# Leaning on Line Pack

## Green energy mandates might overburden gas pipelines.

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Electricity supply and demand have always been variable and uncertain. Hence, in realizing the enormous potential associated with onshore and offshore wind development, system operators must address the critical challenge of predicting wind production and then managing the variability of wind based energy from day to day, hour to hour, and, at a more granular level, in 10-minute intervals.

In terms of seconds or minutes, variations in wind power output have a relatively minor impact on system operations. However, in terms of 10-minute intervals or hour-long time scales, unexpected wind power output variations have the potential to cause operational havoc, particularly if the magnitude of the variance is comparable to the variation in load. Maintaining system reliability and security of supply thus requires the independent system operator (ISO) to avoid operational havoc by rigorous scheduling of various ancillary services. As the penetration of new wind resources increases, the array and amount of ancillary services will necessitate innovation to accommodate intermittent resources. Toward this end, in its notice of proposed rulemaking (NOPR) issued on November 18 (Docket No. RM10-11-000), the Federal Energy Regulatory Commission (FERC) proposes reforms intended to remove barriers to the integration of variable energy resources (VERs) into the transmission grid.

Although existing operational procedures are effective at accommodating wind generation, deeper wind penetration will challenge ISOs regarding the procurement of ancillary services. In addition to strategic actions to alleviate developing problems from adding VERs on the system, enhanced ancillary services can augment or complement traditional automatic generation control (AGC), 10-minute spinning and non-spinning reserves or 30-minute operating reserves. These enhanced ancillary services will require innovative strategies using line pack in interstate pipelines and stepped up communication among gas and electric market participants to preserve reliability objectives in gas and electric markets.

> The supply of ancillary services shouldn't be taken for granted.

### Wind Outlook

Aggressive renewable portfolio standard (RPS) targets (*see Figure 1*), coupled with onshore wind and offshore wind potential, portend substantial increased wind generation in the decade ahead. The U.S. Department of Energy's (DOE's) 20 percent wind penetration target by 2030 requires more than 300 GW of wind capacity in the U.S.[1] ISO New England's (ISO-NE's) high wind scenario envisions 10 GW by 2020.[2] New York ISO (NYISO) high wind scenario envisions 8 GW by 2018.[3] The *Eastern Wind Integration and Transmission Study* has a reference wind scenario with 6 percent energy penetration and a high wind scenario with 30 percent energy penetration (*see Figure 2*).[4] Onshore resources account for the majority of the aggressive wind penetration rate contemplated by DOE, ISOs, the American Wind Energy Association (AWEA), state regulatory commissions and electric distribution companies (EDCs). However, along the Atlantic seaboard there is support for offshore facilities despite the much higher capital and O&M cost to construct and operate offshore wind farms. One inconvenient characteristic of onshore wind production is its relatively greater variability, compared to offshore wind. Associated with this greater variability is much higher prediction error in the day-ahead (DA) and hour-ahead (HA) forecasts of wind production. The DA wind forecast in the latest wind integration study performed in New England shows an overall forecast accuracy of 15 percent to 20 percent mean absolute error (MAE). Forecast accuracy of 15 percent to 20 percent MAE is considered state-of-the-art.[5] By comparison, the load forecast error is typically 2.5 percent in peak months and less than 1.5 percent in off-peak months.

Wind power forecasting (WPF) involves the use of complex stochastic or probabilistic models that draw upon weather prediction results, local meteorological measurements, terrain and topography details, and supervisory control and data acquisition (SCADA) data from the wind farms. There are many different WPF models for the ISOs to choose from. Some ISOs have even done pilot studies with different models in order to identify the best model for

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their distinctive weather patterns and terrains. The performance of the models is strongly linked to the terrain complexity of the region, such that in one benchmarking study the average value of the normalized MAE ranged between 10 percent for flat terrain to 21 percent for highly complex terrain.[6] The WPF error is highly dependent on the wind speed forecast error, which itself depends largely on the numerical weather prediction global model. Forecast accuracy can be improved by using a combination of different forecasts, either from different WPF models or different numerical weather prediction models.

