The Brattle Group

Policy Challenges Associated with Renewable Energy Integration

April 2011

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Prepared for

2011 MITEI SYMPOSIUM:
Managing Large-Scale Penetration of Intermittent Renewables

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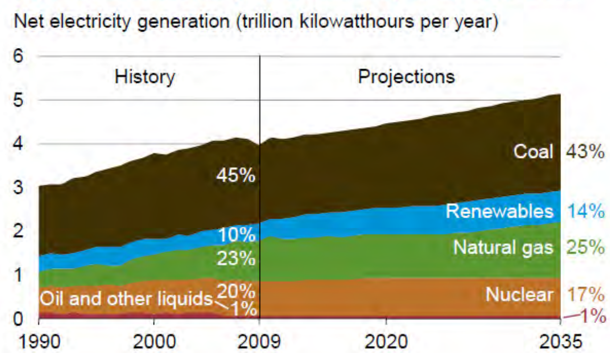
I. INTRODUCTION

During the next 100 years, the world's electricity systems will almost certainly transition to a high degree of reliance on renewable energy generation resources. Over 29 states currently have renewable portfolio standards (RPSs), requiring utilities to purchase a total of approximately 60,000 MW of renewable energy by the year 2025. The Department of Energy's Energy Information Administration projects that an additional 54,000 MW of renewable generation will be added to the US grid by 2035.[1] As shown in Figure A, net energy generation from renewable energy is projected to rise from 10% to 14% of total U.S. supply by 2035.

Figure A



Source: U.S. EIA Annual Energy Outlook 2011 Early Release Overview

For the next several decades, these renewable resources will be added to a system that operates via centralized controls and price signals to balance regional generation and load continuously, but which has very little large-scale storage. In a system for which its safe operation historically has required that total supply be immediately adjustable to match load, the inability to control the output of variable renewable power sources introduces new technical and policy considerations. These considerations require new protocols to maintain reliability at required levels that apply in all three power system time frames: the planning horizon (one to ten years); the commitment and dispatching (operating) time frame (a few months to the current hour); and the reliability time frame of seconds to minutes following a reliability event.

In traditional power systems, the penetration of uncontrollable variable generation sources has historically been quite small. Accordingly, one can compare the difference in the overall costs of building and operating systems with higher and lower amounts of variable supplies and treat this difference as the costs that variability imposes on the system. Today, this is commonly called the costs of integrating variable resources.

While the notion of renewables integration costs is a useful construct today, two accompanying notions should be kept in mind. First, integration costs are not the same as total comparative system costs, as they do not factor in any benefits of renewable sources not captured in the system cost calculations. For example, from the customer standpoint, renewable sources provide

[1] U.S. Energy Information Administration "Annual Energy Outlook 2011" Reference Case, December 16, 2010. Can be found at: http://www.eia.gov/neic/speeches/newell_12162010.pdf

valuable fuel price hedges, but renewables are not credited for this value when measuring integration costs.[2]

The second point to keep in mind is that the underlying benchmark system against which variability's cost is measured is changing gradually over time. As storage becomes cheaper and more common, grid operators develop better monitoring and control algorithms, and dynamic prices self-modulate consumer demand, the costs imposed by variable renewable generation will diminish. Ultimately, we can foresee a much smaller variability premium as the system becomes designed around continuously varying distributed resources and loads.

For the near future, however, these costs are significant. They spread themselves across all three time frames. In this paper, we briefly survey the nature and size of these costs and the policies being adopted to measure and collect them. Although there is enormous overlap with similar issues in the European Union today,[3] we confine our examination to North America.

II. CURRENT OVERALL RESEARCH

Utilities and organizations responsible for grid reliability already have begun to examine the potential issues associated with a significant penetration of intermittent renewable energy. In anticipation of the operational and reliability impacts which renewable resources may have on the grid, the North American Electric Reliability Corporation (NERC) issued a report in 2008, titled Accommodating High Levels of Variable Generation.[4,5] There have also been numerous studies by utilities and independent system operators (ISOs), among them: the CAISO Integration of Renewable Resources studies (2007, 2010),[6,7] the New England Wind Integration Study (2010)[8], the Minnesota Wind Integration Study (2006),[9] the Wind Integration Study for Public Service Company of Colorado (2006, 2008),[10] Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements (2008),[11] Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio (2007),[12] and the NYISO 2010 Wind

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2 See, Peter Fox-Penner, Smart Power (Island Press, 2010), pp. 56-65 for a discussion of the benefits of distributed generation.

3 For example, see "Integrating Intermittent Renewables Sources into the EU Electricity System by 2020: Challenges and Solutions," Eurelectric, 2010.

4 http://www.nerc.com/docs/pc/ivgtf/IVGTF_Outline_Report_040708.pdf

5 One of the seemingly mundane operational questions faced is simply creating a uniform approach to the reporting of renewable resource outages and deratings which is comparable to that for conventional generation. See http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/PAP16Objective1/NERC_GADS_Wind_Turbine_Generation_DRI_100709_FINAL.pdf

6 http://www.caiso.com/1ca5/1ca5a7a026270.pdf

7 http://www.caiso.com/2804/2804d036401f0.pdf

8 http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_es.pdf

9 http://www.state.mn.us/portal/mn/jsp/content.do?contentid=536904447&contenttype=EDITORIAL&hpage=true&agency=Commerce

10 http://www.nrel.gov/wind/systemsintegration/pdfs/colorado_public_service_windintegstudy.pdf
http://www.uwig.org/CRPWindIntegrationStudy.pdf

11 http://www.uwig.org/AttchB-ERCOT_A-S_Study_Final_Report.pdf

12 http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm

Generation Study[13]. These studies vary in scope and methodology, but in general, analyze the potential implications of high wind turbine generation and solar generation penetration on system reliability, scheduling, and planning, as well as the effect on markets and the rules that govern market transactions.

While the precise methods used in these renewable integration analyses vary, their conclusions are more or less consistent. For example, all of the above studies conclude that a high penetration of variable generation will increase the grid's need for regulation, load-following and other ancillary services needed to help compensate for the variability and uncertainties associated with their generation pattern. Estimates for the costs of these ancillary services are in the range of $5 to $20 (2011$) per MWh of wind energy accepted by the system.

