Evaluating the Effects of Managing Controllable Demand and Distributed Energy Resources Locally on System Performance and Costs

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1. Project Objective

The objective of this project is to use the new multi-period version of the Cornell SuperOPF to analyze the system and economic effects of having high penetrations of renewable energy on a network and to determine effective ways to mitigate the inherent variability of these sources. With the new capabilities of the SuperOPF, it will now be possible to evaluate the effects of shifting demand from peak to off-peak periods. Previous research has shown that higher penetrations of renewables are associated with higher annual costs for conventional installed generating capacity ($/MW/Year) due to increased “missing money”. Consequently, there are likely to be substantial economic benefits from reducing peak system demand and the associated amount of installed capacity needed for System Adequacy. These benefits will be an important source of economic value for different types of storage such as utility scale storage and distributed storage (e.g. Plug-in Hybrid Electric Vehicles/Electric Vehicles (PHEV/EVs) and thermal storage). The research will determine the correct economic incentives for new participants in the wholesale market, such as aggregators of controllable demand, and demonstrate how the economic viability of storage improves when the storage is compensated from providing different services to the system. The analyses will be based on case studies using a reduced network model of the NPCC system. This project continues from FY2011.

2. Major technical accomplishments

The main technical accomplishment has been the successful testing of a new stochastic form of multi-period Security Constrained Optimal Power Flow (SCOPF, the SuperOPF). This framework has been used to evaluate case studies that simulate the system costs of operating a bulk power electric grid with high penetrations of generation from renewable sources such as wind turbines. An important characteristic of these renewable sources is that they are inherently variable and impose an additional challenge for system operators to maintain the reliability of supply for customers. Hence, it is important to capture the stochastic nature of wind generation realistically in the formulation and to determine the amount of “reserves” needed for reliability purposes endogenously (System Adequacy). The ability to do this effectively is one of the important features of the SuperOPF.

A primary objective of this research is to determine the correct economic incentives for new participants in the wholesale market, such as Aggregators of Residential Customers (ARC), that reflect the true system benefits of managing demand intelligently at the substation level. Since current retail rate structures do not do this, a secondary objective is to demonstrate how the economic viability of demand response, particularly distributed storage, improves when it is compensated correctly for 1) managing purchases of electricity efficiently through time, and 2) providing different services, such as ramping to mitigate wind variability, to the grid. The analyses are based on case studies using a reduced network model of the grid in New England and New York State. Using the SuperOPF, it is possible to 1) optimize the use of storage capacity over a planning horizon, 2) incorporate a realistic representation of the stochastic characteristics of wind generation, and 3) determine the optimum level of reserve generating capacity needed to cover equipment failures (contingencies) and ramping requirements associated with changes in aggregate demand and wind generation.

A preliminary analysis shows that the optimum composition of hourly dispatch is very sensitive to how the stochastic properties of wind generation are represented in the model. For example, treating potential wind generation as deterministic but still allowing for variability from period to period, makes system costs much lower because less wind is spilled. This demonstrates that it is important to use a realistic representation of the stochastic characteristics of wind generation to determine the true optimum pattern of dispatch.

The main results compare the level and composition of system costs in the wholesale market for five different cases, a base (Case 1) and four cases with additional wind capacity. Case 2 has the extra wind capacity at 16 different sites with no other features and the other three cases have one additional feature compared to Case2. Case 2u adds unconstrained transmission capacity, Case 3 adds deferrable demand at six load centers, and Case 4 adds a similar level of Energy Storage Systems (ESS) collocated at the 16 wind sites. The policy debates of how to integrate more wind generation into the grid generally conclude that building additional transmission capacity is essential. The results show that it is also important to mitigate the inherent variability of wind generation effectively. Without some form of inexpensive mitigation, the ramping costs of using conventional generators to offset changes in wind speeds result in more wind being spilled. In other words, the least-cost dispatch uses less wind generation even though this source is offered at zero cost into the market. For the specific network topology representing New England and New York State, adding storage capacity in Cases 3 and 4 leads to more wind being dispatched than upgrading transmission in Case 2u even though all congestion on the network is eliminated. The results also show that using deferrable demand in Case 3 as a form of storage at the load centers is almost as effective at dispatching more wind as collocating storage at the wind sites in Case 4, and deferrable demand actually provides a slightly higher revenue stream for the wind generators.

The differences in operating costs among the four wind cases are relatively small but they are all substantially lower than Case 1 with no additional wind generation. The main difference in total system costs among the four wind cases is that the total amount of nonwind generating capacity needed for reliability and the associated capital cost are both much lower with deferrable demand in Case 3. It is reasonable to assume that an economically successful smart grid must yield significant economic net benefits for customers. This only happens in Case 3 with deferrable demand and the total system costs are 25% lower than the base Case 1. This reduction is much larger than it is in any of the other cases, including upgrading transmission in Case 2u and adding ESS in Case 4. The main reason is that deferrable demand can be used to lower a customer's purchase of power from the grid at the peak system load, and thereby, reduce the total amount of conventional generating capacity needed to maintain reliability.