To offset the significant prediction error that is inevitably part of forecasting DA and HA wind production, ISOs are expected to rely increasingly on ancillary services provided by spinning and non-spinning reserves. The NYISO study on increased wind generation found that system variability increases and varies by season, month, and time of day, leading to higher magnitude ramping.[7] Higher ramping requirements are tantamount to greater changes in net load over time, to which the dispatchable resources need to respond. Holding constant existing resource adequacy and operational reliability criteria, only about 0.2 MW to 0.3 MW of existing conventional resources can be retired with the addition of 1 MW of wind.[8] The California ISO has found that the addition of solar resources can lessen operational requirements in some hours but increase them in others, compared to wind generation alone.[9]

Fundamental weaknesses in regional capacity markets—that is, low clearing prices due to capacity overhangs, the economy and the ascent of demand response (DR)—make it increasingly difficult for old-style steam turbine generators to remain in the market. This is particularly true for those facing significant capital outlays for environmental compliance.

Also, among the recent fleet of combined cycle (CC) plants, there have been bankruptcies and recapitalizations as assets have changed hands at bargain-basement prices. As gas plants lose market share in terms of energy sales to inframarginal wind plants, the supply of ancillary services available from quick-start and higher magnitude ramping plants shouldn't be taken for granted. ISOs are cognizant of this dynamic and are working to plan around these unfolding events. But as the resource mix is transformed in the decade ahead, will the inventory of ancillary services be sufficient and affordable to accommodate the stepped up integration of wind resources?

**Fig. 1 State RPS Goals**

| State | Goal | Year |
|---|---|---|
| Arizona | 15% | 2025 |
| California | 33% | 2030 |
| Colorado | 20% | 2020 |
| Connecticut | 23% | 2020 |
| District of Columbia | 20% | 2020 |
| Delaware | 20% | 2019 |
| Hawaii | 20% | 2020 |
| Iowa | 105 MW | |
| Illinois | 25% | 2025 |
| Massachusetts | 15% | 2020 |
| Maryland | 20% | 2022 |
| Maine | 40% | 2017 |
| Michigan | 10% | 2015 |
| Minnesota | 25% | 2025 |
| Missouri | 15% | 2021 |
| Montana | 15% | 2015 |
| New Hampshire | 23.8% | 2025 |
| New Jersey | 22.5% | 2021 |
| New Mexico | 20% | 2020 |
| Nevada | 20% | 2015 |
| New York | 24% | 2013 |
| North Carolina | 12.5% | 2021 |
| North Dakota* | 10% | 2015 |
| Oregon | 25% | 2025 |
| Pennsylvania | 8% | 2020 |
| Rhode Island | 16% | 2019 |
| South Dakota* | 10% | 2015 |
| Texas | 5,880 MW | 2015 |
| Utah* | 20% | 2025 |
| Vermont* | 10% | 2013 |
| Virginia* | 12% | 2022 |
| Washington | 15% | 2020 |
| Wisconsin | 10% | 2015 |

Source: DOE Energy Efficiency and Renewable Energy division

***Five states, North Dakota, South Dakota, Utah, Virginia, and Vermont, have set voluntary goals for adopting renewable energy instead of portfolio standards with binding targets.**

## Existing ISO Procedures

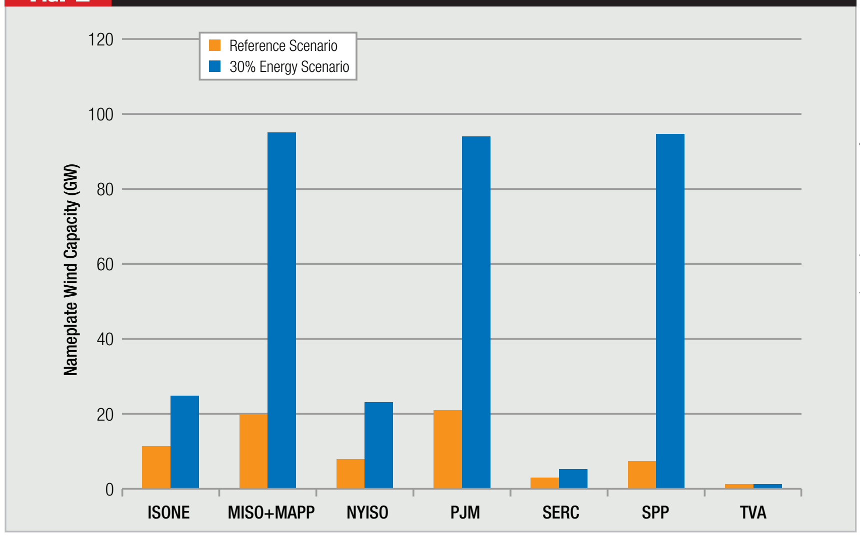
ISOs have implemented various operational strategies to integrate wind generation and may be introducing additional reforms based on FERC's recent NOPR. Applicable mandatory North American Electric Reliability Corporation (NERC) standards have been developed to ensure reliable operation of the system. In their balancing role, ISOs have well-formed planning and operating procedures to ensure that frequency and voltage deviations under normal and emergency operating conditions don't undermine reliability objectives. Thus, NERC standard BAL-001 sets requirements and measures for frequency control under steady-state operating conditions through its control performance standards, while NERC standard BAL-002 addresses balancing requirements under disturbance.

