BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. UNDOCKETED

REVIEW OF TEN-YEAR SITE PLANS
OF ELECTRIC UTILITIES.
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PROCEEDINGS:	WORKSHOP
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER LISA POLAK EDGAR COMMISSIONER RONALD A. BRISÉ COMMISSIONER EDUARDO E. BALBIS COMMISSIONER JULIE I. BROWN
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TIME:	Commenced at 9:30 a.m. Concluded at 12:20 p.m.
PLACE:	Betty Easley Conference Center Hearing Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official Commission Reporter (850) 413-6732

P R O C E E D I N G S

CHAIRMAN GRAHAM: Good morning, everyone.

(Audience response.)

Oh, wow. I like that. I hope everybody had a fantastic Labor Day weekend. I know I did. And I'm glad we didn't have this thing first thing yesterday, because it was difficult getting started yesterday.

All right. Speaking of getting started, let the record show it is September the 7th, 2011. It is 9:30 a.m. And this is a Commission workshop on the electric utility ten-year site plans. And I wasn't smart enough to bring my script down with me, so I am going to look over here to staff. And I believe there is supposed to be a notice read.

MR. MURPHY: Yes, Commissioner.

And we are here pursuant to notice for a Commission workshop regarding the ten-year site plans of electric utilities.

CHAIRMAN GRAHAM: That's simple enough. All right. Introduction. Is that introduction of the board, introduction of people coming before us?

MS. MATTHEWS: I'm not sure, Commissioner. (Laughter.)

MR. BALLINGER: I'm sorry. Chairman, I'll take that one. I was busy reading some other stuff.

You want an introduction for the workshop?

CHAIRMAN GRAHAM: Yes.

MR. BALLINGER: Okay. The purpose of this workshop is to give the Commission and the public a forum to discuss utility ten-year site plans, what their generation and transaction plans are for the next ten years. Staff is required, by statute, to submit a report to the DEP by December determining the suitability of each plan. So this is your opportunity to hear from selected individual utilities and the FRCC about the status of the generating reserves and the plan for the future.

CHAIRMAN GRAHAM: Fantastic. I like that. All right. So who is up first? Ma'am.

MS. ROGERS: Good morning. My name is Sarah Rogers, and I'm the President and CEO of the FRCC. And thank you so much for having me here today.

Although this is a formal presentation, please feel free to stop me at any time to ask any questions that you may have. Let me see if I can figure out the electronics here. All right.

I'm going to cover for you today the FRCC load and resource plan, which is a consolidation of the utilities' plans. We are going to look at the load forecasts, generation additions, reserve margins, demand-side management, fuel mix, and renewables. We are going to talk about the FRCC reserve margin, the generator and transmission maintenance scheduling, interregional transmission planning, and, finally, we are going to talk about fuel reliability.

The purpose of the FRCC is to ensure and enhance the reliability and adequacy of the bulk electric supply in Florida now and into the future. So essentially we exist for one purpose and one purpose only, and that's reliability of the grid.

The load forecast factors, we continue to see Florida unemployment decrease, which is a good thing. The population has picked up some momentum in 2011. Residential customers and energy sales are higher, whereas commercial and industrial sales are lower. The load management additions have slowed down, the projection of those has slowed down, and the forecasted winter peaks are slightly higher in the short-term and the summer peaks are slightly higher in the longer term relative to the presentation from last year.

The podium is very low, so my notes are hard to read. So I am going to pick them up. I apologize for that.

This is a comparison of the load resource forecast from 2010 to 2011. And as you can see, it's very similar in the early years and then picking up a little bit in the future years. And this is the summer peak demand. It is forecasted as of April 1st. And based on the recent economic news, it is our understanding that some of the utilities have indicated that they are evaluating whether these forecasts may be more optimistic relative to what has happened in more recent months.

This is the comparison of the 2010 and 2011 winter peak demand. And as you can see, it has grown in in early years and probably more to what 2010's prediction was in the latter years.

This is our capacity mix chart. It essentially shows what the existing capacity is inside the region, what the cumulative additions are, firm nonutility purchases, imports and capacity outside of the region. And I think this slide demonstrates that Florida is not terribly dependent upon generation outside of the state, and that's a good thing. As a peninsula, we want to be able to match our generation and our load within the state without having a tremendous reliance on importing power, because we have seen that that can cause problems from a reliability standpoint. So this chart shows you that the majority of the available capacity is inside the state of

Florida.

Our planned reserve margins. This chart shows that the reserve margins, which include generation and load management and interruptibles, and throughout the ten-year period we exceed the -- we basically exceed 20 percent, which is a good thing. But the second chart, I want to bring this one to your attention, and I think it deserves a little more time to talk about. This chart, you can see the shadow of the previous chart, but what it is showing you is the percent of our reserves that are made up of actual generation.

And the concern that -- or what we are monitoring at FRCC is you can see in these latter years, 2017 and beyond, that our reserve margin is very dependent upon demand-side management. And the concern there -- demand-side management is a great thing. It's avoided cost to the state and to the consumers. But what we have seen in the past is when utilities utilize demand-side management on a regular basis, the people who subscribe to it often abandon the program. Because it's a great thing to save this money on a monthly basis, but when the utilities have utilized demand-side management, a lot of people have unsubscribed to the program. And so in these future years, '17, '18, and '19, what we would expect is that utilities would have to utilize their demand-side management programs on a more regular basis, and the concern there is the human factor.

What will people do when it is utilized more often? And what we have seen in the past is there is tendency -- it's a great thing for folks to have this credit on their bill, but if it starts to become an inconvenience to them, they are going to make -- some people make the decision that, uh, it's worth the five dollars more a month to not have my pool pump cut off every afternoon type of thing. So this is something that we continue to monitor.

It's the first time we have really seen the reserve margins that are solely made up of generation drop down below the 15 percent level. So overall, FRCC, we want to ensure that the regional planning reserve margin meets the 15 percent criteria, and that criteria has been in effect well over ten years, and the planned reserve margin equals or exceeds 20 percent for all peak periods within the next ten years. But as I mentioned before, we are dependent upon the load management and the interruptibles.

Speaking of demand-side management, FRCC does really well relative to the rest of the United States, the FRCC region on the percentage of demand-side management as it compares to the peak. You do see two areas where the percentage is higher than FRCC, and the reason for that is those are organized markets where there are actually consolidators of demand-side management that bid into these markets actually as a resource. And so in those areas where they have that type of market, you do tend to see a slightly higher percentage than what we see here in Florida.

Our fuel mix. We continue to be very dependent upon natural gas-fired generation within the state. That will grow. That will continue to grow. And this is the net energy for load, and we can compare that to the actual plant capacity, which is closer to 60 to 63 percent going forward.

Renewable resources. This has changed over the last several years. It used to be primarily made up of municipal solid waste plants, but we have seen an increase in the number of biomass plants and solar within the state, so that's a positive, as well. And when we are looking at it from a forecasted standpoint, we continue to see some of the utilities plan for some biomass plants, landfill gas, some incremental municipal solid waste and solar. And we are not seeing in the site plans yet wind, but we know that there have been efforts by utilities to get wind sited.

We look at conservation or energy efficiency. This tells a very positive story, as well. The cumulative reduction in megawatts is about 2,500 due to energy efficiency, so that's very positive for the state. That means that that is generation that we did not have to build. And, you know, it's savings for our consumers. And we continue to see that increase over time.

The nuclear outlook. We do see some uprates planned on the plans. The new nuclear units that have been under discussion are not within the ten-year site, within this window, so that's why you don't see those on this chart, but we are seeing increases in the nuclear capacity due to the uprates.

Energy production from natural gas. We continue to see that increase. It's my understanding that one of the reasons for the jump between 2010 and 2011 is the low natural gas prices, so that is putting it sooner in the economic dispatch order.

So our conclusion is that the results of the resource adequacy review indicate that the FRCC region has planned adequate reserves to remain reliable over the next ten years. And then we just have on our radar screen the two issues of the increasing dependence on demand-side management to supply the reserves and the increasing dependence on natural gas.

Now I am going to go to the next agenda item, which is the generation and transmission maintenance scheduling. We do have a centralized outage system utilized by the utilities to schedule generation and translation outages so that we can ensure that there is coordination between the utilities and that we are not taking too many units out or too many transmission outages out that would impact reliability.

We have an equipment status report that's updated and it's reviewed by the utilities on a monthly basis. We provide a forecast of the monthly unit outages, and we compile that and we distribute it to the utilities, and we also provide to the Public Service Commission a forecast of the monthly reserve margins.

We coordinate among the utilities to ensure that there is adequate reserve margins maintained for all periods. We conduct coordinated transmission and generation outage studies. We do next-day studies, seven-day studies, 28-day studies, and then the seasonal studies, which are the summer assessment and the winter assessment. We conduct conference calls on a weekly basis to resolve any issues related to planned generation and transmission outages.

I'm going to now go to another agenda item, the interregional transmission planning. And I think there's more interest in this as a result of FERC Order 1000 that was issued in early August where they are requiring the jurisdictional utilities to perform more interregional transmission planning, so we thought it would be helpful to show you all what we do today.

We do coordinate the modeling information. There is a group that exists called the Eastern Interconnect Reliability Assessment Group, and we have a multi-regional modeling working group. There's a lot of alphabet soup there. And we develop and maintain a library of the models of the electric system. And so the models include the proposed system expansions and the models are the basis for reliability assessments. So when we do our reliability assessments and we run those models, we actually include a detailed model of the southeastern area of SERC, which is the Southeastern Reliability Council, the region that's to the north of us.

So when we model our system, we actually can model their system, as well. And when we run those models we can see impacts across the border, which is a good thing. We monitor the Florida Southern Interface and evaluate the facilities on both sides of the interface, and any potential issues we coordinate with the Florida Southern Coordinating Group. So quite a bit goes on to ensure that we don't have issues crossing the border.

FERC Order 1000 will require the jurisdictional utilities to develop an interregional planning coordination procedure and develop a process to address cost allocation for efficient and cost-effective interregional transmission solutions.

I'm switching gears on you again. We are going to talk now about fuel reliability. FRCC started a fuel reliability working group in 2005, approximately, and we initiated a gas study project to look at what would happen for potential pipeline interruptions or compression station failures. We look at fuel oil storage and assess the current natural gas infrastructure deliverability and reliability.

This is important because we have seen some issues in the past. In 2005, when Hurricane Rita and Katrina impacted the Gulf Coast, the offshore drilling rigs were out of service for quite sometime, and there were some issues related to deliverability of gas during that time frame. I'm going to show you some of the things that have happened since then that the utilities have done to resolve that issue.

We also have the ability to run a gas flow model the same way we do on the electric system, but on the gas system, so we can take an element out, or a compression station, or a break in the pipe and see what impact that would actually have at the generating station and whether the generators would be able to run or not. So that's a very valuable model for us going forward, and it enables us to really determine what the interdependency is between fuel availability and electric reliability.

We coordinate the regional responses to fuel issues and emergencies. This working group has oversight for the gas study project. They support realtime emergency response, provide input to regional fuel reliability positions at NERC, and we focus mostly -- we call it fuel reliability, but as you have seen from the previous charts, because of our dependency on natural gas generation, that's where our focus has been and continues to be.

Some of the analysis that we have done is we have looked at the failure of the Gulfstream pipeline, the Cypress pipeline, or the Florida Gas Transmission pipeline. We have looked at compressor failure analysis. We are continuing to look at analysis on oil storage. And the reason for that is a vast majority of our gas-fired plants also have the ability to burn an alternate fuel, and that alternate fuel is oil, fuel oil. So in the event that we have an interruption to the gas supply, these types of plants can switch over and start burning fuel oil. And so the amount of storage that they have on hand is important to us because that's a factor in evaluating the reliability over the time period that we look at.

Some of the major changes since 2005. In the Mobile Bay area, the storage capacity held by FRCC members has increased significantly from .16 Bcf a day to 1.06 Bcf a day. The delivery capacity from onshore resources has increased, and that's basically a function of the pipeline connections. In '05, the majority of the connections for the supply came from offshore sources. Today, the utilities can actually get a lot of supply from onshore sources, as well.

The total design capacity into Florida for natural gas has increased from 3.24 Bcf a day to 4.35. Impacts to supply by hurricanes have been mitigated with the storage of natural gas and the onshore resources. And we do have limited activity on the liquid natural gas projects. My understanding is that with the increase of deriving gas from the shale resources has driven the price down, and the liquid natural gas has fallen out of the competitive area at this point in time because of the shale natural gas. We have seen very limited activity on the liquid natural gas side.

Some of the tools and coordination that we use is we have a generating capacity shortage plan. We do have a hurricane manual. We have some communication protocols between the reliability coordinator, the generator operators, the natural gas transportation service providers, and we are very lucky in Florida we have very excellent cooperation between the pipelines and the FRCC. So if we have very high peaks that are forecasted, we actually will hold conference calls between the generator operators and the natural gas pipeline folks, and we can make everyone aware of any potential issues that we have.

The pipelines are aware of the criticality of the deliverability of natural gas during those peak times. So I think it's something that really is a best practice. And, you know, we have seen some issues in other states. In February of this year, there were blackouts in the state of Texas and some of that was related to natural gas supply. And my understanding is they don't have the kind of communications on a daily sometimes hourly basis that we do here at FRCC to make folks aware of what's going on with equipment, what's going on with supply, et cetera.

In summary, our fuel reliability working group going forward -- well, the summary. Natural gas capacity into Florida has increased. Access to natural gas storage and onshore sources has increased. Our communications plans are in place for the pipeline operators. The reliability coordinator coordinates with the state capacity emergency coordinator and the pipeline operators when there is any fuel supply that's threatened or at risk.

Going forward, we are going to continue our efforts. We are reviewing the loss of load event that occurred in February in Texas, what we call the ERCOT February load shed event, and we are going to try to mine to see if there has been lessons learned that we can apply here in Florida to ensure that that doesn't happen to us.

We are going to continue the evaluation of the electric gas interdependencies, assess the gas infrastructure capabilities, and continuing evaluation of fuel oil storage. And one thing that I will bring to your attention that is a concern is what we have done, the studies and analyses that we have done to date are near-term projects looking at the gas infrastructure as it exists today, and the plants as they exist today. And we have done the analysis of what happens if we lose supply. And in general, we are really -- the story is a good story that for the short-term we can handle that. But we're going to continue to evaluate the fuel oil storage issue, because when supply is cut, when gas supply is limited, a lot of the plants do have the ability to burn the alternate fuel, and that's really what saves us in that event.

But the question that we have is how sustainable is that over a long period of time. And there are some estimates that to continue to replenish the fuel oil would require about 50 tanker trucks an hour within the state. And so our question is if we did have a long-term lack of availability of gas supply, how long, realistically, could we burn the alternate fuels and could the fuels be replenished in a timely manner. So that's sort of a next step for us. It's an analysis that we will do this year and in 2012 to make that determination.

Again, just the slide from before on the natural gas. So, in conclusion, in the near term, we don't anticipate any fuel transportation issues affecting resource capabilities considering the fuel diversity, the current fuel supply, and the alternate fuel capability. But in the longer term, the increase in energy production from natural gas highlights that close coordination will be required to ensure that the gas delivery capacity remains adequate.

And that is my presentation, and I'm more than open for any questions that you may have.

MS. MATTHEWS: I have a question.

CHAIRMAN GRAHAM: Thank you.

Ms. Rogers, number one, I want to thank you for coming and giving us your time. I appreciate the work that FRCC does. The modeling that you do, I think it probably keeps our feet out of the fire more times than not, and it keeps us focused in moving forward.

I've got a couple of questions, so I guess I will probably work backward so you don't have to do a whole lot of flipping. If we can go back to Page 30 when you're talking about the generation capacity shortage plan. What is that plan?

MS. ROGERS: It's a plan that looks at two things. It looks at if we do have a lack of capacity due to unplanned outages or forced outages, how we coordinate that. And then also it looks at -- and that is how it traditionally was built, but we added to it the fuel supply issue, as well, so that it's a communication coordination plan that we utilize within the state.

CHAIRMAN GRAHAM: Okay. And back to Page 11.

You're talking about the reserves. We're probably going to have a workshop. We are kind of slammed right now, but I'm anticipating before the end of the year to look at the 15 percent or the 20 percent margin, and which would be best for us. And I'm glad you brought that up and the issue about the DSM, and I need to make sure that you guys are going to be involved in that workshop, because I think this is great information you have put before us, but I just want to let you know that it is coming. And, like I said, it will probably be before the end of the year.

And one last question. Page 8. Looking at the imports, I see the trend that you have here where it looks like pretty significantly the imports drop off at 2015. Two questions I have is it looks like it's pretty consistent from 2011 to 2015. What causes for that to drop like that in year five?

MS. ROGERS: There are actually purchase agreements between the utilities, and it's my understanding that those purchases expire, those purchase agreements expire in 2016. So there is the possibility that those purchase agreements could be renewed, but what is reflected within the load and resource plan is that they are not projecting those at this time to be renewed.

CHAIRMAN GRAHAM: And the last question. What did it look like ten years prior to this? Was it the same, consist that it was from 2011 to 2015, or was it bigger back then?

MS. ROGERS: We do have a limit on the import capability, so it can't be any larger than 3,700 megawatts. So it has never been larger than that. There may have been some fluctuation in previous years, but I think it has been fairly steady.

CHAIRMAN GRAHAM: Okay. Those are the questions I have. I don't know if anybody has any other questions.

Ma'am.

MS. MATTHEWS: Thank you.

You guys don't normally specifically address this, but I thought you might be able to give me some kind of an idea. Most of the ten-year site plans, if not all of them, are forecasting increasing customer growth, customer energy consumption, demand is increasing, and things like that. And I was wondering if you guys had any idea what the reasons were behind those increases in forecasts?

MS. ROGERS: At a high level, I can answer that question. This is our understanding, for the increase in the load forecast. Unemployment has decreased year over year. We have seen some population picking up momentum, and we have seen that the residential and -- residential energy sales are up, so I think those are the primary reasons.

As I did mention, this is data from April, and a lot has happened in the world since April. So I think that some of the utilities are wondering, you know, are questioning whether that load forecast is valid, now given those circumstances.

MS. MATTHEWS: Thank you.

CHAIRMAN GRAHAM: Any other questions?

MR. TRAPP: Mr. Chair.

CHAIRMAN GRAHAM: Bob.

MR. TRAPP: I don't want to take the place of the Commissioner.

CHAIRMAN GRAHAM: You are a wise man.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

And I also was going to draw our attention back to the slide on Page 11 talking about the reserve margin, and that is an issue that comes up every so often, 15 percent, 20 percent. And I heard you, Mr. Chairman, that this is something we will be discussing in more detail at a future date relatively near. But could you speak in a little more detail than you did in your presentation about that issue or potential concern, maybe, about the portion of the reserve margin being made up from DSM versus generation.

MS. ROGERS: I will be happy to. The 15 percent has been in place for over ten years, and when it was put into place, the demand-side management programs were not as popular as they are today. And reserve margin is essentially a buffer for the uncertainty that exists in load forecasts, in weather, in changing economies, and also in equipment availability. So it's a margin on a day-to-day basis that we have in the event that something bad happens.

And so if a unit trips off, or if we have extreme hot weather outside of what we forecast, that's what the margin provides for. And the utilization of demand-side management is something that the utilities can use to meet that margin, to cover to ensure that we don't have rolling blackouts. But what we have seen in the past here in Florida as well as other states, the reserve margin is comprised of almost -- of enough demand-side management that it's utilized on a regular basis, that people tend to unsubscribe from the program. And it makes it something very difficult to analyze, because the amount of generation that we have, the load forecast, those are things that can be scientifically analyzed, but the load management and interruptible issue really has a human factor to it. And people will behave in what some people would call not fully rational ways. You know, the market analysis will show you that. So we have got this human factor related to the demand-side management, and so it's really a risk issue that you have to make a determination on.

If we get to the point where we are utilizing the demand-side management on a regular basis, and it's a voluntary program, and people can unsubscribe to it, it can disappear very quickly, and then your reserve margin could be very low, and that could cause reliability issues. Does that help?

COMMISSIONER EDGAR: And I realize that it's probably ever changing, and difficult, and may be difficult to quantify, but from the perspective of FRCC, do you have a feel for, of that 20 percent margin, about how much now is made up from DSM? And, if so, of that DSM portion, how much is residential versus business/commercial/industrial?

MS. ROGERS: I can partially answer that question for you. If you go to Slide 10, it's harder to see on the screen. I think on the printouts it might be a little easier to see. The shadowed part is the total demand-side -- or the total reserve margin, excuse me, and then the solid part is that part of the reserve margin that's made up of generation. So you can see in 2017, for example, in the summer, you're almost at 50 percent. Does that help?

COMMISSIONER EDGAR: It does. And it is kind of hard to see. I appreciate you drawing me to the rest of the graph that I may have missed.

MS. ROGERS: It almost looks like a printing mistake.

COMMISSIONER EDGAR: And that is what I thought it was, exactly. It reads completely differently now that I see the additional shading. Thank you.

I look forward to more discussions on this. I think it's a very interesting issue. Obviously redundancy in reserve for reliability sake is a good thing, but I recognize there's a cost involved, so I look forward to further discussion. Thank you.

MS. ROGERS: You're welcome.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And thank you, Ms. Rogers. I appreciate your work and the work that the FRCC does.

If I could point your attention to Slide 26, which is the -- I would like a little more information on the gas study project that you mentioned. If you can give me a little more information on that as far as has it been completed, what were the findings, conclusions of that in a little more detail, that would be great.

MS. ROGERS: Well, it's an ongoing project. What we have done is we have worked with the utilities to get information on what kind of pressures that their gas plants need to see to be able to burn the gas. We have worked with the pipeline owners to get information from them on the specifics of the pipeline. And we have created a model, and it actually runs similar to a load flow model, but it's a gas flow. And gas is different than electricity in that if there is a break in the pipe, how much pressure is available depends upon the packing of the pipe.

And I'm getting into areas that are outside of my expertise to some extent, but what we have done is we have looked at critical compression station failures, and run an analysis to see what plants would be impacted, are those plants capable of burning alternate fuels, or some plants have connection to both FGT and Gulfstream, so we have done that kind of analysis to determine how much generation would be at risk for certain types of outages. And we do have that data. We presented some of that in the past, and it's something we could bring to you again.

I don't have those specifics here, but we identify each year what cases we want to analyze, and then we run those studies, and we determine what, if any, generation will be impacted from those outages.

COMMISSIONER BALBIS: Okay. And I personally would like to see that additional information. One of the concerns that I have is having such a high percentage of natural gas fuel generation to really look hard at, you know, how critical any failure would be and what the effect would be.

And then one last question. You mentioned that they have an alternative or alternate fuel they could burn, whether it be fuel oil, et cetera. How quickly can that changeover occur and is that something that you have looked at, or is it pretty much --

MS. ROGERS: I don't know the answer to that off the top of my head, I'm sorry.

COMMISSIONER BALBIS: Okay. All right. That's all the questions I have.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you. Thank you, Ms. Rogers, for your presentation. I just had a quick question.

You mentioned that the FRCC will be conducting an analysis regarding the sustainability to burn alternative fuel sources such as oil at the natural gas plants. What is your timetable for providing that analysis?

MS. ROGERS: Our board of directors asked us to perform that study at our last board meeting. I'm not exactly sure how long that will take to run, but we will be looking at that for the rest of this year and next year. We may have some results that we could share at the 2012 workshop.

COMMISSIONER BROWN: That's what I was going to suggest. Thank you.

CHAIRMAN GRAHAM: Bob Trapp.

MR. TRAPP: Thank you, Chairman.

Ms. Rogers, is it correct that you're leaving the FRCC at the end of the year?

MS. ROGERS: Yes. I announced my retirement earlier this year, so I will be leaving FRCC January 16th.

MR. TRAPP: On behalf of staff, I would like to thank you very much for all the help and hard work that you have helped us with over the years, and wish you the best, and thank you for keeping the lights on.

MS. ROGERS: Thank you so much, Bob. I appreciate that.

And also I would like to recognize my staff, John Odom, who is the Vice-President of Planning and Operations, Vince Ordax, who is the Manager of Planning, and Scott Beecher, who is one of our planning engineers. And he actually does all the hard work of putting this presentation together and making sure I'm as prepared as possible. So, thank you, guys.

CHAIRMAN GRAHAM: Ms. Rogers, I want to thank you, again, for your presentation. And it's a lot of good detail that's here, and for the work that FRCC does. And I didn't know that you were retiring. We'll miss you. And hopefully whatever you do next, we will see you again.

MS. ROGERS: Thank you so much.

CHAIRMAN GRAHAM: Thank you. I think next is Florida Power and Light.

MR. SIM: Good morning, Chairman Graham, Commissioners. My name is Steve Sim. I work for the Resource Assessment and Planning Department at FPL that's responsible for putting together the site plan each year. With me today is Mr. Rene Silva, the director of our department. And I will be giving the presentation today, and Mr. Silva and I will attempt to answer any questions that you and your staff may have.

We have a number of topics to address today, and I will try to move through them as quickly as possible. The item I'm going to spend most of the time on is the 20 percent reserve margin criterion issue, so we have saved that for last, and I will try to move as quickly as possible through the other five topics that we're going to address today.

The first of those are the resource planning changes and assumptions that have occurred since the filing of our site plan in April 2011. And as a reminder, the site plan traditionally is designed to describe the outcome of resource planning in the prior year, and we try to push that a little bit so that it covers the first quarter of the current year, as we have done this year.

First of all, let's start with what our site plan actually showed. And I'm not going to spend much time on this table, because it has been presented in the site plan, but I will touch upon two things. The first resource need that we have is in 2016, and we were projecting in the site plan that we would address that with a greenfield combined cycle. And based on that addition, the next resource need that FPL was projecting would be in 2020, and we were projecting to also meet that with a greenfield combined cycle.

