BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

COLUMBIA, SOUTH CAROLINA

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ALLOWABLE EX PARTE PROCEEDING
FUNDAMENTALS OF ELECTRICITY REGULATION IN SOUTH CAROLINA

TRANSCRIPT OF PROCEEDINGS

PARTICIPANTS IN ATTENDANCE:

COMMISSIONERS: John E. 'Butch' HOWARD, *CHAIRMAN,* David A. WRIGHT, *VICE CHAIRMAN*; and COMMISSIONERS Elizabeth B. 'Lib' FLEMING, G. O'Neal HAMILTON, Randy MITCHELL, and Swain E. WHITFIELD, and Nikiya 'Nikki' HALL

PUBLIC UTILITIES REVIEW COMMITTEE: STAFF MEMBERS Nancy Coombs, Esq., Heather Anderson, Esq., and Andy Fiffick, Esq. Also, Joel Deason, Esq., on behalf of the Office of Sen. Thomas C. Alexander

PSC STAFF: Jocelyn B. Boyd, Chief Clerk/Administrator; Joseph Melchers, Chief Counsel; James Spearman, Ph.D., Executive Assistant to the Commissioners; B. Randall Dong, Esq., and Josh Minges, Esq., Legal Staff; Tom Ellison and Lynn Ballentine, Advisory Staff; Jo Elizabeth M. Wheat, CVR-CM-GNSC, Court Reporter; and Deborah Easterling, Patty Sands, and William O. Richardson, Assistants

OFFICE OF REGULATORY STAFF: Nanette S. Edwards, Esquire

PRESENTERS: Belton T. Zeigler, Esquire; Joseph K. Todd and W. Keller Kissam [SCE&G]; Lloyd M. Yates [Progress Energy Carolinas]; Robert McMurry [Duke Energy Carolinas]; Charles A. White [SCE&G]; Kendal Bowman, Esquire [Progress Energy Carolinas]; Ed Ernst [Duke Energy Carolinas]

I N D E X

PAGE

Please note: PowerPoint presentations (electronic and hard copy versions) are attached hereto.

P R O C E E D I N G S

PSC CHIEF CLERK MS. BOYD: Good morning. On behalf of the Public Service Commission, thank you for taking time out of your busy schedule to attend today's workshop.

First I'd like to acknowledge the presence of some individuals: The staff of the Public Utilities Review Committee, Nancy Coombs and Heather Anderson, in addition to Joel Deason, who is with Senator Alexander's office. He's the director of Research. I'd also like to acknowledge the presence of our Commissioners, including our chairman, Chairman Howard, Vice Chairman Wright, Commissioner Hamilton, Commissioner Fleming, Commissioner Mitchell, Commissioner Hall, and Commissioner Whitfield; and also Commission staff, Josh Minges, Joseph Melchers, Jim Spearman, Randall Dong, Lynn Ballentine, and Tom Ellison.

One of our former directors is present -- Gary Walsh -- and I understand Charlie Terreni is supposed to attend, also. And I also want to acknowledge the presence of the Office of Regulatory Staff Director Dukes Scott. I think he's here.

Next, I'd like to brag a little about an

important group that evolved at the PSC after the implementation of Act 175. This group has been instrumental in helping to shape the reform of the PSC. Prior to his departure, Charlie and I relied heavily on this group for their knowledge and foresight. So to whom am I referring? I'm speaking of the PSC's Advisory Committee. The Advisory Committee consists of attorneys who represent entities from our investor-owned utilities, to large businesses like Nucor Steel, to large industrial users like South Carolina Energy Users Committee. The Advisory Committee also consists of other professionals who represent rural telephone companies and, of course, includes attorneys from the Office of Regulatory Staff and its director, Mr. Dukes Scott.

So what's so special about today? I'd like to share a short story with you about how today's workshop came about. Shortly after Charlie's departure, we knew it was time to schedule another Advisory Committee meeting, so I sent an e-mail to all of our members, and on April 16, 2010, we held a meeting. Several of our members could not make it, so we were few -- very few -- in number. And I remember stating to the members who were present

that day, however, I said I was confident, although we were few in number, that we were going to accomplish a lot and we needed to forge ahead. About an hour into the meeting we talked about petitions to intervene and letters of protest for about an hour, and then I said, "Well, let's try to transition to another subject," and I asked the representatives there to brace themselves in their chairs because I wanted to discuss an idea with them and I really needed their feedback. They listened patiently as I presented the idea of holding an interactive, diverse, educational/emerging issues workshop, with volunteer presenters from utilities, the Office of Regulatory Staff, and any other representative from a committee -- from an entity, rather, who's represented on the Advisory Committee. I stressed these workshops would not be lectures, but should be a dialogue between the presenters, our Commissioners, our staff, and the Public Utilities Review Committee if they chose to participate. I gave everyone present an opportunity to sign up to participate on several committees. one of which was the Electric & Gas Educational/Emerging Issues Committee.

We discussed this concept further, and I have to be honest with you, if any of the members thought it was a horrible idea, not once did they share it with me.

[Laughter]

I want you to know that since that day they have worked diligently to take a concept and shape and mold it into the comprehensive and substantive agenda that is presented today. We also received vital -- and I must stress "vital" -- input from our Commissioners and from the Public Utilities Review Committee staff.

I know we've all heard the saying "You have to start somewhere." That's how I feel about today. I hope that you will not only listen to the presenters today but also engage in a conversation, a dialogue. If you have any question, please ask. And if you are fully versed on the topics that are on the agenda today, I encourage you to ask questions anyway. Maybe someone else in the room can learn what you know. After all, won't we all, including the citizens of the State of South Carolina, be better off for it.

Now we're going to move forward with our agenda with our first presentation by Belton

Zeigler. Mr. Zeigler is a managing member of Pope Zeigler, LLC, and head of its regulatory and utility practice. Mr. Zeigler is a graduate of Amherst College and University of South Carolina School of Law. He has served as General Counsel to South Carolina Electric & Gas and vice president for Industrial Customer Operations of that company. Mr. Zeigler has represented South Carolina Electric & Gas in seven gas and electric rate cases and numerous other smaller proceedings. He has been certified as a transmission systems operator by the National Electric Reliability Corporation and advises a number of publicly owned water and sewer utilities in contractual and rate matters. He also serves as chancellor, or principal legal advisor, to the Episcopal Diocese of Upper South Carolina.

Belton, we want to welcome you.

MR. ZEIGLER: Jocelyn, thank you so much. It's a real pleasure to be here, and an honor to be asked to start off with this. This is a great initiative.

The frustration that I think some of us have with the regulatory process at times is we're focusing so often on the small issues that are very important in a particular case and don't have the

opportunity to pull back and do what you all are doing here today, which is to look at the broader scope and to be sure that the Commission is regulating not only with the particular facts that are necessary to deal with the issue at hand, but also a broad view of the industry.

When Chad asked if I could help with this part of the process -- he was the person that Jocelyn asked to contact me -- I said, "Chad, you want me to do the history of electric regulation and the key legal concepts; that's pretty boring." He said, "Well, it won't be boring for you, because you've got 30 minutes to do it in."

[Laughter]

But I think what I can say to you all is the fact that this is going to be a short one.

I need to start by talking a little bit about the history, give you a sort of a broad overview of where South Carolina has been with electric regulation over the last 120 years, or so, since electricity has really been a part of our lives, and then I'll focus in on some of the key concepts that drives us, going forward, and I think that will help us put into context the issues that are coming here.

The first commercial use of electricity in South Carolina was for motors and street lighting. And you may ask why is that relevant to what we're talking about here today. It's because, when electric street lighting became possible in the 1870s and motors really became effective in the 1880s, entrepreneurs began taking the old street railway systems and turning them into electric street railway systems, and that was the growth of the electric grid in South Carolina. If you look at the statutes, you'll see evidence of that still in the statutes we administer. You all, the Commission, has statutory authority over electric street railways. If there ever is one again, you all are in charge of it.

[Laughter]

Why was this a big deal? Well, if you have ever stood there at the corner Anson and Pinkney Streets in Charleston, near the barn where they keep all the horses that pull those carriages on a hot summer night when the wind isn't blowing very strong, you'll know why it's important. The electric street railways replaced street railways which existed beginning in the 1860s and 1870s, which were horse-drawn. And in fact, if you look

back into history, they had to have one horse usually; with the big hills in Columbia, they had a place where they'd have to stop and put a extra horse in, so you'd have a two-horse team to get you up the hill. But it was smelly, it was dirty, it was a very poor thing for public sanitation. And so when this novel product called electricity came into being and a fellow named Nikolai Tesla created the first effective electric motor, people said, "Wow, what if we put an electric motor in these things as opposed to having these horses draw it?" And so the electric street railways were where we got started.

I spent a fair amount of my practice dealing with the SCE&G bus system, and the reason was the electric street railways evolved into the bus system; the economics changed, and there was a terrible problem by doing all that, but that's part of that history that keeps going forward there.

The electrification originally was this grid that followed those railways. And people would buy a little bit of power off that grid to, if they were really rich and were really early adapters, the kind of people who first got iPhones back in the 1880s were getting electric light bulbs and

then bringing their neighbors in, and, "Wow, what a great thing," and they would just put a line out and pay a charge to the operator of the electric street railway. The other thing, of course, was you had streetlights, and electric streetlights were a big deal. If you look back at the old streetlight contracts, they're specific that streetlights would be operated from dusk until 12 o'clock on moonless nights, so someone had to go out there and decide when the moon was out to decide when to turn those things on.

The point is that electricity was a luxury. There was no sense that it was a vital commodity at this time. And the original electric regulation was done by people who sat in the jobs that Commissioner Fleming had before she came here: municipal councils. The original way that electricity was regulated from a price standpoint was through the franchise contracts, because when you came to a town to build an electric grid as an investor, you had to get the town council to give you the right to build in the town facilities, in the streets and alleys and whatnot. And so the town would cut a deal with you: "We want..." -- really, think about the industrial development

contracts we have now -- "We want an electric street railway. We're willing to let you use the town facilities to do it. We'll give you an exclusive contract for 30 years to do it, so you won't have any competition. And we'll let you charge up to x cents a kW.

I found some data on electric prices in South Carolina in the '20s. The electric rate in the town of Trenton in 1920 was $.35 a kW. That was because they were burning oil. I think Gerebine[phonetic] -- I think it's in Ridge Spring; I may have the wrong name -- they were able to burn biomass. They were burning wood chips and that sort of thing, sawdust. They were able to go down to $.14 a kW. That's in 1920 dollars. It gives you an idea of how much of a luxury product electricity was.

So there was no sense of needing a regulatory structure to set rates. You would set a rate when the franchise was entered; there was a declining cost of service. And so what would happen would be that the utility would be able to reduce the rate below this cap that was in the franchise and, of course, they would want to do it because the more they reduced the rate, the more people wanted to

buy the service. There was lots of elasticity of demand -- I think is the term that Jim Spearman would use for it, in that context. And so, regulation was very light-handed.

Well, what happened? What happened was, there was, first of all, a political debate about who would regulate that began around the turn of the century, because, in some cases this municipal franchise thing worked and in some cases it didn't. And you begin to see for example a constitutional article that is still there and still in force that says the General Assembly can't take franchise rights away from local government; and that's been the basis of a lot of disputes between co-ops and the power companies for years, because it was seen to be such an important attribute of local government to franchise utilities that it's enshrined in the Constitution.

But at the same time, things like electric fans, electric water pumps -- think about it; without electricity, you don't really have indoor plumbing. People began investing in electric lights as their sole source of power. They got rid of the old oil lamps. People started using electricity for things that were really important

to them, and as the public developed a dependence on electric appliances, as they took out the old stuff and put in the new stuff, all of a sudden electricity wasn't a luxury anymore; it wasn't something that you could, "Well, I'll buy some, or not." It became a necessity.

And so, you begin to see, starting in 1910, a real movement to take the power to regulate electricity away from the municipalities and put it in the hands of a panel of experts who would be appointed by the General Assembly with all of the economies of scale and ability to bring expertise to bear into the process. And when the General Assembly looked around for someone to do that, they found this group called the Railroad Commission, which had been setting railroad rates, and they said, "That's who we want to do it." And they changed the name of the Railroad Commission to the Public Service Commission and put them in charge of regulation of electricity.

Now, there was a fight, as you can imagine. People had power and interests in positions, and so it wasn't like the General Assembly just one day said, "This is a great idea. Let's do it." Basically, there are 20 years of statutes between

1910 and 1932, fighting over how electric regulation ought to take place: Should it be left largely in the hands of local government or should it be brought up to the state level? At one point, the Commission had authority over municipal power systems and setting their rates; that got pulled away. The constitutional protection, though, for franchises was a big, thorny issue. You see in the '32 Act, which was sort of the last Act, an attempt to resolve it. Legally, you couldn't just do away with franchises, but they came up with this idea that you could trade an existing franchise for an indeterminate permit, and if you got an indeterminate permit your rates were subject to Commission regulation, and you had a new structure. And the statutes were created to give everyone an incentive to do that, and not to be stuck with these old franchises.

But if you look at the statutes we still operate under, you'll see this notion of franchises and indeterminate permits that the Commission cannot set a rate for electricity that's different from the rate established in a franchise contract. All that history is still in there, and that's where we came from.

So in the '30s, we established the regulatory structure that we still operate under, and in a minute I'm going to go through and talk about the legal concepts that are there. But for now let's just talk about the history and sort of paint the picture of what the landscape looked like.

In the '30s you had these street railway systems that were generating power and distributing into urban areas. You had the first sort of major central-station plants being built. They're tiny plants by today's standards, but they were coal or steam plants. You had hydro plants coming on-line. The first transmission lines, the first high voltage was coming into play. If you went to little towns around South Carolina, they would have some electricity, but it would be a 50-, 60-, 125-horsepower what they called crude-oil motor connected to a Delco generator, and they would run the thing, you know, on -- for example, I think it's -- I think it's Wagner which had electric service in the '20s from dusk until midnight, and on Tuesdays because Tuesday was ironing day and everybody wanted to use an electric iron. And that was the structure. But what happened was, the electric companies began to acquire these small

rural systems, began to consolidate these electric railways that were around the landscape, and began putting together the sort of first recognizable investor-owned electric utility companies for South Carolina. At the same time, the technology was evolving and you were putting transmission lines out there, so you were taking these Delco generators, 150-horsepower motors, out of service and connecting the towns to the grids. And the result was that prices were still headed down. There was economy of scale coming into the system.

When I started work at SCE&G, there was a fellow -- some of you all know the name George Howell, was there. And I asked George one time, "George, how far back can we go and find electric rate orders?" And he said, "Belton, you won't find any past the mid-60s." I said, "Why is that?" He said, "Well, there weren't any. I asked the people around the company back in the '40s and '50s about electric rate orders and we didn't have any." I said, "Well, how is that? The statute says you've got to have them." Said, "Oh, we never had to increase rates. Rates were always going down. When we got kind of embarrassed about how much money we were making, we would go to the Commission

and just file a letter saying, 'We want to reduce our rates,' and they said,'Fine,'" because technology was pushing the rates down during that whole period, and there was really a very informal approach to the whole idea of regulation because, you know, when the pie is getting bigger, nobody's worried about how you slice it. Yes, ma'am.

PSC CHIEF CLERK MS. BOYD: May I -- you said technology was pushing it down. Are we talking about the connection to the grid? I mean --

MR. ZEIGLER: Yeah.

PSC CHIEF CLERK MS. BOYD: -- can you tell us how that --

MR. ZEIGLER: The ability to build bigger plants.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. ZEIGLER: The bigger your boiler --

PSC CHIEF CLERK MS. BOYD: Uh-huh.

MR. ZEIGLER: -- the bigger your generator, the more efficient it is. You've got one pile, you've got one set of coal-handling equipment, for example. You're going to coal, as opposed to oil.

PSC CHIEF CLERK MS. BOYD: Uh-huh.

MR. ZEIGLER: You're getting economies of scale in those plants. To make that work, you've

got to be able to connect as much load as possible to one plant, so this is a time of transmission boom. People began building really big transformers that could handle high voltage. The voltage on the transmission system started going up, the current that you could put through it started going up. And every time this cycle went to another level, the cost to serve went down a little bit.

And it was -- in a lot of ways, it's sort of like a frontier age in the sense that there was so much opportunity there, the question was how do you capture it, not how you carefully decide whether the ROE should be 10.7, 11, 10.5. That would just be foreign to regulation as it occurred at that time.

Of course, the demand for electricity skyrocketed after World War II with the industrial development that took place in the United States, the development of suburbs. And by the way, this is sort of a silly historical footnote, if you will, but I think it's quite interesting: Suburbs like Shandon and Eau Claire were created by the street railway companies as ways to get people -- when the electric street railways came, they would

go out and build a street railway into a bunch of pastureland, and the developers would sell it, and that's how almost all of the '20s and '30s era homes in places like Colombia were built, around that.

Well, after World War II, the decision was made to turn America into an automobile culture, and so the people were building stand-alone, independent houses, apartments were out, you know, people wanted big houses on big tracts of land. Lines were being sent across the countryside. The cities no longer were the center of development. Development was taking place outside of these franchised territories. And electrification had gone all the way to air conditioning, which now we're talking about a real necessity in the South. And so, during the '50s and particularly the '60s and '70s, load growth was just enormous, and electric service was spilling outside of the municipalities, to the point that you were getting into the issue of territorial relationships between suppliers.

