Electric Utilities

IPP Contracting & Regulated Markets: Call with APEX Power Services (Incl. Call Transcript)

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Conference call on IPP Contracting and Regulated Markets

We held a conference call on IPP Contracting and Regulated Markets with Michael Bedley from APEX Power Services Corporation, which offers consulting services for PPA contracting, interconnection to grid operations in the marketplace, particularly for illiquid markets. Our discussion focused primarily on the IPP contracting in the Southeast. The transcript is enclosed for reference.

Tough to compete with utility RFPs, as they seek to lock-in own growth

The call appeared to present a challenging contract market for IPPs, seeking to compete to win RFPs for capacity with both utilities and muni's/coops. It remains readily apparent from recent bids that terms on new utility RFPs are challenging to compete with, with the latest call using Duke's latest Florida RFP as a classic example where self-build appears poised to win, with new build economics of a high-efficiency new CCGT (6,580 heat rate) and $65/kW-year capacity payment indicating this tough market (when translated for a conventional CCGT, result in an effective capacity payment of <$30/kW-yr or <$100/MW-day).

Where is the opportunity? It's with Muni's and Coop's

Where is the sweet spot in the Southeast? We understand it is as being medium-term 4-10 year term contracts to serve municipal and cooperative load, for which they will not likely be a self-build. Our speaker flagged a broader trend towards capacity prices in the range of $7-10/kW-month ($200-300/MW-day) in these longer-term deals, lending these contracts to 'booms and busts' vs. contract expirations. Our speaker remain confident there were still quite a few opportunities to contract around later-dated MATS coal plant retirements, with contracts out for bid currently due to begin in ~2016 period. However, in this context, we flag willingness from regulated utilities to sell 'excess' regulated capacity to these entities as depressed prices as the primary competing factor. Moreover, opportunities continue to be focused on procuring or replacing energy contracts with CCGT capacity rather than filling peak requirements given limited load growth.

What are the lessons learned? Tough market outlook

Lessons learned from our latest call continue to suggest a more sober market environment. In particular, we read the comments as constructive for Duke Energy, given both its ability to continue to sell excess to muni's/coop's as well as the confidence of our speaker in winning its own self-build. With many utilities increasingly struggling to find ratebase growth of their own, we see the ability to structure projects (brownfield or otherwise) that are sufficiently competitive to *win* their own processes (compare the apparent confidence around the Duke bid relative to Xcel's recent success in winning its own utility RFPs). Meanwhile, among IPPs we see Mr. Bedley's comments as emphasizing the need to continue to monetize assets *back* to utilities, as well as the latent 'upside' embedded in many uncontract plants (with pricing on plants, once contracted still in a relatively healthy range vs. competitive markets, likely due to the longer-tenor of many of these contracts). Then again, even the tenor of contracts appears to be contracting as well.

Don't expect much new build outside utilities

We remain sanguine on the opportunity for *new* contracted growth opportunities for IPPs in the Southeast. While utilities may win their existing RFPs with new build due to brownfield sites and other locational advantages, we see a declining opportunity for the likes of Calpine or Southern Power to *develop* new sites on their behalf. Rather, with the relative abundance of uncontracted IPP capacity (and hence pricing), the bias appears to be to lock in existing assets into new contracts.

IPP contracted and Regulated Markets: Conference Call Transcript

The following are highlights from our call with Mike Bedley of Apex Power Services. The comments below have been edited to improve grammatical clarity and provide enhanced context.

Operator: Ladies and gentlemen, welcome to the UBS Electric Utilities with Apex Power Services on the IPP contracting and regulated markets conference call. I would now like to turn the conference over to Julien Dumoulin-Smith with UBS Electric Utilities. Please go ahead, sir.

Julien Dumoulin Smith: Thank you operator. Our call this afternoon is with Mike Bedley, partner at Apex Power Services, to really look into the dynamics of contracting with IPPs in regulated markets with a specific focus on the Southeast. Mike, perhaps you can get our conversation going with a little bit of background on who you are, where you're coming from and what you're seeing out there in the market as far as IPP opportunities to contract for assets?

Michael Bedley: Yes, sure. Julien, thank you so very much. Apex Power Services and Energy Consulting Firm, specializes in electric power, fuel the power, co-generation, industrial generation, IPP's biomass, renewable energy. **We specialize in the area of the IPP's PPA contracting, interconnection to grid options out in the marketplace and how to work the markets in areas that are not liquid.** We have to be out in the market seeing what units are coming offline to maximize strategy.

I've been in the business over 30 years. Apex has been operating for well over 20 years and covering most of North America and Central America. We specialize in areas where

there's difficulty needing unique solutions to otherwise illiquid markets being the Southeast specifically.

Julien Dumoulin Smith: What have you seen in the last 24 or 36 months in terms of contracting, in general, in the Southeast? What's happened and what are the opportunities that you've seen and what's driven them?