Now, our resource planning work is ongoing, and naturally assumptions change along the way. So what we are trying to do on this slide is show you what the planning assumption changes have been compared to those that were in effect when we filed the site plan. The first of those is that we are no longer assuming that we will be doing scheduled plant maintenance in all months of the year. We were in the site plan assuming that we would begin to have to move scheduled plant maintenance into all months of the summer and all months of the winter, and we were recognizing that by an assumption of 350 megawatts would be out on scheduled maintenance in all summer months, 550 megawatts out all winter months. We have, upon further analysis, decided that we can continue to perform that scheduled maintenance without having to move it through all summer months and all winter months.

The second main change is the Turkey Point 1, roughly 400 megawatts of capacity is going to be removed as a generating resource in 2016 where it will serve as a synchronous condenser very similar to what it's sister unit, Turkey Point 2, is now doing.

The third point is there are 26 General Electric 7FA combustion turbines in our existing combined cycle units. We are in the process of upgrading those, and that work will continue through

2015, which will result in roughly 190 megawatts of increased capacity as well as efficiency improvements in those combined cycle units.

And the fourth main item is the recent Commission decision regarding incremental DSM, which will result in slightly lower incremental DSM additions on the order of roughly 20 megawatts a year from what we were assuming at the time of the site plan.

Now, after factoring in those changes, really not much has changed in regard to our resource needs. We still have resource needs beginning in 2016, and we are -- instead of projecting a greenfield combined cycle being added in that year, we are now projecting that we will modernize the Port Everglades site in 2016. And based on that assumption, our next resource need will again fall in 2020.

The next item we will talk about are our inactive reserve units, the status and the plans for those. Now, there are eight such units on our system, and really not much has changed regarding the status and plans for those units with the exception of the four units at Port Everglades. So in Port Everglades 1 and 2, the two smaller units, we plan on retiring those units in 2013 if the Port Everglades modernization project proceeds. The two larger units, Port 3 and 4, those will be returned to service temporarily in 2012 as support for the modernization at Cape Canaveral and Riviera. And upon completion of that work for Cape in 2013, these additional two units at Port will be retired if the Port Everglades modernization project proceeds.

The next item, the existing and planned solar and wind projects. We have completed three major solar projects in 2009 and 2010, 25 megawatts of PV in DeSoto, ten megawatts of PV in Brevard, and 75 megawatts of solar thermal at Martin. Combined, these three solar facilities will be providing more than 225,000 megawatt hours per year. In regard to wind, well, we have been pursuing a 14-megawatt wind energy project in St. Lucie for sometime, but we have been unable so far to obtain the local approvals. But we do remain very interested in trying to proceed with wind in this state and we will be looking for opportunities to do so.

In regard to PV, we have done a lot of planning and we have performed initial permitting and due diligence for a number of additional PV projects that would total roughly 500 megawatts. However, because there has been no legislation supporting the utility development of such projects, we have not proceeded with the construction of these projects at this time. However, if that enabling legislation or regulation were to occur, we would be ready to move very quickly with the bulk of those 500 megawatts worth of projects. And we would like to point out that even though the projects, the PV projects that we put in place in 2009 and 2010 are very recent, there have been some significant improvements in both the cost and the efficiency of photovoltaic, and those would also be part of any project we would bring forward.

Gas pipeline needs is the next subject. We do need additional gas. We do plan to pursue additional pipeline capacity. In that regard, we have been updating our analysis in regard to how much gas and when we would need it. We are in the process of preparing an RFP for pipeline capacity to meet those needs, and we will be bringing that forward and meet with your staff in the next few weeks to discuss.

Plans for improving fuel diversity. We are pursuing that along a number of fronts. Needless to say, we all know that Florida is a peninsula and that we import almost all of the fuels used in the state. And FPL is dependent upon natural gas for over 60 percent of the energy we provide our customers. So fuel diversity is always an important issue for us.

We are pursuing that diversity through the EPU and Turkey Point 6 and 7 nuclear projects. We have mentioned the 110 megawatts of solar facilities that we have recently added, and I have also mentioned that we have additional PV projects in the pipeline that could be brought forward if enabling legislation becomes a reality. We are maintaining the ability to use fuel oil at our four 800-megawatt steam units by adding electrostatic precipitators, and we are continuing to improve our ability to burn natural gas more efficiently by putting in very highly efficient combined cycle units at existing sites, like our West County site, and through modernizations and repowering such as those that have been completed in the relatively near term at Fort Myers and Sanford, the Cape Canaveral and Riviera modernization projects that are ongoing, and the proposed modernization at Port Everglades. And also we continue to pursue the diversification of natural gas supply sources for our system.

That brings us to the last topic we will discuss here today, and that is the 20 percent reserve margin criteria. First of all, our reserve margin criteria is basically designed to help ensure that we have reliable electric service for our customers. And resource planning is an exercise that is dependent upon a number of forecasts. And as we know, all forecasts are uncertain. So, in essence, the resource planning work that we do is, in large part, designed to address that uncertainty. And on this page we have listed three of the items of uncertainty that most readily come to mind.

We could have higher than forecasted peak loads, we can have unscheduled generating unit outages, and we can have lower than projected DSM capability. Another factor might be that we just don't know in advance how much assistance we might be called upon to provide to other utilities.

Now, any consideration of moving from a 20 percent criteria to a 15 percent criteria will have a number of aspects that should be considered, and two among them are system reliability and cost of electricity. And in regard to those two, cost and reliability, FPL's view is summarized on this page. We think that a 20 percent reserve margin, at least, is necessary to provide reliable service for our customers. Switching to a 15 percent criteria, we think would significantly reduce the reliability of service as we will be discussing on the next two pages.

In regard to economics, reducing the reserve margin criteria would not necessarily result in any significant short-term cost savings to customers and long-term cost savings we think are also questionable.

And the reason for that is although you would have capital and other fixed costs that would be reduced by delaying the addition of new generating units, if the generating unit that you are deferring is a very fuel efficient unit, you would have fuel and other variable costs increasing over what they otherwise would be if you had built the unit according to a 20 percent reserve margin criteria and schedule. So you have a balancing act of sorts, and the net cost impact of how much savings, if any, would be highly dependent upon fuel and other variable costs. And I will get to that in a couple of slides with an example.

But first what I would like to do is go through two pages talking about reliability of 20 percent versus 15 percent. And this looks like a fairly complicated slide, and perhaps it is, so let me see if I can simplify it. Because, in essence, it is a very simple example. Now, as we mentioned earlier, FPL right now is projecting that its first resource need is in 2016 with a 20 percent reserve margin. If we were to move to a 15 percent reserve margin, our first resource need would be in 2019.

So what I have done is we have selected a year that falls within that range; we arbitrarily selected 2017. And what we have done on the first of the four rows is we have taken our current load forecast for 2017, the 25,025 value, we have taken our current projection for energy efficiency, which shows up here as a negative 666, and a few columns over we have taken our current projection for load control, 2,080. And we have then worked backwards to see how much generation we would need if we were to exactly meet a 20 percent reserve margin in 2017. And that shows up in the tan colored box to the far left on the first row, the 26,735 megawatts of capacity. And this would enable us to exactly meet the 20 percent reserve margin in that year.

Two things I would like to point out before we leave this row. The first thing is in the far right column, the total reserves we would be projecting to have is a little over 4,400 megawatts. And of that, we have shown that we have 2,080 megawatts of load control and 666 megawatts of energy efficiency. So, in essence, 2,700 of our 4,400 megawatts of reserves would be provided by DSM, and that is a topic we will come back to in just a moment.

But what we next do on the next three rows is we try to account for those three areas of uncertainty I mentioned earlier. The first one is having on the peak hour peak day units out for unscheduled maintenance.

And what we have assumed in the yellow box on the second row is 1,800 megawatts of plant are out for unscheduled maintenance. And this is not an atypical number. In fact, over the course of the last few summers this has been a fairly average number we have seen through the summer.

Now, what that means for our reserves is shown in the far right column. We have seen our 4,400 megawatts of reserves drop to a little over 2,600 megawatts of reserves. So we would still be okay in our ability to maintain service for our customers.

The next item of uncertainty on the third row is that of load forecast. Now, as we go through a year and we look back at our load forecast, we look at the variance between what the forecasted value was and what the actual value was. And as you can expect, if you are forecasting one year out your, variance generally isn't very great. But as you begin to forecast four, five, six, seven years out, your variance continues to grow.

So what we have done here, since we are looking at the year 2017, six years out, we have looked at the range of variance from our forecast to actual numbers. And we have selected not the most extreme of that range that would capture 100 percent of that variance, we have captured 75 percent of that variance.

And what that means is the variance in the load forecast is lightly over 9 percent, and 9 percent off of a 25,000 load forecast is about 2,311 megawatts, which shows up in the pink box on the third row. And this higher load would reduce our reserves in the far right column from a little over 2,600 to roughly 350. Still we're okay.

And, finally, if for whatever reason we had less DSM capability on that year on the peak day than what we were projecting, which we're reflecting here by an arbitrary choice of 333 megawatts of energy efficiency, for some reason, not showing up, we would still be able to meet our load. So what this site tells us is with a 20 percent reserve margin with these assumptions, which we think are reasonable, we would still be able to provide electric service to our customers.

Now, on the next slide what we are going to do is we are going to change one number and see how it ripples through the analysis. The number we are going to change is in the first row, the upper left-hand corner of the tan box. We have calculated how much generation capacity, which would be FPL units and purchases, we would need in order to exactly meet a 15 percent reserve margin. And if you compare the previous page to this, we are dropping that generation capability by roughly 1,100 megawatts.

Now, where this shows up is in the far right column, the 4,400 megawatts of reserves we had before has dropped to about 3,300. We then go through the same exercise. 1,800 megawatts of generation out on the second row reduces the 3,300 megawatts of reserves to 1,500. The higher than expected load of a little over 2,300 megawatts now takes our 1,500 megawatts of reserves and we are now in the negative. We have unserved load. In simple terms that's rotating feeders or blackout for our customers. A 777 megawatt unserved load equates to roughly 275,000 residential customers being affected by rotating blackouts.

If we were then to assume the same lack of performance of DSM of 300 megawatts on that peak hour, the unserved load would grow to a little over 1,100 megawatts, which would equate to rotating feeders for roughly 400,000 residential customers. So what these two pages are showing us is that we certainly believe that the FPL system is more reliable with a 20 percent reserve margin than it is with a 15 percent reserve margin.

I mentioned there are other aspects of the reserve margin criteria that need to be considered, and one of those is how much you would lean on your load control resources between a 20 percent and a 15 percent reserve margin. What this graph does is it takes a look at our residential load control program. And one aspect of it that would be hit fairly frequently, residential air conditioning cycling.

We currently have roughly about 700,000 residential customers who have chosen this option in our residential load control program, and this equates to about 700 megawatts. And what we have tried to do here is project what -- the frequency with which we will push the button. The numbers represent annual number of load control events, but because it is AC cycle, the vast majority of these projected values will occur in the summer.

And as you can see on the left-hand side of the graph, we are seeing projected frequencies relatively low, two times a year. Now, keep in mind what is occurring in those years is we have added the West County 3 combined cycle in 2011, the nuclear uprates are coming in 2012 and 2013, we have got Cape Canaveral modernization coming in in 2013, and Rivera modernization in 2014.

What happens then is let's assume that we stay with a 20 percent reserve margin. As currently projected, we add capacity in 2016, and then again in

2020. The gold line represents that. The frequency begins to increase slightly, but tops out in 2019 at about six times a year, and then drops in 2020 as the 2020 combined cycle is added.

But if we were to go to a 15 percent reserve margin and not build the unit in 2016 and defer it instead to 2019, we see the projected frequency of load control begin to increase fairly substantially topping out at 16 times a year in 2018 before dropping in 2019 when the deferred unit would now be built, and then taking off again on an upward trek in 2020.

The danger here is the more -- as Ms. Rogers pointed out, the more frequently we exercise load control, the greater the likelihood that we will have customers drop out of the program because we are highly dependent upon their continued voluntary participation in this program and in other DSM programs.

Moving on, there are a couple of other aspects regarding reserve margin that we are currently analyzing. One of those is the flexibility we will have to continue to do scheduled maintenance of our generating units. As mentioned earlier on in this presentation, we believe we can continue to schedule maintenance for our generating units outside of all of the summer and all of the winter peak months currently under our 20 percent reserve margin, which is one of those assumptions. We think if we were to drop to a 15 percent reserve margin, we would lose some of that flexibility, and it might make it more likely that we would be having to build or add resources earlier, which kind of defeats the entire purpose of deferring generation capacity additions through a criteria.

And on a related issue, again, Ms. Rogers touched on this, FPL and other utilities as well are becoming increasingly dependent upon our DSM programs and the continued voluntary participation in DSM that this means in order to meet the 20 percent reserve margin. For example, in this year, if we were to extract all of our incremental conservation and our cumulative load control capability and look at what was remaining as a generation-only reserve margin, we would be at about 13 percent.

But if we project out to 2019, even with adding new generation in 2016, and we were to perform the same exercise, our generation only reserve margin would be at roughly 5-1/2 percent. And if we were to move to a 15 percent reserve margin and exactly meet in 2019 a 15 percent reserve margin, our generation only reserves would be at 1.3 percent, which is far too low for what we think we need to provide reliable service.

So, therefore, FPL is conducting analyses to determine whether or not we need to go a step further and add an additional reliability criteria which could be expressed as a minimum reserve margin criteria that was provided by generation-only resources. That analysis is ongoing, and I am certain we will at a future date be ready to discuss those analyses with your staff.

Now, turning from reliability to the economics of a potential change from a 20 percent to a 15 percent reserve margin. As previously mentioned, if we were to switch from 20 to 15 percent, we would defer the 2016 unit back to 2019. So what we did in preparation for this presentation today is we performed some initial analyses as to what the projected cost impact would be to our customers, and we looked at a five-year period. And what the table shows in the first column marked annual fixed cost savings, there definitely would be annual fixed cost savings, meaning capital, fixed O&M, et cetera. However, because FPL -- and let me stress that all utilities are different, but the type of unit that FPL would be deferring would be an extremely fuel-efficient combined cycle unit. We would see higher fuel costs than would be the case if FPL had built the unit in 2016. So fuel and other verifiable costs would go up, and the net result of the two is shown in the next column, the annual total cost savings.

What we see is that in the five-year period we would have three years where our customers would see some savings. We would see two years in which our customers would actually see cost increases. And in nominal dollar terms, if we were to add those up over the five-year period, we would see that our customers would save $22 million. Again, nominal. But this is highly dependent upon what actual fuel and other variable costs will be, which we have tried to demonstrate on the following page.

On the following page on the left-hand side we have replicated without any change the table we just walked through. And on the right-hand side, the change we have made is recognizing that we are at historically low gas prices today and that volatility of fuel prices can easily exceed 5 percent in the short-term, we have boost up the column marked annual variable cost savings by 5 percent. And the result, the net result is shown in the next column, annual total cost savings. We now see that in the five-year period, three of the five years our customers would expect to see an increase in annual cost, and cumulative over the five-year period the 22 million in cumulative savings would flip to be a

$12 million cost increase in regard to that five-year period. So the point here is that any cost savings is going to be utility dependent, and the cost savings are going to be highly dependent upon what the variable costs would be.

In summary, regarding our reserve margin view, we think our customers are best served by the current 20 percent reserve margin criteria, and any consideration of moving from 20 percent to 15 percent is really a consideration of tradeoffs. The tradeoffs would be economically you are going to save in capital and other fixed costs, but you are also going to have higher fuel and other variable costs. And any projection you have today of those cost increases is going to be magnified if you have fuel and other variable costs that are higher than currently forecasted.

Our current projections show that you may have relatively small net cost savings in the short-term, but, again, these are highly dependent upon continued low fuel prices. And trading off against those economics, as slight as they are, you are guaranteed to have more frequent use of load control, you are guaranteed less flexibility in scheduling plant maintenance, and you would definitely have diminished system reliability over all the years.

In FPL's opinion, the risks outweigh the potential benefits, and FPL believes that the current 20 percent reserve margin criteria should be maintained. And as we have indicated earlier, we are analyzing what goes behind the 20 percent criteria to see if an additional aspect of this should address how much of this comes from generation and how much comes from DSM.

And, Commissioners, that concludes our presentation, and we will be happy to answer any questions you may have.

CHAIRMAN GRAHAM: Steve, I want to thank you and Florida Power and Light for your presentation. Once again, a lot of very good data, and a lot of good stuff for us to go back to, especially as we are dealing with the issue of the reserve margin.

Are there any questions from the Commissioners?

Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Mr. Chairman.

Steve, thank you for being here today and a good presentation. I'm going to start with the margin issue, and I'm going to ask a question that's a little different from the regular train of thought, but does the increase in the development of your renewable projects reduce the necessity for a higher margin?

MR. SIM: At this time I would have to say, Commissioner, the answer would be no. Because what we are looking at in terms of -- let's take photovoltaics, for example. It is a great energy fuel saving option for our customers. However, we don't count it currently as firm capacity, so it simply wouldn't be included at this time in our reserve margin calculations.

In the future, as we gain more operating experience, we may be able to assign some percentage of the nameplate rating of the facilities in our reserve margin calculations, but it would likely be a relatively low percentage. So currently it plays no role in our reserve margin calculations, and in the future any role it would play would probably be a relatively minor one.

COMMISSIONER BRISÉ: All right. Going to Page 19. In your second bullet you mention the DSM, and I'm asking is there any reason to believe that the public is going to voluntarily move away from these DSM plans?

MR. SIM: Commissioner, if I may take the liberty of using Progress Energy as my example.

CHAIRMAN GRAHAM: Remember, they follow you.

MR. SIM: My apologies to the Progress folks.

CHAIRMAN GRAHAM: There is no rebuttal; they follow you. (Laughter.)

MR. SIM: But they do come after me, so they could come after me. What occurred in the late 1990s is probably a textbook example of a demand-side management program being almost too successful. At the time, and, again, this was over ten years ago, my numbers may not be exactly correct, but I think the gist of it is going to be accurate.

They had signed up at the time roughly 40 percent of their residential customers on residential load control. They had an extremely successful program. Reserve margin at that time for both Progress and for us was 15 percent. So a significant percentage of their reserves were based on residential load control. They faced, unfortunately, an extremely hot summer. And because so much of their reserves were dependent upon residential load control, they were forced to implement load control to an extent that their customers had not seen in prior years. And by the time they got to the end of the summer, a substantial number of their customers dropped out with very little warning.

My recollection is it was somewhere in the order of 70,000 participants in that program dropped out very quickly, which forced them to reassess plans and to begin to look towards adding more supply or generation options in order to make up the shortfall in their reserves. So I think that -- in our state, that is probably a textbook example of how too much reliance on DSM can come back without much warning and create problems. As I mentioned before, their program was so successful, it actually led to an unfortunate outcome.

COMMISSIONER BRISÉ: I think a couple more questions, Mr. Chairman. I'm going to focus on your solar projects. Would you say that your projects are stable and provide a certain level of continuity in terms of output?

MR. SIM: To the best of my knowledge, sir, I have not -- and I have not looked at the data recently. My understanding is they are operating very close to what they were projected to operate at, and that we are very happy with the operation of those projects. And as I mentioned, we have about 500 megawatts of additional photovoltaic projects that are in the pipeline, so to speak, just awaiting enabling legislation.

COMMISSIONER BRISÉ: Following up with -- so I will go to that point exactly with respect to the legislation. When you say enabling legislation, what do you mean specifically by enabling legislation? Is there something prohibiting you from moving forward, or is it that it's not cost-effective, or what?

MR. SIM: I think the way I simplistically think of these is the photovoltaic facilities are higher than our avoided cost. And currently the rules of the game are we cannot recover more than our avoided cost, so, therefore, we could only recover a portion of the cost of these photovoltaic facilities.

And in regard to enabling legislation, I think it could take at least two forms. One would be regulation that said the utilities are allowed to recover fully the cost of these facilities, and another might be the setting up of a renewable portfolio standard that required a certain percentage of energy were to come from renewable sources.

COMMISSIONER BRISÉ: And the last question. With respect to solar, have your customers benefited in terms of rates as a result of you adding the solar, or FPL adding the solar component to its energy generating portfolio?

MR. SIM: I think overall our customers are paying somewhat higher rates. We certainly are saving on fuel and other variable costs. The capital cost for the photovoltaics, however, is overriding that resulting in a net increase in rates. However, as I indicated in the presentation, those projects, even though they went in in 2009 and 2010, we are seeing significant cost increases, approaching 50 percent in terms of a decrease in the capital cost for the photovoltaics. So we think that any cost impact from future photovoltaics would certainly be lessened and might, in time, turn into a cost decrease for our customers.

COMMISSIONER BRISÉ: And with that in mind, I certainly hope that you get the enabling legislation, because I do think that there is some benefit in renewables, not only for costs over the long-term, but for potential stability within our grid. So, thank you very much.

MR. SIM: Yes, sir.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

And thank you, Mr. Sim, for coming today. I have a couple of questions. The first one, the 500 megawatts of solar that you said is ready to go, but FPL is not moving forward with, is that included in any of your ten-year plans at this time?

MR. SIM: It is mentioned in the Ten-Year Site Plan in the section that talks about potential sites. We do discuss some of the potential sites, but it's not included in any of the analysis for reserve margin or for projected fuel mix. Those only -- the fuel mix, for example, only accounts for these 110 megawatts that we currently have in operation.

COMMISSIONER BALBIS: Okay, thank you.

And then my other comment, really, there is a lot of very good information and discussion on the reserve margin, and I appreciate that. And I'm glad we are having a workshop to discuss it in detail, because obviously if FRCC has a 15 percent number, and then the stipulation is 20 percent, and there is the pros and cons to each one, and I look forward to discussing it in detail when we have more time and information in front of us, so thank you for that information, and that's all I have.

MR. SIM: Yes, sir.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you.

Thank you again for your presentation. Back to the 500 megawatts of solar. If that enabling legislation were enacted, for example, next year, what's the time frame that those projects -- you say that they are in the pipeline, and I know some of them have certifications by DEP, or one of them does.

MR. SIM: I think we have withdrawn that certification at this point, because there is no enabling legislation. But my understanding is we would begin to file those applications and come before the Commission for cost-recovery almost immediately with a fairly large percentage. I don't have a megawatt number in front of me, how much of the 500 megawatts, but it would be a substantial portion, and the project would then be completed once the approvals were gained within a year.

COMMISSIONER BROWN: Okay. Thank you. And one last question. On Page 12, you mentioned that Florida Power and Light continues to pursue the diversification of natural gas supply sources to the FPL system. Can you please elaborate on how FPL is doing that?

MR. SIM: I believe the best answer for that, Commissioner, would be in the RFP that FPL will be coming up within the next few weeks to discuss with the staff. And, I'm sorry, I just don't have the details of what is in that RFP at this point.

COMMISSIONER BROWN: Thank you.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you. At one point a few years back FPL had proposed new generation in Glades County. When that proposal did not move forward, my understanding was there was some discussion, or some analysis, or examination of using that same site location for another purpose perhaps. Is there anything proposed or in the pipeline, so to speak, for new generation in Glades County?

MR. SIM: Yes, Commissioner. We have looked at that as a potential site for photovoltaics.

COMMISSIONER EDGAR: And what would be the status of that?

MR. SIM: Again, awaiting enabling legislation, and there are other sites that we are looking at, as well. It is one of the sites that we are considering actively.

COMMISSIONER EDGAR: And then to follow up on a comment you made a few moments ago, you said that since the '09 and 2010 construction and then operation of the PV in DeSoto, Brevard, and Martin, that you have seen a decrease in capital costs. What is that decrease in capital cost due to or attributable to?

MR. SIM: I think it's -- I think in general terms it is due to worldwide production, particularly in China. The costs have simply dropped for manufacturing of photovoltaic modules substantially.

COMMISSIONER EDGAR: Thank you.

CHAIRMAN GRAHAM: Steve, a quick question. Port Everglades 1, 2, 3, and 4, what is the fuel source for those four?

MR. SIM: Oil and natural gas.

CHAIRMAN GRAHAM: And after the modification?

MR. SIM: It will be a natural gas fired combined cycle similar to what we are building at Riviera and at Cape Canaveral.

CHAIRMAN GRAHAM: Staff, any questions?

MS. MATTHEWS: Yes, I have a question, please.

Mr. Sim, just following up on the Chairman's question just then about the modernization of the Port Everglades site, and you mentioned earlier that you guys are about to put out an RFP for the gas needs at the Cape Canaveral and Riviera site long-term needs, and I was wondering if the Port Everglades site, if you had any plans in place for supply, or if there is any need for additional supply at that site?

MR. SIM: Let me attempt to clarify. The gas RFP is one for the system in total and it would be used at a number of sites. In regard to Port Everglades modernization, what we are looking at there is essentially adding compression that would come from our Fort Lauderdale site essentially pushing gas into the Port Everglades site.

MS. MATTHEWS: Okay, thank you. And just one more. In your discussion regarding the 15 percent reserve margin versus the 20 percent, you mentioned that you might see some savings in the short-term, but not necessarily so much in the long-term. And I was wondering if you have done any analyses and come up with numbers for that, for those studies?

MR. SIM: We have done analyses that look at both short-term and long-term.

MS. MATTHEWS: Okay. Thank you.

MR. BALLINGER: Good morning, Doctor Sim.

MR. SIM: Good morning, sir.

MR. BALLINGER: Just a few quick questions. Could you quickly explain in layman's term a synchronous condenser?

MR. SIM: I was hoping you wouldn't ask me that. (Laughter.)

Again, my simplistic definition is it's a facility that is not producing electricity, instead it is providing voltage support for the system.

MR. BALLINGER: And that is because of the transmission kind of -- I'll call them bottlenecks in southeast Florida, where you don't have a lot of generation in southeast Florida?

MR. SIM: That is correct. And that is why the units that we have chosen for this are way down at the southern end of our system at the Turkey Point site.

MR. BALLINGER: Okay. When was the decision approved by FPL management to go forward with the repowering at Port Everglades?

MR. SIM: I believe, subject to check, that it was roughly June 10th of this year, at which point our executives decided to proceed with filing the waiver request for Port Everglades.

MR. BALLINGER: And when do you expect that FPL will file a need determination for that unit?

MR. SIM: Consistent with what we said in the waiver request, we will be filing before the end of the year.

MR. BALLINGER: Do you know of any other units in FPL's system that may be candidates for modernization at this time?