III. OPERATION AND PLANNING CHANGES

While the existing power system has traditionally been designed to meet varying demand levels from one moment to the next, it has not been developed to respond to large unexpected variations in both generation output and in load. Although load exhibits significant variability, the overall seasonal, daily, and hourly patterns typically result in enough predictability to permit the month, week, and day-ahead scheduling of resources, both in magnitude and kind, *i.e.,* unit commitment. When the variability of generation resources is small relative to that of load, the system uses generation resources that can quickly match their output to the varying demand above "base load" levels. On the smallest time scale of second to second or minute to minute, certain generators are interconnected to the grid in such a way that they automatically respond to those varying demand levels by providing frequency control and regulation services. "*Primary frequency control* involves the autonomous, automatic, and rapid action (*i.e.,* within seconds) of a generator to change its output to compensate large changes in frequency. Primary frequency control actions are especially important during the period following the sudden loss of generation, because the actions required to prevent the interruption of electric service to customers must be initiated immediately (*i.e.,* within seconds).[14]" In addition to primary frequency control, the grid operator must have the capability to provide secondary frequency control. "*Secondary frequency control* involves slower, centrally (*i.e.,* externally) directed actions that affect frequency more slowly than primary control (*i.e.,* in tens of seconds to minutes). Secondary frequency control actions can be initiated automatically or in response to manual dispatch commands. *Automatic generation control* (AGC) is an automatic form of secondary frequency control that is used continuously to compensate small deviations in system frequency around the scheduled value."[15]

On the time scale of generation and transmission scheduling, blocks of energy may need to be dispatched up or down to supplement the wind and solar energy that are used on a must-take basis. Together, one can think of these compensations as "balancing services" needed to maintain system equilibrium and reliability. Balancing services can come from some of the existing generation fleet and demand-side resources. However, planning for the future requires a

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13 http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf

14 Eto, Joseph H. *et al.,* Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Lawrence Berkeley National Laboratory, LBNL-4121 at p. 9. (http://certs.lbl.gov/pdf/lbnl-4142e.pdf)

15 Ibid at p. 9

fresh look at what that optimal mix would be for the coming decades as renewable generation becomes a significant and possibly dominant resource on our systems.

IV. TODAY'S OPERATIONAL CHALLENGES

Electric systems have always had to accommodate continuously changing customer loads and some variability in generator output, including planned and unplanned generator and line outages. A portion of renewable integration costs is simply the result of higher levels of variability in operating generator output than previously experienced. In the operating time frame, the main challenges can be summarized as follows:

First, wind and solar generation resources exhibit significant minute-to-minute variations in their output. Their variations alone may not be troublesome; however, the unpredictability of their variations creates new operational concerns. Recall that the grid operator must continuously keep the system in balance. Thus, the grid operator is faced with "guessing" what resources will be needed to compensate for the loss/gain in output from the intermittent renewable resources. Ultimately, the amount of compensating resources needed depends on how "wrong" the grid operator is at various time frames. For example, regulation services are used to compensate the second-by-second deviations from the 10-minute-ahead forecast that determines the generators' dispatch. As an example, if the operator expected 100 MW of wind for the next 15-minutes, but only 96 MWs (more or less) actually show up, regulation services will be used to compensate those second-to-second deviations from the 100 MW forecast. It is precisely those deviations that drive how much regulation service the system will need.

Given both the uncertainty and the variability of wind and solar generation, systems need more generation than in the past that can quickly ramp up and down, possibly with short start-up times and minimal cool-down times. Whether or not such new demand on cycling and peaking plants can be met by existing generation — which could experience low profitability due to low capacity factors — is an empirical question, and each system must evaluate the physical and economic drivers that its generation fleet faces or will face in the future.

Second, by displacing some of the marginal peaking and cycling generation, wind and solar generation also forces some traditional baseload plants to operate as cycling units, many of which are not designed to do so. This reduces their capacity factors and, revenues, and increases their heat rates. For many units not designed for cycling, the additional ramping can significantly increase going-forward operation and maintenance costs, further reducing their profitability. The combined effect of these first two situations is illustrated in Figure B below.[16]

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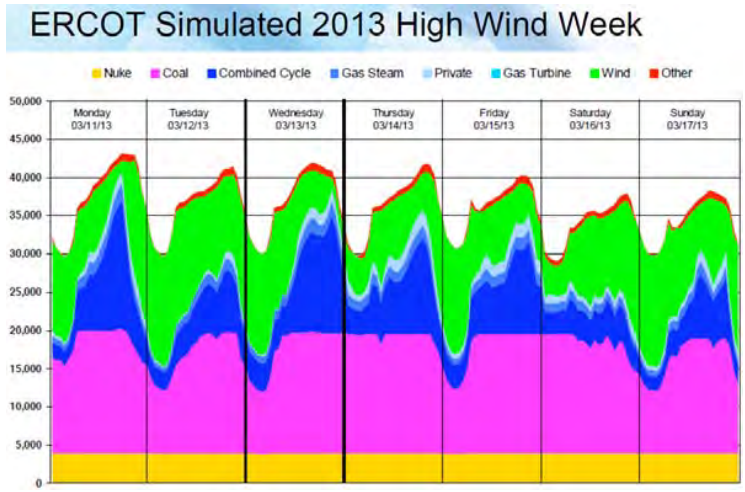
[16] Source: ERCOT Energy Seminar 2009, Chairman Barry T. Smitherman, Public Utility Commission of Texas, November 12, 2009.

http://www.puc.state.tx.us/about/commissioners/smitherman/present/pp/GDF_Suez_111209.pdf

Figure B



Source: ERCOT Energy Seminar 2009, Public Utility Commission of Texas, November 12, 2009

Third, because wind often tends to be stronger during off-peak periods such as during the night, the resulting higher wind generation output tends to exacerbate the existing system's "over-generation" condition. Over-generation occurs when load is lower than the amount of dispatched generation on a system. Most of these situations occur because baseload plants with relatively high minimum generation levels[17] and long start-up and shut-down time, cannot be turned off economically and reliably over-night when they have to be turned back on for the next day. Thus, during those hours in the middle of the night, neither the baseload generators' nor the wind plants' owners would want their generation curtailed. Each of those plant types would be willing to receive zero to slightly negative prices before they would agree to reduce their production levels.[18] This is particularly acute with high penetrations of wind generation because while wind generation output may increase at night, its output is greatly reduced during the day (particularly hot humid days when air-conditioning and other cooling loads are at their maxima) and conventional generation must be energized. Negative energy prices already are observable in Texas and the Midwest, as shown in Figure C for ERCOT[19] system in 2010 and Figure D for MISO[20] in 2009.

