FEDERAL ENERGY REGULATORY COMMISSION

Price Formation in Energy and
Auxilary Services Markets Operated by
Regional Transmission Organizations and
Independent System Operators
Operator Actions
Tuesday, December 9, 2014
Hearing Room 2C
888 First Street, N.E.
Washington, D.C.20426

Docket No. Ad14-14-000

The Commission met in open session, pursuant to notice at 8:45 a.m., when were present:

COMMISSIONERS:

CHERYL A. LaFLEUR, Chairwoman

NORMAN BAY, Commissioner

MEMBERS OF FERC STAFF

EMMA NICHOLSON

MARY WIERZDICKI

JOSH KIRSTEIN

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STANLEY WOLF

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DAVID REICH

RICHARD O'NEIL

ERICA SIGMUND

JENNA MCGRATH

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PRESENTERS: PANEL 1

Operator Actions in RTOs and ISOs

PETER BRANDIEN, ISO New England

MARK ROTHLEDER, California Independent System Operator Corporation

JEFF BLADEN, Midcontinent Independent System Operator, Inc.

AARON MARKHAM, New York Independent System Operator,Inc.

MICHALE BRYSON, PJM Interconnection LLC

SAMUEL ELLIS, Southwest Power Pool, Inc.

PRESENTERS: PANEL 2

Experience with Operator Actions

ANDREW HARTSHORN, NRG/Boston Energy Trading & Marketing

MICHAEL SCHNITZER, NorthBridge Group

MICHAEL EVANS, Shell Energy

EDWARD TATUM, Old Dominion Electric Cooperative

JOHN A. ANDERSON, ELCON

STEPHEN WOFFORD, EXELON

THOMAS KASLOW, GDF SUEZ

MARK SMITH, Calpine Corporation

JOEL GORDON, PSEG

PRESENTERS: PANEL 3

Options to Reduce the Market Impacts
of Operator Actions

DAVID PATTON, Potomac Economics

JOSEPH BOWRING, Monitoring Analytics

MATTHEW WHITE, ISO New England

ANDREW HARTSHORN, NRG/ Boston

MICHAEL SCHNITZER, NorthBridge Group
speaking on behalf of Energy
Nuclear Power Marketing LLC

STEPHEN WOFFORD, Exelon

EDWARD TATUM, Old Dominion Electric

JOHN A. ANDERSON, ELCON

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P R O C E E D I N G S

MS. NICHOLSON: Good morning everyone. We thank your for coming out on this rainy morning to discuss operator actions.

Today's workshop is part of our effort to discuss price formation and organize regional energy and ancillary service markets.

This workshop is part of the Commission's effort to explore improvements to market design and operational practices in order to ensure appropriate price formation and energy and ancillary service markets.

We will use our time today to discuss the technical, operational, and market issues surrounding operator actions.

I would like to thank all of our panelists for being here today for what I'm sure will be an informative and lively day of discussion.

We welcome the chairman, Chairman LaFleur and I believe you would like to make some opening remarks.

CHAIRMAN LAFLEUR: Thank you, Emma.

I will just add a couple of words. It was exciting as I said to a couple of you to drive up First Street and see all the taxis arriving.

I thought it was some kind of a Broadway opening, but actually it's the Third Price Formation Workshop!

Obviously everyone in this group knows the operation of the wholesale electric market is critical to ensuring reliability and ensuring that costs are just and reasonable.

The point of this series of workshops, and then whatever actions ensue from them is to really focus on the energy and ancillary service pricing mechanisms to make sure they reflect the true cost of reliable operations.

If the market prices do not reflect the true cost, then they are not sending in either the correct dispatch or the investment signal for which we are relying on the market.

This is a topic about which the subject of the expression, "the Devil is in the Details," could well have been coined.

If you start reading the materials you get pretty specific pretty fast, but I look forward to be in a listening mode and will be here for as much of the day as I can.

I'm most interested in comments from the first two panels and then recommendations, especially from the third panel on any specific recommendations on practices that either the markets or the Commission should undertake to incorporate more on price operator actions into market prices to improve price formation because there is always the problem after you get all the intelligent discourse, then you figure out what is it that we next do, so we would really welcome suggestions on that.

I will turn the mic back over to Emma and the esteemed team that's running the workshop. Thank you.

MS. NICHOLSON: Thank you very much, Chairman LaFleur, we appreciate your being here today and your lending me your seat, but just for today.

Today we have three panels and to allow for plenty of time to get into the exciting technical details about the price formation in operator actions we will skip the formality of opening statements by the panelists and move directly to the question and answer format that we have had in the last two workshops.

All of the materials that were received from the speakers will be posted to the calendar pages of FERC for this workshop and included also under Docket Number 801414 in e-Library.

Staff will be using the contents of its recently released paper on operator actions to help frame certain issues in our discussion today.

The first panel what we have before us now will take place between 9:00 AM and noon, including a 15-minute break at a natural breaking point.

We have representatives from the Regional Transmission Organizations and Independent System Operators who will discuss out-of-market operator initiated commitments in their respective markets.

They will be asked to discuss whether

and how to incorporate otherwise unmodeled constraints such as voltage constraints into the unit commitment and economic dispatch process.

Staff hopes to learn more about the trade-offs that are involved when RTO's and ISOs make these design choices.

We would also like to discuss how the total costs of both operator initiated and market initiated commitments are included in market clearing prices.

The second panel is scheduled to convene after lunch from 1:15 PM to 2:45 PM and it will explore market participants' views on how operator actions affect their operations and revenues and their efforts to supply electricity and ancillary services and how current practices affect the costs to serve load.

The panelists will be asked to provide specific examples based on their experience of whether the RTOs and ISOs attempts to incorporate an otherwise unmodeled constraints into market processes and appropriately balance the desire to reflect such constraints in energy and ancillary service prices against the ability to incorporate the constraints in a realistic manner.

During Panel 2, after lunch, the RTO and some RTO and ISO representatives will be available at the side table to clarify any technical details and answer questions about markets, rules, and practices.

The third and final panel which is scheduled from 3:00 PM to 4:30 PM will focus on practices that RTOs and ISOs have adopted, plan to adopt, or might consider adopting, to better incorporate otherwise unmodeled constraints and operator actions into the unit commitment and economic dispatch processes and market prices.

These panelists will also be asked to discuss other options to better reflect currently unpriced operator actions.

Today we have a lot of ground to cover in a short amount of time, therefore we would like to request of our panelists to keep their comments related to the topic in question at hand, and if the discussion begins to stray too far outside the scope of the questions, then we may have to interject and bring the discussion back to topic.

Finally this workshop is not for the purpose of discussing or hearing argument regarding specific cases before the Commission.

The docket is included in the supplemental notice and subsequent errata notice where provided out of an abundance of caution given the potential for ex parte communications.

I ask of you to kindly please refrain from discussing the specifics of pending cases and that will prevent staff from having to redirect the conversation.

I will now close with a few housekeeping matters. Please do not bring food or drinks other than bottled water into the Commission's meeting.

Please turn off your cell phone if you have not done so already and outside the doors there are bathrooms and water fountains behind the elevator banks on either side of the building.

As we begin the discussion for those panelists who would like to be recognized to speak, please place your name card up and be sure to turn on your microphone and speak directly into it and I will try to do the same.

When you are not speaking, please turn off your microphone to minimize background noise.

This is a plea for everybody here since we are discussing very technical details and as we have six markets with a whole set of family acronyms, and terms for concepts or processes that are very similar, we request to try to do minimize the use of acronyms.

I know that that is not entirely possible, but please do what you can for us. With that, let me thank you and I'm going to ask my colleagues here at the table to introduce themselves.

If we can start with Stan.

MR. WOLF: Stan Wolf with the Policy Office.

MR. SEIREG: Bob Seireg with the Policy Office.

MR. HELLRICH-DAWSON: Bob Hellrich-Dawson from the Policy Office.

MR. SAUER: Williams Sauer, Policy Office.

MR. NATAL: Tom Natal from the Policy Office.

MR. QUINN: Arnie Quinn from the Policy Office.

MS. WIERZDICKI: Mary Wierzdicki from the Policy Office.

MR. KIRSTEIN: Josh Kirstein from the General Counsel's Office.

MR. REICH: David Reich from Rates West.

MR. O'NEIL: Dick O'Neil, Policy Office.

MS. SIGMUND: Erica Sigmund, General Counsel's Office.

MS. NICHOLSON: And I would like to recognize Commissioner Norman Bay who just walked in. Thank you very much for joining us. Would you like to make a comment?

In that case, thank you all again for coming and with that we can introduce our panel today.

We have Peter Brandien from ISO New England. Mark Rothleder from the California ISO. Jeff Bladen from ISO. Aaron Markham from NYISO. Michael Bryson from PJM and Sam Ellis from Southwest Power Pool.

We are on to our first question. We are going to ask some questions on modeling challenges.

We have found that it is readily apparent that RTOs and ISOs face challenges when determining whether units committed to address voltage issues should be directly included in market models that is making the resulting energy and ancillary service prices reflect the underlying voltage constraints.

Staff would like to hear about the trade-offs involved in using mechanisms such as proxy thermal constraints or other similar constraints, for example, closed loop or nomogram.

We would like to hear if these types of constraints can be implemented in market models on a sufficiently consistent and transparent basis so as to give market participants confidence, but the resulting prices and compensation are reasonable.

Let's start with Peter Brandien. Thank you.

MR. BRANDIEN: Good morning. When I think about voltage constraints, at least on the New England system, we do model them in our day ahead in real time.

We have done off-line engineering studies and we have identified the load for the area at which additional voltage support is required, meaning, the static capacitor banks and reactors, and just LTCs on the transformers, are not adequate to support the voltage and you need to bring a resource on.

We do dispatch the resource to maintain the reliability of the area to provide the voltage support.

Unfortunately, the market is designed around a paying for megawatts and we really do not need the megawatts off a machine. We need the voltage regulator to be there to provide the reactive power.

Getting the megawatts sometimes helps a

little bit because you have less transmission losses bringing power into the area but at least in New England where we are bringing on units for voltage support, and I will talk about low-voltage first, it is really just the voltage regulator that we need from machine.

The machine comes on and sits at minimum. The way the pricing algorithms work is if the machine sits at minimum you don't pay for the megawatts. We don't need the megawatts and we dispatch the reactive power of the machine to maintain the area voltage support.

Unfortunately, for the most part, at least in one area of New England, it generally does not get picked up off a minimum, and ends up all uplift, and in the original report that the staff put out it identifies and shows a lot of red in western Massachusetts were we have this issue where there is transmission reinforcements that have already been approved and are in the pipeline to resolve this problem so that we have less transmission losses and we could support the area without requiring the must run.

I'm not too sure what we can do to price the reactive power in this LNP based design we have. I will pass to Matt White who will be on a later panel to explain what we can do in this LNP world to do it, but I don't have a solution for that.

MR. ROTHLEDER: Good morning. California ISO is similar in nature as Peter described.

We do perform off-line studies to determine what the voltage levels are, what the reactive regulation needs to be in certain areas.

But we are also aware that there is potential voltage stability issues and we will try to create flow-based constraints, flow limitations where the amount of flow is related to the voltage stability.

When there are situations like that where we do that, we will enforce it as a thermal or a flow-based constraint.

In situations where we need a certain voltage support in an area and we need a certain set of resources on, we may also use what is called a minimum online commitment constraint and the minimum online commitment constraint is actually in the day ahead market and it identifies a set of resources, not all the resources necessarily that need to be on, but from a group, a certain minimum set of those resources that need to be on to provide the voltage support in case of a contingency.

In addition to that the resources are interconnected generally synchronize machines and they are required to provide a certain amount of voltage support and within the normal range operators will ask them to provide that voltage support by providing voltage schedules to them at certain locations and they will operate within that.

If we have to back them off on their megawatts or their real power beyond their normal range, there's a mechanism to pay for the lost opportunity that they had because we had a back below a certain range and they cannot provide the reactive capability below that range.

In order to get more reactive than their normal interconnection requirements we could provide them with opportunity costs if we have to do that.

That's a fairly rare event, but that at least a real-time mechanism that allows us to get additional reactive support from resources.

There has been discussion around creating voltage reactive prices that are along the lines of LNPs for reactive, but I think we are far away from achieving that, and I think the accuracy of the reactive state of the system and the state of trying to come up with such an optimization is still a ways away to be able to achieve that.

We will be at least in the next few years continuing to use what we can and try again to build more of the constraints into the constraints that we have converting the flow-based constraints when possible and then where possible using other types of constraints.

Something else we will get into probably later. We are looking at expanding our

constraints to do contingency modeling
enhancements which would allow us to be
prepared for the next contingency after one
contingency occurs in readjusting the system
in a manner that will be prepared for the
next contingency.

Largely, that's again readjusting to get
the flow-based controls back in order, but
potential could be used for also
post-contingency reactive support.

MS. NICHOLSON: One follow up
question. When you mentioned flow-based
constraints, is nomograms another word
for the flow-based constraints?

MR. ROTHLEDER: Nomogram is one
form of a flow-based constraint. A
nomogram is really a simultaneous
relationship between two independent
flow constraints and it really describes
what the relationship is in terms of
simultaneous flows on two constraints.

Nomogram is just a more advanced, more
complicated flow-based constraint.

MS. NICHOLSON: Another follow up.
If you would describe a little bit more

about what conditions would make it possible to appropriately model flow-based constraint because we realize from previous discussions that that is not always possible that system conditions will not make that possible.

MR. ROTHLEDER: Where it is possible is where the voltage performance is related to the flow across a major interface.

In other words, the more flow you have across an interface, and if that interface is susceptible through off-line studies, you determine that as susceptible to voltage stability issues or low-voltage conditions during other contingency events, then it lends itself to being able to limit the amount of flow on that interface to protect against some contingency that could then reduce the voltage performance.

I do not think all situations necessarily lend themselves to flow-based constraints. I would say they're probably more in the realm of some kind of contingency that results in a voltage performance issue rather than kind of steady-state or base conditions where you are just trying to manages the precontingency voltages.

MS. NICHOLSON: Jeff Bladen.

MR. BLADEN: Good morning. What you are going to hear is a fairly similar set of circumstances and I will try to add rather than to repeat.

Philosophically what we are trying to accomplish is a market solution that achieves the reliability outcome that we are aiming for.

When you're looking at voltage constraints, what we are attempting to do is to see as many of the solutions to solving for the multiple voltage constraints actually solved in the day ahead market.

One of the approaches that we are using is we have operating guides that guide us towards which resources would be necessary to solve for the voltage constraints and then your operating guides turn into unit commitments in the day ahead market.

Obviously, that does not solve every constraint that you might run across. There will be issues that occur in when closer in.

We have thermal proxies that allow us to identify resources that would be needed to solve for those constraints and then getting those into the day ahead market, getting those resources into the day ahead market allows for co-optimization.

Just layering on top of the challenges to modeling the constraints that you've already heard about, we are working to see that we do what we can to have those resources committed as part of the co-optimization in the day ahead market.

MR. MARKHAM: Good morning. I will just build a little bit on what others have said because it is very similar in the New York ISO.

On the bulk power system we typically don't see the need for specific generators to solve voltage constraints, so it is more on the underlying system.

We do in the day ahead market model local reliability constraints on the 138 KV network in New York City which tries to basically take a look at the expected load

levels in those load pockets and based on
that we will commit a set of the most
economic set of resources to meet those
voltage constraints which really transfer
that voltage constraint into a thermal limit
on that lower voltage system.

MS. NICHOLSON: Before Michael
Bryson, we have a question from our
colleague Dick O'Neil.

MR. O'NEIL: When you say
"co-optimization," you mean just
including the voltage constraints but
not actually optimizing the voltage?

Because my understanding is that nobody
cooptimizes. They simply just have voltage
constraints. Well, I guess everybody.

MR. MARKHAM: I will take the first
shot at that. The way we do it in New
York is that there is a pocket developed
where there are multiple resources
within the pocket that can solve the
constraint and the optimization looks at
what's the most economic unit to bring
on to solve that constraint.

It may have a choice of multiple units

to satisfy that constraint and it will pick the most economic unit.

MR. O'NEIL: Yes, it is to satisfy the constraint, but it doesn't actually get co-optimized with real power.

MR. MARKHAM: Correct.

MR. O'NEIL: Is that generally true?

MR. MARKHAM: Yes.

MR. O'NEIL: Thank you.

MS. NICHOLSON: Thank you. Now, Michael Bryson.

MR. BRYSON: In PJM we have evolved this certainly over the years from recognizing this day ahead reliability studies that we would need units, but we wind up picking those units up after the day ahead market.

What we do now is to get those studies done and push the units into the day ahead market, so we have the ability to at least have the megawatts set price, if we have to run them, although largely they tend not to set price of older, largely they tend not to set price, and if we have units that we need to persistently run for voltage, or reactive, then we try to set up either a closed loop interface or a reactive interface.

For that longer term one, it means we are going to see if we are months or years we will do a reactive interface. We will use closed-loop interface for a combination of issues, one of them being reactive and they tend to be where it is these units.

We know it is these units. They are not set in price and we run them, so let's work on modeling of closed-loop interface.

The problem with that is, and becoming very similar to what so many of the other panelists have said is, in getting the right combination of lines and load modeled into it, so that it doesn't send the wrong signal to the generator because you want the generator to provide the megawatts and the associated VARS when the reactive problem is there, so the modeling is tricky.

The modeling, we cannot really do it on the fly as it usually takes a day or so. You want to get it into the day ahead market and we get a lot of push back from our members even defining these close term.

They would like us to do these years ahead of time but that is very difficult to do.

MS. WIERZDICKI: One follow up question. When you talk about closed-loop interfaces, does that mean the same thing as earlier where people have talked about flow-based constraints or is that just another form of a flow-based constraint or is it something different?

MR. BRYSON: It sounds to me like flow-based. I would consider either interfaces or closed-loop as flow-based.

MS. WIERZDICKI: But when it's an interface, the flow is on a group of lines instead of just online.

MR. BRYSON: Yes.

MS. WIERZDICKI: Thank you.

MR. ELLIS: SPP has a series of studies that happen prior to day ahead. We have a multiday reliability assessment process, and as a result of that our goal is to define flow-based constraints to represent any violative situation so that could be factored into the day ahead clearing.

There are occasions mostly related to transmission outages either planned or unplanned, or like NYISO, develop operating guides and commit resources as a result of those operating guides that go into the day ahead market as well.

There are occasions mostly related to contingencies that occur after the day ahead market closes where we have to commit resources manually for voltage and in those cases there is generally only one or two resources that we can commit to alleviate the situation and those are pretty rare for us, but those are almost always related to contingencies that happen closer to real time.

MS. NICHOLSON: A follow up question for all of you. Sam Ellis just mentioned contingencies up and after the day ahead market.

How much of the voltage constraints you are modeling are from contingencies that you don't know about when you run the day ahead market versus how much are the things that you know one or two days in advance or things that you know happen every season every year that you can predict in advance.

We can start with Sam.

MR. ELLIS: Yes, I have brought some stats. For voltage conditions that happen after day ahead, in terms of megawatt hours of commitment that is really small. It looks like it's less than 1%, just a fraction of 1% of the commitments that happen, so for us it is fairly small.

MR. BRYSON: I do not have stats. I would characterize it as being very similar to that which is we catch most of these now in the outage coordination days ahead of time or studies on the day ahead of time, so most of them are picked up and we can get the units into the day ahead run.

MR. MARKHAM: I, like Mike, don't have stats, but it is pretty infrequent that a constraint is identified in real time that wasn't presented to the day ahead market.

Typically, it is when a facility trips and you're then preparing for the next constraint that would require an out-of-market commitment.

MR. ROTHLEDER: I have a lot of stats, just not the way you asked for.

The answer is similar to what you have heard from PJM and New York.

It is going to be focused on trying to model these in advance, the vast majority of the time so that we can build them into operating guides and then prepare for them in the day ahead. It's much rarer otherwise.

MR. ROTHLEDER: Similarly, the California ISO majority of the voltage type unit commitments is managed in the day ahead, but I do want to take this opportunity to say that there are opportunities where to leverage more advanced network applications, voltage stability applications that actually mercurially run against our real-time state estimator now to see if there are voltage security issues.

There is an opportunity to leverage those and run those against basically a day ahead market solution or a real-time market solution to test for the voltage security of those systems, and if you do that you can potentially move a little bit away from off-line advanced studies that are done before the day ahead markets, and actually, move them into the realm of testing for that security as part of the market.

That is not getting you to a voltage type optimization, but it does enhance potential security testing of the market solution itself and that's probably the next step in terms of testing the market. It is market solution itself for voltage security.

MR. BRANDIEN: New England is very similar to what you have heard. We are actually working on a better voltage reactive tool for the engineers in the control room to see more real time and see whether or not they got the right dispatch, maybe to release units sooner, or maybe have to bring them on sooner, but for the most part our reactive performance of the system is well known and it is well documented and it is infrequent that you have a lot of transmission or generator contingencies so for the most part our commitments are in the day ahead and not real time.

MS. NICHOLSON: We can take a question from our colleague Richard and then Wil.

MR. O'NEIL: When you put these flow-based nomograms cut set, they have a bunch of different names, but as far as I can tell, they are all essentially the same constraints in the model.

If they bind, you are going to force a different commitment on both sides of the constraint.

Do you allocate the costs of the uplift that is caused by that constraint to the area, to the load pocket or the pocket that it is in?

That is to say, if you have to put a unit on that is not economic in the power market and it causes and has a minimum operating level, arguably you are putting that unit on because there's a voltage problem in a specific area, and I was wondering whether or not those uplift costs get put into general uplift accounts or do they get put into regional or local uplift accounts?

MR. ELLIS: In our case, if we have persistent voltage issues that are at a high level of transmission, which we do have some issues, for instance, going in and out of the Texas Panhandle, we model those as coordinated flow gates and the costs associated with those commitments get allocated regionally.

If we have temporary or shorter term duration, then we model those as usually temporary flow gates and we allocate those costs to a local zone which shares those costs. We do not allocate those regionally.

MR. BRYSON: At PJM, I may have misunderstood your question, but if the interface that we defined, if you bind on that it sets the price and that goes into the LNP, so that is obviously the desired effect.

If you are manually dispatching a unit for just reactive, that constraint that is reactive is charged to the load in the area, the entire cost with the exception to that and I have to verify where if it is at 500 KV which it rarely is then it is socialized.

MR. MARKHAM: In New York, it depends on where the constraint develops.

We typically don't have voltage constraints on the higher voltage system which would be the constraints, so it would get allocated statewide where it is the local constraints on the 138 KV network in New York City and those out-of-market costs would be allocated to that local subzone.

MR. BLADEN: From ISO, the answer is largely the same, highly-localized constraints to where you are trying to control for voltage in a very small regional area we are going to allocate those locally.

MR. BRANDIEN: Where the commitment uplift costs are occurring from the market solution itself, in other words, the LNP is not sufficient to compensate the resources, those uplift costs are generally allocated system wide.

However, if we do some exceptional manual dispatch in the local area because of a particular outage or unmodeled constraint in the local area, those costs could be allocated to the participating tranchion owner of that area.

I will try to make it more complicated.

In New England, if we have a high violative constraint on the system, we view that as a local area problem and high voltage is allocated locally because there are actions that they can take, whether that is a switch transmission cable put reactors in to resolve it locally other than bringing on a unit to get to a leading capability of the machine.

If we have a local area, and that is really what I spoke about before where the area is relatively weak and is susceptible to low voltage on either the transmission buses or the distribution buses, we look at that as something that could drag the system down and low voltage is spread across the system as a whole.

In areas that Mark talked about, and I did not go into this where we could identify the performance of an interface as either thermal stability or voltage and it is the reactive limitations to move power across that interface and the State of Connecticut was like this until we reinforced the transmission system that the reactive transfer capability was limiting the movement of power to that area that is allocated to that area locally.

We have two situations where we locally allocated and one that we allocated system wide.

MR. SAUER: Thank you. Pete had talked earlier today about certainly, as all of you have mentioned from what I have heard, being somewhat of a success story about committing units for reactive into the day ahead and a model into most of the day ahead.

How do those units come in for reactive

support are actually setting prices, part of the LNP price formation. I would like to know how much is outside the market and how much is inside the price prior to market.

MR. BRANDIEN: Once again, this will be kind of a long answer in that those areas where we have had high voltage constraint it tends to be at night and those areas tend to go to uplift and we have been able to resolve most of those by putting reactors in on the system.

Most of that uplift is behind us.

The interfaces that we are able to translate because it was a reactive limitation for the most part those were in the market and they were reflected at LNP.

For the low voltage that we have been dealing with particularly in western Massachusetts they tend to go to uplift.

MR. MARKHAM: It tends to be some areas with a limited set of resources that are getting committed. I know that your report talks about kind of staying at minimum load or at economic minimum for a large portion of time.

There are a few sets of resources that are in that kind of mode. We are still part of the optimization, but being part of the optimization once committed if they are economic to be dispatched above minimum load they are dispatched and we see oftentimes those resources for some hours being dispatched above minimum load.

But if your question is the kind of the ones that are really being committed and never get above that minimum load it depends on the time period. It depends on the season. But it could be a couple of units, less than five usually that are in that position. It also depends on the outages that are occurring at the time.

MR. BLADEN: You are going to hear a lot of the same answer. MISO is going to be in a similar situation to California, that by and large these resources will be temporal depending on the season and depends on the unique situation in the network that day.

If you are in a highly localized area

where you might have to operate in little more conservative conditions because of the limited number of options you have for redispatch that may impact on things as well, but generally, it will be temporal in nature and will depend on the other external conditions.

MR. MARKHAM: I would second or third that depending on where we are on the panel with all the units that are committed as part of the local reliability rules for voltage are able to set price if they come up off minimum majority of the time.

In higher load seasons they are economic and in the off-peak hours, and off-season hours, they may not be economic, so that's when they would actually roll up the uplift.

MR. BRYSON: In PJM, obviously, if they are part of the reactive interface that's what helps us to get them to set the price.

Absent the reactive interface they may or may not set price depending on what they have displaced in the day ahead market, so running in real time they may set price but it is not necessarily without the finding either pg some kind of an interface for it.

MR. ELLIS: Yes, very similar to the others. I do not have a feel for how often those will set price versus just being used as part of the natural commitment for economics and other reasons, so I don't know.

MR. NATAL: A quick follow up that Mark made about the accuracy of the system presenting challenges for modeling reactive power and some potential future modeling procedure.