MR. SIM: I don't believe at this point there are any strong candidates. We have modernized or repowered our Fort Myers site, our sites at Sanford, Cape Canaveral, Riviera. In earlier years we have repowered the Fort Lauderdale site, so we are getting near the end of the old 1960s era steam units that are logical candidates for repower.

MR. BALLINGER: Okay. Is FPL looking at any potential sites for a solar application that it has done at Martin with solar thermal?

MR. SIM: One of the items that I was referring to in response to a question from Commissioner Edgar is Martin is one of those sites, not so much for solar thermal, but I believe it is a site for expansion of PV capacity.

MR. BALLINGER: Okay. And according to your Ten-Year Site Plan, I think FPL's eight largest units are all combined cycle units that were built since the year 2002. And those units are different than traditional steam units in that they can operate in various modes, is that correct?

MR. SIM: Yes, sir. They are -- the bulk of those are either based on three, four, or in the case of Fort Myers, six combustion turbines. And, for example, one of the combustion turbines can come down for maintenance and the remaining unit -- the remaining CTs in the unit can continue to operate. Obviously at less capacity and less efficiency, but it can continue to operate.

MR. BALLINGER: So a combined cycle unit, it is more typical that if there is an outage or a problem it effects partial rating of the unit, not the entire unit coming off?

MR. SIM: That is correct. That's an advantage of the combined cycle unit. Slightly working in the opposite direction is the combustion turbines. The modern version of the combustion turbines that we are using have very rigid thresholds. At which time the number of operating hours threshold is reached, that CT must come down for maintenance. So there is a little bit less flexibility in terms of scheduling maintenance with those units, but, as you mentioned, there is a big advantage in that one of the combustion turbines can come off and the remaining portion of the unit can continue to operate.

MR. BALLINGER: Okay. And on your Slide 19 I think you had the generation-only reserves. We don't need to go there. But did those DSM estimates include the continuation of FPL's existing programs or the goals that were established that is in your plan?

MR. SIM: The slide that we showed had been adjusted to account for the recent Commission decision to go back to the current DSM plan. So it had been adjusted downwards by roughly 20 megawatts a year.

MR. BALLINGER: Thank you.

That's all I have, Chairman.

CHAIRMAN GRAHAM: Any other staff questions?

Hearing none. Steve, I do want to thank you guys for your presentation today and for all of this information.

We are going to take about a five-minute break so our court reporter can rest her little fingers. We'll start back up here in five minutes. Thanks.

(Recess.)

CHAIRMAN GRAHAM: So next up on the agenda is Progress. Sir, welcome.

MR. BORSCH: Good morning, Commissioners. My name is Ben Borsch, and I work in the Generation Resource Planning Group at Progress Energy Florida. We have been asked to address three topics this morning. The first is changes from our April Ten-Year Site Plan to our current thinking, and particularly you had asked us to address a couple of different items. We will address the ongoing outage at Crystal River 3 and the recent changes to the DSM goals impact. We will also address the reserve margin question. And, finally, you had some questions specifically about our renewables planning.

I am going to address the first two of those items. My colleagues, Ms. Tamara Waldmann and Mr. Dave Gammon, who is somewhere, they will be addressing the renewables question. So let me see if I can make the thing go forward. Ha, there we go.

To look specifically at the changes in our reserve margin, these three columns present an example of the reserve margins at the time of the summer speak. The left-most column is as it was presented in our April Ten-Year Site Plan. In the center column, what we did was to look at the reserve margin with the change to the DSM impacts only, that is to say, with the projection of CR-3 still included in the reserve margin. And the right hand column presents a cumulative view with both the DSM and the impacts of the ongoing CR-3 outage.

So what you see in this is if you compare the left-most column to the center-most column, what you are seeing especially in the years, say, 2012 through 2017, are the increasing impacts of the change in the DSM scenario from the 2009 goals setting to the extension of our existing programs as was determined by the Commission this summer. And you can see that that starts out as about a two or three percent impact in the early years and accelerates forward to about a 6 to 8 percent impact by the mid to late part of the decade. After 2018, it's not really a fair comparison, because then you start getting tangled up in projected new units beyond that point.

If you look at the comparison between the center column and the right-hand column, especially in the years 2011 through 2014, what you see is the impact of the outage at Crystal River 3. And you can see that going through those years Crystal River 3 represents about 8 or 9 percent of our total generation, and it's reflected in that reduction in the reserve margin. I think the important point to take away here is that at no time does the reserve margin drop below the 20 percent criterion in this plan, even with Crystal River 3 out of service through 2014.

This next slide shows a comparison of the impacts of the DSM programs. These are cumulative energy impacts due to the energy efficiency programs. In comparison, the way that the goals were structured in our 2009 DSM order, we had a much higher emphasis on energy efficiency than on load control. So consequently almost all of the differential here is seen in energy efficiency programs rather than in load control programs. And you can see that there is a very substantial difference between what we had planned in our earlier Ten-Year Site Plan and what we are projecting in the current scenario that was requested from us by staff.

This is the same comparison done on summer peak load. And you can see the reduction, again, from the yellow line, which is the numbers that were put in the 2009 goals versus the brown line, which is the extension of the existing programs. I threw the red line on there just sort of for reference. You may recall that in discussions with staff we had developed a middle ground, what we called the rate mitigation plan, that just sort of illustrates where that might have fallen out.

Again, most of the differentials in our programs were shown in energy efficiency. Much as Mr. Sim referred to their load control programs, we have a load control differential that is a little bit less than 20 megawatts a year, so that is not a huge impact on the overall system compared to the energy efficiency. And this is what it looks like when you look at it on our summer net firm demand at the time of the peak. So you can see the cumulative impact, and it gives you sort of a reflection of what that looks like in percentage of our overall net demand.

The change in the two growth periods or growth projections changes our overall cumulative average growth rate from about three-quarters of a percentage over that ten-year period up to about 1.6 percent. And then we showed this as a change in our projected resource plan. Our Ten-Year Site Plan, as it was filed in April, showed only a single projected new unit, a gas turbine peaking unit in 2020. We would project, if we were going forward with the existing DSM programs, that we would bring that unit forward from 2020 to 2018, and that behind it in 2019 we would see additional demand for our combined cycle unit.

Turning our attention to the question of the reserve margin, I'd like to thank the work that was done by FPL. They had done a much more detailed example than the one that we have prepared, but I think that our points and conclusions are much the same. So we will work through a slightly simpler example using Progress Energy's numbers. And in our example, we picked the year 2014 just because it happens that with the outage at CR-3, we're going to be right at our 20 percent reserve margin in that year. So it made a handy example for showing kind of how the components of that 20 percent are put together. You can see in this that we had, again, you know, about a 28 percent reserve margin before the scheduled outage for Crystal River 3.

I think the thing that, you know, we wanted to emphasize, and the FRCC talked about this, Mr. Sim talked about this in terms of their view of things, is that when you look at the overall reserve margin, you are talking about a number of different components, both generating reserve, load control reserve, firm and nonfirm load.

So when we look at this, we start out by looking at the question of we have a -- we calculate a total demand from our residential, commercial, and industrial customers, then from that we subtract the expected impact of the energy efficiency DSM programs that are ongoing, which gives us a total number after conservation, if you will. And that's sort of the real demand that we expect to see, given the implementation of conservation programs like insulation, window changing, energy efficiency, and other programs both at the commercial and residential levels that just plain shave load off completely.

Then after that, we calculate the interruptible loads. The interruptible loads, especially also our residential and commercial load management programs, which get us down to the number that we show as firm demand. But much as has been discussed here earlier, it is our intention most of the time to serve that number, which is the after conservation number but before load control, because we also want to limit our usage of the load control to situations where it's really necessary because of adverse weather, because of unit failure, and other conditions and not to rely on that as a regular daily resource. Because, first of all, it limits our flexibility. It will raise customer costs in the variable arena. And, finally, we have the personal experience of having a substantial number of customers drop off our system after extended use of the load control program.

So if you look at the previous example, and this is kind of amalgamating things that were on the previous two slides, we have a total capacity net after the outage at CR-3 of about 11,000 megawatts, and a total load after conservation of just over 10,000 megawatts, which leaves us roughly 1,000 megawatts of reserve before we start tapping into the load control. And this is about, you know, two-thirds of our reserve margin. So in round terms, we are very much on the same plain as the numbers that were presented by Florida Power and Light. That 1,000 megawatts would represent, you know, 12 or 13 percent of the reserve margin by itself.

Out of that 20 percent, or out of that 1,000 megawatts, if you will, we have to reserve power for a number of uses. First of all, we reserve power for our contribution to the regional reserve supporting our fellow utilities in the event of a unit outage. We also recognize that all of these calculations are done on the basis of an integrated hour. The actual instantaneous amount of power that we would have to supply may be somewhat higher or lower than the amount that we have calculated on the integrated hour. So we have a reserve that we maintain for instantaneous load following, and that leaves us with roughly 500 megawatts for unit reliability and for reaction to adverse weather.

And in that area, we have ten units, and not counting Crystal River 3, I should say, ten units that are greater than 450 megawatts of capacity. So, again, much as in the example presented by Florida Power and Light, they chose to look at one unit, one major unit out and half of a second unit. We would be much in the same circumstances where that would use up our unit reliability reserve.

Also, we have calculated that on our system in the summertime, the temperature sensitivity is roughly 300 megawatts per degree. So above the peak temperature for our system-wide average across the 29 counties that we serve, as that system-wide temperature starts to rise, we expect to see an additional demand of around 300 megawatts per each degree that the temperature rises. So, significantly hot weather, or a lack of summertime rain, or those two factors combined can cause us to, you know, pull into our reserves quite quickly.

Then we do have our load control reserve, which is about 700 megawatts. And as I mentioned, you know, it's our goal to use that load control as a final resource in the event of these other resources being exhausted of outages and/or adverse weather affecting us. In addition, we may use that load control to manage local issues which may occur either on the transmission or distribution systems. We can use load control to alleviate local constraints, as well.

So, finally, I think, you know, we have not, perhaps, done the exhaustive numerical analysis that you had seen earlier, but in a qualitative sense we would expect that a change to a lower reserve margin would indeed lead to higher load control utilization. It would have an impact on our costs and our existing load control programs.

One of the things that we do, one of the ways we utilize our load control programs in an effort to control customer cost is that in periods of less than an hour, we'll use load control, especially on water heaters and pool pumps to respond to disturbances in the system. If a unit trips off-line and the system begins to lag, we are required to respond in less than 15 minutes to make up that lag. And, you know, so typically we have two alternative ways of doing that. One is to start our fast start peakers that we hold in reserve, and the other is to fire load control. And then what that does is that bridges the gap while our larger units are able to ramp up and cover whatever that loss of load may be. Because we are able to use load control in these less than one-hour bursts, it reduces the number of starts we have on our fast-start peakers, which is then reflected in a reduced fuel usage over time.

So, that is -- you know, and if we were to reduce the reserve margin and, therefore, be using our load control much more, it would take that flexibility to utilize load control as a cost response measure away from us and would result in higher fuel costs.

And finally, you know, simply the thinner the margins are the higher the risk to reliability would be. And as I think has already been discussed extensively, there would be a substantial trade-off between any potential cost savings and the risk of reliability in the long-term.

And that concludes my prepared remarks. I'll be happy to take questions, and then turn it over to Tamara to talk about the renewables question.

CHAIRMAN GRAHAM: Ben, I want to thank you for your presentation. Any questions of Ben before we move on to Tamara?

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I have one question on Slide 3 of your presentation. Have you looked at or can you provide information if CR-3 does not come back on-line at the 2014-2015 time frame, what would the reserve margin be in the outlying years?

MR. BORSCH: Well -- yes, what we have looked at is if it doesn't come back in 2014, you know, you can -- I mean, you can sort of see on this that if you imagine in your mind's eye that CR-3 represents about 8 or 9 percent of our reserves at this time, you know, that things would be a little tight in 2015, and we would have a substantial deficit going on into some of those later years which would have to be addressed by some kind of a resource increase, either a new unit in 2016 or some kind of a capacity purchase.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Any other Commissioners?

Staff. Yes, sir.

MR. ELLIS: Good morning. I only have one question on Page 7. You showed two changes on this slide, the unknown sited combustion turbine is moved up by two years, and a new combined cycle unit has been added in 2019. Is Progress planning on filing new standard offer contracts to reflect these changes?

MR. BORSCH: We are not at this time. It is our understanding for the time being that this is a scenario response to the data request from staff, and that this does not represent the filing of a new Ten-Year Site Plan. I know that that subject is still under discussion, but until that discussion is resolved we are not planning to at this time.

MR. ELLIS: Thank you.

CHAIRMAN GRAHAM: Any other staff? Ben, we do thank you very much.

MR. BORSCH: Thank you.

MS. WALDMANN: Good morning, Commissioners, staff. My name is Tamara Waldmann, and I manage the renewables and cogeneration section of Progress Energy Florida. These are our purchased power agreements that falls under the Commission's rules for qualifying facilities.

And with me is Mr. Gammon, who is a lead power account manager, and one of his responsibilities includes reaching out to renewable developers in the state and negotiating our contracts with them. We are always pleased to provide an update on our renewable work because Progress remains committed to seeking out cost-effective renewables as part of our balanced solution to serving our customers in the future. And I think our commitment is evident by our current QF portfolio in Florida.

Following along on your handout, I'm on Slide

3. Progress Energy Florida currently has over 1,500 megawatts under contract from qualifying facilities. 682 megawatts come from firm QF facilities that are built and in operation today. That's made up of 509 megawatts from cogeneration facilities, which is a conservation measure, and 173 megawatts from renewable facilities.

Our renewable generators operate at about an 80 to 90 percent capacity factor, which allowed Progress to purchase over 1.1 million-megawatt hours of firm renewable energy last year. So our firm renewable capacity under contract is up to 378 megawatts. This portfolio has more than doubled since 2009.

MR. GAMMON: How did we get here? I always like taking the opportunity to reiterate our open request for renewables, and this is an initiative that has been open for over three years now. And the philosophy is simple, we speak to any interested party wishing to sell renewable energy in the state. And as you would imagine, that keeps Mr. Gammon and I very busy, but the information exchange is invaluable. We get to learn first hand from renewable developers what they need to make their projects work. We have seen a variety of technologies, and we understand the application and the scalability of these technologies.

In return, we get to discuss with renewable developers what we need, what our customers need, and what these contracts need to look like under current regulation.

I think the main takeaway from this information exchange is that developers in the state are keenly aware of our natural resources that occur in Florida, and they are going to target these renewable resources to develop cost-effective projects. So our experience tells us that large utility scale renewable projects stand the best chance of success if they have straightforward technology and, therefore, can perform under contract, and if they have experts or consultants they can reach out to that will address their financing, siting for interconnection on the transmission system, all their facets of permitting and zoning balanced with real good public relations.

As we prepared for this workshop today, we solicited project updates from all of our renewable suppliers, and most of them already provide monthly, if not quarterly, updates to us. But independent of their contractual requirements, what we wanted to put forth as a measurement of their project's progress is very simple. Have you bought land; have you applied for interconnection; have you applied for any permits; and what kind of money have you put forth into the project.

So I'm going to start addressing our solar contracts, and then Mr. Gammon will continue with our biomass portfolio. We have two suppliers that we have executed as-available solar contracts with. As-available. The supplier will be paid our hourly avoided cost, and these are nonfirm contracts, so it does not obligate the supplier in any way. There is no requirements around the reliability, the quantity, or the timing of their solar energy deliveries to the grid.

The first supplier I will go to is National Solar on Page 9. National Solar has a large scale approach to their business model. As they broadly search for facility sites, they executed as-available contracts with us on a county-by-county basis. So we currently have nine contracts in force with them today.

Since then, they have narrowed their focus on four counties here in Florida they feel best fits their business needs, and these include Gadsden, Hardee, Osceola, and Suwannee. A week and a half ago, they issued a media release that they have acquired land in Hardee County, and it is about, I think a little over 1,300 acres, which would more than accommodate a 400-megawatt solar farm. They have contracted with Hansel Phelps Construction Company for the design, construction, and O&M of their facilities. And they are still working on their financing with various U.S. commercial banks.

I am going move on to Blue Chip Energy. Blue Chip Energy is an integrated solar PV company where they also manufacture solar panels right here in Florida. So we have two solar as-available contracts with Blue Chip. Their first facility is called the Rinehart Facility, and it's located in Seminole County. And if you look on Page 10, there is a picture of what 1.2 megawatts of solar panels on the top of their manufacturing plant looks like.

Now, they found it's in the best interest of their project right now to utilize our net metering tariff, so they are doing that up to the two megawatt threshold that's part of that tariff, and then they plan to continue to build-out on the roof and the surrounding ground, which will require some zoning changes that they are aware of, and then the balance they will sell back to us at our as-available rate.

Their next facility is their Sorrento Facility, which is located in Lake County. And actually if you turn to Page 12, that is an aerial rendering of what 40 megawatts of solar panels will look like once installed in Lake County, Florida. So they have purchased land, they have all their zoning complete, they have applied for interconnection, their system impact study is underway, and they plan on breaking ground later this month.

Blue Chip Energy will do their own engineering, procurement, and construction, and they are self-funded, although they are anticipating qualifying for the DOE's Section 1603 tax credit.

Now I will turn things over to Mr. Gammon to continue on with our biomass updates.

MR. GAMMON: Thank you, Tamara.

Good morning. So I want to talk about our Progress Energy biomass contracts, and you really can't start that discussion unless you talk about, first, the units that are on-line and have been on-line for sometime now, and we have five of those units and they are listed here.

You can see that they are -- four of those are municipal solid waste plants. The fifth one is Ridge Generating Station, which mostly burns waste wood. They also utilize landfill gas and tires. Under contract we've got six total contracts right now that are active. Four of them are firm, two of them are as-available. And I'm going to update the four firm -- or three of the four firm, and the two as-available. The fourth firm is U.S. EcoGen, which is an open docketed item, so you should have up-to-date information on that.

So, let's start with Biomass Gas & Electric. This project has been purchased by Rentech, and they have changed the name of it to the Northwest Florida Renewable Energy Center. It's going to be located in Port St. Joe. They have purchased their property, they have gotten their air permits, and they are working on their fuel supply, and their EPC contracts. And for interconnection the system impact study is nearly complete.

The issue that they have right now is financing. They had originally expected to get loan guarantees under the Section 17.05 program from the DOE, and that looked really good right up to the last minute, and then the DOE suggested they move over to the 17.03 program, which they did, but they haven't received any word from the DOE since May. So it has forced them to look for alternative financing, and they are actively doing that right now.

The next project I want to talk about is FB Energy, and there has been a new development actually that is not on this slide, and that is they struck a deal with Central Power and Lime, which is a 130-megawatt coal plant, and they are going to convert -- with this contract they are going to convert that coal plant into a biomass plant that will generate the 60 megawatts required under this contract. So that deal is just being finalized right now. So I don't have a lot of details on that yet, but that's the big news on FB Energy. So if they are going into an existing plant, then that obviously simplifies interconnection, and they will have to modify their permits. But it should actually simplify the project.

All right. TransWorld. TransWorld was approved earlier this year by the Commission. So since then they have identified their site and they are finalizing the purchase of that property. They have received positive response on both their fuel contracts and from the financing community and things seems to be proceeding well with them.

The two as-available biomass contracts we have are with Eliho Energy, which is an MSW, and E2E2, which is more of a biomass -- more traditional kind of biomass. Sweet sorghum, I believe, is what fuel they are looking at. Both of those are -- as Tamara talked about, they are as-available contracts, so there aren't a lot of milestones that they have to meet, but they are still moving forward. Both are kind of in similar positions. They think they expect to close on their financing soon.

So with all that, you can see that we are carefully monitoring all of our renewable contracts not only against their contractual requirements, but the real progress associated with their construction. We are encouraged and cautiously optimistic about the success of all of the projects we have discussed here today. And, finally, you can see our commitment to the balanced solution for the future where renewable and alternative energy play a key role.

And with that, Tamara and I will be glad to answer any questions that you have.

CHAIRMAN GRAHAM: Number one, I want to thank Mr. Gammon and Ms. Waldmann for your presentations and for the information put before us.

Commissioners, any questions? Let's start with Commissioner Brown.

COMMISSIONER BROWN: Thank you.

And I wanted to commend Progress for actively pursuing solar energy through its solar power projects as well as biomass. You all are stellar performers. So thank you very much for that.

The solar farm in Hardee County is very exciting to the renewable energy proponent world. I'm assuming that if financing goes through and is successful, does Progress intend to pursue solar energy through solar contracts with the supplier, the solar farm?

MS. WALDMANN: You're referring to National Solar that is building out in Hardee County?

COMMISSIONER BROWN: That's right.

MS. WALDMANN: Absolutely. As they continue to take this large scale approach in their business model, like I said, we already have nine contracts with them, so we will continue to work with them under these as-available contracts in other counties as they choose to build-out.

COMMISSIONER BROWN: And will that affect your, I guess, next Ten-Year Site Plan?

MS. WALDMANN: Well, these as-available contracts are nonfirm contracts, so they will be in there in that context, assuming that they are built and they are operational and they are performing. So because under this contract structure there is no requirement, again, to the quantity or the timing of their solar deliveries, we will just have to put them in the model as a general displacement.

COMMISSIONER BROWN: And not a firm commitment?

MS. WALDMANN: Right, and not a firm commitment. That's exactly right.

COMMISSIONER BROWN: Okay. Thank you. And just one more question. Regarding the Biomass Gas & Electric project, you indicated that Progress is actively looking for securing alternative financing as a result of the DOE's delay or complete silence since May. How does DOE's delay or silence on the financing portion affect the milestones in the contract for that project?

MS. WALDMANN: This is BG&E that is actively looking for other alternative financing since their support from the DOE failed. So I think they mentioned to us that they are working with a Korean investor right now. A lot of developers are looking toward private equity versus traditional financing as a result of the economy, but they have not given up. They are continuing to be diligent and look for alternatives.

COMMISSIONER BROWN: Is that 45 megawatts, though, in the Ten-Year Site Plan as firm -- as committed capacity?

MS. WALDMANN: No, it is not.

COMMISSIONER BROWN: Okay.

MS. WALDMANN: So simply as I reviewed those, not contractual requirements, but elements of the project that really speak to its progression, until any of these projects get further along and have interconnection, they have permitting, they have a site, Ben and I actually work very close together to put them in our plan.

COMMISSIONER BROWN: Okay. Thank you.

MS. WALDMANN: Sure.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

And, again, I want to congratulate Progress Energy, and I think that it's great that you are pursuing renewable energy projects. And of the 378 megawatts that are under contract, I assume those are either contracted with the standard offer contract or a similar contract, is that correct?

MS. WALDMANN: Sure. The 378 covers the 173 that is currently on-line and operating and then another 205 megawatts that's under development. And those all started from our original standard offer contracts, yes. But those are all then negotiated off of the framework of the standard offer.

COMMISSIONER BALBIS: Okay, thank you. And I assume, or I hope that the key provision of the standard offer contract where the -- and it's just avoided cost is what the payment is for that. And, again, so there will be no additional cost to the ratepayers. And since you are actively pursuing renewable energy providers, what are some other terms and conditions of the standard offer contract that would either encourage additional projects to move forward, or maybe encourage the private equity now that alternative financing is being pursued? I mean, what can we do as a Commission to encourage these projects to move forward?

MS. WALDMANN: Well, under our standard offer, because it's preapproved, anybody who walks through our door can execute that contract and then we are obligated under that, those terms and conditions. But I think we want to be very careful as to what we put in there because, you know, the terms are what we have to live by for the next 20 years.

With that said, I think we can take probably a good review as we draft our next standard offer, as we heard from some of the developers, to see what we can do with timelines. Timing is critical. For instance, one example is some of their contractual requirements today are very close to their commercial operation date, and that was deliberate to give them some flexibility in this world that they are trying to pave the way that hasn't been done before. Maybe there's something there that we can include. I would have to think about it more.

MR. GAMMON: I agree. I think timing -- timing is probably the number two issue behind price.

COMMISSIONER BALBIS: And, Mr. Chairman, if I can continue.

CHAIRMAN GRAHAM: Yes.

COMMISSIONER BALBIS: You know, I hope that you followed the Commission's direction when we approved the standard offer contract that to let these renewable energy and other power producers know that it's a starting point and that we can negotiate the terms. Obviously not the price, but it would have to come to the Commission for approval, and not telling them, okay, we have to wait until the next time we approve the standard offer contract.

MS. WALDMANN: Absolutely.

MR. GAMMON: And I think we have been very creative. I think if you talk to some of the counter-parties, we have been very creative on how we can negotiate those contracts and meet their needs.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Any other Commissioners? Staff. I do want to thank you guys very much for your presentation.

MS. WALDMANN: Thank you.

CHAIRMAN GRAHAM: For last, but not least, we have TECO.

MR. HORNICK: Good morning, Commissioners. My name is Mark Hornick. I'm the Director of Planning, Engineering, and Construction for Tampa Electric. And I've got my colleague, Dave Knapp, who is Manager of Generation Planning over here to assist me, if necessary.

Today we have been asked to address two issues a little bit different than -- one of them is at least a little bit different than the discussion we have had earlier today, that's to give an update on the status of the USDOE grant for carbon capture and sequestration pilot project at our Polk Power Station, and any impact on generation reserves. So I will cover that first, and then we have got some comments. We were requested to discuss studies for possible modification of 20 percent reserve margin criterion, which has been covered previously by our colleagues.

So, first of all, a little bit of the background on that project. The CCS project out of Polk. Polk Power Station, particularly Unit 1, was a clean coal technology demonstration project partially funded by the Department of Energy. It went in service in 1996. It uses integrated gasification combined cycle technology, and it has performed well for us. The DOE continues to view clean coal technology and now including carbon capture and sequestration as important to the nation's long-term energy future. They think it's going to take a number of technologies to be able to use various fuels and use them in an environmentally beneficial way in the future.