To be in compliance with the reliability standards, ISOs have to maintain adequate operating reserves and AGC capability. In the seconds-to-minutes time frame, bulk power system reliability is almost entirely maintained by automatic equipment and control systems such as AGC. AGC is ideally derived from pumped storage plants, but many thermal plants also furnish AGC. Moreover, the cohort group of CC plants is ideally positioned to produce AGC. In the minutes-to-hours time frame, system operators rely on CC units and peakers providing load following to maintain system reliability.[10] NERC standard VAR-001 governs voltage and reactive control. Generating and non-generating resources capable of controlling voltage are used to ensure compliance with the NERC standard.

Overall, ISOs procure or provide five

types of ancillary services to ensure system reliability: dispatch and scheduling; energy balancing; regulation; voltage control; and black-start capability. Daily and hourly commitments of the resources providing ancillary services and other products are determined through security constrained economic dispatch. Balancing requirements are derived from fossil fuels and pumped storage facilities. To the extent natural gas is used, both economic and environmental goals are well served. A second-best solution to the vexsome problem of providing sufficient ancillary services relates to use of premium fossil fuel—in particular, ultra low sulfur diesel (ULSD)—to enable quick-start peakers to start up in the real-time market. However, permit restrictions, environmental effects, and the high cost of ULSD relative to natural gas disfavors this solution.

**FIG. 2 EWITS STUDY ASSUMPTIONS FOR NAMEPLATE WIND CAPACITY BY REGION**




Source: EnerNex for NREL, "Eastern Wind Integration and Transmission Study," January 2010.

Resources that provide ancillary services are compensated under FERC approved tariffs. Some ancillary services are compensated at a regulated rate, while other services are compensated at market prices. ISOs provide dispatch, system control, and scheduling under FERC approved tariffs, the cost of which is borne by transmission customers. Voltage control and reactive power support are provided as needed either at the dispatch order or automatically within the resource's voltage control range. The resources providing these services are compensated for their reactive capabilities on a monthly basis based on a rate set by the tariff. Resources equipped with AGC provide regulation and frequency response service. Charges for this service are determined based on the offers submitted by AGC resources in accordance with market rules that vary among ISOs.

As a general rule, the cost of AGC resources is socialized across load in the market area. To meet reliability objectives, ISOs procure either 10-minute spin, 10-minute non-spin, or 30-minute operating reserves through the market or based on bilateral arrangements. In addition to covering for contingencies, each of these reserves is used to balance load variations. Also, resources designated by ISOs as black-start capability resources are typically compensated under the rate set forth in the tariff. The charges for system restoration are normally allocated to the transmission customers through the transmission rate.

### The ISO's Challenge

At present, the ISO systems' load following capabilities are adequate with limited wind penetration. The following questions need to be addressed:

- Will market participants tolerate increased inefficiencies associated with re-dispatch and uneconomic commitments explained by frequent and unpredictable swings of large magnitude?
- Is the supply elasticity of ancillary services sufficiently high in light of aggressive RPS targets?
- Will ISOs change market rules to accommodate the integration of intermittent resources?
- What is the best way to define a stakeholder process oriented around market rule changes?

**Leaning on the pipeline is a valuable right that's specifically monetized under FERC-approved charges.**

ISOs are required to balance supply and demand 24 hours a day—all 31.5 million seconds of the year. Although energy storage-based regulation can be practical and less costly, it is limited to the short time scale of milliseconds to minutes. Energy storage based regulation can't supply the quantities required in a low-wind crisis event. Reliance on dispatchable and quick-start resources to provide 10-minute spin, 10-minute non-spin, and 30-minute operating reserves can mitigate the cost of market inefficiencies related to the integration of new wind resources. Ensuring that sufficient or additional fast-ramping resources are available could require long term contracts to cover the fixed operating costs of these units.[11]