Finally, because most renewable resources are needed to satisfy the growing renewable portfolio standards, and they have near-zero marginal costs, they are typically operated as must-run

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[17] We have estimated that the coal plants in the Midwest-ISO market have a minimum generation level of about 60% relative to their peak generation capacity.

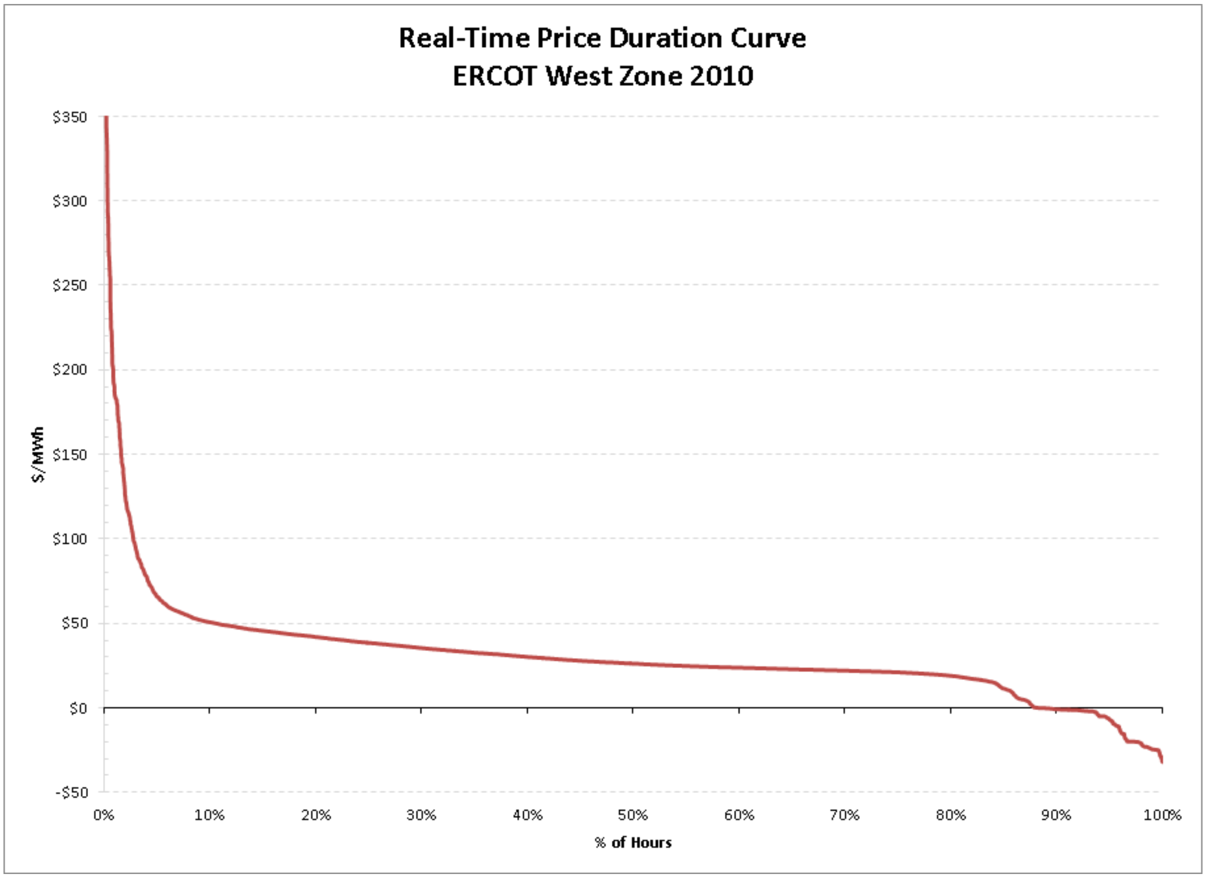
[18] In many cases, wind plants that qualify for Renewable Energy Credits (RECs) and/or Production Tax Credits (PTC) are willing to receive negative market energy prices because their opportunity cost of not producing would be the foregone values of RECs and PTC, which in most cases are greater than \$20/MWh. In some cases, the generator is paid both for the implied value of RECs and PTCs through their long-term contracts with load-serving utilities even if the power is curtailed, in which case, the generators would curtail before receiving negative prices. However, under those circumstances, it's usually the rate-payers who ultimately pay for the renewable generation contracts are left paying twice, once for the environmental attributes that they never received due to the curtailment, and another time for the coal generation that could not be backed off.

