the Midwest. So you also shifted the power flows that were taking place in the Midwest.

We saw reduced transmission line losses. And then the Midwest was then supplying their own demands locally there, and the entire price across the country tended to drop somewhere, though it was most significant up close to the offshore wind installations.

Now when we looked at the regulatory environment there were a few items that we highlighted. It's important that state policies recognize the energy, environmental and economic benefits of the offshore wind in order encourage investment, rather than just simply looking at the initial investment costs. It ought to be looked at in a—with a broader view, and take into account all of the potential savings and benefits to society.

Reductions in the federal permitting and siting processes are also critical to achieving the gigawatt scale offshore winds. The policies that the federal government puts in place can either hamper or encourage development. So those ought to be looked at carefully to make sure that we're doing what we can to bets encourage offshore wind development.

And then current organizational structures in the United States may make it somewhat difficult to obtain the levels of offshore wind that we're looking at. And part of that is—what we mean by that is that the regional entities, the ISOs, the RTOs, that the utilities themselves need to find a way to be able to share the benefits across the entities.

The—it's—a large portion of the benefits tend to accrue in one area and may make it less attractive for others to also support that overall benefit to the entire nation unless there can—a way can be found to share the benefits that accrue from the offshore wind.

So that's a very quick rundown of the overview for what we saw and what is in the report. If you're interested in the report it can be found here at this website. And if you would like to contact me, here's my contact information. So, thank you.

Charlton Clark: Wonderful, thank you very much John. Once again, if anybody has any questions please go ahead and post them into the Q&A section on the webinar and we'll address questions at the very end.

So now if we can go ahead and turn over control to Dr. Ken Loparo, who is an Assistant—who was an Assistant Professor in the Mechanical Engineering Department at Cleveland State University from 1977 to 1979. He's been on the faculty of the Case Western School of Engineering at Case Western Reserve University since 1979.

He's a Nord Professor of Engineering in the Department of Electrical Engineering and Computer Science and holds academic appointments in the Departments of Biomedical Engineering, Mechanical and Aerospace Engineering at the Case School of Engineering. Dr. Loparo is a Fellow of the

IEEE and has held numerous positions in the IEEE Control Systems Society, in fact quite a few different activities through there.

So with that we'll go ahead and turn things over to Dr. Loparo to talk about the Great Lakes Offshore Wind, Utility and Regional Integration Study. Ken?

Dr. Ken Loparo: Thank you Charlton. Tessa, I guess you have control, so let's move on to Slide 2.

So this is just sort of a summary of our project. As Charlton mentioned it's entitled The Great Lakes Offshore Wind, Utility and Regional Integration Study. And the partners were First Energy, GE, NREL and PJM. And the objective, or the technical questions that we were addressing at part of this study were looking at the planning needs that would be related to the integration of large-scale offshore wind into a utility service area.

In particular we were interested in the impact that that offshore wind might have on the requirement of transmission system upgrades that would be needed to, in order to facilitate the capture—the delivery of captured wind from the offshore site to onshore.

We were interested in both what happens in steady state operation as well as dynamic operations, in particular what the impact in the steady state operations would be of the offshore wind as it related to congestions, line overloading, as well as voltage deviations, both above and below the 5% limits that one would like to have on the voltage profiles.

On the dynamic stability side, which is work that is currently ongoing, we were interested in, "What is the impact of offshore wind variability and fluctuations on what might happen to both power angles, frequency and

voltage dynamically when you—when it's perturbed about a steady state operating condition?"

IN particular, the case study that we did in Years 1 and 2 of the study were looking at First Energy as the service territory. And during early parts of the project we worked directly with First Energy and PJM in determining the scenarios that would be considered for the steady state and dynamic analysis.

In the steady state analysis that I will talk about today, since the dynamic stability analysis is still ongoing, I'll talk about a 2015 heavy load case that was projected by PJM, and that was the baseline study both without wind and within for the steady state analysis.

And then in the sort of remaining year of the project, which will begin in January of 2015, the study will actually be involved in, "How do we take the lessons that were learned from the first energy study and actually make them into general guidelines for offshore wind projects?" So next slide please.

The next slide just sort of gives a brief glimpse of what the First Energy Service territory or area looks like. There's more than 8000 megawatts of installed generation capacity within that footprint. And the transmission system in this region has been heavily loaded in the past. It is not as heavily loaded currently. Next slide please.