Can you characterize that a little bit? Are you talking about knowledge of the impedance of the lines or the topology?

What do you mean?

MR. ROTHLEDER: I will clarify that. In the day ahead, it is very difficult to know what your static reactive devices are going to be switched at in the realtime.

We have a good model of the impedance of the system. We are able to model the reactive capability of the resources, but to know what the system conditions are in terms of transfers, voltages at certain buses in realtime, what reactive devices are going to be switching, what the distribution system power factor is going to be.

There are a lot of factors that factor into voltage that make the reactive problem much more complicated than the act of power megawatt problem, and trying to predict those conditions in the day ahead is somewhat difficult even monitoring for those conditions in realtime and having a state estimator that presents those in an accurate way, accurate voltages and what the devices are even in realtime are occurring, that is a challenge in the reactive space.

MS. NICHOLSON: Thank you very much.

We have another question, and I believe we have a sense that it actually can be quite difficult to model the liability and voltage constraints in what would be reasonable in an understandable transparent way which is not always possible.

We are wondering if you could tell us if there are some other factors aside from difficulty in modeling that would make a system less inclined to include reliability constraints within the market models?

For example, are there considerations such as how, including constraints, would affect financial transmission rights funding or other considerations that a stakeholder should be aware of that might introduce some other trade-offs into modeling some of these constraints?

If anyone has any thoughts on that, I would appreciate it, and if you don't, you certainly don't have to respond.

MR. BRYSON: One action we take at PJM when we come across the reliability of a voltage system.

An example of that is we take a look at what are the implications of defining an interface both in terms of congestion revenue, FTR adequacy, those kind of issues so we may implement one to help FTR revenue even though it may have a price setting implication so that we will kind of balance those things and I think we have probably made the decision to go either way to try to improve either FTR revenue adequacy the amount of congestion or setting price in the area.

MS. NICHOLSON: Thank you. Peter, you may have a comment?

MR. BRANDIEN: Yes, and if I may take a parting shot at voltage and then I will go into the other one.

From New England's perspective I know we spent a lot of time here on voltage and modeling and whether or not it is uplift. It is a small issue in New England.

If we spent a lot of time trying to resolve it, we probably have not really resolved some of the issues that you will hear about from the second panel, and the units trying to respond to the needs of the system and if they had better information they could solve those needs.

At least from the New England perspective we do not need to dwell on the voltage aspect of it.

Something that we did not find so much

challenging in New England is the way the day ahead clears in New England where there is a relatively small balance in authority and we have very large resources that we have to cover for operating reserve.

We have got the DC tied with Quebec to Phase II, the 2000 megawatt tie, but generally it operates between 1400 and 1600 megawatts, and sometimes 1700, and then we have got two large nuclear units in the day ahead clears, and it looks at what clears and what is left on the machines and sees whether or not there's enough room on those machines to provide operating reserve and tells if this is a good case.

Then when it gets handed off to us in operations where the reserves are, can we actually utilize them, is a big deal.

We found that we had supplemental commitments because the reserves that we were left with in the day ahead, we could not actually use large resources in the east.

With large or fast start resources in the west part of New England, you lose the east, you bring everything up in the west and there may be some limitations to utilize that and what we have done is we have looked at, and some of that material lies with the changing economics of the system.

Gas prices going down, coal coming off, coal units used to be in the east, they are not there anymore. So the changing economics of the system uncovers constraints on the system that historically were not a problem and we have to react to them.

We reacted to that when we saw it was sustained and we now look at minimum generation requirements in the east to make sure that we have enough operating reserves spread across the system.

So instead of us committing additional resources in suppressing price, we ended up with a surplus in the realtime operation of the system. We get that committed in the day ahead so at least it is optimized and we can better utilize the reserves coming out of the day ahead, but that is something we saw just doing the changing economics of the system.

MR. ROTHLEDER: Your question is a very good question in terms that there is some interplay.

When you try to build more of the reliability constraints into the market you have to think about what is the implication about things like the congestion revenue rights for two reasons, and one is, while at least in the ISO, we run an AC power flow in the day ahead market.

We do not run an AC power flow and the CRR, it is too far ahead, you don't have as much information about what's going on in either the DC power flows.

Trying to even get voltage constraints even in that time frame is even more difficult than what you try to do in the day ahead.

If you try to convert it to a flow-based constraint, and you have some knowledge about that flow based constraint being enforced for a good portion of time you can incorporate the flow-based constraint into the CRR model.

That is the voltage piece of it.

We are grappling with this question as we kind of design our contingency modeling enhancements which is preparing for post-contingency where you need to operate post-contingency and how do you have enough of a 30-minute reserve if you want to return the system to a secure state after the contingency event?

You have created an interplay between reserves and energy where typically the congestion revenue rights model does not usually try to address, so how do you resolve that interplay between a reserve product and a flow-based constraint? That is something that we are at least considering as part of our contingency modeling enhancements because it does take you to that next step.

MS. NICHOLSON: Does anyone else have any comments?

MR. MARKHAM: One of the things that's very difficult to model especially on the lower voltage system would be the actions of transmission owners could take to alleviate thermal constraints where potentially they can switch load from one bus to another.

They can reconfigure the network so that they reduce through flows and sectionalize open breakers.

One of the things that needs to be reckoned with prior to modeling the constraint in the market are all of those actions. Can you effectively model those actions so you get the right market signal and the right market outcome to both day ahead and enter realtime.

MS. NICHOLSON: Michael, did you have anything to add?

MR. BRYSON: I think I started, yes. One of the things that Mark touched on too is we have this balance of transparency where we have the ability to define a reactive interface that our members say, "We want to make sure we post that ahead of time and the monthly FTR auction would be good which is a 15th of the month, maybe the balance of the period will be good, maybe the annual.

A lot of these things are cropping up very close to realtime either based on outage scheduling or potentially based on lines tripping.

Getting them into the day ahead market is important, but that trade-off comes in the transparency to some of our other markets.

MR. ELLIS: In SPP's situation, those are fairly rare. I can only think of two long term duration interfaces in the history of our market that have been associated with transient stability or reactive issues and as we bring on more transmission facilities in that area we haven't really seen much of an issue with that lately so it is not a big issue with SPP.

MS. NICHOLSON: Thank you very much for your information on that. We wrote in the staff paper and they have heard some comments to date that one practice that the RTOs have adopted is to include reliability, related commitments in the day ahead schedule.

First, pretty much concluding them as a constraint and then to some extent they would then be once committed eligible to set the price if they are economic.

We would like to hear a little bit more

from each market about the rationale for including the use reliability related commitments within the day ahead schedule, other than in the RUC which they could have traditionally included in the RUC.

In answering that, what is the decision to include it in the day ahead schedule and yet not have it directly affect prices as we are not defining or setting a price for it.

I realize that we have already touched a lot on the modeling. If you could give us a little bit more about the rationale for including certain liability constraints in the day ahead model.

Is there a threshold that is sufficiently and persistently committed?

What is the kind of decision making process and actually formalizing the inclusion of those commitments in that day ahead schedule?

To be fair we will start with Jeff Bladen and go across so poor Peter does not have to keep answering the first question.

MR. BLADEN: Sure. As I noted at the outset the fundamental philosophical question that we are trying to grapple with is how to have market signals be the primary means for achieving the reliability outcome that we are looking for.

Where you have persistent recurring constraints for reliability reasons that you have to solve for and you have to try to deal with you want to get that into your markets and that would hold true for both the day ahead and realtime and we also have a core philosophical view that you ought to have the same constraints modeled in the day ahead and realtime and that you are not creating a discontinuity between the two markets.

That is the base fundamental starting point that we have.

When you are dealing with constraints that you are seeing on a recurring basis, again, on a regular recurring basis, that's the threshold, and the operating guides that we develop that are based on advanced modeling are how we determine when things are and what the solutions are to the particular constraints that we are looking at and whether the constraints recur in a way that can be resolved.

MR. MARKHAM: From an ISO perspective our intent is to model as much as we can in the day ahead market, number one, it is the best opportunity to provide together the greatest number of resources to solve the constraint.

Our day ahead market starts at 5:00 AM and typically posted by 9:30 that allows resources to go out and procure the fuel they need.

It also gives them a relatively long start up period so later in the day when you would make a decision you may exclude some units based on their start up parameters.

To the extent that we can get it in the day ahead market, and provide that signal as early as we can, it provides the most economics of the units to get that fuel and to actually run.

What else it does is, because you are not making supplemental commitments after the day ahead, it may reduce the overall uplift because you are factoring in those units running at min-run or min-load when you are making the other commitment decisions for the other units.

MR. BRYSON: Very similar to what Jeff Bladen and Aaron said is that the contingencies themselves are as close as possible.

We try to model day ahead in real time, the unit commitment, so one of the things that we've learned over time and we have actually done an assessment to put the units in the day ahead market, or wait until the day ahead market clears and to put them into the RAC run.

The trade-off tends to be if you put them in, if you wait to the RUC run, what you will see is the realtime operating reserves or higher.

If you put them in the day ahead operating reserves, or higher, there are a lot of benefits and the trade-offs tend to kind equal out.

The dollars are the same, just in different buckets, but some of the points that Aaron made become true is if you get those commitments done earlier, if you recognize some of those commitments you may have a better chance of setting price and you get an opportunity for fuel commitments and things like that too.

We have taken a look at the balance.

Again, contingencies are pretty consistent, but unit commitment we have tried it both ways.

MS. NICHOLSON: Thank you.

MR. ELLIS: Something we look at prior to day ahead are resources that help lead times of 36 hours or longer where if we were to call them in a day ahead they would not be available.

In those situations where we think those may be required, that is really what we are focused on, and when we are looking at commitments going into day ahead, and then also if there are anticipated fuel supplies used because of winter weather or other constraints on the fuel supply side.

We also might look at commitments in the day ahead, but those are fairly rare so most of the time we do model the constraints and day ahead let the market in either day ahead or RUC take care of those commitments.

Our day ahead has a financial component as well so hopefully that answers your question.

MS. NICHOLSON: Thank you. Peter?

MR. BRANDIEN: It is easier going after everybody else has gone. I agree with what most everybody else has said.

As far as the decision-making process, we will see something coming through the audit coordination process that we would have to make sure is modeled correctly in the day ahead because we know it is going to be impactive to the market.

Then there are those outages that tend to be recurring and we want to make sure that those are captured in the day ahead for a lot of reasons that Aaron talked about trying to get that commitment earlier in the day so that the resource could procure the fuel, the greater number of resources are at your disposal to bring on.

We tried to get as much as possible in

the day ahead and as it was just said we want the same constraints modeled in the day ahead that we are doing realtime.

MR. BRANDIEN: Yes, we are motivated by wanting to converge conditions between the day ahead and the realtime, so getting them those resources on the day ahead for something that would be a constraint or an operational issue in realtime is important.

We are also motivated by minimizing the amount of uplift, so if you do something completely outside the market rather than them having it inside the day ahead market, you actually increase the uplifts because you don't have the market revenues and you do not have the goals of the market revenues to accrue to those resources if they are actually able to be dispatched and earn market revenues from the day ahead market.

The third motivation is really the motivation to give the opportunity to those resources that would have not otherwise been committed in the day ahead market and provide those resources an opportunity to participate in the day ahead market and earn those market revenues.

For example, again, our minimum online commitment constraint before we had that constraint we would do supplemental, post-day ahead market commitments and those resources would then have the opportunity even to participate in the day ahead market.

Now with the minimum online commitment constraint, they are competitively getting committed and getting online, and if they are marginal, they are able to set the marginal price when they are dispatched above minimum load, and if they are not, they are at least earning the day ahead market revenues and it reduces the amount of differences between the day ahead and the realtime.

We view the minimum online commitment constraint as a progression of trying to get things into the market as much as possible rather than doing things manually outside the market.

There may be opportunities to take it further, but this is an evolution in terms of progression.

MS. NICHOLSON: Thank you very much. Are there any other further comments from the panelists?

MR. O'NEIL: Mark, you mentioned earlier of a trade-off between the CRR market and the day ahead market or realtime market.

In Susan Pope's paper, one of her recommendations is to focus on the realtime market and in essence make the primary focus getting the realtime market right and then work backwards.

If you get the realtime market right, the people who are participating in the FTR, or the CRR market, we are going to try to anticipate what is going to happen in realtime market.

In some sense the realtime market is key to getting all of those other markets right, so I guess I would like to hear people's opinions on what Susan Pope has said, that that is the focus on getting the realtime market right and then work your way backwards, not to be disinterested about the other markets, but to get the realtime market right and work backwards.

MR. ROTHLEDER: Since you mentioned my name, I guess I will answer. Yes, the motivation to get the realtime market right, that is correct, but there are limitations about achieving that.

If every resource could be committed, and started in realtime, you have a much better chance to be able to say, yes, let's focus on the realtime market.

But the fact is, is that you do have physical constraints on resources and you have lead times to get the resources online, and as a result of that you kind of have to focus both on realtime and the day ahead market to achieve a secure unit commitment plan going into the realtime.

MR. O'NEIL: Let me clarify. What you want to do is in the day ahead market you want to get your realtime market commitment correct in the day ahead market, so in essence, it's still focusing on how to get the day ahead because without the day ahead market you probably cannot get the realtime market commitment, right.

MR. ROTHLEDER: If that is the case, then yes, I agree with that. Once you get that market correct, then you can ask the question, "What are the implications for CRRs. Is there some implication about revenue inadequacy that you have to consider? "Is there some new constraint that you have to enforce in the CRR?"

That is a second thought after you get the primary operation of market correct.

MS. NICHOLSON: Michael?

MR. BRYSON: I would agree that getting the realtime market corrective is a priority. The way we approach it now is a consistency between the two may be the priority, but getting the day ahead market is the priority philosophically is the right way.

MR. MARKHAM: Yes, I would agree with that. In New York, we have a daily review process that goes through and looks at the end uplift, it looks at operator actions, it tries to identify differences between realtime and day ahead.

Then from identifying those key drivers we take actions to either true up the day ahead or true up realtime so that those two are in alignment is as best as possible.

I mean you're not always going to capture a forced transmission outage or a generator outage, it is something that is outside your control, but to the extent that things are within your control in making sure that the modeling assumptions and the constraints that are observed real-time actually get reflected appropriately back to the day ahead market is a key primary focus.

Then from there once you get those two right then the subsequent markets should fall out from there.

MR. BLADEN: In the vein of trying to add rather than to repeat, fundamentally you want all of your work to be right.

Of course, it starts with how you are serving load in real-time but to Mark's point we don't have unlimited flexibility so we have to work within the constraints that we have, physical and temporal.

What I would add though is that one of the things that you are looking to do is to identify recurring instances where you needed to take some liability action that was in response to realtime conditions that might be unpredictable in realtime, but predictably unpredictable in the sense that you know that these sorts of things are going to be happening on a recurring basis but you just don't know exactly when.

The example I would give you is intermittent resources. We know that the wind will start and stop blowing at different times and we can predict that it will occur to some degree, but where you can identify market solutions to help manage those kinds of less predictable instances to try to help mitigate the number of auto market actions you want to do that and we have a track record where we have tried to do that.

For instance, the DIR product that was implemented a couple years ago is an example of what we were trying to deal with was a recurring set of reliability interventions that was converted into a market product to try and deal with that to try to get the markets to actually solve the issues that we were seeing.

MS. NICHOLSON: For DIR you mean dispatchable intermittent resource.

MR. BLADEN: That's right, sorry.

MS. NICHOLSON: We try to define acronyms where we can. Are there anymore comments or can we move to the next question?

Something else we noted in the paper is that some markets have defined a specialized product, say it is a reserve product, to address certain types of operator actions that are traditionally handled out-of-market.

For example, a supplemental reserve product to manage uncertainty, be it load uncertainty or generation / fuel supply uncertainty.

Also a ramping product or a ramping constraint to address, for the system to provide ramp capability.

In your market what factors dictate when such supplemental commitments could be better addressed through a reserve product or a binding constraint and who do you think basically makes that decision? I would like first hear from Aaron Markham.

MR. MARKHAM: I will start by saying if the operator actions are taken to solve predictable reliability constraints, then it is appropriate to try to determine if you can model them day ahead.

For instance, in New York we have in eastern New York reserve product which is there to repair the transmission system, the ROL interface from a single contingency.

To the extent that we can predict that we need that everyday we put that in the market solutions. We are working through our stakeholder process to add additional locational reserve requirements as well as some additional statewide requirements to, first, meet the local reliability rules that the state imposes on us as well as an MPCC as well as to provide so market certainty between the markets.

The things that are difficult to model are the unforeseen circumstances, the multiple contingency events that are beyond design criteria, the three or four largest contingency losses, those types of things.

At this point we have not developed a good way to represent that in the market. It may not even be appropriate to represent those in the market. But for the things that are undefinable and we can forecast it that is an appropriate thing to model in the market constraints.

MS. NICHOLSON: Thank you. Could we hear from Michael?

MR. BRYSON: PJM just finished a stakeholder process, energy reserve pricing, and interchange volatility. The energy reserve pricing portion recognize kind of a couple situations. One is the need to sometimes schedule long lead time units prior to the day ahead markets or really anything you wish, you have to make some kind of a commitment to, prior to the day ahead market.

The second one are those days when we may need additional reserves over and above that commitment and in both of those cases the idea now is that we both push those units into the day ahead market very similar to what we talked about with the reactive.

We also will increase the day ahead scheduling reserve to reflect the actual load forecast and the impact of these long lead time units and the effect of that in realtime is we will increase our synchronized reserves and fundamentally double our synchronized reserves so that that gives us pricing incentive in realtime to maintain those additional reserves based on the decisions we made in day ahead or prior to day ahead to schedule additional resources.

MS. NICHOLSON: Sam?

MR. ELLIS: That is a topic that our stakeholders have been fairly engaged in since the design of our market, it was not something that we have had to tackle yet.

We do have a product that they do not

want us to put in our day ahead market for ensuring rampable capacity.

It does not seem like that our process for doing that is working as well as it needs to. We are interested in our creating new market-based products for rampable capacity and other things that we can put in our equation optimized.

We are looking forward to working with them to design something that meets our needs, but right now for some reason they direct us not to put any consideration for those kinds of things in our day ahead market, although we can do that in RUC for liability.

We are concerned, as staff, that that creates a lack of convergence between day ahead and realtime that works, so we are gathering evidence to see if there are things that we can do better and we are in the process of evaluating that right now.

MS. NICHOLSON: Peter.

MR. BRANDIEN: The operators do not have perfect knowledge of what is going to happen. People that tend to look at what, they do have the perfect knowledge and can look back at what they do.

We are trying to balance a lot of things, we are trying to balance the uncertainty, the load forecast in New England, the fuel issue.

Everybody looks at the integrated values hour by hour integrated in the winter time. There is the difference between the instantaneous and the integrated value on a winter peak where it will be a very sharp coming up and down.

It could be 200 to 300 megawatts in a small area like New England. We have always had in our operating procedures the ability to add additional replacement reserves. It was right in our procedures, but it was not priced, so what we did recently was we p priced the replacement reserves.

When the operators look at all the various conditions and determine that they need to do a supplemental commitment to handle these uncertainties we enter that value and when we start binding on that replacement reserve we get it priced.

What we have done is in recognizing that operators have to do things due to these various uncertainties, to have them identify the level at which they are committing additional resources, and rather than having it at a depressed price, or to present a system from binding because they made these supplemental commitments, we have tried to price those into the market and we have done that through placement reserve product.

MR. ROTHLEDER: We consider the need for new products to be responsive.

Two, one's stakeholder feedback, to operational input, what the operators are saying, what issues they are having.

And third, in response to reviewing kind of key market metrics so things like uplifts, price volatility, those types of things, we try to respond to those if we saw something increasing that needed to a potential new product in that regard we have introduced new things like flexible ramping constraint.

We are developing flexible ramping product which would also be both the upward and downward both in the day ahead and realtime market and we are also pursuing development of the contingency modeling enhancements which is basically the post-contingencies responsiveness reserve.

These are complicated. When start to develop them they sound real simple in terms of their intent, but when you start unraveling them and you are trying to deal with all the interplays, they do become complicated and that is why it takes a lot of time to develop these new products.

MS. NICHOLSON: Jeff Bladen, could you in your answer talk a little bit about MISO's new product?

MR. BLADEN: Absolutely. As I noted earlier, we have a history of doing really the three things that Mark just said, responding to stakeholders, looking at operator actions and needs, and then also looking at tracking metrics over time to identify where either new market products or new market approaches might be appropriate to better handle meeting the reliability outcomes that we are aiming for, and that is the key for us is: Is there a market solution to achieve the reliability outcome that we are aiming for?

The examples in the past as I mentioned earlier is the dispatchable intermittent resource. The recently approved ramping product that we are going to be moving forward with in 2015 which I will describe in a little bit more detail.

We are also committed to moving towards not a reserve product per se, but another kind of product or market change that is intended to deal with some of these issues in the form of the LNP which is designed to try and send a better realtime price signal to reflect things like fast start costs so you can get those into the price signal as opposed to into a separate reserve product that might ultimately be required if you are going to dispatch so keep those available.

The ramping product is intended to deal with a number of issues. Historically, we have been operating in a manner not too dissimilar from what Peter just described where the operators, when they needed to maintain some margin for the expected uncertainty, were having additional head room and floor room as part of the operating plan for the day and the ramping product is intended to reflect that in an optimization so that the resources that we may need for transient ramping conditions are available and priced accordingly.

One of the interesting dynamics is the interplay and this was all described in the filings that came through here on this product is the interplay between the scarcity pricing mechanism and what might be a very small increment of time where those scarcity conditions might occur, but the reality is that the emergency that we had available capacity and then we end up triggering scarcity for a five-minute interval, it wasn't necessarily appropriate, and the ramping product is going to help deal with that by having the rampable capacity available to avoid triggering that kind of scarcity.

MR. O'NEIL: For clarification.

You said it wasn't necessarily appropriate. When is a price hike appropriate and when is it not appropriate?

MR. BLADEN: Maybe that was a poor choice of words. The algorithm indicated we were short resources and for a five-minute interval to be short resources, when in fact it is just a matter of repositioning resources from one five-minute interval to another, it sends a signal that we are scarce when in fact we really are not.

It is an outcome of computer algorithms that are designed to handle different things.

MS. NICHOLSON: Thank you very much for that. There's one follow-up question, and do correct me if I am wrong. It's a lot easier to address predictably predictable events as that might just be my new catch phrase of predictably predictable.

It's a lot more difficult to incorporate say N-1-1 contingencies or preparing to put in the system to be resilient according to the mandatory reliability standards.

First, could we have some comment to say if that is true in general, and also, if you could talk about your experience in your system in how you currently incorporate a N-1-1 criteria in your system to the extent that you already haven't already talked about it and if you see any way to better reflect incorporating those criteria in market prices.

MR. BRYSON: Assuming I understand the question, which I think I do, there are two primary ways that we kind of look at.

One is we have situations where we do planning studies and do build years ahead of time and identify reliability criteria, and as we move closer to realtime, if the reliability fix that we put in place in our plan has not been made and there is the potential for that to be an issue as that operating horizon in the planning horizon cross we may add in an N-1-1 contingency to our realtime and we will look for set in prices.

We actually had that happen in the past though we never set a price for it, but we've modeled the contingencies and we monitored the contingencies.

The other way we have really looked at that is we have contingencies that will come up that may be a concern.

A really good example is we still to this day monitor and operate the Cleveland Interface because of the historical concerns in that area dating from the blackout where we actually have a N-1-1 criteria for scheduling units in that area.

But in all the other situations where we schedule and operate units for an N-1-1 tend to be because there is a discussion between us and the transmission owner for kind of an increased reliability concern or local area concern so we will actually schedule units based on an N-1-1 contingency and generally we will charge the TO for that expense.

MS. NICHOLSON: We can go down the line, but certainly, if you do not have any comments you do not have to make any.

MR. ELLIS: It depends on what the consequences of experiencing N-1-1 contingency are.

In the vast majority of cases we might have something that exceeds its system operating limit for a period of time and we have got plenty ability to manage that.

That is not very much a concern. There have been occasions the consequences of something like that could be pretty severe.

Earlier I referred to when we used to have some pretty active constraints going into and out of New Mexico and the Texas Panhandle area. Those probably would be the type of constraints that are more of an N-1-1 concern where we were worried about the transient stability of a fairly large area of our footprint.

Those cases are fairly rare where we will look at that most of the time when we have an N-1-1 event.

Other existing flow gates that we already have modeled and activated can catch that. It might be just a question of adjusting the system operating limit for those flow gates to reflect contingency.

We do have the ability if there are contingencies that happen that we do not anticipate to model new flow gates fairly quickly in SPP.

We have done that a few times, but the need for that has been fairly rare.

MR. BRANDIEN: I will try to be clear in my exploration, but we find N-1-1 very easy to define, but challenging at times.

We tried to go in say that we don't want to be shedding load within 30 minutes of a first contingency.

Post second contingency we will lean on load shedding, but we want enough resources to be able to redispatch the system within 30 minutes following the first contingency.

We may have areas where we cannot take full advantage of say the second contingency limits because let's say we have to redispatch 1,000 megawatts in an area and we only have about 800 megawatts of 30-minute reserves in the area.

Therefore we have a 200 megawatt gap and therefore we have to bring on additional resources into the area that would be charged for those additional costs.

Hopefully, the proxy limit that we are operating this system to, being 200 megawatt short of the full second contingency limit binds in where we actually see a price.

The market saw that we were having this issue in a number of areas trying to operate to this N-1-1 criteria, and because it was a longer-term issue, we wanted to make sure that there was a price signal out there and we implemented our locational foreign reserve markets which identified the amount of 30-minute reserves we needed in an area and we procured that in a forward market so that the market can respond to that signal.

We don't feel it's difficult to operate to N-1-1 criteria. It is very easy to define. It is very easy to look at the reserves in an area and translate that to a market at least in New England.

We have tried to procure the shortfall through the locational foreign reserve market.

MR. ROTHLEDER: I think your question was about the relative complexity when you try to introduce or address things like N-1-1 contingency.

In my mind, if you're just doing base flows, really you're doing it by managing the energy dispatch.

Maybe you have to do some commitment, but it is relatively straightforward pricing. That is relatively straightforward.

Even with an N-1, where you are just trying to survive the contingency, you can go up to the emergency limit of the thermal constraint of the lines.

There, again, it is positioning resources from an energy perspective. Maybe you have to do some additional commitment, but it all kind of falls out naturally from the solution.