Michael Bedley: Oh, a good question. Obviously what's happening in the Southeast is happening basically everywhere around the country. **There is very depressed pricing in the Southeast. We're seeing areas with very little growth, if any and in some cases, declining growth.** This is also adjusted for weather.

What are the opportunities for existing IPPs and what are the opportunities for IPPs to grow, adding new generation, expanding existing generation and so on?

<u>There is a very limited opportunity for long term (greater than ten years) PPAs associated with IOUs.</u> The issue is becoming simply— the buyers, municipals, co-ops and IOUs are very much hesitant to sign a very long-term deal that could put them in a position to be out of the money in future years.

Technology breakthroughs, solar energy, rooftop solar and the lack of growth is causing utilities to pullback, look at their portfolio and not make a decision that could be a 10 or 20 year mistake.

<u>Prices are extremely depressed. IOUs are selling excess capacity at their portfolio cost just to try to add more load. This is prevalent in many locations: Florida, Georgia, Alabama and areas where there's excess generation and very low and poor load growth.</u>

The opportunities are to look at areas where they are going to be displacing old coal fired fossil units and old steam units. They have low heat rates and low capacity factors that try to work with existing municipals, co-ops that will use their units as part of their portfolio.

The opportunities with IOUs, including the Duke Energies or the power and lights is that the existing RFPs for generation are extremely competitive and the

self-builds are at such low prices, most IPPs cannot compete. This is a very critical point.

Julien Dumoulin Smith: Excellent. Do you still see those opportunities? What is driving new contracting discussions now? Is it still more coal retirements or are we really seeing all that play out on a state level? CAPP coal is in relative decline with many retirements already well documented. *How much more is there to go?*

Michael Bedley: There are still come coal plants obviously in Florida. Duke Energies are going to be retiring some. There are some smaller coal facilities that just don't want to upgrade the environmental equipment associated with the units.

So the question is they will be going out, but when they go out and have to issue an RFP for power, these utilities are most likely going to brownfield develop or self-build with an RFP that becomes extremely competitive with the newer machines, the newer heat rate.

I don't know if anybody on the group call is familiar with the recent Duke Energy RFP but the target heat rate on the thousand megawatt machine is 6580 and the capacity payment is 60-something dollars, $65 a KW year, which is extremely competitive and would be very difficult for any new IPP to compete.

Julien Dumoulin Smith: Can you break that down for folks that aren't as familiar? 6580 is an exceptionally low heat rate. I take that to apply to basically a brand new combined cycle of the newer generation and then a $65 kilowatt year is a medium capacity payment. Can you provide context on how to think about that heat rate capacity together? What if you have a unit that's legacy that doesn't have the 6600 heat rate?

Michael Bedley: Well, here's a great example. If you have a 7500 heat rate or a 7200 heat rate and $4 gas, you're conversion rate is $5 a megawatt hour more expensive than the new unit going in for the utility. At $65 a KW month, you may be at $5 to $7 a megawatt hour and an 85% capacity factor for your capacity payment.

That's a very difficult competitor, the utility. If they're building a brown site, existing infrastructure, including open cooling water systems, substation or connection just bodes

well for the utilities to build a unit that nobody can really compete with if they have to build a new machine.

Julien Dumoulin Smith: What enables Duke and others to be able to compete and make it work at that prices level? Is it just low-balling or is it really what the new construction costs are that you're really competing with if it's on a brownfield basis? What are those costs as you see it?

Michael Bedley: Let's look at some of the basic things that are much cheaper. First of all, they have existing infrastructure including natural gas already to the site. Substations will be reused and upgraded if any. Open cooling water systems are given a great advantage to the heat rate that others who aren't going to be able to contract for open water systems versus closed circuit cooling water systems that go ahead and affect heat rate.

In the case of FPL units, they've built three or four plants to existing brownfield sites. I know a lot of the coal facilities are being looked at as well for the new IOU units to be placed in service because of their advantage.

There is a simple fact— the fact that they're lower cost to capital. They spread unit costs cheaper as they may have less maintenance associated with the manpower at the site versus other sites. So there are several things that gives them a great advantage.

Julien Dumoulin Smith: What are the key opportunities that you'll be focusing on again? What is your timeline? Then also, perhaps give us a sense here for when those might play out, just what are those key contracts that are being viewed for today across the Southeast?

If you could flag the ones that are particularly relevant or are illustrative of this concept and are being closely watched across folks in the Southeast?

Michael Bedley: Well, the closely watched opportunities are obviously the RFPs for replacement of coal and other units that are going to be mothballed or just basically cannot compete efficiently.

The key here is to remember IOUs grow with the growth of the rate base. So even though you're competing with a unit or a plant to be placed in service, the utility wants to be successful to build the business.