[19] Source: ERCOT market data from http://www.ercot.com

[20] Source: 2009 State of the Market Report Midwest ISO

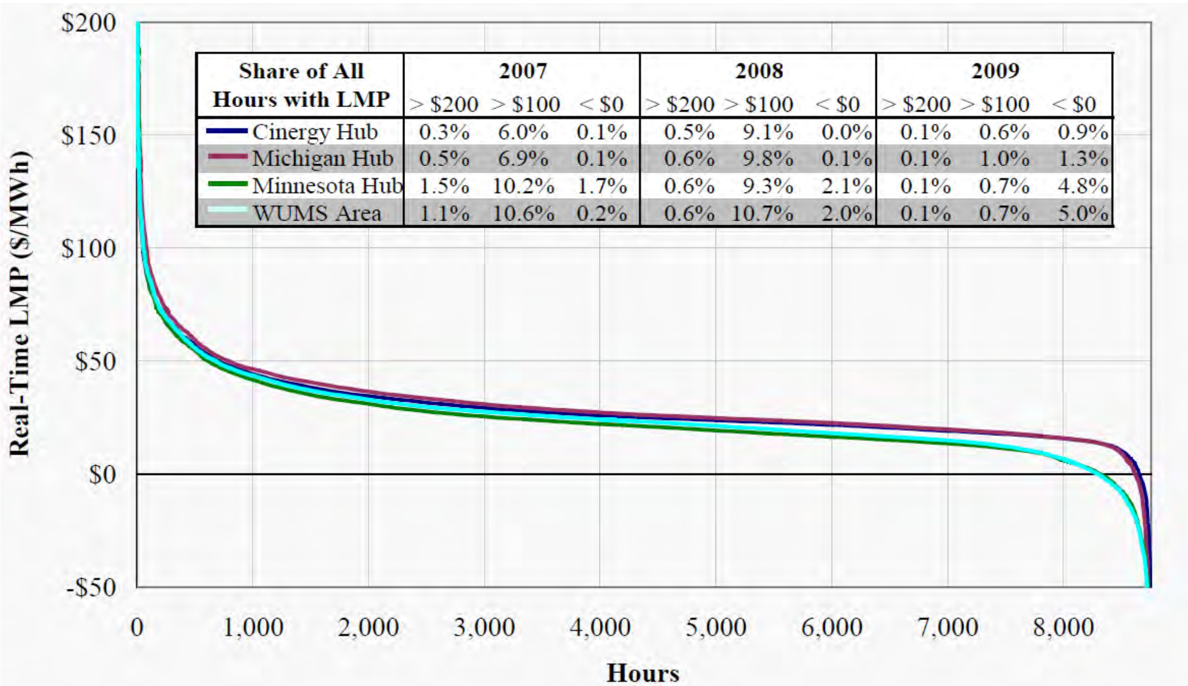
generation, that is, when they generate, the system operator must accept their output. Operated as must-run, they force the grid operator to reduce the output of existing marginal generation resources, triggering all of the adverse impacts noted above. In deregulated markets where generators may have no revenues sources beyond hourly energy sales. The consequent revenue reduction could force some plants to shut down, reducing cycling and peaking generation just when it may be needed.

Figure C



Source: ERCOT market data from http://www.ercot.com

Figure D
Real-Time Price Duration Curve
Midwest ISO Pricing Hubs
All Hours 2009



Share of All Hours with LMP	2007 > $200	2007 > $100	2007 < $0	2008 > $200	2008 > $100	2008 < $0	2009 > $200	2009 > $100	2009 < $0
Cinergy Hub	0.3%	6.0%	0.1%	0.5%	9.1%	0.0%	0.1%	0.6%	0.9%
Michigan Hub	0.5%	6.9%	0.1%	0.6%	9.8%	0.1%	0.1%	1.0%	1.3%
Minnesota Hub	1.5%	10.2%	1.7%	0.6%	9.3%	2.1%	0.1%	0.7%	4.8%
WUMS Area	1.1%	10.6%	0.2%	0.6%	10.7%	2.0%	0.1%	0.7%	5.0%

Source: 2009 State of the Market Report Midwest ISO

In addition to incurring an O&M and heat rate penalty from greater cycling, the latter negatively affects plant and system air emissions and therefore air emissions compliance costs. As noted above, the variability of wind and solar output requires that conventional units operate at lower levels to preserve their ability to be called on for immediate response. Those units are frequently combined cycle gas turbines. Combined cycle gas turbines (CCGT) typically have low NOx burners which reduce their nitrous oxides emissions by lowering the temperature of combustion. However, this type of control has significantly reduced effectiveness if the generator operates at less than sixty percent of its nominal rating, as will be the case when they are operating as a regulation services source for intermittent resources. This also occurs when intermittent generation, operating as 'must-take' units, forces reductions in CCGTs level of output or generation efficiency. In addition, baseload units that have been forced to cycle but are not designed to do so will, as noted above, suffer from increased heat rates, in which case they will be burning significantly greater amounts of fuel to produce the same level of electric output. Such increases in fuel use also result in increased emissions.

V. ISSUES IN THE PLANNING TIME FRAME

The above operational changes are starting to affect the criteria used for long-range system planning. Many renewable integration studies have already identified the need for fast ramping resources to help "balance" the intermittent generation. The ramping requirement is a multi-dimensional puzzle at various time scales, involving capacity, ramp rate (in MW/min) and ramp duration. For example, the CAISO renewable integration studies have estimated the ramping requirement associated with regulation and separately with load-following requirements. The 2010 CAISO study finds that the simulated maximum load-following down ramp rate could be as high as -845 MW/5min, which could pose a challenge to the system.[21] However, these estimated ramp requirements do not directly translate into a specific resource type or capacity size that would be needed to resolve the need.

Some researchers have argued that most of that additional need can be met with existing generation and demand-side resources.[22]. But how much of existing resource can be used to meet the new ramping needs is a non-trivial empirical question that requires detailed evaluation of each system, including inventorying the capability of existing fleet and demand response capabilities to determine if newer technologies would be needed.

In some jurisdictions, the increasing penetration of renewable energy is taking place at the same time that some baseload generation will likely retire due to pending EPA regulation. In addition, as discussed above, higher renewable penetration tends to decrease the wholesale price of energy which places downward pressure on the profitability of other market-priced generation, including some cycling plants that typically can be used to meet the ramping needs at various time scales.

More sophisticated tools for reliability calculations by ISOs and other grid operators may also be needed. Likely of more crucial importance in future planning is accounting for the time connectedness of the states of the system. Many of the planning tools have a kind of implicit time-independence in their calculation of the system's state of reliability, *i.e.,* the system's potential to fail to meet load requirements. That works when the energy source for generation lacks time dependency. The energy sources for intermittent resources, *i.e.,* wind and solar inputs, have a very strong correlation with time and this information needs to be brought to bear on the calculation of reliability. Even using existing models, the reliability criterion may need to be re-evaluated. For example, effective load carrying capability may be a better choice for assessing a generator's potential contribution to the system's reliability than simply its rated capacity and outage rates.[23]

VI. POLICY RESPONSES TO THESE CHALLENGES

A. POLICIES PROPOSED BY FERC

Several of the challenges just discussed and others were the subject of a FERC Notice of Inquiry in January 2010 (Docket No. RM10-11-000). In that proceeding, dozens of industry stakeholders presented valuable comments and perspectives. Out of the several potential layers of issues, FERC decided to first focus on three primary topics in its subsequent Notice of

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21 "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS," August 31, 2010, CAISO at p. viii.