And beginning in the '30s, the Commission had power, as between investor-owned utilities, to determine who got to serve a particular area. And

if there was an unserved area and Duke and Carolina Power Company both could get to it, they would have to go to the Commission to find out who it was, going to serve it. That was not true with this entity that grew up in the '30s called the Rural Electric Cooperative. Co-ops were created by FDR's Administration. They were a New Deal entity. And they really are a reflection of how important electricity had become during that period after it ceased to be a luxury and began to be a necessity. It was considered extremely unfortunate if you had to live without electricity, because that meant no running water, no indoor plumbing, kerosene lamps, you had to have a battery to listen to the radio when FDR gave his fireside chats, and so the people were going to the power companies saying, "Why aren't you putting lines out into these rural areas?" The power companies said, "You know, we'd love to, but we've got a real equity issue here. How can we ask our municipal customers to pay the extremely high capital cost to run the line out to a rural area when we know that we're not going to get the level of service, level of load off that line that's going to support the investment? We're going to be requiring the municipal customers to

cross-subsidize this rural expansion of service." And so FDR's Administration said, "We can fix that. Let's create this quasi-public corporation," sort of non-profit corporation, "called a co-operative, and pump a bunch of stimulus money into it." Stimulus was a big deal back then. They had a real depression at that point. And so the idea was, "We'll put people to work, we'll re-energize the American economy by energizing rural service." So the co-op was born.

And the co-ops and the investor-owned power companies came to heads and, because they were such different creatures, they really never did get along very well. The investor-owned said, "You guys are creeping socialists," and the co-ops said, "You all are a bunch of greedy capitalists," and they started a wonderful sort of -- you can imagine if they had CNN back then, what it would look like. Any case, there was a definite tribal animosity that arose at that time. But the Commission didn't have power to do anything about it, and in 1961 the Supreme Court issued a case saying, "Commission, you don't have the power to -- you can adjudicate a case between two IOUs on territory; you can't do it for the co-ops." And that resulted in several

years of what I'm sure was plenty of legislative wrangling and lots of lobbyists being able to send their kids to college, and there was a statute that created territorial assignment. And the Legislature basically looked at the IOUs, looked at the co-ops, said, "You all go in a room and draw lines on a map, you all agree to it and bring it back to us. You know, we're not going to sit here and parse it out lot by lot. And if there are disputes after that, take them to the Public Service Commission." So that's where we got territorial assignment.

The other piece in that equation is the creation of Santee Cooper in the '30s. Again, a New Deal project to create a public power source and inject public dollars into the economy to try to stimulate the economy, and that dovetailed very nicely with the fact that these electric co-operatives didn't like dealing with those greedy capitalists called investor-owned utility people but were very comfortable with a State agency. So you have this link between Santee and the co-ops.

But what happened? During that time period, electric growth was in the 7, 8, 10 percent range per year, in demand. Just unbelievable, compared

to what we know now. As a fellow that used to testify here a good bit, Johnny McClellan -- some of you may remember him -- he said, "I was at the PSC in Florida during the '70s. We wanted to put every piece of steel in the ground we could get our hands on, because we were just trying to keep from having rolling brownouts, rolling blackouts, having people not be able to run their air conditioning." And if you look at the plants that are serving customers in these states today, South Carolina and North Carolina, the vast majority of that capacity, base-load capacity, was built in that period from the '60s to, ultimately, the '80s.

So sort of like happened with the financial industry here recently, the electric business was in a boom cycle going 120 miles an hour, as fast as they could down the road, to serve everybody, and then the bottom fell out. A combination of the energy crisis, 21 percent interest rates, the economic crises of the late '70s, demand just plummeted. There's also some thought that maybe people didn't really realize that at some point everyone who wanted an air conditioner pretty much was going to have one, and that air-conditioning load would start to, as the growth factor would,

begin to start to level off.

In addition to that, you had inflation generally that was tearing up the construction budgets of the plants that were being built. Then you had this thing called Three Mile Island which was of some importance, because there were a number of nuclear facilities being built at that time. Nuclear was hands-down the base-load capacity of choice during that period. And Three Mile Island changed the economics of that industry dramatically. It was not uncommon to have plants that were anticipated to come in well under $1,000 a kW -- $4-$5-$600 a kW -- coming in at $4,500 a kW. Just extraordinary delays and extraordinary price increases.

All of a sudden, regulation got very interesting in South Carolina. And some of you all were around and will know this, but the reason Dick Riley got to be Governor of South Carolina is because in the runoff campaign against Grant Harvey, he decided to go hell-for-leather after a company I love, called SCE&G, and an institution that regulates it, called the Public Service Commission. And he literally turned that campaign around by capitalizing on the sense that there's a

problem here with regulation. And that resulted in a change of statutes. Those are the statutes that really still are the basis of statutes for electric regulation today, but they have now been supplemented by more the structural changes that occurred with Act 175. But things like the fuel clause, things like the current structure of rate regulation in South Carolina all came out of the legislative initiative -- sort of crisis, if you will -- that came out of the regulatory stress and political stress that was put on the system during the mid-'70s and on forward.

The utility industry, the electric industry, came out of that period with what we'd call a really high-quality product, which was a lot of really reliable and very operationally efficient base-load plants that were going to be there for 60 years and generate a whole lot of power. And what defined the electric industry from the '70s forward is the fact that this resource was in place. And if you look at the fortunes, if you will, of the three investor-owned utilities since the '70s, what you will see is that Duke and Progress came out of that period with the huge overhangs of excess nuclear base-load capacity that Duke was beating

around and going everywhere they could to try to sell some to PMPA or the North Carolina muni's or what do we do with all this nuclear capacity, the sort of problem everyone didn't want to talk about that we've just got so much more capacity than we could possibly deal with. But over the long term, that capacity turned out to be the most valuable thing you can imagine, because it was well built and is efficient. And as depreciation clicks away at the cost of it, as inflation raises the cost of the alternatives, the capacity there has allowed the utilities like Duke and Progress, because of the amount they had, to stay out of regulation for most of that period between the late '80s and 2010. Duke obviously just recently came in for its first rate case in about ten years, and I think – well, I'd have to look at the dates, maybe even longer than that. But the point is that in the utility business if you've got a lot of base-load power and your rates are set on that cost, then as you add customers, if you can supply them using gas-fired simple-cycle peakers to deal with the peak load, it doesn't cost as much to serve a new customer as the rates you've already got built in place, so you can ride that curve until you run out of base-load.

SCE&G ran out of base-load in 1995 when Cope came on. And so a lot of people -- you know, when you look at the more recent cases, the first of the more recent electric rate cases were the Cope cases. And Duke is now building Cliffside and it's the first thing they've built from a base-load standpoint in that period.

So that is where we are with the overall look. Let me check the time here [indicating].

PSC CHIEF CLERK MS. BOYD: Can I ask you one thing?

MR. ZEIGLER: Sure.

PSC CHIEF CLERK MS. BOYD: You mentioned an indeterminate permit. Can you describe that once again for me, what that is?

MR. ZEIGLER: It's a statutory construct that is something you can exchange for your old franchise; it's a new franchise that's issued by the municipality, but it doesn't have a term that sets the rates. It doesn't have a rate cap in it. And it's a way that you create a franchise that doesn't pull in and enforce the regulatory power of the municipality over rates.

PSC CHIEF CLERK MS. BOYD: All right.

MR. ZEIGLER: That, in a nutshell, is the

history. I will just leave you with a very broad overview of what the role of the Commission is from a legal standpoint. And I'm going to say something that may sound a little shocking to you, but bear with me.

You all are basically, as Commissioners, the most sophisticated and technically skilled condemnation panel in South Carolina --

[Laughter]

-- because what is happening is, from a legal standpoint under our Constitution, you cannot take private assets for public use without paying just compensation. So if the highway department wants to come through my property and take part of it for a right-of-way, I can go and have a condemnation award and I get paid through that. The theory of regulation is that an investor-owned utility wants to have a business, it's got its assets, but the State is saying, "These assets are so affected with the public interest," and that's a technical term, "that we're not going to let you just run it as a private business. We are going to tell you you'd have to serve all comers within economic feasibility. You have a duty to serve in your territory. If the cost of extending the service is

too much, you don't have to do it, but if you can serve somebody, you have to. And we're going to tell you what you can charge for that." And legally, that means that you have condemned for public use a private asset. And that's fine. There's nothing wrong with that. That's perfectly acceptable, but you have to pay a just compensation.

And so when you look at the statutes under which the Commission operates in setting rates, it talks about just and reasonable rates. And the "just" piece goes back to the Constitution and says you have to pay just compensation for use of this asset if you're going to impose a public obligation on it and say you have to serve the public with it.

So the whole -- I mean, it's really amazing if you think about it. All of our regulation comes down from that just asset, just valuation concept. And the cases of Hope and Bluefield are the key ones that say you have to allow a utility -- if you're going to make it serve the public, if it's going to serve the public it has to be allowed to earn a return that's generally commensurate with the returns of other investors who own and are investing in other companies of similar risk. And

the courts have done one thing that's very wise: They've said, "We're not going to fly-speck the decisions that are made in this regard. We're not going to take every little determination that goes in a rate order and say you've got to prove a constitutional just-and-reasonable decision there. We're going to look at the overall result," and in most cases it talks about pragmatic adjustments and that it's the result reached and not the method used that's important.

And so the ultimate duty of the Commission is to ensure that the investors who put money into these private companies get a reasonable return on that money and create overall packages that give that return. And that's a good thing that the courts haven't said, "We're going to look with laser-light focus on the constitutionality of every utility decision," because people like me and my brother-in-law Frank Ellerbe would have too much fun, you know --

[Laughter]

And Mitch, of course. I don't mean to leave you out. You know, all of us in the legal profession would just be -- it wouldn't be funny.

But there is that requirement that,

ultimately, the condemnation award, if you will, has to be a just one and the rate has to be a fair one to all involved. And of course, as we pointed out, access to capital is critical for utility services to be efficiently and reliably provided, and so if you tell the investment community this is not a safe place to invest your money, you're not going to have the kind of sterling service that you're looking for.

As you know, South Carolina has recently sort of gone to the forefront of regulation in the use of the Base Load Review Act, where we have taken these flexible regulatory concepts and created ways to allow the State to really be at the forefront of building the next generation of nuclear capacity. We've taken the regulatory compact and defined it in ways that we think -- those of us who support that Act think -- really do balance very well the interests of all the parties, allowing a pre-approval of investment and the guaranty, if you will, that rates will be adjusted in a fair way as long as the pre-approved prices are met, and the rates, the utilities build the base-load generation.

That, I think, is about as much as I have time

for -- maybe even a little more. If there are any questions, I'd be more than happy to answer them. Jocelyn, what time did --

PSC CHIEF CLERK MS. BOYD: Well, we're running a little behind, so with that -- if you have questions, I'd love for anybody to ask them, if you'd like.

PSC COMMISSIONER FLEMING: I have a question. As our official historian, you've done a great job bringing us up to today. And there seem to be key decades along the way. To me, it feels like we're in another one of those key decades, and I'd like to hear you kind of jump ahead maybe ten years and tell us what you think it's going to look like in the next decade.

MR. ZEIGLER: That's really an interesting question. The trends that I see that are important -- you know, the fuel clause was the first place we said, "You know, we need to just have a regular mechanism to make some adjustments." It's not efficient -- and back before the fuel clause if your fuel rates go up, you had a rate case -- to come in and go through the whole process. So there was a decision that's not the efficient way to do it. And then the RSA, the Rate Stability Act for

gas companies. They said, "You know, we really -- we've got the technology now to present the information and do the calculations, to have them reviewed by ORS and others. Do we really need to go through a full rate case to do incremental adjustments in gas rates?" And you know, so let's see how that works. And that seems to be working pretty well. The Base Load Review Act, with the revised rates, has the same sort of idea behind it.

I think what you're going to see is more of that sort of simplification of regulation with the rate case being the milestone; "Let's bring the companies in and go from soup to nuts, put the senior management on the hot seat, dig into the major construction plans and whatnot," and there will be more ongoing, non-rate-related oversight through the Commission and ORS but then lots of little adjustments along the way, because it's just not an efficient thing, with the volatility of today's markets and the importance of moving quickly in today's world, to have to, you know, lawyer up and spend six, nine months -- however long it takes -- to decide when you need to adjust your prices. So I think you'll see more of that sort of flexibility.

You know, what's going to happen -- are the generation decisions being made today the best ones or not? I remember when Jimmy Addison was on the stand in a rate case, someone asked him about the forecast and he said, "The only thing we know about these forecasts is they're wrong. There's no way whatever we forecast today is going to be exactly what happens. This is the best call we can make." What we've done, I think, is create a situation where regulation supports the making of the best choice, and it's not a situation where utilities in this State have to say, "We'd love to do that, but we really don't think regulation will let us do it, so we're going to do the next-best choice."

And I think the public's going to continue to be very focused on utility matters. I think energy is more and more important, and I think the role of the Commission and ORS is going to continue to be pivotal. I don't see anything going away in that regard. That's a long answer.

[Brief pause]

Thank you, Jocelyn. Thank you all for your patience.

PSC CHIEF CLERK MS. BOYD: Thank you. If it's okay for everybody, it's about 9:50, but we'll

continue with the next topic, the overview of the generation, distribution, and transmission system, and we have presentations by South Carolina Electric & Gas Company, Progress Energy Carolinas, LLC, and Duke Energy Carolinas, LLC.

Joseph K. Todd is the general manager of the Fossil and Hydro Operations at South Carolina Electric & Gas Company. Mr. Todd is one of the presenters for SCE&G this morning. He's a graduate of Clemson University and has been employed with SCE&G since 1981. During Mr. Todd's tenure with SCE&G, he has served in numerous leadership roles involving the company's generating units. As general manager of SCE&G's Fossil and Hydro Operations, Mr. Todd is responsible for ensuring the safe and reliable operation of SCE&G's fossil-fuel and hydro generating units.

Mr. Keller Kissam is also a presenter on behalf of SCE&G this morning. He is vice president of Electric Operations for South Carolina Electric & Gas Company. Mr. Kissam is a graduate of The Citadel Military College of South Carolina and has worked at the company since 1988. Mr. Kissam has held numerous positions within the company, including vice president of Gas Operations. In his

current position, he works alongside approximately 1,000 employees who construct, operate, and maintain SCE&G's electric transmission and distribution systems for safe and reliable service directly to customers.

The president and chief executive officer of Progress Energy Carolinas as Mr. Lloyd Yates and he's going to be presenting on behalf of that company. Mr. Yates is responsible for management and strategic direction of the electric utility. He has more than 27 years' experience in the industry, including nuclear and fossil generation, and energy transmission and delivery. Mr. Yates was promoted to his current position July 1, 2007, after serving for over two years as senior vice president in Energy Delivery, and prior to that he served as vice president of Transmission. He came to, then, CP&L from PECO Energy, where he had served in a number of engineering and management roles for over 16 years.

Finally, Mr. Robert A. McMurry is going to make a presentation on behalf of Duke Energy Carolinas. He is the director of Integrated Resource Planning. In that role, he oversees long-term resource planning and short-term action

planning to meet customer energy needs. He's a graduate of the University of South Carolina at Charlotte and a Registered Professional Engineer in North Carolina and South Carolina.

And I want to encourage all presenters to stand wherever you'd like in the room. You don't have to stand behind the podium. If you don't need it, I'll move it to the side. If you're more comfortable standing in the center, please do that, okay?

So we have some handouts for Commissioners and PURC staff. And Mr. Todd, you'll go first?

MR. TODD: Thanks, Jocelyn.

PSC CHIEF CLERK MS. BOYD: You're welcome.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 1]

MR. TODD: Good morning. It's a pleasure to be here again today. And I have to say how nice the dress code is.

[Laughter]

It's nice not having to wear a tie for a change.

I'm going to talk about generation today. She's going to put the hand-outs out, but everything that you have on your hand-out is going

to be on the PowerPoint. And we've got a lot of pictures today. I'll probably be going a little quickly, but if you have any questions please stop me as we go, and we'll try to keep you on schedule today.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 2]

This is our generation map. It shows our generation assets. And you can see, we're in the dark blue on the left side of the map here [indicating]. We've got generating assets located around the State in our service territory.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 3]

And to give you an idea of our generation mix, we have ten coal-fired plants, eight combined-cycle plants, 16 peaking gas turbines, five hydro plants, and then one each of the pumped storage plant, co-gen plant, and, of course, VC Summer Nuclear Station in Jenkinsville.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 4]

I'm going to give you some examples -- and again, I'll just be moving through the different types of assets, but just to give you a flavor of

the different assets we have: Cope Station -- Belton mentioned that was built in 1995 -- it's our newest coal-fired plant, and it's the workhorse for us. And you can see this is just an overview of the coal piles here [indicating], the landfill is there [indicating]. And I'll have some more pictures of the Cope SCR a little bit later. Cope is consistently one of the more efficient plants in the country.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 5]

Jasper Station was built in 2004. It's a combined-cycle plant and it is powered by natural gas. We've got three 7FA gas turbines through here [indicating], and these gas turbines produce electricity directly but they also heat steam that goes to a steam turbine on the side over there [indicating]. And it's really the most efficient way to burn gas in the country, on a large scale. Both Duke and Progress have a lot of combined-cycle also.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 6]

Going back in time -- I'm not going to take you through the history like Belton did, but we do

have an example of an old powerhouse. This is Parr Shoals. It was built in 1910, and it's quite interesting to go in. It's like a museum when you go in there. And I will have to say, the engineers in 1910 really knew what they were doing, because a lot of this equipment still runs, and runs quite well. It's reliable. But again, we're only talking 12 megawatts here for Parr. Big difference from Jasper, which is 900 megawatts.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 7]

Again, this is just another interesting picture of the Parr Shoals Dam and crest gates systems, looking from downstream up. But again, that was built in 1910. Quite an engineering feat at the time.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 8]

Fairfield Pumped Storage was built in 1978, started operation -- you can see the penstocks here, and we've got eight units here [indicating]. Each penstock feeds two units, and we generate during the day, pump the water down -- or generate, let the water go down; and at night, we pump it back up into the reservoir. The reservoir -- you

can't store electricity, but you can store the water, so the reservoir is very much like a battery, and we use it during peak times.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 9]

Saluda Hydro was built in 1930. You can see it -- well, you can't quite see it. It's tucked behind the backup dam. This is the new dam we built. It was a Federally mandated project. You all are aware of that. And McMeekin Station was also built in 1958. And again, it's one of the more efficient coal-fired plants in the country. The intakes for Saluda Hydro are out here [indicating]. The water comes off the bottom of the lake and goes through the hydro into the Saluda River below.