We were looking at 1000 megawatts of offshore wind in Lake Erie and NREL did a study on wind capture in Lake Erie and "What would the sort of 10 minute deltas be if we looked at their percent expectation," which you can see sort of in the left most column, and then looking at the frequency of the events, both the negative and positive deltas, and then the absolute deltas that were evaluated.

And that chart is actually being used in the dynamic stability studies in order to give us some idea of what deltas in wind variation we want to be able to use, what kind of disturbances and perturbations might we expect that will perturb steady state operating conditions in this scenario. Next slide please.

So one of the things that was important, since we wanted to create a very detailed simulation model of 1000 megawatts of offshore wind in Lake Erie and how it would actually connect to the First Energy service territory was to figure out where we might site a 1000 megawatt Lake Erie wind plant.

And in the table to the right you'll see the graphic on the left illustrates where one might bring that power onshore on the coast line of Lake Erie, and the table on the right shows where—the distance between where the wind farm would be located to the onshore points of interconnection. Next slide please.

So we looked at—finally we had about seven or eight interconnection scenarios that we started with, we settled on three interconnection scenarios to look at for both steady state and dynamic operation. And those are labeled EC01, EC02 and EC03.

EC01 looked at interconnecting 1000 megawatts of offshore wind at the 345 kV substation that's located at Perry, which is the largest generating capacity plant within the First Energy service territory.

EC02, where we looked at splitting that 1000 megawatts to 200 megawatts each at five substations; one at Avon Lake at 345 kV, one at Lake Shore at 138 kV, and then one at East Lake Perry and Ashtabula, each at 345 kV.

I should say that this study, when we undertook this study, a number of plants along the Lake Erie shoreline were actually closed or decommissioned by First Energy. And the plants that were decommissioned were taken out of the model in order to do the analysis that I'll present in a minute or two.

And then the third interconnection scenario was looking at splitting the 1000 megawatts into two 500 megawatt inputs; one at the 345 kV substation at Avon Lake and the other at the 138 kV station at Avon Lake. Next slide please.

So the steady state scenarios, and I won't go through these in any detail, you can certainly be able to see these in excruciating detail when the presentation is available for you to download, but they included both Perry being on and off in terms of its generating capacity into the First Energy service territory.

We looked at various kinds of reactive support and voltage regulation that would be available both offshore and onshore and we looked at a total of 36 steady state analysis scenarios for each point of interconnection and then looked at evaluating the impact that each of those scenarios had on the overall ability of the—to maintain let's say voltage and voltage support and line loading and congestion limits within the First Energy transmission system. Next slide please.

So the first thing was in terms of modeling and simulation. So we wanted to create a fairly robust system model. We used PSLF, the GE software, to do all of the modeling.

The system in the steady state analysis actually had about 65,000 buses that were modeled. And the diagram just sort of gives you a sort of rough idea of what we did from the offshore wind generation to the collection system, to the

offshore platform, the export cables that brought the power to the onshore substation, and then how that onshore substation interconnected into the First Energy network. Next slide please.

So the first thing was to look at, for each of the cases, and this is kind of sort of—I guess it's an eye chart to look at for each of the 36 cases that we were interested in, what actually were the range of voltages that one saw across the First Energy transmission system in each of the interconnection studies.

So one thing that you notice right away, that the dotted red lines are actually the +/-5% deviations about the standard limits of voltage that are placed at each of the voltage buses.

And what you notice here is that EC01 and EC02 actually have voltages well within the +/-5% range, but you notice in EC02, that's the place where we split the 1000 megawatts into 200 megawatts each and bring that in from offshore to onshore, that you notice that there are a number of cases where you get absolute voltages that are outside of the range that is actually prescribed.

The interesting thing is that you see for the most part that all of the violations relative to the +/-5% limit are over-voltages and not under-voltages. Next slide please.

The next slide looks at voltages, again within the First Energy transmission system, and because we had no voltage violations in either the EC01 or EC02 interconnection scenarios, this just presents what happened in EC02. And these were voltage violations that occurred within the transmission system and the cases in which they occurred, you will see on the bottom, the case numbers.

And then you will also notice there that actually these are essentially the number of lines that were violating the criteria. And the colors denote what the offshore wind was generation that was impacting the First Energy service territory were, from 1000 megawatts all the way down to 640 megawatts. Next slide please.

Charlton Clark: Ken just a quick note, that's the 10 minute mark, so if you can try to wrap up in the next couple minutes.