22 Kirby & Milligan, "The Impact of Balancing Areas Size, Obligation Sharing, and Energy Markets on Mitigating Ramping Requirements in Systems with Wind Energy,"
www.consultkirby.com/files/milligan-kirby-wind-engineering-part2.doc

23 See L.L. Garver, "Effective Load Carrying Capability of Generating Units", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-85, No. 8 (August, 1966) and L. Soder ad M. Amelin, "A review of different methodologies used for calculation of wind power capacity credit" (http://www.ee.kth.se/php/modules/publications/reports/2008/IR-EE-ES_2008_013.pdf). For an example applied to wind resources, Xcel Energy's An Effective Load Carrying Capability Study for Estimating the Capacity Value of Wind Generation Resources. (http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCoELCCFinalReport030107.pdf) Also, see the discussion in R. B. Billinton and R.A. Allan, Reliability Evaluation of Power Systems, 2d ed, (New York: Plenum, 1996) on Markovian reliability assessments.

Proposed Rulemaking (NOPR) in November 2010 (Docket No. RM10-11-000). In that NOPR, FERC proposed reforms to the pro forma Open Access Transmission Tariff (OATT) to help integrate the growing amount of variable energy resources. The proposed changes include:

1. Require public utility transmission providers to offer intra-hourly transmission scheduling. Specifically the NOPR proposes to require public utility transmission providers to offer all customers the option to schedule transmission service at 15-minute intervals instead of the current hourly scheduling procedure. The more frequent scheduling interval would provide for greater accuracy in scheduling and thereby reduce the amount of ancillary services that systems would need to provide and customers would need to purchase.

2. Incorporate provisions into the pro forma Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to public utility transmission providers for the purpose of improved power production forecasting.

3. Add a new ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area. This service would provide transmission providers an opportunity to recover costs associated with the integration of variable energy resources. FERC specified that it expects transmission providers to implement the intra-hour scheduling and power production forecasting as conditions to collect additional charges under the new ancillary service.

Of the many operational and planning issues and potential solutions FERC has chosen, likely the most relevant ones to deal with renewable resource integration and the transmission system appear in its January 2011 NOPR. First, requesting transmission service providers to set up procedures for intra-hour transmission scheduling is a move in the right direction. FERC's intention in requiring shorter scheduling time intervals is to help manage the systems' variability more effectively and efficiently with less reliance on ancillary services. From a conceptual level, increasing the frequency of scheduling could improve the efficiency of the system and allowing flexible resources to respond to changes of variable resources on the system.

However, based on the comments submitted by many industry participants, particularly transmission providers, how the intra-hour transmission scheduling would be implemented ultimately is currently not yet clear. One commenting party stated: "The Commission should clarify what processes a transmission provider will have to perform at 15-minute intervals. For example, will the transmission provider be required to review and approve E-tags at 15-minute intervals, settle generator imbalance on 15-minute intervals, and review and address Available Transfer Capability, reserve change issues or loop flow change issues at 15-minute intervals?"[24] A less important concern is how the scheduling will coincide with the RTO's calculation of LMPs. The fifteen minute transmission schedule is not problematic if the RTO calculates LMPs on a five minute basis, but may be if the interval is ten minutes, or any other even multiple of five.

Second, FERC would like variable generation resources to provide more forecasting data to grid operators to help them manage the system more effectively. In our view, the NOPR's proposed

[24] Comments by the Pacific Northwest Parties in FERC Docket No. RM10-11-000, March 2, 2011, page 17.

requirement along these lines is a move in the right direction. The proposed policy will increase the demand for wind and solar power production forecasting and over time, those forecasts should improve in their accuracy. Less clear is whether there will be any penalties for failing to forecast with a modicum of accuracy.

Finally, FERC is allowing transmission providers to add a new transmission service to pay for the regulation and frequency control service used to compensate variable generation. The FERC has in mind that such regulation reserve costs will be allocated to those that caused the costs. We believe that such a cost causation principle is appropriate; however the implementation of the cost allocation will not be simple. For instance, every grid operator would need to distinguish the incremental amount of regulation that variable generators impose onto a system. Such analysis would require an assignment and quantification of the amount of regulation used to serve load variability (and perhaps the variability of conventional generation) separately from the amount of regulation used to compensate for wind and solar variability and uncertainty. Further, as we have discussed above, there are other integration services needed and the costs associated with them may require further analyses.

In February of 2011, the FERC also issued a Notice of Proposed Rulemaking on the Frequency Regulation Compensation in the Organized Wholesale Power Markets.[25] In the NOPR, FERC proposes that RTOs and ISOs be required to implement a two-part compensation structure for the provision of regulation. First, a uniform price for regulation capacity will be paid to all resources that clear in an (hourly) regulation auction market. Secondly, an additional "performance payment," which reflect a "resource's accuracy of performance" would also be rendered. FERC argues that "taking advantage of the capabilities of faster-ramping resources can improve the operational and economic efficiency of the transmission system and has the potential to lower costs to consumers."[26] In essence, the NOPR attempts to investigate whether there is a substantial difference in regulation service quality as provided by conventional (often slower) resources vs. regulation provided by newer technology such as battery storage devices. The NOPR cites a recent study by the Pacific Northwest National Laboratory[27], which examined the extent to which faster-ramping resources can replace conventional generation resource, currently providing regulation. The authors found that, "compared to the current CAISO fleet mix providing frequency regulation, which includes fast-responding hydro units, 1 MW of a limited energy ideal resource could replace 1.17MW of the current generation mix."[28]

B. New Rules for Scheduling and Dispatching Renewable Generators

Virtually all RTOs and ISOs have completed wind integration studies and, with active input from stakeholders, are addressing renewables integration issues via specifically-dedicated working groups.