Any questions so far?

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Up near, I think it's the Parr, how much water variance do you have in the upper reservoir?

MR. TODD: Actually, about four feet. It varies between 421 and 425, full pool. And it's not uncommon for it to move that much during the day. We use Fairfield quite a bit for peak.

[Ref: *Overview of SCE&G Generation*

PowerPoint Slide 10]

The Hagood Gas Turbines are our newest generating asset. They're smaller gas turbines, but they're very efficient. They are not combined-cycle; they have a very good heat rate, but these units are very flexible. We can have them on-line within about eight minutes of a call to start, which is very valuable for spinning reserve. And they've run well since we started them up earlier this year.

[Ref: *Overview of SCE&G Generation*

PowerPoint Slide 11]

Next, I'm going to talk about outage maintenance. And again, I'm going to run through this rather quickly. But for us, in outages, we spend a lot of time -- I know I come over and talk to you every year during the fuel hearings about our outages. But for us, safety and reliability is the name of the game with our outages -- just like Keller, with his outages.

[Ref: *Overview of SCE&G Generation*

PowerPoint Slide 12]

This is a picture of the inside of the McMeekin furnace, obviously without the fire. The water walls are here [indicating]. We have -- one

of our main causes of forced outages are tube leaks. We spend a lot of time trying to keep these tubes maintained. And this was one of the outages where we had gone in to do an inspection. The burners are here [indicating]. The coal actually comes in through the burner and it ignites about one to two feet from the burner. And we try to keep the fire off the walls; if the fire gets on the walls it's a bad thing. We try to keep it out in the center of the furnace. And our guys do a really good job with maintaining and keeping them tuned.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 13]

This is an actual boiler tube replacement at Cope Station. I believe this was 2008. These were reheat tubes, and they run at a little higher pressure than the water wall tubes. But you can see the contract workers here making the cuts on the tubes. They've already cut the old ones out, and they're putting the new ones in because these were worn to the point we were about to start having tube leaks.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 14]

This is during the same outage; we did an inspection on the generator rotors at Cope. This just gives you an idea what a massive piece of steel this is. And we pulled it out and did an inspection. Everything was fine, but we have to do an inspection about every seven to eight years on our generators.

PSC CHIEF CLERK MS. BOYD: What's that? Is that a turbine? What is that part of?

MR. TODD: Actually, I've got a little better picture for you.

PSC CHIEF CLERK MS. BOYD: Oh, okay.

MR. TODD: That's actually a part of the generator; it's just one component there.

PSC CHIEF CLERK MS. BOYD: Uh-huh.

MR. TODD: It goes in that way [indicating], and this is the part that spins on the shaft.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 15]

You can see the shaft that runs the length of the turbine, and the steam turns the turbine here [indicating]. This is the high-pressure turbine, the low-pressure turbine, and the generator is right back here [indicating]. It's a massive piece of equipment, and it runs at 3,600 RPMs, so

obviously we have to have it tuned up pretty well before we can start running. But, again, the energy conversion is in here [indicating]. That energy goes through the transformers, which Keller maintains, and out onto the grid to the meter. And Keller, Charlie's group, and our group work extremely well together. It's a group effort, a team effort, to get electricity to the meter, as you can tell.

Any questions? Any others?

[No response]

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 16]

The McMeekin turbine rotor, this is a little closer-up view. The steam actually goes through these stages. We call these blades, but they're like big fan wheels. And it's really smaller than you would imagine, when you look at it. All of the steam actually passes through here [indicating] during its initial pass, and this is where the energy conversion from the steam to the mechanical, to turn that shaft, takes place. We try to get all the energy we can out of that steam before we condense it and send it back to the boiler, and the loop is continuous that way.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 17]

This is the Jasper 7FA gas turbine rotor. A little different technology than the steam, but, in this, all of the power is made here [indicating]. This is the actual power section. There's four stages of blades there, and the gas burns with very highly compressed air and that's what spins that turbine. These 7FAs are rated at about 160 megawatts each, and we've got three 7FAs at Jasper, and then we've also got a 400 megawatt steam turbine and a little more gas-fired capacity in the ducts. That's how you get to the 900 megawatts. And, again, a very efficient way to burn gas.

PSC CHIEF CLERK MS. BOYD: What's "FA"?

MR. TODD: That's just the GE designation.

PSC CHIEF CLERK MS. BOYD: Oh, okay.

MR. TODD: General Electric's, that's their manufacturing designation.

PSC CHIEF CLERK MS. BOYD: Okay.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 18]

MR. TODD: Environmental projects, we've talked a lot about that in the last few years and I just wanted to give you a few pictures and give you

a flavor of it.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 19]

The Cope SCR was built in 2009. It's run extremely well since that time. And the SCR is really not that complicated; it's a big box, it's a lot of steel. That's where most of the cost is. But we inject ammonia in it, it reacts with a catalyst, and the NOx gas turns into nitrogen and water -- pretty harmless, you know -- on the back end. And it's capable of removing about 90 percent of the NOx.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 20]

The Williams scrubber, we've talked about that recently in the rate case. It's a massive piece of equipment, the scrubber, with a lot of moving parts. A lot more complicated than the dry scrubber which we have at Cope. But the gas comes in through the ductwork, goes through the absorber, and out the top, up there [indicating].

PSC CHIEF CLERK MS. BOYD: Would you mind showing -- where exactly is the scrubber on there? As you said, we hear a lot about that.

MR. TODD: Oh, yeah, the scrubber module.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. TODD: That's the module right there [indicating].

PSC CHIEF CLERK MS. BOYD: Okay.

MR. TODD: And then we've got all the piping, the pumps, and all the support equipment. And it's worth noting here that, you know, there's no free lunch here; this scrubber uses about 11 megawatts of energy on its own. And, again, this was a Federal mandate. We had to do it. But it is cleaning up the air in South Carolina quite well now.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 21]

Wateree scrubber, again, this has got the scaffold so you can probably see it a little better. You can see a few men up there on the top, just to give you an idea of the scale of this thing. But it's a pretty massive piece of equipment. But, again, it's capable of reducing SO_2 emissions by 98 percent, and the Wateree scrubber has been running well also since April, when we put it in service.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 22]

The byproduct of this scrubber -- I wanted to just show this. There's been a lot of talk about, you know, the byproducts. But the scrubbers that we put in, the byproduct is synthetic gypsum, and that's the same gypsum that goes into the wall board that I think most of us have in our homes today. So it's a pretty benign product, the solid product that comes out of the wet scrubbers.

PSC CHIEF CLERK MS. BOYD: Do you have like a separate -- where do you collect that from the scrubber? How do you collect that?

MR. TODD: What actually happens -- that's a good question -- there's a slurry in here [indicating], and the SO_2 reacts with this slurry, with this water. It's like a huge rainfall in there, like a tornado almost. But it has to go through that, and it contacts with the water and it takes the SO_2 out, and it reacts with the limestone to make this gypsum. But what we do is we pump this slurry out to a dewatering area, which is not shown on here. And once we dewater it, it's how it comes out on the back end, and we have to transfer it, you know, from there.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. TODD: And it reacts with limestone;

that's the main thing that helps remove the SO_2.

PSC COMMISSIONER HAMILTON: What's the volume of the gypsum that you get from each of these scrubbers?

MR. TODD: Boy, I knew that number. And I could guess. But I'd have to get you that.

PSC COMMISSIONER HAMILTON: Is it a large amount or --

MR. TODD: It is a pretty large amount, yes, sir, that comes out of there.

PSC COMMISSIONER HAMILTON: Do you have a market for it?

MR. TODD: We are looking right now at markets. Obviously, it can be used in wall board, and we're having some discussions right now. We don't have anything locked up, but we're trying our best to find markets for ash, gypsum, anything that we can, to avoid putting it in a landfill.

PSC COMMISSIONER HAMILTON: But right now, you're landfilling it?

MR. TODD: Right now, we are. Yes, sir.

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 23]

And just a final slide, this just shows the evolution of Wateree. Wateree was built in 1972.

It's a super-critical furnace -- you can see right here [indicating] -- so it's a pretty efficient furnace. But in 2002, we put baghouses in. We had old electrostatic precipitators, and these baghouses capture about 99 percent of the particulate emissions, so they're very efficient in pulling the fly ash out of the gas stream.

In 2004, we were required by the EPA to put in the SCRs. Those were put in in that earlier timeframe. And those can remove up to 90 percent of the NOx emissions. And this is very similar to the SCR we put in at Cope, the one at Wateree, and we've got one at Williams also.

And then, finally, most recently, we put the scrubber in, in 2010, and again, that was a Federal mandate to reduce the SO_2 emissions, and it can reduce SO_2, as I referred to earlier, by almost 98 percent. So Wateree is a very clean plant now, from an emissions standpoint. But this just gives you an idea of the evolution and also the real estate. It took up a lot of real estate down there, with all of this emissions control.

PSC CHIEF COUNSEL MR. MELCHERS: How much reduction in efficiency did you have for the baghouse?

MR. TODD: The baghouse was not -- the baghouse and the SCR don't use nearly as much megawatts as the wet scrubbers do. I daresay the baghouse was probably a megawatt or two, tops. Still, you know, some, but not like the wet scrubber. And then the SCR is very little. It's not really any moving equipment with the SCR; you just inject ammonia in and it's a pretty passive reaction, you know, from there. You don't have the pumps that you do with the wet scrubber; that's the main reason they're different. I imagine the SCR is less than a megawatt.

PSC COMMISSIONER MITCHELL: I know it probably depends on future legislation, but what do you see with the scrubbers in the future, as far as -- or do you see the scrubbers increasing in work force, or not?

MR. TODD: Increasing --

PSC COMMISSIONER MITCHELL: Well, actually, you see using more scrubbers as you try to take out the emissions, to meet standards? Or do you see a decrease? I know it probably depends on legislation down the road, but what's SCE&G's plans for the future?

MR. TODD: Honestly, it does depend on the EPA

and the Federal Government and what they come out with. As I understand it, they're reworking some of the CAIR regulations right now, and I don't know what those are going to be yet. But even with the addition of the scrubbers, we still are a net purchaser of allowances. We have a lot less allowance that we have to buy now, but we still have to buy some. So I would have to say, depending on those regulations and how they fall out, we could look at having to do something else in the 2015 timeframe.

PSC COMMISSIONER MITCHELL: Are you within the mandates now?

MR. TODD: Yes, sir, we are. We're able to meet everything that we -- we meet all the mandates. We still have to buy very few allowances right now, but that could increase, obviously, if EPA comes out and lowers the cap again.

Yes, sir.

PSC CHAIRMAN HOWARD: Following up on that, what about mercury emission? If EPA comes out with some stringent requirement on mercury emission, can you utilize your same scrubbers, or will it be involved in modifying, or do you have to buy new scrubbers?

MR. TODD: I meant to say that. Thank you for bringing it up. The wet scrubber actually reduces mercury a great deal also, and we've done some testing down there, but it's a very substantial reduction. I think it's in excess of 70 percent reduction from the wet scrubbers at Williams and Wateree. And also we get a reduction in mercury with the dry scrubber at Cope. So again, depending on the regulations, we don't know what's coming down, but we feel like we've got a very big benefit already out of these scrubbers, with mercury control.

PSC CHAIRMAN HOWARD: Let me follow up on another question. There's a lot of conversation now and a lot of concern over ash ponds. What percentage of your ash storage is in wet ponds versus dry ponds, and what would be the financial implication if it is decided that ash is a hazardous waste, and how would you dispose of it in that case?

MR. TODD: I've got to be honest. If it is determined that ash ponds are hazardous waste, it's going to be a big impact on us financially. Because if you have to go and start treating ash as hazardous and storing it as hazardous, we don't

have that capability right now, so we would have to go back and probably construct some hazardous waste facilities and that's going to take time and probably a fair amount of money. We do have ash ponds. As far as the percentage, I don't know the exact number, but we've got ash ponds at Wateree and Canadys right now. All of our other facilities are dry storage -- Williams, Cope, and the other units, most of those are dry storage. But there will be an impact, and it could be big.

PSC CHAIRMAN HOWARD: Thank you.

MR. TODD: Thank you. Yes, sir.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Going to your Wateree slide --

[Ref: *Overview of SCE&G Generation* PowerPoint Slide 23]

-- if you had to do something for carbon emissions, where would it go and what would it be?

MR. TODD: When you say carbon emissions, what are you --

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Well, just say, you know, they're talking around all sorts of restrictions on CO_2 emissions.

MR. TODD: Oh, CO_2?

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Yes.

MR. TODD: To be honest with you, there's not a really mature, good technology out there right now for CO_2 capture. And some of the numbers that I've heard are pretty scary as far as how expensive it could be. You know, I talked about station service load before, but some of the capture technologies that I've heard about can use station service up to 25 percent of the plant, which is a huge number. So right now I would say there's not a good technology for it. And, you know, if there's a cap-and-trade I think it'll just have to be an allowance type situation for us right now, because we don't have anywhere to sequester it in this area either, below ground, like some of the states are talking about.

PSC CHAIRMAN HOWARD: Assume, with the forecast load growth and everything involved with the new nuclear plants, if you had the capability and you could take one of the coal plants off-line, which would be first to go?

MR. TODD: We are taking a look at that right now. We're just looking -- we're always planning; we're always looking. And right now, we've got a lot of flexibility with the plan we've got in place, our generation plan. I don't have that

answer for you today, but I can tell you that's something we're taking a look at.

PSC CHAIRMAN HOWARD: Thank you.

PSC VICE CHAIRMAN WRIGHT: A question. You had a conversation a minute ago about the fly ash --

MR. TODD: Yes, sir.

PSC VICE CHAIRMAN WRIGHT: -- and the ash ponds, or if the ash was considered a hazardous waste it would be kind of expensive. If cap-and-trade were to go into effect the way they're talking, what's going to have the most impact on the ratepayer? Is it going to be the hazardous waste, the ash; or would it be cap-and-trade?

MR. TODD: I think cap-and-trade would, by far, probably be the most expensive. If you talk about a number of, you know, $15 or $20 a ton -- I don't have the actual numbers today. But if you run the math on those, those are big numbers when you look at the actual CO_2 emissions of the plants.

[Brief pause]

PSC CHIEF CLERK MS. BOYD: Thank you.

MR. TODD: Thank you all, very much.

[Applause]

MR. KISSAM: Thank you all for the opportunity

to be here. Carol Clemson, my business manager, I want to introduce her to you all. I don't get around a computer that I don't have her with me. And her father was a long-term lineman for Edisto Electric Co-op, so we have her -- we let her work here anyway, at SCE&G.

[Laughter]

But we'll go ahead and get the presentation started.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 1]

The first slide, it shows you there -- it shows some of our transmission linemen out working on the structure. We really put that up there so, in the back of everybody's mind, they can say, "I'm glad I don't have to go out and do that and earn a living." But it brings up a good point. If you look at the next slide, you'll see --

[Ref: SCE&G *Electric Operations* PowerPoint Slide 2]

-- electric workers out there have the sixth most dangerous job in the world. Power line work is the sixth most dangerous job in the world. They're right up there with the crab fishing you see on TV. One of the reasons for that is why we

focus so heavily on safety. Joe talked about it; we focus on it, as well. This shows our accident frequency ratio, and what this is, is any OSHA reportable per 200,000 people-hours worked. Now, OSHA reportable is anything from a fatality to someone having to have sutures or a strain or a sprain that requires them to get a prescription for medication. And so we focus on that.

One of the things we're very proud of is the fact of how it's trended down. And you can look, six out of the last seven years we've been in the quartile Southeast Electric Exchange, and if you look at a year ago -- or, two years ago, excuse me, that 6.04, we were the top-rated T&D company. And why is that important? It's important because of the dangerous situations these linemen find themselves in each and every day, but at the same time, our priorities, our three priorities: employee safety, public safety, customer service.

If you take care of your employees and you focus on their safety above anything else -- and we tell them there are two things they have to do to work here: number one, focus on your own safety and the safety of your fellow worker, and get along. Those are the two things you've got to do

to work here; if you do those things, we'll be fine. And one of the things that's been interesting as we charge down the line on that focus, you focus on their safety and, guess what: you care about them, then they care about the customer, and they care about public safety, and they care about maintaining that system, and so it goes, and so it goes.

One of the interesting things that's a trend for you all to consider is the workforce and having a qualified workforce to come in and do this work. I say to people that we bring into the company now, they've got strong wrists but they got weak backs. They can move a mouse around on a computer, they can type on a keyboard, they can work a joystick, but they don't know a set of channel locks from a crescent wrench.

[Laughter]

And so that's what we're faced with, and so we have to train them.

We have -- one of the things we've done is we've gone in and -- this is important -- we used to have 35 percent attrition when we've brought young people in to come and do this laborious work. So what we've done is we've gone in now, and we

have a certified program by the Department of Labor where we can go in and they actually perform a field assessment. That's more important than the interview. Yeah, we want them to have a good appearance, we want them to have a good haircut, we want them to be able to go out there and represent our company, but at the same time we want them to have mechanical skills. So we bring them in. We bring them all, line them up, and say, "Dig a three-by-three-by-three-foot hole. Put it in a wheelbarrow, push it 50 feet, bring it back and fill the hole back up"; "Take a sledgehammer and a maul, drive a ground rod in the ground three feet, wiggle it around, and pull it back up"; "Go up a 40-foot ladder, transfer a sack with an insulator on it from one side to the other." That's where you separate the wheat from the chaff and that's where you find out who can actually come in here and perform this type of work, because wearing this FR uniform out in the heat for the last 60 days, you can imagine what their jobs have been like, and God knows I love 'em for what they go out there and do each and every day. But they go out there and get it done, not just when there's storms but each and every day.

