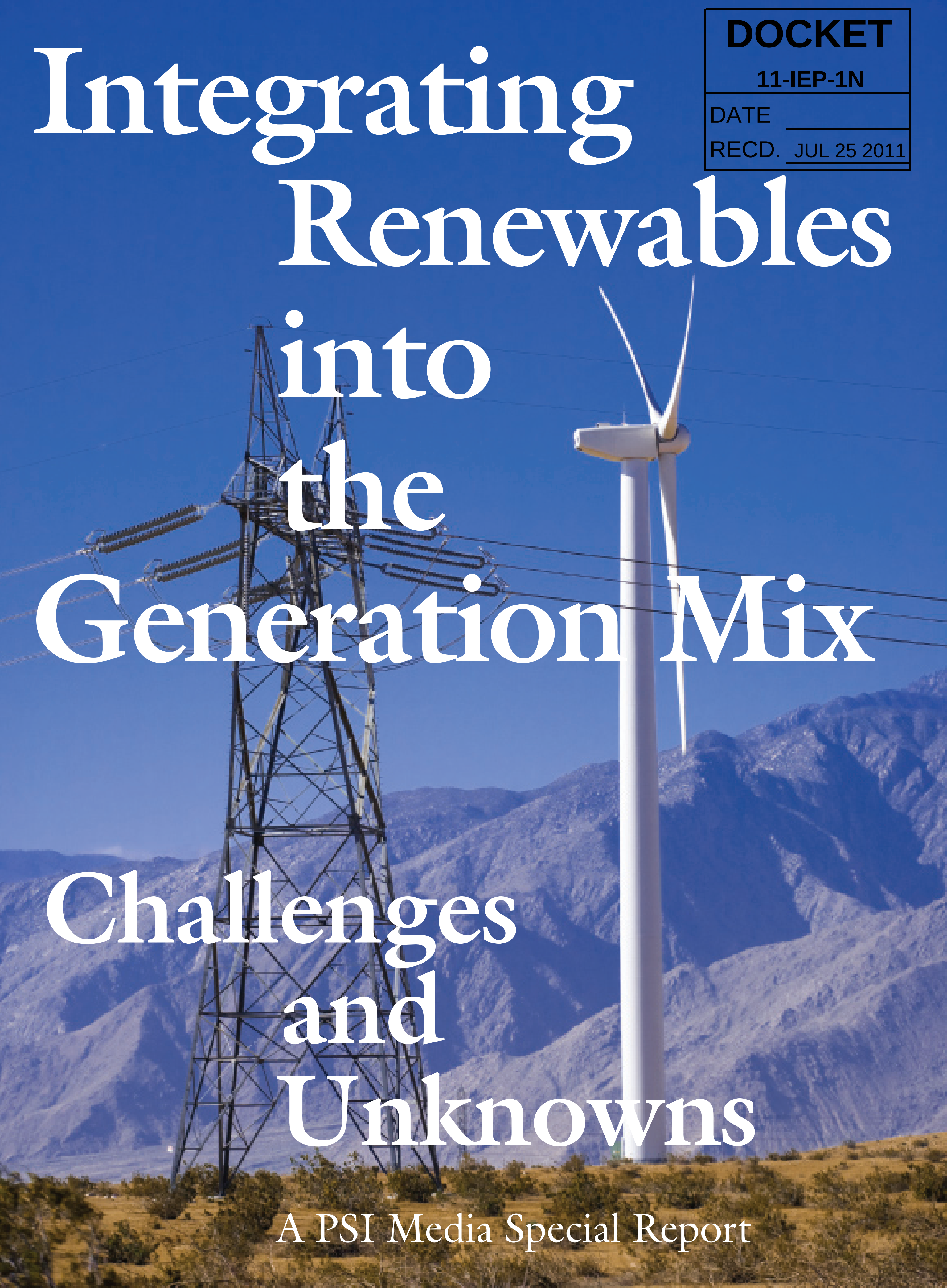

Integrating Renewables into the Generation Mix

Challenges and Unknowns

A PSI Media Special Report

Integrating Renewables into the Generation Mix

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Editorial Staff

Robert G Schwieger Sr
Editor and Publisher
bob@psimedia.info

Scott G Schwieger
Senior Editor
scott@psimedia.info

Kiyo Komoda
Creative Director

Clark G Schwieger
Special Projects Manager

Regional Technical Consultants

Americas:
Jason Makansi, Pearl Street Inc

Europe:
Giorgio Dodero, IPG Srl

India:
Sridhar Samudrala, IECC

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PSI Media Inc
7628 Belmondo Lane
Las Vegas, Nev 89128
Tel: 702-869-4739
Fax: 702-869-6867

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Most of the material in this special report by the editors of Las Vegas-based PSI Media Inc, content developers for print and electronic publications focusing on energy technologies and markets, came from presentations and discussions at "Integrating Renewables Into the Generation Mix: Challenges and Unknowns," a one-day workshop, September 13, developed by CTOTF in cooperation with NV Energy.

Goal of the meeting, presented and managed by Wickey Elmo, president, Goose Creek Systems Inc, Indian Trail, NC, respected in the electric power industry for forward-looking technical conferences and companion exhibitions, was to explore how state-mandated Renewable Portfolio Standards (RPS) may impact operation of the nation's electric power system. Experience to date indicates that wind—the preferred renewable resource based on installed capacity and planned additions—often does not blow when power is needed most. In fact, wind generation maybe at its peak in the evening, when demand is lowest.

To meet the RPS, utilities without bulk energy-storage assets must send out renewable power as it is produced. At night or during the shoulder months, kilowatt-hours from renewables can be as much as 50% of the total energy supplied—possibly more. Mother Nature may be somewhat predictable, but not entirely so. This dictates the need for back-up generation resources, energy from neighbors via the grid, load shedding, and/or other immediate solutions to compensate for the shortfalls in energy production from intermittent renewables. Where fast-start/rapid-ramp assets are optimal for backing up renewables, or at least part of the solution, gas turbines are the likely generation option and the reason CTOTF hosted the workshop.

The report begins with an executive summary that captures the meeting's highlights. It is followed by in-depth coverage of 14 selected presentations discussing the challenges renewables present to grid operators and the wear and tear wind and solar assets can cause conventional generating units. A couple of presentations profiled discuss the promise of the smart grid and demand-side management (DSM) solutions for mitigating renewables impacts; two case studies illustrate real-world experience.

Finally, this report's companion website at www.integrating-renewables.org, scheduled to go live December 1, is designed to enable the free flow of information and ideas, share experiences, identify best practices, etc, to facilitate the transition to an electricity supply system with a large renewables component. Discussion forums include grid operations, smart grid/DSM, O&M impacts on conventional generation, and energy storage. Sign up today and join the dialogue.

SPECIAL REPORT

Integrating renewables into the generation mix: Challenges and unknowns

The adverse impacts on powerplant performance and economics associated with injecting large amounts of renewable energy into the grid are of great concern to many owner/operators of conventional generating assets. Many industry events have covered this topic in recent months, but the first to hit it head-on was a one-day critical-issues workshop at the CTOTF's fall meeting in Reno, Nev, September 13.

Although the challenges of renewables integration were expected by most seasoned industry veterans, CTOTF Chair Robert G Kirn of TVA said that the speed at which intermittent renewable resources have penetrated certain markets, regions, and balancing authorities have resulted in grid security and plant operational issues that will require innovative solutions and extraordinary cooperative effort across non-traditional lines.

Speakers at "Integrating Renewables into the Generation Mix: Challenges and Unknowns" defined the principal elements of the challenge, and then proposed solutions—strategic, technological, operational, and regulatory. The challenges can be classified in broad terms this way:

- Existing generation resources must have more flexibility. Whether they can achieve that flexibility economically and without sacrificing other performance goals, such as safety, reliability, and efficiency, is another matter.
- Markets and balancing authorities must institute new measures to value, pay for, and/or reward dispatch at sub-hourly time scales—perhaps down to minutes.
- Costs of cycling generation resources must be more accurately assessed and accounted for.
- Grid issues respective of the magnitude and type of renewables connected vary dramatically across regions. Solutions may require regionally based approaches and levels of renewables based on operational characteristics versus renewable energy source goals.

The solutions, in turn, can be grouped into these broad categories:

Photos by Mark Severts

Meeting Chair John E Borsch, manager of California plant assets, Colorado Energy Management LLC

Jeffrey L Ceccarelli, senior VP energy supply, NV Energy

- Modify existing plants to operate more flexibly.
- Revise market-value and reward profiles for ramping, intra-hour dispatch, turndown, and other market products reflective of increased grid security requirements.
- Seek or demand greater regional cooperation among individual balancing authorities.
- Expand bulk and distributed energy-storage installations, which could offer greater operational flexibility at lower cost than traditional options.
- Improve cost allocation and compensation to grid resources for ancillary services.
- Revise interconnection standards to recognize and assign renewable owner/operators costs for incremental system security and for ancillary services required to accommodate the operating profiles of renewables.
- Seek a legislated "sunset" to renewable energy production tax credits (PTC), especially for wind, which would slow wind penetration and create a more level playing field with respect to economic dispatch.

Setting the stage. Perhaps as simply and as eloquently as possible, Kevin Geraghty, VP power generation, NV Energy, which worked closely with CTOTF to develop the workshop, opened the meeting by observing that electric utilities today must serve as a safety net—that is, take the "extra juice" from grid-connected distributed generation (DG) resources, including renewables, and fix problems when they occur.

The idea of utility service has changed, he said, from one where perhaps 10 outages per year at your house might be okay to one where even a blinking digital clock is not okay. NV Energy must meet a 25% Renewable Portfolio Standard (RPS) by 2025, one of the most demanding state statutes in

CTOTF's Kirn calls for national forum of stakeholders to address impacts of 'must take' renewables on electric system operations

In recent years, CTOTF has expanded its historic roundtable profile from strictly technical discussion of combustion turbines to include all plant systems and components, as well as critical support services. As the complexity of powerplant operations has continued to evolve, discussion roundtables such as high-voltage equipment, generators, environmental, regulatory compliance, and management programs have been added both to maintain a comprehensive technical overview and to better understand the impact of the deepening intricacies descending upon the energy industry. Given the wide scope and high potential impact of the mandated addition of renewable generation resources, the formulation and presentation of a proactive program specifically dedicated to their operational impacts is a natural and necessary extension.

The economics, operational characteristics, and environmental impact of renewables—particularly wind and solar—are increasingly the focus of objective debate as global warming studies and the combustion of fossil fuels are systematically reviewed. However, in the interim, little attention has been paid to the operational impacts of adding "must take" renewable generation assets to the transmission grid.

The burden of compensating for the abrupt generation swings and low capacity factors ultimately cascades onto conventional powerplants, most notably, combustion turbines. In recognition, CTOTF's Integrating Renewables Workshop was specifically designed to identify operational issues and to stimulate comprehensive national discussion. Although only lightly touched in this forum, but of direct relevance, future discussions should also include "smart grid" and "smart metering" given similar potential impacts.

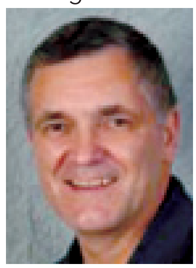
Taking the addition of renewable generation resources as a given, the workshop gathered industry experts to systematically profile the unique operating characteristics of renewables, the challenges they pose to transmission operations, the new operating demands for existing conventional generation, and potential solutions—including new equipment designs and energy storage.