The third slide is actually an excerpt from a brochure from the Department of Energy. I just thought that we could highlight that the DOE does continue to view coal from the IGCC plant. I have described it as a super clean coal-based IGCC demonstration plant, and also a plan up in Wabash River, Terre Haute, Indiana, as kind of key notes of that technology. And if you look in the lower right in the bubbled area, you can see that the DOE has a continued concentration on lowering the cost of pre and post-combustion capture CO2, and also a continued concentration on identifying, validating, and testing suitable sites for safe long-term storage for carbon dioxide.

The next slide is a little busy, but we took that from the DOE's Southeastern Regional Carbon Sequestration Partnership, or SECARB. Tampa Electric is a member of SECARB, but this project is not funded by that agency. But I thought it might be helpful just to give you an understanding of the level of knowledge and research that has gone into this whole area of science. In the SECARB region, the yellow dots there are point sources of carbon dioxide. They include all stationary sources, power plants, cement plants, and other large emitters. The arrow there just gives you an idea of the approximate location of Polk and where that project will take place.

The other thing that I did want to point out to you there in the next slide is the region of Florida roughly south of the I-4 corridor that's in blue depicts an area of kind of special geology that has saline formations, deep saline formations a mile to a mile and a half deep that are capable of storing carbon dioxide. As you can see, Florida does have the capability to do this from a geologic perspective.

In the lower right table, we have also highlighted a row there that talks about Florida's capability, geologic capability for storing CO_2. And in the third column from the right you can see that saline formations primarily in the southern half of the state have about 16.8 billion metric ton capability for CO_2 storage, and if you took all the CO_2 generation from point sources and stored that in that formation it would be capable of storing 127 years of emissions.

So I guess the point in including that is there is a fair amount of research and really a fair amount of capability for the potential storage of CO_2.

Obviously we have got to prove that technology, and that's what this project, in part, will accomplish.

So a little bit more then about the project itself. Back in September of 2010, the DOE announced the funding of this project. There are really two parts to it. One, to demonstrate a warm gas cleanup system which will remove sulfur at elevated temperature along with the integration of carbon capture and sequestration. The funding level for this was significant. It was $168.8 million. It comes from the DOE, and it's ARRA, or stimulus funding is the source of those funds.

The project is designed to treat a portion of the syngas, or the fuel gas that's created by the gasifier out at Polk, about 25 percent, taking it into a slipstream, treating it to remove the sulfur and CO2, and then returning that treated gas back to the process for use in power production. There is activity taking place on the project right now, but the operation phase is currently expected to be in 2014 and the first half of 2015.

This one is a little complicated, and I won't take you through the whole process flow diagram for that technology out there, but the box on the upper right really depicts the scope of the project. And just moving from left to right real briefly you can see a vertical line that goes up to a box that is called HTDP, that is the high temperature desulfurization process, and that is that slipstream that comes out of the Polk Primary Process Unit.

So that HTDP takes out the sulfur. There is another process unit called a water gas shift reactor, and chemically what that does is it takes carbon monoxide and water and shifts it to carbon dioxide and pure hydrogen, and that's important for the operation of this process. We then cool it in that syngas cooling unit. The fourth box from the left that's labeled aMDEA, is an amine solvent, and that basically separates then the CO2 from the hydrogen in that stream. The hydrogen would then go vertically downward and be added back to our process. And then the CO2 is compressed and will be injected in the ground for long-term storage.

So you get the idea that it is a slipstream, about 25 percent of the syngas, and I will talk about it later, but that whole process unit is able to be isolated from our process so that we can shut the valves and kind of let that be a stand alone and hopefully not impact reliability or the operation of the unit.

Okay. Quickly, then, discussing the key project participants and the goals that each project participant has. The DOE, like I said, they are funding the project substantially out of ARRA funds. Their objective is to demonstrate this technology at an operating IGCC. That is a high priority for the DOE. There is a lot of these projects that are going on in our country and around the world, but they really want to see one in operation and prove the viability. It would be the first one in Florida, and this is a high visibility project for the DOE folks in Washington.

RTI International's Research Triangle Institute, they are actually the primary owner of the WGC technology and the prime contractor, so Tampa Electric is essentially a subcontractor to RTI for this. Tampa Electric will provide the host site and we will be responsible for the sequestration permitting and operation. Our benefits, Tampa Electric benefits is to be able to evaluate the technology that demonstrates CCS at our site and the experience with that, and we would have the option to retain that equipment for use in the future. Should it, number one, be proven viable, because it is a demonstration project, and economically feasible, it would be an option for us to comply with future CO_2 regulation.

Another item that I'm going to talk on just a little bit because there is a synergy with a regional reclaimed water project, so we will use one injection well from that project. A few other entities. Shaw Group, BASF, and then the University of South Florida has actually done quite a bit of work to help us research and model the geology under the site.

Okay. A synergistic project that we have already in place is on the next slide, and that is the Regional Reclaimed Water Project. What we will do there is take wastewater from the City of Lakeland, pipe it about 15 miles south along State Road 60 and then State Road 37 to Polk Power Station. We will then treat that water, and we will use the treated beneficiated water to our reservoir, and then the effluent from that treatment will be injected into two deep wells directly below the site. That project is underway and it is partially funded by the Southwest Florida Water Management District, and we expect that project to go in-service in 2013. So that is kind of a stand-alone, but it does have a significant synergy to this project, to the CCS project.

On the next slide, Slide 10, that water project technology really requires two underground injection wells. Those injection wells -- we have already completed the first well -- really help provide a good geologic evaluation for water injection, but also the potential for CO_2 injection. So there was intellectual knowledge that was gained from that, geologic knowledge.

During the CCA demonstration period, we can use one of these wells for the CO_2 injection, and it can still serve as the backup to the primarily injection well. And the key for this really is that we can use this, one of the injection wells as an in-kind, quote, unquote, contribution towards DOE for the cost sharing requirement. What we would actually do is the economic benefit of that well, which we are doing anyway with the water project, will be allocated to the Department of Energy and they will count that as our cost sharing towards the project. So essentially no incremental expense out of Tampa Electric or its customers towards the CCS project. So that was one of our goals and objectives in order to move forward with this.

A couple other things that have come out so far, and it is encouraging. The Polk Power Station site does appear to be quite suitable for carbon capture and sequestration. There is an injection zone between 4,000 and 8,000 feet deep, and excellent confining unit at around 4,000 feet. It's about 1,000 feet thick. It's essentially nonporous, and any material that is injected below that should not find any way to come to the surface. It will stay down there.

Some of these projects that are going around in the country. You have to worry about seismic issues. We really don't have that. We have got stability in Florida. In our area of the state there are very few penetrations through that confining layer, so that's another benefit that is positive to this project.

If you have been out to Polk you know that the surrounding area is largely rural and there's phosphate mining in the adjacent area. So that is really a good benefit, as well. And then we are sited along with USF that the modeling that we have done for the geology down there really indicates that if you put CO2 in that area it will very rapidly be trapped and mineralized on the order of years rather than decades or potentially even centuries that some other geology you would expect. So we are excited, and the DOE is excited about the suitability for doing this at the site.

In terms of project status and schedule, we are almost complete with the front end engineering design, or FEED work. There are definitive agreements that are being negotiated right now for the detailed engineering, construction, and operation, primarily between Tampa Electric and RTI. We would expect construction to take place in 2013. And as I said before, the operation to take place in 2014 and the first half of 2015.

A couple more on this, then. I mentioned before that it would use about 25 percent of the slipstream of the syngas. Important to us is that we can isolate this equipment at our sole discretion at any time. So in terms of impact or reliability of the unit, by the operation of this pilot we are trying to minimize that such that we can essentially close that system off if there is any kind of upsets, and hopefully not have any adverse effect on the operation of the plant. That being said, when the project is in operation, we do expect a reduction in net plant output to still be determined, but on the order of ten megawatts, maybe a little bit more.

However, and I will talk about this a little bit more, that will not result in an increase in cost. The project will bear the cost of any fuel and purchased power incremental cost there, and the DOE would reimburse Tampa Electric and its customers for any impact due to the operation of the project.

In terms of reserve margin and the primary issue that we have discussed today, the project can be isolated, so if we need it on peak, if we need the complete capacity of the unit, we can isolate the project and operate as normal. And also because of the way we can isolate it, any maintenance that is required on the demo unit shouldn't affect the operation of Polk Unit 1. So good stuff there.

Lastly, on the cost and funding, I probably have covered these. The DOE cofunding will cover the direct costs of this project for Tampa Electric and its customers. We are negotiating agreements to provide for that reimbursement of direct labor expense, you know, items that we would do in support of this project that we wouldn't normally do, otherwise do, will be reimbursed. Fuel costs and purchased power, as I mentioned, would also be reimbursed. So that is one of our standards and objectives for moving forward with this project. And, again, on the capital side, the only thing that we are required would be that in-kind contribution for the second well.

So hopefully that covered some of the questions that were out there in the Ten-Year Site Plan supplemental data request. I certainly can answer any more questions on that topic. But moving along, I'm trying to wrap up here, recognizing the time. What has Tampa Electric looked at with respect to possible modification of 20 percent reserve margin. Just some broad considerations. I think some of these have been mentioned before. You know, we are in peninsular Florida. There are limited interconnections. The investor-owned utilities, they do provide a large amount of the supply-side support for the state. As we experience and other utilities, forced outages occur randomly, and the planning criteria can sometimes differ from the actual situations that we experience. Instantaneous peaks can and do exceed planning peaks.

I'll talk a little bit more about size of units and how that impacts reliability versus system size, and then a little bit of historical. You know, what have we experienced in the recent past. Here's a summary of Tampa Electric's generating units from our 2011 Ten Year Site Plan Schedule 1. These are net summer ratings for the units, and I guess the point that I wanted to make with this slide is if you look at it as a percent of our system, you can see that the Big Bend units, which are coal fired, are about 9 to 10 percent of our total capacity. If you get down to the Bayside units, which are combined cycle, each unit represents -- Bayside 1 is 16 percent of the total, Bayside 2 is 22 percent of the total of our capacity. While I'm on that, let me just point out, because it was discussed before, I think staff asked a question on it, that those units are -- Bayside 1 is a three-on-one combined cycle, Bayside 2 is a four-on-one. So that represents, you know, the total capacity of the unit. If you lost one CT, one combustion turbine, it would be a lesser amount reduction than that, say, for Bayside 2 than 929. But if you did lost a steam turbine, there are contingencies where you could potentially lose that whole unit.

Our peaking fleet then is represented below that. But you can see that in the case of Tampa Electric, if we lose one or potentially two units it can amount to a significant proportion of our reserve margin pretty quickly.

The next slide is kind of a brief summary of information that we supplied as part of the supplemental data request. And just looking back historically at our actual, our peak demand versus our available capacity. And let me clarify, this is retail peak. This is total retail peak. So it does not have load management and interruptibles removed from it. But if you look back, in 2007 we had two months in actual where our capacity was lower than our actual monthly retail peak. 2008 was two months that were short, so to speak; 2009, one month; and 2010 another month. So what we do and did in those cases is we were able to rely on the market to purchase additional power so that we didn't have to interrupt our interruptibles or exercise load management. I'm not 100 percent sure that in each one of those months that was the case, but that is our goal, and generally we have been available and successful in finding power to make up that shortfall from the market.

On an annual basis, then, really the last three out of four years we were short on the annual peak, and we did look -- just kind of roughly, if we went to a 15 percent reserve margin that would have taken it to four out of four years being below the retail load in terms of our available capacity on the annual peak.

So the last slide, summary. You know, Tampa Electric feels that decreasing the current 20 percent reserve margin criteria to 15 percent, you know, it would increase the risk of interruption to customers, including firm customers, during peak demand. I would point out that the relative size of generating units to the total system really makes adequate reserve margin more critical. We are subject to a higher percentage loss of generation for each of our units. And based on our recent history, it kind of indicates that the 20 percent reserve margin is appropriate for our system.

So that concludes my prepared remarks. I would be glad to answer questions.

CHAIRMAN GRAHAM: Mark, I want to thank you and TECO for your presentation and the information you got before us. And, Commissioners, any questions of Mark or Dave? Commissioner Balbis.

COMMISSIONER BALBIS: Thank you. I just have one quick question concerning the carbon sequestration pilot project. You mention in here, and you don't have numbers on your slide, but I'm sure you are familiar with the slide, that agreements are being developed to provide for reimbursement for the labor costs, et cetera. I assume those agreements are with the DOE?

MR. HORNICK: The agreements actually would be with RTI with funding from the DOE. RTI is the prime contractor, but the DOE has been involved in the discussions. They are aware of the term sheets and, you know, the issues. We don't expect a problem there, but those agreements are being negotiated currently.

COMMISSIONER BALBIS: And my other question is if those agreements fall through, or if the DOE backs away from funding the project, what will TECO do in that case?

MR. HORNICK: Hopefully that won't occur, but we are not obligated to move forward, so our stand has been that we would not have an incremental expense to the company or our customers, and that's the basis of our negotiations moving forward.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Any other Commissioners? Staff?

Mark, thank you very much. I appreciate it.

Staff, other related issues, what's that?

MR. BALLINGER: No, sir. I don't think we have any at this time, and I think we could go to the public comment, if there is any.

CHAIRMAN GRAHAM: All right. Public input.

Do we have anybody from the public? Come on up.

MS. KAUFMAN: Thank you, Chairman and Commissioners. I just have a brief comment.

I'm Vicki Kaufman. I'm here on behalf of the Florida Industrial Power Users Group. And we have had a lot of discussion today about you all looking at the 15 versus 20 percent reserve margin, and we will look forward to participating in those discussions with you.

But as I have listened to some of the comments, I have heard a lot of discussion about DSM and the interruptible customers, and it seemed to me that the interruptible customers were just sort of being lumped in, perhaps, with residential DSM. And I just wanted to make it clear that the interruptible rate is very different than the residential DSM programs. And we have had discussions in the past as to whether the interruptible rate should even be part of the DSM program. That's a discussion we have had and we may have it another day. But I wanted to let you know that, number one, the interruptible rate requires interruptible customers to give notice, and it is a significant period of notice if they were to leave the rate. So they are not like someone with a residential pool pump, or whatever, who can simply say, hey, I don't want to be on this rate any longer.

Secondly, the utilities do not plan in their planning for the demand of the interruptible customers. So, again, they are different than the residential DSM programs. I'm not aware of interruptible customers leaving the rate, though we have had some discussions with you and with the utilities in regard to our concern about the low credit that is given for the interruptible rate, but I just wanted to tell you at kind of a high level that there are a lot of differences between large industrial customers on the interruptible rate and their ability to come and go as opposed to, as I said, the residential DSM programs that I'm not intimately familiar with, but I understand require a very slight amount of notice for a customer to leave the program. We will be looking, as you all have, at the issue of the

15 versus 20 percent. And as I said, we look forward to that discussion. Thank you.

CHAIRMAN GRAHAM: Ms. Kaufman, we probably need quite a bit of input from you guys, specifically the interruptible customers. Because my understanding, there were some problems in the past, not being fully educated on what the problems were, and I'm sure you can tell me first-hand what they were and how they were addressed. And I'm sure you have plenty of people that were there back when it was 15 percent, and now that it is currently 20 percent. I don't think we are going into this workshop with any agenda. It's just a matter of looking at the numbers and seeing what makes sense. You know, we may decide that where we are currently is the best place to be, and that's quite possible.

MS. KAUFMAN: I appreciate it, Mr. Chairman and Commissioners. And, as I said, we will certainly plan to give you our input, and any information that you might need from us, we'll be happy to provide it.

CHAIRMAN GRAHAM: Thank you. Any other input from the public?

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. Just kind of a wrap-up comment before we close for the morning, mid-morning. These workshops always provide a lot of really good information. It's difficult to absorb it all, but really good information from all of presenters and from all of the slides that they use to share with us.

I have two take-aways, and the first, and I think it is a very important point, and there are many who deserve credit, but that the state of electric reliability in the State of Florida is strong, and I think that's an important message to remember and to get that word out. And also obviously from the presentations and from the questions that we have had, the interest that we all have in furthering renewable development and fuel diversity in keeping with our statutory authority, and as it was in the past, is in the present, and may be in the future is something that is very exciting, and I know that we are going to continue to work on.

And I would just like to add my thanks to Sarah Rogers and the FRCC, an organization that is very quiet and not very well known, but does really vital work for the State of Florida. Thank you.

CHAIRMAN GRAHAM: I do want to thank all the presenters today and for the information that is in front of us. This is always very good reading and very good reference material. And that all being said, we are adjourned.

(The workshop concluded at 12:20 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 30th day of September, 2011.

Jane Faurot

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732

Florida Public Service Commission

2011 Ten-Year Site Plan Workshop

FRCC Presentation

Sarah Rogers
President & CEO

September 7, 2011

Parties/Staff Handout
event date 09 / 07 / 11
Docket No. Undocketed

Agenda

- **FRCC Load & Resource Plan**
  - Load forecast, generation additions, reserve margins, DSM, fuel mix, Renewables
- **FRCC Reserve Margin**
- **Generator and Transmission Maintenance Scheduling**
- **Inter-Regional Transmission Planning**
- **FRCC Fuel Reliability**
  - Fuel Reliability Working Group (FRWG)
  - Gas Study Project
  - Fuel Issue Response Coordination

Florida Reliability Coordinating Council

The purpose of the Florida Reliability Coordinating Council is to ensure and enhance the reliability and adequacy of the bulk electricity supply in Florida, now and into the future.

FRCC

Load & Resource

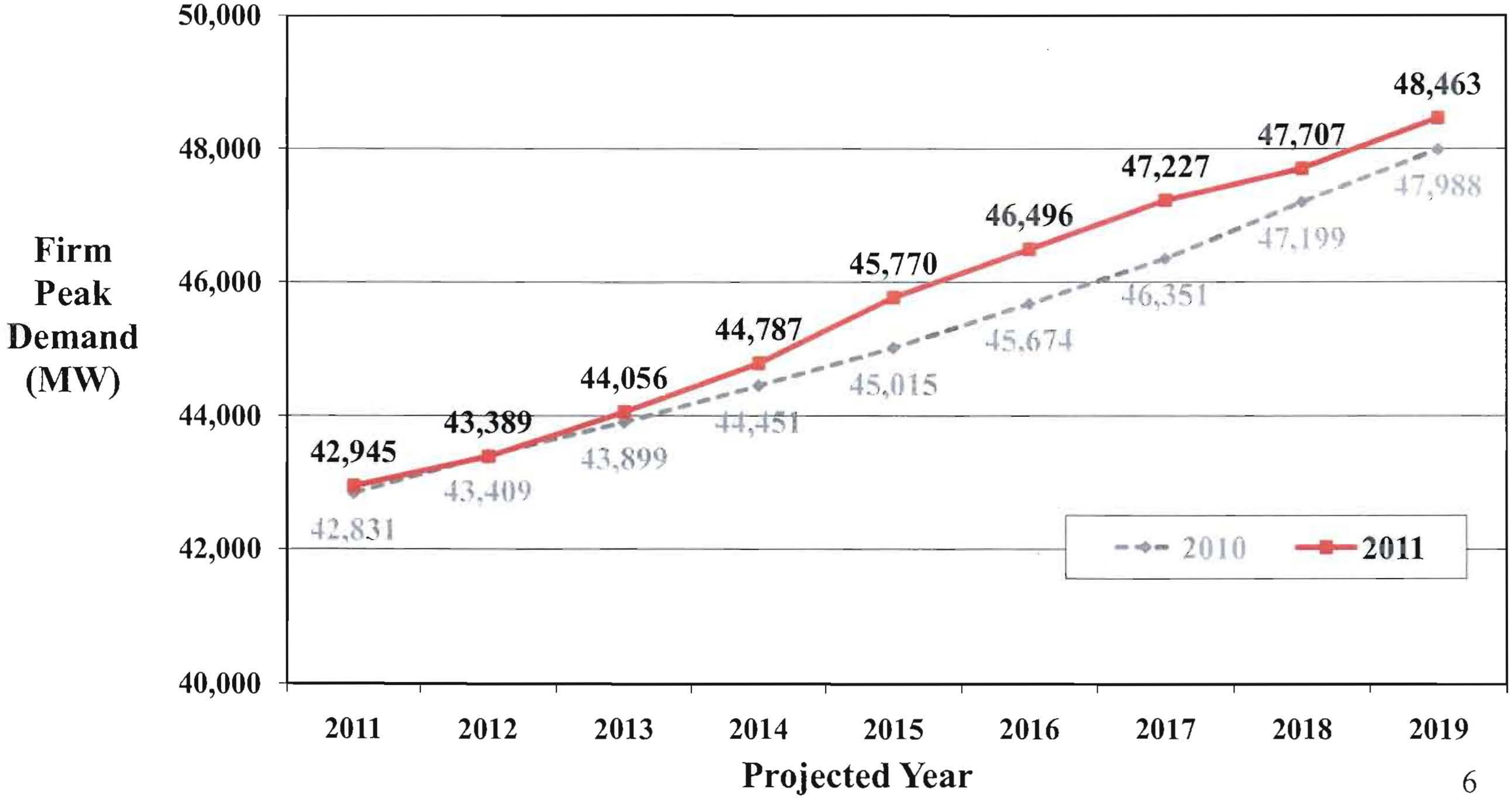
Plan

Load Forecast Factors

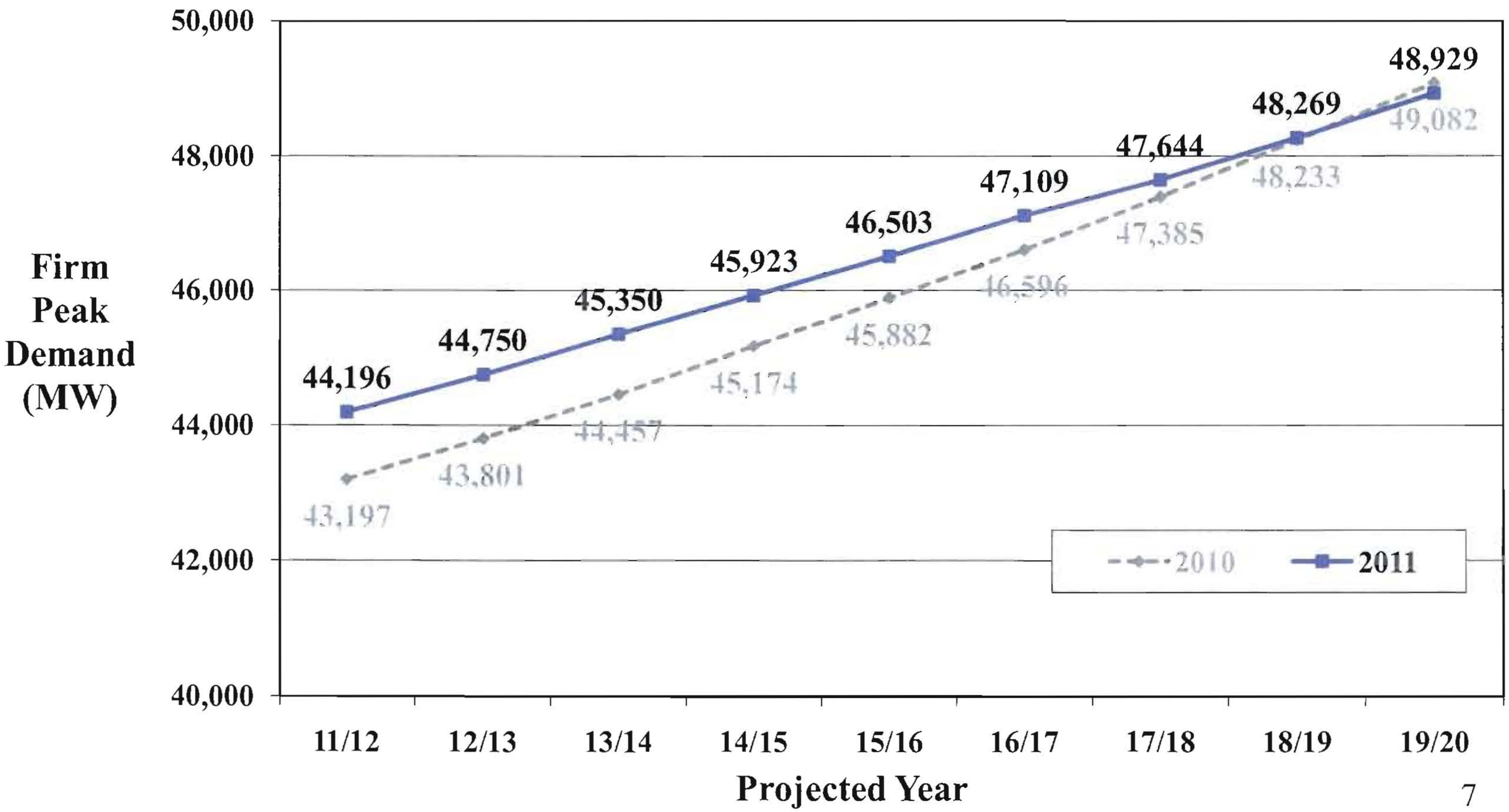
- Florida unemployment decreased over 2010
- Population picking up momentum in 2011
- Residential customers and energy sales are higher; commercial and industrial are down
- Load Management additions have slowed down in the 2011 TYSP
- Forecasted winter peaks are slightly higher in the short-term; summer peaks are slightly higher in the long-term