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25 Notice of Proposed Rulemaking. Frequency Regulation Compensation in the Organized Wholesale Power Markets. FERC Docket Nos. RM11-7-00 AD10-11-000.
http://www.ferc.gov/whats-new/comm-meet/2011/021711/E-4.pdf

26 Ibid. at p. 2.

27 Makarov, Y.V., Ma, J., Lu, S., and T.B. Nguyen, "Assessing the Value of Regulation Resources Based on Their Time Response Characteristics," Pacific Northwest National Laboratory, PNNL-17632, June 2008.

28 In the study, an "ideal resource" was defined as a resource that has a ramp rate equal to its entire capacity in one minute.

The California Independent System Operator (CAISO) published its first comprehensive wind integration study in 2007[29] and recently completed a second study focusing on the operational requirements and generation fleet capability at 20% RPS.[30] CAISO's present focus on meeting the challenges of renewables integration is defined by an updated 20% RPS resource mix, which includes 2,200 MW of solar resources and the intent to investigate the sub-hourly operational challenges presented by the mix of solar and wind resources on the California grid. The CAISO found that introducing solar generation to the renewable portfolio changes the initial 2007 findings relative to a wind-only case. Integrating solar generation is expected to increase the load-following down and regulation down requirements in mid-morning and the load-following up and regulation up requirements in early evening. On the other hand, the mix of wind and solar generation can reduce the operational strains in other hours due to output diversity. Finally, the CAISO concludes that there may be significant reductions in energy market revenues to thermal generation due to the displacement by wind and solar and the reduction in market clearing prices. The study recommends that market and operational mechanisms to improve utilization of existing generation fleet operation flexibility be evaluated. In addition, CAISO suggests investigating ways of obtaining additional operational flexibility form wind and solar resources and making improvements to the day-ahead and real-time forecasting of operational needs.

In 2010, NYISO completed its most recent Wind Generation Study.[31] The study was a follow-up to its 2004 study, which had concluded that the New York Power System can reliably accommodate up to a 10% penetration of wind generation (3,300 MW) with "only minor adjustments to and extensions of existing planning, operation, and reliability practices."[32] Given the presence of more than 3,300 MW of wind on the NYISO interconnection queue and the New York RPS standard of 30% by 2015, an updated examination of wind integration issues and challenges was needed.

In terms of reliability, the study finds that the addition of up to 8,000 MW of wind generation to the New York Power System "will have no adverse reliability impact."[33] However, the addition of wind generation will increase system variability as measured by net-load, with the increase varying over seasons, months, and time of day.

At present, NYISO has a FERC-approved (2008) centralized wind forecasting system for scheduling of wind resources and requires wind plants to provide meteorological data to the ISO for use in forecasting their generation levels.[34] In addition, the NYISO wind interconnection process requires wind plants to participate fully in the ISO's supervisory and data acquisition processes and, to meet low voltage ride-through standard, and to conduct tests to determine

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29 "Integration of Renewable Resources," November 2007, CAISO.
http://www.caiso.com/1ca5/1ca5a7a026270.pdf

30 "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS", August 31, 2010. CAISO
http://www.caiso.com/2804/2804d036401f0.pdf

31 "Growing Wind: Final Report of the NYISO 2010 Wind Generation Study." September 2010. NYISO
http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf

32 Ibid. at p. i.

33 Ibid. at p. iv.

34 Ibid.

"whether the interconnection of wind plants will have an adverse impact on the system voltage profile at the point of interconnection."[35] Moreover, in 2009 FERC approved NYISO operational rules that allow system operators to dispatch wind plants down to a lower generating level—in case of failure to follow down instructions, wind generators are charged the market price for regulation down service. Wind generators are also fully integrated in the economic dispatch process via NYISO's "wind energy management initiative."[36]

ISO-NE also recently completed a wind integration study of its system.[37] The study found that "New England could potentially integrate wind resources to meet up to 24% of the region's total annual electric energy needs in 2020" conditional on system transmission upgrades, "availability of existing supply-side and demand-side resources as cleared through the second FCA," the "retention of the additional resources cleared in the second Forward Capacity Auction, and increases in regulation and operating reserves as recommended by the study."[38]

Following FERC Order 890, ISO-NE instituted a pilot program, the Alternative Technology Regulation (ATR) Pilot program. The aim of the program is "to allow ISO-NE to identify the impact on the New England system of alternative technologies with new and unique performance characteristics."[39] Among the resources participating in the program are flywheel technology, battery technology, and certain Demand Response resources.[40] ATR resources are compensated "based on AGC performance (*i.e.,* mileage payments) and availability to provide Regulation (*i.e.,* time-on regulation payments) at the Regulation Market's hourly Regulation clearing price."[41] In the context of increasing regulation and load-following service needs due to higher renewables penetration, such market policies are aimed at increasing efficiencies. In its February 2011 NOPR on Regulation, FERC notes that "both [NYISO and ISO-NE] have a relatively higher concentration of faster-ramping resources, easily meet NERC reliability standards, and yet procure less regulation capacity, as a percentage of peak load, than other RTOs and ISOs."[42]

ERCOT has also worked actively to address the challenges of integrating wind generation. In 2008, ERCOT completed its wind integration study, which identified operational challenges for the ERCOT system.[43] ERCOT procures regulation service by analyzing recent historical deployments and deployments from the same month from the prior year and utilizing a formula derived from the results of the 2008 study.[44] The formulaic procurement results in adding incremental MWs of regulation for each 1000 MWs of increased installed wind capacity. In December of 2010, ERCOT moved from a Zonal Balancing Energy Market, which executed

[35] Ibid.

[36] Ibid.

[37] "Final Report: New England Wind Integration Study." GE Energy, EnerNEx, AWS Truepower. December 2010

http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

[38] Ibid. at p. 14.

[39] http://www.iso-ne.com/support/faq/atr/#faq1

[40] Ibid.

[41] Ibid.

[42] FERC NOPR at p. 20.