Dr. Ken Loparo: Okay I will. So the next couple of slides sort of summarize voltages in the offshore system, again over all of the interconnection studies. Next slide please Tessa.

This slide deals with loading in the First Energy transmission system and the, sort of the dotted green line just indicates the baseline. And so you notice that in most of the cases the loading is well below what we had in the baseline operation.

Next slide please Tessa, just sort of shows that for EC02. And the next slide please Tessa, shows the same thing for EC03. If we can just sort of move on to the final slide, which is Slide 18 Tessa.

Conclusions and Future Work.

We noticed that the dominant impact on voltage regulation is related to the geographical location of the points of interconnection; it's very, very important. The reactive power support capability of both the machines installed offshore and the SVCs that are present, potentially at the points of interconnection, are very, very important for voltage regulation.

Finally I'll just sort of say where we are right now. We're looking at small signal dynamic analysis for both voltage and frequency, that's ongoing and should be completed by the end of December this year. Okay, thank you.

Charlton Clark: Very nice, thank you very much Ken.

Dr. Ken Loparo: Sure.

Charlton Clark: So with that I think we'll go ahead and turn control over to Dr. Willett Kempton, who is a Professor at the University of Delaware's School of Marine Science and Policy within the College of Earth, Ocean and Environment. Dr. Kempton is the Research Director for University of Delaware's Center for Carbon Free Power Integration.

Dr. Kempton is a national renowned expert in two renewable energy fields; offshore wind power and electric vehicles. Dr. Kempton researches—has conducted considerable research in offshore wind turbines as a source of energy.

Focus includes the viability and efficiency of offshore wind farms, as well as gauging public support and public opposition. He's widely quoted by news outlets on proposed East Coast offshore wind farms, off the coast of Delaware and Cape Cod amongst other locals. So with that, Dr. Kempton?

Dr. Willett Kempton: Thanks for that introduction, it sounds like that came from a public relations department. I'm also—I have an appointment in electrical engineering. So this is transmission and integration into PJM. So it's drawing with—from my co-PIs on the project, who are listed on the cover there.

So we didn't start with a 20% goal or whatever, we started with what's the resource adjacent to PJM. Sometimes we'll talk about this as the PJM ocean, which is a very non-official designation. But this is a resource that is contiguous with PJM interconnect territory.

So we started with a detailed look at that resource, eliminating conflicting uses, shipping lanes, bird flyways, areas close to shore and so forth, then mapping the resource there. And then looking at it, just arbitrarily dividing into a series of five build levels, the first of which are the BOEM wind energy area, so that actually has an official designation. But then we just went out to what the actual resource is.

So we'll—I'll talk about Buildout Levels 1 through 5 with installed capacity of up to 69 gigawatts, that's assuming no deeper than 60 meters of water depth and a 10x10d spacing of turbines. So if you can go deeper or are willing to go closer, you could increase those numbers. But at the highest buildout level we're covering 42% of PJM load. We assumed here a 5 megawatt machine, but that doesn't make much difference.

So the objectives of this study were to look at offshore wind penetration that are consistent with DOE targets. Actually we're going beyond those, and then with the resource sought. So we're trying to be realistic with exclusions of conflict in uses and so forth.

We also compared radial connection with HBBC Network, which was mentioned in John Daniel's presentation also. We do a high resolution examination of power fluctuations at each node. That is ten minutes being higher time resolution.

And we looked at the wind resource with a WRF Model, Weather, Research and Forecasting Model, so if you have 90 meter wind speeds at each of the wind farm areas that are in this hypothetical build out.

The point here is to understand the connection to PJM and the ability of PJM to absorb these sort of large builds. And so to do that we used a model which combined unit commitment as well as power flow, which was developed by Princeton University. And that is, rather than using a commercial model, we're using something that is, you know, source codes acceptable and so forth.

We also used prior PJM forecasts on land wind farms so we could understand the forecasting errors which affects the requirements for reserves and so forth.

Okay so this is long-term thinking, it's not sort of what the volume areas are, but it's the total resource and with the total capability here is around 77 gigawatts. And we can kind of bottom line the conclusion here, "How much can we integrate with today's power management and PJM?" We think that number is greater than 36 gigawatts. That is without making changes in how PJM manages their system. If we have perfect forecasts, which is a limit case, we could do that—double that just about, so 70 gigawatts. So if you preview here is that forecast is very important.