Comparison of 2010 vs. 2011 FRCC Firm Peak Demand Forecast

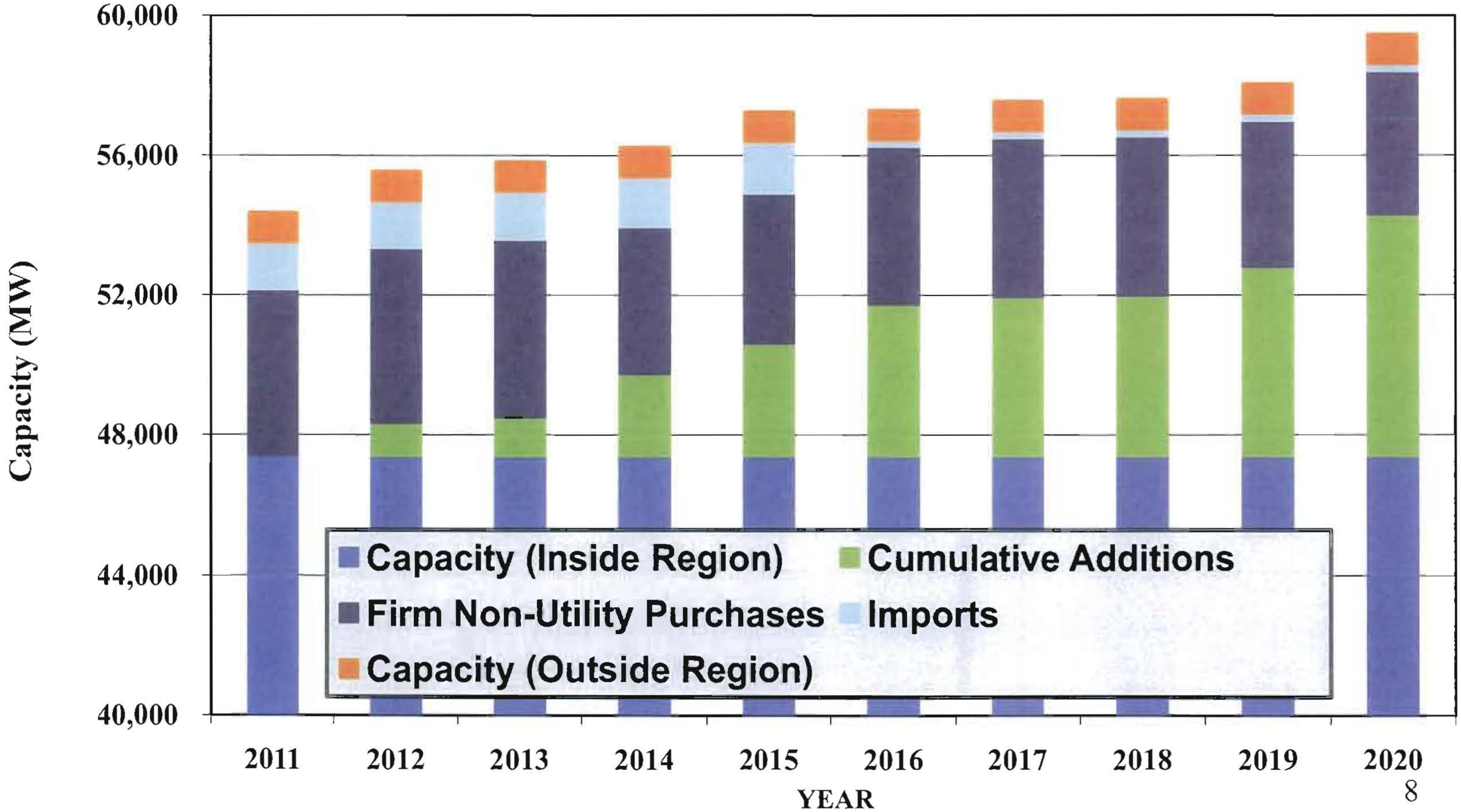
(Summer)



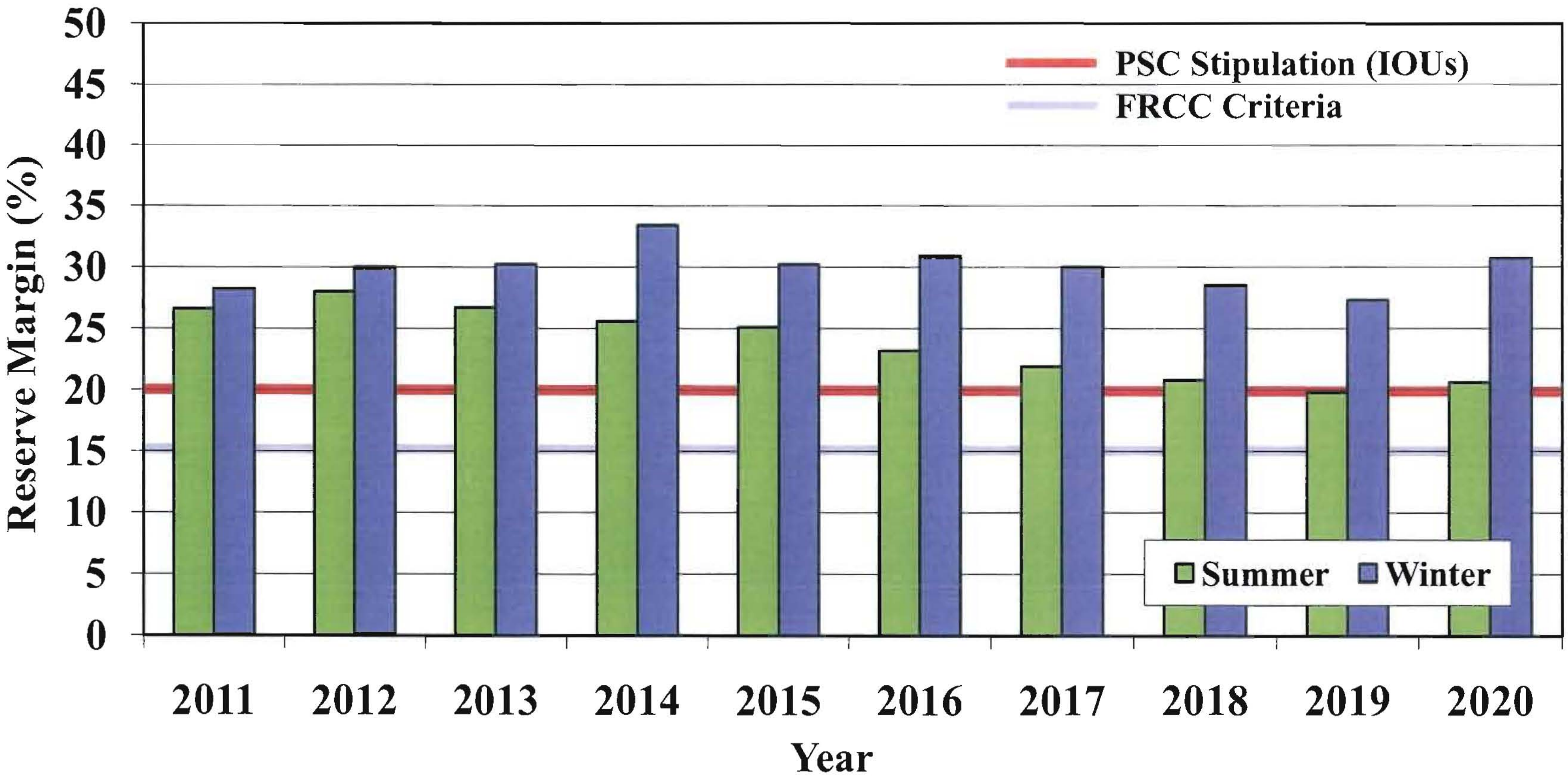
Comparison of 2010 vs. 2011 FRCC Firm Peak Demand Forecast
(Winter)



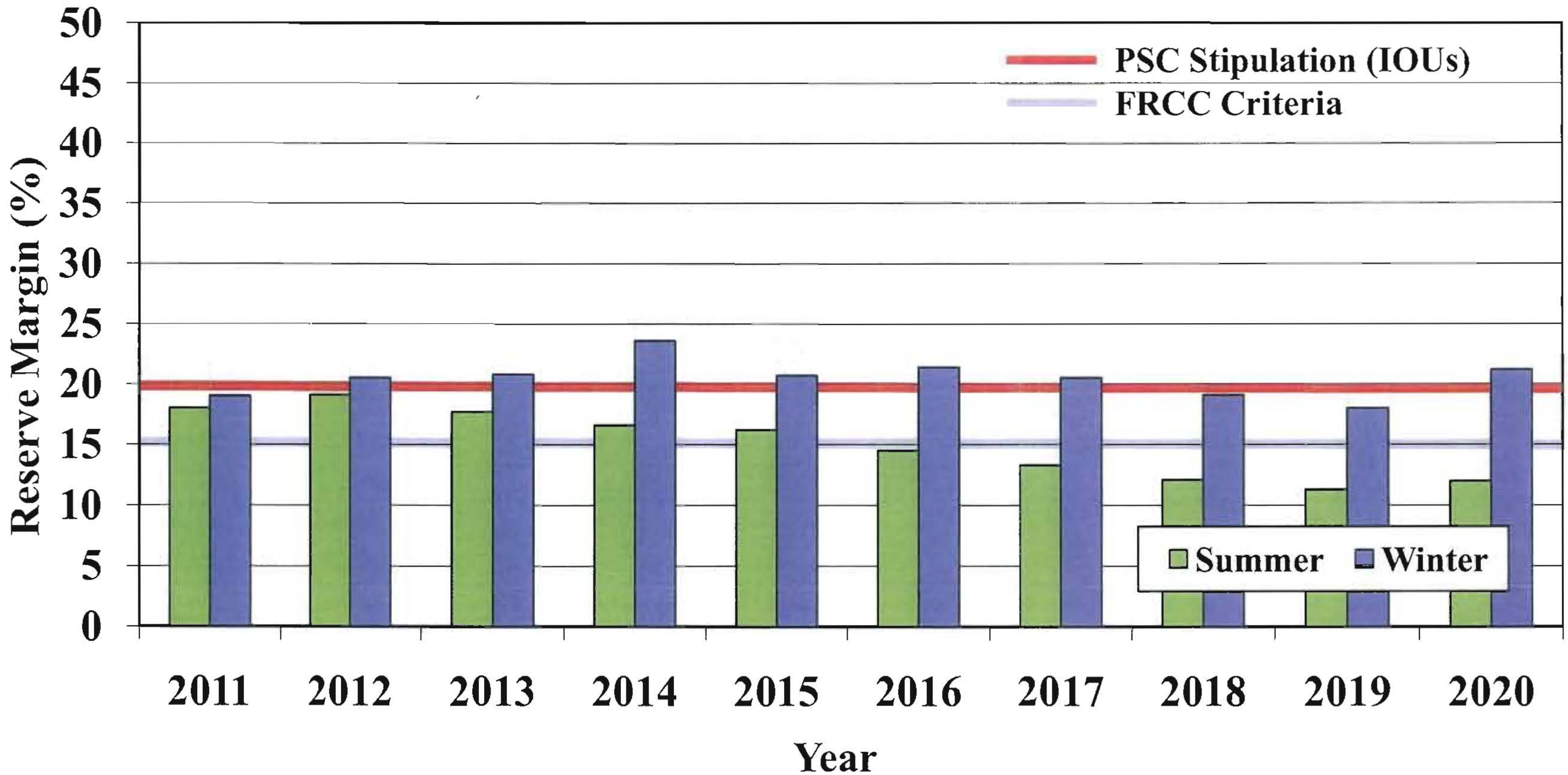
Load & Resource Plan
Total Available Capacity
(Summer)



Load & Resource Plan
FRCC Planned Reserve Margin



Load & Resource Plan
FRCC Planned Reserve Margin
(without exercising LM/INT)

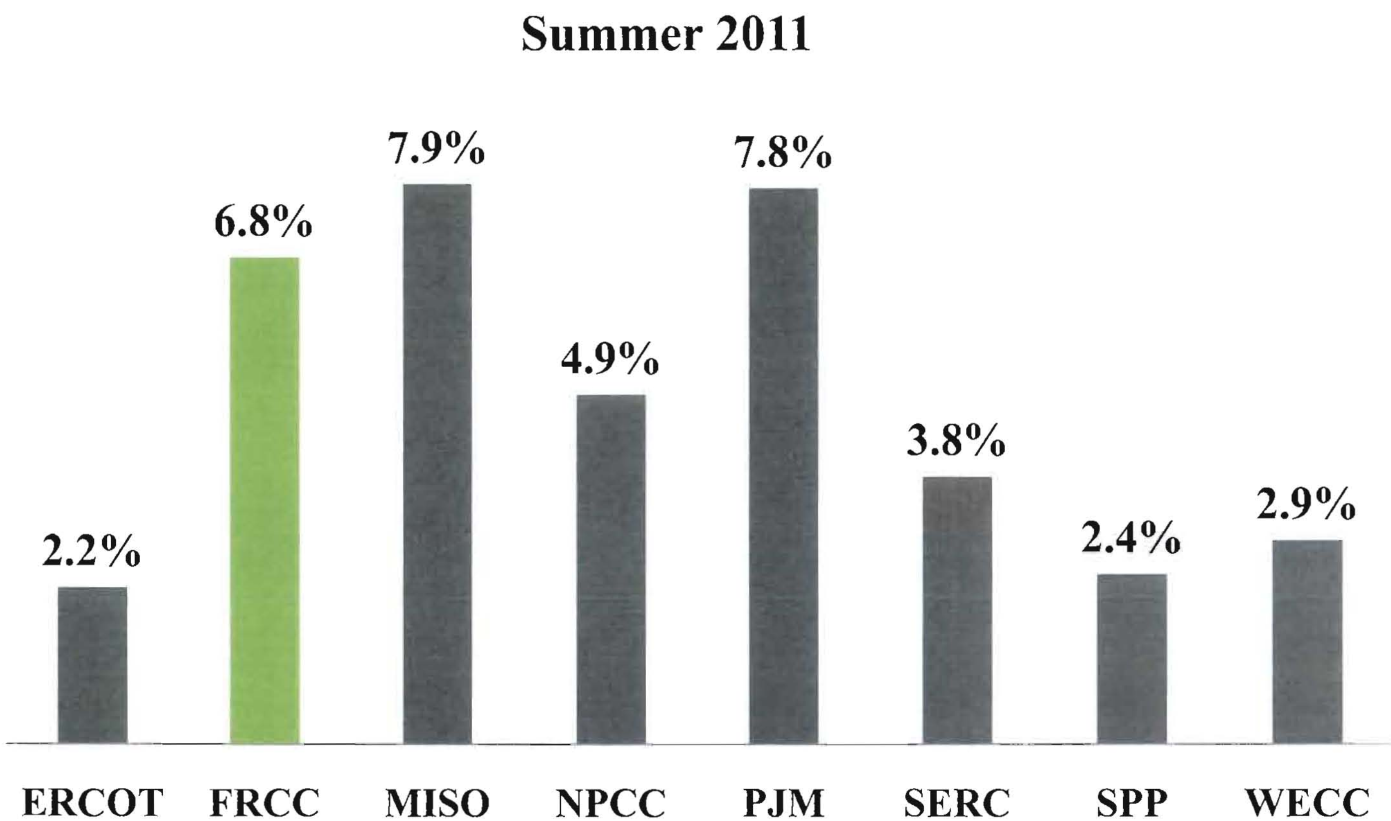


FRCC
Florida Reliability Coordinating Council

FRCC Reliability Assessment
Reserve Margin Review

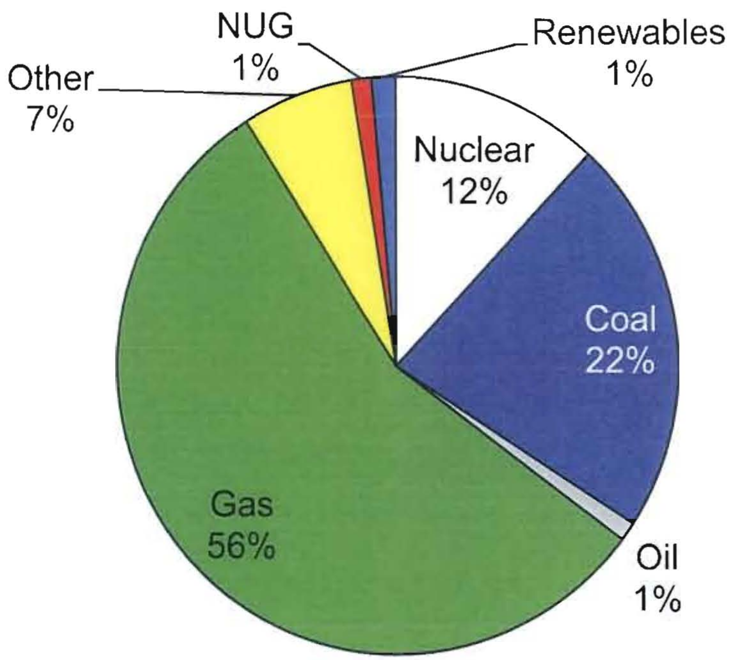
- Ensure that the Regional Planning Reserve Margin meets the 15% FRCC Criteria
- Planned Reserve Margin equals or exceeds 20% for all peak periods for the next ten years (with the availability of dispatchable LM/INT)

Load & Resource Plan
Dispatchable Demand Side Management as a Percentage of Regional Peak

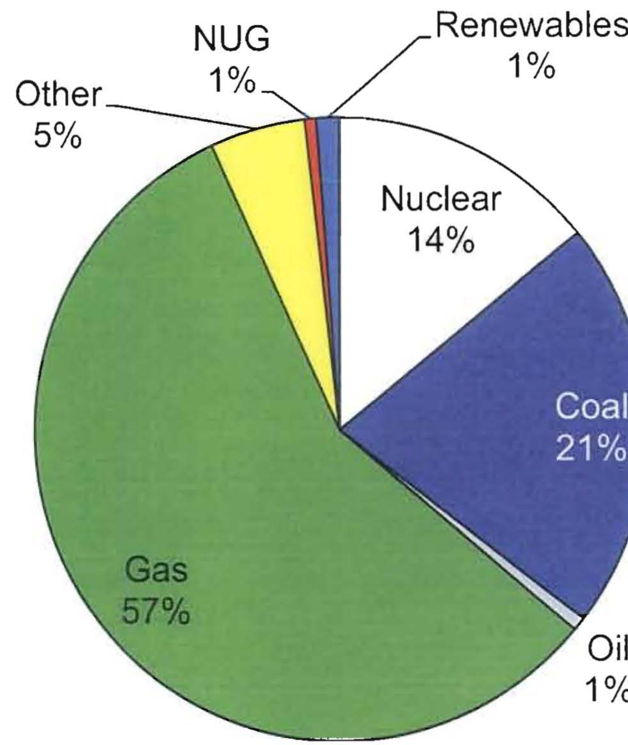


Fuel Mix (Energy)

Net Energy for Load (GWh)



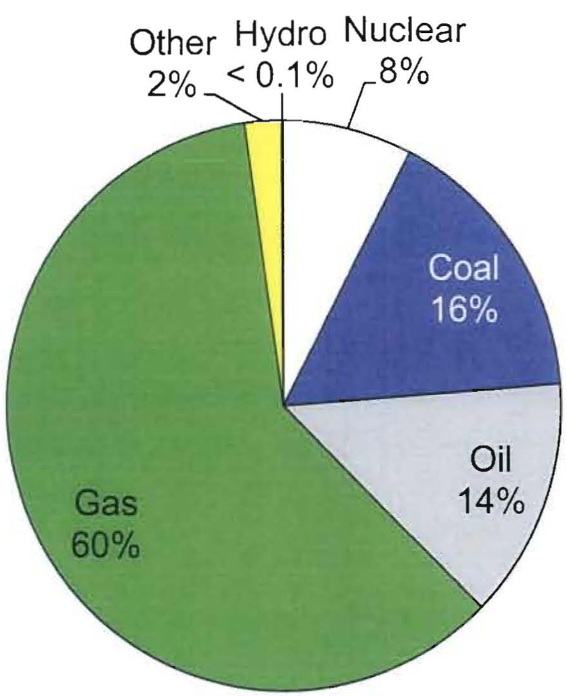
2011
225,326 GWh



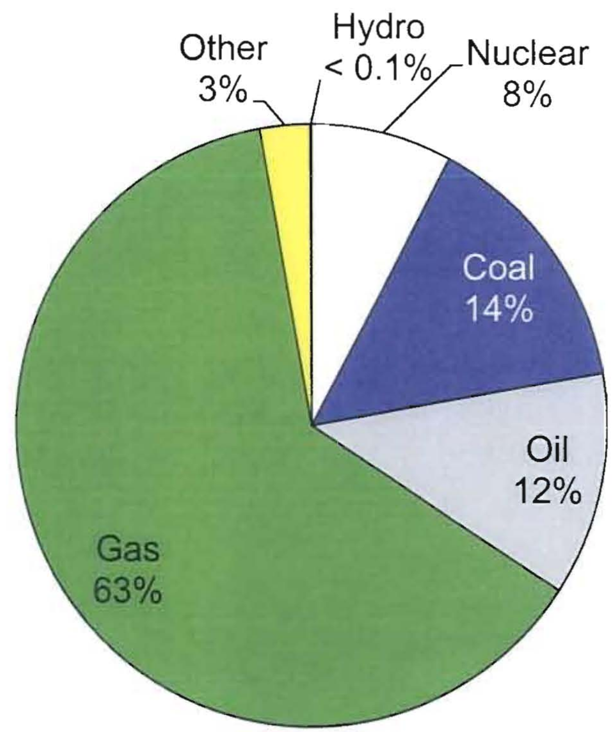
2020
260,660 GWh

Fuel Mix (Capacity)

Summer Capacity (MW)

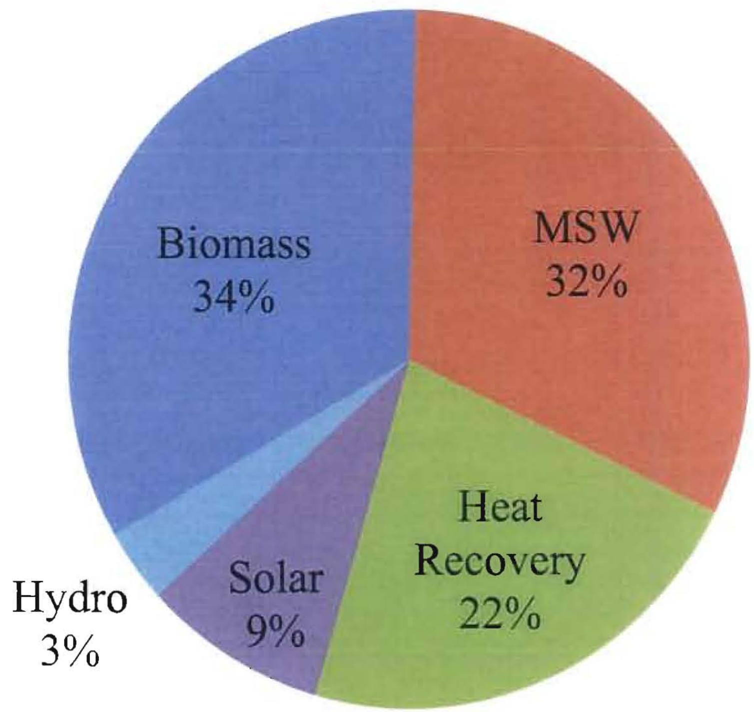


2011
52,157 MW



2020
58,409 MW

2011 Renewable Resource Capacity



1,282 MW

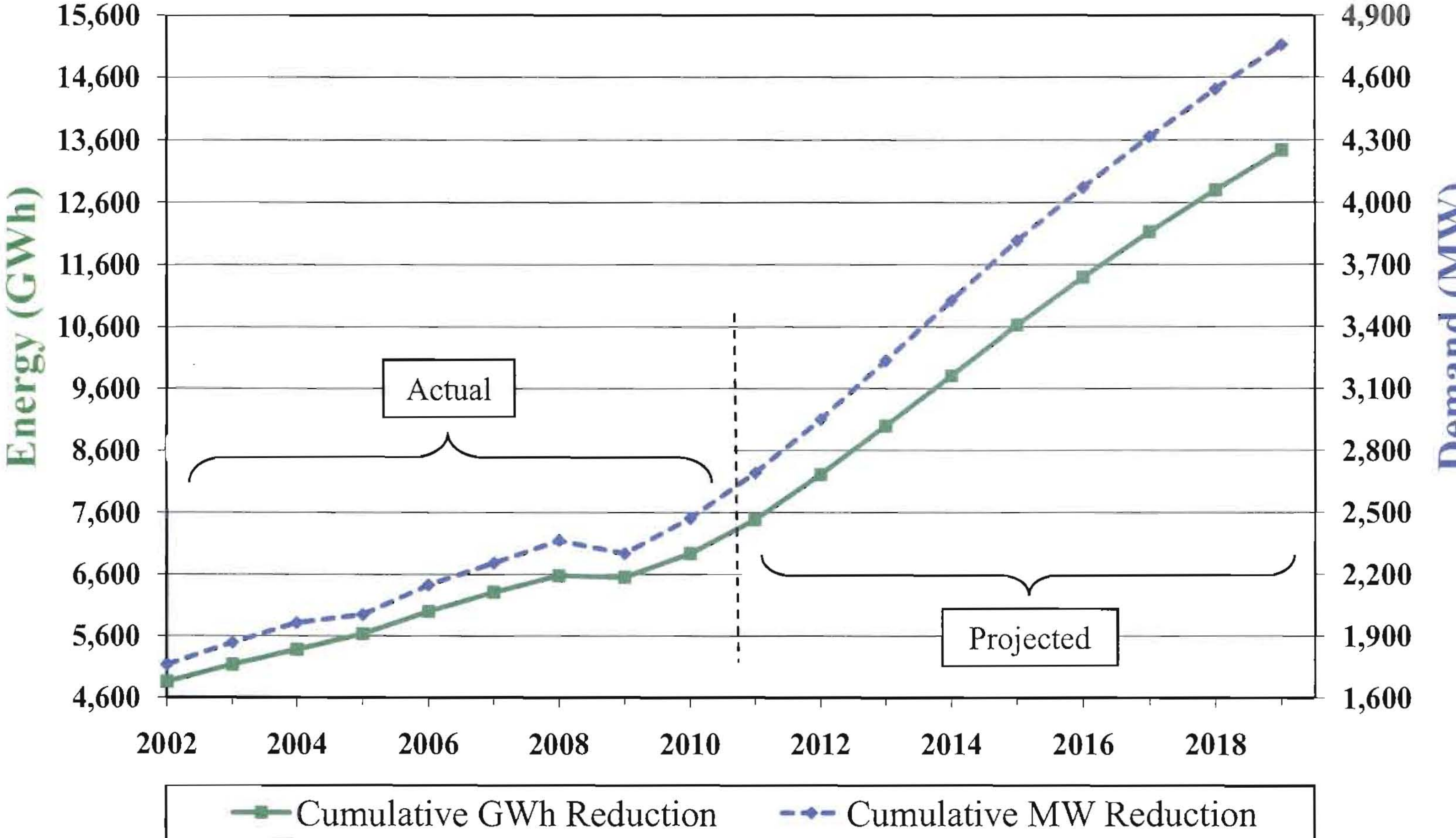
Renewables Capacity Forecast

Existing Renewables Capacity	1,282 MW
Planned Additions (thru 2020)*	
Biomass	308 MW
Landfill Gas	18 MW
Municipal Solid Waste	75 MW
Solar PV	325 MW
Solar Projects (other)	39 MW
Wind	0 MW
TOTAL	765 MW