When you start getting into protecting against first contingency and then being prepared for the second contingency event, now you have created this interplay between not only energy dispatch and precontingency flow management, but you have now created this interplay with reserves and now you have got basically reserves and you can manage that constraint by doing one of two things.

One is you can reduce your precontingency flows or you can get more responsive capability on the downstream side of the constraint to be responsive within 30 minutes to get back into a secure state.

That complexity of the interplay between now precontingency flow management and reserves, at least from ISO's perspective, is a bit of a next step and we are trying to take that next step of addressing that interplay again through the contingency modeling, enhancement modeling, and there you would get explicit prices both in terms of energy that could be affected by that constraint, but also reserve prices for that 30-minute responsiveness capability.

MR. BLADEN: I am not sure that there is a lot to add. The conditions that lead you to need to operate in the N-1-1, tend to be very localized conditions that limit your options to resolve the challenges that are created.

If you have to deal with those contingencies, and the details of specific locations, and what the specific resources are that you have available, tends to be somewhat unique, but I don't know that I need add, as we have covered a lot of ground already on this.

MR. MARKHAM: In New York there is an area of the system that we do operate N-1-1 based on some local reliability rules, so the New York City load pockets of the day ahead market does ensure they are sufficient for generation capacity available in those load pockets to be able to meet the N-1-1 criteria.

As I alluded to, we are working through our stakeholder process to bring in some additional reserve products in certain areas of the state and in particular southeast New York to be able to manage N-1-1 contingencies.

There are some very visible public N-1-1 contingencies that we do secure to under storm watch conditions which is also a local reliability rule as a result of the Blackout in New York City in 1977.

When thunderstorms are within an hour of the New York City area, we do secure as if the first contingency has already occurred, we do that through our market systems.

We do coordinate on some flow gates with PJM during those times. In that instance there are a lot of resources both within southeast New York and in other areas that can assist meeting those requirements.

To the extent that those conditions are met, we do introduce that into the pricing algorithm and take market actions to secure those.

MS. NICHOLSON: Thank you very much. At this time, I would like to ask if Chairman LaFleur or Commissioner Bay have any questions before we break?

CHAIRMAN LAFLEUR: At this time, I do not as I have followed the conversation as best I can.

I am very interested in the different approaches that are taken in the different ISOs because I am mindful that what they do on this topic relates to certain ties to all the other differences in the tariff, but I have nothing to add.

MS. NICHOLSON: Thank you very much. We will now have a break and we can reconvene at 10:35, please. Thank you panelists and we look forward to Part 2 of this panel.

(On resuming after a 15 minute recess.)

MS. NICHOLSON: Thank you for coming back. The next line of questions we will ask about is day ahead and realtime price convergence.

A common complaint that one reads and hears from market participants is that sometimes realtime outcomes can be unexpected or counterintuitive.

For example, if extreme weather is expected on an upcoming day market, participants would expect to see high prices in realtime if those expectations are realized.

However, in some cases the realtime prices may in fact be lower than the day ahead prices and the corresponding hour due to supplemental commitments by operators.

Can you tell us a little bit more about what types of commitments or other types specific operator actions can cause such price differences or misalignments between the day ahead and realtime outcomes and these circumstances is focusing on extreme weather events.

We will start with Sam Ellis from SPP.

MR. ELLIS: With SPP, we have a high percentage of our generation fleet as wind, so we have about 8 gigawatts of wind we are dealing with right now.

Particularly with extreme weather there are all kinds of things. This is one of our biggest challenges in terms of for our day ahead market, it is whatever the wind resources choose to offer for day ahead versus what happens in realtime.

But even then we find that we had to do a lot of commitments based on changes in the forecasts for wind.

Other things that we struggle with in that vein are load forecasts, so obviously if weather doesn't materialize as we expect the loads can be substantially different, we have to make commitments to cover changes in load. We are in some situations due to weather loss of load.

The other big situation that we struggle with at SPP, which is maybe somewhat unique is we have very permissive rules for realtime interchange scheduling transactions and because of that so far, at least keep in mind we are not even a year into our market, we are having a very difficult time predicting when those are going to occur.

Of course, some of that is dependent on financial situations and price differences between our markets, so we do a lot of commitments for those and that is really our top three that we are worried about right now.

That would be just a recap. Load forecast changes due to things that we do not predict wind generation changes and scheduled interchange transactions.

MR. BRANDIEN: I struggle with the extreme weather, but allow me to talk about a few things.

Dr. Pope's paper was brought up earlier, and in that paper it said ISO in New England in 2013 made supplemental commitments every day.

I am not sure where she got that information, but I suspect that a lot of it is the information she got maybe were self-schedules. So units that self-schedule in the reoffer period is one thing that we see.

With New England during cold weather, and even in extreme cold, weather gas prices could spike, and as a result of that prices start to rise and we see our ties respond to that and we will see in realtime the ties be higher than day ahead even, so between self-schedules and the ties being greater, those things that could counter that.

From an operator perspective we have to look to at information that we get from the gas system because we are in a very constrained fuel delivery area and we have to understand whether or not units have the potential to be curtailed, can we maintain reliability if they get curtailed?

If we lose imports from Quebec that is not gas. If we lose nuclear units, that is not gas, and we have to in turn start burning more gas, can we actually allocate or activate our reserves?

So are there things that the operators have to take into account and do some supplemental commitments.

We are in a better situation today because of our placement reserve product, so if we have to do those supplements to commit, we would at least be able to reflect that in the pricing and to try not to have too much of a deviation between day ahead and realtime but understand just a natural load shape in the winter time and the lumpiness of generators and their min-runtimes and their eco-mins.

We have a morning peak and then it is a slow decline through the day until you get to the evening peak which tends to be much higher than the morning peak. There could be a lot of hours during the day when we have a lot of reserves on the system that can depress the realtime price relative to the day ahead price.

Then hopefully we can get some convergence if we have made all the right decisions as the load picks up and the market responds to those signals.

There are a lot of variables at least in New England between tie self-schedules, the operators adding some replacement reserve to the system.

MR. ROTHLEDER: A similar theme here. What drives differences in prices in the real-time are largely demand and supply forecasts differences certainly with variable resources now.

The additional level of variability in uncertainty around supply has increased and that has transpired into increased potential for differences between day ahead and realtime.

When we set up our interchanges we had to do so at least from the market perspective about an hour before the operating hour and even that hour of uncertainty between what the conditions will be an hour later going into the operating hour can lead to situations where the operators are going to have to make some decisions about what the expected load is and make some adjustments, and in doing so, they could potentially where we have seen this at times where they potentially over procure ties or under procure ties, and the differences then result in differences in realtime prices and we try to minimize that, but that's because the interchanges are being set up an hour before and that is the potential.

Now with 15-minutes scheduling, and the opportunity to do things intra-hour more that potential is reducing, so that is a good movement.

In terms of reducing the supplemental commitment we have taken a lot of actions to try to reduce a supplemental post-day ahead optimized solutions.

The residual unit process itself is intended to take care of those differences between the amount of load cleared and our demand forecast.

We have to account for things there that are differences between the day ahead bid load, the amount of load differences, but also what are we doing with the convergence bids, virtual bids, what are we doing with the variable resources they are scheduling?

What is our forecast for those variable resources?

There are many aspects that we have to factor in when we get to the residual commitment process, and we try to have that information as solid as we can in terms of forecast and not over forecasting, being within reasonable levels of certainty on those forecasts which has helped over time.

We really have through the minimum line commitment constraints and we are trying to get things back into the day ahead market itself we reduce the supplemental exceptional dispatches if you want to say post-day ahead.

MR. BLADEN: This is mostly a similar response, so I will not repeat what you just heard from my colleagues from New England and California, but instead try to add in addition to all the things you just heard that drive differences in what you have to do in realtime to meet reliability and what you plan to do day ahead to meet reliability.

We like others at this table also use tools to develop optimal supplemental commitments that are intended to reflect the best most economic options to meet the changing conditions.

While there will at times be a need to have supplemental commitments, I don't want it to be perceived that these are done without an eye towards an optimal economic outcome given the information that is now apparent as you get closer to realtime versus what was known when the day ahead market was cleared.

That is an important understanding. These are not done without an automated eye towards optimizing the choice of which resources are now necessary given the better information closer to realtime and all of the changes that you just heard about from New England and from California are nearly all of them would be things that we would experience whether it is wind, intermittent resources, and the change in positioning you need to do to manage for that, to changes in actual demand versus forecasted demand, all of those things are also relevant for us.

MR. MARKHAM: A similar theme for NYISO, at least for the drivers for what causes supplemental commitments after they are processed.

The New York day ahead process does do both, I will say, a market-based solution as well as a reliability pass to ensure that we have sufficient resources on to meet our forecasted load and transmission constraints for the next day.

Obviously, that process runs about 5:00 AM, so there are a lot of opportunities for updates to the weather forecasts and load forecast changes from there, but we do take actions through the software to secure that on a day ahead basis.

As far as interchange uncertainty and load forecast uncertainty, we have put some market tools in place such as 15-minute transaction scheduling to try to deal with those, but on these peak load days it is usually the region, if not the interconnection, that is suffering the shortage per the conditions.

There is less ability, I will say, to lean on one's neighbor during these conditions and so to the extent that we know that through coordination calls ahead of time we will take actions to commit additional resources.

Something else we have done recently is we have changed some of our scarcity pricing mechanism such that if the operators call our demand response programs, there is a "but for" test that occurs being kind of an "after the fact" calculation from the dispatch such that it looks to see would we have been short of meeting our reserve requirements had the demand response been called -- well, would we have been able to meet our reserve requirements if the demand response had not been called and if that is true then the higher prices prevail.

That is one of the ways that we have tried to incorporate the operator actions into the realtime pricing.

MR. BRYSON: A couple of things that people talked about the day ahead load forecast whether it is up or down being different from realtime intermittent resources interchange, those are all the same.

We may have made a lot of steps particularly in the last 12 months to reduce the supplemental commitments significantly and I would say really optimize them. We introduced some operator tools to help with that both days in advance day ahead and in real time.

The other thing too that separates the point that you brought up about the price separation between realtime and day ahead.

As you will see virtual transactions and day ahead will bind a constraint, cause a price in day ahead to be very high and that constraint may not bind at all in realtime.

A lot of the virtual activity has also caused some of that separation.

MR. ELLIS: In terms of tools we also had tools when we do supplemental commitments that look at economic aspects during those commitments.

What we are working with our stakeholders on is a reliability unit commitment process that triggers much closer to the operating hour and also has more of a 15-minute granularity versus an hourly granularity.

We anticipate that will significantly reduce the supplemental commitments that have to be made by operators.

MS. NICHOLSON: Thank you. You have raised a good point where sometimes it might not be entirely clear from the materials that you have when you make out-of-market commitments and the operators do so.

Do they frequently have tools that assist them in making the least cost commitments? I think I read about PJM and CTO optimizer and AS optimizers.

Would anyone like to comment about some of the tools and devices that operators use when they do make commitments out-of-market that help them do so on at least a cost basis?

MR. BRYSON: Just briefly on the CTO which is a CT optimizer. Essentially, what we did is we took the reliability run engine and we now run that in day to optimize CT commitment which has given the operator a really good tool to not over commit in the day with the CTs and then we measure that using our perfect dispatch tool.

MR. MARKHAM: What the New York ISO implemented in 2005 is our realtime commitment process. It is an evaluation that runs every 15 minutes that looks out two and a half hours in 15 minute blocks.

In 2005, when it was put in it was really meant to optimize 30 minute and 10 minute GT commitments as well as hourly interchange schedules.

Since 2005 we have moved to 15 minute scheduling on some interfaces with Hydro Quebec with PJM, so that tool now is really looking to make the economic transaction schedules 15 minutes in the future at least for the CTS bids.

It is really attempting to line up some of the granularity with load changes, with transmission constraints with other resource offers on a 15-minute basis.

That greatly reduces the number of, I would say, out-of-market GT starts that the New York ISO has had to make.

We try to get it into the market.

MR. BRANDIEN: I am in left field here for New England. Gas really is a big deal for us in the availability of gas to the burner tips of the units and we have done a lot of work developing a gas usage tool where we got to scrub the bulletin boards to see what is nominated at all the constraint points that takes us out into New York and to Pennsylvania as far as what can come into New England.

We have correlated the local gas distribution companies load to the heating degree day, so we have an understanding what their base usage is.

We look at the Kenneport and how much storage they have and how active they are on our market district gas, how much storage they have, how much they are planning in the market, are they available to call and get more gas intra-day for a unit?

That has significantly helped us out.

We hired a field coordinator. She used to purchase gas for generators, so she has firsthand knowledge of what it takes to arrange supply and transportation.

That has been a huge input to our decision-making process of whether or not we need to make any supplemental commitments because we can't get anymore fuel into New England on any particular day.

Then probably what other people have done is better wind forecast tools so that you are able to understand your intermittent resources when during the day you can spend cutting in and out and that helps us out as well.

MR. ROTHLEDER: In California we also do use a realtime unit commitment that looks out on one and a half, there is one run that looks out as far as four hours out, it runs every 15 minutes and that same unit commitment process, it not only manages short start resources, but it also manages configuration management.

The complication of combined cycle and what configuration you are on, we use that to manage that on an optimal basis because it basically is a mini-commitment decision. We move from one configuration to another.

I should have also mentioned some of the differences between day ahead and realtime are a result of some of the unscheduled flows in the interconnection and this year we have enhanced that in the day ahead by moving as a full model in trying to forecast what the flow effects of those are in the day ahead, thus trying to reduce the differences, the conditional differences between day ahead and realtime that would otherwise have occurred.

MR. ELLIS: SPP uses what we call a quick start tool, so it shows all the available uncommitted resources and for a given start up time period, it will rank the resources in economic merit order in terms of start up and loads so that would be very similar to the outcome of RUC and we use that today for operator commitments.

MR. BLADEN: I started this by saying we have a series of tools that we use for prepositioning the system for all "out of operations."

There are a whole bunch of acronyms that I will not say here, but we look at this on a multi-day forward basis, on a next day forward basis, and then on hours ahead.

We are using tools that will allow the operators to enter information about the conditions on the system that the tools then give them the options and generally the optimal solutions set solving for the now current conditions as we best understand them at that stage of the unit commitment process.

In addition to having tools that allow the operators to make optimal unit commitment decisions, we are on a daily basis scoring actual cooperations against what was ultimately needed to meet load in that scoring process, that allows us to help manage how effective our operations are at meeting load in an economic way.

MS. NICHOLSON: Unless we have any other comments, then thank you for that.

We can ask a new line of questions about other types of operator actions that effect market outcomes.

The paper we issued, and a lot from what we have been discussing, we so far have talked about supplemental commitments and operator initiated commitments.

There are also other factors such as transmission constraint relaxation penalty factors and also there may be other penalty factors like power balance constraints.

I would like to ask each of you to describe in a brief way if possible some of the penalty schedules that are included in your tariff, for example, relaxing transmission constraints and whether or not they are eligible to set the price.

We would also like to know about the degree of operator discretion that is involved with those penalty factors, if they are allowed to not trigger them by some other type of action.

We should start now again with Peter if I recall correctly?

MR. BRANDIEN: I thought you would do that and now I am drawing a blank on this one.

MS. NICHOLSON: You can pass.

MR. BRANDIEN: Yes, if I could pass to start with? I may have something later.

MR. ROTHLEDER: May I pass too? No? Actually, I do not consider the constraint relaxation parameter as an operator adjustment because those parameters are set in the tariff and some of them were in the VPN and they don't really change by operator action.

But what they do do is they are intended to basically get to a point where it says I am going to try to resolve a constraint whether it be a transmission constraint or call balance, and I am going to do everything I possibly can within the economic bids until it becomes basically ineffective to the point where it is not rational to keep on going and that is where, for example, a transmission constraint relaxation kicks in and it gets to the point where it says, "I have done everything and now it does not make more sense to move something that is very ineffective, a lot of megawatts to get a very small amount of relief."

There must be something else that needs to occur and it is at that point the constraint parameter kicks in.

We have a scheduling run that basically then tells the operator how much is the constraint, how to relax, it indicates that that constraint parameter kicked in by the price.

In the pricing run what it does is it will, basically in the pricing rental, use the maximum bid price which is $1,000 in the ISO for relaxing and pricing purposes in the pricing run.

You could have in the scheduling run the parameters set it greater than the $1,000, and in our case in realtime it is $1,500, and in the day ahead it is $5,000 for transmission constraint relaxation.

That allows you to get at least a

reasonable set of bid in resources, effective resources to respond to the constraint and then in the pricing run we price around that parameter where that lands in the constraint based on the maximum bid price of $1,000.

It does not mean that in a locational price could not go above $1,000. It does not even mean the shadow price could not still be above $1,000.

It could have been an economic solution that still arises between the skit pricing run parameter and the scheduling run parameter that could still be discovered in the pricing run.

That is how prices are set.

I should say that with our recent implementation of the energy and balance market we initially started using those parameters and we did ask for a six day waiver to discover the price in the energy and balance area based on the last on marginal movement rather than these parameters for 90 days which is to allow things to stabilize.

In terms of the operator actions, again, the operator is adjustable parameters. What the operator is doing is they are looking at the constraints, the flows of the constraints, make sure that they are matching actual flows and there can be flow differences, and in that regard, the operators do make conforming adjustments at times to the limits to account for any flow differences that are observed between what the market is seeing as the flows and what the actual flows are because it does not make sense to bind a constraint when it is not truly binding in reality.

So those conforming adjustments are intended to true up those small differences that we observe.

The conforming adjustments are also potentially used to, as you approach a constraint, you will want to be right up against the constraint all the time because you could be going back and forth over the constraint, so sometimes the operators will use the conforming adjustments to build a small amount of margin in, so that are not right up and potentially at risk of going over the constraint and risking a security violation.

MS. NICHOLSON: Thank you.

MR. BLADEN: The noteworthy item of difference here is the approach that MISO has taken to use a demand curve when looking at managing transmission constraints.

It is not something that is generally an operator action, per se, I think similar to where Mark was going with this, but rather the tariff defines the limits and they are getting posted.

To the extent that there was some need for a reliability coordinator to make changes they do have some discretion to change that in the tariff, but generally that would be a relatively extreme condition, and as long as that gets posted after the fact, that is sufficient under the tariff.

The approach is to have a very clear set of parameters that sets the conditions where the constraint will be managed, the transmission constraint will be managed using a demand curve approach and allows for that kind of transparency.

MR. O'NEIL: Do you change those in the pricing run?

MR. BLADEN: Do we change them?

MR. O'NEIL: Mark said that there was one price in the dispatch run and then they substituted a different price in the pricing run. I think you used the prices in the same set.

MR. BLADEN: Yes, we do not change them.

MR. MARKHAM: At the ISO, we do have a transmission demand curve that would kick in at the $4,000 shadow LBNP or shadow price -- excuse me -- that is not something the operators change. That is based tariff based. That is the constraint price that exists.

Where the operators get involved is if that demand curve is continually kicking in and you are actually about to exceed an SOL, the operators will get involved and take action such as moving fixed resources or fixed interchange schedules to make sure that they don't violate those loose SOL constraints. That is few and far between, but that is required to happen.

MR. BRYSON: I am going to answer this from an operator's interaction perspective.

There are really two levels of control room floor interjection and to constraint management one is that they can obviously change the percentage of binding on a constraint.

If constraints come up very quick and we have trouble controlling them, we can bind them at a much lower percentage and that is fairly common.

Something else that we had the capability of doing on the floors is changing the marginal cost associated with the constraint that allows for some of that relaxation and that is generally done by a support group.

We have a market's support group that helps out on the floors, so usually if that happens that is going to be call out to one of those.

Those are kind of the two interactions

that we will have from an operator perspective.

MS. NICHOLSON: Can you talk a little bit about when you change the marginal costs associated with the constraints in some of the decisions that help you make that choice?

MR. BRYSON: It is a lot of the things that we have discussed already.

If you have a situation where you are binding very hard on a constraint, you may be over on an SOL, and you are affecting a significant amount of generation at very low distribution factor, that is usually when we will get involved.

That is one situation.

The other one is where you have two constraints that are fighting so you have a generator that's a help on one constraint and a hurt on another constraint and they are duking it out and we will need to make a change to be able to essentially dismiss one of the constraints or prioritize a constraint.

MR. ELLIS: We have demand curve to

transmission violation it is one that cannot be adjusted by operators.

Our processes are really similar to NYISO and to California's ISOs in terms of how they have described it.

When we see situations like that the vast majority of the time those situations only exist for one or two intervals, so it may just be a while that it takes for the system to reconfigure itself to address that and we do not normally take any action.

If it is a persistent issue, then we have to look at, do we need to commit additional capacity or make other changes similar to the process as others have done and that is how we would address a persistent violation.

MR. BRANDIEN: I do not have much more to add than New England does not experience a lot of problems. My peers here do. Just physically here where we are located.

New England and the Maritimes are radial from the eastern interconnection. I want to import. I want to under generate. I want to export. I over generate.

The same thing with a lot of the interfaces in New England. I do not have a lot of the loop flows where I am fighting various constraints due to maybe looping from one area through the system or trying to VAL a constraint in an area.

In that regard, New England benefits from being radial to the interconnection.

MS. NICHOLSON: Thank you. Do we have any other comments on the constraints?

MR. O'NEIL: Most of the discussion about transmission has been essentially on the reliability constraints.

There are other things that transmission operators can do as part of the optimization.

For example, one thing they do or probably do not do to my understanding is set the phase angle regulators to optimize the system dispatch.

They are often done for other reasons and there are also obviously other things that the transmission can do and not necessarily that the ISO operators can do.

How much do they participate if at all in the optimization process, that is to say, to get a better solution, rather than just a reliability solution doing these dispatches?

The other thing is, it does not appear to me that the way we compensate the transmission owners that there is very much incent for them to participate, that is to say, they do not financially benefit.

Could you comment on that?

MR. MARKHAM: In New York there are a lot of PARs in the dense network around New York City. Those PARs are able to be optimized by the dispatch to alleviate congestion.

Once the software recommends that those PARs be moved, we work with the transmission owner if they are not already moving the PARs in that direction to alleviate the constraint.

As far as compensation, really, the compensation method is gained by offering a lower cost product to their consumer, to their loads, by being able to optimize those PARs.

MR. O'NEIL: That is a straight pass through, is it not, in most cases?

MR. MARKHAM: Yes.

MR. O'NEIL: It is a nice thing to pass through cheaper cost to your customers, but you do not keep any of it?

MR. MARKHAM: Right. Another thing we do with PJM, under the market-to-market regime, we do optimize flows over the branch program of Haupakong to Rentapo facility which changed a few years ago based on constraints in both markets the coordinated flow gates.

To the extent that New York is binding on a constraint that that facility would have cost reduction, if we move flows into New York, will coordinate with PJM to move those flows in that direction.

If that causes congestion within PJM there's a cost sharing mechanism and we will essentially pay for that service and vice versa, and the PJM side, if it is more constrained on the PJM side, then we will move that facility towards PJM to alleviate the cost, and if that causes congestion in New York, they will pay for it on the least cost basis.

MR. O'NEIL: Do you do that in realtime?

MR. MARKHAM: Yes, we do that in realtime.

MR. BRYSON: And PJM too with a very small exception. We are the TOP as well and that distinction is only important from a decision-making process.

Clearly, we are not switching and doing SCADA control, but we are making the decisions.

The transmission owners certainly honor those decisions and the benefits to them tend to be pass through benefits and optimizing the transmission system there are no direct monetary benefits.

Most of the PAR optimization, the same as Aaron described on our side, we do not have as near as many as they do, but we model a lot of the same ones they do.

MS. NICHOLSON: For the benefit of the transcript, would you mind defining TOP?

MR. MARKHAM: TO is "transmission owner" and TOP is "transmission operator".

MS. NICHOLSON: Thank you very much. Unless we have any other comments on that.

MR. ROTHLEDER: I do have one. We have the capability of optimizing things like phase-angled regulators, and stuff, we do not do it, we don't have any of those situations right now that we do.

The one exception is in the case of an internal DC cable, the TransBay Cable, we do optimize the power order on the cable to address any congestion that occurs in the system.

In terms of compensation, there is not any direct compensation for that because the cable is basically compensated through the transmission access charge, but it's a tool as we are doing congestion management, is able to use to help manage congestion to optimize the system.

MR. O'NEIL: You control it.

MR. BRYSON: Yes.

MR. BRANDIEN: We are a registered transmission operator, ISO New England is, and it is similar to PJM, and New York ISO, we have the authority over setting those. It is particularly important in Boston.

More comes from the south than from the north to supply the NEMA Boston and Northeast Mass Boston area of our footprint and we also coordinate some phase angle regulators with New York around the State of Vermont for local reliability to maximize transfers.

MR. ROTHLEDER: I should clarify on the cable. We control the Act of Power Order, the reactive is basically under someone else's control, PG&E manages that, the reactive.

MR. O'NEIL: Peter, you said you manage those phase shifters, but are they part of the optimization?

MR. BRANDIEN: No, the operators, when they are running the studies in real time, if they see any constraints, then they would advise the regulators to relieve those constraints.

They are not in our unit dispatch software. It's not trying to optimize coming out of a solution and telling the operators where to set the phase angle regulators. They are doing contingency analysis seeing a constraint and adjusting it to relieve those constraints.

MS. NICHOLSON: Thank you. We are going to move away from phase angle regulators to our next topic which is transparency.

If one were to look on the websites of the RTOs, we can see some reporting about operator actions, but it does seem to vary the types of information provided by each market, and also, the frequency with which it is provided.

If we could hear from each of you the types of information that your market currently provides the frequencies which might be monthly, annually, or some other timing and if we can start with Mark

Rothleder.

MR. ROTHLEDER: On a daily basis, we do post on OASIS the amount of exceptional dispatch that is occurring.

We also post our original unit commitment even though that is part of the optimization we do provide that information.

On a monthly basis, we enhance that with monthly reports about the exceptional dispatch. We have now enhanced outbid cost recovery information to also provide it down to aggregate by local area.

Roughly every six weeks we have a market performance and planning meeting which we go through kind of key performance metrics and in there we do have an opportunity to review things like minimum line constraint performance and so we discuss how much commitment was done through minimum online commitment, how much of that committed resources were actually dispatched above minimum load and we have that discussion.

We also described what the minimum online commitment constraints are. I should say on a daily basis we do post what the description is, the definition of the constraints as well.

It is protected information, so it is not an OASIS, but participants who have signed a non-disclosure agreement do have access to the definitions of the constraints and now the limits that were in the day ahead were enforcing all those constraints.