So let's go and look at some of the things. If you focus on safety --

[Ref: SCE&G *Electric Operations* PowerPoint Slide 3]

-- the next thing you focus on is maintaining that system and public safety, and one of the biggest things we do for that is vegetation management to ensure reliability. That is one of the most important things we do. You say, "Well, how do you figure out what you're going to cut and where you're going to cut it?" Well, here's the criteria. You look at the trim cycle. We'd like to be on a five-year trim cycle; that's the goal, to maintain a five-year trim cycle.

We look at circuit reliability. One of the big indices that we have is called SAIDI. That's system average interruption duration interruption [sic] per customer, on an average. So we look at these different circuits and we say, "Okay, what are the ones that we've had outages on?" That's some of that smart-grid stuff coming back to you, interrogating your system to tell you what maintenance activities you should undertake. It's not all sophisticated but it gives you that information. So we use that. We also look at

vegetative SAIDI, we look at the reasons our circuits are out. If we have vines and trees and things of that nature, then it's going to move up in the priority ranking. We look at critical customers on that circuit: hospitals, laudromats, human-needs type facilities, nursing homes. We populate those on the circuits. We look at priority customers on that circuit. You'll say, "Keller, what's the difference between a critical customer and a priority customer?" Well, a priority customer is somebody like USC or some large commercial establishment that, if they don't have electricity, they're sending people home during the day, okay? And so that's the difference between them. And then, of course, we get management input.

The other thing I've got for you --

[Ref: SCE&G *Electric Operations* PowerPoint Slide 4]

-- is just to look at some pictures here. This is some before-and-after. This is down in Charleston. We've got a lot of back-lot construction. I hate back-lot construction; I wish it was all on the road. I mean, we'd like to dig the engineers up who put all this in, out of their

graves, so we could fire them again, but --

[Laughter]

-- bottom-line is, this is difficult, and what you have here is a lot of interaction with customers in their backyard, and it's very contentious. One of the things that helps us is this new smart equipment we have. This is a backyard bucket [indicating]. You can go in, and usually it has two wheels on it; you can take the wheels off and, like that, it can go through a chain-link fence gate and it can get in the backyard. We have backyard digger derricks, and what they can do is they can drag an 800-pound pole through that same gate to get it to somebody's backyard, get it up in the air on their pole, and set it. They can take a 400-pound transformer back there, as well, and set it up on the pole. Why is that? Quick restoration. You don't have linemen back there, three and four, trying to block-and-tackle and get that up there. But that just shows you some of the challenges.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 5]

Here's a rural circuit in a rural area. You see some of the growth that's there? Look at it

now [indicating]. And DOT even likes when we do this. Why? Because the deer have a landing area before they run out in front of people in the road. I mean, they like it. And you know what we'll do? We'll come back and we'll put an application of herbicide on this a year later, and what it does is it promotes the native grass growing, and your Forbes, okay, and wildflowers and things of that nature, but it eliminates your volunteer gum, your volunteer oak, and your pine, which are the things we fight more than anything else out on our rights-of-way.

PSC CHIEF CLERK MS. BOYD: Keller, I've got to ask one.

MR. KISSAM: Yes, ma'am.

PSC CHIEF CLERK MS. BOYD: You mentioned circuits. Are you talking about the lines there, the power lines, when you say --

MR. KISSAM: Yes, ma'am, circuits. We have about 480 circuits on our distribution system.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. KISSAM: And they go from substation to substation. When we say "circuit," we're saying Point A to Point Z --

PSC CHIEF CLERK MS. BOYD: Okay.

MR. KISSAM: -- and all those customers served in between. We've probably got 1,700 to 2,000 customers that are typically served off of an urban circuit. So when that circuit has a fault on it, that's how many people are without power.

PSC CHIEF CLERK MS. BOYD: Okay.

PSC COMMISSIONER MITCHELL: Let me ask you a question --

MR. KISSAM: Yes, sir.

PSC COMMISSIONER MITCHELL: -- about the spraying the herbicides. Is that taking some pressure off of actually trimming?

MR. KISSAM: Exactly, and that's why we do it. It's a lot cheaper. We spend about $1/2 million a year on herbicide treatment, herbicide application, on the distribution side. And we've found with these new chemicals that they are -- you're exactly right, and I've got a slide coming up I'll show you that's going to hit on your point, but when you come in and you spray it, guess what it eliminates: mechanical trimming. When you go back, you're basically focusing on your side trimming and grinding things up, instead of having to go in there with mechanical trimming, which is costly. So, the herbicide has been a big plus for us.

PSC COMMISSIONER MITCHELL: Not having any large legal problems with that, though, are you?

MR. KISSAM: No, sir. You know, we had one customer, he planted an orange tree right there underneath the guy wire and the pole, which that's a poor place to plant a tree. So we try to educate people: right tree, right place.

So with the herbicide, you know, you've got to be really careful you don't spray it on a windy day. You've got to watch out for your drift. But, you know, most people don't even notice it. We also went in and experimented with one we spray in the wintertime. So, what you do is you spray in September and October, and when people see those dead pine trees they just think they're deciduous trees and dropped their leaves and nobody notices. So you pick your times on when you do it to keep the public outcry down.

[Laughter]

Timing is everything, Commissioner Mitchell.

And here is your slide. Here it is, this is exactly what you're talking about. Look at that [indicating]. All right? That was cut just like the circuit we showed before. Look at it. You don't have to bush-hog that. That's three years

after we applied herbicide. It's over in Lexington. And you see it, and it works, okay? But you've got to be real careful. Like anything else, you've got to be a good steward of the environment and pay attention to what you're doing.

Go ahead.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 7]

This is transmission. As y'all know, Federal law requires maintenance of transmission assets 230 kV and above, on our system. And Charles White will talk to you later on; they may be coming on down to 100 kV. This is over in Cayce. This is actually in somebody's backyard. And you can imagine, they were proud of these trees. But you've got to go, and now you've got no choice; you got to go in and take those out. A grow-in or a fall-in, on vegetation management -- here's another trend for you. The Federal Government continues to exert more and more control over those transmission assets, based upon the safety of the grid. And here's a practical aspect of what that trending does. If we have a tree fall into a 230 line and lock it out, the first thing out there is not a bucket truck to put those lines back in the air;

the first thing out there is an individual with a tape measure who's pulling a tape to find out if that tree fell from off the right-of-way, meaning on the right-of- -- we're not talking about off and on a horse, but off the right-of-way. If that tree was growing on the right-of-way, then we have to report it.

Now, Charles -- we report everything that happens on a 230, whether it's on the right-of-way or off the right-of-way, but if it's growing on that right-of-way or a vine grows up a pole -- and you could have a cotton field and the farmer does a great job of keeping weeds out of it, but you'll see one of our lines in the middle and here's this vine growing up it. Well, if it gets into it, we have to report it. And you subject yourself to censure, you subject yourself to fine, and you subject yourself to them mandating O&M activities that you will perform on your transmission assets.

Fortunately, since those rules have come out, we have not had one of those situations, but you've got to be working at it every day and you've got to have your mind focused on what you're doing.

The other trend that you need to look at is, who do you have out there representing you with the

customer. It used to be, when we would cut right-of-way, we would take old linemen and put them in a truck and let them go cut the right-of-way, let them be in charge of the people who cut the right-of-way. Then it got to the point where you had to be a certified forester in order to be able to cut right-of-way. Well, now you've not only got to be a certified forester, you've got to be a certified arborist, and we require that. The reason we require it is because with so many agreements -- Mount Pleasant, Walterboro, you know, Bluffton, all over, Shandon, where you have these trees that people are real proud of, and how we go in and cut and manage those trees -- and we even have side agreements with these municipalities on when we're going to cut, how we're going to cut, and a lot of them have arborists now, so it is a challenge.

Go ahead.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 8]

This will show you sometimes we have to mow -- this is just a track hoe with a timber-tangle bush-hog on the end of it. These are wax trees in there. Their leaves, they don't take that poison up too good, the herbicide, so this is a case in

point where we have to go in and mechanically mow.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 9]

This just shows you a situation -- here's a nice subdivision. This guy came in and brought a spade -- we try to educate, the right trees in the right places -- and he planted all those. You can't even see in this picture, but look what he planted them under [indicating]. So that was not a good day when we had to go and work with him to get those trees removed.

[Laughter]

Right tree, right place; that's what we're trying to do.

Go ahead.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 10]

This just shows -- everybody likes to see this. This is the helicopter. You all know we've got a lot of swamps. I mean, I don't think your district *[to Chairman Howard]* is anything but swamp. But anyway --

[Laughter]

-- we have to come in --

PSC CHAIRMAN HOWARD: We got historical, too.

MR. KISSAM: I know. I was with Riverland Terrace Garden Club. I know all your folks. But anyway, what they do is in these areas we've got to bring in a helicopter, and if you look at that helicopter, it's got about 15 skill-saw blades on the bottom of it, and we use it for side trimming, because in South Carolina you can't go everywhere with a truck and you certainly can't pay people to go up there and climb the trees with hooks and a chainsaw. They just make no progress. This can come in -- and you usually bring it in around November, October/November timeframe, and that's what we use to cut a lot of the swampy areas that we have around.

Go ahead.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 11]

This is important. I'll go through this real quick. This has to do with safety and maintaining the system. You've got that vegetation management is what you've got to do, and then you've got to inspect what we've got out there, the poles. We're on an eight-year inspection cycle with our poles and all the assets. And what we do is we go out to the pole, we have a device where we get the GPS

coordinate for that particular structure, we take a picture of it. We take a picture of every pole and any apparatus that it may have on it. Then we bring all that information back in, unload it in a big PDF file, and the engineering designer can actually sit there and look at every structure along that entire circuit.

And some circuits are a half-mile -- he's got a circuit in his *[Commissioner Mitchell's]* area that's 176 miles long, so that just gives you some variation. Sometimes the more rural, the longer the circuit.

Basically, what this shows is that last year we actually went out and took pictures and inspected 73,008 poles. As we went out there and looked at them, we found that 90 percent of those poles were in good order, no need to do anything with them. .22 of them were emergencies. That person called in immediately and we had to get out there. Might be missing a guy wire, might be hanging in the street, something along those lines; you've got to go fix it now. 6.3 percent of it was a design form; we have to come up with a work order. When you ride out and you see these guys with all the rubber hoses and blankets on the

system and they are working there, then -- and they're changing poles out, that's part of this circuit correction. Okay? Service work, we just send a two-man truck or a one-man truck out there and they will fix it quick, maybe put a guy guard on a wire there or a sidewall if somebody bumped into it. And then the other one is treated poles. These wooden poles tend to shell out. One of the things we do, we have a carbon rod that's about this long [indicating], and you drill a hole in the pole and tap it in there, and when water migrates down that pole, it forms an epoxy, so we're able to actually repair these poles, some of these poles, in the field without having to change them out, and that saves us a lot as well, kind of like the herbicide on the vegetation management side.

Go ahead.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 12]

This just shows our dispatch. We have consolidated from five dispatch areas in all our districts down to two. We could just have one, but they said, "You're going to have two, in the event a catastrophe occurs somewhere else." We also have a backup facility in Peak, in the event that both

of them have a problem, okay? But a lot of what we do and a lot of what we've talked about now, this is a lot of that smart-grid technology that you all hear about all the time. And, you know, we're doing a lot of it. Now, we didn't buy commercial time during the Super Bowl or anything to advertise it, but it happens each and every day, and it's just pulling this information off the system. That's Ralph in our dispatch area, but I want to show you what he's working on.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 13]

This is another key to reliability, another key to reliability. These are SCADA switches -- Supervisory Control and Data Acquisition. We've got over 500 of these switches on our system on the distribution side. And basically what happens is, if you're on a circuit and, say, the circuit is this tape right here on the floor, and there's a substation where the cart is and a substation where the screen is, a tree comes down in the middle of it, bam, you've got 2,000 customers who don't have power. Well, Ralph, sitting right there in dispatch, with the click of a mouse -- we like some people to be stronger with the mouse -- all he has

to do is go in there and click and enter a password, click and enter a password, and he opens the switch here [indicating] and he opens the switch here [indicating], and the only place that's without power is where that tree is, and we pick up the load from the substation here and the substation here [indicating]. So instead of having 2,000 people that have power out for four hours, you've got 20 people that have power out for four hours, and the other people have it out for less than five minutes. That's what the SCADA switches does for us, and so that's the important thing -- or, do for us. That's the important thing that I'm showing you.

We try to keep it simple and not have too many things. You've got vegetation management, you've got to inspect and correct your system, and then you've got to have these devices in there so you can operate your system, and that's pretty much it in a nutshell.

Go to the next slide.

[Ref: SCE&G *Electric Operations* PowerPoint Slide 14]

I want to show you this because this is interesting. You say, you know, a lot of times

these guys, they only get press when the lights are out, or we're going to assist somebody with a hurricane or something along these lines. There's a tremendous amount of daily maintenance that's done, and troubleshooting. Joe Todd and I work quickly together. If Joe Todd has an outage on his system, you can be guaranteed that my people are there. We work closely with Charles White. Charles will talk to you later. We do not touch our transmission system unless his system control tells us we can do it, as far as taking lines out of service and being able to work on them or do any type of remediation work.

This is a case in point of something that's interesting, and I just felt like I wanted to show you all, technology is a good thing. This is a thermal imaging picture that you see, with a thermal imaging camera. We have individuals that go around a lot of our substations and certainly Joe's power plants, and they actually point it at the switches and take pictures. Why do we do that? This particular switch right here showed a temperature of 701 degrees. What's the next thing that's going to happen? It's going to melt, you're going to have a fault, and you're going to have a

lockout coming out of that substation. And you're going to have it -- this happened in -- I think it happened in June, the end of June. Okay?

Now, if we'd had that that day, it would have impacted a lot of people because it was about 102 degrees that day. With this, as soon as they saw it, we were able to schedule it with Charles White, system control, we were able to get crews out there at 10 o'clock that night after the load went down, and they were able to go in and change out this switch. Predictive, preventive maintenance day-in and day-out, and that's what you have to be about, as well.

We even had it -- you talk about the trending. We do pull stuff from our system. We have a web portal where if any of our transformers -- the big transformers in the substations -- start getting loaded up on these distribution circuits, it sends a page to that district manager to let him know it's getting up there, so he can be alert and be thinking about switching distribution load around and taking some of the load off of it, to help that asset.

That's all I've got. You got any questions?

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Keller?

MR. KISSAM: Yes, sir.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: You've got -- down on the coast, basically, you've got the swamps.

MR. KISSAM: Yes, sir.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: You've got your pines and your sweet gum and stuff here. Now, up in the Upstate you've got the kudzu.

MR. KISSAM: Yes, sir.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: What do you do with the kudzu, because that stuff grows like --

MR. KISSAM: What you do with the kudzu, you've got to mow it with that track hoe you saw. You've got to mow it, and after you mow it you've got to come back and spray it. And you could just go out and spray, but the reason we don't go out and spray it is, when you spray, it looks like, you know, brown earth. I mean, it looks like you're just burning something up over there, and that just doesn't go well with the public. So what we do is we mow it, and they just say, "Well, they're cutting grass." Then we go back and we spray the tendrils with herbicide, and that's the way you keep it back.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Herbicide actually works on it?

MR. KISSAM: Yes, sir. You can't buy this stuff at Lowe's, now.

[Laughter]

What else, anything? Yes, sir.

PSC LEGAL STAFF MR. MINGES: You touched on it some, but what do you see as the benefits of the smart-grid technology?

MR. KISSAM: I see the benefits of gathering information. That's what it is, gathering that information in order to use it. And I think probably the best improvement we can do is on the customer end, with metering. But, you know, I'm a simple fellow. At your house if you want to control your electricity usage, I don't know if you need a monitor out there to look at it. You just operate your thermostat in a different manner. Close the door. You know, it's all the stuff that our parents told us to do.

But what we do with smart grid -- we do a lot of smart grid; it's just not called smart grid. But it's gathering all that information, tying it from the power plant to system control to out in the system to what maintenance activities we

perform. That's what it is, bringing all that information together. And Randy Senn will talk to you later; we've got a pretty robust system in order to allow us to do that.

Anything else?

[No response]

All right, thank you -- yes, ma'am. Yes, ma'am.

PSC COMMISSIONER FLEMING: What are your -- with your vegetation management issue, as you've become more stringent with that, what are your figures showing as far as reliability? Has that increased it?

MR. KISSAM: Our reliability has increased substantially, and our -- just getting on a five-year cycle. And we track it by -- you know, I told you about the circuits. Well, we look at that SAIDI index, and that SAIDI index has been cut almost in half because of us being more aggressive with our vegetation management. And that's the number one cause of outages that we have, is vegetation. You focus on that -- and you know, I can tell you --

PSC COMMISSIONER FLEMING: Well, that cuts down the cost, as well, doesn't it?

MR. KISSAM: Yes, ma'am, it does. And, you know, keeps the meters spinning, too. And the bottom-line is, you know, it's important but it's a constant battle. I had to go down to St. Matthews the other day -- that's in your district, Commissioner Hall, and that's where I'm from, so I had to go down there because these people weren't going to take no for an answer from anybody else. But actually had to sit there and while the tree trimmers came in there and pruned away. And I told -- and the lady was just giving me a hard time, and I said, "Ma'am, I just want to tell you, being from down here, I get hundreds of calls about people's lights being out. This is the first call I've ever had of anybody complaining about the degree of tree-trimming that we have." And, Commissioner Fleming, that's how it is a lot of times: You know, the same people that get on you about cutting trees, they're the first ones to call you when the lights are out, the same very people. And it's just about maintaining that balance. But we've seen significant improvement in the outage duration that our customers have experienced, and that's the number one maintenance thing we can do to provide that reliability.