* Contains non-TYSP data

Conservation

Cumulative Energy (GWh) & Summer Demand (MW) *



* Excludes LM and INT

Nuclear Outlook

Existing Nuclear Capacity

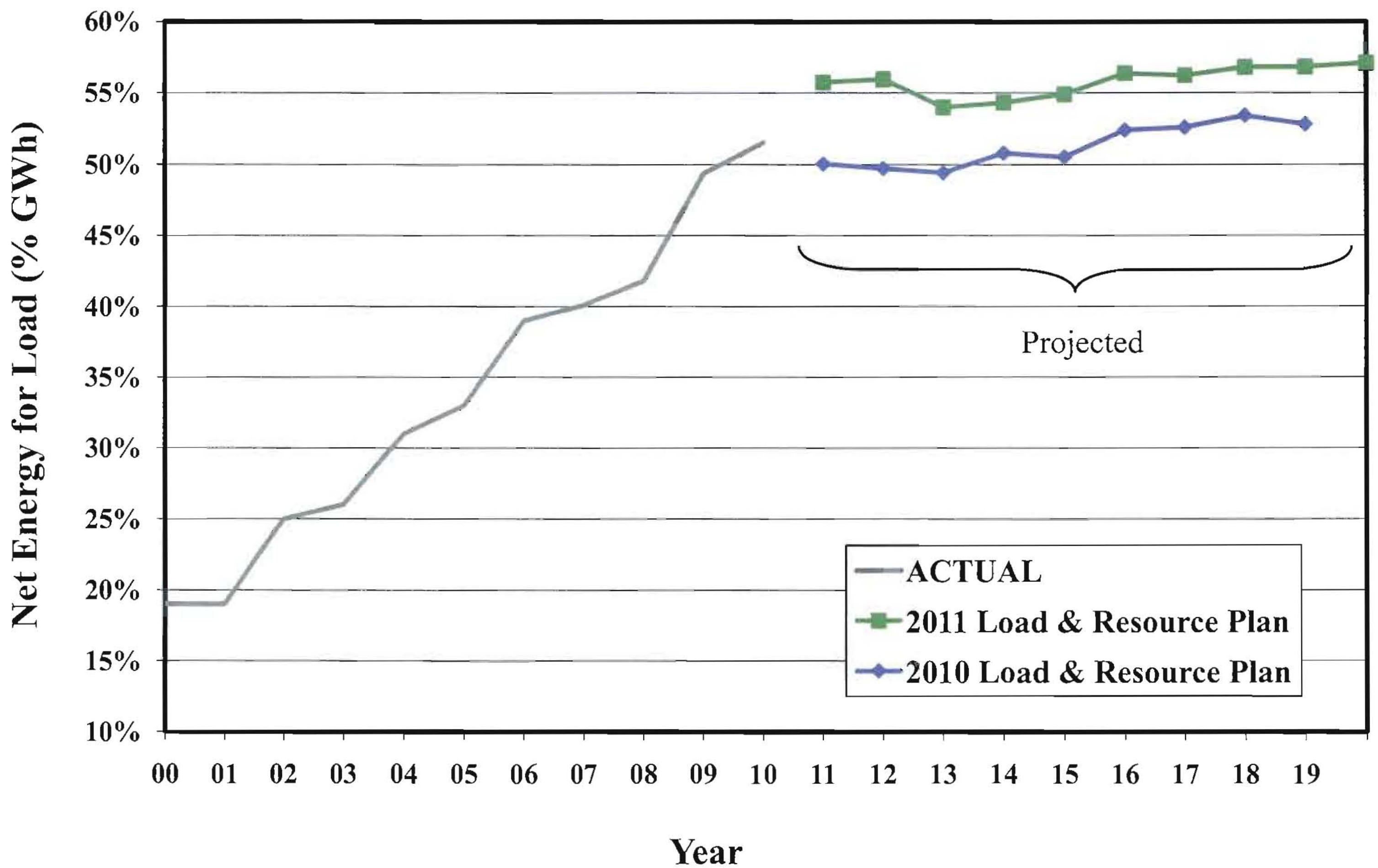
Crystal River 3		849 MW *
St. Lucie 1 & 2		1,678 MW
Turkey Point 3 & 4		1,386 MW
	Total	3,913 MW

Planned

Crystal River 3 (uprate)		~ 7 MW	(2011)
St. Lucie 2 (uprate)		20 MW	(2011)
St. Lucie 1 (uprate)		122 MW	(2012)
St. Lucie 2 (uprate)		~ 108 MW	(2012)
Turkey Point 3 (uprate)		109 MW	(2012)
Crystal River 3 (uprate)		~ 156 MW	(2013)
Turkey Point 4 (uprate)		109 MW	(2013)
	Total	~ 631 MW	

* Extended Outage

Energy Production from Natural Gas



FRCC Load & Resource Assessment Conclusion

The results of the resource adequacy review indicate that the FRCC Region has planned adequate resources to remain reliable for the next ten years.

Generation & Transmission Maintenance Scheduling

- Centralized outage system utilized by Utilities to schedule generation and transmission outages
- Equipment Status Report updated and reviewed by Utilities monthly

Generator Maintenance Scheduling

- Monthly unit outage forecast compiled by FRCC and distributed to Utilities
- Forecasted monthly Reserve Margins provided to PSC
- FRCC coordination among Utilities to ensure adequate Reserve Margins maintained for all periods

Coordination and Reliability Studies

- FRCC conducts coordinated transmission and generation outage studies:
  - Next-day
  - 7-day
  - 28-day
  - Seasonal Studies
- FRCC conducts conference calls on a weekly basis to resolve issues related to generation and transmission outages

Inter-Regional Transmission Planning

- Coordination of modeling information
  - Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) develops and maintains a library of models
  - Models include proposed system expansion plans
  - Models are the basis for reliability assessments
- FRCC Studies / Assessments
  - Include detail models of Southeastern area of SERC
  - Monitor the FL-SOU interface
    - Evaluate facilities on both sides of the interface
    - Potential issues coordinated with the FL-SOU Coordinating Group

Inter-Regional Transmission Planning (cont)

- Pursuant to FERC Order 1000
  - Develop an inter-regional transmission coordination procedure
  - Develop a process to address cost allocation of efficient cost-effective inter-regional transmission solutions

2011 FRCC Fuel Reliability

- Fuel Reliability Working Group (FRWG)
- Gas Study Project
  - Pipeline Interruptions / Compressor Station Failures
  - Fuel Oil Storage
  - Assess Current Natural Gas Infrastructure Deliverability/Reliability
- Fuel Issue Response Coordination
  - Tools and Plans

Fuel Reliability Working Group

- Dedicated group of FRCC / Member representatives
- Continue to review interdependencies of fuel availability and electric reliability
- Coordinate regional responses to fuel issues and emergencies
  - Oversight of the FRCC Gas Study Project
  - Support for real-time emergency response (i.e., storms)
  - Provide input on regional fuel reliability positions for NERC Regional Reliability Assessments
- Natural Gas (NG) Focus
  - NG energy production continues to grow
  - Continue to assess existing natural gas delivery infrastructure to serve growing demand

Gas Study Project Analyses

- Failure of Gulfstream, Cypress or FGT lines
- Compressor Failure Analyses
- Analyses continues on oil storage
- Diversity of gas pipeline interconnects
- Conservative assessment assumption
- Near-term "Regional" assessments

Natural Gas
Capacity into Florida has Increased

Major changes since 2005:

- Mobile Bay area storage capacity held by FRCC Members has increased from 0.160 Bcf/day to 1.06 Bcf/day
- Delivery capacity from onshore sources has increased from 0.5 Bcf/day to 1.5 Bcf/day
- Since 2005 - Total design capacity into Florida has increased from 3.24 Bcf/day to 4.35 Bcf/day
- Impacts to supply by hurricanes mitigated with stored NG and onshore sources.
- Limited activity on Liquid Natural Gas projects

Fuel Reliability Coordination Tools and Plans

- *FRCC Generating Capacity Shortage Plan*
- *FRCC Operations - Hurricane Manual*
- *FRCC Communications Protocols – Reliability Coordinator (RC), Generator Operators and Natural Gas Transportation Service Providers*
- Continued cooperation between pipelines and FRCC
- Fuel Oil backup is key to reliability for catastrophic failures

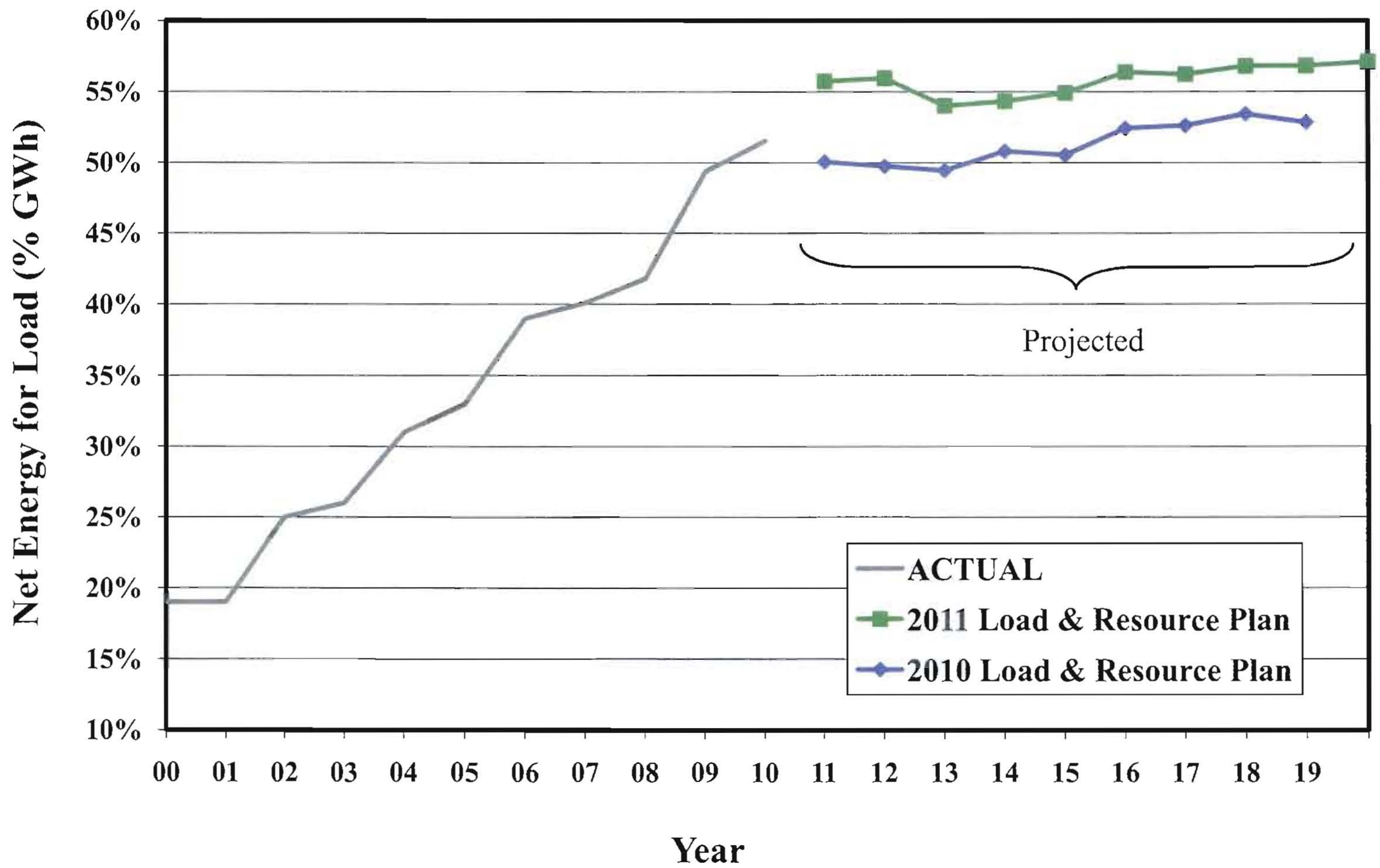
Summary

- FRCC Operating Committee
  - Continues to promote fuel reliability awareness
  - Continues to refine processes for minimizing impacts of fuel issues (all types of fuels)
  - Performs proactive near-term fuel assessments & studies
- NG capacity into Florida has increased
- Access to NG storage and onshore sources has increased
- FRCC communications plans are in place with pipeline operators
- RC coordinates with State Capacity Emergency Coordinator and pipeline operators when fuel supply is threatened

Summary (cont.)

- FRWG will continue its efforts:
  - Review ERCOT February load shed event
    - Looking for lessons learned
  - Continue evaluation of Gas / Electric interdependencies
    - Gas / Electric compression station
    - Electrical needs of compression stations – controls
    - Pipeline communications during emergencies
  - Assess gas infrastructure capabilities
  - Continue evaluation of fuel oil storage
- The FRCC continues to look at NG infrastructure on a Regional basis to identify potential generating capacity issues

Energy Production from Natural Gas



Conclusion

- In the near term, FRCC does not anticipate any fuel transportation issues affecting resource capabilities considering:
  - Fuel diversity
  - Current fuel supply, pipeline capacity and pipeline diversity
  - Alternate fuel capability of generation
- In the longer term, the step change from the 2010 forecast and projected increases in energy production from natural gas highlight that close coordination will be required to ensure that gas delivery capacity remains adequate

Questions ?

FPL's 2011 Ten Year Site Plan: A Presentation for the FPSC's 2011 Ten Year Site Plan Workshop

September 7, 2011

Parties/Staff Handout
event date 09 / 07 / 11
Docket No. Undocketed

Agenda

- Resource planning changes since the April 1, 2011 filing of FPL's 2011 Ten Year Site Plan (Site Plan) (which addresses FPL's resource plans as of end of 2010/1Q 2011)
- Status and Plans for Inactive Reserve units
- Status of Existing and Planned Solar and Wind Projects
- Status of Gas Pipeline Needs
- Plans for Improving Fuel Diversity
- Review of the 20% Reserve Margin Criterion

FPL

FPL's 2011 Site Plan projected the following major capacity additions/reductions (assuming FPL's approved 2009 DSM goals)

Major Capacity Additions / (Reductions)[1]

Year	Change	Summer MW
2011	West County 3 Riviera 3 & 4 (removed)	1,219 (565)
2012	Nuclear Uprates Oleander contract ends	231 (155)
2013	Cape Canaveral modernization Nuclear Uprates	1,210 219
2014	Riviera modernization	1,212
2015	---	0
2016	Greenfield CC UPS contract termination SJRPP purchase (suspension)	1,191 (931) (375)
2017	---	0
2018	---	0
2019	---	0
2020	Greenfield CC	1,191

1) Represents long-term capacity additions / (reductions) of 100 MW or more.

FPL

The following major, long-term changes in planning assumptions and the resource plan have occurred as part of FPL's on-going analyses

Long-Term Changes in Planning Assumptions

- **FPL no longer assumes that an average of 350 MW Summer & 550 MW Winter of generation will be on scheduled maintenance in all peak months**
- **Turkey Point 1 (396 MW Summer) will be removed as a generating resource to serve as a synchronous condenser starting in 2016[2]**
- **26 GE 7FA combustion turbines (CTs) in existing CC units will be upgraded by 2015 resulting in approximately 190 MW increase (Summer)[2]**
- **The recent FPSC decision regarding incremental DSM will result in somewhat lower incremental utility DSM additions**
- **After factoring in these changes, FPL continues to project a resource need in 2016 and 2020**
  - -- The projected 2016 Greenfield CC addition has been replaced by a 2016 modernization of Pt. Everglades[2], consistent with FPL's Site Plan discussion regarding modernization of existing generating unit sites

2) Projected net savings (CPVRR) to FPL's customers are approximately: $65 MM for Turkey Point 1, $210 MM for the CT upgrades and $400 MM for Pt. Everglades modernization.

FPL

Agenda

- Resource planning changes since the April 1, 2011 filing of FPL's 2011 Ten Year Site Plan (Site Plan) (which addresses FPL's resource plans as of end of 2010/1Q 2011)
- Status and Plans for Inactive Reserve units
- Status of Existing and Planned Solar and Wind Projects
- Status of Gas Pipeline Needs
- Plans for Improving Fuel Diversity
- Review of the 20% Reserve Margin Criterion

FPL

FPL's plans for its 8 generating units now on inactive reserve status have not materially changed

Status and Plans for Inactive Reserve Units

Unit	Summer MW	Comments
Sanford 3	138	To be retired in 4Q 2012
Cutler 5 & 6	205	To be retired in 4Q 2012
Turkey Point 2	392	Operating in synchronous condenser mode (to provide voltage support)
Port Everglades 1 & 2	426	To be retired in 2013 if Port Everglades Modernization project proceeds
Port Everglades 3 & 4	761	• To be returned temporarily to active service in 2012 during Modernization work at Cape Canaveral and Riviera; • To be retired in 2013 if Port Everglades Modernization project proceeds
Total	**1,922**	

FPL

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FPL

FPL's 3 major solar facilities are operational and projected to provide more than 225,000 MWh of energy annually

Existing and Planned Solar and Wind Projects

- **FPL's 3 major solar facilities are operational**
  - 25 MW PV in DeSoto County (2009)
  - 10 MW PV in Brevard County (2010)
  - 75 MW solar thermal in Martin County (2010)
- **FPL has pursued a potential 14 MW wind energy project in St. Lucie County for several years, but has been unable so far to obtain local approvals**
  - FPL remains interested in pursuing wind energy development
- **FPL has done extensive planning and performed initial permitting and due diligence for a number of additional large-scale PV projects totaling approximately 500 MW**
  - Because no legislation supporting utility development of new solar power generation facilities has been passed at this time, FPL has not proceeded with the construction of these projects

FPL

Agenda

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FPL

The FPL system needs additional gas and FPL plans to pursue additional pipeline capacity

Status of Gas Pipeline Needs

- **Gas transportation needs:**
  - FPL continues to pursue gas transportation alternatives which create supply diversity and strengthen the reliability of FPL's and Florida's gas infrastructure portfolio
  - FPL is updating its analysis with respect to future gas needs for the FPL system
- **Request for Proposal (RFP):**
  - FPL is currently in the process of preparing an RFP for pipeline capacity to meet future needs
  - As per the Final Order on the Florida EnergySecure Pipeline, FPL will be prepared to discuss the RFP with FPSC Staff in the next few weeks

FPL

Agenda

- Resource planning changes since the April 1, 2011 filing of FPL's 2011 Ten Year Site Plan (Site Plan) (which addresses FPL's resource plans as of end of 2010/1Q 2011)
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FPL

Fuel diversity is being pursued along a number of fronts

Plans for Improving Fuel Diversity

- **FPL is continuing its efforts to increase the fuel diversity of its system through additional nuclear capacity with the EPU and Turkey Point 6 & 7 projects**
- **FPL's existing 110 MW of solar facilities (PV and solar thermal) are also contributing to lower dependence upon natural gas**
  - As previously mentioned, other potential solar projects would also contribute to lower dependence on natural gas
- **FPL is maintaining the ability to use oil at its 4-800 MW steam units by adding electrostatic precipitators (ESPs) at these units**
- **In addition, FPL is continually improving its ability to utilize natural gas more efficiently through the addition of highly fuel-efficient combined cycle units at new sites (e.g. West County) and through modernizations of existing sites (e.g. Fort Myers, Sanford, Cape Canaveral, Riviera, and Port Everglades)**
- **FPL continues to pursue the diversification of natural gas supply sources to the FPL system**

FPL

Agenda

- Resource planning changes since the April 1, 2011 filing of FPL's 2011 Ten Year Site Plan (Site Plan) (which addresses FPL's resource plans as of end of 2010/1Q 2011)
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- Review of the 20% Reserve Margin Criterion

FPL

A reserve margin criterion is designed to ensure reliable electric service for a utility's customers

Why Have a Reserve Margin?

A reserve margin criterion is designed to help ensure that FPL can continue to serve its customers reliably in the future even if unexpected circumstances occur, including, but not limited to:

- Higher-than-forecasted peak loads
- Unscheduled generating unit outages
- Lower-than-projected DSM capability

FPL

Consideration of potentially changing the current 20% criterion to 15% has both system reliability and cost aspects

Overview of the 20% Reserve Margin Criterion

- **FPL's view of the 20% reserve margin criterion can be summarized as follows:**
  - A reserve margin of at least 20% is necessary to provide reliable service for FPL's customers
  - Switching to a 15% criterion would significantly reduce the reliability of service to FPL's customers (as shown by the example that follows)
  - Reducing the reserve margin criterion would not necessarily result in significant short-term cost savings to customers (and long-term cost savings are also questionable)
    - -- Capital and other fixed costs would be reduced, but fuel and other variable costs would be increased
    - -- The net cost impact will be highly dependent upon fuel and other variable costs

FPL

The 20% criterion is necessary to maintain reliability

Possible Outcomes in 2017 With 20% Planned Reserve Margin

Year	Month	Total Generating Capacity at 20% RM (MW)	Unavailable Generation Capacity (MW)	Available Generating Capacity (MW)	Projected Peak Load for 2017 (MW)	Projected Reduction in Load Due to Energy Efficiency (EE) (MW)	Reflection of Upper 75% Variance in 6 - Year Ahead Forecast (MW)	Actual Peak Load (MW)	Generating Capacity Reserves above/(below) Peak Load (MW)	Projected Load Control (LC) Available for Use (MW)	Remaining LC Reserves above/ (below) need (MW)	Total Remaining Reserves on Peak Day (MW)
2017	August	26,735	0	26,735	25,025	(666)	0	24,359	**2,376**	2,080	2,080	**4,456**
2017	August	26,735	(1,800)	24,935	25,025	(666)	0	24,359	**576**	2,080	2,080	**2,656**
2017	August	26,735	(1,800)	24,935	25,025	(666)	2,311	26,670	(1,735)	2,080	345	**345**
2017	August	26,735	(1,800)	24,935	25,025	(333)	2,311	27,003	(2,068)	2,080	12	**12**

The above outcome assumes everything (installed capacity, peak load, DSM additions) occurs in 2017 exactly as projected six years earlier with no plant unavailabilities. The projected reserve margin is set exactly at FPL's previously approved "minimum reliability criterion" of 20%.

The above outcome assumes that 1,800 MW of generation are unavailable; all else is as projected.
This outage estimate is based on the possibility that one of FPL's largest units is unavailable and that 1/2 of another unit is also unavailable, a not uncommon situation.

The above outcome **also** assumes that the actual peak load before DSM is 9.2% higher than the 25,025 MW forecasted.
This variance is consistent with the projected variance for a 6-year-ahead forecast based on historical data.

The above outcome **also** assumes that only 50% of the EE materializes.

FPL

The 20% criterion is necessary to maintain reliability

Possible Outcomes in 2017
If Planned Reserve Margin is Reduced to 15%

Year	Month	Total Generating Capacity at 15% RM (MW)	Unavailable Generation Capacity (MW)	Available Generating Capacity (MW)	Projected Peak Load for 2017 (MW)	Projected Reduction in Load Due to Energy Efficiency (EE) (MW)	Reflection of Upper 75% Variance in 6 - Year Ahead Forecast (MW)	Actual Peak Load (MW)	Generating Capacity Reserves above/(below) Peak Load (MW)	Projected Load Control (LC) Available for Use (MW)	Remaining LC Reserves above/ (below) need (MW)	Total Remaining Reserves on Peak Day (MW)
-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
2017	August	25,613	0	25,613	25,025	(666)	0	24,359	**1,254**	2,087	2,087	**3,341**

The above outcome assumes everything (installed capacity, peak load, DSM additions) occurs in 2017 exactly as projected 6 years earlier with no plant unavailabilities, **except that FPL's generating capacity is reduced, because the projected reserve margin is arbitrarily set (for this example) at 15%.**

| Year | Month | Total Generating Capacity at 15% RM (MW) | Unavailable Generation Capacity (MW) | Available Generating Capacity (MW) | Projected Peak Load for 2017 (MW) | Projected Reduction in Load Due to Energy Efficiency (EE) (MW) | Reflection of Upper 75% Variance in 6 - Year Ahead Forecast (MW) | Actual Peak Load (MW) | Generating Capacity Reserves above/(below) Peak Load (MW) | Projected Load Control (LC) Available for Use (MW) | Remaining LC Reserves above/ (below) need (MW) | Total Remaining Reserves on Peak Day (MW) |

|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | August | 25,613 | (1,800) | 23,813 | 25,025 | (666) | 0 | 24,359 | (546) | 2,080 | 2,080 | **1,534** |

The above outcome assumes that 1,800 MW of generation are unavailable; all else is as projected.
This outage estimate is based on the possibility that one of FPL's largest units is unavailable and that 1/2 of another unit is also unavailable, a not uncommon situation.

| Year | Month | Total Generating Capacity at 15% RM (MW) | Unavailable Generation Capacity (MW) | Available Generating Capacity (MW) | Projected Peak Load for 2017 (MW) | Projected Reduction in Load Due to Energy Efficiency (EE) (MW) | Reflection of Upper 75% Variance in 6 - Year Ahead Forecast (MW) | Actual Peak Load (MW) | Generating Capacity Reserves above/(below) Peak Load (MW) | Projected Load Control (LC) Available for Use (MW) | Remaining LC Reserves above/ (below) need (MW) | Total Remaining Reserves on Peak Day (MW) |

|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | August | 25,613 | (1,800) | 23,813 | 25,025 | (666) | 2,311 | 26,670 | (2,857) | 2,080 | (777) | **(777)** [illegible] |

The above outcome <u>also</u> assumes that the actual peak load before DSM is 9.2% higher than the 25,025 MW forecasted.
This variance is consistent with the projected variance for a 6-year-ahead forecast based on historical data.