[43] GE Energy, *Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements*, March 28, 2008

[44] http://www.ercot.com/content/meetings/etwg/keydocs/2010/1001/2010-2011_Ancillary_Services_Methodology_Presentation.pdf

every 15 minutes to a Nodal Balancing Energy Market, where the Security Constrained Economic Dispatch (SCED) executed every 5 minutes. One expected benefit of the transition is that more frequent execution of the real-time market should result in less required regulation.[45]

In November of 2010, ERCOT also published the Emerging Technologies Integration Plan (ETIP), which documented "recent ERCOT stakeholder efforts to integrate renewable and other emerging technologies," presented a list of recommendations and strategies and established a framework "to guide and track further integration activities."[46] Among the key issues that have already been addressed via changes to market rules and procedures are: finding a common understanding of the impact of wind generation on operations among market participants and stakeholders, replacing wind generation resources wind schedules with ERCOT wind forecast, and establishing ramp-rate limitations for wind generators.

PJM recently completed the bidding process for initiating a system-wide comprehensive renewable integration study. The study is expected to build upon PJM's present experience with wind and solar generation and establish the full dimension of challenges the system is expected to face as multi-state RPS scenarios are met across PJM's control area. PJM has already worked on establishing a range of market procedures that are directly related to renewable integration. These procedures require "new wind–powered generation to maintain a power factor of 0.95 leading to 0.95 lagging, measured at the point of interconnection; and that wind projects connected to lower voltage systems be designed to operate to a voltage schedule, reactive schedule or power factor schedules designed to meet local transmission owner criteria."[47] In addition, PJM implemented a centralized wind power forecasting service in April 2009 for use in PJM reliability assessments—this includes a day-ahead (mid-term wind power forecast) and a real-time (short-term wind power forecast).[48] PJM generating resources are also "able to submit negative price offers, enabling wind resources to submit flexible offers that better reflect the price at which they will reduce output."[49]

C. North American Electric Reliability Corporation's Activities Around the Integration of Renewable Generation

While NERC has been actively involved in analyzing the potential effects of integrating large volumes of variable generation resources on system reliability, almost no specific operating reliability requirements have been changed. In NERC's recent comments submitted in response to the FERC NOPR described above, NERC states that it has not identified any insurmountable hurdles that would prevent the industry from providing intra-hour scheduling flexibility. In addition, NERC has recognized that the wind ramping events are slower than the conventional system contingency events, such as contingency reserves that have been traditionally designated to meet sudden, quickly occurring events such as the unanticipated loss of a generator or transmission line. Such resources are not necessarily best suited to compensate for the burdens

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45 Ibid. at p. 5.

46 "Exhibit A: Emerging Technologies Integration Plan (ETIP)", ERCOT, November 2010 at p. 2. http://www.ercot.com/content/meetings/etwg/keydocs/2011/0105/Item_06e_-_Emerging_Technologies_Integration_Plan.zip

47 http://www.usea.org/Programs/EUPP/globallowcarbonworkshop/Mar2/Ken_Schuyler_Integrating_Renewables_in_PJM_Interconnection.pdf

48 Ibid. at p. 19.

49 Ibid.

imposed by wind and solar generation on the transmission grid. In that regard, NERC has suggested that the frequency of ramp events would need to be studied to determine which part of wind and solar ramp events are compatible with contingency reserve use. NERC believes that the industry should consider developing rules governing reserve deployment and restoration, similar to those that currently address conventional contingencies.

D. Policies Adopted by States and/or Utilities

Faced with a number of pressures acting to increase customer rates, state regulators in many jurisdictions have become conscious of the many issues described above. With ratepayer advocates questioning the costs associated with meeting renewable energy requirements, several utilities already have begun to evaluate the likely cost implications of integrating large amounts of wind onto their systems. The results of those studies have been used by regulated utilities in their Integrated Resource Plants. For example, Xcel Energy (both Northern State Power Company and Public Service Company of Colorado) has been analyzing the potential cost of integrating various levels of wind onto their systems. Xcel has added those costs to the cost of delivered wind in their long-term resource plans. In doing so, NSP and PS Colorado have explicitly accounted for the expected system costs associated with increasingly adding wind resources onto their systems.

Because NSP and PS Colorado are both vertically-integrated regulated utilities, these integration costs are subsumed into the overall costs paid for by their ratepayers. However, estimating the cost of integrating wind helps the utilities plan their systems while accounting for many of the challenges discussed above, in addition to the actual capital and operational costs of the wind generators. While state regulators have not explicitly required utilities to include such integration costs in their plans, it has become a useful way for utilities and regulators to evaluate some of the tradeoffs between building conventional generation and variable renewable generation. PacifiCorp represents another set of regulated utilities whose systems have significant wind penetration and expects to see more added in the future. In 2010, PacifiCorp initiated a wind integration analysis that estimated the cost of wind integration will likely be in the range of $8.85 to $9.70 per MWh integrated on its system.[50]

In addition to using integration cost estimates as part of resource planning, similar and consistent with an aspect of the proposed policy from FERC described above, some utilities have requested FERC to allow certain "home" utilities to pass a portion of those costs to "beneficiaries" of the wind resources located on their systems. For instance, in March 2010, FERC accepted Westar's proposed transmission tariff change to allow charging new generation regulation and frequency response service to generators located in Westar's balancing area whose output is delivered outside of Westar's balancing area.[51] In all likelihoods, given the pressures that state regulators face from rate payers, FERC's policies will ultimately allow those systems with significant amount of wind used by external utilities to charge those who "cause" the costs.

[50] PacifiCorp 2010 Wind Integration Resource Study, September 1, 2010, can be found at http://www.pacificorp.com/es/irp/wind_integration.html

[51] FERC Docket No. ER09-1273-000, March 18, 2010.

E. EMERGING POLICY QUESTIONS

1. Reliability Criteria May Need to be Re-Examined

Today, the use of frequency control and regulation services help system operators match generation's second to second output to the load on the system. Such demand is anticipated to significantly increase with greater penetration of intermittent generation on the system. The amount of regulation service procured today by system operators is typically in the range of approximately one percent of load. For example, PJM's operational manual specifies that it procures 1% of its daily forecast peak load for all peak hours and 1% of its forecast valley load for all off-peak hours.[52]

Much of the current practice is based on rules-of-thumb from operators' past experience subject to their need to meet NERC reliability requirements or control standards.[53] Even if the fundamental NERC reliability requirements and standards do not have to change along with the high penetration of intermittent resources, historical rules-of-thumb around the procurement of regulation services will likely need to be adjusted.