Economic inefficiencies can arise from certain operational restrictions in ramping up gas-fired generation; »

availability of gas on no notice or short notice; and strictly enforced reliability standards governing acceptable frequency and voltage deviations. On the electric side, these inefficiencies encompass sub-optimal unit commitments and uplift. Involuntary load shedding is an operational fix of last resort. Load shedding might be necessary when a system operator doesn't have other resources available to ramp-up fast enough and in large enough increments when wind production unexpectedly drops off the proverbial cliff. The problem is compounded when load is racing in the opposite direction. Hot, humid days frequently characterize exactly this situation, when load soars and wind forecast error deviates from MAE. However, temperate nights when load is stable but wind forecast error deviates from MAE also can stretch the system operators' ability to procure sufficient ancillary services to avert voltage collapse. Penalties that are enforced on the gas system for unauthorized overpulls associated with gas use on a no-notice or short notice basis deter quick-start resources from "answering the bell," that is, providing the requisite ancillary services to minimize or avoid market inefficiency.

February 26, 2008, was a learning experience both for the system operator in Texas and ISOs elsewhere in the United States and Canada. In the early evening, ERCOT declared a grid emergency resulting from the abrupt loss of 1,400 MW of wind resources in West Texas, coupled with increased load due to colder-than-expected weather. ERCOT curtailed about 1,100 MW within 10 minutes.[12] The prospect of cascading power loss was averted by calling on reserve capacity including loads acting as a resource (LaaR)—large industrial and commercial customers who are compensated for curtailing their electricity supply. Service to the interrupted customers was restored in about 90 minutes, but operational changes have since been implemented, including DA and HA wind production forecast modifications, and more regulation.[13] Also, LaaR has come under greater scrutiny as a dispatchable resource. And ERCOT implemented wind resource scheduling commitments in the DA market, and penalties for under-performance.

The new generation of quick-start peakers has a hard time complying with restrictive pipeline tariff conditions and the daily nomination cycles set forth under the North American Energy Standards Board (NAESB) governing DA nomination and confirmation cycles,

> **Ever improved wind forecasting techniques won't eliminate significant forecast error.**

including changes to the DA schedule and the intra-day schedule. NAESB recognizes that timely gas nomination cycles occur well before the time when ISOs clear their timelines and commit for the DA market. According to NAESB, "this disconnect leaves some generators two main options of either a) purchase and nominate gas transportation on a timely basis and risk not having their bid subsequently clear the power market or, b) wait to see if their bid clears the power market and risk relying upon the intraday gas transportation nominations without the level of assurances offered in the timely cycle for firm gas transportation services."[14] Generators are faced with the unenviable choice between purchasing and nominating gas in the timely nomination periods and risking the bid not being cleared, or purchasing gas in the intraday market at a premium over DA prices and at the risk of triggering additional fees for unauthorized use.

While pipelines and local distribution companies (LDCs) administer penalties and resolve imbalances in different manners, gas burning power plants generally can't lean on the pipeline or LDC system for free. Doing so could hinder reliable service to entitlement holders who pay top dollar in exchange for the pipeline's promise to deliver the requisite flow of natural gas at a specified minimum pressure. In actuality, leaning on the pipeline or LDC system is a valuable right that is specifically monetized under FERC and state commission approved charges. These charges often deter quick-start units from firing on natural gas, especially during the heating season, November through March, when congestion patterns along interstate pipelines and local systems make it expensive and risky to pull unauthorized gas volumes from the network. Wind production is generally higher in winter months, especially during cold snaps. However, turbines have cut-out wind speeds, typically 25 meters per second, above which their operation is curtailed. Icing of the blades can also be problematic in winter months if the plant isn't equipped with a cold weather package that ensures the turbines operate in temperatures as low as minus 22 F. Therefore, during the heating season, absent a flexible gas supply and balancing arrangement, quick-start units have no choice but to burn oil, almost always at a large cost premium relative to the delivered cost of natural gas.

**Pipeline as Current**

Rationalizing the use of pipeline line pack is a natural synergy between gas and electric stakeholders that can simplify and expedite the integration of wind resources. But exploiting this synergy will require a transaction structure that safeguards reliability objectives in both gas and electric markets. How best to rationalize a transaction structure that maintains gas and electric reliability » objectives while providing appropriate compensation to market participants isn't presently well understood.