While successfully providing an over-arching profile of a generation sea-change that has the potential to fundamentally amend nearly every aspect of the electric power industry, the resulting number of questions greatly exceeded the number of answers. This leaves us, as a nation, with the ultimate questions of the "why, who, what, when, and where" do we go from here?

With the universal recognition that the availability of affordable electrical energy is fundamental to economic vitality, there must be credible and objective discussion in order to "get it right the first time"—technically, economically, and environmentally, near-term and long-term. At CTOTF, with its more than 150 member companies, our hope is that the Integrating Renewables Workshop will serve as spark for the extensive technical and objective discussion that must follow.

Robert G Kirn
Chairman, CTOTF

Robert G Kirn, *Senior Program Manager for Business Ventures, TVA*



Kirn's 35-year career in the electric power industry includes positions in engineering and in the management of construction and operation for multiple types of generating plants and power delivery systems at both regulated electric utilities and independent power producers. He has served as chairman of CTOTF since 2008.

the nation. Today the company ranks first nationally in installed solar energy capacity per person.

Jason Makansi, president, Pearl Street Inc, and executive director of the Coalition to Advance Renewable Energy through Bulk Storage (CAREBS), then framed out at the industry level the challenges that confront generation owner/operators. While many of the driving forces favoring renewable energy are well known—for example state RPSs, the "environmental gauntlet" facing coal-fired plants, and pending federal legislation that could escalate renewable energy penetration—many attendees were surprised to learn that from 60% to 90% of all generation interconnection requests in six independent system operator (ISO) and regional transmission organization (RTO) jurisdictions are renewable energy (mostly wind).

Another surprise to some: Large amounts of wind energy in certain balancing authorities and areas—including the Electric Reliability Council of Texas (Ercot), Bonneville Power Administration (BPA) in the Pacific Northwest, and the Midwest ISO—can drive market prices into negative territory because of the PTC subsidy.

Characteristics of this renewable resource important to any economic evaluation include the following: Wind-energy strength curves are opposite of electricity demand curves; availability of wind energy can shift dramatically in a few minutes; wind capacity factors rarely average more than 30%. Thus plants powered by gas turbines and coal are penalized by having to undergo deeper and more frequent cycling to "fill in" around intermittent wind.

Jason Makansi, president, Pearl Street Inc; executive director, CAREBS

Also of interest: Less than 10% of Ercot's total wind capacity is considered "available" during summer-day peaks. Plus, wind energy in PJM Interconnection is credited with only 13% of its capacity value during peak periods. And MISO representatives report that swings of up to nearly 2000 MW are common.

Makansi suggested four broad solutions options, adding that all ultimately would be deployed in some combination in regions affected by large-scale renewable energy penetration. The options:

- **Smart grid.** Enhanced wind monitoring, forecasting, and communications with grid operators, combined with demand side management (DSM).
- **Gas + wind.** Deeper and more fre-

Michael Roberts, managing director of power asset management and operations, Iberdrola Renewables

Stephen J Beuning, director of market operations, Xcel Energy Inc

'Solar power could crash Germany's grid'

That was the headline for an article posted on the website of Reed Business Information Ltd's magazine *New Scientist* October 28.

The article had a familiar ring: "Subsidies have encouraged German citizens and businesses to install solar panels and sell surplus electricity to the grid at a premium. Uptake has been so rapid that solar capacity could reach 30 GW, equal to the country's weekend power consumption, by the end of next year."

A spokesperson for DENA, the German Energy Agency, was reported as saying, "We need to cap the installation of new panels." The article also mentioned a warning by Stephan Koehler, the agency's chief executive—in an October interview with the *Berliner Zeitung*—that at the current rates of installation PV could trigger blackouts.

New Scientist reported that the German Solar Industry Federation rejected DENA's concerns. Its belief: Solar energy takes the pressure off high-voltage power lines because it usually is generated close to where it is used.

Whether you believe large quantities of solar power could crash a grid or you don't is not so important. What the German experience points to are the unintended consequences of widespread renewables development without adequate preparation. The impacts of intermittent renewables on grid operations and on the health of conventional generation assets are not well known anywhere on the globe and should be studied carefully before assuming RPS goals are achievable technically and economically.

Wind. A press release on the DENA website noted that the agency has just given the green light for research into the expansion of wind energy in Germany. This is the second part of organization's grid study to justify increasing energy supply from renewables to 30% of the kilowatt-hours sold by no later than 2025. Part 1 of the study was finalized in spring 2005.

Wind generation will be evaluated under technically difficult conditions—such as high winds, a lack of wind, and peak-load times. Grid impacts, realistic transmission distances, flexibility of conventional generation, role of energy storage, etc, all will be researched. Study assumes 20 GW of offshore wind and 28 GW of onshore wind; also, that the expansion of the EHV grid outlined in Part 1 of the study is completed in timely fashion.

quent cycling and dispatching of existing fossil assets, and the addition of more flexible gas-turbine-based assets.

- **Energy storage.** Build a new layer of bulk and distributed storage options, which offer greater flexibility than alternatives for meeting sub-hourly dispatch requirements.
- **Business as usual.** Run old fossil units into the ground.

Ultimately, all of these solution sets will be deployed in some combination for all regions affected by large-scale renewable energy penetration.

The advantages bulk energy storage offers are considerable, Makansi went on. Pumped hydroelectric storage (PHS) and compressed air energy storage (CAES) are both commercially available, *investible* options long on operating experience. They can move from idle to full load in less than 10 minutes; comfortably charge and discharge for two, six and even 12 hours; have no emissions (PHS) or a minimal emissions profile (CAES); and suffer less deterioration in cycle efficiency and emissions degradation than simple-cycle gas turbines or combined-cycle systems.

Most importantly, perhaps, PHS and CAES can function *both as load and generation,* making them ideal for ancillary services. Dozens of new PHS and CAES plants are being developed nationwide and regulations and policies at the state and federal levels are being shaped so that storage can be included as a viable asset class for grid operations.

Generating companies speak. Michael Roberts, managing director of power asset management and operations for Iberdrola Renewables Inc, Portland, Ore, the leading wind-energy producer worldwide, noted that his company designed a combined-cycle plant, Klamath Falls, specifically for daily cycling. Grid flexibility in the West is "being used up," he cautioned.

Although some point to the flexibility of hydroelectric plants for integrating wind energy, Roberts noted that,

Jonathan Hawkins, manager of advanced technology and strategy, PNM Resources

Adrian Pieniazek, director of market policy for the Ercot region, NRG Texas LLC

Renewable energy: The ultimate balancing act

The art of balancing is nothing new to energy utilities. We continually balance the needs of customers with environmental sensitivities, with regulatory oversight, and with shareholder interests. However, our well-honed traditional equilibrium skills will need to be razor-sharp in this exciting era of growing renewable-energy portfolios.

Balance is especially important in the Desert Southwest, and specifically in the state of Nevada, as we need to strategically assess the benefits of utilizing different types, sizes, and varieties of renewable-energy projects that will benefit customers. NV Energy, for example, has 23 geothermal projects, eight solar projects, five biomass projects, five small-hydro projects, two large wind projects and one waste-heat-recovery project that are either in production or under development. No project in our current 1.2-GW renewable energy portfolio is easy, but each one will benefit our customers, the environment, and our shareholders.

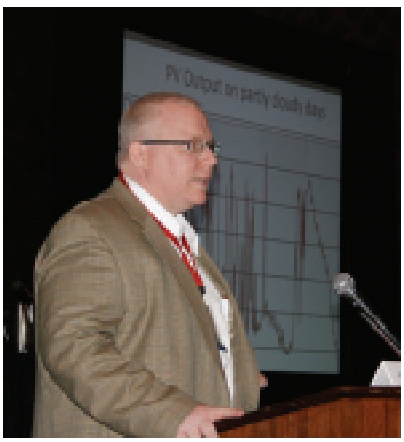
While the benefits seem so apparent, the development of renewable projects is not as easy as we might expect. Balancing the needs of all stakeholders in the siting process is difficult. A state mandate to grow our customer's renewable-energy supply does not tip the scales in the favor of developers and proponents as many might expect. Careful planning and managing the opposition by groups that oppose all forms of utility-scale energy projects is a balancing act without a safety net.

One of the most significant balance-beam issues, of course, relates to legislated requirements for Renewable Portfolio Standards (RPS) and their related cost impacts. While I firmly believe that the cost of renewable energy will become more and more competitive, most electricity customers throughout the nation don't fully appreciate the impact that "free wind" and "free sunshine" will have on their individual utility bills.

Obviously, there is a very fine line that companies such as ours must walk—to make sure customers are prepared for higher renewable-energy costs—without our company somehow being perceived as being resistant to renewable-energy growth. Again, another balancing act must be performed.

Other significant situations that require careful analysis and astute balancing skills can be summed up in these questions:

- How much of our renewable energy portfolio should be secured through power-purchase agreements and how much should we build ourselves?
- What is the ideal mixture of wind energy, geothermal energy, solar thermal, solar photovoltaic, biomass, waste heat recovery, and small hydro for our customers and service territory?
- Considering the fact that we have an increasing RPS to meet and that many renewable projects can be delayed, cancelled, or have under-production problems, how much renewable energy should we over-subscribe to assure that we meet the annual stair-stepping RPS requirements?
- Should we take a leadership or a "fast-follower" approach to cutting-edge renewable-energy designs for such opportunities as solar thermal projects with storage capacity, or new methods for integrating solar thermal into our combined-cycle natural gas plants?



- How do we resolve the "chicken and the egg" question about when to build transmission lines to accommodate renewables.
- What is the proper balance between utility-scale renewable-energy projects and home solar or wind applications for individual customers?

Even after we master the issues associated with these types of questions, the largest elephant in the room may be the unanticipated consequences of injecting large amounts of intermittent energy into our local systems or our regional grid. "Balance" will take on a deeper meaning. How can we maintain system balance without cannibalizing our traditional generating assets and reducing efficiencies?

In other words, if we start changing the role of base-load units to become renewable-energy responsive load-following assets, what will that do to our maintenance costs? What will be the impact to the plant's life cycle? Will there be significant losses in operational efficiency? Are there plant safety implications?

The solutions to these and other questions will not come easy. It will take a combination of many solutions to resolve this challenge. And, it will require cooperation, partnerships, and concessions as an industry. The solutions undoubtedly include:

- Modifying our existing generation resources to be more flexible to renewable intermittency;
- Seeking greater regional cooperation among individual balancing authorities; and
- Implementing smart-grid technologies—still in the incubation stage—to facilitate seamless integration of renewables in the future.

Albert Einstein once said that "life is like riding a bicycle—to keep your balance, you must keep moving." Such is the case with today's unbalanced challenges surrounding renewable energy. We simply "must keep moving."

Kevin Geraghty
VP Generation, NV Energy

at least in the Pacific Northwest, they are usually under ecological restrictions to manage fish life. He also noted that no formal market exists for flexibility, although BPA is headed that way.

While Roberts urged the development of flexible energy products, he conceded that the contractual obligations to meet such products would be "a mess," the maintenance component of the costs of cycling units is difficult to quantify, and complex computer modeling is necessary—that is, at once user-friendly to traders, operators, and forecasters. He asked the audience, what is the "surcharge" for the necessary flexibility? Growth in wind power makes life difficult for grid managers, he stressed.

Iberdrola's observations as an independent generator were contrasted somewhat by those of Stephen Beuning, director of market operations for Xcel Energy, the top wind provider in the nation. He believes that renewable energy to date hasn't been required to dispatch, but future systems will be, and that fast intra-hour dispatch will mitigate the balancing-area challenge and provide market signals as well.

