2013 IREP Symposium-Bulk Power System Dynamics and Control –IX (IREP), August 25-30, 2013, Rethymnon, Greece

Oral Discussions on Session: "Markets" – Part II

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Abstract

This paper contains the second part of the transcribed oral discussions of Session "Markets" of the 2013 IREP Symposium – Bulk Power System Dynamics and Control, held on Wednesday morning, August 28, 2013. Papers [1]-[4] were presented.

Discussion

Chair: I'll start the questions and Fernando is first to start.

Fernando Alvarado (Wisconsin): One question for Mr. Hedman [3] and one question for Mr. Van Horn [2]. My question is: it's clear that part of the problem is that the reserve markets and N-1 constraints are often not incorporated properly into the day-ahead clearing prices. In effect the reserves are done on a zonal basis as opposed to a nodal basis. And it will be very straightforward, very straightforward, to create and value reserves on a node-by-node basis. There is some reluctance to do so but it is easy enough to do that and likewise the incorporation of N-1 constraints into the clearing prices should be straightforward. I am not saying that you will necessarily eliminate all out-of-market corrections but the objective ought to be to greatly reduce them. Have you considered the use of nodal reserve prices and full incorporation of N-1 constraints in the determination of market clearing on a day-ahead basis?

Kory Hedman (Arizona State University): Great question. So, you are right. Mid-West ISO has, I think, six zones. You cannot rely on the reserve in the south to go all the way up to North Dakota, so yes, reserve is handled on a zonal basis, but if you want to move to something else… there are a couple different options. There is always the trade-off between market efficiency and complexity. You can take the models we have today and you can simply formulate an extensive form stochastic program that explicitly represents all N-1 requirements. That would then come up with the optimal implicitly determined reserve requirement and that would take care of this approximation that I mentioned, which we have today, where we just not do that. If you do not want to formulate that type of the stochastic programming formulation, and do something else on a nodal basis, which you can do, then you come back to the same debate in terms of the market efficiency vs. computational complexity trade-off. One way of also getting rid of the out-of-market corrections is just to blow up the reserve requirement rules. We can just acquire more reserves than we really need and then once we test it with contingency analysis, we won't have to do something like this. So that's the trade-off. And you can always go back and try to make the model more complex to get rid of this problem, but that's a computational issue or you can adjust the rules to make it more expensive.

F. Alvarado: I don't think the computational issue is a big issue and really there is certain simplicity in having uniform price, I mean just a simple price for your reserves at a node, so the system will tell you: is your node more valuable for providing reserves or providing energy without having to do that. Just a comment: I am agreeing but I think the computation is not the barrier. I think it's the mental status of people being reluctant to consider that this really is a step forward.

K. Hedman: That is also true and there is work, as I said today, going forward with the stochastic unit commitment to begin with and that's why what I am saying is that if you want really to identify what the benefit of the stochastic unit commitment is, like what Jean-Paul Watson of the Sandia National Labs is doing, which is what the Arpa-E which is the program funding him, as well as our project with Shmuel, then you want to incorporate this type of analysis to come up with a right answer. So, that's also what we are saying. It's not as if you cannot get rid of it.

F. Alvarado: Not entirely…

Chair: I would like to add that there is lot of complexity that can be added and we always try to add more and more things explicitly in the market, but for example the California ISO is now looking at having things like predictive corrective dispatch, because usually one of the things that is being done out of market is making sure that

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you have enough resources so that if you have a contingency occurring you can recover back to normal state within 30 minutes, which is the NERC rule. So you often dispatch out-of-merit in order to ensure that, but you can make it now explicit constraint but that now makes the dispatch so much more complex trying to anticipate every contingency, making sure you have reserves to be able to restore normal to operation in 30 minutes and it's an endless process, you can do it more and more complicated. So, this is always is a trade-off. Do you do it out of market or do you try to put all this operating behavior in the constraints?

F. Alvarado: I disagree that it is more complex. But anyway, we'll take it off-line. The results are very simple. It's just a simple price. My second question is to the Gross and Van Horn paper [2]. I was a little surprised with the conclusion that DRR exacerbates the impact of congestion. I can see how it happens, but my question is: do you think that it's a general result or do you think that it is just the quirk of the example you were using?