The U.S. pipeline network is in effect a vast horizontal silo that's packed and drafted daily to meet the scheduling requirements of gas utilities and power generators alike. In response to higher wind penetration rates, enhanced use of pipeline line pack—the volume of gas stored in a pipeline—across the consolidated network of pipelines and storage facilities can be used like a battery to hedge against wind intermittency. Line pack depends on the pressure levels in the pipeline, and it constantly changes as pressure is varied. Typically, pipelines build up line pack during periods of decreased demand and draw it down during periods of increased demand.

Heavy penalties for unauthorized overpulls hinder a generator's reliance on line pack. ISOs are understandably cautious regarding the formulation of incentives that might paradoxically deplete line pack and cause pipelines to clamp down on a generator's unauthorized use, not to mention the harm such depletion could cause to gas customers. In Britain, line-pack depletion during low wind periods was shown to limit the ability of the gas network to fully supply gas-fired generators.[15] The study modeled line pack in Britain's pipeline system over a two-day period with a two-hour time step under three scenarios: base (2009), low wind (2020), and high wind (2020). The difference between high and low line pack was 6 million cubic meters (mcm) in the base and high wind scenarios, and 11 mcm in the low wind scenario.

Line pack is highly dependent on pipeline specifics, but another way to consider it involves the gas pull from the activation of gas turbines (GTs)—in this case GE's LMS100.[16] Figure 3 summarizes the gas requirements of an LMS100 both at steady state and during the first 10 minutes of ramping. In a low wind situation, such as occurred in Texas in 2008, one to 10 LMS100-type gas turbines might be required to fill in between 100 MW and 1,000 MW of needed generation for one to two hours.

This withdrawal of roughly 16,000 MMBtu would be a worst-case scenario, since it's unlikely that all the GTs would be located at one location on one pipeline. But such a withdrawal would be in addition to the present average daily line-pack swing and could challenge the system unless the event doesn't coincide with the current maximum dip in daily line-pack fluctuations.

Depending on the length of the supply chain, it takes many hours—or even days—for natural gas to complete the journey from the wellhead to the city-gate in order to replenish line pack. Therefore, much more aggressive management of line-pack inventory across a pipeline or a pipeline route segment should be implemented in order to avoid harm to core gas customers. Such an initiative requires an orchestrated effort among gas and electric stakeholders to determine how best to price and manage the use of line pack to accommodate renewable generation.

Communication between the ISO and the pipeline about wind forecasts could enable a pipeline to increase line pack before a low wind event. Even better, routine operating procedures should be developed to ensure pipeline readiness to supply gas in response to abrupt reduction in wind energy production. A pipeline and the suppliers behind it must be compensated for the additional fuel used to replenish line pack in order to offset under-performance when wind conditions are lower than expected. Subject to stakeholder satisfaction, market rules could evolve to compensate gas suppliers for pressurizing pipelines when needed on short notice or no notice. Likewise, market rules could evolve to allow for the socialization of imbalance charges and penalties borne by generators providing the array of ancillary services when intraday gas scheduling restrictions trigger these additional gas-side costs.

**Fig. 3 Gas Consumption of Typical Quick-Start Gas Turbines**

| | One LMS100 | Ten LMS100s |
|---|---|---|
| **MW** | **99** | **990** |
| Heat Rate LHV (Btu/kWh)* | 7,600 | |
| HHV/LHV | 1 | |
| Hourly Gas Consumption at Steady State (MMBtu/hr) | 828 | 8,280 |
| First 10-min Gas Consumption (MMBtu) | 69 | 690 |
| First Hour Gas Consumption (MMBtu) | 759 | 7,590 |
| Two Hour Gas Consumption (MMBtu) | 1,587 | 15,870 |
| *Heat rate at the generator terminals. | | |

Source: General Electric LMS100 Product Specifications and author analysis

**Gas requirements of a GE LMS100 gas turbine, at steady state, during the first 10 minutes of ramping, and in normal operation.**

## Ensuring System Integrity

Ever improved wind forecasting techniques won't eliminate significant forecast error. The discrepancy between dispatched generation and actual load should be the sum of the wind prediction errors and load forecast errors; they are proportional to the total MW of installed wind and total load. To accommodate the expected heavy penetration of wind to meet RPS targets, ISOs will need to step up their procurement of short time-scale ancillaries, such as 10-minute spinning, non-spinning reserve, as well as longer-duration ancillaries, such as 30-minute reserves. Like AGC, these products can be obtained from pumped storage, pondable hydro, the ramping up and down of thermal plants, and quick-start peaking generation.