To do this most effectively, Beuning suggested to utilities with their own balancing authorities in the West to work more on a regional basis. Today, gas turbines and other powerplants must be committed to accommodating wind energy.

As chair of the Western Electric Coordinating Committee's (WECC) Seams Issues Subcommittee, Beuning was able to offer insights into regional activities. WECC, he noted, has only limited congestion management procedures and only six transmission paths available to manage congestion.

WECC's "efficient dispatch toolkit" includes an enhanced curtailment calculator for the entire footprint and an energy imbalance market. The RTO is currently evaluating a process called "virtual consolidation" and is expected to complete a benefit/cost analysis by the middle of next year. With wind resources projected to increase beyond 50,000 MW by 2019 in the Western Interconnection, variability impacts must be addressed now.

PNM Resources, according to Jonathan Hawkins, manager of advanced technology and strategy, plans to solve integration problems at the distribution level, providing a firm, dispatchable renewable resource by adding large scale batteries and smart-grid technology. Beyond 20% renewable energy penetration, community energy storage systems—neighborhood units with the look and feel of those "green" transformer boxes—may be investigated.

The view from grid-side. Echoing a comment made by several presenters, Clyde Loutan, a senior advisor in the California ISO's Market and Infrastructure Div, said that the West does not have much inertia in its grid, unlike the eastern part of the country. He also mentioned hydro resources, but "what about a bad hydro year?" It bears remembering that a very poor hydro year helped precipitate California's electricity crisis a decade ago, and that ultimately forced the governor out of office.

Astonishingly, 18,000 MW of thermal generation will be retired or repowered in the next 10 years in California, while 20,000 MW of wind and solar is expected to be added. Currently, the state faces separate challenges balancing wind energy and solar resources. Almost all of the generating resources in the state are only capable of 20-MW/min ramp rates, or less.

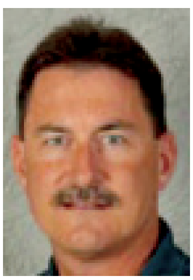
In addition to the day-ahead and hour-ahead schedules, the system may need the capability to dispatch units on a five-minute basis, a significant departure from current practice. However, Loutan suggested that, up to a certain point, deviations in supply and load can be "picked up" and managed in frequency regulation—one of several so-called ancillary services. To manage the impacts of the state's demanding

Panelists discussing issues included speakers, top plant executives

Jeff Chartier, *Combustion Turbine Manager, Tri-State Generation & Transmission Assn Inc*

Chartier has years of gas turbine experience on a wide range of General Electric and Westinghouse machines. He currently manages fleet-wide O&M and capital improvements for 10 GTs at four plants.

Steve Hedge, *General Manager, W A Parish Generating Station, NRG Energy Inc*



Hedge recently celebrated his 25th anniversary in the electric power business, where he has worked as an engineer, plant manager, and general manager at conventional steam, combined-cycle, and peaking plants.

Scott Takinen, *Plant Manager, West Phoenix Generating Station, Arizona Public Service Co*

Takinen has more than three decades of experience at APS in the engineering and management of nuclear, coal-fired steam, and combined-cycle generating plants. Currently leads a team of 59 employees at West Phoenix, providing both power and ancillary services. Another responsibility: Generic safety and environmental issues across the company's gas/oil-fired plants.

Ozzie L Lomax, PMP, *Manager of Gas & Renewable Generation, AmerenUE*

Lomax manages 15 gas-fired powerplants (3000 MW) and the "Methane to Megawatts" facility under construction. Strategic planning and O&M budgeting for the Power Operations Div are among his responsibilities. Before joining Ameren nine years ago, Lomax spent 22 years at Kansas City Power & Light Co in various leadership and engineering positions. His sits on the advisory boards for two colleges incorporated into Southern Illinois Univ.

Michael Rutledge, *Manager of Plant Technical Support, Salt River Project*

Rutledge's group supports all generating facilities and other company departments with a broad spectrum of specialized technical know-how. He is a respected three-decade industry veteran.

RPS by 2020, CalISO and others are looking at integrating storage into supply scenarios.

Although employed by NRG Texas LLC, Adrian Pieniazak, director of market policy for Ercot, gave an Ercot/IPP perspective on wind integration. In Texas, upwards of 41,000 MW of wind could be interconnected in the coming years. One of his eye-opening stats: Last August 16, peak-hour load was 64,805 MW; wind output averaged only 650 MW, from a resource base totaling more than10,000 MW.

Pieniazak started by reminding the audience that FERC has no jurisdiction in Texas. Wind energy is suffering in Texas not only because of curtailments, but because curtailed wind resources are then limited in how fast they are allowed back onto the grid. Ercot now requires new wind turbine facilities to provide their own voltage support; some machines must be retrofitted as well.

Ercot also modified regulation and added more "non-spin" at 30-min intervals but may have to go to a 15-min non-spin regulation product. He noted that Ercot as a whole "hasn't done well on ancillary services cost allocation." Pieniazak focused attention on Texas' Competitive Renewable Energy Zone (CREZ) transmission line build-out. CREZ will help with integration long term, but the first lines won't be in operation until after 2012.

On the solutions side, Pieniazak believes that newer-model wind turbine/generators can provide frequency control and be placed on AGC just like gas turbines. Nevertheless, the high-wind-week projections for year 2013 look "really scary," he said.

A trio of speakers from NV Energy—Richard Salgo, director of electric systems control operations; Gary Smith, director of smart technologies; and Dariusz Rekowski, director of generation O&M, gave a "grid operator" perspective on integration issues. Most of the presentation was a well-needed refresher on balancing areas.

A recurring theme was the quality of spinning reserves versus the quantity. Nighttime minimum load in northern Nevada can be as low as 750 MW, which poses operational challenges for conventional generation assets because half that demand, possibly more, is under contract as "must-take" renewable power. This obviously limits the "range of motion" of generating units that can't be taken offline.

Part of the solution will come from the utility's Advanced Service Delivery (ASD) program, demand response management anchored by smart meters, and customer "ownership" of their energy usage. But NV Energy's generating assets still will have to make sacrifices in terms of increased cycling, faster ramp rates, and lower-load operation, which negatively affect performance. Lower efficiency and higher fuel consumption and CO_2 emissions are among the impacts. Consequences for NV Energy and its customers will be incrementally higher fossil-plant O&M costs and increased investment in units that will generate fewer megawatt-hours.

Enter storage. Bob Kraft, CEO and president, Energy Storage & Power LLC (ES&P), Bridgewater, NJ, told the audience that his firm is evaluating CAES systems up to 460 MW in size for greenfield sites, as well as the retrofit of existing F-class turbine plants for this service.

Other features of a modern CAES plant, compared to the pioneering version demonstrated at the McIntosh facility in Andalusia, Ala, include these: three-minute bottoming cycle startup from a warm condition; use of commercially available components, not custom equipment; state-of-the-art combustor technology; and split system with multiple compressors and expanders to add flexibility.

According to Kraft, a "CAES 2" plant can ramp at rates up to 28 MW/sec. Another interesting offering from ES&P is a humid-air turbine, which regains cold-day performance on a hot day and promises a 13% power boost for today's standard combined-cycle plant at less than $350/kW.

Flex machines. The new capabilities being built into today's gas turbines was amplified by Bruce Rising, strategic business manager, Siemens Energy. Rising claimed that a Siemens simple-cycle Flex-Plant™ 10 can reach 150 MW in 10 minutes, the 150-MW combined-cycle Flex-Plant™ 30 in 30 minutes. Advanced power diagnostics and an integrated fuel-gas characterization system are features that will enable such plants to better handle deep cycling and dispatch. Rising reiterated the unintended consequence of fast ramping: Reduced efficiency of environmental controls.

A planner's perspective. Victor Niemeyer, technical executive for EPRI's Climate Program, connected wind integration to global climate change issues. He began by saying in the low-carbon future, coal "is toast," which made even this natural-gas-oriented audience wince. Of course, what he meant was that, long-term, carbon is a factor even without an imminent federal policy goal for carbon. At $100/MWh, he said, wind could displace all of the nation's coal.

While that may make wind enthusiasts cheer, another observation was more sobering: The idea that wind from one region will compensate for wind in another is not true. Sometimes there is no wind over a broad area. Niemeyer pointed to some modeling and analysis work conducted over a seven-state region (the Dakotas, Minnesota, Iowa, Missouri, Kansas, and Nebraska) which showed that low wind output can persist for extended periods.

Niemeyer concluded with these three points: Adding transmission enables greater utilization of wind (although "lots of line-miles are necessary"), cost of wind delivered to load is much higher than the simple cost of generation, and the "anti-correlation" of wind with load and the need for new interregional transmission "greatly limits" the fraction of coal generation displaced by wind in a de-carbonized future.

Presentations by Thomas Mastronarde, Gemma Power Systems LLC, Glastonbury, Ct, on integrating combined-cycle heat-recovery steam generators with solar thermal, and by Steve Gressler, Structural Integrity Associates Inc, San Jose, Calif, on material considerations for equipment under increased cyclic duress, rounded out the day.

Panel discussion. Some of the more salient points gleaned from the workshop's two panel discussions:

- In Ercot, municipal utilities with a rate base are the only ones that can build and finance peakers and "flexible resources."
- Ercot rules forcing wind turbine plants to retrofit reactive power and voltage control are under appeal by the Texas Public Utility Commission.
- Interconnection standards for wind machines were proposed by the CalISO for all non-synchronous units, but were rejected by FERC.
- CAES-based storage has natural reactive-power capabilities.
- ISOs/RTOs have learned a great deal about committing resources to manage wind penetration, but industry participants must get beyond long-term averages because forecasted operations and actual operations can be vastly different.
- Owner/operators need to rethink maintenance strategies when a nominal 650-MW fossil unit is being replaced by, say, a half-dozen generators at smaller facilities, not to mention hundreds of wind generators hanging hundreds of feet in the air.
- The $6-billion cost for CREZ in Texas is being socialized across the Ercot load, but industrial and consumer groups are fighting the policy. California is also considering CREZ-type approaches to add transmission infrastructure that enables wind.

Overview

Wind potential and economics

Victor Niemeyer, the technical executive for EPRI's climate change program, offered an objective view of wind drivers and economics. It was wind from 30,000 ft, quite unlike most other presentations at the workshop, which focused on specific ways to accommodate the variable nature of wind and to move the electricity it produces from point A to point B.

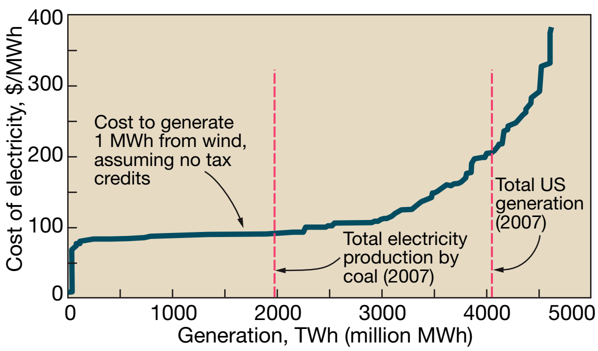
He said that if the federal government were to write into law a national policy to curb CO_2 emissions below current levels, the legislation would likely initiate a competition to replace existing coal. Renewables, nuclear, and carbon capture and storage (CCS) would be among the high-profile solutions. Passage of climate legislation, Niemeyer continued, would initiate a "voyage of discovery" leading to an energy paradigm for the future that is much different than exists today.