The things that are facing the utility, including the declining load growth, can begin a death spiral. The most important thing for IOUs is to begin the process of building their rate base. Other areas to concentrate on are municipals and co-ops that have long term contracts, which are expiring with IOUs.

To find opportunities, it is important to see when their PPAs are coming off contract and old units are being displaced. These opportunities would benefit the IPPs as they're looking forward. The municipals and co-ops need to be worked. You need to understand the politics of the decision because it's not about rate base. It's about providing a least cost alternative long-term without volatility if possible to bring in the co-ops and municipals because they're owned by their community, the least cost stable energy over the time.

Julien Dumoulin Smith: Interesting. What are some of the big RFPs out there with utilities and what are some of the big, at least publicly stated, RFPs out there with some of the munis and co-ops to pay attention to?

Michael Bedley: Well, in the case of Florida, FPL has finished several of those years now. They're a couple of years old. Duke Energy has out one right now that's actually due today for 1800 megawatts.

I know Duke finished last year. I think the utilities in Mississippi will be looking for opportunities as well as Alabama as their fleets are continually monitored for efficiency and long term competitiveness.

Julien Dumoulin Smith: How many megawatts are we seeing out of those, just to give us a sense for the market share? What is available or up for grabs?

Michael Bedley: No, I don't but within Alabama, there's a lot of coal-fired units that will not be upgraded that will have to be competitively bid or self-built through Power South, municipals and including the Southern companies.

Julien Dumoulin Smith: Are a lot of these units that we're still looking at today in contracts, are those still for 2015 around the idea that mass is going to take these units out? Or is this more around, we have a little bit more latitude and timing

because we're going to get latitude from EPA or otherwise. This is about contract that will take effect in '16 or '17?

Michael Bedley: All of the above. Most of the parties supporting municipals are looking at all this. They're looking at the upgrades. They're looking at competitiveness. Can they buy power in the market cheaper? What's the best alternative?

So it's all up in the air at this time and being reviewed by many engineers and consulting companies to determine what's the best option for the utilities at this time and going into the future in '16, '17,'18 and beyond.

Julien Dumoulin Smith: Gotcha. There's still something to be done for 2015, as it could be as close as that?

Michael Bedley: I don't really see anything in the near-term. Near term contracts are pretty firmed up at this time. Most utilities are looking out four to ten years. But for '14, '15 and specifically '15, they will be very limited opportunities that I see at this time.

Julien Dumoulin Smith: How far ahead of time do you see these utilities come to market? Is three years ahead of time for contract or new build a good ballpark to think about this?

Michael Bedley: Well, contract and new build, at least three years for replacement of existing capacity under long-term PPA (3-5 years). Most municipals and co-ops are looking for 2-3 years out.

Julien Dumoulin Smith: So the opportunity today really is about 2016?

Michael Bedley: Absolutely, 2016 and beyond.

Julien Dumoulin Smith: Gotcha. All right, but it's still MATS related even in that case?

Michael Bedley: Absolutely.

Julien Dumoulin Smith: Are you seeing a lot of potential for more coal plant retirements than what was initially predicated as they revised their assumptions about gas being cheaper? Is that part of what's driving the contracting opportunity here too?

Michael Bedley: Looking at the data, **I absolutely believe retirements are driving current contracting opportunities. The competitiveness, the stability of gas pricing, even on**

very cold days today and looking forward, the efficiency associated with the newer units that can be built is providing a benefit. They may just consider that option prior to looking at any upgrades, the risk associated with long-term operation of coal and also the liability associated with closure.

Julien Dumoulin Smith: Gotcha. As you think about the munis and co-ops, if that is the opportunity, what are some of the big contract opportunities out there on that side as you see it? Are there any key names you would be focusing in on or paying attention to over the next 24 months that will come to market?

Michael Bedley: Over this past summer, some at an electric co-op in Florida had a large RFP for several hundred megawatts of peaking power. Alabama Municipal Electric Authority is looking as well. Power South is looking at opportunities to meet their needs in the future. Everyone is soliciting for a long term power supply.

If there's an opportunity where they can jump on it at a very cheap price, I think they'll go ahead and move on that. That's key for the group, understanding that prices are low. I understand you don't want to go long in a soft market. However, the opportunity to term long term may be better today than it may be tomorrow if pricing should rise a little bit.

Julien Dumoulin Smith: You talk about jumping on cheap pricing. Can you give us a sense of where prices have come and where they are today as you think about availability? What does a cheap price look like?

Michael Bedley: That's a good question. I make the statement that wholesale power prices are cheaper now than what they were 30 to 40 years ago, unadjusted for inflation. Simply looking at the portfolio, we'll start from the very far south. <u>We look at a portfolio such as FPL, which currently, during mild conditions, has an average heat rate of 7 and is having delivered gas associated around 4, 4-1/4.</u>

You're looking at a $30/MWh pricing for energy only. Now, we look at adding capacity in the excess capacity associated with southern power, southern JEA with excess capacity and many utilities are trying to be as competitive as possible to

give that power pricing away. What are municipals and co-ops seeing out there in the marketplace today? Long-term pricing starting at $40 and $50/MWh.