Deferrable demand also provides ramping services that mitigate the variability of wind generation and reduce the ramping by conventional generators. In fact, it is providing this service that makes deferrable demand in Case 3 a better option than upgrading transmission in Case 2u. Even though there is a substantial amount of congestion on the network when the system load is high that limits the transfer of wind generation to the load centers, eliminating all congestion in Case 2u does not deal with the uncertainty of wind generation effectively and the amount of wind dispatched is virtually the same in Cases 2u and 3. Case 3 is also a better option than installing ESS in Case 4. Even though ESS is a better way to mitigate the wind variability, it does not reduce the peak amount of power purchased from the grid by customers.

3. Deliverables

Papers published and presented at professional conferences:

1. Mount, Timothy D.; Alberto J. Lamadrid, Surin Maneevitjit, Robert Thomas, and Ray Zimmerman, "The Hidden System Costs of Wind Generation in a Deregulated Electricity Market," *Journal of Energy Economics*, 33 (1), 173-198, 2011.
2. Tim Mount, Alberto Lamadrid, Wooyoung Jeon and Hao Lu, "Is Deferrable Demand an Effective Alternative to Upgrading Transmission Capacity?" prepared for the 31st Annual CRRI Eastern Conference, Shawnee PA, May 16-18 2012.
3. Tim Mount, Alberto Lamadrid, Wooyoung Jeon and Hao Lu, "Is Deferrable Demand an Effective Alternative to Upgrading Transmission Capacity?" prepared for the 31st Annual CRRI Eastern Conference, Shawnee PA, May 16-18 2012.
4. Tim Mount and Alberto Lamadrid, "Using Deferrable Demand to Increase Revenue Streams for Wind Generators" prepared for the 25th Annual CRRI Western Conference, Monterey CA, June 27-29 2012.
5. M. Kezunovic, Vijay Vittal, Sakis Meliopoulos and Tim Mount, "Smart Research for Large-Scale Integrated Smart Grid Solutions", *IEEE Power and Energy, Vol. 10 Num. 4, 2012.*
6. A. D. Dominguez-Garcia, S. T. Cady, and C. N. Hadjicostis, "Decentralized Optimal Dispatch of Distributed Energy Resources," submitted to IEEE Conference on Decision and Control, under review.

Presentations:

1. Tim Mount, Wooyoung Jeon, Alberto Lamadrid and Jung-Youn Mo, "Utopia Electric: Developing a Smart Grid that Customers can Afford", Presented at the Workshop on "Advances in Electricity Planning & Policy Modeling", FERC, Washington DC, 10 November 2011.
2. Tim Mount, Wooyoung Jeon, Alberto Lamadrid and Jung-Youn Mo, "Utopia Electric: Developing a Smart Grid that Customers can Afford", Presented at the Workshop on "Towards the Smart Grid", Lehigh University, 20 January 2012.
3. Tim Mount, Wooyoung Jeon, Alberto Lamadrid and Jung-Youn Mo, "Utopia Electric: Developing a Smart Grid that Customers can Afford", Presented in the LBNL seminar series, Berkeley CA, 20 March 2012.
4. Tim Mount, "Could there be an era with much lower utility bills?" Presented at the NY Association of Energy Economics, 26 April 2012.

4. Risk Factors

The new multi-period SuperOPF is a very complex model and the initial investment of effort needed to get it operational was greater this year than expected. However, there are now major benefits associated with using this analytical framework, such as the ability to optimize and evaluate the use of storage and deferrable demand on a network. It is expected that new, interesting results will continue to be forthcoming for the remainder of FY2012.

5. Proposed Research for FY2013

It is clear from the case studies completed in FY2012 using the SuperOPF that there is a great deal of potential for demand resources, particularly deferrable demand, to play a larger role in operating the electric grid more efficiently by 1) lowering total system costs and customers' bills, 2) improving system reliability, and 3) accommodating substantially more generation from renewable sources effectively. The proposal for FY2012 is to continue this type of analysis to 1) cover operations over a year and make it possible to incorporate capital costs more effectively, and 2) determine the total cost to customers of investing in their own demand capabilities. The basic objective is to understand the tradeoff between customers providing some services/capabilities versus the traditional way in which the utilities supply all of the services needed to run the grid reliably and meet load.

With these analytical capabilities in place, it will be feasible to model demand-side participation in operating the grid. In other words, wholesale customers and Aggregators of Residential Customers (ARC) would manage their own demand resources and respond to real-time price signals at the substation level. The objective of these demand operators would be to minimize net payments made to the ISO while still meeting the local energy needs of their customers. This hierarchal structure would be compatible with running the grid using a rolling horizon that puts a greater emphasis on the real-time commitment of resources rather than the traditional day-ahead scheduling. If operations are optimized in real-time as new information becomes available on wind resources, for example, demand operators could respond (or establish automatic controls). It would also be necessary to follow the practice used in Australia, and more recently in Texas, for the ISO to provide forecasts of future prices. These prices need not be binding for transactions but are needed to schedule storage and deferrable demand efficiently. Modeling this type of hierarchal control of the electric grid would involve the use of computer agents to represent the behavior of demand operators at different substations.