Beyond that, we do a monthly report that has a lot of information again about exceptional dispatches and big cost recovery.

Also our department of market monitoring goes through and does their reporting about things like "exceptional dispatch constraints" that are being enforced, any kind of adjustments that are being made, but conforming adjustments they do report out about that and which constraints are being conformed and how much they are being conformed up and down.

MR. BLADEN: Like California we have tons of information that is posted on a daily basis about the markets and the outcomes and that is all posted to our website.

In addition, and maybe more importantly, we are producing a monthly report that attempts to distill the volumes of information, of volumes of data into good information that can be used and that information forum report does provide scores across a number of different metrics in a way that is intended to give people a sense of overall performance.

While the details behind each of these metrics are not published, the trends on those metrics would be indicative of things about changes in the amount of uplift or supplemental commitments that were out of market, things like the unit commitment scores changing in one direction or another would be a good indication of those kinds of things, so we are trying to be as transparent as we can and that really is our default position to be transparent wherever possible.

MR. MARKHAM: Similar to Californian and MISO, we do make a lot of data available on our website and any unit committed through the day ahead reliability unit process would get posted their unit name hours, and if there's an associated local reliability constraint, that would also get posted.

The day RUC units are actually units that would get presented to the optimization to the day ahead process as a must run unit, so it's really used for potentially long lead time start units or in the areas of the local network where the constraint is not modeled.

The unit would get called on and presented to the day ahead market. If the day ahead market is economic, there is no cost associated with that commitment to the local area, but to the extent that it is out of the market, then it would get charged to the local area that brought it on.

Supplemental resource units are units that would be committed after the day ahead market up until realtime based on changes either in transmission configuration or for a need that it was not identified day ahead, those units are posted, the unit, the hours, and then what products of either energy reserve, or regulation that they were committed for, so that is posted, as well as units that are operated out of merit in realtime those units hours and the reasons are also posted.

Similar to the other ISOs, we also do a monthly report that rolls up a lot of the metrics that we look on a daily basis as far as bouncing market congestion residual, individual unit uplift statewide or local uplift.

It tries to boil it down into some summaries so that trends can be identified.

Also as part of that monthly metrics if a unit is committed for an area application of reliability rules, ARR, that is a document that is also public on the website that identifies these specific units that are needed to meet the specific constraints.

Most of them are during transmission outages on the lower voltage network or for peak load conditions, but that is all rolled up in that monthly report to provide transparency to stakeholders.

MS. NICHOLSON: PJM, Michael Bryson.

MR. BRYSON: When you talk about

transparency, I assume what you mean is everybody gets to see it? Let me clarify that.

As opposed to when a unit knows they were committed because from an operator action point of view what we do not do is post unit commitments that we make to the whole market.

We post aggregate data.

I think it is daily, but it is not as of the last day as there is a lag in it, and then both PJM's markets group and also our market monitor Joe Bowring posts and presents monthly aggregates of operating reserve dollars and reasons and those kind of things too. So we don't do kind of the discrete data publicly.

MS. NICHOLSON: As a follow up. You say you do not publicly present units specific data, but do you give data to individual units?

MR. BRYSON: Yes, we do provide commitment data back to unit owners.

MS. NICHOLSON: Aaron, in the reporting, say if you have made a supplemental commitment, do you post the unit name?

When you say a specific unit, does that actually mean it is publicly available, the unit name?

MR. BRYSON: Yes, on OASIS, the unit name is public.

MS. NICHOLSON: The constraint associated when appropriate?

MR. MARKHAM: When appropriate, yes.

MS. NICHOLSON: Sam Ellis.

MR. ELLIS: With respect to unit commitments we do post a reason to the resource owner for why we committed the unit and the reasons are pretty broad.

There is manual day ahead, so they do know they are committed manually, but it is not clear to them why.

As far as globally available information, we do not post any resource specific information.

Everything is in aggregate. Every report monthly both from our market monitoring unit and from operations to stakeholders where we report in aggregate comparisons of day ahead volumes and number of commitments versus realtime and then we try to explain using aggregate numbers what drove those differences?

So far we are iterating with them and they make requests for additional information for the following reports since we are fairly new and we have been accommodating as we can request for more information, but so far philosophy has been to do everything in aggregate and not talk about specific resources or specific commitments for specific constraints.

MR. BRANDIEN: We are probably similar to PJM in that we don't make unit specific requirements transparent.

Even the generators, we give them a weekly schedule and they know whether or not they picked up day ahead or got picked up in the reliability commitment afterwards, but we do not say, "We are bringing you on for voltage and we are bringing you on for this contingency to cover," but they know it is for a reliability purpose and did not get a day ahead commitment.

Very similar to the other ISOs.

We have a lot of information that is provided both from near realtime to a day layer or monthly.

If you go to our website you will see if we are binding on any constraints you could see that and you could look at the LNPs and whether it is positive or negative congestion and you could understand that.

Generator outages, we don't make transparent to the public, so that is not out there, but transmission outages are there that has been submitted to the ISO for study from its pending approval to its approval so in the study process they could see the date and times that it is going out that could utilize that information or make some determination based on cause and effect based on transmission topology.

Very similar to others we provide a monthly report that is 150 pages of various metrics to our stakeholders that have all sorts of metrics on how well we do on a load forecast, what is our "min" and "max" error throughout the day to what is our error on a monthly basis, how did the realtime versus the day ahead prices track, how did they track gas prices, there are all sorts of metrics on pricing on uplift where the uplift charges were allocated.

Was it for voltage? Was for first contingency? Was it for second contingency? Was it to the eastern part of New England? The western part of New England?

You could see exactly where the charges are going and it gives people an opportunity to ask questions of my boss.

It depends upon the line of questions. I wanted to put the line of questions, but there's a lot of information out there. I do not go to those reports to determine and hopefully are for realtime and for people to make decisions and probably the next panel would be better qualified to answer that.

MR. SAUER: From your experience, are there reports especially detailed enough essentially to provide a market that has information to have informed dialogue with RTO staff or is this just an indicative data point for here is a discrete area that we should start a conversation about?

This is in general, as I am trying to better understand whether there is enough information for the market enough to say, "Here is this problem. I understand the problem. Here is a solution that we should talk about through a stickle process," or another process or is it essentially the start of a conversation?

MR. BRANDIEN: Let me give you just one example of the level of detail.

We actually graph the LNPs for each one of our zones in New England both day ahead and realtime and any deviations and spikes will put a reason why that spike happened.

We are actually pointing to it and I think there is enough information out there to report that if they are not getting based on the questions that are being asked, we do try to supplement that report with some additional information to make it useful.

It is pretty good and probably all the ISOs are good as far as responding to their stakeholders, and if the information is not transparent enough, then we try to enhance the reports to make it useful.

MR. ROTHLEDER: The answer from my perspective. We are providing a lot of valuable information in terms of the areas and the reason for the constraint or a reason for the dispatch, but I think I do also hear from our stakeholders that they would like to have more both in an operational timeframe, they like the operators, to be able to tell them exactly why they got committed or didn't get committed or what the constraint was and what more information on the operational floor.

That's a little difficult for operators who are trying to focus on the system and they may not have all the reasons why.

Maybe the software did something to answer those questions. So that is a point of tension.

Once you are off the operating floor, the back office oftentimes from a settlement's perspective they like to understand more information about the constraints.

We try to be responsive to those requests as much as we can, but there is always a desire to have more information than what is available, and then when you make more information available, this leads to additional questions about, "Now I understand that, so what is next?"

MR. O'NEIL: When you approve a transition outage, do you take economics into consideration?

MR. BRANDIEN: In New England, we have two opportunities where we actually take the economics into account. When we have a long-term process, and then a short-term process, they are all defined in our procedure as to what falls into long-term and short-term.

We do an economic impact of those generator outages and we work with the transmission owner to try to position it to minimize the outage and not just the system costs, but to an asset owner.

It does not show up as a system cost,

but it is significantly impactive to the generator because you are taking him out for three weeks, he is losing a lot revenues, but it doesn't show up in any LNP.

We try to work with the generator, the transmission owners, to minimize the overall economic impact on any given player.

Hopefully we can get things worked out and position the work that needs to be done to minimize the impact, and when it gets closer to the outage we will take another run at it to see whether or not all of the assumptions that we had four months ago are really materializing or then we put it in a worst position and should we be working with the parties to try to reposition it again?

Your opportunities to try to reposition as you get closer to the outage are minimized because everybody has made arrangements for contractors, men and new equipment, to do the workload.

We do try to look at it in both the long-term and the short-term.

MR. ROTHLEDER: We do not coordinate outages based on economics.

It is only on reliability. Do we coordinate the outages?

That said, what we do is an advance run two days, three days ahead of the market day, and we use those results to indicate if there are any reliability issues that are cropping up when we look at the combination of outages and if we have to make some adjustments there that those are used for informing the outage coordinators of that.

MR. BLADEN: MISO's process is very similar to California's. It is not taken into account economics and not taken into account in coordination of transmission outages, but we are very closely following the reliability implications on a multi-day in advance and certainly as we get closer to the operating day.

MR. MARKHAM: The process is really to focus on the reliability impacts of the outage.

We do have a longer-term planning process that looks at transfer capability impacts as well as outages that would impact the same general region of the system and those are looked at to make sure we can sufficiently secure the system.

The fall out of that is really where economics does kind of play in because the need to secure that area, the system has a pricing impact, and to the extent that we can work with the transmission owners to move outages or to reduce the duration of those outages, or move them to a more optimum time, that will fall out of that process.

MR. BRYSON: We primarily handle it two ways. One is we have a gating process, one for FTR, so a year in advance, if they are long outages, and then, once you hit it like I call it the "31 Day Rule," you can schedule an outage five days in length regardless of congestion or economics.

Once we get into the month, if it causes congestion, we will cancel the outage or we will give the TO the option of paying for the outage.

If it is a submission, if it is an emergency outage, and they have to take an emergency they can take that and then we will have to redispatch for it.

MR. ELLIS: SPP is somewhat like CAISO. We just look at it from our liability perspective.

MS. NICHOLSON: Thank you.

MR. SAUER: I was not sure that you were going to answer my question as you had your card up for Dick's question.

MR. BRYSON: I did for yours and somebody answered. It just had to do with: "Do you think the data is sufficient enough to have a conversation?"

And my only measure of that is we have the conversation everyday, so it seems like it is and they are not shy about asking, and I'm sure they will comment, since some of them are here on the second panel. So thank you for circling back.

MS. NICHOLSON: I am going to ask another question that is related to the transparency again and it deals with operator discretion. We all realize at the end of the day humans are making decisions.

To what extent would you, in your opinion, do individual operators in your markets make different calls when they are afforded operator discretion?

And, how does your market manage that in order to try to have consistency and more transparency in your operating procedures and market outcomes?

MR. MARKHAM: Maybe I should have pushed it to Jeff first. I would say the operator discretion at the NYISO is really managed by processes and procedures.

It is really setting up the guidelines such that you need to meet these reliability criteria you have to take into account all the known information to meet that reliability criteria, and to the extent you make decisions based on that, you need to be able to demonstrate why you made that decision.

I did mention the next day or the next business day market review, so we have come a long way in refining processes and procedures to make sure to the extent possible we have removed as much discretion from that process as possible.

MR. BRYSON: I would answer that from a perspective that we give our operators, the operators being transmission operators, shift supervisors, and reliability engineers very significant discretion.

Part of the reason for that is, and kind of at the top of that pyramid, is at the discretion to shed load without checking for anybody.

Having said that we need to give them the discretion to exercise any of the tools available to them to keep from shedding load so they have a lot of discretion.

Having said that, we have a very significant operator action follow-up process, daily review actions, monthly review actions, report outs to our committees to set up processes to try to take those one-off operator discretion activities, and really to operationalize, put them in the procedures, and figure out a way to reflect them in the price and those kinds of things.

MR. ELLIS: Mike touched on the key which is to have frequent feedback, plus assessment, daily meetings, we do all of that to try to insure consistency and follow up.

I think reporting structures within the operations floor are key and so we have shift supervisors that we hold accountable for the operation of the floor so we can just have contact with one person and they are expected to follow up with the operators under them and make sure that their actions are consistent case to case.

MR. BRANDIEN: I think your question went to transparency. Very similar to New York, we have posted on our website our system operating procedures and those are very detailed, but it gives anybody the opportunity to go in and see how the operators are utilizing the software that they use to operate the system and what discretion they have to be able to change any sort of bias to get units moving faster and things along those lines.

It should be transparent to people that want to dig and it is a hard read. It is a hard read for myself, if you are using the tools, but at least it is publicly available to the stakeholders.

I talked about replacement reserves and our ability to move those replacement reserves.

That information is actually posted as a line item on our morning reports so any of our stakeholders, anybody who can get to our website can look at our morning report and see that line item for replacement reserves and whether or not we are moving that up or down.

MR. ROTHLEDER: Yes, we use training and reviews process to ensure consistency and adherence to procedures.

Some of our procedures are posted. Some of them are protected because of security concerns about the procedures and we use a process review of what has occurred and we also use the metrics and review metrics with the operators to feedback to them what the implications are and show them that there is consistency.

We also use the metrics in combination with the operator discussions to say if you are doing this manually is there an opportunity to automate that or to get it into the market and we use those purviews to discuss those things.

MR. BLADEN: Going last makes it a lot easier. It really is a lot of the same types of tools and choices from training, to objective metrics, they use for scoring how operators are performing in their daily duties looking for ways to maintain consistency across individual operators so that the outcomes would be largely the same no matter which operator was on duty.

In addition, we are measuring as I mentioned earlier where we are seeing recurring manual interventions. We are looking for ways in which we could turn those into market solutions instead and we have, as was noted earlier, a track record of doing that with dispatchable interruptibles with now the ramp product.

We are moving towards LNP.

All of these are examples of where there is a reliability outcome that the operators at one point were having to take manual interventions to maintain the system that we are looking for the ways to turn those into market solutions.

MS. NICHOLSON: Thank you very much for your transparent answers to that question.

Switching gears to our last line of questioning to discuss resource and flexibility and self-scheduling the extent to which these parameters and generator bids and operation is operational and financial parameters effect, the need for the market, the operators, and the market as a whole to make out-of-market commitments and then as a follow on to that, so how does self-scheduling and resource flexibility in general affect the need to take greater actions.

Secondly, what can be done in your opinion to increase the incentives of resources to offer their capacity more flexibly to the market. I believe we would be starting with Michael Bryson of PJM.

MR. BRYSON: A couple of thoughts.

I will start out with self-scheduling. I don't think it is a huge issue from our perspective units to decide to self-schedule, they do take a penalty of not being made whole if we have to dispatch them off, so that's kind of a balance of incentives.

Resource flexibility is one that we certainly see contributes to some of the out-of-market payments that happen and they are a combination of perfectly legitimate resource flexibility issues and want to use an example of just combine cycles or units that have to put mills in and things like that, the ability for PJM's systems to model that well and the actual flexibility parameters of the units, those two things are kind of fighting against it, so sometimes operators have to take actions.

We are constantly looking at ways to improve the modeling from that perspective and also working with unit owners to reduce inflexible parameters if that is a reasonable action.

Then the last one.

Here I just hit a point of, and I don't know if I can say this, but on the resource flexibility we have been working with our stakeholders on looking at a new capacity performance product. This is something where we built an incentive to be more flexible.

MS. NICHOLSON: To clarify my question. When I am speaking about inflexibility, I am not speaking about financial parameters because if you can pay them they will move which is flexibility.

I am specifically referring to Ningen, self-scheduling, and slow ramp rate which I understand they are physical properties of the machines. Thank you for your answer, Michael, and we can go on to Sam.

MR. ELLIS: Let me pass for now and maybe I will wing in later after I have heard other responses.

MR. BRANDIEN: We struggle with inflexibility all the time in New

England and you said inflexibility and out of market and we try to do everything in the market.

Sometimes when we bring an inflexible unit we need 200, but it is a two-by-one combined cycle, and it is eco-mins 530, so we end up not being able to set the price.

We brought it on through the markets, but because of the lumpiness of the unit and its inflexibility, it does not really get reflected in the market price.

We found a number of resource owners who have taken their two-by-one cycle units and made them so that we can operate a unit one by one configuration and that helps us out quite a bit.

Another inflexibility when I read in some of the reports that you put out is on the fast start units. We may have an issue where we have to bring on the fast start units where they may have a minimum runtime time, but more so than that, they have got a minimum downtime.

Once we get through the situation where we had to bring those fast start units on, we like to shut them down, but we cannot just shut them all down because then we would go deficient in our operating reserves.

We have to slowly peel them off and coordinate them with system conditions and be able to maintain operating reserves because once you shut them down, then they are gone for where a lot of them have them a minimum of one-hour downtime, so then you have lost the ability of those fast start resources for operating reserves.

Some of that inflexibility in even those fast start units play into, let's say, out of market payment or contribution to uplift payment in that setting the price.

Slow-moving units we are faced with that particularly in the winter time because we have to bring them on for some fuel diversity and maybe we need them at full load the 4:00, 5:00, 6 o'clock hour and they are moving that 3 megawatts a minute and it is eco-mins at 120 and it is a 600 megawatt unit, so you have to start moving them at 2:00 in the afternoon to get them to where you need them to be for the evening peak, so those inflexibilities play into the markets in the uplift. It is probably one of our larger contributors to uplift.

Even when you think about a combined cycle unit being very flexible when we have to operate them in the winter time with high fuel prices, they have a very high start up cost, a high no load cost, and then maybe their energy cost is somewhat competitive, but you get tagged with the whole thing that contributes to a lot of uplifts, so that there is flexibility that started them up, and shutting them down when you need them and not have to bring them on and incur those costs for hours on end for their min-runtime, so it is placed heavy into our uplift charges in New England.

MS. NICHOLSON: Mark, in your answer, could you also describe the multistage generating generator resource sittings in your market?

MR. ROTHLEDER: We have strived to recognize maybe in terms of complexity to a fault, the physical limitations of the resources and the constraints.

At least those that can be modeled on an intraday basis.

As you point out that motivation did lead to the multi-exchange generator modeling which allows us to, again, make those decisions about transitions, what the lead time is for transitions, what the minimum runtime is from one configuration to another.

The motivation of that was, before we did that, we thought we were concerned that we were seeing resources self-schedule to manage basically those constraints themselves and allowing now with the multi-exchanger remodeling the expectation is that those resources will make themselves available so that the operations can make decisions about those configurations.

There is a trade off. We do see those resources being made available in the configuration management being made available, but then as you use more of those decision-making processes, oftentimes the resource owners say, "You are moving me too much. That is not the configuration I really want to be in," and they start either tightening up the parameters stories or they reduce at times what offerings they are making in terms of what configuration and when.

Trying to strive, do it just right, but also trying to do it and making sure there is an explanation about why we committed a certain configuration is important.

Where we still have some limitations, and this is a difficult one to do, it is where the limitations of the resources are not contained within a day.

For example, the maximum number of starts a year, emission constraints over a longer period of time, those are very difficult to internalize into the optimization that is only optimizing over the day or intraday basis.

That does lead at times to operator interventions having to say, "Even though I made this decision, if I do this, I am going to lose the resource for the summertime period."

Those do come into play at times when the operators have to review the results and if they are running up against limitations that extend over a longer period of time they are going to have to factor that into their reliability decision-making processes.

MR. BLADEN: I am not sure there is a lot to add because we have covered a lot of ground on flexibility of the resources.

The only other point that might be worth noting is, and again, it is not specifically to flexibility, but it creates one of the potential discontinuities in the market is that it is not automatic at all load is bidding into a day ahead market such in realtime conditions you may need to commit resources to meet load that was not bid in the day ahead market.

It tends to be a very very small percentage of load that is not bid in, but it is there and is probably noteworthy.

MR. MARKHAM: On inflexibility, the ability to take away the market incentives for a resource to be inflexible is key.

Things like pricing five-minute

settlements, five-minute dispatch points make whole payments to units who self scheduled, having the ability to update bids in realtime, takes away some of those market incentives, I will call it, to be an inflexible.

And to the extent that you can make the prices or set the prices that desire flexibility, to the extent possible that should incent the resource to actually go out and procure the flexibility.

There are physical constraints with units as we all know. Some of the bigger units have long lead times, start ups, the combined cycle units, the lumpiness was mentioned.

I am not sure from a market products perspective if there is anything that can be done there, but at least setting the price such that it is advantageous to the resources to be flexible, I think, is key.

MR. ELLIS: There are some ways that we allow units to model inflexibility and their offer is through ramp, so we have ramp profiles that say they are in certain operating areas of the unit they cannot move as quickly and then we have a turnaround or a ramp rate factor that basically says, "I do not like being moved up and down, so if you move me up under certain circumstances you cannot move me down for a while."

I guess to the extent that we model that, then that creates the opportunity for people who are more flexible to set price because, obviously, when they say they cannot we are using other resources to meet that need.

That is one thing that I would like to add and a lot of what the others have said applies to SPP as well.

MR. ROTHLEDER: Let me add, on the market side we did further incentive not to self-schedule especially for variable resources lowered out bid floor form unit 30 to native 150 and that is starting to have some effect as we are starting to see some more variable resources offer that downward flexibility and that will become an increasing issue as we get into over generation conditions at times.

Also the flexible ramping constraints and ultimately the product will be also market motivation to made more of the flexibility resources available.

These are all things we can do within our market in conjunction with the California Public Utility Commission.

We have strived to make long term resource adequacy, longer term resource adequacy resources, recognize the need for flexibility in addition to generic capacity requirements and local capacitor requirements is now a recognition of a certain amount of that has to be ramp dispatchable capable flexible resources.

That will be a continuing theme of making sure that we have the right mix of resources made available to the market and then within the market incentivizing those resources and compensate those resources for that flexibility.

MS. NICHOLSON: Thank you very much. To wrap up this panel, there is one last question that has two parts.

We have heard a lot about getting more operator actions into prices, and my question is, when we say that, do we mean making prices higher or do we mean getting things in the prices to get them more efficient in the overall market outcome. Some prices will be higher and some will be lower.

My second question is, if you could choose one aspect of operator actions to improve how it is priced, what would that be and why? Is there a volunteer?

I will repeat the question and start with the second question. What would be the most important operator action to include in prices, if you had to pick one to focus on today?

MR. ROTHLEDER: It is not a matter of getting the prices higher. It is a matter of getting the prices right and reflective of the conditions.

So to the extent that there is something that the operators are doing outside of the market, then it is keeping the prices from being reflective of those conditions that they are responding to.

There will be some prices that may go up and there may be some prices that go down and there may be new products that need to be developed to compensate for what the operators really need. That would be the answer to the first question.

If there is a particular one that needs attention right now, I think we are trying to focus on those with again the contingency modeling enhancements, recognizing the need for some kind of post contingency ramping capability and continuing to evolve our flexibility constraint into the product which we recognize both upward and downward flexibility and compensate those resources for both directions.

Those are the areas that we are appropriately focusing on.

MR. BLADEN: First, I would like to reflect on the nature of the first question which was the idea that we need to get operator actions into prices.

I guess I do not want to leave us with the impression that they are not already in prices.

By and large, when operators take actions, they ultimately find their way into prices, and as everybody on this panel has noted, we have tools that are designed to assist the operators to take the optimal action given the information that is known at the time that the action is needed.

The prices as best as we can model the system today prices and the operator actions that are taken they are reflected in the outcomes.

It is not a perfect system, so I do not want to leave that impression, but it is one that there's a lot of good tools that are at the disposal of humans that operate the system.

What to improve?

There are always opportunities to improve. The fact that we have an order with a ramp product that's going to be implemented next year is evidence of that and we are looking forward to putting that into place.

It would occur to me that the need for flexibility as we move forward is going to continue to increase and this ramping product, and other tools like LNP, offer the potential to help assist us as the nature of the electricity network changes towards resources on the supply side that are more intermittent in nature and towards demand that is less predictable in nature.

That would be where I would focus and where we are focusing.

MR. MARKHAM: Just like in Jeff's comments. No matter what we do for a market system, you are always going to have operators involved where they are making decisions based on potentially more updated better available information than the software tools have.

To the extent we can price a majority or even all of the known issues, at this point, there is still always going to be some out-of-market action that may result just based on the nature and the dynamics of the power system.

The end result of putting more things in the market would be a more efficient solution to the extent that those things can be predictably predictable to quote that phrase from today.

But to the extent that there are things that happen outside the market solution that need to be represented for liability there is always going to be that need for a one offer out-of-the market solution.

As far as where to focus on next, as far as New York is concerned, where we are looking to focus next and where I see the need is really those additional reserve products I mentioned both in southeast New York and statewide to reflect that reliability need that exists there.

MR. BRYSON: The question on the price, without sounding too much like a cliché, the price has to be correct.

When you take the amount of dollars and uplift, and combine it with the LNP or the nodal price, or whatever, I cannot imagine that that makes it go down.

The more important thing is the transparency of LNP for both the supply side resources and demand side resources all understanding what it is at that point to be able to operate the system.

Uplift tends to hide that cost. It tends to not incentivize long-term resource commitment whereas getting it in pricing is a better incentive.

On operator action, I would say there are a lot of things out there, but if I had to pick a big bang for the buck it would be figuring out, and it's a combination of the way we model unit inflexibility, and the way unit owners manage unit flexibility is working together to make that more reflective of the way system operations work so we can improve that and get that out of uplift and into LMP.

MR. ELLIS: Getting the tools that our operators have, I do not see from a pricing perspective almost all of their commitments would be the same kinds of decisions that our RUC process would make and pricing has the same impact that RUC has in terms of late commitments.

Some areas we want to look at are ramp

products with better access for fast start resources into our market.

Mike mentioned "make whole" so we want to start looking at what drives make whole payments and see if we can design markets to incorporate that more in the pricing side versus the make whole side and so we are optimizing for that.

MR. BRANDIEN: Yes, the operators do a pretty good job, but I am very biased in that regard.

There are very few of the actions that they actually take that are impactive to the market and significantly benefits the reliability of the interconnection.

As others have spoken, we need to get the price right whether that directs things higher or lower. If the price is right, you get the right investments and with the right investments you are going to meet your reliability and your policy goals which includes the environmental goals that we would like to see met in going forward.

Flexibility is what is big for me and that flexibility includes making sure that the units have fuel and the operators could operate the system and not have to be managing the fuel input to it and have that flexibility so that they could meet the reliability objectives and not have to step in and take these operator actions as a result of uncertainty of the performance of various units.