So trying to speed up here to not run out of time. This is a quick look at our, you know, exclusion analysis, what areas we're not building wind farms in. Challenges here are that there no good measured data over the ocean, we've got the buoys out there, which are 5 or 10 meters. They're pretty sparse.

There's no real 90 meter wind speeds that we can pair against WRF Model, that we generated synthetic actuals and then we took a plausible error forecast—sorry, plausible error of the model, error between real and models

based on all the wind farms that are in PJM now, and all the forecasts that are used for those. So we have a real error analysis, we have a forecast from WRF and then we generated actuals from that. If that makes sense.

The problem of course with unit commitment is you have to—you have ramp time and you have to commit generators ahead of time. The wind may change unpredictably so that you have too few or too many generators online and in production.

I'm going to just move this. (Unintelligible).

Okay, and as I mentioned we used buoys and towers that are available, even though they're not at 90 meters. We use that to synch up the WRF Model. And as I said before, we use the errors at PJM's current site.

So what we're looking at is the existing on land wind farms and the forecasts associated with them, as well as the actual output. And then we're projecting to an offshore buildout. There we're just showing the centroids of the various areas that were in our full build.

So we had to look at, carefully, at our errors and what the forecast errors were in a realistic, commercial forecasting model and then apply that to the offshore data. So looking to buildout 4 and 5, the higher levels with capacity of 48—or 49 and 70 gigawatts.

The amount of wind that is available that is generated versus how much we could use due to consistent constraints. You can see that as we get—as we build more wind, as we go to higher levels, we're able to use the smaller percentage of it. The ramping reserves that we necessary go up as we go to

higher levels, but if we have perfect forecast, we've got a dramatic reduction in how much ramping reserves are needed.

We also have, you know, we gotten to demand shortage, in other words, given the current operation of the system we would not be able to meet load sometimes. So we have that also with current forecast, but not if forecasts are extremely accurate.

So we're also measuring power—modeling power flow. I'm going to skip a little bit faster here. We're using our DC bottle for approximation and then checking sporadically with the A Team Model. There's—this is showing thicker lines for more power flow. And I'm going to ask Tessa if you could run the animation quickly, which is a separate movie file just to show the real time operation of the model.

The circles are generation. It's not coming up, but I'll give you the (unintelligible) yes. So the circles are generation, you can see the size of the offshore generation in green there. Quite significant compared to the generation of the rest of the PJM system, and also obviously fluctuating.

So then as the generation changes in different location we have power lines that are at higher or lower capacity. So this is just kind of quick snapshot of the dynamics of the system. When the power lines go to red we are overloaded. Looks like this one section we're not overloaded. So could you go, Tessa, to the slides—next slide?

So yes. So here we had—this is an example of forecasted offshore wind. That's the worst model. And then we used the errors of the land-based wind farms to say, "What's our actual winds that hour?" Sort of backwards, but it gives us a good test of unit commitment on the PJM system.

So you see all those little lines, (SIM 1) through (SIM 7) are things that might actually happen given that our forecast is the dark line. And it's when the, "Actual" wind is very different. That's when we have problems with the use method.

I am pushing the Down arrow and not getting an advance. Okay, sorry.

So under the conditions of uncertainty, standard PJM in reserves, high penetration of wind, we have a number of times where we would have a shortfall or excess. We would have a system problem, those are circled here.

If we actually have high certainty of what the wind is going to be, then we eliminate in this one sample case here, all of those. Which means you are using—to do that you are using less steam and more gas due to the faster ramping.

Also the grid constraints here, if we have AC radials going from each wind farm to points of interconnection versus an HVDC backload where we have a multi-terminal system where you can direct power to your points of interconnection rather than just going with AC flow. We're able to use a large fraction of available wind.

So the blue line, you go to higher buildout levels. We do have an inability to use all the wind at the really high levels, but at each of those levels we can use more of it if we have an HVDC backload rather than on a wind farm to a point of interconnection. This is showing Buildout Levels 1,2 and 3 represented here.

If we do not have a grid constraint, that is, we build as much transition as needed to use all the power, then we're able to go up to the full Buildout Level 5. And again, with perfect forecasts, we have very little need for ramping reserves. With, you know, kind of current forecast we have actually quite a bit need for ramping reserves 14 gigawatts. So you can see in this graph the incredibly high value of better wind forecasting.