Wind resource potential is huge, he said, exceeding half of the nation's current electric needs at $90-$100/MWh, and possibly exceeding current generation from coal (Fig 1). Unsubsidized wind, the economist added, is competitive with $8/million Btu gas on a pure energy basis.

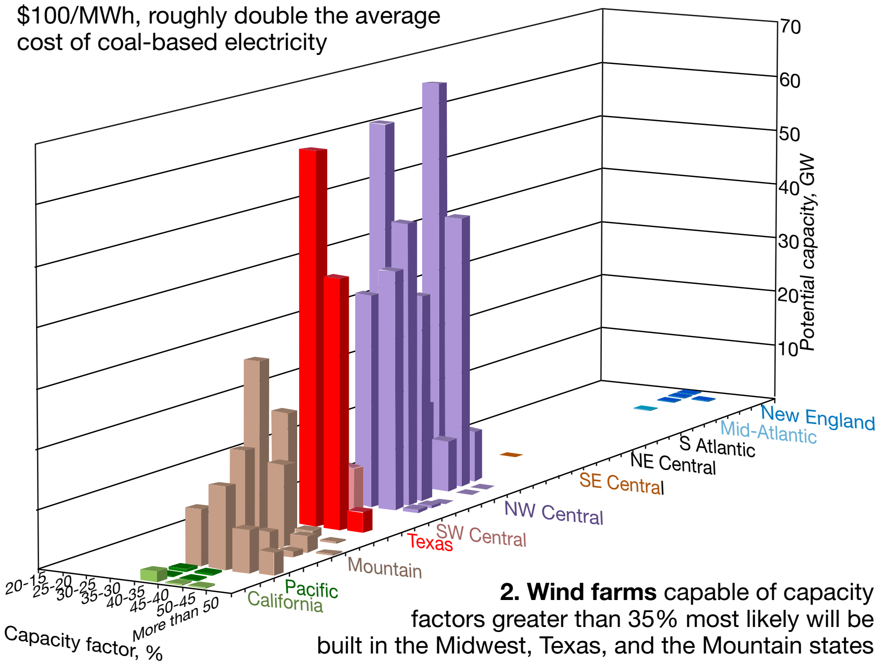
Niemeyer qualified his remarks by saying wind potential is adversely impacted by:

- Long periods of calm with no output over large geographic areas—swaths of real estate that may extend over several states.
- Rapid changes in wind generation over relatively short periods of time—an hour or less in some cases.
- "Anti-correlation" of wind with load.
- The cost/ability to permit new transmission needed to move wind energy to consumers.

The economist added that while he was not expecting climate legislation anytime soon, because it could happen might discourage power generators from considering coal as a viable option for future capacity. One of his slides plotted the CO_2 emissions reductions required to satisfy several pieces of legislation introduced in the last several years. A couple of the laws proposed would require that CO_2 emissions be halved from 2005 levels within 25 years, and cut to 80% below historic levels by 2050. Access Niemeyer's presentation at www.integrating-renewables.org.



1. Wind resource potential is huge, exceeding half of the nation's current electric needs at $90-$100/MWh, roughly double the average cost of coal-based electricity



2. Wind farms capable of capacity factors greater than 35% most likely will be built in the Midwest, Texas, and the Mountain states

Next came a few numbers to illustrate the magnitude of the challenge associated with curtailing CO_2 emissions—and the cost. The electric sector, Niemeyer said, produced 39% of the country's CO_2 (and one third of its total greenhouse-gas emissions) in 2006; 83% of the industry's CO_2 was emitted from coal-fired plants burning fuel at an average cost of $2.50/million Btu.

He believes that any cap-and-trade legislation seeking to cut emissions well below current levels would include incentives for new generation to back out coal; also, the national CO_2 "price" would be whatever it takes to displace existing coal.

Wind potential. EPRI engaged AWS Truepower LLC, Albany, NY, to get a comprehensive assessment of wind resource potential. It identified more than 5000 viable utility-scale (100 MW minimum) wind-farm sites nationwide based on actual hourly meteorology from 1997-2008, assuming installation of 1.5-MW turbines.

Variables such as distance to the grid, terrain/wake effects, and exclusion areas were factored into the analysis. Fig 2 shows where the wind farms (capacity factors greater than 35%) would most likely be located.

An example analysis conducted for the North West Central (NWC) region is instructive, illustrating key points regarding the behavior of wind. About half the nation's wind potential exists in this seven-state area (Minnesota, North and South Dakota, Nebraska, Iowa, Missouri, and Kansas). However, regional demand would be largely satisfied with less than 10% of that amount were it built. "Use it or move it," Niemeyer said. Easier said than done: The regional grid can't handle anywhere near the amount of wind power that could be produced.

More wind than load produces a local surplus that must be "spilled" if it can't be exported. If you must spill, capacity factor of your wind turbines decreases and your pro forma takes a hit. Given adequate wind resources, the challenge is to match market needs.

The EPRI study was based on the following facts and assumptions: (1) actual state hourly load data for 2007 from Energy Velocity LLC, Boulder, Colo; (2) correlation of energy consumption with meteorological data to quantify the impact new wind generation would have on regional demand; (3) an additional 50 GW of new wind capacity installed in the region at qualified sites offering the highest capacity factors.

Figs 3-5 offer grid operators and power generators unfamiliar with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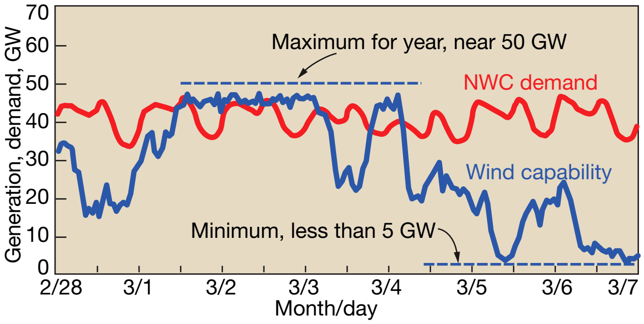
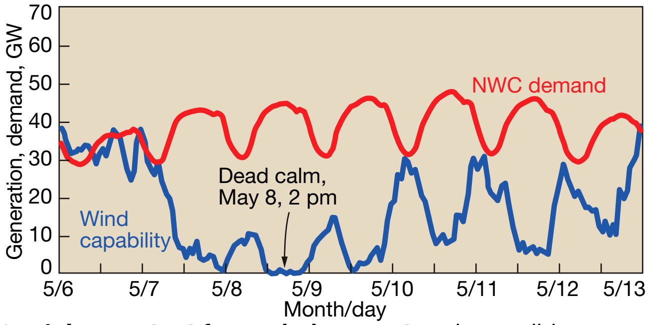


3. Variability in wind production is evidenced by nearly 50 GW of capacity early in the week, less than 5 GW at week's end



4. Low output from wind generators is possible over long periods

wind's idiosyncrasies a short course on its variability and electric system impacts. The NWC time series from Feb 28, 2007 through March 7 (Fig 3) reflects the week of highest wind output for the 2007 simulation. Keep in mind that this simulation includes the 50-GW addition to the wind capacity existing in the region.

The wind curve illustrates the variability in electric production experienced. Dispatchable capacity early in the week is close to 50 GW as a cold front moves through the region, and less than 5 GW at the end of the week after the front has passed. "Wind comes and goes," Niemeyer said, putting up the next slide in the series.

Fig 4, for May 5-12, 2007, illustrates a prolonged period of low wind; a dead calm is experienced the afternoon of May 8. The EPRI executive said many people believe that although wind might not be blowing at any given point in the region, it is blowing elsewhere. That's not necessarily true, he continued, showing a national weather chart for May 8 that revealed a stall extending over more than just NWC.

The time series from Aug 9-16, 2007 illustrates a typical summer pattern in NWC (Fig 5). Note that the wind pattern is more consistent day to day in summer than it is in winter (refer back to Fig 3). More importantly, the chart clearly shows the anti-correlation of wind with load—that is, wind production is highest when demand is lowest. Looking ahead, conventional assets backing-up wind will require the ability to ramp up and down quickly to maintain the continuous balance between load and generation needed for a reliable power system.

Niemeyer summed up his thoughts with these three points:

- Adding transmission enables greater utilization of wind resources.
- The cost of wind delivered to load is much higher than the simple cost of generation.
- Anti-correlation with load and the need for new interregional transmission capacity limit the amount of existing coal-based generation that wind can displace in a decarbonized electric future.

How much will wind cost? Niemeyer answered this question based on AWS TruePower's national wind energy supply curves and EPRI's estimates of generation and transmission asset costs. The exercise was to estimate the cost of producing and delivering 1000 TWh, or about 50% of the energy supplied by coal-fired powerplants (Fig 6).

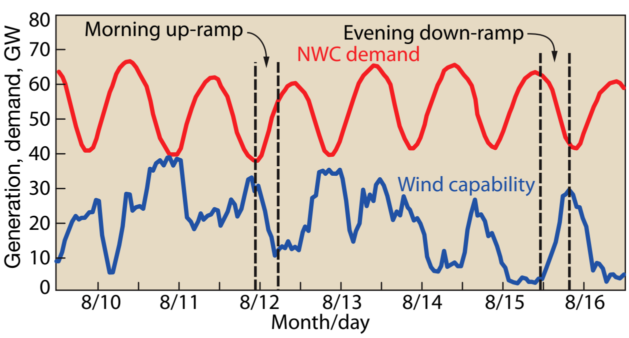
The answer: It would take about 175,000 1.5-MW wind turbines to accomplish the goal at a total installed cost of about $650 billion. Delivery of the power produced would require about 13,000 line-miles of extra-high-voltage (800 kV dc) transmission lines at a cost of approximately $50 billion. Niemeyer mentioned that the biggest question is not about the cost of transmission, but rather if you can construct it at all.

Referring to the chart, he said that delivered cost jumps up right away (point A), because you must integrate the new capacity with the existing grid. It is about $450/kW for *induced* transmission associated with backing up wind, Niemeyer continued. If you add a couple of wind turbines, there is no associated grid cost impact because you can squeeze them onto the existing infrastructure.

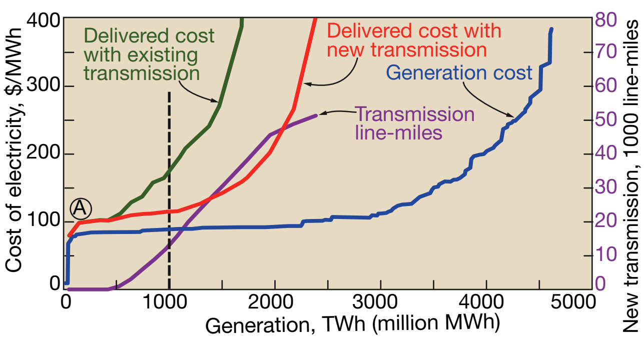
But the installation of wind farms rated in the hundreds of megawatts require upgrades to transmission assets. And the further wind resources are located away from the load, the higher the voltage must be to reduce line losses. The curves of delivered cost are steep, he added, because wind does not line up with load (anti-correlation)

Dr Victor Niemeyer, *Technical Executive for Global Climate Change, Electric Power Research Institute*

An economist by education, Niemeyer conducts research to help energy companies manage the risks from global climate change. In particular, he assesses the cost and competitive-market implications of potential climate-management policies.



5. Anti-correlation of wind and demand is clearly in evidence for this week in summer. Wind production is highest when demand is lowest and vice versa



6. Addition of about 175,000, 1.5-MW wind turbines could displace half the coal-fired generation at a cost of about $700 billion, including transmission and capacity factors for wind turbines decrease as you add more and more wind.