MS. NICHOLSON: Thank you very much for our super panelists who did two full panels.

We are going to break for lunch.

Since we are a little behind schedule let's reconvene at 1:25 PM which gives us our one hour fifteen minutes for lunch. Hope to see you in the afternoon session.

(AFTERNOON SESSION)

MR. SAUER: Welcome back and thank you for joining us. We know it can be tough after the lunch hour and we do appreciate everyone here waiting their turn to speak.

I have a feeling that you will see a lot of overlap in the questions that are asked between the last panel and this panel.

We will see if the answers are different. I expect that they will be, but we will get to that soon.

The goal of this panel is to really hear about experiences from the markets themselves in regards to operator action.

A lot of our questions will be experiences in specific markets or in cross markets for inclusions that you can draw across the markets and we will get questions on transparency.

A lot of what we heard at the end of the last panel was on unit flexibility and certainly we will ask some questions there as well.

At the end of every question, the RTO and ISO and any of staff will be given the opportunity to add to the record if they feel they need to and so we may turn to staff at the side table in the event that they think the record needs to be expanded upon.

Given the large panel we will not be going down the line, but feel free to speak if you have something that is relevant, and is compelling and let us know by putting your tip card up and keep it up until you have spoken and we will try to get through as many questions as possible where we selectively ask questions and not require everybody to respond.

The staff always reminds me to do a spiel on ex parte communication, so I will read my printed material.

Finally, this workshop is not for the purpose of discussing or hearing argument related regarding specific cases before the Commission.

The dockets included in the supplemental notice and subsequent errata notice were provided out of an abundance of caution given the potential ex parte communications.

Please refrain from discussing the specifics of pending cases and that will prevent staff from having to redirect conversations.

With that, let me introduce the panelists and to say thank you for being here.

Andrew Hartshorn from Boston Energy Trading. Mike Schnitzer from NorthBridge.

Mike Evans from Shell Energy. Ed Tatum from Old Dominion Electric Cooperative. John Anderson from ELCON. Steve Wofford from Exelon, Tom Kaslow from GDF SUE. Mark Smith from Calpine and Joel from PSEG.

Thank you all for being here.

We can start with a generic question. Tell us your experiences with operator initiated action and resource commitments that are not based on economics.

We specifically want to hear any comparisons between the RTOs and also to understand the reason for that commitment of that operator action.

Andrew?

MR. HARTSHORN: I will kick this one off. Right before lunch there was a question asked of each of the operators, "What is the most important operator action that needs to be reflected in the prices?"

For me the most important one, and I will give an example, it is definitely the peaking unit pricing.

It is getting the GT setting price when

the units are started and when the units are told not to stop after their minimum runtime.

We would see significant instances where we would see a whole bank of GTs called on. They would not set price at any point during their minimum runtime and then we would call up the system operator on the system, and say, "We have not been economic through the hour or two hours minimum runtime. We think we should be shutting down," and they would say, "No, we need you to stay on," so from that standpoint and the ISO in question has a 90 percent threshold on the 10 percent of the resources eligible to set price so that from an operator's standpoint you look at a situation where they say, "I capacity to solve this problem."

They are not going to commit 200. They are going to commit something more than that. So they would commit our 300 megawatt bank to solve the problem, but unfortunately 270 megawatts of our capacity goes into the bottom of the stack because only 10 percent is able to be eligible to set price.

To me making sure the prices are right

when the units are started and ripe and when the units have stopped and ripe is the most important operator action that needs to be reflected.

MR. O'NEIL: What is the 10 percent. Where does that come from?

MR. HARTSHORN: The 10 percent is the amount by which PJM relaxes the lower dispatch limit in their pricing software.

MR. O'NEIL: I understand now.

MR. HARTSHORN: And also stating that those units are not eligible to set price in the day ahead market. They are given no flexibility to set price in the day ahead market.

MR. O'NEIL: Your argument is that when you reach the 10 percent level you are still not setting the market clearing price?

MR. HARTSHORN: Yes, that is correct and like with some of the other ISOs they should be relaxing the limit down to zero when they are first switching them on relaxing it down to zero when they say, "Don't turn off."

MR. WOFFORD: As Andrew pointed out, an example that Exelon has, and we have seen it consistently, although it is getting better is the over commitment of CTs.

Normally we see that happen during more peak conditions where you put the CTs on and there is very good reason that the operator is looking to put the CTs on and putting more than you would expect because he may have an expectation of imports change or he may have an expectation of unit performance, but all of the CTs perform and they stay online and they stay online past their minimum runtime and you do not see them set price.

Exelon is in the interesting position, and PJM, for example, we have a fleet that is primarily nuclear in nature peaking in nature and the peaking assets run a small percent of the time as far as capacity factor.

When you see them run, you would like to see them set price or to have someone else setting price versus being at the bottom of the stack as Andrew said.

We have also seen, and you have to think about operator action not in just the short term dispatch action which is the operator action in setting policy.

For example, the winter RFP for oil in New England last year was an operator action that impacted price.

It was put in place for a very good reason, from a reliability perspective, but had a significant impact on pricing because people who would not have otherwise put oil in the bank, put oil in the tank.

The commitment of combined cycles we have seen and that was mentioned by the ISOs where the software itself in many of the markets do not recognize the differences between one on one, two on one, three on one, and they will end up committing a three by one resource with a very high three by one minimum versus committing the one by one.

That is a problem.

It needs to be looked at. Those are three examples that we have.

MR. SAUER: Tom. Then Ed.

MR. KASLOW: Thank you. I will

just throw out two examples that were from this year and I will explain why I wanted to use those examples.

Certainly in the winter time this past January was a big time of uplifting New England and I would imagine that we were not alone.

We have combined cycle units that were brought on in the residual unit commitment process on several occasions in that period.

To give you an idea, around one of the days we had three units on all at their minimums, so not only are you burning expensive gas but operating at the least efficient operating point, et cetera.

I raise that.

First, I want to identify that in any of the things that I am raising here, it is not a criticism of the ISO New England system operations.

I think Pete and his guys do a great job and they coordinate well with us. We have both combined cycle and a very large fast start resource so that coordination is very helpful.

The difficulty that we see in the market is that the day ahead process where most of the scheduling takes place and where most of the energy is sold in New England with the improved demand clearing it is upwards of 96 percent or more of the generation sold day ahead.

We focus a lot more on how can we improve the day ahead pricing.

There is a particular concern in New England where in the highest demand periods, the periods where the prices might go very high there is an unfortunate other mechanism in the market that provides a rebate to all load serving entities that pay for capacity and our belief is that that could have some disincentive on demand clearing levels.

Whether it is driven by that or it is driven by any other factors something that we think is important is if we want to get good energy pricing we need to have good reserve pricing.

In the day ahead process that means pricing the operating reserves and right now there is no day ahead price for operating reserves in New England.

There is no cooptimization of energy and operating reserves.

My understanding is that the reserve constraints which are for the contingency protection plus that replacement preserve category are in the unit commitment process and not cooptimized, so the total solution.

We feel that that would be an important area or would be a focus and it relates back to the January unit operation.

If ultimately the resources that are needed to support load the next day are there as a form of reserve, and in this case they are not 10 to 30 minute resources, there are multiple hour start times.

Ultimately if they need to be relied on they need to understand that they are going to be relied on and they need to have some opportunity to be compensated for actions they may take to give the very services that it sounded like Pete Brandien was very interested in.

As an example on those days, if there was a sufficient compensation for operating reserve it may justify some type of a gas package for the next day that involves a reservation charge, and without that, and without knowing you would be the one that might be called it is difficult to go out and engage in those arrangements.

Thank you.

MR. SAUER: We will go to Ed and then Mark, then Mike Schnitzer and then Mike Evans.

MR. TATUM: Thank you very much. I just remind everyone we are a not-for-profit electric cooperative. We are a member of the NRECA.

In general, our food group is interested in securing reliable cost effective powers that our members can go out and actually do things with it and be more protective.

Along with our cousins at APPA we generally have a very strong consumer focus.

As far as examples, I have got two. One I enjoyed from this morning's conversation that the detail that you all went into on voltage, and the problems with that, we did have an example, it is not ex parte, it is all done, so I can give you the reference.

It was about 2012, EL 1341 and EL 1302 and that's when gas prices went under coal, and lo and behold to our surprise, we were committing CTs in the day ahead, but we could not take advantage of those guys because we needed the older out-of-market or out of the money whole to run to provide that reactive.

So for a very short time we were paying not only the lost opportunity costs for the CTs that didn't run, but also the higher costs for the coal that had to run and we felt we lost the promise of a competitive market.

We got that fixed, but there was still an issue of cost allocation and our friends in Richmond at Dominion filed a complaint in October of that year where they are estimating their outlay and their costs as a result of this misallocation of the change between the realtime and day ahead was about 40K a day, about $90,000 a month, and they anticipated that if it continued on that it would be about almost $500,000 by the time it got to the beginning of March.

That is just one example.

Another example I have, and I want to thank my attorney and everybody involved with this conversation, but for Old Dominion, this past January provided quite the experience in lessons learned and we thought this should be instructive.

However, we do have pending before this Commission requests related to that experience, so I will not discuss it here.

For those interested, the docket number was included in the notice, and instead, I would like to focus on a report that PJM put out from January and with apologies for my tardiness in getting in distributed.

It is a May 8, 2014 report entitled "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events."

I am not going to give an acronym for that, but there were three figures that I thought were somewhat compelling.

One is Figure 15 which talked about the generator outage rate and at the very beginning of the month, January 6 through 8, polar vortex, and towards the end of the month another big cold snap, but the generator forced outage was about 22 percent when that first hit and that was instructive to our operators.

Their role, they do a lot of things, but I think their role that they have had for maybe since we have vertically been integrated which was to keep the lights on, so they saw a 22 percent forced outage rate and I think that influenced their thinking as we got later on in the month.

Fortunately, you will see that the outage rate improved from 22 percent to 15 percent, of course, it was no where near the 7 percent average.

There is another figure that is 28 which also is instructive for this discussion which compares average realtime LNPs with average day ahead LNPs for both events.

At that time we first got done the polar vortex the day ahead LNP it wasn't too high, but that realtime it jumped right on up there and it got up to about, I think this is average, I think Joe will tell me it is about

$1,800 or so that we saw in realtime.

Later on in the month you will see that the day ahead did pretty good, and it says, "We experienced this before. We had a learning," so there is an expectation the realtime price would be higher, but it didn't happen and why did it not happen because when you look at the realtime you can take a look at Fig. 35 which actually shows the balancing rating reserve margins, and if you look at January 6 through 8th, they are kind of low.

If you will look at the latter part of the month, they are kind of high and the reason is the operators had every reason to expect that performance might not improve.

Their job is to keep the lights on and I am delighted that Mike Bryson has a lot of discretion with his operators because I think it is important when push comes to shove that we keep the lights on.

These are things that we saw.

The only other lesson I have from that is to give some consideration that we talk about knowing where all the constraints are and we have a new constraint here that we really had not thought about.

It has been around, but now we have markets. This is January. Was it a one in ten? Was it a one in twenty? Was it a one in thirty?

It does not matter. It was a one in 17 under competitive markets and that is what the experience is here and so what we learned is that with gas becoming more important, gas scheduling when pipelines are constrained, is a constraint that we need to be thoughtful about in the dispatch.

MR. SMITH: Mark Smith with Calpine. Maybe I will state the obvious.

Our experience with operator actions that are outside the market tend to suppress LNPs and increase uplift.

Operator actions that are outside the market, the ones that we experience most often result in commitments of additional generation and we can talk about the amount of discretion and what reasonable discretion is. I am sure that will come up in a future question.

I suspect it will.

Nonetheless as units are committed on it at min-load in all markets, I believe, except for a couple of fast start units, they are not allowed to set LNPs. It shifts the supply curve out to the right and lowers market clearing prices.

I will give you two examples each of which Calpine lives and breathes. A direct impact of that and indirect impact of that.

The direct impact is that when we have units that are dispatched to min-load for some unpriced constraint, that is in the market the best we can do is to recover our costs.

As I said in panel number one, no generator wants to live in a world of uplift. It doesn't create the price signals that will encourage even simple investments and resources.

We also have resources that are fairly routinely intra-marginal and many of those resources, for instance, those in California are often looking up at what we think is a suppressed price.

Suppressed because we know that there are 20,000 heat rate units running when our 7,000 heat rate machine is setting the market.

Again, the same impact.

Those investments and combined cycles can be made if the right price signal is there to increase their flexibility and to increase the responsiveness to the ISO's needs.

That gives you two examples.

One from each side of how operator actions grossly may be oversimplifying impact generation.

Thank you.

MR. SCHNITZER: Let me start with another combined cycle, a recent combined cycle example, then go from there and echo some of the comments that have been made.

This is a unit that offered and did not clear day ahead within the last month and got a call at 4:00 AM and scrambled to get some gas and was given startup instructions around 5:00 in the morning at basically a minimum run, ultimately it was on for a minimum run, and ran at minimum in every hour except one and unsurprisingly generated uplift over that commitment period.

That is what we know.

The question is: Why is that? There are a number of possibilities.

One is the lumpiness or non-convexity issue that we heard from the first panel and Andrew talked about one partial solution to that with the CT kind of thing, and fair enough, it could have been that.

The other is this notion as to whether there were unpriced constraints that contributed to that.

I don't know the answer to that. I listened with great interest this morning to the first panel and what I think I heard is that more of the ISOs are moving to put those constraints into the optimization which is not necessarily the same as putting those constraints into the pricing, nonetheless, I heard that piece of it.

I also heard at the first of these technical conferences during one of the operator panels repeated references to conservative operations or posturing the system conservatively or things like that none of which I am arguing with.

I echo the comments that were made earlier that the operators do need to do what they need to do and they should keep doing what they need to do.

The fact that we see a lot of uplift coincidently in extreme weather that happens to coincide with days when maybe there was conservative operations at least ask the question, "Are we really internalizing all of those constraints when we are going to conservative operations?

From a generator perspective we see what we see. We see that we get called at 4:00 in the morning.

We see that it looks like we were not doing much besides providing our minimum generation and some reserves for I think seven of the eight hours of the commitment period and we popped up above minimum one, maybe a second hour and overall we generated uplift.

I cannot tell you whether that is a lumpiness non-convexity problem and we need a pricing solution for that or whether it is also some set of constraints that were not fully incorporated, not just in the scheduling algorithm but in the pricing algorithm.

MR. EVANS: Mike Evans with Shell Energy. My message is really one of transparency.

There will be probably some natural push back on that. I am afraid that RTOs are probably going to be concerned about what is a market participant going to do with this information living in a little bit of fear.

I hope we can actually move to a point where information actually helps the market and improves the market.

We really need a market that reflects the fundamentals and then when it deviates from fundamentals we need to understand what the ISO has done and why it deviates.

Just a couple of examples.

We had a situation where the ISO put a constraint on the system. We didn't really know why and we searched and there is no explanation on this particular constraint.

We talked on the first panel about nomograms and it drove prices at Palo a minus $3, this is last week, minus $3, interpret prices in SP which is the southern part of the CAISO system to $51 and prices to the northern part of California $41.

No explanation on the limit and then a difference in prices in the two regions and yet no transmission constraint across the state, so everything really should be at the same price.

It should be at $41.

The problem I run into is with bilateral trading CCICE starting to walk up. Why is this happening? I don't know. I don't have any information on it.

I will not leave $10 on the table and then all of a sudden prices are approaching $51 in SP when they were trading at $41, kind of more reflecting fundamentals.

Lack of information and spontaneous rules have kind of just dropped out there end up costing the market.

We really encourage and look for and try to understand information that ISO publishes so from October 15th to the 31st, that published positive losses in the northern part of the state, NP.

This does not really make sense. We had a tough time understanding that. We try to find out. How do you then continue to trade? How do you trade forward? What happens to your hub price? Your hub price goes crazy.

Your hub price is really your reference price per the bilateral trades.

If we can understand what was going on or that model was put in place inaccurately and then they reverted back to the accurate model at least tell the market what we know and then we can respond and we can handle that appropriately.

When actions do not reflect fundamentals we need more than just "Don't run your unit."

I appreciate that we have gotten to a point now where information on the model, and the model is very complex, the operator may not know exactly what is going on, but we need to know more than just, "Don't run your unit."

Those are a couple of out of market concerns that we have experienced. Thank you.

MS. WIERZDICKI: Just a follow up for Mike Evans. You said when the ISO tells you, "Don't run the unit," you need to know more than, "Don't run the unit?" Talk a little more about what you would need to know and why?

MR. EVANS: In retrospect, what we found is that in some cases the utility has simply called up, and said, "We are going to take line up service," so does ISO have discretion over that, as it affects that particular location?

That would be one example.

Then we have had situations at some of our generation interconnection points where we still don't know the reason.

MR. QUINN: In that example do you feel like you need that information at the moment you are told not to run the unit or would you be fine waiting a day because the issue is always about there is sensitivity about announcing non-public transmission information to one party without announcing it to the markets.

The two solutions to that are usually either just to announce it to everybody at the same time or announce it with a lag.

In that example, do you feel like you use that for diagnostic purposes, so waiting a day to find out that the reason your unit did not run was because of a line outage, do you feel that you needed that information more in realtime?

MR. EVANS: I really needed the information as soon as possible. It affects gas procurement.

I have to buy gas at 5:30 in the morning in order to support a dispatch that I get at 1:00 in the afternoon.

I have all the scaffs and I am buying it for the next day and my first question is: How long is this outage going to last?

Do I need to buy gas for tomorrow, and I would say, to answer your question, let everybody know. Let everybody know. You have taken this out of service.

The ISO's mitigation protocols for running other units and controlling prices at efficient market power.

I would say that information is very helpful to the market and prompt information is very helpful to the market.

MR. SAUER: I will go with Joel and then John, and Mark after that.

MR. GORDON: From the first panel from this morning, they said it was easier as you later get into the panel discussion.

Giving examples of how units have actually been affected, it is a little more difficult when everybody has gone ahead of you.

What I would like to approach is, and we have talked about it from a generator perspective, the other thing that happens when these out-of-market actions happen and the prices do not come out right and it generates uplift, we don't like to be the unit that is operating and not getting the correct clearing price that we are receiving in realtime, and we do not like to be operating and just being paid in uplift component because there is no real money in operating that way, but there is a lot more risk to the unit and to the business.

In fact, what I would say is that about 80% of the times our units are called on in New England as peaking units to generate what paid uplift which means the clearing price across that hour doesn't justify the economics of that unit in the hour.

However, let me point out which is a little different from what I think everybody else has commented on is as load serving entity as someone who is trying to serve load and hedge that position bi-forward to cover the obligations when these out-of-market things that happen that create uplift I cannot hedge it and I have a very difficult time forecasting it.

I cannot predict it and I cannot hedge it. There are no products in the market to cover those obligations.

At the extreme level this past winter during that very difficult period in January

- February - at one point the uplift cost was $20 a megawatt hour for a load that was serving in the market.

I mean our average clearing price in New England is under $40 for a period of time to have the load cost to be $20 a megawatt hour, and I can tell you that there's not a lot of load serving entities that made money in the first half of 2013 as a result of that.

A different perspective.

MR. ANDERSON: As your token consumer representative today in all three panels -- oh, excise me, that's right, Ed, you helped me out.

I may have a little different perspective and I do want to emphasize that I am in absolutely no way criticizing the procedures that are out there, the people that are out there.

I think people are very knowledgeable, very smart, they are working hard and they are well intentioned and all of that.

There is just a different perspective and also especially on last the last panel, and some of it on this panel we are down not only in the weeds, but we are chewing on the roots under the weeds, and that is way past my pay grade, so I will admit that right away. I will be at a much higher level.

I will assert that everybody agrees that prices should be right. The real problem is what is right we all have different opinions on what is right.

Consumers are very very concerned about unnecessary wealth transfers and raising prices to all generators which is something that I keep hearing over and over, "Will building and procedures that later makes oversight very very difficult."

Once you have cranked them in there, then they are there and they just run.

Let me emphasize that no matter how good the mathematical constraints, the computer's constraints that are there is going to be out of market transactions.

Plainly there are going to be.

THE WITNESS: And since they are in my view by definition out-of-market many of them at least cannot have market solutions.

It is almost definitional.

I have heard a lot of suggestions today from the first two panels on how to change the constraints in that, but I haven't heard any consistent methodology and we strongly urge you to take real caution and do no harm.

That would be the overriding thing of do no harm especially to consumers.

In almost every case, what you do is you are going to have unintended consequences.

It is going to and this may be especially true as the electric industry goes through what will be some wrenching changes.

If we go from economic dispatch to environmental dispatch, who knows what that will do to the rules that are set up in the eyes of the RTOs.

If we don't have demand response, then we don't have markets and I do understand from the solicitor general, it was yesterday or today, has requested a motion and the Supreme Court agreed earlier this morning to postpone until January 15 so that there is a possibility that Order 745, at least, it will be debated before the Supreme Court and that is good.

But if we lose the demand response, we really have a problem with the markets so I raise that and I urge you not to do anything until we find out at least about that size of the market.

We haven't seen any evidence that significant changes are needed to these markets right now, and at this time, we would rather stay with the uplift concept than to crank into a whole bunch of prices on things that may or may not make a lot of sense. Thank you.

MR. SMITH: Thank you. I was actually responding to Arnie's question to Mike Evans of Shell of when do we need information?

Yes, I completely agree with everything Mike said, but if you can raise it up a few steps.

Where we should head is in understanding that the ISOs and RTOs will do what they must in order to maintain reliability.

And we all get that.

But the next two steps are equally

important and the next two steps are, "Show us what you have done," so get into transparency in the timing of necessary, transparency and I am certain there are other questions, and then finally, "Find a way to price those things that you can price."

I agree that there may be things that simply cannot be priced into the markets.

Going through these steps, particularly I think with PJM and with the ISO, we have made substantial and incremental progress.

Mark Rothleder talked about contingency modeling enhancements and I have to slow down when I say that just to make sure that I get it right.

He talked about contingency modeling enhancements which, essentially, is a reserve product that matches the needs and requirements of system operating limits.

Even though historically we have probably reserved this capacity, and we have now found a way to build a reserve product, and not only that product, but also price its unintended consequences on other LNPs.

Moving forward, do what you must. Show

us what you did. Find a way to price it.

MR. TATUM: I do appreciate Joel bringing up the LSC perspective as that is important. Old Dominion is an LSC and we are very concerned about the right price. This makes a big deal to us.

However we are also concerned about the overall price to our ultimate consumers, so we start to worry about what you can and cannot do and that gets back to the concept of, "Can you model all the constraints," and this is kind of a mantra that we would like to suggest is, if you can accurately model it, then let's put it on in LNP, and if you cannot, then let's do something else with it and let us be thoughtful about that.

I would hope another part of that would be that once we decide what we want to do with it, let us also make sure that it does go out with the lowest possible cost to consumers.

Models are just tools to help our operators.

John, there is also a lot of other

things we can do that are not price based in order to help reduce uplift and make sure that we don't get into that situation that we saw at the end of January in PJM.

One of the drivers that might keep Mike Bryson up at night is uncertainty. What is going to happen? We had 22 percent forced outages and we never had that before. What's going to happen again.

Models are not going to be able to foresee every future event because if we could put one together we could retire.

But that is just not going to happen and so we don't want those guys to be limited by that.

More clear information to the operators about unit characteristics and PJM sent a great job over this past year in coming up with surveys to get better information about their specific units, their design characteristics, their fuel limitations and back and forth.

They are working on a clear prescripted operator communications for unit commitment and additional transparency as well.

What is of most concern to Old Dominion and to me, it is because I am getting a little long on the tooth, so I remember what it was like, but when the operator calls us we need to respond and we need to be able to not be second guessing them or wondering what the consequences are going to be.

We are moving their discretion and trying to get more into price that may or may not be the best view from our standpoint.

MR. O'NEIL: Everybody wants transparency, but I assume that most of the generators will stop the transparency argument at some place where their operating conditions are made public all the time.

The question is: What exactly do you want from transparency? Do you have a list? Because transparency means different things to different people. Not that you need to do it right now.

MR. KASLOW: It is actually consistent with the point that I was going to make anyway.

The argument that I hopefully made

earlier, and I will clarify now, is the best transparency is putting all of the requirements that are needed to create that next day operating plan into the market and pricing it in the market because that does not require getting down to the level of the information that you might have been referring to which you are right, at some level it is sensitive and somebody could actually use virtual bids in a strategic way that would not be too helpful to the resource.

But if you do it that way you know when you are needed. You know the extent to which you need it and you can take appropriate actions and there is some compensation to justify that.

I will now give you a little bit of a context: because often times we have different charts and they tell the picture that is based on the explanation provided to the picture.

It was a chart demonstrating on a particular day last winter where there was the 11,000 megawatts of gas units and only

3,000 were operating and someone made the observation at the meeting, "Does that mean that the rest of them were unavailable?" and the answer was, "Not necessarily," and we do not have the information on which ones were and which ones were not.

But on that particular day that was one of the oil versus gas pricing version days and gas was much more expensive than oil and a lot of oil units were running.

In going into those data, it is very confusing to the resources that are at or near the margin. Am I needed? Am I not needed? Should I be looking for gas? I cannot commit to the gas for the reason that was cited earlier.

MR. O'NEIL: Mike's statement about fuel procurement for the next day is very telling to understand how long that line is going to be out or whatever.

MR. SAUER: Yes, we will just switch directions and then keep going with the transparency theme.

Let me add a couple of questions on top of what Dick said and we will open it up to everybody.

Specifically we would like to hear what the goals of transparency should be. Is it kind of near term understanding or should that be near term or long term transparency goal?

Is it for kind of an indicator of where there might be inefficiencies in the market?

Is it an indicator or participation in the market either short term or long term or is it a direct indicator of where there could actually be marked improvements?

That first, and third are probably pretty similar so let me explain that.

The first one was where there are inefficiencies in the market and I see that as where there is an indicator of millions of dollars in uplift as you all have been talking about over a stated time period.

That is an indicator of where a conversation should happen. I guess I see that third point as enough information to really not start a basic level of the dialogue with the RTO staff, but instead move towards talking solutions.

Those are three goals. I am sure there are many more, but on top of Dick's questions, let's move there.

MR. TATUM: Thank you. Dick does have a good question. With regard to transparency, there are many different ways to follow this.

While I like the way you asked the question is when we see uplift what should we do with it, and I do see it as a warning sign or an indicator.