So in conclusion, we looked at developable offshores for areas for wind development, created a (unintelligible) model of the offshore wind forecasting error using existing PJM wind farms and existing commercial forecasts that they're getting for their on land wind farms.

Developed this model by Princeton University, it's called the SMART-ISO Model. It simulates the grid. And by using that analysis we're able to look an constrained versus unconstrained grid of perfect forecasts, you know, versus you know, current imperfect forecasts. And then the amount of reserve needed under these different scenarios. We also have not completed this, but we compare use of HV and DC in terms of losses offshore.

So that's the presentation. I didn't—I don't think we had a slide, but I will mention our partners here, Princeton University, PJM Interconnection, the Atlantic Wind Connection and Sailor's Energy, which provided the wind forecasting models. Thank you.

Charlton Clark: All right, thank you very much Dr. Kempton. Very interesting work so far. So now we'll go ahead and move on to our last, but definitely not least, presentation by Robert Burner, who is the Director of Commercial Transmission Development with Duke Energy Corporation.

Bob is the—is an electric utility expert with expertise in both regulated and merchant electric power industry related to transmission planning, system operation, energy marketing and the interconnection of local and regional transmission networks.

He has managed activities related to the interconnect and operation of over 10,000 megawatts of merchant generation across various NERC regions in the U.S., and has an in-depth understanding of the behavior and operation of large scale interconnected power systems and RTO, or Regional Transmission Organization.

So with that we'll turn it over to Bob.

Woman: Bob are you on mute?

Coordinator: It does look like Bob's line has disconnected. I'll see if he has dialed back in. One moment.

Charlton Clark: Okay. Well hang on. Sorry folks. We'll take just a minute and see if we can shoot an email over to Bob to make sure that he's aware that his audio is disconnected.

Coordinator: Bob rejoins conference.

Robert Burner: Hello, can you hear me?

Charlton Clark: There, now we've got Bob on. All right.

Robert Burner: I called (unintelligible).

Charlton Clark: Sorry, I guess we accidentally lost you there for a minute. So I've already gone through and given your bio background.

Robert Burner: Yes I heard you (unintelligible).

Charlton Clark: So with that, we'll turn it over to you.

Robert Burner: Let me get started here.

All right good, there's control. Let me first acknowledge the partners and the collaborators on this, which were our usual cast of characters, ABB, AWS Truepower, NREL and UNC Chapel Hill, and our Carolina Offshore Wind Integration Study, COWICS for short.

Objective was at three different offshore generation levels to evaluate the impact from an electric utility perspective. This particular study has a very heavy emphasis on the impacts to the electric utility system.

The project was defined by six tasks, as you can see there. And before we go to these, Task 1, the site selection as mentioned in the previous reports, the site selection was based on, in ours on COWICS, on 26 different criteria. So relatively extensive criteria. I don't know if it's readable to you, but those were the imports to determine the site selection.

And then moving back, the site selection, if you can see the offshore locations, this is for the 1000 megawatt scenario. And the little dots up by the Outer Banks of North Carolina are the locations—the offshore wind turbine locations. There's a few more down by Pamlico Bay.

As I forward to the 3000 megawatt scenario you can see more location, what we called, the North and South Zones—I'm sorry, North and Central. And now some locations are starting to show up on this South Zone. Here's the 5600 megawatts scenario and you can see the—kind of the nature selection of these turbine sites.

The University of North Carolina and National Renewable Energy Laboratories provided the list of the 26 exclusion criteria. Visual impact from shore was not one of those criteria. The siting study demonstrated that there is an abundance of high quality development areas offshore North and South Carolina at relatively depths, sufficiently to meet the DOE study target.

A variety of factors were considered including the wind resource and predicted plant output, distance to potential interconnection points and proximity to sensitive of protected areas.

The GIS based approach to site screening is designed to ensure that all quantifiable factors affecting a site's suitability are considered in a systematic fashion. And appropriate offshore plant size or range of sizes, and distance between wind farms to minimize the impact of wakes was considered.

As you can see, three distinct zones emerged from the selection exclusion criteria in the siting model. We refer to those as simply North, Central, South Zones.

The Northern Zone is near Northern Carolina and near the Virginia border. And Central Zone is your North Carolina Outer Banks. And the Southern Zone is near Myrtle Beach.

ABB analysis with sliding data recommended that a combination of AC and DC connections from offshore collector stations to onshore interconnection substations would be appropriate given the diversity of distance from the offshore collector platforms to the onshore substations. And also the breadth of the wind turbine lighting fields.