Anything else?

PSC COMMISSIONER FLEMING: Are you working with municipalities on the proper kind of plantings that can go under lines?

MR. KISSAM: We are. And they do a great job. And we also have agreements with them as to how we cut. And we use the national arborist guidelines; that's why these guys and gals have to be certified arborists. The State Forestry Commission, I'll just tell you they are a wonderful resource, because they have arborists and they are a third party so it's not just the utility arguing with them back-and-forth, back-and-forth. We actually bring a third party in and they go with us to the garden clubs, they go with us to the neighborhood associations. And if there's a tree out there -- we had a ginkgo tree that we've cut, and actually today a State Forestry arborist is coming down to look at it with us and make recommendations on what cuts need to be made. So they're a great resource for us and we use them a lot.

And, you know, like I said, it's everything from Riverland Terrace down there on the river where we go and meet with garden clubs and they send out engraved invitations and have a formal

meeting, to --

[Laughter]

-- just individual homeowners. And it's very consuming. It is.

But the municipalities are pretty good about it. They'd like us to go to a two-year cycle to cut everything, so it doesn't look like everything's cut back so much. But look at the cost of mobilization to get a crew in there to be on a two-year cycle. So you want to cut to that five-year cycle and use those arborists' guidelines.

PSC COMMISSIONER FLEMING: But you think that is the safest cycle, five years, as far as being cost-effective --

MR. KISSAM: Yes, ma'am.

PSC COMMISSIONER FLEMING: -- and getting the job done?

MR. KISSAM: Yes, ma'am. And, you know, like I say, it's a balance. We've had situations where they said, "Oh, don't cut this tree. Don't cut this tree. It was planted by my husband when we got married," and all this. And the next thing you know, two little kids have climbed up that tree and not gotten in direct contact with 2-3,000 volts,

but it certainly knocked them out of the tree. And that is something we can't live with. You just can't live with that. So we try to get 10 to 15 feet clearance around our primary lines. That's what we have to maintain. And if it's a tree like an old gum tree or something like that, then we want to take it to the ground.

PSC CHAIRMAN HOWARD: What about -- and you made reference to it. Probably the largest amount of conversation I get is -- your arborist, he looks over the health of the tree. What about the cosmetic, aesthetic value? That's what I get more conversation about, particularly down there in Charleston.

MR. KISSAM: Yes, sir.

PSC CHAIRMAN HOWARD: And who is there first, the tree or the wire. I guess the wire was there first. How do you allow the tree to get that big?

MR. KISSAM: It's 10 to 15 feet --

PSC CHAIRMAN HOWARD: Just give me something to tell them, is what I'm saying.

MR. KISSAM: Yes, sir.

[Laughter]

It depends on who you're talking to, Commissioner. But, anyway, what we try to do is,

the whole thing is the arborists recommend that you have to make those cuts because in order to improve aesthetics, you want to train that tree to grow around that power line. And you're talking about live oaks in your area, I know. And you want to train that tree to grow around that power line. And with the arborists' specs, it is more of a cut than what we used to have, but like with a live oak, if you'll just be patient, in less than a year's time -- because they don't lose their leaves -- you'll find it's bushing back out and that green growing up around that.

And that's the best thing I can tell you. The arborists' guidelines say you can't just cut a branch. You cut a branch out here -- like say this [indicating] is a tree branch. If you cut it right here [indicating], it's going to splinter, it's going to get diseased. Cut it right here [indicating], same thing is going to happen. But if you take it back to here [indicating], that's going to promote the health of that tree, and the aesthetics come a year and a half later when this is able to bush out with leaves, and then it's trained to grow around that power line.

PSC CHAIRMAN HOWARD: Thank you.

MR. KISSAM: The answer is not to put everything underground because that's what everybody says they want.

PSC CHAIRMAN HOWARD: Oh, yeah.

MR. KISSAM: But, anyway, thank y'all for your time.

[Applause]

[Ref: Progress Energy Carolinas *Overview of Generation, Distribution, and Transmission Systems* PowerPoint Slide 1]

MR. YATES: Good morning. Thank you for the opportunity to be here. As Jocelyn said earlier, I'm Lloyd Yates, president of Progress Energy Carolinas.

[Ref: Progress Energy Carolinas *Overview of Generation, Distribution, and Transmission Systems* PowerPoint Slide 2]

Let me give you a brief overview of the Progress Energy Carolinas system, and you can see a couple of things here. We have, I'll say, assets -- coal, wire, plants -- like all the other companies you want to hear about. I think one of the things I'm most proud of that differentiates our company is those 5,500 employees. I think they make the difference in terms of delivering high

levels of customer satisfaction. Again, for the fifth year in a row, we finished in the top quartile, and we're gaining in customer satisfaction, and we're really proud of that. But I think our customers -- I mean, our employees, in terms of how they think about and deliver satisfaction to our customers day-in and day-out is what makes the difference. And we do have 12,600 megawatts of generation. We serve 1.5 million customers, with 172,000 of those customers in South Carolina.

The system has been growing robustly for a long period of time. The other thing you'll notice about the system is the very large service territory, over 34,000 square miles. And you can see it's pretty continuous down from the Virginia line all the way into South Carolina. How we got to Asheville out in western North Carolina, I have no idea. Somebody must have gone on vacation or something, out there one day --

[Laughter]

-- and decided to buy a small utility. But we do serve out there; it's a very mountainous region.

[Ref: Progress Energy Carolinas *Overview of Generation, Distribution, and*

Transmission Systems PowerPoint Slide 3]

Of those 4,600 megawatts, we have 18 generating sites: over 5,000 megawatts of coal, 19 units. 45 units of natural gas and oil. They're mostly combustion turbines. Four nuclear units. We use some hydro units. But in the State of South Carolina we have the nuclear plant in Darlington County, a 700 megawatt nuclear plant, our Robinson Plant. We have a coal-fired plant in South Carolina. About 800 megawatts of combined-cycle and CTs in South Carolina. All of our generation is over in the Darlington County area.

Something that we thought about and worked on and we announced in the fall of last year is a coal and conversion process -- I mean, coal-to-gas conversion process. I want to talk a little bit about that and try to give you some of our thinking around that.

So if you look, we have 19 coal units. And over the last -- from about 2003 or 2004 until about 2007, we scrubbed all of our large coal units. So we have some scrubbers. We did have 11 units in North Carolina that were not scrubbed. Most of those units were 600 megawatts or less. As we looked at more environmental investment on those

units, putting on scrubbers and SCRs and other things like that, for those 11 units what we saw was an investment of about $2 billion necessary to keep those units environmentally compliant.

We also started thinking about a couple of things that changed for us in that area. One is this shale gas. You know, they used to drill natural gas down and pull the gas out like a straw, then somebody invented horizontal drilling where they can go down and then drill horizontally, and then they use either water or chemicals and they break up the rock. So we went from having to import natural gas in the United States from countries like Russia and other -- Kenya, I mean, in Africa and other unstable countries, to, in the United States we believe there's about 100 years of natural gas supply in the United States, as we see gas today.

So our thought was, instead of investing $2 billion in those older coal plants which were 40 years old, we looked at the numbers, the economy looked down a little bit, and looked at we could build two new natural gas facilities in the Carolinas and spend about the same $2 billion. Actually, we're going to build three natural gas

facilities in the Carolina. So what we're going to do is we're going to build three new combined-cycle gas turbines in the Carolinas: one in Richmond County, one in Wayne County, and one at Sutton. They'll be about 2,000 megawatts, and we're going to shut down 11 coal units between 2013 and 2017, which will be a huge transition, not only from an employee perspective but spending more money, taking a risk on natural gas. The way we thought about this thing was a trade-off from environmental risk -- we're going to trade some environmental risk for some fuel risk, because natural gas has been a much more volatile fuel, but the interesting thing here is it wasn't as risky as we thought it was.

[Ref: Progress Energy Carolinas *Overview of Generation, Distribution, and Transmission Systems* PowerPoint Slide 4]

So the way we were structured before, almost 90 percent of our energy came from base-load coal and nuclear. I mean, we took those big coal plants we had and those nuclear units, and they essentially generated most of the energy, and then the smaller coal-fired units made up some of that. As we transition into natural gas, even though, in

terms of capacity, about a third of our capacity will be natural gas, the actual energy that will be produced from those gas plants will be around 20 to 24 percent natural gas, so we're not moving in as much gas as we think. We think we're going to have a much more balanced portfolio when this is all said and done. We'll have, again, 3,200 megawatts of nuclear. We'll be sitting -- instead of 5,000 megawatts of fossil -- at about 3,500 megawatts of fossil, and about 3,000 megawatts of combined-cycle and natural gas -- natural gas turbines, which is very highly efficient generation. So we think we'll have a very balanced portfolio, and we're investing in new facilities versus old facilities.

And that $2 billion didn't include any consideration of what might happen in ash, because all of our coal plants -- we handle wet ash in all of our coal plants, and we have ash ponds. So when we take these 11 units out, we'll shut those ash ponds down and we'll eliminate that environmental risk. So when I talked about that, I wasn't even considering the $2 billion of -- I wasn't even considering the money that we talked about associated with ash, as new ash legislation comes out from the EPA.

[Ref: Progress Energy Carolinas *Overview of Generation, Distribution, and Transmission Systems* PowerPoint Slide 5]

Again, this shows you where all of our plants are, with a lot of plants all over the Carolinas.

Switching gears to talk a little bit about energy delivery, transmission, again, over 6,000 miles of transmission. The thing I think we've done well over the last ten years, we've continued to build new transmission lines, so we have a very robust system of 500 kV, 230, 115. We do have about 12 miles of 69 kV. And the way to think about this, the bigger the cake, the bigger the transmission bowl. It's just like a big pipe; you can get more voltage and energy through those transmission lines. So with all the new requirements from FERC and NERC and SERC coming down on transmission, we think we're sitting in a pretty competitive position to have a very reliable long-term transmission facility. We'll hear more about transmission planning from Kendal later on.

Our distribution system: 1.4 million poles with 66,000 line miles. So, again, a large distribution system. I like to think about the 1.4 million poles as every customer has a pole --

[Laughter]

-- and we try to maintain them in a highly reliable way.

Our call center handled 6.3 million customer calls last year. We like to think of that as an opportunity to interact with our customers. Though during high bill season those opportunities aren't as good as they used to be but, I mean, we're handling those.

One of the things I think is good, our customer service organization, we have moved a lot more calls to our voice response unit. Our customers have become more technically savvy, have become much more comfortable dealing with the voice response unit, especially during outage calls, and that's become a very effective, low-cost communication mechanism with our customers that we're extremely proud of.

But we're moving more of our customer contact to the Internet and to the voice response unit. It's still easy to get to our customer service reps. I think our customer service reps handle more extensions and billing issues, and a lot more outage calls and simple accounting inquiries are handled by the voice response unit.

So with that, short and sweet. Questions?

PSC CHIEF CLERK MS. BOYD: Can I ask you one question?

MR. YATES: Absolutely.

PSC CHIEF CLERK MS. BOYD: You mentioned the phrase coal to something else.

MR. YATES: Coal-to-gas conversion.

PSC CHIEF CLERK MS. BOYD: Okay. Thank you.

PSC COMMISSIONER HAMILTON: You want to talk about your rate decrease?

MR. YATES: Always glad to talk about our decrease.

[Laughter]

And again, we're coming off some very high coal costs a few years ago, and since the price of coal has dropped, the price of natural gas is going down, I mean, our customers can take advantage of decreases in those rates, but that's clearly in our fuel people doing a better job of purchasing fuel, we're doing a better job of using that fuel more efficiently, and then the commodity prices going down.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Where do you have your 500 kV lines?

MR. YATES: Well, they're all over.

Primarily, between Virginia -- from Virginia into the Carolinas, there's a pretty robust 500 kV; and then there's a 500 kV line along -- let's see -- the Richmond County corridor, right on the edge of South Carolina, but going -- I guess that's east to west there.

Yes.

PSC LEGAL STAFF MR. MINGES: What's Progress's perspective on the price of the carbon future?

MR. YATES: I think one of the reasons why we did this coal-to-gas conversion is, again -- think about this -- natural gas usually produces about half the carbon of coal, so it reduces our exposure. This is going to be a pretty long-winded answer. I think ultimately the way we think about this, ultimately, there will be carbon legislation and, of course, when it gets to the feds we're not sure what that looks like, but I think eventually there will be a price associated with carbon.

I guess the point -- the thing we try to think about long-term is, if we're going to invest money to reduce carbon, we want to put -- the dollar we invest, we want to get -- for every dollar we invest, we want to get, you know, the most carbon reduction for that dollar invested. Right now, you

know, I think our long-term strategy -- and we talk about this in a balanced way -- is driving more energy efficiency, bringing in renewables, and then building new nuclear, long term, because we think that's the only carbon-free base-load generation.

But I think, you know, this carbon issue is a long-term strategic issue. We're talking about reducing carbon between now and 2080. We have to start planning for it now.

Now, I think if the feds try to drive that price up too fast, there will be some huge issues in our customers' rates, because what will happen is we can't build nuclear plants and shut down coal plants fast enough to -- fast enough -- we can't build nuclear plants fast enough to shut down all our coal and still supply energy to people and meet all the carbon constraints. So what will happen in the legislation is you'll pay a penalty for that, which you'll pass on to your customers.

So we're spending a lot of time in Washington, making sure our legislators understand this equation, because at the end of the day, today, half the energy in the country comes from coal, so if you do this too fast and you think you're going to shut down all the coal and still provide energy

to the people, I mean, it's an impossible endeavor, and I think you end up spending a lot of money unnecessarily.

PSC COMMISSIONER WHITFIELD: What did you say about your customer calls? That's a high number. Were you saying they're more billing or service -- or what was the breakdown of that again?

MR. YATES: Well, some of those are outage calls. Credit. They change. I'd say of those 6.3 million calls, about half of them -- 3 million of them -- went through the voice response unit and are no longer being handled by a customer service rep, but are being handled by technology.

PSC COMMISSIONER WHITFIELD: But you didn't really say a breakdown of what was --

MR. YATES: No, I don't have a breakdown off the top of my head on where those calls went. And they change year to year, depending on what's going on in the company.

PSC CHAIRMAN HOWARD: Mr. Yates.

MR. YATES: Yes, sir.

PSC CHAIRMAN HOWARD: Do you have a timeline on any future nuclear generation? Or where exactly is your thought process on nuclear generation, and has the Florida Public Service Commission played a

part in your thought process?

[Laughter]

MR. YATES: Well, talking about the Carolinas, so let me answer your second question first. The Florida Public Service Commission has absolutely played a factor in our thought process around nuclear.

[Laughter]

On the other hand, again, we're looking for, I'll say, milestone or trigger points, points of inflection. If we get significant carbon legislation, I mean, that's going to drive us to have to build more nuclear. Today, as we see it, we look at the cost of nuclear, we look at with the economy and the growth kind of flattening out, today we don't see having to have to be building new nuclear before 2020 or 2021. Now, if you get significant carbon legislation, that may change.

So we do have a COL, or a combined operating license, application in to the NRC, to build two nuclear plants, but we're going to watch the mileposts here, the trigger points, to see when it makes sense to pull that trigger, but we're going to maintain that option to do that. And if we get significant carbon legislation, it will make more

sense.

Today with natural gas at $4-$5 in a million BTU, and building new natural gas for about $750 a kW versus $6,000 a kW for new nuclear, I mean, it makes sense for us to build new natural gas today, but we want to maintain that option.

PSC COMMISSIONER FLEMING: Talk a little about your vegetation maintenance program and your --

MR. YATES: We have a robust vegetation system. In the Carolinas, we spend about $22 million a year on vegetation management. We do it a little different. We focus on a five-year frequency or five-year cyclic -- cycle plan, although we have a risk-based plan. There are some feeders -- we have about -- we have 1,143 feeders, and there are some feeders that we don't do five-year cycles on because it hasn't been a significant reliability issue for us, so they may go six years. Nothing goes more than seven years, but mostly -- so our focus is five years; everything is not on five years. We have some cities where we have to do two-year cycles because of the requirements in the city. They don't let you cut; you can just trim around the wires. But we spend a fair amount of time and money on vegetation, qualified

arborists, environment -- qualified arborists and foresters.

PSC COMMISSIONER FLEMING: So five years is kind of the standard that everybody goes with, or that you share?

MR. YATES: I would say in this region. In some other parts of the country it's four, some -- you go out in the Southwest it changes. In this region, about five years is the right cycle.

PSC COMMISSIONER MITCHELL: Tell me about the pole management. What's the life existence, or do you consider on poles now? Is that changing any? I know there's been some talk about that. Just wondered what your position is.

MR. YATES: It depends on the pole and the environment. So we have poles -- we spend a lot of time on pole -- we have poles that -- so we do pole inspections every -- our goal is every ten years to inspect that pole. Some poles need to be changed out more than others, depending on the environment they sit in. So some poles are, you know, near the beach or near the ocean or in the swamps, so whatever environment, the frequency of changing out those poles is much more than a pole that sits, I don't know, in a dry environment, in an urban area

that just doesn't get a lot of use. So we have a robust pole maintenance program. We probably spend today about $20 million a year on pole replacement, pole inspection program.

PSC COMMISSIONER MITCHELL: Well, what's the average life? Do you know that offhand? I used to hear ten years -- 10 or 15 years. You just don't look at that much anymore?

MR. YATES: We just don't look at the average life, because it varies so much. I mean, I see them go in ten years, and I have some 60 years. So it's a wide variation. I think it depends much more on the environment the pole is in, and the type of pole.

[Brief pause]

Thank you, very much.