"The bottom line is that the country has a vast potential wind resource, but there are fundamental forces that limit how much we can use," Niemeyer said in his summary remarks. The biggest is that wind output just does not line up that well with loads. The anti-correlation effect clobbers the economics of wind once you start to generate more than 10% to 20% of total electricity demand—depending on whether or not a large amount of interregional high-capacity transmission can be built.

The climate-change expert closed with this thought: Wind can play a strong role in a low-carbon electric future, but it will not be a dominant role."

Grid impacts

How intermittent renewables impact CalISO

"Pretty challenging times," said Clyde Loutan as he began his presentation on how the CalISO works today and what changes probably will be necessary to accommodate the state's aggressive 33% RPS by 2020. An intermediate step: 20% of California's kilowatt-hours must come from renewable resources by 2012—a goal most other RPS states have established for 2020. California policy also calls for emissions of greenhouse gases to be at 1990 levels by 2020.

The CalISO controls about 80% of the state's load, which was about 50.2 GW during the peak year of 2006.

Specific operational challenges faced by CalISO over the next 10 years include the following:

- Increased supply volatility. Expectation is that more than 20 GW of wind and solar capacity will come on line by 2020 to meet state policy goals.
- Uncertainty surrounding thermal resources. Approximately 18 GW of thermal generation will be retired or repowered in the next 10 years.
- Less predictable load patterns. Changes to current load patterns are expected as reliance on distributed generation and electric vehicles increases.
- Changing revenue patterns. Decreasing marginal prices and changes to the dispatch of generation resources will force stakeholders to re-evaluate business plans.

Loutan had three slides to illustrate how intermittent renewables impact grid operations. Fig 7 was developed from wind production data for April 2009. Each line tracks wind generation for one day that month and shows how difficult it is to predict with accuracy the production of wind resources in the day-ahead and hour-ahead timeframes.

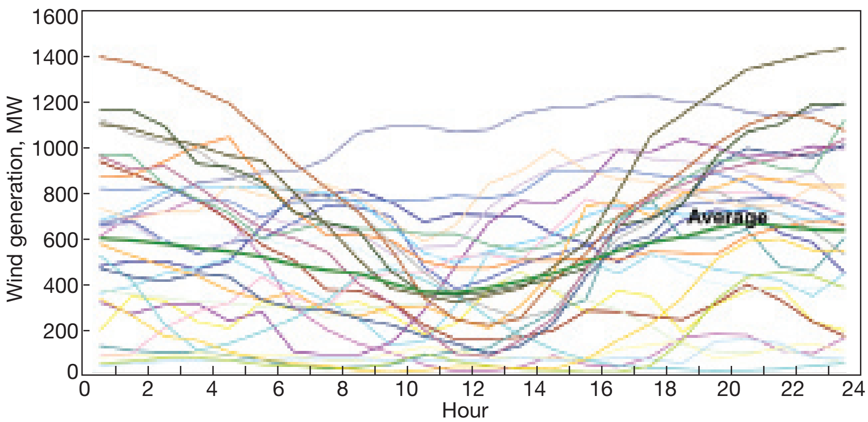
The variability of wind and solar are presented together in Fig 8, actual data for last June 24 (a cloudy day) recorded for a 150-MW wind farm and a 24-MW solar PV field. "How would you balance these resources in real time?" Loutan asked the workshop participants.

Next, he showed the group how dramatically the dispatch of conventional resources would change with significant contributions of solar and wind power (Fig 9). Before intermittent renewables, generation resources would be dispatched to follow load, the top curve. But when solar and wind are added to the mix, dispatch of conventional resources would have to follow the red curve.

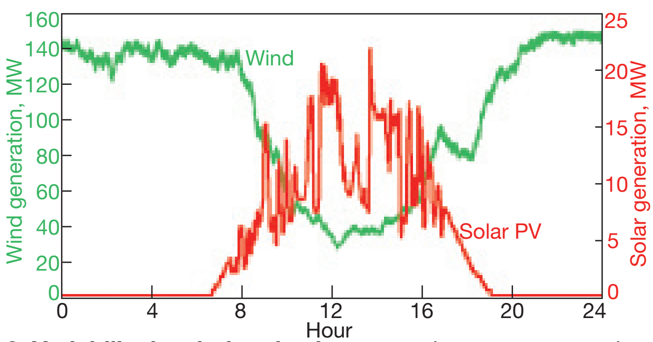
The CalISO has roughly 60,000 MW of capacity at its disposal today, including 5000 MW of dynamic schedule. Ramps up and down will be one of the biggest challenges for conventional assets going forward, Loutan told the group.

Fig 10 shows current ramp rates for the ISO's generating units. Note that relatively few assets can ramp at 20 MW/min or more, and most of those are hydro. The grid expert stated that on a typical summer weekday, between 8 and 10 am, load can increase by about 4000 MW an hour.

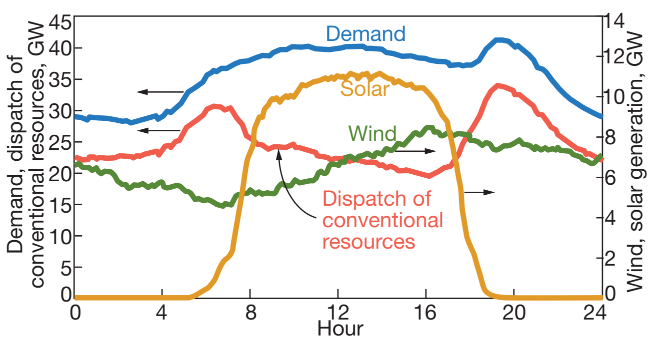
Today, the CalISO can meet this hourly ramp requirement, mitigate



7. Wind generation can vary dramatically from day to day. Each curve above illustrates the wind generation profile for one day in April 2009. Knowing what to expect from wind when lining up resources a day ahead is challenging for grid operators like the CalISO, which developed this chart based on its system data



8. Variability in wind and solar generation are compared for a cloudy California day. The solar PV field is rated 24 MW, the wind farm 150 MW



9. Dispatch of conventional resources does not follow the typical load curve when significant amounts of intermittent renewables are injected into the grid unexpected intra-hour variability, and comply with control performance standards with a combined ramp rate of 60 to 100 MW/min. However, to meet the 33% RPS, technical studies show ramp rates may triple, which is not possible for the ISO's conventional generation as configured today. Loutan thinks the need for flexible conventional generation going forward cannot be overstated.

Perhaps the most valuable part of the presentation for many in the room who had spent their careers managing generation assets was Loutan's description of how the CalISO works. This was important so all could grasp the challenge grid operators would face if too much intermittent renewables capacity were added before existing infrastructure was upgraded or replaced to accommodate the wind and solar generation.

Referring to Fig 11, note that grid operators begin lining up available generating assets a day before they are needed by issuing a "day-ahead schedule" for each hour of the next operating day to meet expected hourly demand (blue). The day-ahead market closes at 10 am the day prior to the operating day.

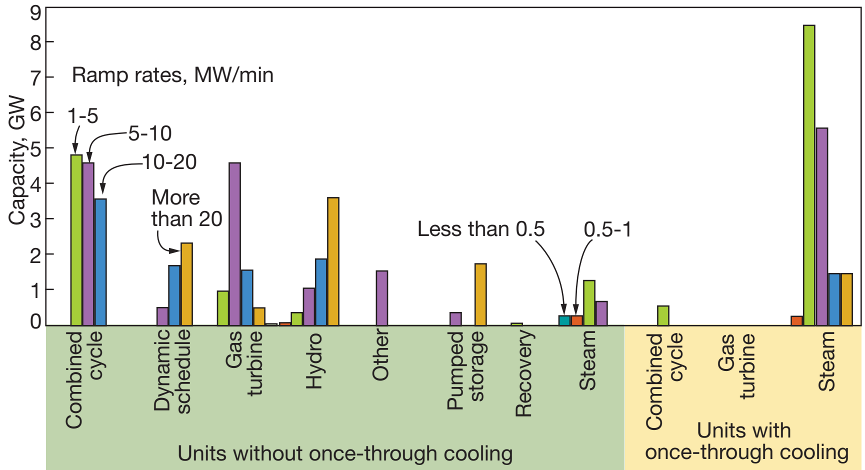
A mixture of extremely long-start units (those requiring more than 18 hours to start), long-start (between five and 18 hours), medium-start (between two and five hours), short-start (less than two hours), and fast-start (less than 10 minutes) resources are lined up in "economic order" to serve load at lowest cost to consumers.

Generation requirements are adjusted continually based on forecast revisions. The green line shows the hour-ahead adjustment needed based on the revised hour-ahead demand forecast. The short brown arrow between the two horizontal line segments represents capacity that, in this case, must be added to meet the load expected.

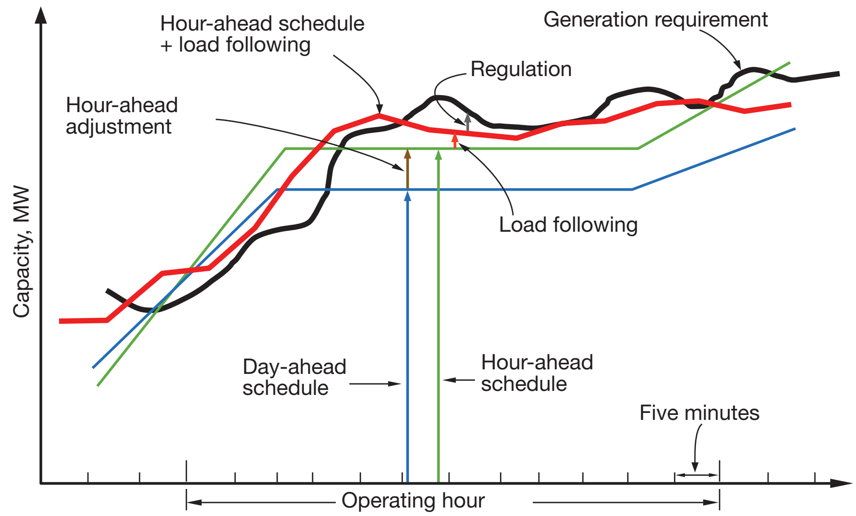
Currently, the CalISO interchange schedules and self-scheduled generation are changed from one hour to the next over a 20-min ramp period beginning 10 minutes before the hour ends.

On a more granular scale, every five minutes, the CalISO economically dispatches its generation fleet to follow the expected load five minutes ahead of time. In the diagram, observe that "load following," or the five-minute dispatch, is the difference between the hour-ahead curve and the red line defining current requirements every five minutes. Asset flexibility is especially important for load following.

To illustrate how challenging load following might become under an aggressive RPS, Loutan offered this example: A fast-moving cloud bank can knock out a 500-MW PV field within



10. Ramp rates for CalSO generating assets today may not meet the grid's needs once the wind and solar generating facilities required to meet the 2020 33% RPS are up and running



11. Fleet operating flexibility is critical for accommodating the supply variability of intermittent renewables. Think for a moment about the challenges facing operators in this five-minute dispatch market where a 500-MW PV facility can potentially go dark within that time increment because of a rapidly moving cloud bank. This is not the same as losing a 500-MW combined-cycle plant because the impact on the system is different and the response to the lost generation would be different

five to eight minutes. It's unlikely such an anomaly could be completely accommodated with generation resources available to the system because of ramp constraints.

Additional support through dynamic schedules from a neighboring balance area, load reduction (via a demand-side management solution), and storage devices might all be necessary to balance the system with a high penetration of renewables generation.