Kai Van Horn (University of Illinois): Thank you for the question, it's a good one. It's definitely system dependent. I was drawing the attention in my presentation to the arbitrage bandwidth in the system and as I showed in that particular case this is about four times less than the other cases and this is definitely the contributing factor to that. So, yes, it's not a general result, but it is something that may arise and that's why we drew attention to it.

Alex Papalexopoulos (ECCO International): I vehemently disagree with Fernando.

(Laughter)

A. Papalexopoulos: We are in the business of developing LMP markets all over the world. We have tried this nodal AS procurement. It's very, very complicated and there is no need to do that. The zonal procurement for ancillary services works very well actually. And we have become smarter over the years to do nested configurations, overlapping configurations with zones. We have developed all the math, what it happens when the unit is within the nested zone or within the overlapping zones and this works very well in most markets. Kory Hedman has another paper about other zonal configuration definitions and so on, but the fact is the zonal representation can change to accommodate congestions and procurement at zonal level works very well all over the place. So what you say, "Computationally we can do it, it's a simple question to do it", it's not! We have been doing it for 15 years and it's not. It's very complicated and there is a point, where we need to stop putting more things into the design to make things more and more complex. If something works, we shouldn't touch it. So that's the comment for Fernando Alvarado. I have two questions. One is for Kory Hedman [3] and the other is for Kai Van Horn [2]. Kory, in your presentation you really touch upon a very important and sensitive subject: The out-of-market corrections. I agree with you in most of what you said. But we need to be very careful. The reason we are doing out-of-market corrections most of the time is because we have failed to represent specific constraints in the model. A lot of constraints could be put into the model to minimize the out-of-market corrections. We chose not to do it because things could be more complex and less transparent, for example three-dimensional nomograms that the west has. We could do that. Or nonlinear nomograms, we could also do that. It's just a balancing act. The higher the cost of out-of-market, the less efficient the market is. Because it pollutes the prices signal. So, in other words it's not a big problem. If we do the modeling accurate, the number of exceptional dispatch is really manageable. But I want to stay on a comment you made about multiple UC solutions. You refer to a previous paper. This is another very sensitive subject. What we have seen over the last five years, if you tie enough the integrality gap in the MILP formulation, all these multiple solutions go away. We have tested that with CAISO for years. It is almost true. In a rare case, you can make a rare case, but if this were true there would be lawsuits every day in the most litigious society in the world, which is USA. If this were true, with the MILP formulation, modeled properly with all the right constraints put-in to the model with very tight integrality gaps and we can sacrifice certain performance to have another few minutes execution time, you can get to a really very good solution that is not arbitrary. If you relax that integrality gap in order to solve the problem faster, yes I can see this problem…

Chair: It's not. You can tighten, you can change the integrality gap by 10 to the minus 6 and the solution will flip. So if you look … we tried it with multiple integrality gaps …

A. Papalexopoulos: Right, but which formulation? It's a matter of formulation. Which implementation do you use?

Chair: We've got our own software – I mean for unit commitment

A. Papalexopoulos: Which software? I am sorry. It's a matter of the implementation. If you pick up a very solid software that the ISOs use, you don't have this problem. If you use an off-the-shelf, Matlab prototype, university-type program, yes I can see that. But if you use a very…

George Gross (University of Illinois): What's wrong with the "University-type"?

A. Papalexopoulos: But George, it touches upon a very sensitive issue. There are millions of dollars tied to this. If we say that we go to very different solutions that affect market participants, the market is very compromised.

Chair: It doesn't have to do with the software. It has to do with the nature of the problem. The optimum is very flat…

A. Papalexopoulos: Yes, we agree.

Chair: … and you are changing the integrality gap by small amounts and you can use Lagrangian relaxation, you can use CPLEX the solution will jump around and it creates winners and losers. People are not aware of that and nobody makes a big fuss. That's the reality. You smooth things out with make-whole payments. Make-whole payments are smoothing out the implications for the stakeholders.