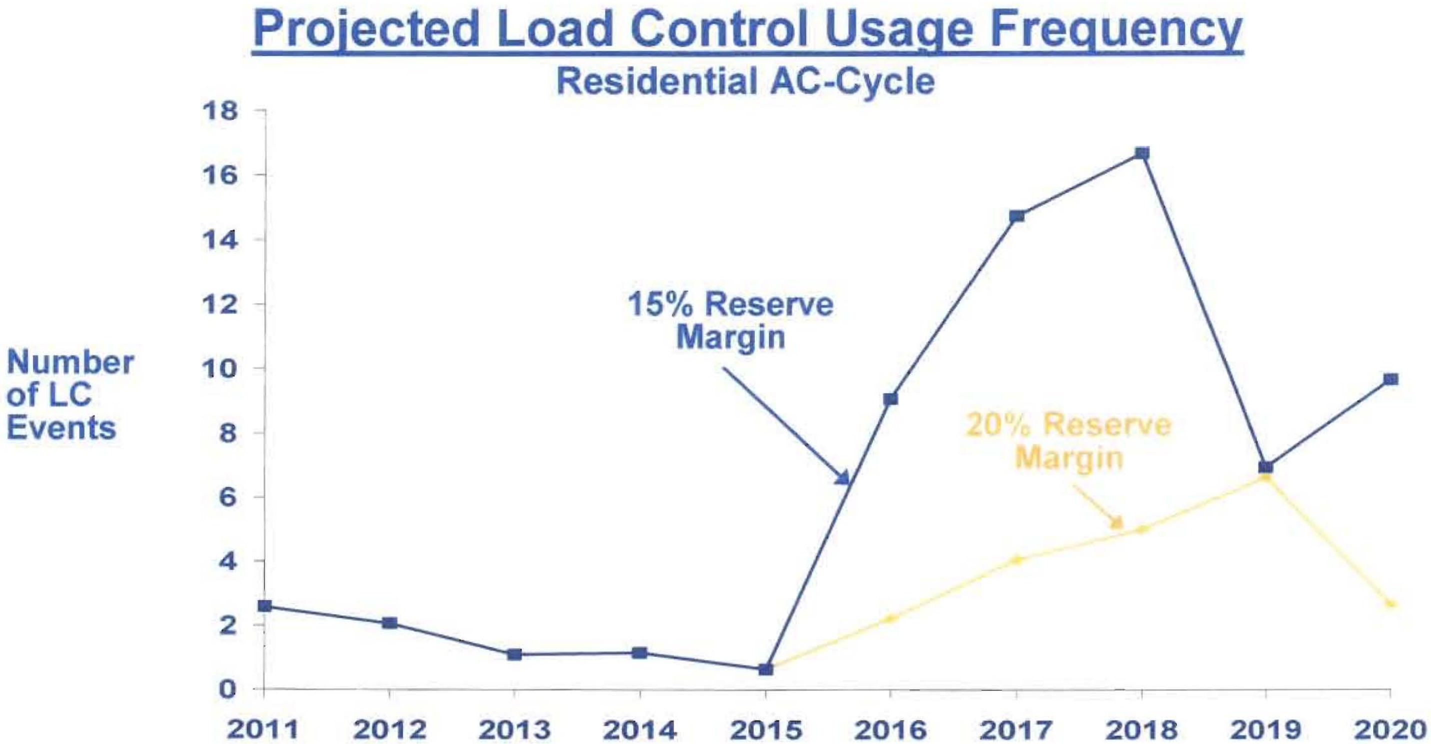
| Year | Month | Total Generating Capacity at 15% RM (MW) | Unavailable Generation Capacity (MW) | Available Generating Capacity (MW) | Projected Peak Load for 2017 (MW) | Projected Reduction in Load Due to Energy Efficiency (EE) (MW) | Reflection of Upper 75% Variance in 6 - Year Ahead Forecast (MW) | Actual Peak Load (MW) | Generating Capacity Reserves above/(below) Peak Load (MW) | Projected Load Control (LC) Available for Use (MW) | Remaining LC Reserves above/ (below) need (MW) | Total Remaining Reserves on Peak Day (MW) |

|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 | August | 25,613 | (1,800) | 23,813 | 25,025 | (333) | 2,311 | 27,003 | (3,190) | 2,080 | (1,110) | **(1,110)** [illegible] |

The above outcome <u>also</u> assumes that only 50% of the EE materializes.

FPL

Another aspect that is related to the reserve margin criterion is the projected frequency of FPL's load control (LC) resources



These projected LC frequencies could increase significantly with higher load, unscheduled outages on peak days, etc.

FPL

There are still other reserve margin criterion-related aspects that FPL is analyzing

20% Criterion is Necessary

- **Planning based on a 20% criterion will better enable FPL to have sufficient generation in service to allow generating units to be scheduled for planned maintenance in off-peak months**
  - If planned maintenance must be scheduled in peak months, reserve margins would drop, further necessitating the need for additional generation
- **In a related issue, FPL is becoming increasingly dependent upon continued voluntary participation in DSM to meet its 20% criterion**
  - For example, if DSM's contribution were excluded, FPL's "generation-only" reserve margin in 2011 would be 13.1%
  - However, by 2019, FPL's "generation-only" reserve margin is projected to significantly decrease to 5.6% under current plans, and would drop to 1.3% if FPL exactly met a 15% criterion
- **Therefore, FPL is currently analyzing whether an additional reliability criterion should be utilized -- a minimum reserve margin contribution from generation-only resources**

It is questionable how much short-term economic savings would actually be realized by a change from a 20% to a 15% criterion

Economic Aspects of Using a Lower Criterion

- **Changing to a 15% criterion would defer FPL's next capacity addition from 2016 to 2019**
- **The projected total savings over 5 years is $22 MM (nominal) and customers will have higher annual costs in 2 of the 5 years**
  - However, as shown on the next page, even a small change in fuel and other variable costs would significantly alter these projected savings

Initial Analysis of Reducing the Criterion

Year	Annual Fixed Cost Savings ($MM)	Annual Variable Cost Savings ($MM)	Annual Total Cost Savings ($MM)	Cumulative Total Cost Savings ($MM)
2016	$110	($107)	$3	$3
2017	$189	($165)	$24	$27
2018	$186	($196)	($10)	$17
2019	$117	($60)	$57	$74
2020	$109	($161)	($52)	$22

FPL

A small increase of only 5% in fuel and other variable costs would significantly alter the projection

Projection With Current Variable Cost Forecast

Year	Annual Fixed Cost Savings ($MM)	Annual Variable Cost Savings ($MM)	Annual Total Cost Savings ($MM)	Cumulative Total Cost Savings ($MM)
2016	$110	($107)	$3	$3
2017	$189	($165)	$24	$27
2018	$186	($196)	($10)	$17
2019	$117	($60)	$57	$74
2020	$109	($161)	($52)	$22

Projection With 5% Higher Variable Cost Forecast

Year	Annual Fixed Cost Savings ($MM)	Annual Variable Cost Savings ($MM)	Annual Total Cost Savings ($MM)	Cumulative Total Cost Savings ($MM)
2016	$110	($112)	($2)	($2)
2017	$189	($173)	$16	$13
2018	$186	($206)	($20)	($6)
2019	$117	($63)	$54	$48
2020	$109	($169)	($60)	($12)

The projected cost impact of changing to a 15% criterion is now increased costs of $12 MM (nominal) and customers would see higher annual costs in 3 of the 5 years

FPL

FPL's customers would be best served by the current 20% reserve margin criterion

Summary

Consideration of decreasing the current 20% reserve margin criterion to 15% is a consideration of a trade-off between the following:

- Savings in capital and other fixed costs
- Higher fuel and other variable costs (that will be magnified if fuel and other variable costs are higher than currently forecasted)
- Relatively small net cost savings in the short-term (but which are highly dependent upon continued low fuel prices)

Compared to:

- More frequent use of LC
- Less flexibility in scheduling plant maintenance
- Diminished system reliability for all years

Because the risks outweigh the potential benefits, FPL believes that the current 20% reserve margin criterion should be maintained

FPL

Florida Public Service Commission 2011 Ten Year Site Plan Workshop

Progress Energy Florida

September 7, 2011

Parties/Staff Handout
event date 09 / 07 / 11
Docket No. Undocketed

Progress Energy

Overview

- Changes from April 1, 2011 TYSP Filing
- CR3 Outage Impact
- DSM Goals Impact
- Reserve Margin

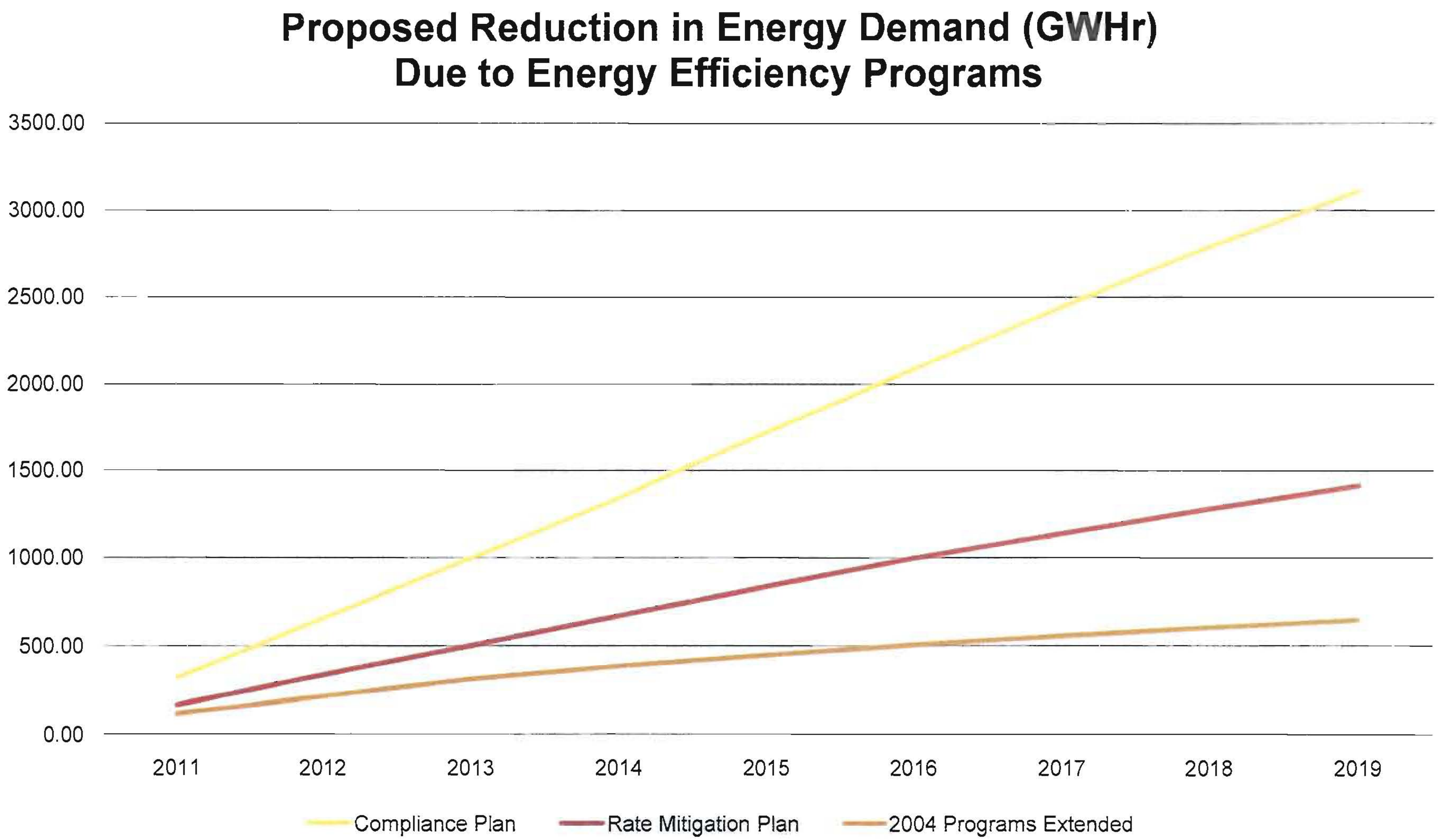
DSM & CR3 Outage Impacts

RESERVE MARGIN AT TIME OF SUMMER PEAK (SCHEDULE 7.1)

YEAR	APRIL 2011 TYSP RESERVE MARGIN % OF PEAK	SEPTEMBER 2011 SCENARIO – DSM Only RESERVE MARGIN % OF PEAK	SEPTEMBER 2011 SCENARIO – DSM & CR3 Outage RESERVE MARGIN % OF PEAK
2011	34%	33%	24%
2012	36%	34%	25%
2013	35%	30%	22%
2014	34%	28%	20%
2015	34%	27%	27%
2016	29%	22%	22%
2017	28%	20%	20%
2018	27%	20%	20%
2019	23%	23%	23%
2020	24%	21%	21%

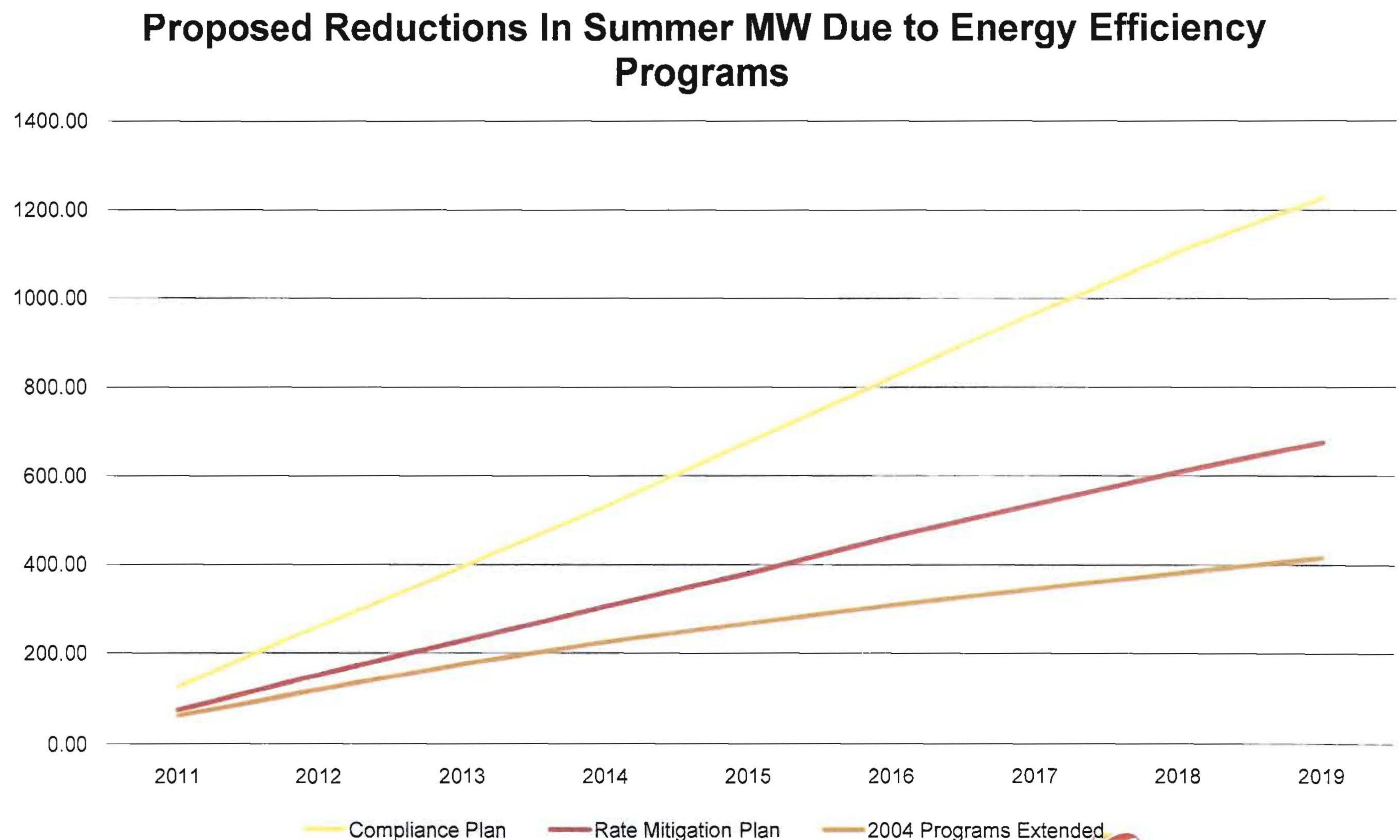
Progress Energy

DSM Programs Comparison (GWHr)



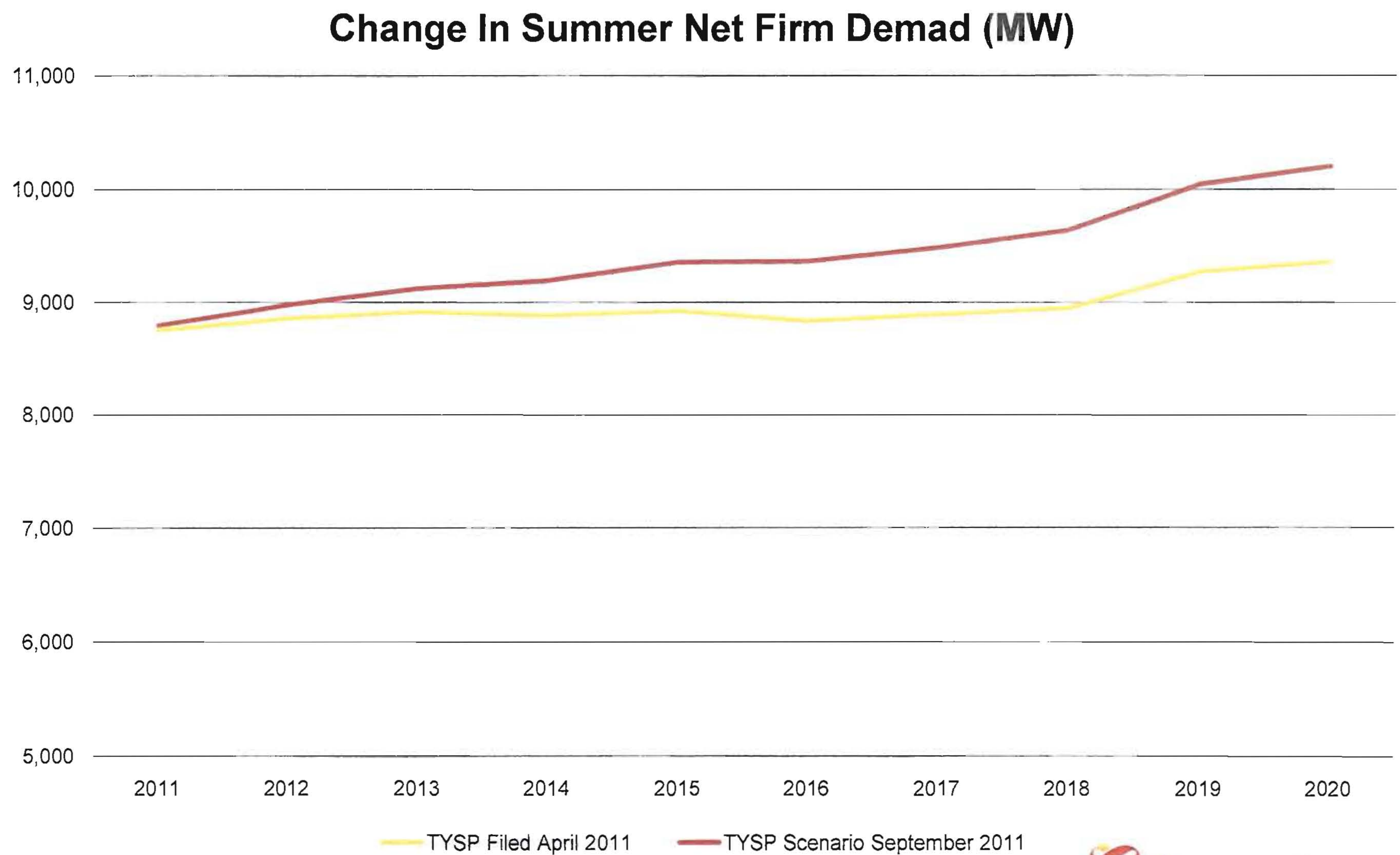
Progress Energy

DSM Programs Comparison (MW)



Progress Energy

DSM Program Comparison (Net Firm Demand)



Progress Energy

Potential Changes to Resource Plan

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

PLANT NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	CONST. START MO. / YR	COM'L IN-SERVICE MO. / YR	NET CAPABILITY[a] SUMMER MW	WINTER MW	STATUS
CRYSTAL RIVER	3	CITRUS	NP		11/2014	154	154	A
SUWANNEE RIVER	1-3	SUWANNEE	ST			(131)	(133)	RET. 5/16
UNKNOWN	1	UNKNOWN	GT	06/2016	6/2018	178	205	P
UNKNOWN	1	UNKNOWN	CC	06/2016	6/2019	767	875	P

Reserve Margin Overview

SCHEDULE 7.1
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK

YEAR	TOTAL CAPACITY AVAILABLE MW	SYSTEM FIRM SUMMER PEAK DEMAND MW	RESERVE MARGIN BEFORE MAINTENANCE MW	% OF PEAK	SCHEDULED MAINTENANCE MW	RESERVE MARGIN AFTER MAINTENANCE MW	% OF PEAK
2014	11,799	9,193	2,606	28%	789	1,816	20%

Progress Energy

Elements of 20% Reserve Margin

SCHEDULE 3.1

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	TOTAL AFTER CONSERVATION
2014	10,841	413	294	10,134

SCHEDULE 3.1

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

YEAR	TOTAL AFTER CONSERVATION	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	COMM. / IND. LOAD MANAGEMENT	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
2014	10,134	378	339	103	120	9,193

Progress Energy

Elements of 20% Reserve Margin

- Total Capacity (Net of CR3) = 11,100 MW
- Total Load After Conservation = 10,134 MW
- Available Reserve Before Load Control = 966 MW

Elements of 20% Reserve Margin

- Contribution to Regional Reserve – 194 MW
- Instantaneous / Load Following ~ 300 MW
- Remainder for Unit Reliability ~ 500 MW
    - PEF Has 10 Units greater than 450 MW Capacity
- Load Control – 708 MW
- Temperature Sensitivity – 300MW / degree

Potential Impacts of Change to 15% Reserve Margin

- Higher Load Control Utilization
- Impact on Existing Load Control Programs
  - Disturbance Response / CT Saver
- Higher Fuel Cost
- Higher Reliability Risk

Progress Energy Florida
Renewable Energy Update

Florida Public Service Commission

September 7, 2011

Parties/Staff Handout
event date 09/07/11
Docket No. Undocketed

Progress Energy

PEF's Balanced Solution for the Future

- Cost-Effective Alternative and Renewable Energy Sources Should Play a Role in Developing a Balanced Energy Future
  - Energy efficiency
  - Modernize existing resources
  - Renewable/Alternative energy sources

PEF is Committed to Cost-Effective Renewables and Alternative Energy Sources

- PEF has over 1,500 MW under contract from QFs
  - 682 MW are firm, built and interconnected

173 MW Renewable + 509 MW Cogen = 682 MW Total QF

PEF's purchased more Renewable energy in 2010 than of any other Florida utility

Progress Energy

PEF's Renewable Resources

- 378 MW of firm renewable energy under contract
  - 173 MW in operation
  - 145 MW approved and under development
  - 60 MW executed and Docketed for FPSC review
  - Four renewable suppliers have executed as-available agreements

PEF's Renewable capacity has more than doubled since 2009

PEF's Request for Renewables (RFR)

- PEF Maintains an Open "RFR"
- The Open RFR allows for:
  - A Renewable Contact Database
  - Understanding Renewable Project requirements
  - Sharing PEF's requirements
- Targets In-State Renewable Energy Sources

Progress Energy

PEF's Renewable Project Development

- Characteristics of Viable Large Utility-Scale Projects
  - Straight forward technology
  - Financing expertise
  - Interconnection ability
  - Permitting and public affairs
  - Ability to operate and perform

PEF's Renewable Project Progression

- Meaningful information to measure progress includes:
  - Real Estate Acquisition
  - Grid Interconnection
  - Permitting
  - Deposits

Progress Energy

PEF's Solar Contracts - Update

- As-Available Tariff-type contracts are Non-firm
- Two suppliers have executed solar contracts
  - National Solar (~400 MW)
  - Blue Chip Energy (~50 MW)

PEF has more solar under contract than any other Florida utility

National Solar – Status Update

- Nine Solar As-Available contracts
  - Land broker and Short List of Counties
    - Gadsden, Hardee, Osceola, Suwannee
  - Hardee County land purchase, (~400 MW)
- Facilities are expected to be on-line by the end of 2014
- Hansel Phelps Construction Co. is under contract for the design, construction and O&M of the facilities
- Established financing relationships with multiple large US commercial banks

Blue Chip Energy - Status Update

- Two Solar As-Available contracts
- Rinehart Facility, Seminole County – (~10 MW)
  - Located at solar panel manufacturing plant in Lake Mary
  - Installed 1.2 MW on roof top; utilizing Net Metering Tariff
  - Remaining 8 MW will be ground mounted

Progress Energy

Blue Chip Energy – Status Update, Cont.

- Sorrento Facility, Lake County (~40 MW)
  - Land purchased
  - Zoning completed
  - System Impact Study is underway
  - Anticipated ground breaking 3Q 2011
- Blue Chip Energy will act as EPC contractor
- Self-funded and anticipating DOE's Section 1603 tax credits

Blue Chip Energy – Sorrento Facility

Progress Energy

PEF's Biomass Contracts - Update

- Biomass facilities delivering renewable energy
  - Lake County MSW – 12.75 MW
  - Metro-Dade County MSW – 43 MW
  - Pasco County MSW – 23 MW
  - Pinellas County MSW – 54.75 MW
  - Ridge Generating Station Waste Wood – 39.6 MW

PEF has more Biomass online than any other Florida utility

Progress Energy

PEF's Biomass - Update, Cont.