AC connections were recommended for shorter distances with the inherent advantage of lower cost, but limited current carrying capability due to capacitive charging current. DC connections were recommended over longer distances with the advantage of reduced losses, but higher convertor terminal costs.

The recommended connections change for each generation scenario in all three zones, and in general what you may see from the picture, the lighter blue offshore is the 30 Meter or Less depth, the darker reds represent the higher wind qualities, wind speeds for the site selection.

Second task was the capacity and energy profile analysis. The chosen sites were evaluated to determine the amount of capacity that could feasibly be developed. There were ten minute energy output profiles used for the time period from 1999 to 2008.

A composite turbine power curve was used with those characteristics. Validation was performed for the available measurement stations from NOAA, the National Data Buoy Center. And because of the relatively small difference between year, relatively large difference between months, the Year 2000 was selected.

And the other condition, was again from a utility perspective, high peak—peak load differences between summer/winter peaks and offshore periods of

fall/spring. And the table is just the capacities and the actual energy outputs, or the three scenarios in the three zones.

The third task was an interconnection and deliverability study that was based on the NERC (unintelligible) power flow models representing 2018, 2021. As I mentioned, the three scenarios, 1000, 3000 and 5600 megawatt offshore nameplate capacity was studied.

Offshore collector stations were interconnected from the three zones, and it varied whether it was an AC or DC connection primarily based on distance, that is 50 miles with the rough bogey we used to determine whether it should be AC/DC. And the network upgrades were measured at the interconnection point onshore.

The results of the interconnection study were actually minimal upgrades were required even for this level of offshore wind generation. I think primarily due to the fact that we were—the location offshore was kind of a counter flow to the normal North Carolina power flows, that is West to East and also I think it's a demonstration of the robustness of the electrical system in the Carolinas.

Here are—we're trying to represent where the onshore connections are, offshore to onshore. In the Northern Zone for the 1000 megawatt scenario it was an AC connection into the Kitty Hawk area. In the Central Zone it's projected to go through Pamlico Bay, and due to the distance, that was recommended to be a DC connection. In the 1000 megawatt scenario there were no sites in the South.

Three thousand megawatt scenario, the North connection has not changed. Central Zone we know—Central Zone now kind of separates itself naturally into two parts. Still the connection through Pamlico Bay, but due to the

location of the turbines for 3000 megawatts, there's a second Central Zone connection. And now you also see an onshore connection in the South, in the Bucksville area.

Fifty-six hundred megawatt scenario, what I would not here is not only in the North Zone that connection to the Outer Banks is no longer sufficient to connect that amount of capacity, so it's projected to connected to the offshore PJM DC bus.

Central Zone, let's see, Central Zone connection has changed from Bayboro to New Bern. And the Southern Zone connection has changed to a DC from an AC connection, again due to the increased capacity that's being connected.

Task 4 was dynamic stability and the simple result is that—or NERC, what used to be Categories A and B is now TPL P0-P1 Standards, no instability was noted in our dynamic stability testing.

Operating reliability impacts, the capacity reserves is another way of saying, "Given the amount of nameplate capacity how much would be credited in a capacity market such as PJM?" And based on the measurement and the energy output if was roughly translated to be about 39% capacity credit.

Contingency reserves, the redundant connections in the Central Zone and the North Zone, the North Zone was actually kind of a forced second connection. Reason being for single contingency testing the criteria in the Carolinas presently limits the maximum outage to about 1300 megawatts. And in order to respect that a second connection was recommended.

Regulating reserves increase slightly from the existing reserve requirement. We have a frequency response, it was—the wind was deemed capable of

contributing inertial reserve and primary frequency response. But to do so, you just operated less than a full nameplate capacity.

And the final task, production cost analysis, which is still in progress, you can see the results. The production cost and second column is production cost savings due to wind.

The graphic at the bottom shows you the wind output, how it displaces coal. And there actually is—we have pump storage on the Carolina system. It actually affords a bit greater pump storage operation due to the wind resource. And I will stop there. Thank you.

Charlton Clark: All right. Thank you very much Bob. Once again, a very interesting presentation and look forward to the completion of this and the other studies that are still being worked on.

So technically I think we've reached right at the 4:00 o'clock hour. So hopefully folks are able to hang on for a few more minutes. We do have a few questions that we posted into the Q&A session.