I see it as something that helps reveal to us that we don't have perhaps everything in the right algorithm or maybe not and that is fine, because again, we are still figuring out how this is going to work.

We have not experienced everything that we are getting ready to experience. I see that as an early warning.

Regarding what you do with it, that is where some transparency can come in. We have, and Dr. Bowring perhaps will talk about this when we visit with him later this afternoon, but we have a lot of uplift and Dr. Bowring has a top ten list of those contributors.

It is very hard for a market participant to offer an intelligent or meaningful solution to what that technical problem might be.

Is it a voltage problem? What is going on there and so it is very hard to really know what is the best solution for that.

That goes back to the example that I wanted to discuss with you about with regards to the reactive power and those limitations.

If we are having recurring events that we can see and then we do a closed loop interface or a reactive interface, those are good things to do, but within PJM we know they do it, but we are not certain precisely how it comes about so that there is a lack of transparency there.

I understand that sometimes they work really well and sometimes they don't. Sometimes they are in day ahead and sometimes they are realtime and sometimes they are in both.

But my question is: Why are we not building transmission if we are seeing this recurring because if we have the overall concept of lots of buyers and lots of sellers getting together, and we have this reactive limit which is a regulated transmission constraint, then why are we not taking care of that? So transparency in that arena will be helpful.

The transparency that we got from our January operations I mentioned earlier we are delighted that Old Dominion provide as much detail about our unit design, our operating units design characteristics and our fuel supplies that PJM and updated and keep it updated so that when push comes to shove in the cold weather emergency events PJM knows precisely what we have and we go through that.

Those are three areas of transparency that are important.

MR. EVANS: I would like to draw an analogy to the NERC standards and we had NERC reliability standards that went into effect and all of a sudden you were penalized for not meeting these standards where before they were just guidelines.

Then all of a sudden everybody just got really quiet and they stopped sharing information and we have really struggled through that just still effectively communicate information but have forcible guidelines.

We can very easily be going down this path with this transparency too because the ISO does not want to be held accountable to find out that they are doing things wrong.

On the other hand, we really want to understand what is going on. I think fundamentally we need transparency when the market doesn't match fundamentals where we know constraints that are in place, the western grid is a little bit different than the eastern grid because it is a little bit more spread out so that we have these nomograms instead of thermal limits.

Please let us know.

When you lift a binding constraint like the SOCAL binding constraint you have to be really careful about the information because last year on September 30, the ISO lifted the

SOCAL binding constraint and it shifted the heat rates downward.

It allowed a lot more imports to come into southern California and poorer prices came off. It was a huge shift of millions of dollars.

When do you release that information? How do you release that information? Can you at least release it over a time period where people can incorporate it into their forward procurement.

Transparency is really only needed when the market does not reflect fundamentals.

This goes directly to price formation. I want LNPs that reflect fundamentals.

We are struggling right now with just bidding in day ahead gas prices and so we have commitment costs that are based on two day old gas prices.

We are struggling through that with some stakeholder processes, and we are not really making progress on that at this point in time and maybe with the M2 ruling we will do a little bit better but price formation is also very critical to transparency.

With regard to generation information and how much information is really out there, outage information is already available for generators and fundamentally you should see operation of units based on prices on the grid and so you should have really the transparency you need if people understand the constraints on the grid.

I think in general transparency means, "Tell us when the operator does something, imposes a new constraint. Tell us when they do something manually on the disk, just the load forecast."

They miss a renewable forecast. They do not incorporate a renewable forecast into the day ahead forecast and of over procuring in the day ahead. But please let us know.

MR. SMITH: What is the goal of transparency? That is a really big question so let us try to narrow it down.

What is the goal of transparency on out of market actions by the operator?

As far as I am concerned there are probably at least two goals. The first goal is to fix whatever caused the operator to take action.

The second and probably the more controversial, but the second really is to provide a counter balance to overly conservative actions.

We can take them one at a time. We cannot fix that which we cannot see.

If we do not understand the drivers behind actions taken by the operators we cannot design products.

We cannot modify protocols. We cannot modify models or tools that you heard about earlier in ways that would lower or eliminate the need for those.

We want to help get an understanding of those and that is one main purpose of transparency in terms of operator actions.

In terms of overly conservative actions if there is a review and I will take PJM because we like the PJM perfect dispatch model, it seems to have wrung a lot of efficiencies out of PJM dispatch and Mike would probably attest to that.

It is a big number that they have found

and changed because of the perfect dispatch review.

If the perfect dispatch review not only provides metrics in terms of what has happened and how it could have been improved and it affects compensation which I believe it did affect compensation in PJM, you create a counter balance.

Now not a counter balance that is going to effect reliability and nobody wants that.

But one that is going to cause the operator to sit back and ask, "Do I need 200 or do I need 1,000?"

We cannot fix what we cannot see and we will get some counter balance to the otherwise compelling and understandable reliability incentives.

MS. WIERZDICKI: Mark, just a quick clarifying question.

When you said PJM's perfect dispatch effects compensation, do you mean compensation to the staff operating the system or to individual market participants.

MR. SMITH: I believe so, but Mike can probably answer that much more directly than I.

MR. BRYSON: Yes, for perfect dispatch from 2008 through this year was part of the corporate goals affecting the bonus for all employees.

MR. WOFFORD: What is the goal of transparency. From Exelon's perspective it needs to be said, it is not to second guess the ISO operator.

They need to be able to do what they need to be able to do in realtime. It is not to judge their actions.

It is to understand what their actions are being directed for both in short term and long term.

The question was asked before. When do we need to know that information? If you are asking me to keep a unit offline and it is a $200 unit and prices are $500 units hour after hour, then I need to know why you would like to keep that unit offline.

I do not want to go to a point where I have to self-schedule the unit and you direct me off, direct from a Capital D NERC perspective, directly me offline because I am going to aggravate a constraint, but our desire is not to do that.

In realtime I want to understand what the issue is. If you can automate that process that is great.

Last week we saw a situation in New England where they lost a tie line and prices went very high. We had a combined cycle plant, and LNPs were $1,000.

DDP was pushing us down.

So the dispatch signal was pushing us down. We didn't know if there was an issue with our control system, if there was an issue with our offer, or if it was something else.

It was being dispatched down after the fact, we understand, to create reserves which is fine.

If there is a mechanism and we know that in realtime it resolves a lot of confusion.

Relative to transparency from my perspective is a long term goal to understand how are prices being formulated.

Are they being formulated by the rule sets that need to be optimized?

Are they being formulated by operator actions?

We seem to be talking about operator actions, and when I read the staff paper there are a lot of things there where the operator can have perfect actions and the rule set could still lead to a price that is lower than what we would like because of the way the prices formulated.

Long term transparency gives data to everyone, right, it gives data so the market participants can have dialogue with the ISO about how do you go about changing the rule sets to reflect which start papers, for example, in the pricing and it also goes to why are operators doing what they are doing and there is a mechanism to establish other products, whether it is to reserve product or something else.

They don't have to take that conservative action on their part because, as Ed said, they think maybe the forced outage rates can be 22 percent. Maybe there is a better solution to that.

Finally, what is worth saying from the

Exelon perspective. When we talk about this we are similar to PSEG. We are also a load serving entity.

One of our desires is to get all of this in a price that is hedgable and long term that is in the best interests of the load that we serve and it is in the best interests of the market in general.

MR. HARTSHORN: In terms of transparency for me, and I spend a lot of time writing in gory detail the parameters of every single pass of the New York USUC, and RTC, and RTD, when we went through SMD back in 2002 to 2004, there was no transparency in the objective function.

I am getting down into a level of detail that is mixed up, but this is really really important.

What is the objective function as the operators are looking at these reliability assessments and what is it in the day ahead market process?

What is it four hours after the day ahead market process and what is it four hours before you get to real time? What is it they are looking at?

What gives me comfort is I look at the New York design because they do not commit additional resources in the day ahead market unless they have fully exhausted all of their quick start capability.

Those entities that decided not to participate in the day ahead market are fully exposed to the potential of real GT prices in realtime and that is an important dynamic.

And if you break down that objective function, and you say that at some point the operators are jumping in with, they had plenty of peaking resources that they could run, but they are choosing to start a bigger lumpier unit in the middle somewhere what is their objective function? To me that is completely opaque.

I know a lot about market rules, but I could not tell you even in the slightest what all the models that system operators were talking about this morning because they were all talking about the fact that they are all looking at models and looking at reliability.

What are these models and what are those models objective functions because that is defining how these markets really are going to function.

MR. O'NEIL: Let me ask you to clarify that. We pretty much know the unit commitment and the dispatch, the SKID models have an objective function.

Are you talking about the fact that they have lots of models and are looking at different possible responses and we do not know exactly how they choose among them?

MR. HARTSHORN: It is both. Some of the reliability commitments that are happening during or after the day ahead market process and specifically the second thing which you said is the models in between day ahead and realtime.

The objective function is really really important. If all the peaking units were all set to zero when they are free we do not commit to anything else unless you absolutely have to assure reliability.

MR. O'NEIL: Do you think they are

set to zero?

MR. HARTSHORN: I know they are in New York because I wrote the tariff and I helped put the software in place.

MR. O'NEIL: And what are we setting to zero?

MR. HARTSHORN: The RUC, the unit commitment cost. The unit commitment cost of the peak is in the reliability path is zero. They will not commit an additional thermal unit unless they have exhausted all of the peaking units in the reliability pass.

This is an important construct and it is important for the day ahead market and realtime convergence as it is important to assure participation in the day ahead market in a fair and balanced way for both generation and load.

MR. SCHNITZER: Let me hitchhike on that if I can, Andrew.

I may think about this in the opposite way. I do not think about transparency as the goal.

I think about what are the

inefficiencies and what are the solutions and then what is the role of transparency. I think that that was the sense that you are asking it.

It is pretty clear what the source of the potential inefficiencies are. We are just talking about one of them here, but basically, if you are doing your commitment either day ahead or realtime in your dispatch without all the constraints in it, so you do it once and then you do a separate thing for other constraints except as it is done in New York that is an inefficiency.

When you do an RUC which is separate and apart from the day ahead commitment, never mind the prices, you are going to incur total variable costs that are higher than they need to be.

If you do that with constraints or objective functions misspecified you get the same result, so that is the static inefficiency.

The longer term inefficiency is, if I get the prices wrong, what is going to happen that I do not want to happen and that is everything from demand response to units with flexible capability to units investing to get more flexible to pressure exit from the market.

Those are all the inefficiencies that can result over the long term from chronic mispricing.

Frankly, I'm not sure what role transparency has in the solutions, so we need to get those things right.

We need to get the commitment and dispatch models to incorporate all the constraints that can reasonably be incorporated with the right decision rules and objective functions to marry them.

We have then got to pick off these pricing problems that we have, and as I said at the earlier technical conference, we should not be lulled into any kind of complacency by looking at how big those distortions night be on average.

The question is: How big are the pricing problems when they matter under periods of system stress, under periods of fuel delivery stress, and similar situations and, as was alluded to earlier, in those periods they are pretty big and that is not a cause for comfort.

I would hope that what the Commission does is try and focus on finding the solutions to these particular inefficiencies that have been identified and figuring out what transparency is appropriate along the way, but I view the central goal, and I hope you do as well, as to better triangulate these inefficiencies that are in the markets and figure out how to get after them.

MR. SAUER: We will turn to flexibility. Certainly we have heard a lot from the last panel that one of the priorities from the RTO staff was flexibility.

Certainly we have heard some views from this panel already and from some of the prior workshops.

If you get market pricing right the flexibility will come and there will be investment in flexible technologies.

I would like to expand upon that a little bit more and dig into the market rules.

Are there current market rules sufficient in providing flexibilities if we fix pricing, then the RTOs will get the flexibility they need or are there issues with the current market rules in that they are not allowing sufficient flexibility for the resources and possibly putting units in situations where they might be artificially limiting flexibility for whatever reason.

That is a lot, so thank you.

MR. KASLOW: In answer to one of your questions, who ultimately gets the flexibility that they need, and the question is: How efficient is the means by which they get there?

They can get the combination of resource commitments to meet the next day needs plus contingency response, but the real question is some of those require, as Pete Brandien had mentioned, committing lumpy resources which they pretty much know when they commit them they are going to have some impacts on price, but at that point in time there wasn't another choice.

I think there are things that need to be changed in the market rules.

I have focused a lot on the reserve piece and I will give you another example and this one was from last Thursday.

We have a large storage facility of 1100 plus megawatts that can respond pretty quickly and some of that we sell into the forward reserve market and get paid for that reserve response.

The other portion of it we are not paid in advance and last week what happened is, and I do not know if there were additional residual unit commitments, but once they got into the day based on some communications with Quebec, they actually did turn a unit on and I think it was one of ours.

What that told us was they actually needed more resources coming into the day, but there was not a payment for that.

Now go a little, but later into the day, it was about hour ending 17 where the event started to unfold at least in terms of cutting imports into New England, we went from zero prices for reserves prior to that, it started at about $700 and then went up to $1,000 and then back down to $700.

Clearly, there is a value to reserve before you got to the deficiency.

There is a bit of a frustration owning a resource like that as well as owning combined cycle units that frankly on the prior panel someone had mentioned that there are changes to those units that could happen with time and money, but there has to be the money in the signal that there is actually value in doing that otherwise the investments will not be made.

Even in terms of realtime reserves going from zero to very high deficiency prices does not seem to make a lot of sense from our perspective.

I know that some other regions have looked at operating reserve demand curves which I would see as an extension of what we currently have.

You have the deficiency, the reserve constraint penalty factor structure. Some surplus beyond that is not zero value.

Certainly with respect to a certain

portion of the imports on that day or economy imports, whenever an economy import is made, the neighboring regions are selling from their operating reserve so you better have operating reserve to cover it.

If by virtue of that economy import coming in means pushing resources that were part of the New England of the New England operating plan down and depressing prices, it means that that reserve is still important and it is above and beyond what is needed to meet the primary contingency reserves.

To my knowledge that is not reflected in the operating reserve requirement and hence not the prices.

So some tweaking needs to happen with respect to realtime operating reserves.

One final piece is with respect to the granularity of the price.

Right now we have integrated hourly prices in realtime and our resources because they are fast start most often do not coincide with the start up to clock hour, so that we will come online and we will get an integrated average locational marginal price which may put us into the uplift category.

And, by the way, it also puts other resources for example in a big resource as a forced outage and actually causes the higher pricing in the latter half of the hour, they actually get the integrated hourly average price, they actually get a higher price for the amount they generated in the first half of the hour because of the averaging effect.

It works both ways and neither are efficient, so we are in support of going to five minute prices and we understand that ISO New England is interested in that as well as part of their wholesale market plan.

It is just not something that is going to happen in the very near future.

MR. O'NEIL: Do you know why we went to average pricing in the first place? I do not have the answer to that.

MR. KASLOW: The we is a collective we, so I cannot answer for that, but I can claim some culpability --

MR. O'NEIL: But you were in the market participant process?

MR. KASLOW: I have culpability in the New England process. I will be very frank.

What was done at the time we went to the restructured markets in New England was really saying we have some shared savings concepts that work under a shared or power pooling arrangement and how do we map that over?

All of that was done on an hourly basis and so a lot of that was really not knowing what we should have known and I was one of the guilty parties on that and I will take some blame for that.

MR. O'NEIL: What are the arguments against going to the five minute pricing?

MR. KASLOW: The hurdles, and I will use that term, have been identified where if you try to do that with the revenue quality metering information the meter readers have indicated substantial burdens and problems on their end.

I understand that ISO and New England what they are looking at are their ways to use telemetry that ends up using that to modify, essentially, the revenue quality data. Perhaps Matt can talk about that on the next panel.

MR. SAUER: I am going to be unfair here by cutting everybody else off from the settlement discussions so we can move on.

Let us get to the flexibility discussions and then we will throw one question out there in terms of where should we start first.

MR. HARTSHORN: Flexibility. I was going to say the five-minute settlements, but I will not say anymore.

Realtime cooptimization of energy and operating reserves. It is not consistent across all the markets and it is really really important for units that want to offer their full flexibility to the market to be sure that they are going to be compensated when they get moved from one form of reserve to another form of reserve or to regulation or to energy the prices need to be consistent with each other.

They need to be fully cooptimized so that if I get switched from one product to another's product, that I am fairly and properly compensated which also goes to our five-minute settlement.

What is also important here and this is not consistent across all markets is intraday offer price changes and there are two aspects to that.

One is your ability to have a different offer price at 9:00 AM in the morning versus 6:00 PM at night so that you have a longer runtime unit, you do not want to be started at 6:00 PM where you are only going to get two hours of evening peak revenue before you go into the off-peak hours, the costs that you need to get covered to cover your no revenue through the midnight hours past midnight where you are not going to get compensated are very different to being started at 9:00 AM.

The fact then that in some of the markets you cannot submit a different off price at 9:00 PM versus 9:00 AM is a really important issue.

Secondly, your ability to change your offer price between day ahead and realtime we have heard from the New England representative talk about gas market issues and people's inability to get gas market, well that is real, people need to be able to have a different offer curve in realtime than they had in the day ahead, even if they got clear in the day ahead their redispatch costs may be different so those two things are really critical in terms of creating flexibility on the generation fleet.

MR. GORDON: You asked if there were any specific rules that perhaps get in the way of offering up some flexibility.

I will give you a story from 1999 when the markets first opened.

I got into this business because I was a finance person for a big hydro fleet and I used to work with Tom on that fleet and we provided all the regulation service in the pool for probably 20 years prior to the markets opening and the day the markets opened we provided zero, and they said, "What happened? This is a big revenue stream that we were projecting. Go find out where it is."

We went into the market rules and we found that there is a perfectly good pricing algorithm that it looks at because regulation allows you to move up and down, you look at the prices that you offer on the upside and if it is too high they put a penalty in and it is called the "look ahead penalty" and I believe it is still in the regulation market today.

The way to solve that is to reduce our ramp capability on the units significantly so we could never get into the high priced offers for water that we didn't want to flow.

There are some of those that are still out there, but generally a lot of those we have figured out how to adjust to.

Where I was going to go also is that five minute price rule. To me it is really important when you are talking about getting units to enhance their ability to be flexible you need to send them the right price signals in the right time frame.

We heard this morning, and I do not remember which RTO it was that said, "When we see a little price spike, we just do not let that one go through because it is transitory and there is not really a constraint that caused that price spike even though that is what the algorithms came to.

I recall from actually the last panel that we had that PJM will do that up to 45 minutes at a time.

They call it price bounding and they will suppress the real clearing price if they think it is just a transitory shortage condition, it will get solved we hope within the 45 minutes and then it will just go away.

We have spent a lot of time trying to figure out how to get fast start units to price correctly in the market and then to have the ability to just put your thumb on the scale, and say, "We are not going to show them to anybody. We are not going to let anybody respond to them. It just does not make any sense at all.

They think that that is a really critical component between the two which is moving to that five-minute pricing, but you have to be able to let it show.

We could spend all of this time trying to get the prices right, trying to get them correct, to reflect all the operator actions but then if we mute the signal, we have not gained anything.

Thank you.

MR. SCHNITZER: I certainly agree with a number of the comments that have been made.

It is easier to describe than to implement measuring sticks of how you know when you have got it right.

The first is do the existing quick start units make money in the energy market?

We heard a statement earlier that 80 percent of the revenues are uplift. That is a pretty good measure that if the existing quick start stock is not making money in the energy markets on their capability to be quick start, then you have got some work to do.

That is yardstick number one which is necessary but may not be sufficient.

The second is looking at the universe of probably combined cycle, other units that are capable of having more flexibility, but presently are indifferent to it because of uplift pricing and asked the question, "Have I got enough pricing reform so that those units can increase their profits as opposed to just decreasing their fuel costs and uplift payments.

When the answer to both those questions is yes, that the existing quick starts are profitable in the energy market, and some of the existing combined cycle fleet could make more money in the energy market by becoming more flexible, then you are headed in the right direction.

MR. TATUM: I am thinking about flexibility from the operator's standpoint and I have got so much confidence in Mike Bryson that he will keep the lights on regardless of how flexible the resource mix that we have.

The flexibility from an operator's standpoint is a technological issue and right now until we get the gas electric straight it is a gas electric coordination issue especially during times of pipeline restrictions.

As we start talking about the ability to do five-minute pricing and going back and forth, we do need to be careful and mindful that we are looking for the real costs.

I'm not certain that the five minute or the one minute cost is the real cost.

In PJM maybe we thought of those as false positives if you will.

I appreciate the units coming on are lumpy and there definitely is a spot for a quick start and all the new technologies that can come on, but we have this whole generation mix that is still used and useful.

I am not sure how much a nuke is going to be jumping up and down or old coal plants.

I suggest that these are all good comments and good thoughts, but the proper sweet spot would be a balance in between which is what can actually indeed be achievable given the actual technology that is really available for quick start.

I like what the folks are saying about

the combined cycles and more can be done there.

We have this whole other fleet of resources that are equally important to keeping the lights on.

MR. SCHNITZER: When I think of flexibility, I think of the need to dispatch a lot of resources quickly primarily for integration of renewables.

That is the big driver and before that we could kind of fudge a little bit with contingency reserves.

We had a product at the ISO where you would simply get a settlement back and they would say, "We used you for some reserves and you got this payment," then all of a sudden the people that we were representing are like, "How can we get this payment?"

As the grid operator looks at how they are going to balance out a potential deficiency in California ISO, they are looking at 13,000 megawatt ramp rate that some of that imbalance uncertainty is going to be solved through 15 minute scheduling and imbalanced energy, but somewhere they are going to want to point to a fixed quantity of reserves that they can call on that is fixed out there.

If you have transparency associated with pricing quantity that they are procuring that you could have a product similar to an ancillary service, that is a daily product that people bid into, the price is visible, the quantity that the ISO is procuring are bought everyday is very visible that that would provide a price signal so that people would know when it was needed.

Our suggestion would be to move forward on a product with that kind of structure as opposed to the flexible capacity mandate that we are pursuing in California that is kind of an interim solution right now.

MR. SMITH: The poster children for needing flexibility, at least in today's markets, would be ERCA in California in my view.

The penetrations of variable resources in both of those markets has been pretty dramatic. That secular shift has created fundamental changes in dispatch patterns.

It has changed what used to be a combined cycle run 16 hours in California, closer and closer to a double peak dispatch model and therefore flexibility is absolutely required.

The ISO has attached this and has approached this from many directions some of which you heard Mark Rothleder describe not the least of which is combined cycle modeling.

In Calpine's fleet, not for every resource because of some constraints on those resources, and quite honestly, the learning curve for understanding what they call multi-stage generation modeling we have moved several resources completely offset self-scheduling and fully into economic bids.

A pretty dramatic change.

There have been other factors that have influenced that too such as the enormous decline in financial liquidity in ISO and across over-the-counter markets.

But nonetheless realtime prices alone really should be enough to encourage people as Michael said earlier to offer in bids from a purely profit motivation.

What we need in that regard is volatility and what we need in that regard as Joel indicated was no thumbs on the scale. We need to see prices run up when they need to run up and we need to see prices run down so that we can decommit units and we can bid so that the ISO will decommit.

MR. WOFFORD: Just quickly here, what could be considered completely an unrelated example, but it is an indication that if there is a price signal people will be willing to do things that they otherwise would not be willing to do and until we have the appropriate price signal you are not going to see what they are willing to do.

For Exelon because of negative price signals deep negative price signals in the midwest caused by lots of problems we have worked with PJM and we are offering a solution to that which is movement of our nuclear units which historically we would not do, but as a matter of last resort, if that is the only thing to solve the problem we are willing to do that and we are going to monitor how that works because there is a price signal that says to us we need to do something.

One other comment just because I have been around a long time.

The hourly price versus five minute. The hourly price is just from the power pool days.

That is PJM, New England, and that is what we established when we started the market and we have just not changed it.

The excuse of not changing it now is the settlement cost of not changing both on the ISO side and the market participant side.

But a five-minute price signal is the correct price signal.

Having something other than than that leads to behavior that is not appropriate and PJM has indicated that to market participants.

The way people are ramping power in and out of the system is not appropriate and they are just doing that to arbitrage an hourly price average versus a five minute so that does need to be fixed.

MR. SAUER: Please try not to take any inference from my wanting to move on from the five minute settlement.

We certainly talked about quite a bit during the last conference and I think we had quite a bit of record from that. Please do not take any inference from that.

I promised one last set of questions. We are essentially overtime, so do this very quickly so just a couple words each. What essentially should be our next step or what should our focus be?

MR. HARTSHORN: PJM unit pricing. Get it fixed. We have waited for eight years in MISO to fix it since the Irish G debacle started there. New York has got it right. PJM has it wrong. We need to get it fixed.

MR. SCHNITZER: I will take that one and then I will add to that. Getting all the constraints you can into the pricing algorithm and putting them in where you can in a form where they are actually buying as opposed to putting them in a form where they are guaranteed to be slack.

MR. O'NEIL: Do you have a solution? You say fix it. When I tried to fix that problem, I ran into ramp rate constraints. When you relax the minimum operating level you can easily generate ramp rate constraints.

You can easily generate price separation without congestion and the question is, have we completely thought through that issue?

If it was simple as you said, then maybe we could have done it yesterday.

MR. HARTSHORN: That is directed to me.

MR. O'NEIL: Yes.

MR. HARTSHORN: Yes, there is a solution that has been out there and functioning since 2003.

The reason why New York solved the problem first is that New York City and Long Island functioned primarily --

MR. O'NEIL: I know, but are they a special case because like I said, when I do that relaxation in other models, I can generate ramp rate constraints that are completely artificial and I can generate price separation without congestion.

MR. HARTSHORN: Yes, and when you talk to PJM about this, and the reason why they have their 90 percent parameter is that they are worried about keeping physical control of the system.

If they are setting a price that is consistent with the GT, they are going to get many megawatts of over generation on the system and they are worried that they cannot control the system.

That just means that they have more peaking units on than they need, so the over generation signal that they will start to see is they are controlling the system will be a signal that they need to turn off some of their GTs that are outside of their minimum runtimes.

There are solutions, but is that really simple, no, it is not really simple, but they can be solved and it is not specific to New

York.

It is actually harder in new York and Long Island because they specifically depend on those for all constraints as opposed to occasionally needing them for some regional constraints.

MR. SCHNITZER: I need predictability in the market. I need a market that reflects fundamentals and I need transparency when the operator does things that changes the fundamentals.

MR. TATUM: I need gas deliverability as a constraint during pipeline restrictions.