As wind gains market share, the 2008 Texas electric-side contingency reminds us that these standard ancillary services need to be bolstered by a complement of sorts, perhaps a new 60-minute or longer ramping service to safeguard against this type of multi-hour event. Wind integration studies point to the increased need of AGC and operating reserves. This is part of the solution, but not the entire solution, *per se*. Without proper gas supply on a short or no-notice basis, most effective quick-start operating reserves will be unable to provide load following ancillary services in the required magnitude—unless existing environmental permitting restrictions are liberalized to enable many more starts and stops on ULSD or kerosene. However, the liberalization of air permit restrictions to provide for much greater operating flexibility on premium fossil fuels doesn't appear likely at this juncture.

In the ISO's centralized role as the provider of balancing services, longer duration ancillaries can be obtained from quick-start units through line pack. While CC plants and quick-start non-spinning GTs have the potential to furnish an affordable, environmentally benign array of ancillary services, price signals should promote the substitution of gas for oil, thereby promoting the use of pipeline line pack and storage withdrawals to meet the intra-day gas nomination and confirmation cycle associated with quick-start resource requirements.

Reasonably straightforward operational actions, implemented across the supply chain from the wellhead to the citygate, can avert or reduce the prospect of harm to core gas customers. Pipeline operators as well as the gas suppliers behind the network of interstate pipelines might need to alter the traditional packing and drafting of the system. For example, with timely notice, suppliers can increase production at the wellhead or at gas gathering and purification facilities to inject more natural gas into the pipeline. Since gas moves through the interstate system at transport speeds no greater than 25 miles per hour, increased scheduling at the wellhead or at interconnects deep in the production center won't bolster the requisite line pack in the market center.

> **Market rules could evolve to compensate gas suppliers for pressurizing pipelines when needed on short notice.**

Additionally, pipeline companies can increase the amount of horsepower at key compressor stations along the supply path, particularly in segments where CC plants or quick-start generation are expected to pull gas from the system to furnish ancillaries. Based on preliminary transient pipeline modeling work, one pipeline reported that under normal operating conditions on a summer design day—and, of course, subject to appropriate tariff services being implemented—the pipeline could accommodate the ramp-up and subsequent two-hour operation of up to 10 LMS100s by increasing the horsepower at major compressor stations located deep in the market area.

Pipeline companies can quickly modify the scheduling of gas at key interconnects in the market center to bolster line pack across affected route segments. Pipelines can even reverse the flow of gas across bidirectional route segments when required to increase line pack or respond to gas-side contingencies. Likewise, storage operators in the market center can step up storage withdrawals on a firm or interruptible basis, subject to tariff provisions and other operational safeguards. Regasification of LNG can be increased as well, where there is good access to LNG import terminals such as at Cove Point, Md., Suez Distrigas near Boston, Repsol Cannaport in New Brunswick, or Costa Azul, Mexico. There may be other opportunities to use peaking gas as a source of ancillary services as well.

U.S. pipelines already have a dazzling array of new services that affect how line pack is managed. Park and loan; firm and interruptible storage service, premium hourly services; and cash outs for imbalance charges are just a few of the services that form part of the solution associated with accommodating increased wind penetration. But they haven't been tailored for quick-start units and CC plants that run afoul of rigid NAESB scheduling protocols. Streamlined coordination and communication among gas- and electric-side participants, including natural gas suppliers and storage operators, is therefore an integral part of the challenge of unleashing the power of line pack to integrate wind into the resource mix.

In the final analysis, there's only so much line pack to go around. During cold snaps line pack is and should always be reserved for system integrity to ensure that entitlement holders' superior requirements are met. However, the rest of the year there is a veritable gold mine of ancillary services that can and should be exploited to accommodate laudable green path objectives.

Rationalizing the use of this valuable commodity can be achieved through careful study, improved communication, and relatively minor changes to the ISO's tariffs in order to allocate the extra costs invariably borne by generators who are asked by the ISO to ramp up or down quickly. Arguably, there is no such thing as a minor change to an ISO's tariff. But the track record of industry cooperation, innovation and achievement is the foundation on which renewable energy can be integrated on an expedited basis. FERC and state interest in renewable energy goals should help promote tariff changes that meet these objectives.

**Endnotes:**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16. An LMS100 is GE's quick-start gas turbine offering 100 MW of electricity at 44 percent thermal efficiency with a wide range of operating flexibility for peaking, mid-range and base-load operation with lower start-up emissions and 10-minute starts.