Julien Dumoulin Smith: How do you translate that back into the capacity payment element for a kind of return on capital versus the marginal fuel cost?

Michael Bedley: **We're seeing marginal fuel prices in the 30s, lower 30s and capacity payments in the maybe $8, $7 to $8, the $10/KW month.**

Julien Dumoulin Smith: Seven to ten/ KW month? Right, $7 to $8 on average and then $10 is kind of the outside number?

Michael Bedley: Yes, that would be a higher number today. Today the energy prices are extremely competitive coming out of the portfolios today. A lot of the portfolios being offered to municipals from other utilities do include nuclear, coal and a portion of renewable and also sometimes mostly gas. You add those two together and they can be very competitive.

Julien Dumoulin Smith: Right. But it's still in that ballpark of $7 to $8 even. It's not more depressed than that necessarily?

Michael Bedley: No.

Julien Dumoulin Smith: Thank you. What's keeping it up in that level? If there's so much supply, is there a concern that you could continue to see pressure there?

Michael Bedley: Absolutely, until we have more units either turned up or more displacement of existing assets. So if utilities are going to displace, we will see some pricing pressure upward to higher capacity payments.

But we haven't seen much movement on the energy pricing, so the combination, too, is keeping most of the overall pricing depressed. But we may see some increase in capacity. As new builds come online, as the units are getting more expensive to build, we will see increase in pricing on the capacity side.

Julien Dumoulin Smith: Where was pricing previously, relative to the $7 to $8 you discussed?

Michael Bedley: We were at $7 to $10 a KW month in the late '90s. We absolutely have not seen a move in energy prices.

Julien Dumoulin Smith: Interesting. Why is that the case?

Michael Bedley: Good question. It comes through the cycle of one of the bankruptcies of one of the major IPPs restructuring, the financial restructuring and then looking at bidding the market and winning.

It's no different in a liquid market, the baseload units stay on at night. Do you want to win and run and make some money or do you want to come off and stay off and not run? That has depressed pricing tremendously.

Julien Dumoulin Smith: But where was it at its peak? So you're saying it was $7 to $10 back in the late '90s.

Michael Bedley: I've seen numbers up to $14, $15/ KW month.

Julien Dumoulin Smith: That was at its height in like 2007? Is that a good way to think about it?

Michael Bedley: Yes, or slightly before.

Julien Dumoulin Smith: <u>So really you've seen prices come down by 25%.</u>

Michael Bedley: Yes, that's a good number, 25% to 30%.

Julien Dumoulin Smith: Excellent. When you think about the trajectory for pricing itself, is the excess getting a bit tighter because more coal is coming out of the market? It's somewhat correcting itself given a new?

Michael Bedley: Well, just a case in point, if we do shrink the existing base of units, there should be a need for gas. <u>If that need is displaced or replaced by the utilities with their own self-build, the market for the IPPs will continue to dwindle.</u> <u>They will be competing for less opportunities in the market if the IPPs don't go out for an RFP or you become competitive.</u> The key will be to price such that you are competitive and sustain yourself economically.

Julien Dumoulin Smith: What kind of units are we looking for? What are we contracting for? Is this strictly a game about new build or brownfields for the utility relative to an existing asset for the IPPs or are we actually talking about new build for IPPs as well here, just to be clear?

Michael Bedley: Both. There'll be some new builds, some Greenfields that would be somewhat competitive for the IPPs to bid against,

for an RFP, and then some of the existing brownfields that may be a little bit more difficult because of the overall cost structure.

Julien Dumoulin Smith: Interesting. What kind of capacity are we looking at peaking versus combined cycle? Are we seeing demand for one over the other? Is it typically peaking needs at this point?

Michael Bedley: We see very little peaking needs. It's a very interesting question. In the market, we mostly see quasi base loaded combined cycle with a capacity factors greater than 60%.

With regard to peaking capacity, there's been some RFPs for some peaking, but with the existing summer that has past adjusted, weather adjusted peak loads and overall loads, we're just not seeing the need for the peaking RFPs at this time.

Obviously there's always a chance of displacement of existing peaking assets, but there are peaking assets available. If anyone on the call does have peaking assets, there may be opportunities for those utilities to continue to look for cheaper alternatives if there are.

Julien Dumoulin Smith: Interesting. So it's all about combined cycles

Michael Bedley: At this time, it's absolutely

Julien Dumoulin Smith: What's the pricing discrepancy if you can talk about liquid pricing discrepancy between selling peakers versus the combined cycles?