So at this point I think I'm going to try to go back and I'll read out the question, and if it's directed at any specific speaker please go ahead and field the response.

So let's see here. One for John. "How did you value the production cost savings in vertically integrated markets like the Southeast where there are not the same market bidding mechanisms as you have an organized ISO and RTO markets?"

John Daniel: Yes. The—in considering what we did in NOWEGIS it's important to draw a clarification between how we saw the potential for say locational market pricing dropping, and that kind of situation versus the production costs that we did.

What we were actually looking at were production costs which were based on fuel rates, fuel prices, the amount of energy that needed to be generated in order to meet the load demands throughout the year.

So what we did was in every—and every NERC was calculated independently and/or we broke it down into the NERC regions. And we first started with a base case with no wind so that we knew what our baseline was, of what the production costs of that energy would be. Then when we added the offshore wind, the savings that we've highlighted in the report is the differential, the drop of the production costs.

Now that doesn't mean that those production costs will necessarily translate into spot price changes. The utilities have different ways of how they might have to deal with those changes in their lower production costs. And so I want to draw that distinction between production costs and what folks often think about as the market pricing.

Charlton Clark: All right. Thanks John, I think that definitely at least answered the question in my mind. So a quick note, if anybody does have any other burning questions we've got a few other ones that are lined up, but if you do have anything else that you want clarified, go ahead and submit those questions now.

So I'm going to put a little bit of a caveat out before I read the next question, just clarifying the fact that any of the views expressed by the presenters

represent the presenters themselves and do not necessarily represent the views of the Department of Energy.

So as you can guess, this might be viewed as somewhat of a controversial question coming up. "What are the specific reductions in federal permitting and siting processes identified in the NOWEGIS Study that are critical in achieving a gigawatt scale offshore winds deployment?"

So John I guess that one is right back at you again.

John Daniel: Well I appreciate the two questions. This one I'm going to have to punt on. I am not—the details of the regulatory aspects of it that were pulled out of it I can't speak to in as intelligent of a way as my colleague, Spencer Haynes over at Duke Energy. He's well-versed in these types of things. And I apologize, but I'm not able to elaborate on the details of that very well. I could make...

Charlton Clark: I guess that just means that our questioner will probably have to go dig out the study and enjoy all of the wonderful—rest of the information that's buried in there.

Willett Kempton: I could take a shot (unintelligible).

Charlton Clark: Okay sure.

Willett Kempton: This is Willett Kempton. So we have a policy group, offshore wind policy group here. Short answer, "We've got two separate consenting processes, as it would be called in Europe. One is for ocean space and the other for off take. That is sale of the electricity." This is very difficult in multiple ways.

If those two could be bundled together so that the potential developer could secure access to the area, and a power contract at the same time, it would be much easier to invest. Otherwise you're looking at, as we've seen in a couple of places already, you're putting you know, $5 to $10-12 million down on some ocean space without knowing whether or not you can sell electricity or at what price. So that would be a quick answer to the question.

Charlton Clark: Okay. All right, thank you very much Dr. Kempton. And it looks like the next question that we have queued up is basically centered directly at us here at DOE. It may have been somewhat have been tweaked a bit by the last presentation, which was looking at Duke Energy Carolina service territory. But the question was related to any thoughts on designing a meaningful interconnection study outside of an organized market?

As we saw the last presentation was basically centered outside any of the organized markets. But just to kind of elaborate a little bit more on this, because of the fact that each of these studies was the product of a funding opportunity announcement, which is basically an open solicitation, we're somewhat limited in any of these selection by the number of applicants that applied to the funding opportunity that we had out.

Though we do sometimes do fund studies directly internally, typically led through our national laboratories where we do have a little bit more oversight and control over various studies. For this particular set of studies, you know, we were kind of limited to what various applicants suggested that they wanted to try to look at.

But definitely appreciate the question and it is something that we are keeping in mind going forward as we craft additional sets of interconnection and integration studies on other areas that we might want to look at.

So we have run a few minutes over, past the 4:00 o'clock hour, but it looks like we haven't had any other questions added in. So with that I'm going to go ahead and thank everybody for taking to the time to listen in. Hopefully you got some great information.

You know, so far we only have one of the studies that's been fully completed and is available, but we hope that you guys keep an eye out for the final results of the rest of these studies. And with that, we're going to sign off. Thank you very much.

Coordinator: That concludes today's conference. Thank you for participating. You may disconnect at this time.