Let us put those non-constraints LNP, but let us recognize the modeling limitations and let us not expect to capture all of the costs because that is going to be impossible to do.

Let us be mindful of the overall cost to consumers as we make any of these decisions.

MR. ANDERSON: Thanks, Ed, I appreciate that focus on the end-use customers.

Everything I heard so far would increase revenues for suppliers and not keep the focus on end-use customers.

I urge you to keep that focus, and thanks again, Ed.

I want to point out that price signals are far from perfect today and no matter what you do to them they are going to be far from perfect in the future.

You are just not going to get them perfect. Partial fixes may not be the thing that are going to bring the kind of benefits that all of us want.

I say look at them very very carefully. Keep in mind also that price signals will incent. There is no doubt about that, but in which ways?

Higher prices in load pockets is going to incent people not to take care of the congestion because that can hurt their profitability in the load pocket.

You have to look at them in all different ways.

I agree completely with Dick. We do not agree all the time, Dick, but we have not thought about all of these things completely and we have some really really big ones that need to be thought about.

I conclude again with what I have said so many times today, just keep in mind, "Do no harm." That is the main thing to do because everything you do is going to have all kinds of consequences intended and unintended.

MR. WOFFORD: It is not obvious to me what immediate action needs to be taken by any of the ISOs.

They have all taken action over the last year and a half to two years and some of the changes that they are putting in place are just being put in place.

I'm not sure how those changes are going to impact things. Some of the changes that PJM is doing now they are in peak condition that is going to resolve some of the CT scheduling issues that was talked about.

Some of the things that the ISO is doing with hourly pricing is going to solve some of those issues.

What I would like to see is just a

continuation of changing the rules in an incremental fashion as we see a need to change the rules and that means data transparency, so we know what the problems are and continuing dialogue between the ISOs and market participants for these incremental changes.

There is no silver bullet that is going to solve all of this.

MR. KASLOW: I agree, there is probably no silver bullet, but there is certainly plenty of room for improvement and I will end with what I started with.

Good energy pricing requires good reserve pricing. We know we have gaps between the reserve that is ultimately needed to meet the next day operating plan for the ISOs and what is actually purchased and paid and in fact in New England that is an easy one.

Nothing. No reserve is purchased day ahead unless it is purchased through the forward reserve market.

We think that is where we need to start New England and New England has a particular issue with the day ahead market given some of its other design challenges. That is the only thing I would suggest.

MR. SMITH: We heard a lot of diversity in approaches this morning between the ISOs and the RTOs. A very targeted action to take is to capture the best practices of all of those and those best practices might be focused on providing the transparency that would be necessary about operator actions to unleash the intellectual capability of the whole stakeholder community to find solutions to those actions that would be put into the market.

MR. GORDON: Let me find those best practices which we know now are five-minute pricing. We know it is realtime offer, hour offer for flexibility so that recourses can price things in.

Those are big things to address and to fix it you do not have them in your market.

New England just finished the two-year project to get hourly reoffers in place and I believe they are now on the next step-five minute pricing which is going to take another two years, the end of 2016 is what I believe the schedule is.

We can also look at some of the incremental things, the low handing fruit that is out there that we can be talking about getting some of the peaker prices better.

One of the things we did not address in that is looking at three part bidding.

If you take out three-part bidding and a peaker price you are going to get a better LNP when it gets turned on for whatever period of time it is eligible to set the price.

These are The easy things that we can go after so we ought to get those when we can and the longer things are we need to start as soon as possible.

MR. SAUER: Thank you all. Let me PJM staff if there is something they want to add quickly for the record.

MR. BRYSON: Yes, for clarification. We agree with Joel that we want to post prices every five minutes.

Price bounding is due to an apparent error in the calculation due to a mismatch between dispatch and pricing. We have to correct that before we post incorrect errors.

MR. SAUER: Thank you. We will take a ten minute break and we will start the next panel at 3:05.

(Upon resuming after a recess.)

MS. NICHOLSON: Thank you very much everyone for coming back. We are on our third and final panel for the day.

We are scheduled to end at 4:30 and we will do the best we can to do that. Let me now hand over the floor to Chairman LaFleur.

CHAIRMAN LAFLEUR: Thank you, Emma. I am happy to be back. Obviously folks know I missed most of the day as I was working on items for Jenna next week and a few other things. But I understand from my spies that you were so "deep in the weeds" you were chewing on the roots!

I thought I would come back for as much

as I could for the "genius" panel here that is going to tell us what to do and kick it off with a question of having heard everything you heard over the course of the day.

This is probably the most technical of the three conferences we have had. If there is a number one item, what do you think the first thing the Commission should look toward to make improvements in this area or if you think we should back off you can say that too just to kickoff the discussion.

Thank you.

Thank you, Emma.

MS. NICHOLSON: Thank you, Chairman LaFleur. Let's start with David Patton.

MR. PATTON: This is a vexing question. I would say conservatively that a third of all recommendations we made to every RTO fall into this area and they're all of the place because so many things are connected so it is nearly impossible to pick one.

But it is certainly one that I am passionate about that we have not talked too much about today is the relaxation of transmission constraints.

There is a fair amount of confusion in the terminology when people talk about relaxing in transmission constraints.

If I have a limit on a transmission constraint of 100 megawatts, and I cannot solve it as an RTO, so the flow is 115, in a sense it has been relaxed because I have allowed the dispatch to solve, but when we talk about constraint relaxation, we knew what we are really talking about is how do you price that constraint?

There are algorithms operating in a number of the RTOs that almost arbitrarily reduce the price of that constraint.

MISO had an algorithm running, and I want to give credit where credit is due, was written in PJM, that wiped out a third of $1 billion of congestion a year on violated transmission constraints.

We have never seen anything approaching the level of distortion of this one algorithm that took us five years to get it turned off.

It is extremely important to price

transmission constraints particularly when they are in shortage when they are in violations correctly because it sends all sorts of signals that are important to the day ahead market to price more aggressively and the constrained area, commit more generation, and to guide investment so you will hear RTO say things like, "We do not have any actions we can take. We don't want to just set an arbitrarily high price."

Well, yes, you do.

You want to set a price that reflects the reliability cost of not being able to manage the constraint and you will hear them say things like, "The constraints only allows for 10 minutes, so why should we price it?"

It is transitory and leads to price volatility and our customers do not like price volatility, but if we sit up here and we talk about wanting people to be flexible, then we have to pay people for the ramp capability that helps us solve these problems.

The most valuable units in these markets are units that can move fast, like pump storage units, or units that can start quickly and pricing five-minute ramp shortages or 10 minute ramp shortages is extraordinarily important to send that signal.

If you do not send that signal, then you are not going to get the flexibility and they are not going to get paid what their resources are worth and so I will start with that one.

MR. BOWRING: As somebody pointed out at one of their earlier panels, all operator actions are already reflected in price.

That is important to remember.

What was also pointed out is this is really a discussion about which operator action should be priced and how they should be priced.

It is important not to forget that we have a good well-functioning LNP model which price is right most of the time and based on thermal constraints in a DC power flow model.

We have to be very careful in defining variations from that and it is very easy to have a knee jerk response to that with a better.

I am going to grab this on here and I am going to grab that on there. As people have pointed out all day you can have unintended consequences very easily.

Closed loop interfaces is a good example of what not to do. They are relatively subjective.

They are relatively non-transparent. The are pricing things that you really can't price properly in the LNP model and it is not at all obvious that we can go into a more detail not at all obvious that they are not causing more issues than they are solving.

On the positive side we have talked about reflecting operators action, so reflecting the operators actual need for reserves in the reserve demand curve, and therefore in reserve price, and therefore energy prices is something that can be done and that would be an excellent first step.

I agree with Steve Wofford that it makes sense to be incremental about this lest we cause unintended consequences that exceed the intended consequences.

The dispatch of units, this seems obvious, but the dispatch of units in response of thermal constraint should set price and a lot of the frustration that you have heard up here is one that appeared to be not occurring.

The question of why that is not occurring, five-minute settlements is clearly a good idea, and that should be something that we are all working towards recognizing that it is going to take time and there is a cost, but that does address a lot of the issues that have been raised.

The gentleman from the last panel said something that I thought best summarized it. He said something along the lines, so forgive me if I do get it wrong, "that transparency" and what I took him to mean is, when the operators do things, it is important that everyone understand what was done and what it affected the price the way it did.

Even if it is examples, and even if it is after the fact, so people can understand that going forward, so transparency, and then price what you can price.

To price what we can price is a nice little nugget and what that means or implies is do not attempt to price what you cannot price which is also an important lesson here.

Transparency, and tried to the extent possible within the limits of the model, to let prices reflect fundamentals. Thank you.

MR. WHITE: It is a pleasure to be here, Madame Chair and Commission Staff.

Madame Chair, if I may, I would like to give just a small piece of what I think is helpful context to today's discussion which will lead into a very specific answer to your question.

When I listened to the last panel, the high-level theme I took away from the participant comments is that it would be desirable to have all of the costs of running a reliable power system compensated through transparently priced products and services in a high-level on what is a completely laudable goal.

We have gone a long way to getting there over the last 15 years and using New

England's statistics we have a $10 billion energy market.

Uplift is consistently about 1% of that total $10 billion, so most of the costs are compensated through transparent transfer market prices.

The question is how do we deal with that last 1%? That is what this is all about today and that is a hard problem because for one thing if it was easy we would have done it already.

Uplift. People have been upset about that for 15 years, so we knew we could do it, and the second reason is, it is really not just a matter of technology or better computers that is the problem.

The problem is that most solutions that come down the pike when we put them through our filters as professional market designers we start to see incentive problems or unintended consequences or countervailing effects that probably not a great solution because the biggest concern is that maybe the cure may be worse than the problem.

As Steve Wofford said, the end of the

last session, I don't think there's a silver bullet. I think it is a problem of chipping away at the remaining 1% in the ways that you are really focusing on the most important issue in each region.

This, Madame Chair, is where we come to the question that you put to us. My view is that what is most important in this last 1% is very different in different regions and it may not be helpful to have a generic direction from the Commission that all regions should devote substantial resources and any of these issues will take substantial resource.

None of these are simple problems to the same thing. To add to some specifics to that, for New England in particular, fast start pricing is a particular key issue.

Mr. Hartshorn mentioned that, and I fully agree with his comments, and that was the first comment you hear at the beginning of the last panel.

We have been working on that and we will continue to work on that next year, sub-hourly settlements, and the five-minute pricing for reasons you have all heard before as a priority.

I am not sure those are priority issues because of fast start pricing in many of the other regions at the same time.

David Patton to my right just talked about the importance of dealing with transmission constraint relaxation in our markets.

I do not think that that is an issue whatsoever, and in fact, if we had to go through a long proceeding on that, it would distract us from working on really important issues like resource flexibility and fundamentally the gas issues in New England that you all know much about.

I hope, and I say this with a little bit of risk that Mr. Patton agrees that the transmission constraint relaxation is a major issue in some parts of the country and it is not really a major issue in other areas where the transmission system is really well-developed.

I mention these primarily as examples to say we all need to work on the challenges and the specific issues to chip away that last 1% that are the principal focus of the ISOs and the stakeholders in each region and they will not likely be the same everywhere.

CHAIRMAN LAFLEUR: Is the 1% a national number or that is an ISO New England number?

MR. WHITE: That was me on-the-fly sitting here without the written down advanced dividing our total uplift divided by the size of our total energy market for New England.

CHAIRMAN LAFLEUR: Thank you.

MR. HARTSHORN: I think I made myself pretty clear on the last panel, so I will not repeat the peaking unit pricing and will go at a slightly higher level.

This is something that I talked about at the Nodal Trader Conference and that is that each of the ISO's softwares work and they have a unit commitment step followed by a dispatch step and what I call a gap between the commitment path and the dispatch path does not ever get appropriately passed into the product for which the unit is actually being committed for.

Take an example where you have pretty much reached your optimal solution and you are just short of regulation in hour 19, and at hour 19 you have to commit a 16 hour minimum runtime unit to provide that last chunk of regulation for that last hour.

The algorithm kind of understands the need to do it because it has to meet that regulation requirement, but the cost of committing that unit, the uplift associated with committing that unit cannot ever appropriately get captured in the regulation price for hour 19 and I call it the Commitment McGrungeon Problem.

It was what the convex hole in the original ELMP was designed to solve and we could not get there because it was a bridge too far. It was even more complicated than all the algorithm things that were being talked and talking about today.

Why I am concerned about that is, and it was mentioned in the previous panel, that ERCOT in California in particular, again, faced the problem because of the proliferation of the renewable resources and the volatility of the schedules of those associated renewable resources.

We need to come up with new products to address the ramp requirements that will be needed to keep these markets functioning and keep more of the stuff out of uplift.

The problem is we need to find a product as a lot of these ramping products look like additional operating reserves so that means committing additional resources and further suppressing the prices of regulations and 30 minute reserve in energy and further exacerbating the uplift problem.

What I ask everybody to go away with, and I'm trying to think better is how do we address this commitment of the McGrungeon problem, and solve this problem without making this issue worse in some of the markets that are coming up where I think that we are going to come up with new products and actually make the uplift issues worse. Hopefully someone can come up with an answer.

MR. SCHNITZER: I am going to

continue the pattern here of not exactly answering the question as asked, but what I'm taking away this morning, and I guess, Matt, I would take a flight issue with the 1%.

That 1% can be disproportionately important in terms of incentives and things of that nature.

I don't want to just kind of feel like we are 99% of the way there because, even if uplift is down to 1%, it can have a big impact on a lot of things that we care a lot about including the flexibility, including fuel security, and all of those kinds of things.

With that said, there are two competing theories of why this is a problem that we are talking about both of which are true to some extent.

The first is that we do not have all the proper constraints in the price setting process, or going to Andrew's point, we don't have them properly represented in a manner where they bind to tell us, "Yes, we did hour 16 and we incurred $5,000 in costs just for that on the margin."

There is that theory about that, that is, the source of our pricing problem, is that we have not found a way to incorporate the constraints in the pricing algorithm in a proper way.

They are in the optimization routine.

We are getting a fairly efficient result, but the pricing algorithm is disconnected in that respect due to the way we are representing the constraints for pricing purposes and there are a number of different ways to try to attack that problem some of which have a higher payoff and some that don't.

Those that are related to reserve products, they can be very usefully attacked through reserve demand curve and go that route.

The other one is that we have the lumpiness, the non-convexity, the generating resources where you have minimum segments and you have minimum runtimes, et cetera, and there, we basically have another set of techniques that are designed to try to deal with that problem in terms of the ELMP, the peaker CT kind of pricing it, et cetera, and there is some overlap between these two techniques.

Matt, I would agree with you that what the most productive place to focus on and which of those pots could well vary by market and I think strategy, challenge for us all is to find the highest payoff in each of those two buckets and figure out how we can get at it in each market and as Matt suggested that may not turn out to be a universal, but we should start looking at it.

That would be my "taxonomy" for trying think about where are the payoffs and getting better pricing.

MR. WOFFORD: I am going try to answer the question. There is a twelve-step program for recovering engineers and as an engineer you try to answer the question.

I think the question is what should or could we do in all markets in near term to address the effect of operator action that leads to uplift payments versus being reflected in an LNP.

When I think about that it is hard to think about one size fits all. The ISOs are different. They are different as far as the geographical size of load serve. It is different for PJM versus New England.

Let us not pretend it is not. It is different based on the generation mix. Some of the problems that we are seeing now are reflective of the fact that the mix is changed over time from some of the resources we had ten years ago.

It is going to be worse in a few more years. There are other proceedings that were probably were effective in dealing with that.

Some of the capacity in performance products that are being dealt with in both PJM and New England, that is going to solve some of the issues.

It is different from a fuel mix and it is different from a transmission capability or topology, so let's not pretend that what works in California or SPP with their level of intermittent resources is going to work in PJM. It is not that simple.

What I also think about is an operator because that is what I am. I am not an economist. I am not a regulator, so I wonder why I am here and on this panel particularly because I am none of those things.

It is not a problem all the time. It is a problem some of the time, so let's not try to implement a solution to solve something all the time if it doesn't exist, right?

On the dollar per megawatt hour for load served, it is not a huge problem, but let us not take that to mean it is not a problem.

If you compare it to the total dollar per megawatt to serve load in PJM, it is not a big number, but it is a big enough number that it makes a difference for some generators whether they are going to be viable long-term or not so that is a problem we need to address.

With all of that said, what would I do?

I would make sure that we have the appropriate reserve levels for the appropriate conditions so the operator does not have to create additional reserve of his commitment because of what he expects will happen.

His expectation is that he is going to have a winner like January 6, 7, and his expectation is that the forced out is going to be 22%.

You put an operator at that dispatch desk he's going to commit additional resources.

While I was listening this morning there is something I wrote down telling us the following. "The lights never go off in day ahead commitment."

In realtime, the lights can go off and the dispatcher is going to do what he needs to do to keep the lights on.

Let's help him in doing that by establishing the right reserve levels for the right market conditions.

With reserve levels there is a reserve demand curve, so let us make sure that we reflect appropriately the price, so that it does not go from zero to 1000, it reflects as you start needing the reserves you see that price reflected and let us make sure that that is both in the day ahead in the realtime market which for some markets that don't have the day ahead commitment for reserves and they should have.

MR. TATUM: Madame Chairman, this is Ed Tatum from Old Dominion. I suffer from the same engineering issues as Steve has.

I thought I heard your question a bit differently, though, as to what is the first thing the Commission should possibly be looking for regarding operator actions.

I would suggest that you help give the industry a little bit of guidance as to how we might modify the "Serenity Prayer" for this particular instance to know the things that can grow in price, and the things that cannot grow in price, and subsequently the wisdom to know the difference.

Matthew, clearly, I was not clear enough during the first panel. I'm not certain that you can get everything in the algorithms offer for a price.

If I was able to get those models straight, I would not be here. I would be doing something else and would be a very wealthy person.

There are lots of things that can be done beyond pricing to take care of operator actions. From our perspective we think that a lot of operator actions are driven by uncertainty.

Uncertainty is what is going on out in the field. What are the unit design parameters? How is their fuel doing? Do they have gas? Do they have a firm supply and prior experience?

PJM has been doing a great job putting together getting additional information from each individual generation owner to the operators.

We got other things where we are having recurring transmission constraints. We have reactive problems, voltage problems, natural gas deliverability during pipeline constraints.

Some of these are recurring reactive constraints raises the question as to what about that transmission solution for the regulated transmission both either locally and or on a regional if they have a reactive interface.

Dr. Bowring mentioned the closed loop interfaces. It is my understanding because I don't know a lot about them, but the transparency there is not particularly clear.

Sometimes they work and sometimes they do not, but we are uncertain about.

Overall, going back to the Serenity Prayer, I echo what Steve was saying. In realtime we need to keep the lights on.

Last January, PJM did an excellent job in keeping those lights on and that is what those operators are doing. That is what they are all about.

As we move through this exercise here, let us make sure that we do not unduly take away some of that really essential discretion they have to keep us moving.

As the token consumer here, I really thought I would be all alone and I'm very pleased to say that several of our panelists have focused on consumers and I really really appreciate that.

As I think you know, Madame Chairman, many consumers would love to stuff the toothpaste back into the tube, but that is not going to happen.

We are going to live with the constraints that we now have. I don't: call them markets because markets need to be competitive and these are not, they, the constraints.

What I urge you to do is to look at changes very very carefully and do no harm. Try to avoid as many unintended consequences as you can and keep everything as simple as you can because, frankly, these constraints have gotten so complex that many of us mere mortals have a tough time keeping up with them.

Presently it seems to me that some of the suppliers at least, maybe many, seem to think that when they win they keep the earnings, but if they lose they want to come before you and get a make whole payment.

That certainly is not the way competitive markets work, and if markets are broken, only if they work in times with no constraints, if markets are only working in times of no constraints, then they are clearly broken.

It seems to me that the issue before us is a 1% issue, but that is 1% of the time that we have really bad problems and that is what you heard at the last workshop.

Maybe there is something, and I do not have the right answers to these things, but it seems to me that we should focus on that 1% and look for fixes that don't put all the costs on end-use consumers.

Operator initiative out-of-market commitments are not and cannot be competitive. They require strong oversight.

The appropriate just and reasonable test to me under the Federal Power Act is to allow recovery of all legitimate, prudent, and verifiable costs.

This can and should raise materiality issues that are best addressed by in hearings and settlements.

Perhaps it is time for you to look at some things outside the box if you like on some of these and I will mention a couple of them.

I don't know whether they are right or

not. They are probably going to stir up some conversation, but at least for near-term, they may be something that you could at least look at to see what kinds of results should or could out-of-market transactions be cost based in that 1% of the time.

Should there be cost-based price caps for individual generators in that 1% of the time? I am saying that the rest of the time it seems to work fairly well, but that 1% is different.

Should we functionalize some generation as transmission which gives operators a lot more ability to control those generators in times of urgent needs.

Should out of market payments be netted against capacity payments if they have been receiving them over time?

Again, this is only a partial list. This is just a few things I wrote down here.

At least it is things like this that we need to consider in people who are a lot brighter than me can probably add to that list.

Finally, I would suggest that you do

absolutely nothing until you know what the decision is going to be on Order 745, and Order 745, if the court's decision is upheld and we lose sizable amounts of demand response in this market, we do not have a competitive market.

We have one-sided markets and that just does not work. Thank you very much.

CHAIRMAN LAFLEUR: Thank you very much for all those answers. We do strive to have the wisdom to tell what is important enough to work on not always successfully.

I strive to have serenity also, almost never successfully, but that will certainly stick with me and I will now turn it back to Emma. Thank you.

MS. NICHOLSON: Thank you very much. Those were very interesting answers for us and offers guidance.

I would like to ask a question that goes towards the economic nature, but if you do not have any comments to add, you are not under any obligation to answer this question.

In what ways in your opinion is the

realtime price useful? Do you expect market participants both on the supply and demand side to react to realtime prices in realtime or is the realtime price primarily useful to send long term investment signals to entities that and might invest in either their response capability or supply and flexibility assets or is it more as a driver to incentivize optimal exchange between markets or finally is it more of a signal to give load an incentive to bid a greater share of their requirements in the day ahead market versus the realtime?

If we could have some thoughts on what is the realtime price accomplishing in these markets and when is it not accomplishing, that would be helpful.

Would you like to start, David?

MR. PATTON: Yes, to all of the above. The realtime price cannot be underestimated. It serves all of those purposes and just to sort of tie it together with some of the things that we have talked about?

We talked about the need to do RUC

commitments after the day ahead market, and can we model these constraints and get some of those commitments more deeply embedded in prices.

You look at that and a lot of times you are making the RUC commitments not because there is anything wrong with the modeling in the day ahead market. It is because the modeling is wrong in the realtime market.

Take New England, for instance, which we have produced a lot of recommendations along this line. They generally procure 94% of their load in the day ahead market.

On certain days they commit a lot of resources after the day ahead market and their peakers frequently do not set prices and has measurable impact on realtime prices.

What would you think the load would do if they saw higher prices in realtime? Keep in mind that the day ahead market has not only load in generation but virtual traders who are arbitraging the two prices.

If you resolve the peakers not setting price issued in the realtime market, you are going to get people buying more in the day ahead market and what is that going to do?

That is going to result in more commitment and less need for the operator to commit things after the day ahead market.

Another connection here that nobody has really talked about is the allocation of the uplift. We generate uplift because there is a disconnect, but only in MISO has an RTO really gone through a process of trying to figure out what is causing the uplift and can we allocate it in a way that creates incentives for people to change their behavior in a way that minimizes uplift, so back to the same issue in New England.

What do you think would happen if we allocated the commitment costs of these peakers to the load that is not buying their full load, the deviation?

They would buy more.

There would be less uplift and it would change the need for operators to take out of merit action. It is very important in all the markets to focus on the uplift allocation.

Realtime price flows.

It does govern what people do and how flexible they are going to be in realtime which is why I stress the importance of pricing ramp constraints in the realtime and when you are ramp short sending that signal even if it is only for five minutes.

It really does impact the willingness of resources to be flexible, the five-minute settlements. Not only do you have to price it, but you have to settle on the basis of it and that undermines operations.

When you move ahead, as I said, it affects the day ahead market and that is probably the most critical aspect is the connection between the realtime price and the day ahead market outcome.

Then it does affect the longer term particularly shortage pricing in the realtime and so it would be hard to pull your question apart and say it is more important in one context than another.

MS. NICHOLSON: Thank you.

MR. BOWRING: I am not sure that I have a whole lot to add after that. That was a vociferous yes and I certainly agree with that.

It matters for realtime. It matters for day ahead. It matters for the short-term and it matters for the long-term. It matters for interface pricing.

Realtime prices, to summarize, I agree are very important and we should continue to focus on making sure that they reflect to the extent we can the underlying fundamentals.

MS. NICHOLSON: I should put a warning here that Wil had mentioned before, please do not draw the inference that FERC put pricing on that question.

We would like to get a sense of what are those signals if you can and the value they serve to the market?

MR. WHITE: You were gesturing at me, so I assume that I should answer the question.

I will try to be succinct because I do agree with David and Joe who are to my right.

Just to say in an unequivocal fashion, realtime pricing is the backbone of every commodity market and electricity is not different. It is the most important aspect of pricing.

All forward markets are based on and predictors of if they work right in realtime prices so they are only as good as the realtime pricing.

In the power markets realtime prices are essentially the entirety of the short-term performance incentives for resources to do what we want them to do, and if they do not do that, the lights do not stay on. You cannot make it more fundamental than that.

There is also the short-term consumption center for consumers. If we had more properly developed price response, true price responsive demand throughout our markets, the peak piece that is still undeveloped in the power industry.

This would be the fundamental realtime signal we would want to send to have them making efficient consumption decisions to enhance the reliability of the system because it is the basis for forward markets and forward prices are really the price signal for investment, they ultimately drive investment decisions.

In business schools, if you take courses on commodity market design the first thing they will teach you is all forward markets are designed second after you design the capture spot market and electricity markets the same principle applies and that is why we had day one RTOs first and day two RTOs second. it embodies that basic economic conclusion.

MR. HARTSHORN: There is really nothing else to add, so just yes to all of that, and motherhood and apple pie. Thank you.

MS. NICHOLSON: If no one else has anything to add, then we can move on. Thank you.

In going forward, we can take that approach where we do not need to go down the line. If you don't have anything to add to these questions, then by all means you can just listen like the rest of us.

This question is related to eco-min relaxation of black loaded fast start units.