Michael Bedley: It's a difficult question. I'm just not seeing much activity for peaking in the Southeast at this time.

Julien Dumoulin Smith: That's a very fair comment. So in aggregate, if you were sitting here as an IPP, what would your strategy be? If you're sitting here as an uncontracted IPP, what would you recommend they do?

Michael Bedley: Well, let's start from the basics. Know your portfolio well. Secondly, know your nearby buyers well, state municipals, co-ops. Work with your IOUs if there's an opportunity. Know when municipals may be issuing RFPs. In some cases, municipals may be looking for opportunities in the marketplace without going out to public release, knowing

consultants. There are others in Atlanta, outside Washington DC, who actually manage RFPs for municipals and co-ops quite often. There were several in Eastern and Western Texas for not a lot of generation, but they're always going out in the market for small allotments of power. Know how to bid against other options that are out there at this time. The second thing, be competitive because future pricing is uncertain.

Julien Dumoulin Smith: Excellent. We have been focused on one half of the equation here, which is contracting. What about the idea of selling the IPP assets back into rate base? What is the opportunity there? Have you seen much success broadly speaking? What are the impediments? What about relative arbitrage?

Michael Bedley: That's a great question. The question was obviously very viable with Entergy many years ago, buying existing units and buying existing plants. There were some other IPPs in Nebraska that were recently sold in municipals or sold to the share of municipal organizations.

The opportunity in the future and the price of selling the entire plant that may be older and more competitive at a lower capacity cost with a higher heat rate may be the best option for an IPP as the IOUs or others go out.

I'm not talking about new build. I'm talking about an existing station that may have difficulties in the market as we have less load growth that may have difficulties sustaining its economic viability.

It would be a better option to try to work with co-ops and municipals to sell a part or all of it that might be able to provide greater benefit to both parties.

Julien Dumoulin Smith: For the contracted assets themselves, I suppose they are a bit fungible. What is the tenor of these contracts we're seeing? Are they long-term such that it's a quasi-sale or the tenor much shorter typically?

Michael Bedley: The tenor is obviously much shorter. We are seeing mostly five to ten year agreements at this time. We're not seeing anything between 10 to 20 years. Obviously standard offers and RFP are 20 to 35 years.

But we're tending to see a lot of organizations more in the range of a ten year agreement. They want comfort. They want to make sure they don't make decisions that are bad for the future. They want to make sure they're competitive and provide stabile pricing for their members.

Julien Dumoulin Smith: So what's the pricing discrepancy then, if you think about the shorter versus the longer term? I mean, you would imagine there would be a greater risk premium put on the ten year contract. How much bifurcation is there? Is it pretty stable?

Michael Bedley: Actually it's pretty stable. We don't see some pricing in the future, but nothing that you haven't seen in the past. We don't think the buyers, meaning the municipals, co-ops and others really believe that power pricing is going to be substantially higher in 10-20 years from now. We may see the escalation associated with O&M, with fuels, but in many cases on IPP, if the fuel is a pass through, then the fuel can be provided at some heat rate. We're not so sure we're going to see extremely high prices.

Julien Dumoulin Smith: Now, we've seen a few complaints out there about the transparency of RFPs and the ability to compete. Can you comment broadly? Are the IOUs being too guarded about their execution on these things? Typically they have competitive solicitations with external parties broadening them. If you want to compete, can you compete? Or is it really being kept in-house?

Michael Bedley: Many of the utilities, their RFP process, if not all, have an independent monitor. I think that the bottom line is I won't say the word manipulated but can somehow be played to the advantage of the utility in the RFP process.

The answer is obviously there're benefits. One, sensitivities run, the gas profiles, the portfolio, the amount of dispatch. All those things can change and how they run their models is critical to the choice they make, whether it being an in-house or an IPP that bid into the RFP.

That's critical. Transparency is very important but at the end of the day, the IOUs have to report or present to the utility commissions for approval. But remember how the machine operates and how it operates in portfolios, all dictated by the utilities in their ten year site plans and how they plan

their unit dispatch into the future. So is it an unfair advantage? I don't know if it's an unfair advantage but it is an advantage.

Julien Dumoulin Smith: And then let me just be clear about this: In the past, especially for IPPs, transmission limitations have really been a constraint and I imagine with lower demand and the ability just broadly speaking, greater at deployment of transmission. I mean, is that less of an impediment? Or is that - how would you characterize the interconnectivity of IPPs as a hurdle to getting contracted up?

Michael Bedley: The answer to that question is pretty simple<u>. Transmission is always a problem. It is not an easy solution to any transmission path associated with bidding an RFP and moving from one area to another, another electric utility area.</u>

It's very difficult to get transmission. In some cases, it could be critical to the acceptance of the IPP and their bid to an RFP. If there's substantial risk of transmission, non-delivery from a third party utility, then that could be the big decision based on a go or no-go. So it's always a very critical time consuming and may actually be the decision maker.