A. Papalexopoulos: You may want to talk to the surveillance committee about this. Talk to the CAISO about this integrality gap. If you have a solid implementation, not prototype implementations, and you're tight enough, and you put the proper constraints, this problem almost, almost goes away.

K. Hedman: I want to make a clarification point here. So let's go with what you are saying, Alex, that this isn't an issue when you solve the model. But in terms of the example I gave, with an ISO, what they actually do, let's say they take your software and you are saying you get rid of the problem. You get one solution. They take that solution, they look at it, they go back to the software and say: Never choose that again and they re-run the software. If you say don't choose that again, you have to get a different solution and that's what they do. They do that to look for different unit commitment solutions that are within a range with the same cost. So it doesn't matter so much whether or not the unit commitment solver itself is not going to have so much sensitivity, they specifically are going back and saying "get me something else".

A. Papalexopoulos: OK. That's a different objective. If you want something else, because you don't want to put a specific constraint to solve a realistic problem and the solution you get does not give you the right solution in terms of meeting a specific reliability concern, I can see that. But making a comment that we have multiple solutions because the space is flat… For 15 years we know the space is flat, but we have formulations today, and the vendors produce software, that with a very tight integrality gap and the proper implementation of the constraints we need to put in, we get very, very good solutions and we don't have arbitrariness as we thought we did eight, five years ago. That's not the case today. I encourage you to talk to your market operators at the CAISO about this. Ok? I have the second question for Kai [2]. You say that the penetration of RES affects the value of the benefits you get. From the test system you showed, it seems you reach that level when you are about 14-13%. Is that the case?

K. Van Horn: Do you mean the value of energy storage or the demand response?

A. Papalexopoulos: The demand response. Once you reach that level the benefits are kind of diminished.

K. Van Horn: Diminishing margin of returns of the benefits as the penetration deepens.

A. Papalexopoulos: Did you look into systems where the knee, the inflection point of the composite supply curve is very different? Because, where that threshold is, depends on the composite supply curve of the system. You can reach that much earlier, depending on that point beyond which you have almost exponential supply. Have you looked at different systems with different inflection points to confirm that?

K. Van Horn: Yes. I mean the two examples I showed use different composite supply curves. One of them was representative of the MISO supply curve and one of the ISO New England curve. And I know the ISO New England curve in general has two inflection points, one that goes up, then it flattens and then goes up again. So we did look at a couple of different, yes.

Claudio Cañizares (University of Waterloo): My comments and questions are regarding the second paper [2]. I enjoyed very much the analogy you gave between demand response and energy storage and how you compare them and their different impacts. What I am curious is: what was the cost assumed for each one of them? How do you treat them within your model? I couldn't figure out from the paper. That is my question. This is a bit of a loaded question because having worked in home energy management systems, industry management systems demand response for the last 5 years or so with actual customers, we start realizing that the cost of demand response is going to be really high to get to the levels you were discussing, 5, 10 and 15%. Maybe comparable with what it costs you to introduce energy storage in your system. So all of a sudden you have this sort of trade-off and depending on the cost you put in the system maybe the results would be different? I would like you to comment on that. Thanks.

K. Van Horn: Thank you for the question. I'll address the second question first and then the first question. We consider both resources to be operative system resources, used by the ISO to maximize the social welfare objective in the market. So, they are not operated by a private entity to maximize profit. And regarding the question related to the cost: First, we were looking at short term cost, the market outcome, and so we didn't consider the installation cost of the energy storage which can be a significant component of what we have to consider if we want to talk about actual implementation. But, I don't see that the implementation cost of the demand response will grow very much as the penetration deepens. It seems like it would be scaled with penetration. In addition, communication equipment cost is the same as you install more demand response.

C. Cañizares: Our experience with demand response has been that for a fraction of the people willing to participate in these programs they are willing to take that amount of money, whatever they are offered. But as you want to increase participation, the cost of demand response starts going exponentially because in order to attract more people into the program, you need more incentives. So, that's what I was referring to. This is an issue. From my own experience with the industry, actual industrial customers, actual home-owners, unless you give them big incentives, they just really don't care. Some of them do, but the majority do not. And unless you start increasing either the cost of electricity, or give them more incentives to participate in these programs, you know reaching the levels you were discussing seem to be not feasible, at least from my experience in Ontario.