PSC CHIEF CLERK MS. BOYD: Thank you.

[Applause]

PSC CHIEF CLERK MS. BOYD: If everybody is okay, Mr. McMurry, can we proceed with you and then take a break? Okay.

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 1]

MR. McMURRY: Good morning, everybody. I

really enjoy coming third here, because of all the good speakers we've had before, and I'll try to build on what they've had. We've had scrubbers defined, we've had generation technology defined. I'm a little weak on the distribution side, so if you'd ease up on those questions, I'd appreciate it.

[Laughter]

But with that, I'm going to give an overview of where we are today and where we're looking to the future, in very quick fashion.

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 2]

And with that, this is the Duke Energy service territory. You can see the map in the far left-hand corner there. The left-hand corner is kind of where we are, and basically it's comprised of nuclear plants -- we have about 5,200 megawatts of nuclear. We really have -- there's really more than that; that's the 450 megawatts that we own of Catawba, but Catawba is really 2,200 megawatts. So where you see here it's 5,200 megawatts, that's really 7,000 megawatts in this service territory.

We have about 7,700 megawatts of fossil

generation, represented by the red dots on the map; we have about 3,200 megawatts of combustion turbines, represented by the yellow dots on the map; and about 3,200 megawatts of hydro, but 2,200 of that is pumped storage at Jocassee and Bad Creek, located in the western part of the South Carolina service territory, so we have about 1,100 megawatts of traditional hydro.

With that, so that's where we are today. So where are we headed to in the future? And one of the big things that's coming down the pike is, we have 1,650 megawatts of coal-fired generation that we're projected to be retiring in the 2015 timeframe. It's mostly driven by all the environmental regulations that's coming down, and these are all non-scrubbed units. And we're also taking 400 megawatts of older generation in combustion turbines. Basically, they're jet engines. They were built in the 1969-to-'71 timeframe. Basically they're just getting to the end-of-life.

So you look at those retirements; you can see where those retirements are, and it's at Dan River at the north end, Buck, Riverbend, Cliffside 1 through 4, Lee, and Buzzards Roost is a combustion

turbine station. That is where all of these retirements are located.

So we have to have something to replace this generation with. And so when you look -- well, first thing you're looking at is this first generation that's coming on is our Buck and Dan River combined-cycle generation. We have combined-cycle generation being brought along in 2011 and '12. And you can see with the bull's eye there, it's located at Dan River and Buck. Buck will be on-line by October of next year, and Dan River will be on-line by October 2012.

Another way we're replacing this generation is with coal. We've got the -- I think most of you are aware -- Cliffside Unit 6 effort that we're undergoing. It's more than halfway completed. It's 825 megawatts. And you can see where it's located -- where that'll be located. That is expected to come on-line by June 2012.

And last but not least is, what is our view for long-term power needs. And in a carbon-constrained future, we think nuclear must be a part of that solution, and right now we're developing a site at -- you know, I didn't put a green triangle on it, but it's right there at 99 Islands where Lee

Nuclear will be located. And it's expected to be brought on-line in the 2021 timeframe.

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 3]

With that, I'd just kind of like to give you an overview. I think these slides are interesting -- this is created out of our resource plan -- about how capacity will be met. So if you kind of look at the bottom down here, our projected peak is about 17,700 megawatts for 2010. When I say "peak," that's that 5 o'clock on a July afternoon at the hottest part and the most electricity used throughout the year. That would be our peak planning. And by 2029, we're looking at about 25,000 megawatts of peak.

So you kind of get a feel for our system now: About 27 percent is nuclear, 36 percent is coal, and about 30 percent is CTs and hydro right now; that's how our capacity's being met. But it changes out in the future, and the big change comes from coal. Coal is now 36 percent but by 2029 with this higher projected peak, it's only going to be 29 percent.

So what's really making up that difference in

capacity? Well, it's mainly your combined-cycles and CTs. The capacity addition does include Lee Nuclear, but it only increases by 3 percent from 2010 to 2029 as a percentage of your total generation. But the big decreases in coal are being made up primarily with the CTs and combined-cycles.

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 4]

Energy looks a little different. Energy, right now, we have about 52 percent of our energy generated with nuclear generation. Coal-fired generation is about 42 percent. You can see we have really no combined-cycle generation in terms of this, no renewables, and very little energy efficiency/conservation. So, we're projected to grow from 189,000 [sic] megawatt-hours to 124,000 megawatt-hours by 2030.

So what do we look like in the future? Again, the big change is in coal. We've go from 42 percent to 31 percent of our generation mix being met with coal. And where is that being picked up at? Well, it's being picked up with combined-cycles, increased conservation due to energy

efficiency, and about 5 percent of it being met with renewables.

PSC CHIEF CLERK MS. BOYD: Can I ask a question?

MR. McMURRY: Yes.

PSC CHIEF CLERK MS. BOYD: Do you think that you'll eventually, let's say 50 years from now, not need coal, or maybe will decrease by another 50 percent by that time? Do you foresee, in the future, not using your coal plants at all?

MR. McMURRY: Well, that's very long-range planning.

PSC CHIEF CLERK MS. BOYD: Yeah, very.

MR. McMURRY: And we've looked at a 2050, just like on a spreadsheet exercise -- not doing detailed hourly modeling -- because it's really just scenario planning. And if you start looking at the age of our existing coal assets, every coal asset we own will have to be retired prior to 2050.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. McMURRY: What's that replaced with? You know, if we get carbon capture and sequestration becomes a better option in the future, I would say that we would have more coal generation.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. McMURRY: But right now, all of the existing coal-fired generation -- with maybe the exception of Cliffside Unit 6 -- will have met their end-of-life by 2050.

PSC CHIEF CLERK MS. BOYD: Okay.

MR. McMURRY: Yes.

PURC COMMITTEE STAFF MS. ANDERSON: What types of renewables are you all looking at?

MR. McMURRY: The majority of the renewable that makes up this in our current plan is biomass, and that's really been promoted earlier. There's a lot of challenges to biomass right now, and that's a great concern to us that, you know, we have a North Carolina requirement to meet, and biomass was included when they set those requirements for us to meet, and now there's all these challenges, you know, can you really burn wood waste products on a sustainable basis.

But there's also -- but that's early. We have a chicken-litter requirement where we have to have a certain amount of our renewable energy by burning chicken litter as a fuel; and we have a hog waste requirement; we've got a solar requirement. The solar requirement is fairly low, but those are carve-outs that we have to meet as a part of this.

Longer term, when we're looking at meeting these energy needs, longer term, that is driven primarily with wind. I don't know if it's coming from the coast of the Carolinas or if it's coming from the mountains or if we're getting this delivered to our service territory from other regions. We've had opportunities to pursue that, but we haven't struck any of those at this time.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Does this -- on your hydro, are you assuming that FERC relicenses all the dams?

MR. McMURRY: That's correct. Basically, we're not adding new hydro. That's the reason for the decrease between 2010 and 2029.

PSC LEGAL STAFF MR. MINGES: You've got some, I guess, solar that's being -- or, solar I guess around the Charlotte area, feeding some power into the grid. How is that working out?

MR. McMURRY: The best -- I mean, I work within 20 feet of the renewable energy group, so I hear stuff over the cube walls, so I get their company line. It's working very well. You know, there's been challenges and we've had a TPA with SunEdison that was north of Charlotte, and they had financing challenges right in the middle of this

recession. But when they brought the power on, it's operating as expected.

You know, basically, we've got a one megawatt facility in Shelby that just opened up and is generating power. So, best of my knowledge, it's delivering what it said it would deliver. But from a planning perspective long-term, we can only really count, because of the seasonal variations, on about 20 percent capacity from that solar generation, so it's not -- even though it's a zero-carbon resource, it's not replacing that base-load nuclear in the long term.

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 5]

Let's see. Transmission. Remember what I said when I opened up. This comes from Ed Ernst; I think you'll hear from him a little bit later today. That's where I got this information from.

We've got 13,000 circuit miles of transmission. It's made up primarily of 44 kV, 69, 100, 161, 230, and 500 kV. These are quotes from Ed, that you'll hear from him a little bit later. But the 230 and 500 are representative of the red lines -- the 500 -- on the map, and the 230 is

represented by the blue line. And in his best -- I said, "Put it in simple terms for me, Ed. How can I explain this to my audience today?" And he said, "Basically, they're the highway of your generation. That's how you get power all over your grid. One area goes down; you've got another way to get power to that area. So that is your highway. And the 100 kV and lower is really the delivery to your customers."

So that's about as basic as he could put it, and at least it made sense to a civil engineer, so --

[Laughter]

But as we go through, we've got 21 interconnects with nine neighboring control areas. So this is very versatile; we've got a lot of places that we can connect outside of our service territories.

And planning for the future, like I said, I got this from Ed and he was basically saying as load increases, we're trying to utilize our existing infrastructure as much as possible. We'll be making line upgrades or adding additional lines to the system structures, but we really don't like to look long-term to adding new power lines and new

right-of-way. One exception would be right here at Lee Nuclear where we would be putting -- we would have to have some transmission access to that, so that's kind of the one exception of new transmission that we may have to add long-term.

And also, as the load increases, of course, the number of distribution stations we have will have to also increase.

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 6]

I don't think I got us back on schedule, but I'll be glad to take any questions.

PSC CHAIRMAN HOWARD: Of your DSM, what part of that is your efficiency and what part is DSM? You've got it split, but you don't have -- you've got it combined.

MR. McMURRY: Well, on the energy slide --

[Ref: Duke Energy Carolinas Generation, Distribution & Transmission Systems PowerPoint Slide 4]

-- all of that would be conservation or energy efficiency, so we really don't count on a lot of energy being reduced in demand-response. That only happens at that very peak hour. There would be

some small percentage of energy we would save with demand-response.

PSC CHAIRMAN HOWARD: So that would be your Save-A-Watt program?

MR. McMURRY: Well, Save-A-Watt has a demand-response, Power Manager/Power Share, and it also has an energy efficiency portion also, so I mean, that's combined. But if you go to the energy, that's all coming from conservation: a new heat pump at your house, a better motor at an industry, LED -- not LED -- CFL lighting. So all of that is conservation; and demand-response is, you know, where you have agreements with your customers to curtail their load, and they can meet that with other forms of generation.

And as you can see, as compared to capacity --

[Ref: Duke Energy Carolinas *Generation, Distribution & Transmission Systems* PowerPoint Slide 3]

-- this 4 percent DSM, about 75 percent of that is coming from demand-response on the capacity side, but your -- only, you know, maybe 1 percent of that would be from the conservation.

[Brief pause]

Thank you, very much.

[Applause]

PSC CHIEF CLERK MS. BOYD: We're going to take a 15-minute break and come back at 11:30.

[WHEREUPON, a recess was taken from 11:15 to 11:30 a.m.]

PSC CHIEF CLERK MS. BOYD: It's time to start again. I appreciate your patience. Let me just tell you about some schedule changes, quickly. What we're going to do is continue on the agenda with transmission planning and the Eastern Interconnection Planning Collaborative. So those presenters will -- the time we've allotted for them is from 11:30 until 12:30. Okay. At 12:30, I will return to the podium and make some other announcements, including the importance of you completing an evaluation before you leave today.

We've scheduled another workshop on August 18th for the smart grid and smart meters topics, and then the settlement process in utility matters will move to August 18th. That's a Wednesday. I'm looking at some space on our second floor. We don't lease the space for the Commission. It used to be leased by KB Home. And I'm hoping we can conduct the next workshop there. I just need to find some tables and chairs. So, but I will let

you know of the location as soon as possible.

So, we're moving -- we will next move to the presentations on transmission planning and the ICPC, okay? We'll stop at 12:30, and I'll make some comments, and then I'll ask that you please complete an evaluation that we have for you to complete, before you leave. That's essential. As we move forward and possibly tweak this process, there may be some things you think we should change, improve, additional topics that you think should be presented, so your information is vital for us improving the process today. I think today's been great -- that's just my personal opinion -- but I think as we move forward, we want to get better, maybe as to the topics that are presented, or the length. I'll leave that up to you when you complete your evaluations.

Okay. So our presenters for the next session include Mr. Charles White from South Carolina Electric & Gas Company; Ms. Kendal Bowman, Progress Energy Carolinas; Ed Ernst is joining us by phone, from Duke Energy Carolinas.

Charles White is vice president of Electric Transmission at South Carolina Electric & Gas Company. Mr. White has a BSEE and an MBA from

University of South Carolina and is a Registered Professional Engineer. He's been employed with SCE&G since 1966. During Mr. White's tenure with SCE&G, he has served in numerous leadership roles in various areas of the company. As vice president of SCE&G's electric transmission, he is responsible for planning the local and interconnected transmission system, as well as ensuring the safe and reliable and compliant operation of SCE&G's electric transmission system.

Ms. Kendal Bowman is an associate general counsel for Progress Energy. She currently provides counsel or support for North and South Carolina legal and regulatory affairs. Prior to this position, she led the Federal Regulatory Affairs Group within Progress's Legal Department and was responsible for all FERC, legal, policy, and compliance matters.

And finally, Mr. Ed Ernst, with Duke Energy Carolinas, is the director of Transmission Planning. He is responsible for development of the long-range electric transmission expansion plans for Duke Energy Carolinas' service area in North Carolina and South Carolina. He has a Bachelor's and a Master's Degree in electrical engineering and

is a Registered Professional Engineer in North Carolina and South Carolina.

Mr. White -- Oh, Ms. Bowman.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 1]

MS. BOWMAN: I'm going to actually start it off. We're going to tag-team the presentation, so I know many of you have it, and it seems very thick, but it's going to be all three of us doing it together, so we don't have three separate presentations. And I am the only attorney on the panel, so I get to talk to you about the legal implications, not the actual planning piece of this.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 2]

So, transmission planning and assessment: It occurs at the local level. Each utility conducts their own plan, their own transmission plan. We also now do it at the regional level, and this encompasses more than one utility footprint. So, for Progress Energy Carolinas and Duke Energy Carolinas, we have the North Carolina Transmission Planning Collaborative -- and I'm throwing out a lot of acronyms to you today -- the NCTPC. And Ed

is going to go in detail about what the NCTPC does for Duke and Progress. And then South Carolina has their own: SCANA and Santee Cooper have the SCRTP, which is South Carolina Regional Transmission Plan. So this is at the regional level.

Then we also have the multi-regional level, where we do planning and assessment. We coordinate our plans through bilateral interchange agreements. These are what I call the old agreements, wherever you had an intertie with another utility, you entered into an interchange agreement. Some of them date back to the '40s, '30s, '50s, '60s, and we even have a few in the '70s. We do coordination of plans through those interchange agreements.

We also do assessment of plans through various industrywide groups, such as NERC, SERC, the Electric Reliability Council, and down in Florida we do it through the FRPC.

Then we have the Southeast Interregional Participation Process. Another acronym: SIRPP. This was created after some FERC orders that I'm going to go over, and Ed is going to talk to you in detail about what the SIRPP does. Duke, Progress, and SCANA all participate in the SIRPP.

Then we also have, at an even higher level,

the Eastern Interconnection Planning Collaborative, and this is the entire Eastern Interconnect. Charles is going to talk to you about the Eastern Interconnection Planning Collaborative. And another acronym: EIPC.

So where did all this come from?

[Ref: *Overview of Transmission Planning* PowerPoint Slide 3]

Our focus today is going to be on the FERC orders related to transmission planning. We're going to talk about our regional planning, the SIRPP, the Eastern Interconnection Planning, and I'm going to talk to you briefly about our current proposed rulemaking at FERC to implement even more rules on transmission planning and cost allocation. The billion-dollar question is how do you pay for these transmission lines, and who is going to pay for them, more importantly. So we'll spend a little bit of time on that.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 4]

Just some background: FERC Orders 888 and 889. These were landmark orders that altered the face of the electric industry. These were released in 1996, right after the Energy Policy Act of 1992,

where they opened up the wholesale market and the Federal Energy Regulatory Commission determined that there was not enough open and transparent use of the transmission system, so they came up with these companion orders, 888 and 889. Oddly enough, they were named after the location and address of FERC's new building up in Washington, DC, which was 888 First Street, Northeast. So that's how they came up with these numbers for their orders.

Order 888 required transmission-owning utilities to provide nondiscriminatory access to transmission customers. They had to open up their transmission system for any other transmission customers to use it. They also required utilities to post information about their transmission system on the Internet. Another acronym for you: We call this system OASIS, Open Access Same-Time Information System.

Anybody in this room, if you wanted to, could go onto your Internet and access utilities' OASIS sites. It has real-time data about the transmission that's available, and people can schedule transmission service through the Internet. We do require that if you're going to schedule transmission service, you have to get a specific

digital certificate. So not just anybody can schedule transmission service; you actually have to prove that you have a need to schedule transmission service.

It also mandated the functional separation of transmission and our merchant functions. This was the famous FERC Standards of Conduct, that I'm sure many of the Commissioners have heard about, and it has spawned quite a few other orders making tweaks here and there to the Standards of Conduct. But these are the landmark orders that kind of kicked off the whole concept of transmission planning and making it more formal from a Federal perspective.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 5]

Then came along FERC Order 890. This was issued in February 2007. Now, this rulemaking encompassed a lot more than just transmission planning. It was an 800-page rulemaking. I'm only going to go over the aspects of Order 890 as they relate to transmission planning, and I'm going to hit them very briefly.

It provided certain reforms to the planning aspects of 888 and 889. It required transmission providers to establish an open, transparent, and

coordinated transmission planning process. And each utility had to make a compliance filing in December of 2007 to meet these requirements. That's more affectionately known to the utilities as our Attachment K's. I'm sure many of you have heard that term; that's what these are. These are processes in our actual transmission tariff that we file on FERC, that tells you how we meet the requirements of Order 890.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 6]

Okay. What did 890 actually require from a planning standpoint? You had to have coordination. You had to work with your neighboring utilities. I look at my plan and your plan; do they work together? Is there a way we can improve them? So that's when we created the North Carolina Collaborative and then the South Carolina RTP. We're working together. We come up with our own plan, and then we work with Duke. They come up with their plan, and we look at them together, and we come up with a way to improve them. So you have to coordinate your plans.