Julien Dumoulin Smith: Let me just think out loud. As we look forward here to FERC 1000, in theory, that should improve at least the transparency of transmission? Does that really change the name of the game in the Southeast?

Michael Bedley: A very good question. Will it change the game tremendously? I don't think so. Will there be difficulties continuously? Remember the utilities system and the transmission system is a dynamic business.

It's a dynamic process and is currently being evaluated as things move, plants go away, plants come online, the load changes, load shifted, load path efficiency. All those will be - I still think it's going to be something that needs to be obviously analyzed and looked at but there's always going to be difficulty.

Julien Dumoulin Smith: Let me just transition the conversation a little bit. You said the procurement and renewable contracting, in many different markets - and I understand this is a little bit less renewable intensive than others. But how are you seeing it

there, because that seems to be a market where third party developers have had greater success at the end of the day. How are you seeing that right now, if you can comment on it briefly?

Michael Bedley: If you want to ask how utilities are doing with renewable developers, the answer is they're having a lot of success for the simple reason of sustainability price.

Fixed price contracts are very much in demand to eliminate any volatility associated with fossil fuels. <u>So if you have a product, such as a landfill gas product, that may be able to provide a fixed price product over an extended term, that would be of great interest to the co-ops munis and even IOUs.</u> They can be separated because they're not socially associated with gas costs, which can play differently in the portfolio. How they dispatch for a high capacity, very low energy payments, could put you in a position to be dispatched first and running more hours. So that could be looked at a plus versus another gas machine coming on line. <u>Fuel diversity is critical to these utilities to eliminate volatility to the rate base.</u>

Julien Dumoulin Smith: What are the incremental opportunities around contracting for new renewables? Why are we not seeing more utility driven investment of renewables? Why are they proving to be less successful here?

Michael Bedley: In general, Entergy, let's talk about Louisiana, Mississippi, Alabama, Georgia, North Carolina and South Carolina. The objectives and the whole basis for rate making is to provide the lowest cost alternative to the rate payer. In the case, if renewables can provide a least cost alternative, they will be accepted.

Unfortunately at this time, with the price of natural gas and the forward pricing, they are not competitive at this time so the utilities haven't stepped forward unless they're forced to purchase power from a renewable at a higher price.

Julien Dumoulin Smith: Generally speaking, you're saying there's no renewable portfolio standards (RPS) to support procurement in this this region?

Michael Bedley: Exactly.

Julien Dumoulin Smith: How are you seeing competition for contracts for conventional capacity between other adjacent utilities? One of the aspects that Duke has talked about a lot of late, is being able to sell to munis and co-ops from its own regulated service rate base. How do you see that tension playing out where presumably it's a lot cheaper to come off of existing assets and rate base than it is necessarily vis a vis for anyone else?

Michael Bedley: That is what I've been driving off earlier. IPPs have to compete against other utilities. <u>In the Duke RFP, FPL, Jacksonville Electric Authority, some are going to be competing and actually trying to look for opportunities to sell maybe not their excess but some power within their portfolio because they have too much reserve margin at this time.</u>

What can they sell that at to still preserve for their rate base but also sell power to get the overall capacity factors up on that unit? Your competitor is fierce. They're winning most of the RFPs at this time or a large portion of the RFPs, municipals or co-ops are being won by other municipals and other IOUs.

So, if for instance Duke goes out and builds this unit, they have six years of excess capacity as they build up their gross projections, let's say. So when we look at other utilities looking for power, they would bid into those RFPs and ultimately be successful.

Julien Dumoulin Smith: Given what you just described, what is the outlook if you're like a Calpine or an NRG or one of the other independent IPPs? What is the outlook as you see some of their existing contracts roll off? If you were sitting here making a bottoms up assumption on what were to happen to some of those assets, what price would you assume they would get re-contracted at? How much of a reduction would this be? Is there an ability to replace all these megawatts? Are they going to roll-off the contract? Just how do you think about it broadly?

Michael Bedley: The one thing that's important for our business is we're fortunate enough to see a lot of different bidders and different markets. If you have a contract that's in the money for yourself and way out of the money for municipals, do

they want to go back in and contract it at a lower price for that generation need? They may want to contract it at a lower price, but at the same time, do they need that generation? Is that key? Are there other alternatives that are cheaper? Understanding your buyer and the position you're in at this time is key and working with them to see if they would like to extend the agreement?

Are there options on the agreement? I would highly encourage anybody, who has options to continue to look at how that affects both sides and try to put something together rather than be exposed to the market where you may be competing against an IOU that just wants to sell that reserve margin because they have too much capacity at this time. That's not a very good position.