K. Van Horn: I see then. In the United States, when we are referring to demand response participation in the day-ahead markets, the regulations currently in place require the compensation of the resources at the LMP and then additionally they would be receiving the benefit of the energy not purchased at a price that they would have purchased it at the high LMP. So it's not so much selecting the level of incentives, and perhaps you may be right in that at that level the incentives may not be sufficient since the prices would be depressed by the existence of the demand response itself. At the moment the incentives look strong. I didn't show those slides, but the incentives for the demand response are actually much greater than the benefits to the buyers in the system.

Le Xie (Texas A&M University): I also would like to follow up the discussion on the second paper [2]. I applaud your efforts for what you are trying to do so that you provide a unified view of, what I think we can name, energy storage services to the grid. I think in 2009, January, issue of Nature there was a letter about that and we did some similar work on the IEEE Transactions last year about providing this multi-timescale, unified view of energy storage to the grid, of which DRR is part of. I think for this community in particular, one of the perhaps deeper research questions is: given the heterogeneity of the demand response resources and energy storage service providers, what is the right kind of abstraction for these heterogeneous resources, similar to how we treat generators in the EMS or MMS? For example, one of the problems we face is if you are to allow this DR and energy storage in the day-ahead market and things like that, what is the right kind of a ramping rate for a demand response? And this particularly has to do with these multi-timescale and inter-temporal effects. So we know the physics of the generators pretty well. And there are relatively few categories. But demand response is going to be a whole huge different thing. So should we do it in a kind of similar physics-based approach, or should we do it in a data driven approach? What is your comment on that?

K. Van Horn: Thank you for that question. I haven't looked into that too much, but I would just comment to say that definitely for demand response and heterogeneity we can't really draw any broad conclusions about how we represent them. But I think that with time and experience as demand response grows, as I think it can be expected to over the next decade, we can definitely get some insight and make those determinations.

Chair: You know, one of the issues is: what's the best use of demand response in the whole constellation? This is now the hot burner in California, where they are creating flexible ramping products and must address the problem of how different resources can participate in the provision of flexible ramping capability. So, for example, one of the ways the California ISO is defining flexible ramping capability is that you have to be able to sustain a constant ramp for three hours. This is becoming the standard ramping product. And the question then is how do you use other resources, further resources, like demand response, or people even talk about using curtailment of intermittent resources as a way to fill in that need and to match and I think that's what the money for demand response is really going to come from because if you are not going to do that, if you look for projection, the need for flexible capacity it's becoming totally unsustainable because with 33% renewables and maybe going to 40%, we are going to have so many gas units, standing-by on minimum load that it is going to undermine both the economic and environmental benefits of renewable generation. So demand response is really going to play a big role in filling that gap and how to account for that and how to value that capability, is going to depend on creating those markets.

G. Gross: First of all, a comment to what Claudio said before: one of the key issues in demand response is not so much the incentives. In the US they are specified by FERC, so we do not have a choice of offering more or less, or anything like that. That's decided. But, what our analysis has dealt with is also to look at the cost of the energy recovery. Usually most of the studies that we have seen absolutely ignore energy recovery. And that's where this effect of uneconomic behavior might come in. The second issue, in terms of what was just discussed now, in terms of ancillary services, I really see that's where the biggest value is going to come for demand response and it will for the following reason: we will be able to reduce the reserve requirements, if we have reliable demand response, because we don't have to keep all those gas units fired up to provide for that unusual event that we need them, the reserves. What we will be able to do make use of demand response at very strategic times and that's where I see the biggest value in terms of what's coming out in the coming market. But in this work [2], we did not represent anything in terms of the rampability. We were just looking at the value in terms of energy. It was all in terms of day-ahead market analysis.

Chair: Well, I think I am going to close this session so that we can have more time for the IREP business without cutting too much into our break.

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