The black curve at the top of the chart represents the actual load demand, which also corresponds to the total generation requirement. Regulation, defined here as the difference between generation and load in real time (so-called "imbalance"), is not dispatched through the CalISO's market software.

Rather, it is dispatched through the CalISO's energy management system every four seconds to correct for deviations in system frequency and deviations from interchange schedules with neighboring balancing authorities.

With the ISO primer putting everyone in the room on the same page, so to speak, Loutan summarized the results of a study the CalISO conducted to identify the operational requirements and resource options needed to operate its grid reliably under the 2012 20% RPS and the 2020 33% RPS. Another objective of the study was to provide information required by other stakeholders—including state agencies, market participants, etc—for decision-making.

Loutan began by identifying the

Clyde Loutan, PE, *Senior Advisor, California Independent System Operator Corp*

Loutan, who was the principal investigator for the ISO's 2007 renewable-resource integration study, focuses on power-system operational performance. Previously he worked at Pacific Gas & Electric Co in real-time system operations, transmission planning, and high-voltage protection. Loutan has a Master's Degree in Electrical Engineering from Howard University and is a senior member of IEEE.

renewable portfolios assumed for the study (Table 1). Then he revealed the expected increase in regulation and load-following capacity requirements (within the hour) to meet those portfolios (Table 2). Note that in 2006, load was the only significant variable; for 2012 the variables primarily are load and wind, so capacity requirements increase significantly; in 2020 the variables will be load, wind, and solar, requiring a doubling of the 2012 requirements. Detailed study results were presented for the summer; however, spring, fall, and winter requirements are available at www.integrating-renewables.org.

Stand back for a moment and think about the variability that might have to be accommodated by the grid for the cases defined in the tables. Example: What if 10,000 MW of wind is forecast in the day-ahead timeframe and a substantial amount does not materialize during the operating hour? This scenario can create significant operational challenges—such as the ability to commit resources with the ramping flexibility to meet real-time variability.

As part of the study, CalISO investigated how operation of the combined cycles on its system would be impacted by the additional solar and wind generation assumed for the 2012 case compared to the baseline 2006 case. Results (annual basis) are presented in Table 3.

Loutan summarized the operational impacts of intermittent renewables, as defined in the study, this way:

- Increased frequency and magnitude of generating-unit ramps across various timeframes (minutes, hours).
- Increased load-following (up and down) requirements to accommodate intra-hourly deviations from hourly schedules, possibly requiring additional reserves.
- Increased regulation (up and down) to accommodate minute-by-minute requirements within 5-min dispatch intervals.
- Increased frequency and magnitude of over-generation conditions (minutes, hours).

Two additional considerations for the CalISO, the grid expert added, are these:

- The large difference in generating requirements in going from minimum load to peak load in the same day could be about 25,000 MW. This difference could increase depending on the production levels of variable generation.
- The grid must have sufficient inertia and frequency response should a major generation asset trip offline unexpectedly. In the Western Interconnection today, the loss of a large generating facility results in post-contingency frequency dropping to its minimum level within about eight seconds and governor response stabilizing the system in about 30 seconds. High levels of renewables penetration can impact this response if proper measures are not put in place.

CalISO is actively pursuing operational and market enhancements to support renewables integration, Loutan said. The list of valued operational enhancements includes the following:

- More accurate wind and solar forecasting tools—day ahead to real time.
- Over-generation mitigation procedures.
- More sophisticated grid monitoring systems.
- Higher degree of coordination with neighboring balance areas.
- Generation interconnection standards.
- Pilot/demonstration projects to assess the value of new technologies—including bulk energy storage, synchrophasors, demand response.

Market enhancements valued:

- New market products; changes to market rules.
- Increased regulation and reserve requirements.
- More sophisticated day-ahead unit commitment algorithms.

Summing up, Loutan segregated the resources required for renewables integration into three buckets: generation, storage, and demand response. Characteristics of the generation portfolio would include quick-start units, fast-ramp capability, wide operating range (especially the ability to back way down in load without exceeding emissions limits), and regulation capability.

Storage assets should enable the balancing authority to shift energy from off-peak to on-peak, mitigate over-generation, and provide voltage support and regulation. Demand response should be capable of frequency correction, provide rapid response to gaps in wind energy production, respond quickly to ISO dispatches, and be able to distinguish between loads that are price sensitive and those that are not.

1. Renewable portfolios (MW) assumed in the CalISO study

Reference case	Biogas/biomass	Geothermal	Small hydro	Solar	Wind
2006 actual	701	1101	614	420	2648
2012 20% RPS	701	2341	614	2246	6688
2020 33% RPS	1409	2598	680	12,334*	11,291

* Solar thermal, 6902 MW; PV, 5432 MW

2. Regulation and load-following capacity requirements (MW) in summer

Requirement	2006 actual	2012 20% RPS	2020 33% RPS
Regulation, up	277	502	1150
Regulation, down	-382	-569	-1112
Load following, up	2292	3207	6797
Load following, down	-2246	-3275	-6793

3. Comparing combined-cycle operation for the 2006 and 2012 cases

Parameter	2012 20% RPS	No new wind, solar since 2006	Change, %
No. of starts	3362	2492	35
On-peak energy, TWh	32.4	36.3	-11
Off-peak energy, TWh	26.1	31.1	-16
CO_2 emissions, million tons	24.3	28.0	-13
Revenue, $ billion	3.5	4.1	-16

Renewables force WECC to rethink grid operations

The Western Electricity Coordinating Council (WECC) coordinates and promotes bulk electric system reliability in the Western Interconnection, which extends from southern Canada into northern Mexico and from the Pacific Ocean to the Colorado/Kansas border. The vastness and diverse geography of the region served create unique challenges in coordinating the operation of the interconnected system and in maintaining reliable service across nearly 1.8 million mi^2 (Sidebar 1).

Steve Beuning, director of market operations for Xcel Energy and chair of the WECC Seams Issues Subcommittee, spoke to the need for a paradigm shift in the way the Western Interconnection operates to satisfactorily address the challenges posed by injecting large amounts of renewable energy into the grid.

He began his presentation, "A Stakeholder's View of the Proposed WECC Balancing Market," with a review of Xcel Energy's capabilities (Sidebar 2) and acknowledgement of customer demands for clean energy. Two states Xcel operates in—Minnesota and Colorado—have RPSs requiring that 30% of the kilowatt-hours come from renewables in 2020. Beuning reviewed the variability and uncertainty associated with wind and solar, citing less predictable and less controllable flows on the grid from large-scale penetration.

Another potential sticking point for grid operators is optimizing the line-up of conventional resources for backing-up intermittent renewables. There's no standard methodology used by balancing authorities to determine the type and quantity of conventional resources required to maintain system reliability, he said. One result of this could be that overly conservative system operators might commit resources in excess of those required to balance generation and load, increasing costs and emissions.

Next, Beuning provided needed perspective on the challenge of renewables integration. By 2019, he estimated, state RPS targets in the Western Interconnection would require a minimum of 50 GW of renewable resource nameplate capacity. If those targets increase, as they have in California and Colorado recently, to an average of 27% across the WECC, wind capacity could hit 69 GW and solar 13 GW.

Those numbers themselves don't mean much, so Beuning provided an example of the impact they could have on the grid. He cited the May 2010 "Western Wind and Solar Integration Study" prepared by GE Energy for DOE's National Renewable Energy Laboratory as the source. He said, "At renewable production levels possible within the next decade, the state of Wyoming could have variable generating capability installed that exceeds demand variability by a factor of 57.

Traditional balancing-area methods that seek to internalize such high variability would be quite stressed, Beuning continued, adding that it wouldn't be economically feasible to build enough gas turbines to handle the assignment.

However, data from the study demonstrate that fast intra-hour dispatch across the WECC could be used to mitigate the balancing-area challenge. Beuning pointed to a geographic diversity benefit for this approach. You spread variability over a larger area, he said. There are clouds here, sunshine there and no wind here but wind there, simulating weather patterns from the podium with his hands.

Likewise, there's a coordinated balancing effect to working region-wide rather than within a smaller utility-controlled balancing area. It can mitigate the variability that a given plant might have to handle, thereby reducing the number of on/off cycles, steepness of ramps, etc. The market signal created allows others to respond when opportunity and price are right.

Another benefit is that the amount of local generation required to offset balancing-area variability can be reduced, thereby holding down the cost of electric service.

In general, Beuning said, in the WECC outside California, the balancing-area mindset is traditional "utility." Specifically, operations focus on fixed hourly energy interchange (exports or imports) and all net variability is contained internally. He said that this traditional style of operation already poses significant challenges to some utilities in the Western Interconnection.

One of the behaviors of many western utilities is their fierce independence and disdain for federal "interference" in their operations. Beuning suggested that the traditional mindset in the region might have to change to accommodate large-scale renewables integration and pointed to the California Independent System Operator Inc and others as having demonstrated viable solutions.

He next summarized some of the work WECC was doing to assure a reliable, well-functioning grid in the future—such as developing what it

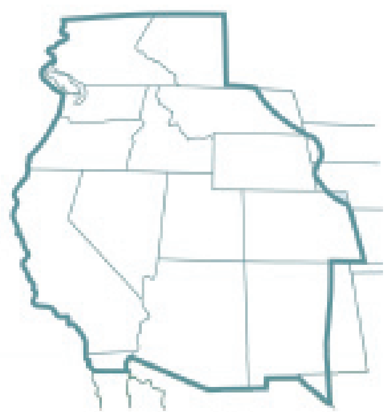
Stephen J Beuning, *Director of Market Operations, Xcel Energy Inc*

Transmission service and interconnection portfolio rights management are among Beuning's responsibilities, which also include wholesale market stakeholder representation on behalf of the four Xcel Energy operating companies in both the Eastern and Western Interconnections.

1. WECC history

In addition to coordinating and promoting bulk electric system reliability in the Western Interconnection, the Western Electricity Coordinating Council assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission-access disputes, and maintains an environment for coordinating the operational and planning activities of its members.

WECC geographically is the largest and most diverse of the eight regional entities that have so-called Delegation Agreements with the North American Electric Reliability Corp (NERC) to develop and enforce reliability standards within defined geographic boundaries. It is the successor to the Western Systems Coordinating Council, which was founded in 1967 by 40 electric power systems operating in British Columbia and the 14 western states identified on the map.



WECC was formed in April 2002 by the merger of the WSCC, Southwest Regional Transmission Assn, and the Western Regional Transmission Assn.

calls an Efficient Dispatch Toolkit. First tool, the Enhanced Curtailment Calculator, already is being used on a limited basis. Its job is to allocate curtailment responsibility during congestion. Second tool is the Energy Imbalance Market (EIM), to provide fast regional dispatch of generation.

The EIM would rely on security-constrained economic dispatch of voluntary generator offers on a regional basis. Positive operational impacts expected include increased reliability and lower operation costs. Perhaps, most importantly, the EIM retains existing utility balancing areas, but achieves a "virtual consolidation" for operating purposes.

Key point: Although the EIM proposal includes a regional balancing-market function, it does not establish a regional transmission organization or a consolidated regional transmission tariff. This feature is important to several WECC utility stakeholders. The EIM as presently configured would be different than any other market footprint in the nation. Beuning said gas-turbine operators should like it because cost recovery is through a regional market rather than indirect allocations through tariffs.

A benefit/cost analysis of EIM is funded in the WECC's budget for next year with the goal of completing the study by next summer. Open items include the need to develop a tariff for use by participating systems. Plus, a market monitor for detecting and mitigating abusive market or scheduling practices. Assuming WECC stakeholders approve the proposal, it still must pass muster with NERC and FERC.