Then they have to be open and transparent. You have to have a stakeholder process. All the

marketers, the merchants, the muni's, and the co-ops need to be able to come and have input and look at your plans that you're putting together, because they affect them as well. So it has to be an open and transparent process.

You also have information exchange. You have to share your data with the stakeholders. Whatever data you use to build your models and your studies, you need to be able to share that data with the stakeholders so they can replicate them.

Comparability: Everybody needs to be on the same level playing field. Everybody has an equal footing.

Dispute resolution: You need to have a mechanism to handle arguments. Now, not everybody's Attachment K has the same thing when it comes to dispute resolutions. Some say they're going to defer to their states to be the arbiter, some are going to take it to FERC, others are going to hire an independent arbiter. But you have to have some kind of dispute resolution mechanism.

You also have to have regional participation. It can't be just one utility and you meet the Order 890 principles. You have to be bigger than just one utility.

You also have to have economic planning studies and a cost-allocation mechanism for economic planning. Traditionally, the utilities do reliability planning. We plan to keep the lights on. What do we need to build from a transmission standpoint to keep the lights on? But when 890 came out, FERC wanted you to also look at economic transmission projects. Somebody wanted to send power from Louisiana up to Maine; you know, is that really reliability or is that economic? So FERC wanted you to look at that, as well, and they created a principle in 890 that these regional planning processes need to look at economic planning studies.

And then they wanted you to come up with a method for cost allocation. If you build this big economic project, who's going to pay for it?

[Ref: *Overview of Transmission Planning* PowerPoint Slide 7]

And now I will turn it over to a Ed. Ed, if you're there?

By the way, if you have any questions, just feel free to ask along the way.

MR. ERNST (BY PHONE): Okay. This is Ed Ernst, and I appreciate the chance to go through

these slides on our North Carolina Transmission Collaborative.

We'll move to Slide 8.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 8]

I'll talk a little bit about is what the planning collaborative is, and it is a process by which we develop a collaborative transmission plan for the systems of both Progress Energy and Duke. We do that for the footprints of the two companies in both North and South Carolina.

It was created back in 2005 by an agreement between Duke; Progress; NC Electric Membership Corporation, which is the co-operatives in North Carolina; and ElectriCities, which are municipalities in North Carolina. And in 2007, as we got Order 890, we went about and modified the framework of the planning collaborative to meet the various requirements and principles in FERC Order 890.

We'll look at the next slide, Slide 9.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 9]

The structure of the planning collaborative, we have an Oversight Steering Committee which

provides the overall direction for the planning process, and has members from Duke, Progress, North Carolina EMC, and ElectriCities. We have a Planning Working Group, which is our technical engineering group that actually does the analytical work, builds the computer models, performs the studies. And again, Duke and Progress, North Carolina EMC, and ElectriCities have representatives on that group.

The Transmission Advisory Group, or what we call the TAG, this is our stakeholder group. It's open to any and all interested participants, and we have the Transmission Advisory Group to meet about four times each year through our planning cycle. We have folks come from neighboring utilities. We'll have developers of potential new merchant generation. We'll have consultants, we'll have regulatory staff. Folks come particularly from North Carolina. So that group meets four times a year and provides input on the whole planning process through the year.

And then we have an independent third party, a gentleman by the name of Rich Wolyka, who facilitates our planning process through the year, and in particular, takes a lead role in arranging

our meetings with our Transmission Advisory Group

If we look at Slide 10 --

[Ref: *Overview of Transmission Planning* PowerPoint Slide 10]

-- what we talk about in the collaborative and what we produce is an annual collaborative plan for the transmission systems of both Progress and Duke, and it does cover the footprints of the two systems in North and South Carolina.

So even though the name of the process is the North Carolina Collaborative, we're addressing the systems of the two companies in both states, in the planning process.

Slide 11 --

[Ref: *Overview of Transmission Planning* PowerPoint Slide 11]

-- I'll get all these points up here. We've been at this since 2005. And, let's say, some of the benefits we've observed, obviously, is greater communication amongst all the interested parties. So, from that communication comes better understanding on how transmission planning is done, and some of the information we use in the transmission planning models. We've also used the planning collaborative to talk about things that

are going on at NERC in terms of viability standards, or FERC in terms of open or pending orders that could impact the way we do transmission planning. And then, as I said, the objective of this whole process is to produce a plan, and a plan is a list of projects that the companies will then go build to reliably serve their customers. And doing this collaborative planning, we have on occasion developed what I would call a better solution to a project than if each company were looking at things totally independently.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 12]

Slide 12 kind of lays out the steps that we go through. It is an annual planning process. Early in the year, we finalize a scope of work for the year. The Steering Committee will put that together, get input from our Transmission Advisory Group. We'll finalize that study scope. In the February-through-June timeframe, our Planning Working Group, our engineering group, will go out and build the computer models, and we do the computer simulations to look at future years to perform the various transmission planning studies.

Through the summer, we begin to get dumps from

that analytical work. We begin to see what kinds of potential issues or problems the models are indicating to us we will have in future years, and what sort of improvements or solutions we need to put in to address those problems so that we're serving users of the transmission system reliably.

In late summer, typically at a point where we have a meeting with the Transmission Advisory Group, we're reviewing that analytical work with them, soliciting their input on alternative solutions. We're sharing with them what we're thinking, but we're asking for input on possible other things we could consider as solutions to address the problems we're finding.

We then take that input and finalize on the final select group of solutions involved. We then begin to develop a draft report which describes what we've done for the year, as well as the various projects that we're planning to do.

We bring that back to our Transmission Advisory Group in the December timeframe, get their input on that draft report. And then early in January, typically, we'll release that as a final report. Then we'll start the process all over.

So the annual process, there's some

stakeholder input through our Transmission Advisory Group about four times a year, and the final deliverable is that annual plan which describes the various projects of the companies we're planning to do over the next ten years.

With that, I'll kind of complete my discussion on the collaborative and return the call back to you folks.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 13]

MS. BOWMAN: Okay, we're going to turn it over to Charles now. I do want to let everybody know that Ed is actually up in Chicago right now at the first-ever Eastern Interconnection Planning Collaborative stakeholder meeting. This is the big first meeting. They've been up there -- I think they've been up there since Wednesday -- Ed, is that correct?

[No response]

But that's where he is, he's calling in from up there.

MS. SANDS: He's muted, I'm sorry. Did you want to talk to him?

MS. BOWMAN: Well, no. He'll have to come back for another portion, though.

MR. WHITE: I'm Charles White. Thanks for having me here. Glad to be here. If you have any questions, don't hesitate to ask. Kendal will be back after I finish the SCRTP and EICP.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 14]

What is the SCRTP? It was created in 2007 in response to the FERC 890 order that you've heard a lot about from Kendal and Ed. It is a planning process for the systems of SCE&G and Santee. SCE&G and Santee, we have a very tightly interwoven system in South Carolina. We serve a lot of the same areas, and 12 of our 22 ties are with Santee Cooper. So it made sense for us to have a process with them.

Again, it provides exchange of information and open communications with all the stakeholders. We allow them to provide us with their information, tell us about their future loads, tell us about their future resource needs. We show them our plans and they give us input and suggest alternatives and things like that. So we use the same kind of a process that we just heard about.

Again, it involves the stakeholders through their stakeholder group members, to provide us all

this input, and to do that we have quarterly meetings where we present them information, and then they come to the meeting, give us input, we present information again and they come back. So it's an integral process throughout the year.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 15]

The types of planning we do are reliability and economic. The reliability plans that we do from a local standpoint plan transmission to serve our customers. We do a very good job of that, as well as Duke and Progress. We make sure that we can get our generation to our customers. We have a very robust plan, a very robust transmission system. And we share that information with the stakeholders so they'll see what we're planning, they'll see what we're doing, they'll see how we're serving our customers, they'll see what the model of the system is and what our planning process spits out.

We do economic planning, and the stakeholders have a right to ask Santee and SCE&G to do economic studies to tell us -- give us information as to what the transmission costs may be if you wanted to move 500 megawatts across the system, or into your

system, or out of your system, tell us -- now, this is information for the stakeholders to use in future requests for real transmission. This is not to develop an economic plan for them; it's just information for them to decide in the future if they wanted to move that 500 megawatts across the system, and it gives them an idea for their future planning.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 16]

The stakeholder group sectors, as you see here: Transmission, network and point-to-point customers, co-operatives, muni's, marketers, generation owners, state regulatory representatives -- the ORS either comes to our meetings or they join by a conference call. We also have FERC members that either come to our meeting or join by conference call. So we have good participation from the State and FERC to watch our processes and ask questions and be part of the ongoing process.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 17]

The activities: Again, we present and discuss our transmission process and our plan. One of the questions that we had from the stakeholders when we

started this process is, "Tell us how you do your plan. You know, you're the ones that plan the system, but we don't see what you do, so please explain that process," so we go through and explain the process, and we explained our plan that we'd come up with to serve the customers in our footprint.

We exchange data and information, as I said: load data, generation data. The key assumptions we make in the model, we share our model with them. We actually put it on the websites so the stakeholders can actually take our model, take our plans, and look at what we've done and replicate the studies -- if they want to replicate the studies that we've done, just to make sure that we've done what we've said we've done, they have the right to do that.

Again, the stakeholders identify up to five economic transfer studies that we perform for them, provide them that information for their future decision-making and future plans in how to use the system. And that's the economic power transfer studies that we do and provide the information.

So, again, we have a robust process very similar to the North Carolina Collaborative in

South Carolina, and then these plans get put together in other processes that we have as transmission planners, to make sure we all link together and we all understand. We've been planning together since -- a long, long time -- long before I even came, so we know how to do it, we've been doing it for years, and we still do it.

And Ed -- Ed, you on the phone?

[Ref: *Overview of Transmission Planning* PowerPoint Slide 18]

MR. ERNST (BY PHONE): Yeah. We'll talk next about the SIRPP, or the Southeastern Interregional Participation Process. And I'm looking now at Slide 19, I believe it is.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 19]

And to just describe to you what it is -- and, you know, as Charles and I have described the various regional processes, if the stakeholders want to look at things that go beyond regions then we have this process in place in the Southeast where stakeholders can request that we look at economic studies very much as Charles just described from the South Carolina plan, but we can do this on a broader interregional basis. So this

is what the SIRPP is all about, is a stakeholder-driven process to look at studies that cut across the four regions, and it was put in place back in 2007 as each of the Southeastern transmission providers worked on their Order 890 compliance filings.

If we move to the next slide --

[Ref: *Overview of Transmission Planning* PowerPoint Slide 20]

-- you can see the various companies that make up the SIRPP. Included in that is South Carolina Electric & Gas, Santee Cooper, Progress, and Duke. And then you can see the other companies, which would include companies such as Southern and TVA and Entergy. So it really covers the footprint of the whole Southeast, and so it's a mechanism for us to do studies that would impact these systems across all the Southeast.

In terms of the organization or structure, on the next page --

[Ref: *Overview of Transmission Planning* PowerPoint Slide 21]

-- once again, we have a stakeholder group and their primary role here is to define each year the various economic studies that they want the various

SIRPP companies to go and do analytical work on. So each year, we go to them and we say, "You have five studies you can look at. Tell us the five most important things you want to know about, and we'll translate that into study work."

[Ref: *Overview of Transmission Planning* PowerPoint Slide 22]

Slide 22 gives you a flavor of the type of studies that we do. And I think the main thing I would draw from this slide is that these are large blocks of power moving across multiple systems. As you can see, the actual studies that we're doing in this year's cycle: 3,000 megawatts for Midwest ISO and PJM West to SIRPP at the bottom, as an example. So these are typically large blocks that go across multiple regions, so that what we're giving the stakeholders back is information on not only the impact that we would see here in the Carolinas from these various transfers, but what the other companies -- Southern, TVA, Entergy, et cetera -- would see.

Charles, I'll turn it back to you to talk about the EIPC.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 23]

MR. WHITE: Okay. Thank you, Ed. This is a lot of information, I know. So, again, if you have questions, don't hesitate to ask.

PSC CHIEF CLERK MS. BOYD: Can I ask one?

MR. WHITE: Sure.

PSC CHIEF CLERK MS. BOYD: On a basic level, can you just talk about how -- for example, you talked about SCE&G and -- I'm sorry, Duke Energy and Progress working together on a plan. How do your systems interact -- on the transmission systems -- interact on a daily basis? Do you know when something is wrong?

MR. WHITE: Yes.

PSC CHIEF CLERK MS. BOYD: Do both of you know at the same time? If you could, just on a basic level, describe that, I think that would help.

MR. WHITE: All utilities -- and you'll see in a slide in just a minute -- in the country are intertied, especially in the Eastern Interconnect. We're tied together through our intertie lines. As I mentioned, we have 12 of 22 lines with Santee. We have the other ten tie lines with Southern, SEPA, Progress, Duke, and then they tie to neighboring utilities. So we're all tied together, and we have a control room that we monitor the

system in real-time, 24/7.

So when something happens in Canada, we can see it. Now, it doesn't affect us as badly down here if it happens in Canada, as if it happened on our system or on Duke's system next door, but we monitor the system in real-time. We get data from our system every four seconds. Duke gets that in four seconds. Progress, Southern, everybody. So it's an intertied system, and you heard Belton talk this morning about the utilities, that they began to buy smaller systems and put in bigger plants and grow, grow, grow. But that process occurred a long, long time ago, when people said, "Well, I've got this big plant and I'm serving this area here, but when that goes down I don't have enough plant. So wait a minute, there's a plant over there. Somebody else, another guy has a system. So let's tie together, so if my plant goes out, we have agreements and you help me," and that's how it grew. So we're now an interconnected system throughout the whole United States, basically, although the stronger ties we have are here.

PSC CHIEF CLERK MS. BOYD: Thank you.

MR. WHITE: Sure. Okay. EIPC, as you can see we do a lot of planning. We all do a very good job

of doing local planning for our customers and ratepayers; we do a very good job of interconnected planning to make sure that we are interconnected and we do know what's going on the system and we can manage it.

As you know, the Federal Government's involved a lot in the planning process to make sure we're doing a good job and to make sure the stakeholders know about it. With some of the talk of a new energy policy and some other things that are going on in the industry, the word is coming out that maybe there should be a third party to do the planning in the Eastern Interconnect.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 24]

And the Eastern Interconnect is this half of the country [indicating], all the way up into Canada, so Canada's part of our Eastern Interconnect. So what we were hearing was, you know, there should be another party doing the planning, and so the planning authorities in the Eastern Interconnect -- and I'll show you a list of them in a minute -- said, "Wait a minute, we are responsible for the planning. We do a good job, we plan for local interconnected systems. So why

don't we band together and we be that planner for the Eastern Interconnect," and therefore --

[Ref: *Overview of Transmission Planning* PowerPoint Slide 25]

-- the EIPC was born. It's the Eastern Interconnection Planning Collaborative. The planning authorities throughout the Eastern Interconnect, including US and Canada, met, got together, we arranged agreements, signed contracts, to do this planning for the eastern half of the country and Canada.

We have over 600 gigawatts of connected customer load. And again, we cover a large, large area and we're responsible for planning in a large area.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 26]

These are the companies that have signed and are part of the Eastern Interconnect: Progress, South Carolina Electric & Gas, Duke, Santee. As you can see, we have IESO, which is in Canada, and we have New Brunswick in Canada. They're signatories to our process also. So, truly, we cover the whole eastern half of North America.

You see a term here [indicating] "principal

investigators." The American Recovery and Reinvestment Act gave the DOE money to fund some of this planning. So we said, "Well, we have a group together. We're planning authorities, we do the planning, so let's bid on the DOE contract." The DOE contract requires what they call principal investigators to be responsible for meeting the DOE contract terms and for providing some of the accounting and tracking that's required by the DOE funding. So there are some of those companies that stepped up to the plate and said, "We'll be the principal investigators and we'll deal with DOE and we'll deal with the accounting measures, and the rest of you just help us do the planning process," which has worked out great for us.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 27]

This is a very busy slide. I'm not going to go through every piece. Certainly, if you have questions on it later, you can ask, and we'll provide information. But as you see, there's lots of information in lots of places.

The EIPC sits here, the DOE, the states, FERC. Everybody has a right to provide input into the process. One of the things that we wanted to do as

Eastern Interconnect Planning Collaborative was to make sure that we rolled up our local and regional plans -- and you'll see this repeated again. We want to make sure that we use our local and regional plans as the foundation for the planning process that expanded throughout the Eastern Interconnect. And again, the process allows input and scenarios from people who want to look at wind, for people who want to look at alternative energy, look at fuel prices and things like that.

So this is a very busy slide. Lots of input, lots of process, but the EIPC takes all that input, develops the models and the planning processes to look at all the scenarios that come out of the stakeholder process.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 28]

The objectives: Number one is gone, but that's okay. It is, again, to make sure we have a local and regional planning process as our base; that's what number one said. Number two is to develop possible interregional expansion scenarios to be studied; look at the different scenarios that people might want to say, "Well, look at expanding this, and expanding that, and give us information."

Again, information scenarios. We're committed to an open and transparent process, as the 890 process requires. So, again, it's a lot of stakeholders, a lot of involvement, a lot of people.

Roll up analysis of local and regional plans, possible interregional expansion scenarios.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 29]

The structure's in place. We have 26 planning authorities, which I've shown you. We have a website, if anybody wants to go out to the website and look, get more information about the EIPC, it's there.