We understand from discussions of the RTOs and ISOs, they were kind enough to have discussions with us that there are some trade-offs involved in relaxing the eco-min of the fast start unit to make that eligible to set the price.

Can we please have some comments as we would really appreciate to hear some of the trade-offs involved, so we better understand them. Who would like to be the first to answer with all of the economists who are out here?

MR. WHITE: I am happy to defer to others, but I am happy to speak. It seems that a lot of my time is thinking about these issues, so let me try to stay a little high level before we delve into the weeds because the nature of your question requires to go a little bit into some of those weeds.

The context of this question is best thought of in the context of what are called block loaded units, typically, combustion turbines, but not always, and by that I mean they are either on or they are off.

It is a 10 megawatt unit. It is either zero or it is producing 10 and it cannot really run anything between.

One of the things that comes up with fast start pricing is that generally those units operational characteristics and that operational characteristic itself will prevent it from setting the LNP.

The staff paper sometimes says it is ineligible to set the LNP. I think that particular choice of language sometimes obfuscates the real driver here.

It is really that the operational characteristic of the unit means it will not set the LNP because it is block loaded and it will not be seen as the incremental unit to mean another unit of demand.

One can make pricing think it is not block loaded and therefore let it set the price, but there are some trade-offs which is where I think you are headed.

Just to see some of the issues.

Imagine that we are running our power system and demand goes up by another 2 megawatts and in the least cost way to meet that additional 2 megawatts of increased demand is to turn on the 10 megawatt block load fast start unit.

But we only need two more megawatts. We have to have a power balance. What are you going to do with the other eight?

Somebody else who is already on who is dispatchable you have to push down and the unit you are pushing down it will generally be cheaper at the margin than the fast start unit you had turned on and that is why that unit was running first.

Think about what are the possibilities.

Possibility one which happens often in our markets presently is that we would set the unit. We would tell the 10 megawatt unit to start and we will respect that in its dispatch, the pricing reflects presently the exact assumptions we use in dispatch.

That unit, if we had another increase in demand, I mean, it went to 3 megawatts, it is not the fast start that would be changed for dispatch to meet it.

It would be that unit I pushed down, that would be the one I push up to meet it, so it is that cheaper unit that is marginal and the cheaper unit will set the price.

Now from some economic criteria that's the right thing to do. Price really is reflecting the marginal cost of a megawatt.

Another economic perspective is, wait a minute, if you do this consistently all the time that faster unit there never earns a profit.

You might be made whole by uplift, but no one invests as was said today to make uplift and over the long term this will be an issue.

There are various ways to do this and one of them is your eco-min relaxation comment which basically says when we go to price that unit may be one way to do this is to pretend it is not block loaded just when we calculate prices.

Dispatch has to the treat this as block loaded. It is a physical limit. Well, pretend it is not block loaded. In that case when the pricing comes in, it will say, "I am going to pretend it is not block loaded, so I will only set the output to two megawatts in the pricing run."

Then the pricing run will see the

software, and say, "If there is no demand, I will push that unit up to three," and maybe sets the price at the higher fast start.

Sounds great, right? But there is a problem. The reality is that I have a 10 megawatt unit. I had to push that cheaper unit down by 8 megawatts to balance the power system.

I set the price at this high fast start. What is the financial incentive for that cheaper unit to do? It does not want to stay low. It has strong financial incentives to stay exactly where it was and to not follow the dispatch signal down.

This kind of design, if applied uncautiously, can create situations where the units that you need to move to maintain power balance have very strong and clear financial incentives to do the opposite of what you want them to do.

There are fixes for that, but like I mentioned in my opening comment, nothing is simple in this world. The only really good fixes to solve the incentive problem involves creating another form of uplift.

I saw some nods. That is the reality. That is it. You have a trade-off. You can help the fast start set price. They can generate profit. Those are probably the right long-term investment signals to help them to do so and there are benefits there, as we heard earlier today, but you have to potentially create other forms of uplift to make sure people have the proper dispatch for incentives.

That really is the core of the trade off. Economic theory doesn't tell you directly exactly where we should draw these lines and you really have to go in relation to some earlier comments and I will close this long professorial explanation here for you.

You really have to go into the details of a particular market and how often this would occur and what would the relative benefits and costs of this be to help stakeholders and the ISOs understand the magnitudes of these trade-offs and form these decisions.

MS. NICHOLSON: Thank you.

MR. PATTON: I will just add a little bit to that. I'm a little bit worried that the tone of voice was like, "Does not this sound crazy to you?"

In reality he is right about the trade-offs. One problem one thinks about in terms of these block loaded units, and why is it such a problem, it would not be a problem if our flexible units and our block loaded units were sprinkled throughout the supply curve, the reality is our flexible units are $60 and below and our block loaded units are $60 to $90, so you have entire price ranges where you are dominated by units that have a very difficult time setting prices.

What makes it worse is they are generally not committed through the five-minute dispatch process.

In a lot of cases they are committed through a mechanism that may cause too many of them to be committed and now you have turned a bunch of these expensive units on and they are all sitting at their minimum and one of them can set price.

You look at that, and you say, "We are

in a situation where what is power worth?"

I have a bunch of $60 to $80 units on. I will definitely not be able to meet my energy and operating reserves if I turn them off, but I have a steam unit here at $50 that is setting the price. What is the right price?

Technically, for the next megawatt, if you respect all of their restrictions, $50 is the right price, only it is definitely not the right price because it doesn't reflect the true cost that you are incurring on the systems.

These trade-offs are things you need to think about. The uplift is very important. You have to get the incentive right for the folks that you're moving down, but I would say because I think a lot of people who have been talking about ELNP and MISO somehow think this is a new idea, it is very important to recognize that New York has been doing this for 12 years.

We have lots of data on how this works and how it can be implemented and how the trade-off can be managed.

MR. SCHNITZER: Just one other comment about that. Technically, obviously, I am in full agreement with what has been said.

But just to remind us all. The cost-benefit trade-off that has been eluded to there, the potential cost and benefits are way broader than one might first think.

For instance, if we are looking forward to a fleet transformation where we think we are going to need no flexible resources and we have a market where flexible resources can't make any money in the energy market, that is a problem, that is a serious problem looking forward.

Matt can correct me.

I believe that the ORTP's in New England between a frame CT in a fast start CT, there is a $4 or $5 kW month gap between the two, that is how much money the fast start CT should make in the energy market to compensate for the fast start capital premium relative to an ordinary CT, if you will.

That is what I think is at stake here in the transformation of the fleet in one respect.

In another respect, it is what is at stake for the fuel infrastructure and the non-gas units that are in the marketplace that are getting the lower price instead of the higher price on a sustained basis and may decide to exit the market.

And we have had some of that in New England. As everybody knows New England is not the only place that is exposed to that. I do not want to single them out.

We have fleet transformation going on in PJM and MISO that is driven by some environmental considerations and the question of the energy prices and what they say about retention and the composition of the fleet are fairly serious issues and they are all tied up in this seemingly arcane issue of how to price of these combustion turbines or fast start block loaded resources.

MR. SAUER: Just a quick follow up. You mentioned the uplift that would have to be created. I assume it is a lost opportunity cost that would be paid essentially as a unit that is dispatched down.

It would be at the LNP which would be essentially the price at the block.

MR. HARTSHORN: This goes back to the general premise of today which is talking about pricing in operator actions and something that gets lost, and I did mention it earlier, is that we want to make sure that when we are making a decision to turn on one of these peaking units or we are making a decision to not turn it off once it has made its minimum runtime, those are unambiguously situations where they need to be eligible to set price.

In between when you make the decision to turn it on, and when you are able to turn it off, there is some ambiguity about, "Well, do I really need it or do I really not need it to make the load?"

There are certain points when the operators are making actual decisions about, "Do I turn it on? Should I turn it off?" That is unambiguous and if you decided to keep it on, then it needs to be eligible to set the price.

Some of that ties into what the New England representative had talked about earlier about the fact that sometimes as they are managing their GT fleet they cannot turn off their peakers because they had minimum downtimes, and if they had the minimum downtimes, then they cannot meet their 30-minute reserve requirement.

That really highlights and heightens the point that would need to be cooptimizing the reserves in the energy in realtime market and the day ahead market to make sure that those interactions are happening appropriately.

If you cannot be turning off this peaker in realtime, because if you do, you are going to be short 30-minute operating reserves where you need to know what being short 30-minute operating reserves is and that needs to be incorporated in your realtime dispatch price signal in a cooptimized way.

MR. BOWRING: I have just one minor point which is that it is important in all of this to remember that some of the limitations on new operations are real and some are not and it is important that parameters which is really what we are talking about which are their representations in their flexibility reflect the real physical capability of the units and not something else and they can reflect other things.

They can reflect attempts to withhold. They can reflect our artificial inflexibility so it is important to think about that when we are thinking about pricing and the impact of inflexible parameters on pricing.

MS. NICHOLSON: Thank you.

MR. WOFFORD: It seemed like we were moving along well, so I was not going to say anything, but I have to respond to Joe.

From an operator engineer's perspective there is technical flexibility that exist, but they don't exist based on how you are paid currently for a machine that is a 1970 vintage frame five GECT that runs at 2% capacity factor which means I can actually operate that machine less than 15 megawatts.

Its heat rate is horrible and it beats

the heck out of it, right, and there is no mechanism for me to recover that fact.

I basically end up setting at a minimum very high heat rate and I beat the heck out of it and I have recovered my cost.

Joe is correct, but you need to make sure that there is a mechanism to incentivize folks to give you that flexibility.

When you say peakers or block loaded they do not have to be block loaded. They operate more efficiently block loaded than down at a minimal operating level because that is the way they are designed and you beat them up when you are down at a minimum operating level.

If there is a different payment mechanism that incents us to operate that way then we will operate differently, but most of these machines run a very few amount of hours that look past the factor and the revenues are capacity revenues, so you want to operate them in a way that they are reliable long term and that is what you do.

MS. NICHOLSON: I have a follow up on that. Is the fact that you have to submit an upward sloping supply curve in most markets, I believe CAISO is different because they have the multi-stage generating capabilities.

Is that what would cause you to submit so the block load is --

MR. WOFFORD: It makes it challenging because their no load is very low and their heat rate, their average incremental heat rate is very high at low loads, so yes.

MR. SCHNITZER: I do not disagree with what you said, Steve, I mean, clearly there has to be incentive. You really have to be paid if it costs more to operate it at minimum loads.

I was actually talking less about block loading than I was about some of the other parameters including mid-downtimes, min-runtimes, and all the rest of the parameters that equally affect the pricing algorithm.

MR. ANDERSON: This is a fascinating discussion. Let me begin by saying that it is absolutely essential from a consumer standpoint that we have adequate generation especially at critical times in peak loads to have a reliable supply of power, but when the discussion just goes on and on about making sure that every generator gets every dollar of its cost recovered, I just want to bring two examples about how at least large customers think about it.

In January of this year with a polar vortex and the cold thing, many of my members were hit by very very big uplift charges.

Their bills were twice, three times, and maybe even more than what they usually were, and yet, they have absolutely no venue where they can come in and seek any kind of compensatory relief.

They cannot pass the costs along because of the competitive markets that they deal with. You don't get a lot of sympathy when you are hearing this.

They look at it and they say, "Those are the rules. That is the way they were. We don't like it, but that is it."

Then maybe even more so.

A decade ago we published a report on the economic impacts of the August 2003 blackout. In that event there was a loss of 61,800 megawatts that served more than 50 million people in the US and Canada.

The direct and indirect economic costs of the blackout were estimated between $4 billion and $10 billion.

The failure of an operator in that particular case, or the failure to trim a tree that grew overnight, or whatever it happened to be, was a very significant harm to thousands of businesses and the businesses were made whole with compensation provided by utilities who callously disregarded prudent planning and operation of the electrical grid.

I ask you to think about how these discussions go. If we are going to have rules, and if we are going to have the rules out there, then let's play by the rules.

I just say it doesn't rest well to hear that generators have to have every dollar covered at every hour of every time.

We have to have them there when they are needed, but there are other ways of doing it than just changing LNP and whatever else we are talking about. Thank you.

MR. TATUM: I cannot disagree with John Anderson. I am appreciative of Steve's comment because it finally helped me better understand why I was so comfortable with this conversation.

Matthew started off talking about the trade-offs, the benefits, costs and whether something has to go into upload and thankfully the engineer brought it home for me.

Why would we want to operate a CT outside of its most efficient design parameter? I am just having a hard time with that.

I mean those units were designed specifically for that. You are right. It is a 70's vintage and were designed in other CTs and combined cycles combining them back and forth with new characteristics.

It seems to me how I would operate my household? I would go ahead and try to keep a piece of equipment and run it per its stack so that it is there for the long term.

This type of conversation, I appreciate the need for fuel diversity, for resources that are involved going back and forth, but this is one of the areas where I would wonder if we have enough of a benefit in cost and hopefully you all would help us get the right to "serenity moment" out of that.

MS. NICHOLSON: Do we have any other comments on that particular line? Then we are moving on to the next topic. I pose to you a general question which is: In your view, what is the best way to address local reliability issues that don't have an immediate short-term solution, say, a voltage program or problem, a problem that can only be resolved with a piece of equipment or machinery that you cannot get installed by tomorrow morning?

We have heard today and have seen that some of the proposed solutions are more enhanced localized reliability products.

I would like to get your thoughts on

those as a potential solution. Also what factors should influence the desire to develop more localized liability products?

Ed, your card is up.

MR. TATUM: Thank you for that question. When I think local, I think of planning and I think of local transmission and I do apologize for that.

A lot of what we have seen since about 2012 is we go through a log of reactive constraints that are recurring, that are empirically based but we are were seeing them nonetheless.

I know that we have in PJM a mechanism. I think there could be a lot more transparency. There can be a lot more clarity of the guidelines of how something moves through call operation performance.

The whole promise is being able to get lots of suppliers facing lots of buyers and the way you do that is making sure the regulated transmission system can actually make that happen.

That is your biggest bang for the buck.

We move further away from markets, I view LNP in the day ahead and the realtime when it is unconstrained and when we have relatively normal prices that is as close to a world competitive market as we are going to get.

We have bantered over here at the resource adequacy construct. We have bantered over here with a scarcity construct market, a construct, let's get the transmission planning so we have a minimal amount of additional constructs and more market.

MR. HARTSHORN: I have heard two discussions today that relate to the conversation. One was a voltage support stuff that was very early in the day and my reaction to that discussion, when it was ahead, was that that is not a problem we can solve without first defining a voltage support product in a way to put it into the pricing algorithm, and entity to charge the voltage support too for whatever schedule you define for the voltage support and how you define it.

Nobody has solved that problem, so I do not know that we can solve that one.

But the other one that was discussed a bunch was the N-1-1 or even -2 contingency stuff.

For one-off situations, the only way to resolve those things is doing what they are doing now which is that transmission outage causes are very transient one day, two day kind of thing, to commit the unit, they have to maintain reliability, they don't have a whole lot of options, and there is not really a construct in the market.

For those that are more persistent, and New York discussed this today that they are introducing Hudson Bailey Southeast, Hudson Bailey Reserve Constraints specifically for their summer time contingencies, if you are having N-2 contingency issues on a consistent basis, and you are doing this every day, then it should be possible to define our location or reserve requirement or reserve product that would at least capture some of what you need to do in terms of revenue stream for the units that you are committing in that region as opposed to just leaving it all to the uplift market.

MR. PATTON: A couple matters. Yes, the N-2 of the continuing N-2 needs are the biggest uplift generators in most of these markets.

In a lot of cases they exist because an operator will look at an area, and say, "When my first contingency happens, can I become N-1 secure again in 30 minutes?"

But they don't have quick starting gas turbines in that area, so the answer is no which is the case in a couple of areas in MISO South where we are generating huge amounts of uplift by starting steam units, not because we need them, but because of the first contingency happens it is the headroom on those slow starting units that is our 30 minute reserves unfortunately.

There it is the only reasonable solution that in some areas are very similar to define a local reserve product and hopefully a 30-minute product to price that requirement, and when you can't satisfy it importantly, it gives you a mechanism to price the shortage of that product where you are N-2 reliable, but really, you want to be because the gas turbines are not going to build in that area unless there's a price there, so if you just rely on uplift there's no chance of resolving that problem through the market.

I will say one more thing and it may be a little heretical because a lot of people sit up here, and say, "I'm not going to criticize the operators. I do not want to second guess the operators. They are keeping the lights on."

A bit part of my job is to second guess the operators which the operators understand who interact with me.

Every time you design a reserve product you attach a value to it, so we will call it an operating reserve demand curve, and if we attach a $500 operating reserve, but I do not want to see operators taking actions that cost more than $500, otherwise we have either specified the demand curve improperly or they are taking actions that are excessively conservative and it is important to figure out which of those two is the case and resolve it and usually we have found issues on both sides and resolve those.

It is very important as this is a very difficult problem to solve is that operators don't feel like they can abide by the economic limitations that we design in our shortage pricing.

They will go way beyond those economic parameters and just destroy the prices during shortage or near shortage conditions.

Somehow we have to bring together the NERC requirements and these market requirements and figure out how to solve that tension.

MS. NICHOLSON: Does anyone have any questions? No. Moving to the next line of questions which is somewhat related.

This goes back to what Joe had mentioned in the last workshop that we would like to hear a little bit more about.

You had mentioned it in this one, some of the operational trade-offs involved in modeling proxy thermal constraints.

You had said before that in your estimation they could be seen sometimes based on arbitrator assumptions or something that wasn't entirely transparent.

We would like to hear your thoughts on that and have some of the panelists if they have anything to add?

MR. BOWRING: When did I say this? This is about the closed loop interfaces, I presume. Is that what you are referring to? Sure.

There are a couple of examples of closed loop interfaces. PJM does them for three basic reasons.

One is to let the demand side set price which simply is not the right way to do it, and if they want high prices they should have more locational scarcity pricing and not use the fact that the demand side has an inappropriately high offer cap and then create an artificial constraint in order to set price because PJM believes it is the right price.

That is an example of subjective price setting and that is one way that the close of interface is worth it.

The other way is more directly intended to what you're asking me about are for either voltage or reactive constraints.

Again, the question is why is it being done? What exactly is the objective function that PJM is following? Why do they do it at times and not at other times?

I do not think that any of those things are clear and in fact I don't see the benefit in doing it all.

It reflects the fact appropriately enough that some reactive constraints cannot be modeled in the DC power flow.

The question is: If you decide that you are going to do that, what are the secondary consequences?

It is a relatively large area and sometimes you are providing the wrong price signal to units to provide real power, so you are actually providing a price signal which suggests to units that they should ramp up when you don't actually need them for a power balance and then you have to pay them uplifted back down.

There has not been careful enough thought given to the costs and benefits of it. It is as a way to reduce uplift perhaps, but that does not make it the right answer.

In fact, I don't think this has been as I said careful enough analysis done of exactly why with the costs and benefits of doing it and why we are not better off not doing it at all which is what I think the right answer is.

MS. NICHOLSON: Can you clarify what you mean by not doing anything at all?

MR. BOWRING: I do not mean that literally, but thank you for requesting that I clarify that.

MS. NICHOLSON: For the transcript.

MR. BOWRING: Simply, if you have a reactive problem you need to turn on the unit for reactive support that you turn it on out of merit and pay it uplift.

MS. NICHOLSON: That is what I thought you meant.

MR. HARTSHORN: I generally agree with what Joe is saying with the possible exception, if it is possible to define it in a way where you can consistently model it in the day ahead market, and the realtime market it makes sense.

It is something that you can communicate transparently to the market so the market knows that it is a real binding constraint.

It is not something that is going to be here today and not be there tomorrow, that it will be there the next day and have no clarity, so a little bit gets back to the transparency.

The worst scenario is that we do it in one place and not the other. The closed interface that occurred in the summer time when we have $1,800 prices, it was not modeled at all in the day ahead and created just tremendous revenue inadequacy that the just permeated through the market in a way that was completely unintended was just a really bad market outcome all around.

MS. NICHOLSON: Thank you. Michael and then Ed.

MR. SCHNITZER: Let me suggest one

addendum maybe to Joe's answer which he can accept or decline, but the consequence of that variant of doing nothing which is doing what you need to do for a liability in paying uplift, as opposed to finding a way to price the voltage product is you are discriminating against similarly situated units that are actually providing the same voltage solution or contributing to the solution to the voltage problem.

That is another "not perfect solution" so we should not rest there.

We should look to see if there is a way to reflect voltage in the pricing in a fashion that would price the voltage product in a nondiscriminatory manner to whatever resources were contributing to it.

I am not the expert on this, but I do know that this is an area where Bill Hogan thinks that there are vehicles for incorporating voltage into the pricing algorithm that would have these properties.

If that can be accomplished, it would be an improvement over either of the alternatives that are otherwise out there for us.

MS. NICHOLSON: First, a question from Dick.

MR. O'NEIL: Are you talking about the ACOPF?

MR. SCHNITZER: I don't know if it has a name.

MR. O'NEIL: The alternating current optimal power flow which basically does, if you could solve it, and by the way the problem is to solve it in the time we have, but if you could solve it, it would solve the voltage problem.

MR. SCHNITZER: Yes, I am not sure that that is it. Bill has got a family of solutions in the pricing set that that can incorporate voltages and I'm not sure if it involves --

MR. O'NEIL: I have not seen that part of that yet.

MR. SCHNITZER: Right.

MR. O'NEIL: Because he had a big

debate about ten years ago about whether
we should price react.
MR. SCHNITZER: No, this is a late
vintage idea.
MR. O'NEIL: The interesting thing
in response to Ed is that a lot of these
reactive power solutions can come on the
demand side, in the transmission assets,
and from generators and it is mostly a
capital solution.
It is not necessarily a variable cost of
reactive power except when you get on the
trade-off part of the D curve.
There are ways to essentially
incentivize people to make those investments
and a lot of the reactive power we are paying
for were paying for generators to operate at
minimum load for real power because of the
stability constraints.
I mean we put them into the real power
market, but they are really reactive power
costs.
MR. TATUM: I'm not used to Dick
making my points, but that is exactly
where I was going with that, so yes, I

thank you.

It is fascinating to talk about the idea of a product, but again, let me have a little serenity here. It is not going to solve, it is a dynamic issue, and it fairly is straightforward.

If we were back in the olden days, we plan the generation, the transmission system in lock step. We actually thought about not only thermal issues, but voltage stability as we built and we sighted generation plants near fuel supply and water and railroads in both the transmission run but it was a lock step.

Theoretically, it is fine to consider that maybe there is a right price for an old thermal unit to provide that reactive, but I don't think we have seen it.

There are a lot of other new technologies that can provide that type of capability.

I also want to echo what Joe was saying about the closed loop interfaces. When I hear Joe talk about them, it gives me pause because Joe is PJM's independent market monitor has a lot more transparency and understanding of what is going on with those close loop interfaces than I do.

Yet sometimes they seem to work good. Sometimes they don't, but it is very unclear and is very opaque and that is a concern to this stakeholder.

MS. NICHOLSON: David Patton, do you have something to add?

MR. PATTON: Let me state this quickly. If this were our biggest problem in the markets we operate, I would be so happy.

Voltage support is a pretty small contributor to uplift, and most of the markets do have thermal proxies in certain locations for voltage because what they don't want to do is to create voltage drop because of large power flows and where the production cost savings are getting from transferring power from one area to the other is this big compared to the units you have to commit to provide voltage supports.

I do think they serve a useful purpose, but I do not view it as a big issue.

MS. NICHOLSON: That is very helpful.

MR. WOFFORD: It depends on the location, how big the issue is as far as if you are the load paying for it, it could be a big issue.

What I wrestle with is if you just continue to show it in uplift, then how do you eventually solve the problem because the generator that is being committed to solve the problem he has committed all the time to solve the problem there are mechanisms for him to receive additional monies above and beyond his cost and he is going to continue to solve the problem.

But that is not necessarily the optimal solution. A perfect solution, if you could put it somehow in the LNP, and the LNP is high enough, it will lead to competitive generation options to solve the problem.

If it leads to other unintended consequences, as Joe said, I mean that is problematic, but just sort of hiding it behind uplift is not the appropriate solution.

Maybe an appropriate solution is something completely out of the box which is that there is some competitive merchant type process where you are looking at transmission alternatives.

You're looking at generational alternatives and you are looking at load response alternatives depending on the size of the uplift that is created in that particular location.

I don't agree, just because of the total dollar basis, it is not huge that we should just leave it alone we should continue thinking about what is the appropriate solution.

MR. O'NEIL: If I can comment? The one thing that I do not think I want to put in to the LNP is reactive power costs because the LNP is supposed to give you a real power signal.

I agree with everything, but first of all, I have no idea of how to put it in the LNP, and secondly, I am not sure if I did, that it would be a good idea.

MR. WOFFORD: I certainly don't

have an idea of how to put it in either. What I think about LNP, LNP as designed is the energy component to meet load is the congestion component, it is the loss component.

The question for these kind of reliability commitments is could there be a fourth component? That is part of it if you could design it appropriately and I don't know the answer to that.

MR. O'NEIL: One of the problems is we used to socialize those costs over a very broad area and when you stop socializing the cost of the reactive power which is usually a very local constraint and you allocate the costs properly you can very often get a much better solution.

You either replace an old clunker with a better generator or you install a capacitor or even may be a steel plant, its reactive power device that controls the voltage, you could set your static core compensator.

There are a lot of interesting solutions that we have not fully worked our way through especially when we are sitting with a very old generator who has a very long minimum runtime and a very high peak rate which generates very high costs sitting there for reactive power that you could probably get at one tenth the cost.

MR. TATUM: I think you could do that just by seeing the uplift in that localized area to take care of it.

Theoretically, I cannot disagree that it would be nice to be able to do the price, but until such time as we know how to do it, at least to be clear as to what we are seeing and not hide it behind a closed loop interface as well.

Dave, I am sorry, I have to disagree. This is a huge problem and it was a huge problem in 2012 in the western part of the PJM system and I think we are seeing a log more of this.

MS. NICHOLSON: Thank you very much. Are there any more questions from FERC staff?

Let me thank you. We could not have had such interesting workshops without our panelists and we thank you very much for coming today.

We thank the RTOs especially for being with us from the beginning and all of the effort that you all took to travel with us.

Now I will turn it over to Mary.

MS. WIERZDICKI: Let me echo our, thanks to all of our panelists on all three workshops.

Many of you are curious about what our next steps will be. We plan to issue a targeted request for comments sometime after the first of the year, so no one needs to worry about sending us comments before the Holidays or New Year's Eve.

Stay tuned for that.