2. Xcel Energy facts

Regulated operations in eight states: Colorado, Michigan, Minnesota, New Mexico, North and South Dakota, Texas and Wisconsin

Four utility subsidiaries: Northern States Power Co-Minnesota, NSP-Wisconsin, Public Service Co of Colorado, Southwestern Public Service Co

Operates in the both the Western and Eastern Interconnection; specifically in the Midwest ISO, Western Electric Coordinating Council, Southwest Power Pool

Generating capacity (owned): 16,446 MW

Energy mix based on electricity sales: coal, 50%; natural gas, 24%; nuclear, 12%; wind, 8%; hydro, 5%; biomass, 1%; solar, less than 1%

Nation's leading wind-power provider with more than 3000 MW owned or under contract

Customer base: 3.4 million electric; 1.9 million gas

Learn from Texas

Adrian Pieniazek opened his presentation with a personal evaluation of the Texas experience in integrating renewables. The NRG executive said the Electric Reliability Council of Texas (Ercot) likely is a few steps ahead of the nation's other regional transmission organizations (RTOs) regarding renewables integration (Sidebars 3, 4). And while many milestones in its integration plan have been achieved successfully, he continued, there are lingering issues, and much work remains to meet established goals.

Ercot, which operates the electric grid and manages the deregulated market

Billions needed to move Midwest wind to market

Electric Transmission America (ETA), a joint venture between units of American Electric Power Co, Columbus, Ohio, and MidAmerican Energy Holdings Co, Des Moines, Iowa, released in mid October its Phase 2 report on the transmission capability needed in the Upper Midwest to support renewable energy development and transport that energy to population and load centers.

The cost: $25 billion in round numbers.

The Strategic Midwest Area Renewable Transmission Study (SMARTransmission), was sponsored by ETA along with American Transmission Co LLC, Waukesha, Wis; Exelon Corp, Chicago; NorthWestern Energy, Sioux Falls, SD; and Xcel Energy, Minneapolis. ETA was established to build and own HV transmission assets (345 kV and higher voltages) in North America, but not including Ercot.

Quanta Technology LLC, Raleigh, NC, conducted the study. It evaluated extra-high-voltage (EHV) transmission alternatives to support the integration of 57 GW of nameplate wind capacity in the 11-state study region (North and South Dakota, Ohio, Michigan, Illinois, Indiana, Nebraska, Missouri, Wisconsin, Iowa, Minnesota). The 57-GW number reflects a federal RPS requirement of 20% with adjustments for states that have approved RPS requirements or goals in excess of 20%.

SMARTransmission's goal was to develop a 20-yr transmission plan that ensures reliable electricity transport, provides an efficient system to integrate new generation and foster efficient markets, minimize environmental impacts, and support state and national energy policies.

The transmission alternatives chosen for economic analysis during Phase 2 were determined during Phase 1 of the study (access details, including maps, at www.smartstudy.biz). The three systems evaluated during Phase 2 involved building:

1. Nearly 8000 miles of EHV lines, primarily 765-kV.
2. More than 7600 miles of 765-kV and HVDC lines.
3. More than 8600 miles of line, including 4400+ miles of 345-kV service and 3900+ miles of 765-kV service.

The alternative systems transcend traditional utility and RTO boundaries so the study was designed to incorporate a high level of stakeholder input. More than a 100 participants from public and private utilities, state utility commissions, FERC, RTOs, wind developers, and others were involved.

The SMARTtransmission analysis is not all-encompassing. The study did not address cost allocation or routing and siting requirements, and the results are not intended to be used as the basis for RTO approval of specific projects.

for three-quarters of the state, has more installed wind generation—nominally 10,000 MW—than any other region in the country. Wind capacity is expected to almost double soon after the transmission build-out in West Texas is complete in three or four years from now— according to the current schedule.

One thing for certain, there's much to be learned from Ercot's wind-integration efforts. The need for advance planning and new thinking in grid design and operation are particularly important to success. Pieniazek said, "You can't plan the grid the same way you did in the pre-renewables era; it's completely different."

Two points important to the discussion that follows:

- The Ercot grid is not synchronized with either the Western or Eastern Interconnections, by choice, leaving it electrically isolated from the rest of the US except for a couple of dc interties with a total capacity of about 1100 MW.
- Ercot apparently has done an excellent job of integrating stakeholders into its decision-making process to gain consensus before important decisions are made. Pieniazek, for example, NRG's director of market policy for Texas, is a member of the Ercot Technical Advisory Committee, the market-participant group responsible for making recommendations to the board regarding the RTO's policies and procedures.

Getting started. Texas is much like other wind-rich regions: The resource is not where the load is. In Ercot's case, most renewables potential is in the western and panhandle portions of the state while load is in places like the Dallas-Ft Worth metroplex, Houston, San Antonio, and Austin—all of which are in the central and eastern parts of Texas.

Pieniazek described getting started in renewables to meet the goals of the state's RPS as a "chicken and egg" problem. Transmission providers were reluctant to design and build the infrastructure necessary to transport wind energy from remote areas to the loads if the wind generators weren't going to show up; and the wind developers did not want to develop more wind plants until there was some certainty that transmission would be built.

To reconcile the issue, the Texas Public Utility Commission established so-called Competitive Renewable Energy Zones (better known by the acronym CREZ). The CREZ process identified wind developers that had demonstrated financial commitment—that is, posted collateral, leased land, etc. Once there was sufficient financial commitment from wind developers, the PUC then would have an indication of the amount of transmission they would ultimately approve.

While the PUC was working on CREZ, Ercot developed transmission development scenarios for 12,000 to 25,000 MW of wind-energy transfer capability and commissioned GE Energy to study ancillary-service impacts to test the RTO's ability to absorb such massive amounts of wind energy.

In summer 2008, the PUC selected Ercot's 18,000-MW transmission option at an estimated cost of $5 billion. The planned build-out is being done in phases and in priority order. Targeted completion for all CREZ projects is yearend 2013. Based on results to date, Pieniazek thinks the project might cost more and take slightly longer than planned.

Wind is a high-profile energy resource in Texas. Ercot is investigating the viability of about 41,000 MW in its queue. There has been far less interest in solar in the region to date.

The speaker then confirmed what previous presenters had said about the unpredictable nature of wind and offered an overview of Texas' renewables experience. Here are a couple of bullet points:

- Wind as a percentage of total energy resources in Ercot on a monthly basis varied in the first half of 2010 from a low of 6.8% in February to 12.1% in April. The highest percentage to date was recorded last June 12 when wind generation hit 7016 MW for one hour—15.8% of the load being served at that time.
- During Ercot's peak-hour load of 64,805 MW on August 16, however, wind output was only 650 MW.

The big challenge to successful integration of variable renewable resources, Pieniazek said, was achieving the goals in a manner that (1) maintains system reliability, (2) ensures costs are assigned in a fair and non-discriminatory manner, and (3) does not undermine existing market structures. He made a special point about the importance of attempting to assign costs to those who create them—as much as possible. The proper alignment of incentives and/or costs increases market efficiencies.

There's nothing like a major system disturbance to help focus attention on the challenges, Pieniazek continued. In February 2008, a dramatic variation in wind energy output and a significant deviation from submitted wind energy schedules did just that.

The risks to grid reliability associated with poor integration procedures are magnified in a region such as Ercot's because there's no interconnection with another major balance area for backup. Black-start resources must be well-maintained in Texas.

Pieniazek put up several slides to illustrate dispatch schedules for an actual spring week in 2009 and a projected spring week in 2013, based on a system model that assumes CREZ work will be completed and 18,000 MW of total wind generation will be commercial (Fig 12). While the timing probably is optimistic, the result is about the same

3. NRG's Texas operations

NRG Energy Inc operates nuclear, wind, and coal- and gas-fired plants in Texas with a total capacity of 11,500 MW. Renewables (wind) account for 440 MW, NRG's share of the South Texas Nuclear Project is 1175 MW, coal-fired units produce 4150 MW, and gas-fired assets generate 5735 MW.

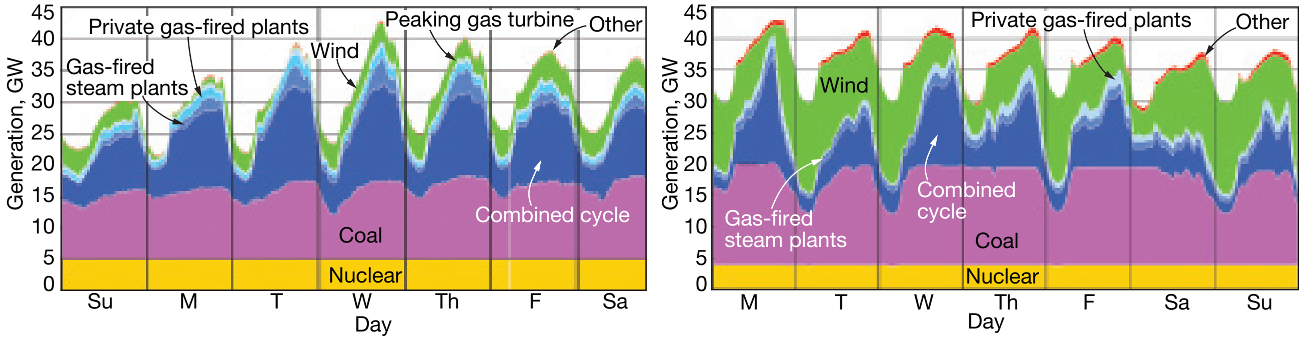
In terms of operating duty, 5325 MW are base load, 4991 MW are in intermediate service, and peakers total 744 MW. The company's four West Texas wind farms are not included in these totals.

4. Ercot by the numbers

Customers served: 22 million (85% of Texas demand)
Area served: 75% of Texas land
Installed capacity: 84,237 MW; wind accounts for 9865 MW (2010)
Available capacity: 75,755 MW (less than 10% of the wind capacity, and less than half the capacity of the region's two dc interties, are considered "available" on-peak)
High-voltage transmission: 40,327 miles
Record peak demand: 65,715 MW

Adrian Pieniazek, *Director of Market Policy for the Ercot Region, NRG Texas LLC*

Pieniazek manages regulatory matters for NRG Texas with an emphasis on wholesale market design and policy. He is a member of the Ercot Technical Advisory Committee, the market-participant group responsible for making recommendations to the board regarding Ercot policies and procedures.



12. Actual dispatch map for Ercot generation assets during a typical week in April 2009 (left) and how that would compare to a windy week in March 2013 (based on modeling results) when almost double today's wind generation is expected in operation

whether it's spring 2015 or later.

Looking at the chart, the NRG executive noted the deep back-down of coal-fired assets and said "this is a huge operational challenge," adding that work is ongoing to ensure the grid will be able to accommodate such a scenario when it occurs.

The real world. Pieniazek updated the group on how Ercot has responded to the challenges of renewables integration encountered thus far, noting pitfalls to avoid and best practices to embrace. The RTO's responses are grouped as follows:

- **Dispatch/operational.** (1) Congestion between West Texas and load centers has been chronic and Ercot operators often must reduce wind as necessary to maintain transmission equipment with rated limits. CREZ is expected to help here.

  (2) The generation (MW) and prices offered by wind resources to curtail often are in negative territory because of zero fuel cost and production tax credits offsetting the payment to generate.