<u>We know the city of Lakeland in Florida is looking at alternatives for emissions upgrade regarding their coal unit.</u> That would be a good place to look at and understand what's going to be their cost and understand how you can come in and provide a product that's similar to their needs at a cheaper cost than putting any more capital to an older coal facility. That's the key element looking forward.

Julien Dumoulin Smith: All right; Are there any questions out there?

Questioner#1: Thanks for the overview. With the expansion of the Midwest ISO into Entergy's former region, you now have in effect, a competitive RTO market infringing upon parts of SERC. Going forward, do you see opportunities for SERC-related entities to move power into MISO or perhaps out of MISO?

Michael Bedley: Thanks for the question. We know there's very much difficulty going from MISO into SERC. Those of you who are in the wind power business, you realize that transmission is difficult if not impossible to transact.

With regard to MISO, Entergy does have a lot of older assets, so if you're looking for opportunity to go into an ISO, to build new IPPs or build some type of hybrid associated with a cogen, there may be opportunity there, obviously if you're the most sufficient unit in that market.

<u>Do we see some of the generation moving from one to the other? There may be some but I think that's a very difficult wheel to be moving from SERC into MISO in a competitive</u>

market. There're a lot of competitive gas units currently on the IPP side that may actually start to displace more as we get more economically liquid displacing some of the assets associated with Entergy.

Julien Dumoulin Smith: With regards to the MISO expansion into Entergy, how do you see the opportunities for contracting something like the classic NRG assets? Does that give them a wider pool to potentially sell to? How much of an uplift does that give them?

Michael Bedley: With regards to transparency, do we get uplift of knowing where the market it? Yes. But, do we get a position where can we contract long in that market? Maybe not. Can we find alternative buyers because of the liquidity of that market if you're a low cost provider? The answer may be yes, from a traditional IPP.

With other opportunities, we talked about IPPs developing more fluid movement of power as we're getting an ISO versus working with Entergy. Everybody knows on this call, we've had difficulty with Entergy for well over 20 years with the movement of power from cheaper sources in the north to the south.

I know they worked out some of those bottlenecks, but at the same time, it will be a very competitive market in an area where there is growth. There is going to be probably some new generations coming on associated with CoGens, new chemical facilities and existing chemical facilities expanding as well that'll meet the needs of very competitive priced power. So I'm actually excited to see what's going to happen in that market. It's a very large market and it's actually very good for our firm.

Julien Dumoulin Smith: From the cogeneration perspective, what are you seeing with all the industrial growth in the Gulf region? How are they servicing themselves? Are you seeing more CHP type opportunities?

Michael Bedley: That's a very good question and the question is very close to Apex. To be honest with you, with the capital expenses associated with the cogeneration, it's very difficult to displace natural gas fired boilers with a new cogeneration facility based on the power prices we're seeing today.

That does not mean that larger steam facilities that can provide excess power to the grid that also serve the needs from the industrial customer cannot be competitive. Certainly with regard to Shell Gas and their location and how they're located, they provide a great benefit to developing in those areas.

There were some things in plants about that today in other areas, looking forward and seeing there probably will be some developments. Now, new facilities, almost every new facility we were seeing, cogeneration is part of the development of the chemical facility.

Julien Dumoulin Smith: You're saying basically it's hard to see a new cogeneration l facility where there's an existing legacy steam unit.

Michael Bedley: It is tough. Larger coal facilities that have coal fired boilers, maybe older paper facilities, old chemical plants that have coal fire boilers that want to displace and build cogeneration, in those cases, it will work. But remember, it's still a very tight economic option. Obviously chemical facilities have very high hurdle rates and it's usually the utility portion of the plant that is usually the lowest priority.

Julien Dumoulin Smith: Excellent. Lastly if you can, what are the markets that are worth paying attention to when it comes to the contracting opportunities? Maybe something as far away or as esoteric as the EIM [*Energy Imabalance Market]* in the West. What other efforts to improve transparency are worth monitoring?

Michael Bedley: That's a great question. I love the MISO area in some areas, the south. North Texas is very tough if you're in the cogeneration area. Power prices are very cheap. For examples, parts of PJM, obviously in a good location for power and opportunities, obviously the Northeast.

When you look at it in aggregate, the perception from the utility buyer is that we're seeing no pricing increase in the future. We're seeing marginal load growth. Decision making is somewhat slow because we don't know if tomorrow is going to be a day that you're going to have growth and we're going to need to purchase.

If anything, nobody will be purchasing large blocks. This goes back to our question earlier, what kind of opportunities are there? I don't think we're going to be seeing co-ops or anybody buying large blocks.

They may be buying 100 megawatts, 50 megawatts for five to seven years, 100 laid on top and continuing the cycle rather than going ahead and taking the whole 700 megawatts associated with an IPP facility.

In conclusion, challenge your providers, look at opportunities, understand the markets, understand the buyers. The municipal co-ops may be the best option at this time. And just keep pushing forward.