We have formation of the Stakeholder Steering Committee. We've worked on that process; the Stakeholder Committee has been formed. Some of the initial meetings are going on in Chicago. There will be more meetings, obviously, to move forward with the scenario planning and the information that goes into the plan. We're very well represented here. We have people from Duke, Progress, and SCE&G; Clay Young, my planning manager, Ed Ernst you've heard, [name inaudible] from Santee -- from Progress is on there, and Commissioner Fleming is also a part of the Steering Committee. So our area

is very well represented, and that's by design. We want to make sure that whatever plan comes out of here does not negatively impact our local and regional plans. We don't want a negative impact on customers, if at all possible.

Again, DOE announced funding, which we bid on. We received funding for the planning process, and also funding for state participation, which ICPC and the states received that funding and there'll be very, very good, very involved participation in the process going forward.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 30]

Again, our primary task from the DOE project is having an open and inclusive stakeholder process, which we do. Integration of existing regional plans to form the interconnection, widen the planning process. Potential resource futures, economic analysis. Look at possible resources into the future and how will they impact the transmission system. Complete interconnectionwide analysis of stakeholder scenarios based on our transmission topology, the model, how it's interconnected and what goes into the transmission system.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 31]

Again, you'll see this again: Roll up our integrated plan, which we use that as the foundation. There will be macroeconomic studies, sensitivities, you know, different fuel assumptions in the future, how will that affect the transmission system. Different cap-and-trade or carbon legislation, how will that affect it. So we'll try in our plan to look at those types of things and measure some of the sensitivities and say, "Well, if this happens, the transmission system will look like this. If that happens, it'll look like that." So we'll provide that as information to the policymakers and all those parts and pieces you saw in the earlier slides, so they can make better informed decisions, so, "If we decide to do this, gee, that's the cost. If we do that, then something different."

Three future resource scenarios, and we're required to have the DOE project -- fall of 2011, our first report; and fall of 2012, the second report. Now those dates are always subject to change, obviously.

[Ref: *Overview of Transmission Planning*

PowerPoint Slide 32]

This is a busy slide, also, but this sort of depicts the process that we use for the regional planning. We start with regional planning, goes into the models, and Ed Ernst shared about that team that develops models. Get scenarios from the sub-processes, the state, the DOE, and other stakeholders, and then runs through the process. And at the end we'll publish a final report, which is used in policy discussions.

Again, it's an information process to provide information to the policymakers so that they'll understand what they're doing will affect the transmission grid cost. We want to make sure, again, it doesn't negatively impact our needs here. We want to make sure that when people think about moving wind, say, from the Midwest to the East, what is the cost of doing that and who does it impact. We want to make sure -- we'd like to make sure that the cost-causer is who pays for it, not -- if we don't get benefit of it, we don't want to have to pay for it. The person that gets the benefit or causes the cost, we'd like to make sure in this process that they understand the cost as well as who needs to pay for it.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 33]

The sectors and seats: Again, we have the Steering Committee: three transmission, three generation, other suppliers, and right on down. You see state representatives, Canadian Provincial representative, ex officio members from the DOE and EPA, and others. So it's 29 members. Those sector representatives vote the positions of that sector. For instance, generation folks, those three representatives vote the generation sector desires. The transmission votes the transmission sector. So, obviously, there are more, for instance, transmission providers in the Eastern Interconnect than just three, so there's a process.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 34]

There's a caucus process where all the transmission providers in all the Eastern Interconnect get together and they meet and they talk about "How do we want you, as our sector representative, to vote?" It's a similar process to generation, similar process for all the other sectors. This is just representative of the caucus type process.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 35]

The schedule for 2010 is: July 6th, we announced the Steering Committee members. The meeting in Chicago is just the setup meeting, the beginning of it. Obviously, there are going to be many, many, many more meetings following this initial setup meeting. And September/October, initial results from the 2020 integrated regional case. The models that we would be working was a 2020 model, and the 2020 model will include everything in the transmission and generation plan that we all either have put in, plan to put in, into the grid, so the model will be inclusive. And the fall of 2010, initial work on the macroeconomic analysis.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 36]

And that's the discussion of the EIPC. There's a lot of information there. Again, we want to make sure, one, it's a bottom-up planning process; two, make sure it does not negatively impact our customers; make sure we provide good information so that the policymakers know that the decisions they make going forward, how it impacts

the transmission grid, the cost, and the customers. So again it's a lot of information, but any questions?

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Charles, what authority does ICPC actually have?

MR. WHITE: ICPC? The DOE requirement was that the states have considerable input into the scenarios and decision-making as to what planning is, so they have a good bit of authority, good bit of input.

PSC EXECUTIVE ASSISTANT DR. SPEARMAN: Can they require a state to change their plans, or a utility to change their plans?

MS. BOWMAN: No.

MR. WHITE: No, they cannot.

MS. BOWMAN: The planning collaborative, all it is is a study and a plan. It doesn't mandate anybody actually constructing transmission underneath that plan.

MR. WHITE: We do not develop transmission construction plans. What we provide is information. As planning authorities with all the information about what scenarios you want to study, what thoughts you might have moving this here, there -- it's really similar to the SIRPP process;

we don't develop plans there either. We develop information, so that we inform the policymakers, "If you make this policy decision, understand this is how it will affect the transmission." So the decision, we hope, will be better informed, maybe different than what the scenario was. But it is information. So, there are no plans that come out of that, no construction that comes out of that, and no authorities that can cause anything to be constructed.

Yes.

PSC COMMISSIONER WHITFIELD: Back on -- I think it's Slide 26, you had the planning authorities, the slide with the planning authorities?

MR. WHITE: Uh-huh?

PSC COMMISSIONER WHITFIELD: And you talked about the investigators on the DOE project. If you could maybe expand on exactly what those investigators do, and did you say they were -- it was voluntary? Or were they appointed? Or how were those investigators chosen? Because I notice there are none from any of the South Carolina IOUs or Santee Cooper or anything. I just wondered how those were chosen.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 26]

MR. WHITE: Well, the planning authorities, the 26 that signed the contract to do the planning, we're all on equal footing in terms of input, in terms of plan. We all work together to develop the model, we all work together to do the planning studies based on the scenarios that come in. The DOE contract required someone to have -- and as you notice, most of them are very large -- PJM, Southern, they're all large, so they had a very large infrastructure that could take on the requirements that the DOE and Federal Government had for accounting, tracking, payments, contracts. So they stepped up to the plate and volunteered, said, "Hey, we've got infrastructure that supports that. It doesn't affect how we all are involved in the process but we'll just take on that burden of the administrative piece."

PSC COMMISSIONER WHITFIELD: Entergy? Some of the larger --

MR. WHITE: Entergy, yes. Yeah.

MS. BOWMAN: They're managing the funds.

MR. WHITE: Yes.

MS. BOWMAN: And most of the funds are going

to pay a consultant, I think it's Charles River Associates --

MR. WHITE: Yes.

MS. BOWMAN: -- to actually conduct the modeling and the studies.

MR. WHITE: Yes.

MS. BOWMAN: So they're kind of managing the fund, and I think PJM is the treasurer of that fund.

MR. WHITE: Right. DOE required someone that they could develop the contract with, sign the contract with, and manage the funds, and manage the administrative portions, so they said, "We'll do that for the EIPC group," and frankly, we were happy for them to take that on, because it's a tremendous burden to meet some of the DOE administrative and funding requirements.

Any other comments you have on that?

MS. BOWMAN: No.

MR. WHITE: Any other questions?

[No response]

Again, it's a lot of information. If you have questions I'm sure you'll find a way to get them answered. And thank you, very much.

[Applause]

MS. BOWMAN: Now, we did segue into the discussion on the FERC transmission planning and cost allocation NOPR. "NOPR" stands for Notice of Proposed Rulemaking, for those who want to know. I'm throwing out another acronym for you to learn today.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 37]

Apparently, with the discussion of a new energy policy, all the renewables, the desire to possibly create a transmission superhighway where you build 765 kV lines to bring in all the wind power from the Midwest over to the east coast where the load centers are, there's been a lot of discussion and apparently FERC thinks we need to do a better job in our regional and interconnection planning. They also want to help utilities figure out a way to get that paid for, to actually construct those facilities. So they came out with another Notice of Proposed Rulemaking, maybe make some more changes again to Order 890 and Order 888, and they came out with this rulemaking. They came out with it July 17th, so it hasn't been out there very long, but it's out there now if you want to go to their website and look it up. Comments are due

on August 30th.

The rule requires transmission providers to consider not only transmission solutions but also non-transmission solutions. So, you know, that includes a vast array of things, from energy efficiency, demand-response, possibly locate generation close to your load so you don't have to build transmission. So not only do they want utilities to consider our basic what-do-we-need-to-build-to-account-for-load, we've also got to take into account all of these other non-transmission solutions.

They also want us to take into consideration public policy requirements in our planning process. This is fraught with concern, at least from my standpoint. There are jurisdictional issues, because states have their own public policy requirements; the Federal Government has their own policy requirements. We've got a lot of people pushing for even new Federal public policy requirements that haven't even been made into law, so how are the utilities going to weave that into their transmission planning? Just questions to think about.

They're also proposing to eliminate the right

of first refusal to construct transmission facilities. Now, a lot of the regional transmission organizations -- for example, PJM, New England ISO, the incumbent transmission utilities that actually own the assets -- have what they call right of first refusal to construct new transmission. When those regional transmission organizations come up with a plan, transmission plan, and we need to construct x, y, and z transmission, the utility in the service territory that line needs to be constructed has the right of first refusal to construct that line. And I think in just about every case, the utility constructs that line. Number one, they have eminent domain. Condemnation. They can condemn land and get an easement to construct that line. They also have a duty to serve those customers. So, you're starting to get into questions of your regulatory paradigm that Belton talked about.

If FERC requires this elimination of the right of first refusal and they allow merchant transmission owners to come in and build merchant lines when they have no retail load to serve, what happens to your duty to serve as an incumbent vertically integrated utility? Also, what happens

to eminent-domain condemnation? How do you give this merchant transmission company eminent domain to construct these lines? How are they going to prove a need for public convenience and necessity? So, interesting legal jurisdictional arguments that this NOPR raises.

MR. WHITE: Excuse me. It raises other issues like integration of merchant transmission into your existing transmission system, in terms of integration, operation, safety, maintenance, and so it introduces a lot of different things.

MS. BOWMAN: And what rate are you going to charge for that transmission line? How is that merchant company going to recover their rates? Are they going to recover it through the utility? And then you've also got to consider what is the ultimate impact to the consumers. How will this affect their rates? So, a lot of things in this NOPR that need to be thought about.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 38]

It requires interregional transmission planning agreements to be filed with FERC. So this big Eastern Interconnection Planning Collaborative, we're going to have to be all re-signed to an

agreement, and if you can imagine, getting an agreement from 29 utilities is not an easy thing. I think I spent seven months on the phone on the Legal Committee negotiating the terms and conditions with 29 other utilities who had their various legal representatives, so it's not necessarily an easy thing to come up with, but we're going to file one with FERC.

We're also going to have to put in place a method or set of methods for allocating the costs for these regional and interregional facilities. We already have cost-allocation mechanisms built in the North Carolina Planning Collaborative and the South Carolina RTP, and we have a cost-allocation mechanism in the SIRPP. We don't have one yet for the EIPC. And again, 29 utilities coming up with cost allocations is going to be a difficult thing.

One of the things FERC did say in the NOPR is that they're going to give the utilities a chance to come up with your cost allocation on your own, but if you don't do it in x amount of time -- and I think they give us six months.

MR. WHITE: Right.

MS. BOWMAN: If you don't come up with it in x amount of time, they will do it for you. Right now

it looks like they're taking the beneficiary-pays approach, so whoever benefits from that big line being constructed will be the one that pays for it, but it's still kind of up in the air.

We're all participating in this process, we're all going to file comments. I think there is a group of Southeast utilities working together to file comments jointly. I don't think everyone will sign on; obviously, we have different opinions there. But it's definitely something that needs to be followed, not only from the utility level, I think, but from the state level, as well, because it does have a lot of jurisdictional ramifications.

This is a hot topic right now in Washington, DC. You see all of the trade rags, everybody talking about the high-voltage transmission system. You have a group of people who think socialization amongst the entire Eastern Interconnect is the best thing. You can build a big 765 kV line from Indiana to New York City. They think everybody in the Eastern Interconnect, all ratepayers, should pay for that line. I'm not saying that's what's going to win the day, but you have arguments on both sides of the fence. So it is a very hot topic right now.

[Ref: *Overview of Transmission Planning* PowerPoint Slide 39]

All of the materials that we used in our presentation today can be found on various websites. We have the North Carolina Transmission Planning Collaborative website, the Southeastern Regional Planning website, Santee Cooper and South Carolina Electric & Gas have their own website, the Eastern Interconnection Planning Collaborative has its own website, and then obviously all the FERC orders I talked about can be found on the FERC website. So all the resources are here. I figured you didn't want to take home big binders with Orders 888 and 889.

With that, any questions? I'll open it up to Charles and Ed.

PSC COMMISSIONER FLEMING: I have a question. Could you give us a little information as to how you decided, of the two transmission groups for North Carolina and South Carolina -- Duke and Progress Energy both serve South Carolina.

MS. BOWMAN: Sure.

PSC COMMISSIONER FLEMING: It seems that they would -- you would have been a part of the South Carolina, as well as North Carolina.

MS. BOWMAN: We actually created the North Carolina Transmission Collaborative Planning before Order 890 even came out, even before it was in a rulemaking standpoint. The North Carolina Utilities Commission I think wanted Duke and Progress and the municipalities and co-operatives in the state to work together, so it was more of a state-created thing, and we'd already created that process ahead of time before Order 890 came out. We obviously invited SCANA and Santee Cooper to join, but I think they made the decision they wanted to do their own path in South Carolina, and I'll let Charles speak to that.

MR. WHITE: Yeah, their process has already been developed, and again, they modified their process with 890. We had not developed a process and we were developing one from the beginning, so rather than them to undo their process and put one together, it made sense for Santee and SCE&G to do it together. Again, we're interlaced throughout the South Carolina territory that we serve. 12 of our 22 ties are with Santee, so it just made sense for us to do that. It did not affect -- it does not affect the overall planning that we put together. They do theirs, we do ours, Southern

does theirs, TVA does theirs. We all do these pockets of plans, but we also have other mechanisms where we sit down and we piece it together and do it. So it doesn't have any inefficiencies in it. The efficiency was they had their process to go forth with it; we'll develop a process that we'll put together. So it actually, I think, is simpler, because we have better touch with our customers in our territory, and they have better touch with their customers in their territory.

MS. BOWMAN: And FERC has approved our Attachment K, so I think FERC has blessed those as a regional entity.

PSC COMMISSIONER FLEMING: I just wondered how it all got started with that.

MS. BOWMAN: Uh-huh.

PSC ADVISORY STAFF MR. ELLISON: Do you foresee the state commissions having any input or approval authority over any of the cost-allocation process?

MS. BOWMAN: Well, ultimately they will, because they're the ones who will approve the rates when we try to recover the costs from the customers. I think they do participate in the stakeholder processes of these planning

collaboratives that we've just described, and we would definitely seek their input on whatever cost-allocation method we were going to put forward.

MR. WHITE: We would hope that through the processes that we have in place, through the SIRPP and especially EIPC -- because the EIPC is where a lot of the scenario from these other resources is going to take place, you know, the information planning for that. We would hope that we, as utilities throughout the Southeast and our regulators and other regulators, will have input into that to say, "You know, this is what we believe is best for our customers, and therefore we'd like to see it this way," and hopefully through a process of working together we can come up with a solution that says, "Hey, the causer pays for it. Don't socialize it. And let's make good decisions about policies that affect the transmission grid so that we don't make a decision that affects one area, like ours, negatively."

So we're hoping that through our processes, we have enough input and enough time to work together to make sure we don't get in a situation like that.

PSC CHAIRMAN HOWARD: How does this vary from GridSouth?

MS. BOWMAN: GridSouth was a full-blown regional transmission organization that actually operated the transmission grid. We still maintain the operation and the functional control of our assets right now.

PSC CHAIRMAN HOWARD: But we were still recovering costs from that even after we got on the Commission.

MS. BOWMAN: Yes.

MR. WHITE: To tack on, we obviously own the assets; we plan the assets. Our goal was to make sure that we plan a system that serves our customers, and GridSouth would have been the one to have operated and controlled the assets. Right now, we control it; we maintain it; we operate it for the benefit of our customers. That's the way we like it. So there is a big difference.

[Brief pause]

MS. BOWMAN: Thank you.

[Applause]

PSC CHAIRMAN HOWARD: I just want to take this opportunity to thank Jocelyn for the job she did, and everybody working for her. I think they did a great job.

[Applause]

PSC CHIEF CLERK MS. BOYD: Well, that completes our program for today. I want to thank Mr. Senn with SCE&G, Ms. Harrison, and Mr. Denton -- Ms. Harrison with Progress Energy and then Mr. Denton with Duke Energy Carolinas -- for agreeing to hopefully come back on the 18th. And then I also want to thank Mitch Willoughby and Frank Ellerbe for agreeing to make their presentations on the 18th of August. We'll keep you posted on the location. We'd like to have it set up in an arrangement similar to this, if everybody is okay with that.

I want to thank everybody again. I really enjoyed today's workshop. I hope that you gained something from it. And we're going to distribute the evaluations now. If you would please just take some time to answer the questions, and we're going to use this -- I'm going to share the responses, of course, with the Advisory Committee as we move forward with other workshops, so that we can kind of address some of your concerns as best as possible. Okay?

Oh, and please make sure that you complete your statements, too, for the allowable ex parte statute provisions we have to comply with. They

probably tracked you down if they don't have your completed form yet. Thank you, again.

[Applause]

[WHEREUPON, at 12:30 p.m., the ex parte proceedings in the above-entitled matter were adjourned.]