- Biomass contracts under development:
  - Biomass Gas & Electric – 45 MW
  - FB Energy – 60 MW
  - Trans World Energy – 40 MW
  - US EcoGen – 60 MW

PEF has more biomass under development than any other Florida utility

Biomass Gas & Electric - Status Update

- Rentech is new Project owner, NWFREC (45 MW)
- Land has been acquired
  - Port St. Joe
- Air permit has been received
- Term sheets in place with fuel suppliers, additional contracts expected soon
- EPC negotiations underway
- System Impact Study near completion

Progress Energy

Biomass Gas & Electric – Update Cont.

- Financing Challenges:
  - Expected loan guarantees from the DOE under the Section 1705 program
  - DOE gave BG&E the opportunity to move to the Section 1703 program
  - No word has been received from the DOE since May
- Alternative financing structures are being pursued
  - Term sheet with a Korean investor

FB Energy - Status

- 60 MW Project
- Land has been acquired
- Permitted in underway
- EPC contractor has been identified
- Financing negotiations are underway

Progress Energy

TransWorld Energy – Status Update

- A site for the 40 MW Facility has been identified and the purchase is being finalized
- Received positive response and favorable pricing from potential fuel suppliers in the area
- Received interest in financing this project and is evaluating potential financing offers

PEF's As-Available Biomass Contracts

- Eliho Energy, (~8 MW)
- E2E2, (~30 MW)
- Financial closing is expected soon for both projects

TECO
TAMPA ELECTRIC

Florida Public Service Commission Ten-Year Site Plan Workshop September 7, 2011

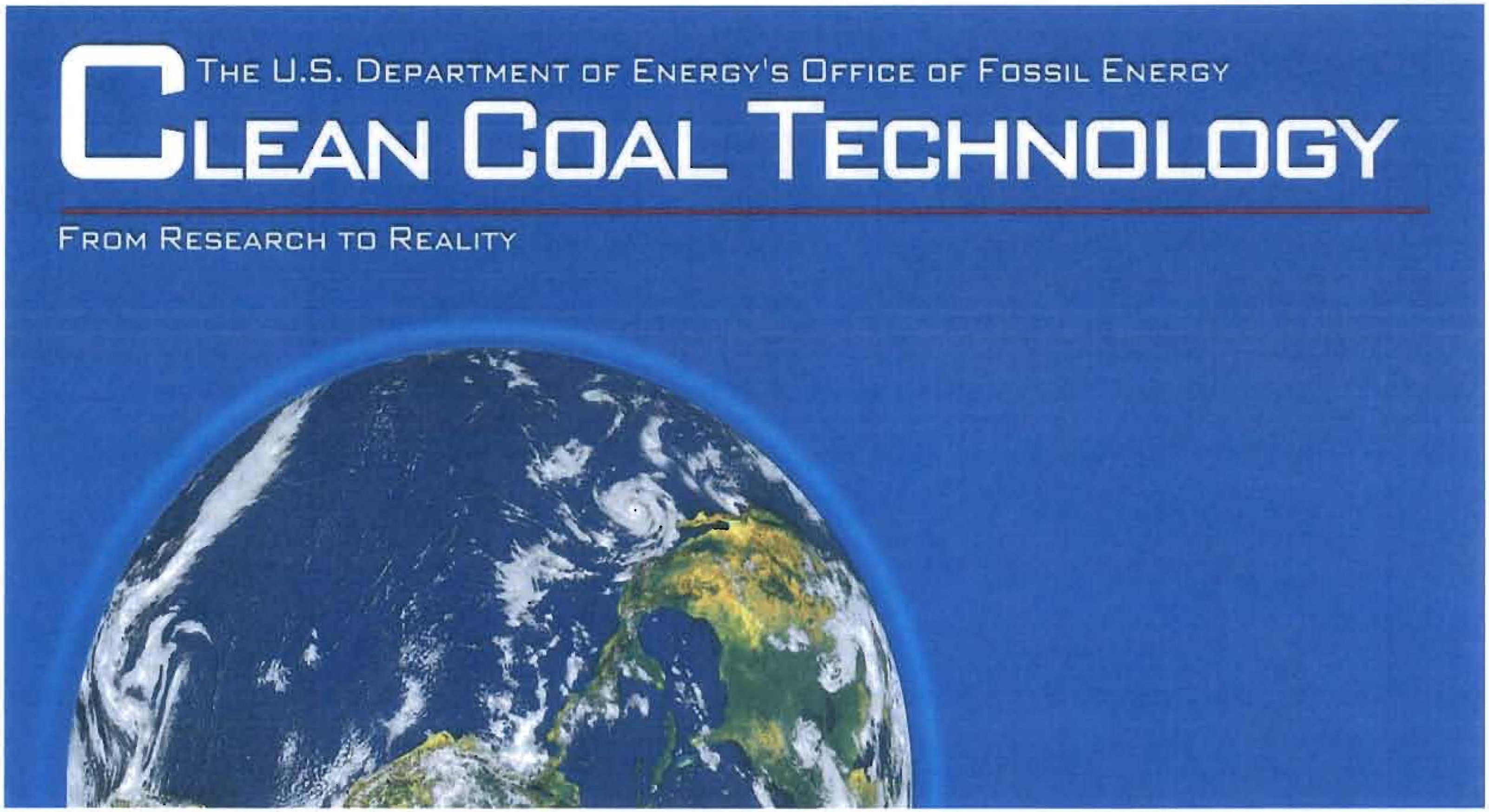
Tampa Electric Company Update

TECO
TAMPA ELECTRIC

Agenda

- Status update of U.S. Department of Energy grant for carbon sequestration pilot project and impact on generation reserves.
- Results of studies for possible modification of 20% reserve margin criterion.

TECO
TAMPA ELECTRIC

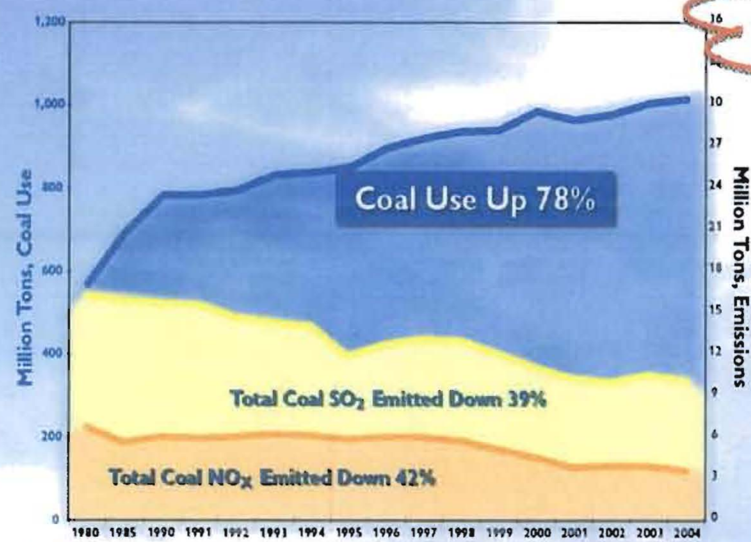


- Tampa Electric's Polk Power Station Unit 1, entered commercial service in 1996 and was partially funded by U.S. DOE Clean Coal Technology program.

- DOE views Clean Coal Technology, now including Carbon Capture and Sequestration, as important to the nation's long term energy future.

TECO
TAMPA ELECTRIC

Coal Use Up, Pollution Down in Electricity Generation



All data in million short tons. Figures are rounded. Total emissions reductions are due to several factors, which include increased commercialization and deployment of clean coal technologies.

(Sources: Energy Information Administration, Environmental Protection Agency)

Clean Coal Technology = Advanced Coal Power Systems

- Two "super clean" coal-based IGCC demonstration plants have operated reliably: Tampa Electric IGCC Power Plant in Mulberry, Fla., and PSI Energy Wabash River IGCC Power Plant in West Terre Haute, Ind.
- The JEA Northside Generating Station in Jacksonville, Fla., is one of the world's largest circulating fluidized bed combustion power plants.
- Future demonstrations of carbon capture and storage technologies are planned at multiple commercial-scale integrated gasification combined-cycle (IGCC) coal power plants that will be operational by 2015

Highlights – Research and Development

- Demonstrations of two mercury control technologies for existing plants aimed at 50–70 percent removal now and 90 percent removal in a few years.
- Lignite drying technology that can raise generating efficiency and lower pollution.
- Moving clean coal technology forward, including improvements to IGCC, bringing down the cost of CO_2 capture, finding better ways to store carbon dioxide, moving toward a hydrogen economy.
- By 2012, advanced turbines, capable of firing up to 100 percent hydrogen, will be integrated into power plants that separate and capture CO_2.
- Continued concentration on lowering the costs of pre- and post-combustion capture of CO_2.
- Continued concentration on identifying, validating, and testing suitable sites for safe, long-term CO_2 storage.
- By 2015, build on R&D advancements in IGCC and CCS technologies achieved over the past five years to at least double the amount of carbon dioxide sequestered, compared with earlier goals.

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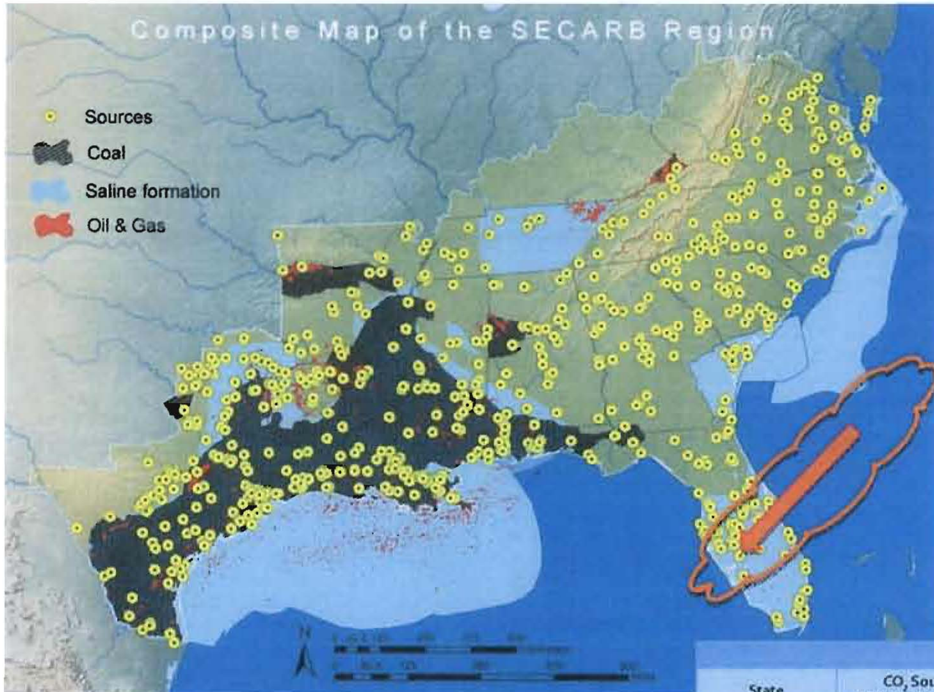
DOE’s Southeast Regional Carbon Sequestration Partnership (SECARB) information



Composite Map of CO_2 Sources and Geologic Storage Formations

The distance between stationary source and geologic storage formation is calculated as the shortest straight-line distance from each point. While these results do not give a complete picture of the transportation and infrastructure requirements, it does give a first-order interpretation of the magnitude of the requirements.

The sources in SECARB match up well with the potential storage reservoirs. For example, more than 70 percent of all sources (by volume) in the SECARB region are located within 50 kilometers of a storage site. Approximately 40 percent of the sources are co-located with an appropriate storage site. This especially occurs in the Gulf Coast region where many of the sources overlie saline formations, coalbeds, or both.

The table below identifies how many years' storage is possible, given the current annual emissions and the known CO_2 storage resource.

Drill core and drill chip logging from site characterization at the Mississippi Test Site. (Courtesy of Southern Company and Advanced Resources International)

Estimated Years of Storage

State	CO_2 Sources (Million Metric Tons)	CO_2 Storage Resource (Million Metric Tons)				Number of Years Storage ***
	Total	Oil and Gas	Coal and Shale*	Saline*	Total	
AL	[illegible]	344	1,944	12,900	15,188	[illegible]
AR	35	250	15,675	4,304	20,229	572
FL	143	109	1,275	16,725	18,109	127
GA	90	-	-	4,909	4,909	55
LA	102	6,781	8,325	139,497	154,603	[illegible]
MS	34	399	5,400	[illegible]	[illegible]	1,546
NC	77	[illegible]	[illegible]	1,352	1,352	18
SC	40	-	-	1,995	1,995	49
TN	66	-	-	500	500	8
TX**	373	4,005	33,025	205,548	242,578	650
VA	46	10	231	159	400	9
Federal Offshore	N/A	17,754	-	484,996	502,750	N/A
Total	1,085	29,652	65,875	919,313	1,014,840	935****

* Low estimates used.
** Eastern Texas, TRRC Districts 1–6.
*** Years of CO_2 storage at the current emission rates (State CO_2 storage resource/State annual emissions).
****Average years storage for whole SECARB area (total CO_2 storage resource/total annual emissions).

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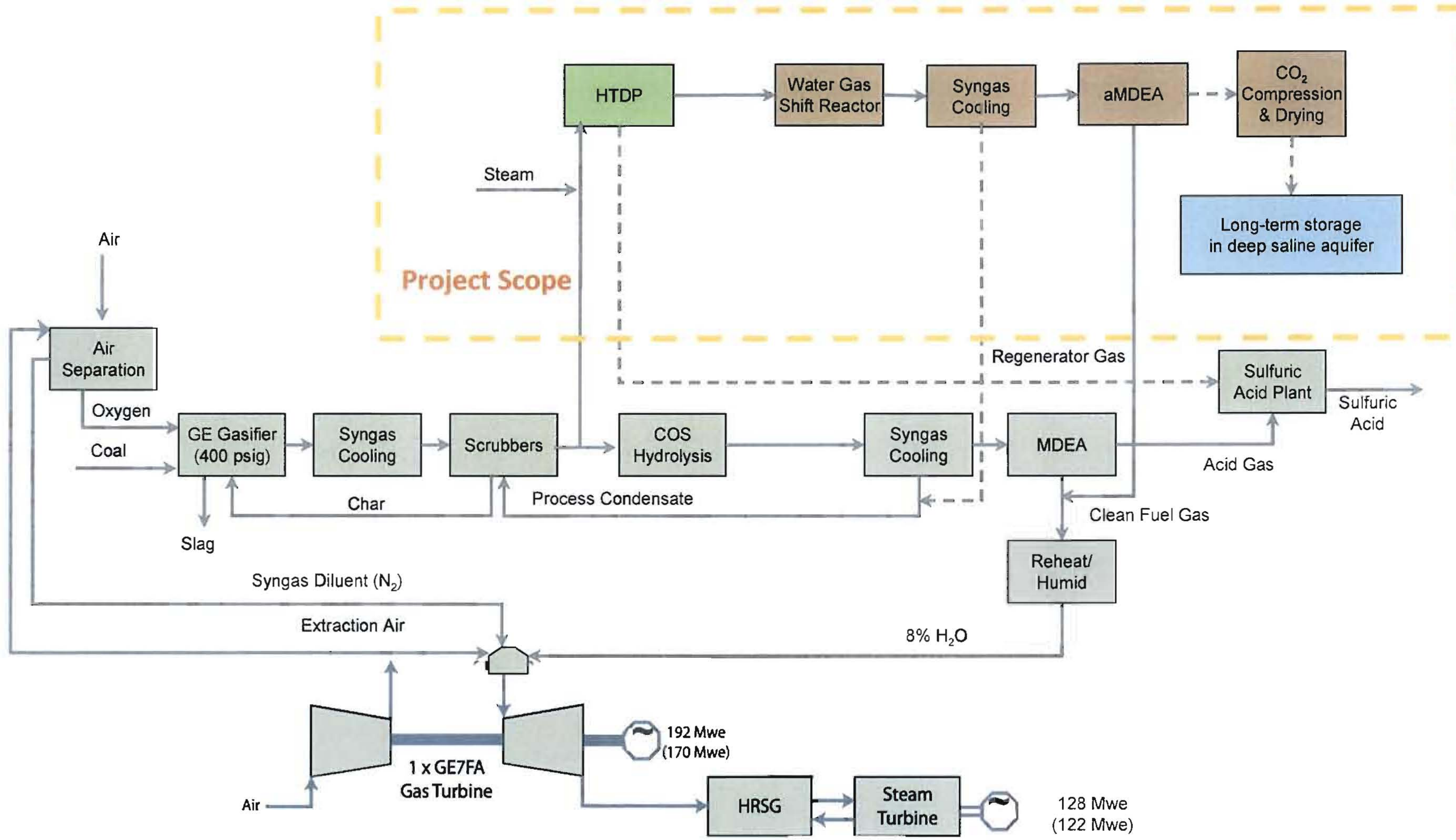
Polk Carbon Sequestration Demonstration Project

- On September 7, 2010, the U.S. DOE announced the funding of a project to demonstrate a warm gas cleanup system (WGC) to remove sulfur at elevated temperature along with the integration of Carbon Capture and Sequestration (CCS).
- DOE funding level is $168.8M.
- Project is designed to treat a portion (≈25%) of the syngas produced by the Polk 1 gasifier by removing sulfur and CO_2, then returning the treated gas to the process for use in power production.
- Operation of the pilot project would take place in 2014 and early 2015.

Integration of Warm Syngas Cleaning and CCS



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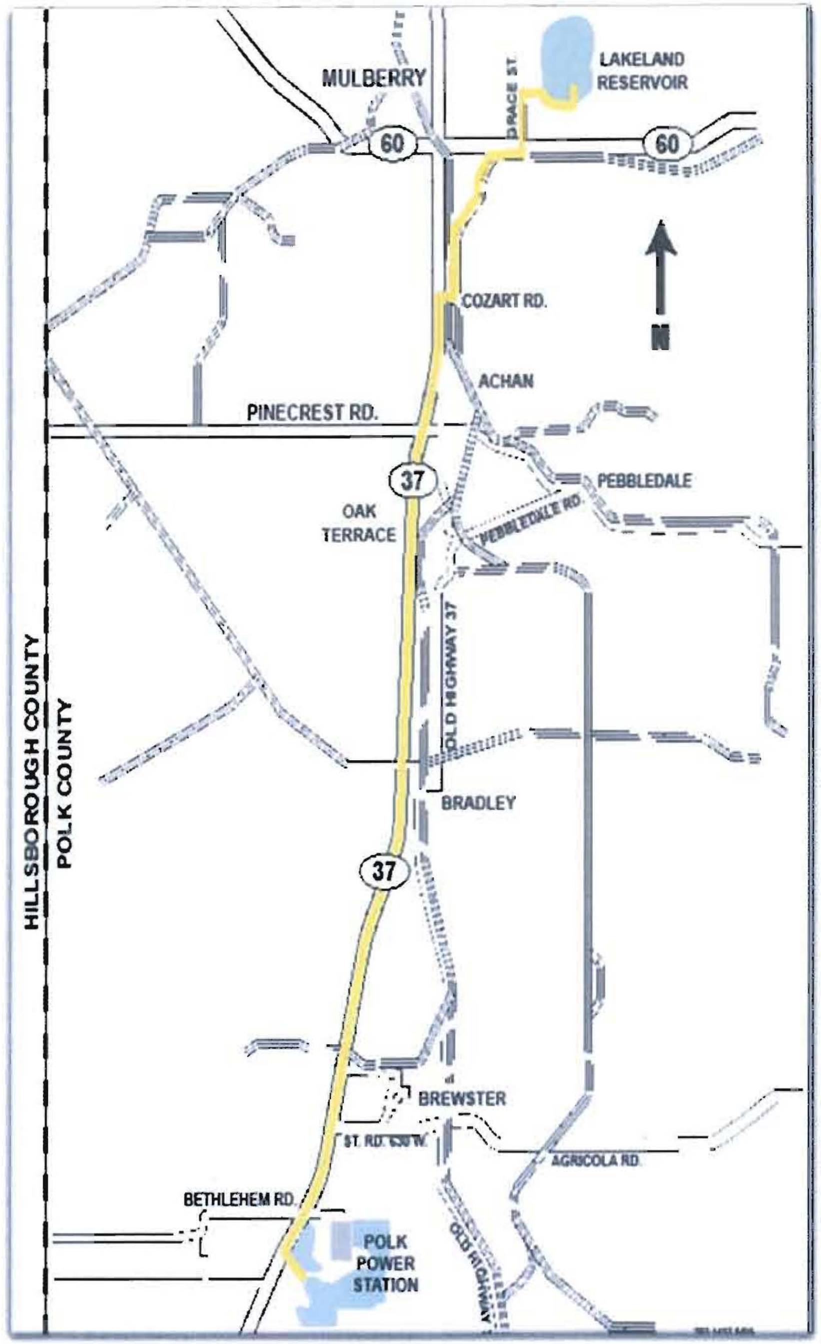
Key Project Participants/Goals

- **US Department of Energy**
  - Funding project, $168.8M, Clean coal program and ARRA funds
  - Demonstrate WGC/CCS at operating IGCC, high visibility strategic project for DOE
- **RTI International**
  - Prime contractor, WGC technology owner
  - Develop WGC technology for licensing revenue
- **Tampa Electric**
  - Host site, sequestration permitting/operation
  - Evaluate technology, demonstrate CCS, option to retain equipment for future use
  - Utilize one injection well from ongoing Regional Reclaimed Water Project
- **Shaw Group**
  - Engineering, construction, operation
  - Potential technology owner
- **BASF**
  - CO_2 capture technology owner
- **University of South Florida**
  - Geologic research and modeling

Regional Reclaimed Water Project
Utilize waste water from City of Lakeland to increase water supply to Polk and offset ground water use.



__Project Elements__

Pipeline - Approximately 15 miles of pipeline routed from Lakeland reservoir on SR60 to Polk Power Station

Treatment System - Process reclaimed water using a reverse osmosis system in conjunction with pretreatment technologies

Injection Wells - Construction of 2 deep wells for disposal of treatment system effluent.

In service in 2013

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CCS Project Synergies with Reclaimed Water Project

- Lakeland reclaimed water project requires installation of two underground injection wells.
- Geologic evaluation for water injection is useful to understand CO_2 injection potential.
- During the CCS demonstration period, one well could be used for CO_2 injection and still serve as backup to primary water injection well.
- Use of injection well for CO_2 is considered an “in-kind” contribution towards DOE cost sharing requirement (no incremental expense for Tampa Electric or it’s customers).

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PPS Site Suitability for CCS

- Suitable Deep Injection Zone – (4100' to 8000', CO_2 fluid).
- Excellent Confining Unit/Caprock.
- Geologic/Structural Traps.
- Seismic Suitability/Stability.
- Well Inventory, very few penetrations through confining layer.
- Phosphate Mining & Adjacent Land Use.
- Geochemistry of Injection Zone – indicates very rapid trapping.

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Project Status / Schedule

- Front End Engineering Design (FEED) nearing completion.
- Definitive agreements for detailed engineering, construction and operation being negotiated.
- Construction to take place in 2013.
- Operation to take place in 2014 and first half of 2015.

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Operational Objectives and Impacts

- Project will use 25% slipstream of syngas.
- Demonstration equipment can be isolated at any time at TEC's sole discretion.
- Operation of project will reduce net plant output (on the order of 10 MW, to be determined with detailed engineering).
- Project can be isolated, if required, on peak, so rated unit capacity will not change.
- Maintenance of the demonstration system should be able to be done with no impact to Polk Unit 1.

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Cost Impacts/Funding

- DOE co-funding will cover the direct costs of this project for Tampa Electric and it's customers.
- Agreements are being developed to provide for reimbursement of labor expense, fuel costs, purchased power and other incremental costs associated with the project.
- Tampa Electric's contribution will be limited to the "in-kind" value of utilizing injection well 2 for CO_2 storage. No incremental expense.

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Agenda

- Status update of U.S. Department of Energy grant for carbon sequestration pilot project and impact on generation reserves.
- Results of studies for possible modification of 20% reserve margin criterion.

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Reserve Margin Considerations

- Peninsular Florida with limited interconnections.
- IOUs provide a large amount of supply side support for state.
- Forced outages occur randomly.
- Instantaneous peaks may exceed planning peaks.
- Size of units versus total TEC system.
- Historic peak demand versus available capacity.

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TEC Generating Units

Type	Unit	Net Summer MW	% of TEC System
Base	Big Bend 1	385	9% *
Base	Big Bend 2	385	9% *
Base	Big Bend 3	365	9%
Base	Big Bend 4	417	10%
Base	Polk 1	220	5%
Intermediate	Bayside 1	701	16%
Intermediate	Bayside 2	929	22%
Peaking	Bayside 3	56	1%
Peaking	Bayside 4	56	1%
Peaking	Bayside 5	56	1%
Peaking	Bayside 6	56	1%
Peaking	Big Bend CT4	56	1%
Peaking	Polk 2	151	4%
Peaking	Polk 3	151	4%
Peaking	Polk 4	151	4%
Peaking	Polk 5	151	4%
Peaking	COT	6	0%
Total		4,292	

*Operate on one FGD system (18% total)

From 2011 TYSP Schedule 1

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Historic Peak Demand Versus Available Capacity

- **Monthly 2007-2010**
  - Actual monthly peak demand versus available capacity
    - » 2007 2 months short
    - » 2008 2 months short
    - » 2009 1 month short
    - » 2010 1 month short
- **Annual 2007-2010**
  - Short 3 out of 4 years on annual peak
  - Short 4 out of 4 years on annual peak if TEC was at a 15% RM

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Summary

- Decreasing the current 20% reserve margin criterion to 15% will increase the risk of interruption to firm customers during peak demand.
- The relative size of generating units to the total system makes adequate reserve margin more critical.
- Recent history indicates that a 20% reserve margin is appropriate.