Operator: We have our first question.

Questioner#2: I appreciate you allowing me to be here. I'm not in the same crowd as the other listeners, I'm afraid. I'm with Public Staff.

Recently I was involved in a proceeding where I was asked to pretty much give an opinion on the cost of a CT.

What I found is that it's hard to find the prices of CTs because obviously I don't build CTs. I'm a staff regulator. I looked out to things like cost and entry reports that PJM and MISO put out as publications on the cost of the CT today. Do you have any other suggestions to where I can look out for current cost of building a CT including the land and interconnections on the greenfield side?

Michael Bedley: There's just not a lot of information out there. Obviously the question is very unique to the markets, the land where you're at, the interconnections, the size of your facility, the transmission voltage. All those things are very key.

I would ask you to go ahead and send me an email offline and I'll provide you to the areas which may provide the best benefit. But obviously, it depends on the project. Everybody can get the cost of building a common CT, but the uniqueness of the project and the size of the project is also critical.

Julien Dumoulin Smith: What do you think the new cost of new entry is for a contract? At what price would you see new entrants into the market? Is it the $14 kilowatt month pricing? Is that where it needs to get to from a capacity payment perspective?

Michael Bedley: I think it may be even north of that as well.

Julien Dumoulin Smith: North of $15 to $20. Is that kind of the ballpark?

Michael Bedley: Possibly.

Questioner#3: Hi. Thanks a lot. I was just curious how competitive it is to beat an incumbent utility self-built. As a follow up to projects that the utilities end up self-building, how much do they go back to the public utility commissions to ask for cost overruns or reimbursement of cost overruns?

My question is implicit that, you can low ball these numbers and then beat out everybody but then go back to the commissions and ask for money that just suddenly never was contemplated.

Michael Bedley: That's a good question and obviously a risky proposition, should you want to low bid a bid to be successful only hoping that another, at a later time, that you could go back in for valid changes to the build.

I think in the instances of the IOUs, I have to be honest with you, they've been very, very good at pricing the builds and pricing brownfield sites. As a matter of fact, if we went back and read some research, most of them come in *under budget.*

Julien Dumoulin Smith: You're saying they're very accurate at it, or frankly, they're under bid or are under budget?

Michael Bedley: Most of them come in under budget. They're extremely accurate and most of the self builds come in under budget. We're building 3-on-1 combustion turbine machines on existing sites and they have a great handle on existing costs while building a greenfield site is a much more difficult situation.

They know what the substation and interconnection costs are. If they're brownfield, they have all this already numbered. The risk of the build for the utility is minimal compared to the risk of a new site that you may have considering you've got to bring gas in and everything else associated with that.

With regards to the facility in Southern Mississippi, the coal gasification, that's completely different. We're talking about

a simple 3-on-1 or 2-on-1 machine that's being built by the utility at this time.

Questioner#3: Well, I would compare greenfield to greenfield but, I think the brownfield certainly would have an advantage.

Michael Bedley: Remember, greenfields have actually been property that have been queued in and owned by the utilities for numbers of years. It's not 30, 40, 50 years. Some of the utilities have sites that they purchased land 20, 30 years ago.

They do have a better idea because they bought the area and needed transmission systems to make the interconnections cheaper than picking a site that you have to examine the opportunities to interconnect at certain areas. These are already set up at that time, maybe before they even built the transmission systems.

Questioner#4: The last question was asked and one of your statements was IOUs have come under budget. I have seen that here in North Carolina as well. I don't believe those costs analyses done are audited. We review plans going forward, but also we have a difficult time reviewing them after the fact.

When you say they come in under budget, are those audited financial statements that say these project were done by independent evaluators? Are they self build projects that were accurately done under budget or accurately reported under budget?

Michael Bedley: In many cases, that data and information is presented to the commission staff. In North Carolina, I don't know the procedures associated with that. In many cases, it's audited by a third party. I'm not so sure, and I don't think so.

However, I do know that that information is provided to the Public Utility Commission staff that they have the ability to look at it and analyze it. When it's brought in under budget, if they were already competitively bid and nobody was successful and they were under budget, it pretty much leads us to believe that they've done even a better job.

Julien Dumoulin Smith: Great. Well, with that, Mike, thank you very much for taking the time this afternoon. For everyone, all the listeners, thank you again. Take care and have a good day.

Michael Bedley: Thank you, Julien. Have a good day everybody.

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Risks for Utilities and Independent Power Producers (IPPs) primarily relate to volatile commodity prices for power, natural gas, and coal. Risks to IPPs also stem from load variability, and operational risk in running these facilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off Competitive Integrateds. Further, IPPs face declining revenues as in the money power and gas hedges roll off. Other non-regulated risks include weather and for some, foreign currency risk, which again must be diligently accounted in the company's risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates.

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Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%
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