Likewise, the magnitude of reserve requirements, such as spinning and non-spinning reserves, tends to be based on the largest potential failure or contingency on a system.[54] The largest single contingency on any system tends to be a high-voltage transmission line or a large baseload power plant. Some have contended that wind or solar are not likely to become the largest contingency on a system even when all of the wind/solar capacities on a system exceed that of the largest baseload generator or high-voltage transmission line. That is because wind and solar generators tend to be geographically spread out such that they are not likely to fail simultaneously.

However, even if large wind and solar plants are unlikely to experience drastic large failures simultaneously, the magnitude of reserves will need to increase to accommodate the un-anticipated variations in wind and solar output. Such additional reserve requirements will depend partly on the history of deviations of actual wind and solar output from the forecast used by system operators to schedule generators (and transmission). The better the schedule (based on forecast information) can match the actual output, the less reserves will be needed. Thus, the magnitude of the additional reserve requirement will not only depend on how good the forecasts are, but also on how frequent the forecasts can be updated and effectively used during scheduling.

52 PJM Manual 11: Energy & Ancillary Services Market Operations, June 23, 2010, Section 3.2.4 Regulation Requirement Determination. The Manual also states that the requirement percentage may be adjusted by PJM to be consistent with NERC control standards.

53 For a general treatment, see: http://www.nerc.com/docs/oc/ps/tutorcps.pdf

54 PJM carries 150% of its largest contingency as Primary Reserves. New York ISO carries 50% of its largest contingency as 10-minute spinning; total 10-minute reserves equal to it largest contingency; and 30-minute reserves equal to 50% of its largest contingency. ISO-New England carries an amount of 10-minute reserves equal to its largest contingency (with the split between spin and non-spin that can vary), and the amount of 30-minute reserves is equal to 50% of its largest contingency.

2. The Capacity Credit for Renewable Generation and Its Implications for Resource Planning

In regions with centralized capacity markets, the capacity credit provided to wind and solar generation is usually a simple function of how much generation can be expected on the "super-peak" hours of the year. However, the severely limited amount of historical experience is a poor basis upon which to estimate the capacity contribution from intermittent resources. Some studies have shown that the capacity value of wind is highly sensitive to the load shape and wind profile used in the analysis.[55] Yet modeling multiple load shapes with a reasonable distribution of future wind profiles is almost impossible to achieve today. Such difficulty may result in over- or under- building conventional generation to meet the resources adequacy (and reliability needs).

3. Definition of the Customer for Cost Allocation Purposes

One institutional issue that may need attention is the definition of a transmission customer, or more abstractly, the geographic locus of benefits provision from a particular transmission service, capital improvement, or ancillary service. This issue recently arose forcefully when New England state regulators objected to the fact that the FERC allocated a portion of the cost of a new phase shifter installed to prevent loop flow around Lake Ontario to them despite the fact that they had no customer relationship with the transmission company in Michigan who installed the equipment.[56] The protest notes that the Federal Power Act does not allow FERC the authority to spread the costs of facilities that do not provide service under a tariff to entities who happen to be connected to the grid. This would appear to constrain significantly the ability to allocate certain types of grid integration costs.

VII. CONCLUSION

Research and experience are both demonstrating conclusively that high levels of variable renewable energy sources can be safely and reliably integrated into modern power systems. However, as power system technologies and institutions evolve, this integration clearly comes at a cost. These costs include a greater need for overall regulation and ramping resources (which someone must build and pay for), cost penalties on traditional incumbent generators, and enhanced (though perhaps more costly) forecasting (especially in short term) and more complex operating procedures for system operators.

The primary policy challenges associated with these integration needs arise around cost causation and allocation. When cost causation as well as associated benefits are relatively broad and highly interdependent with system configuration and conditions – as is often the case for renewables integration – the costs take on the nature of quasi-public goods and cost allocation to the "users" or "beneficiaries" becomes difficult. In this case, allocation inevitably involves issues of equity that must be resolved by policymakers, ideally without reducing efficiency incentives.

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55 "Final Report: New England Wind Integration Study." GE Energy, EnerNEx, AWS Truepower. December 2010 at pp. 315-328.

56 Motion to Intervene and Protest, New England Conference of Public Utilities Commissioners, Docket No. ER11-1844-000, November 17, 2010. Similar comments were filed by the Sacramento Municipal Utility District in the FERC Cost Allocation NOPR, Docket No. RM10-23-000, September 29, 2010.

It is likely useful to distinguish between integration costs that reduce the value of existing assets from costs that require system operators to incur additional costs. The latter category can be further divided into costs that are more tracked to a causal agent or beneficiary and those that are more public in nature.

Broadly speaking, utility regulatory policies vary between these three types of costs. The reduction in existing asset values is akin to a stranded cost, which is recovered when regulators agree that constitutional and long-term market efficiency considerations call for it. When approved, these costs have been collected rather broadly from market participants, with appropriate protective conditions in place.

In the latter category, where costs can be allocated to customers or beneficiaries to a substantial degree this is usually both the fairest and most efficient solution. Most of the FERC's proposals aim in this direction, notably their approval of Westar's proposal to charge renewable integration costs to customers outside their retail footprint who were consuming locally-generated renewable energy. However, it is inevitable that some costs will be lumpy, indivisible, and not marginally assignable—for example, the costs of an RTO adopting a more complex scheduling framework. Regulatory bodies must inevitably allocate these costs on the basis of fairness and efficiency.

Fortunately, these difficulties are certainly not hindering the considerable progress being made by the RTOs and ISOs, the FERC, utilities, and state policymakers. We do not see any grand, unifying theory of cost allocation for the costs of renewable variability, nor do the institutional differences, legacy generation, or indigenous resources, across regions of the U.S. and other global power systems lend themselves to uniform solutions. Instead, the allocation of each element of integration costs will call for extensive research and thoughtful advocacy on the part of all stakeholders and great care on the part of regulators to balance economic efficiency, administrative burden, and fairness considerations. While the road ahead may be contentious and laborious, there seems to be no technical or economic reason why a well-functioning regulatory system cannot find its way to a sustainable, reliable, and economical destination.