  (3) Wind generators are limited in how fast they can respond when released from dispatch instructions to avoid frequency spikes.
- **Forecasting.** Ercot implemented a central, real-time forecasting system that uses site-specific meteorological data (wind speed and direction, temperature, barometric pressure) and wind-turbine availability information in its predictive model. All wind farms are required to use the forecast Ercot develops in their daily resource-plan submittals.
- **Ancillary services.** Ercot has modified its ancillary-service methodology by incorporating wind-forecast uncertainty into operational reserve requirements for non-spinning reserves (30-min availability) and frequency and regulation reserves (online and immediately available).
- **System modeling.** Ercot is working on improving the accuracy of its planning and real-time contingency analysis models. Pieniazek pointed out that the tools used to model a wind farm are not as well developed as they are for large thermal plants.
- **System planning and interconnection standards.** (1) Ercot has placed a renewed emphasis on managing its generator interconnection queue. Reason: Interconnection requirements have changed; those used in the pre-renewables era did not consider the operational challenges of wind generators.

  (2) Wind farms now must provide voltage support and meet voltage ride-through requirements like other types of generation.

  (3) Wind plants also must now provide primary frequency response.

Note that (2) and (3) are in line with Ercot's goal of treating all market participants in a fair and non-discriminatory manner.

On-going work to facilitate renewables integration. As Pieniazek said at the beginning of his presentation, much progress has been made, but there's still much more to do. Here's a punch list of on-going work:

- Determine the impact of wind generation on system inertia to help dampen frequency oscillations; develop potential solutions.
- Develop ancillary-services cost allocations applicable to wind and other intermittent resources and determine if new ancillary services are needed.
- Evaluate the benefits and potential applications for energy storage.
- Investigate the potential benefits of a smart grid in facilitating integration of renewables and conventional resources.
- Study the electrical interactions between transmission lines and wind generators.
- Most importantly, perhaps, ensure that market design provides the proper incentives to install flexible backup generation. The idea here, Pieniazek said, was that if you're going to impose a cost on the system that cost must be allocated back to you. Not an easy thing to do, he added.

Technology solutions

CAES ready to go main stream

Ask most experienced electric-generation professionals about the value proposition offered by compressed-air energy storage (CAES) and you'll likely get a yawn. They probably will recall the lone US plant (there only are two in the world), installed nearly 20 years ago in McIntosh, Ala, to prove the concept's viability, and then add something like "it works, so what?"

Such a response may have been warranted because CAES had no compelling economic justification until the recent addition to the generation mix of a critical mass of intermittent renewables. Bob Kraft, who has spent his career designing and improving gas turbines and their component parts, told the group that in a world demanding ever smaller carbon footprints CAES can play a significant role by maximizing the value of wind and solar resources at an affordable cost.

Pumped-storage hydro (PSH) can achieve the same result, he acknowledged, but its penetration is limited by environmentally driven siting constraints and significantly higher cost of development. Kraft also noted that the price of a CAES system does not increase with size as quickly as it does for a PSH facility. The example he offered: To double the megawatt-

hour storage capacity of a PSH plant you have to double the size of the reservoirs, a major budget item; you also must double the size of the CAES reservoir, but it is only about 15% of project cost.

One of the most important points Kraft made during his presentation was that the faster the electric system can respond to the ups and downs in load given the inherently variable generation characteristic of wind and solar resources, the less capacity you need to back up and smoothly integrate renewables. That piqued the interest of many in attendance who had listened over the last year or so to gas-turbine OEMs touting the need for essentially 1 MW of fast-response GT capacity (or spinning reserve) for every megawatt of wind installed.

Kraft figures CAES can back up intermittent renewables with less than half the capacity (megawatt rating) that would be required if peaking GTs were selected to provide the same service. Plus, much of the CAES capacity could come from underutilized conventional gas turbines converted to energy-storage assets. Energy Storage & Power LLC, the company Kraft manages, owned in part by PSEG Global LLC, is working on several major CAES projects—one involving the retrofit of a GE 7B engine for energy-storage service.

Note that CAES responds very quickly to a change in system demand because the expander turbine operating on compressed air from storage can ramp at rates that could top 25 MW/*sec*. Ramp rates for gas turbines generally are about 30 MW/*min* today. For a warm start, the expander turbine can reach full capacity in about three minutes.

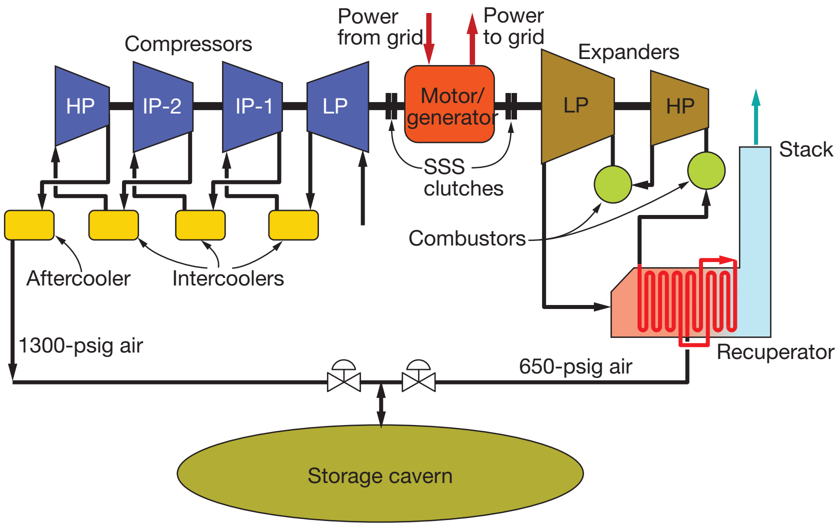
First-generation CAES. To illustrate the recent advancements in CAES technology, Kraft showed a diagram of the McIntosh system (Fig 13). The purpose of this facility was to optimize base-load coal and nuclear generating plants and increasing peaking capacity. Important points to remember:

- McIntosh has a single compressor train that puts 1300-psig air in a storage cavern solution-mined from a salt formation 1500 ft under ground. The size of the 22-million ft^3 cavern is roughly equivalent to the volume of a 20-story building occupying a typical city block. The cavern is relatively small compared to similar facilities used for storing natural gas.
- In charging operation, the motor/generator is disconnected from the expander turbines by opening the right-hand SSS clutch shown in the diagram and engaging the other clutch. The m/g operates as a motor, consuming 0.81 kWh of grid power for every kilowatt-hour of power generated when air is released to the expanders.
- When fully charged, this cavern can support 26 hours of continuous power-train operation at rated output. Heat rate is 4100 Btu/kWh.

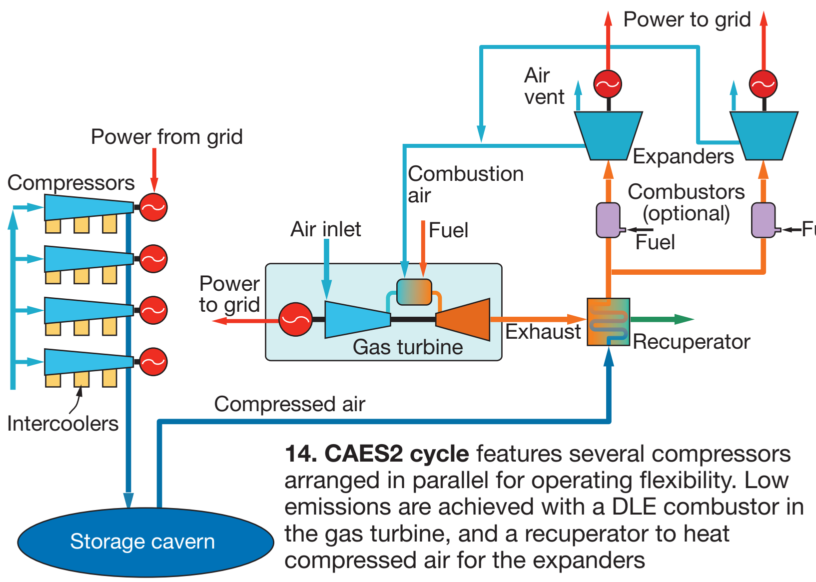
ES&P's CAES2. Kraft introduced his company's CAES2 system with Fig 14, showing how a new or existing simple-cycle gas turbine could be transitioned to energy-storage service. Using gas turbines of different sizes, the cycle shown is scalable and adaptable to a range of conditions, with a unit producing from 5 to 450 MW. For applications requiring from 5 to 20 MW of CAES, compressed-air storage is practical in an above-ground vessel; from 20 to 450 MW, storage would be in an underground cavern. Kraft stressed that the CAES2 uses only proven technology and equipment.

Bob Kraft, PE, *President & CEO, Energy Storage & Power LLC*

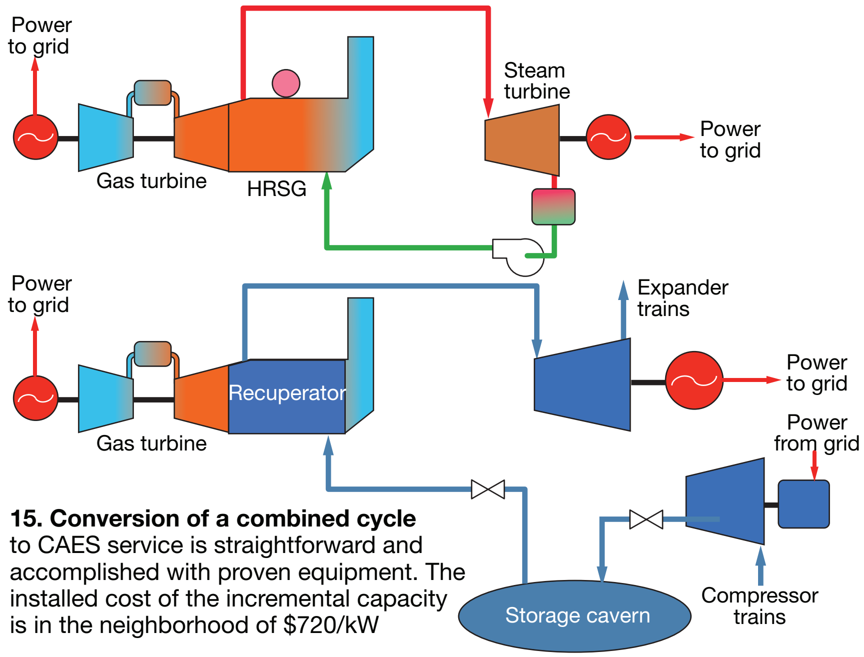
Kraft was one of the founders of PSM, the world's largest aftermarket supplier of hot-gas-path components for GE7FA and W501F gas turbines. The 25-yr industry veteran spent more than a decade designing military engines at GE and P&W before switching to the industrial side. At PSM, now owned by Alstom, his leadership and vision were key to developing the company into a 250-person global organization with service, repair, and commercial operations capable of competing head-to-head against the OEMs' aftermarket businesses.



13. First-generation CAES is characterized by a single train of air-cavern charging compressors and external combustors for the expanders



14. CAES2 cycle features several compressors arranged in parallel for operating flexibility. Low emissions are achieved with a DLE combustor in the gas turbine, and a recuperator to heat compressed air for the expanders



15. Conversion of a combined cycle to CAES service is straightforward and accomplished with proven equipment. The installed cost of the incremental capacity is in the neighborhood of $720/kW

Key points of this design include the following:

- Multiple compressors, each equipped with its own intercoolers, arranged in parallel for charging the storage vessel or cavern. This improves flexibility for renewables integration and enables simultaneous charging and discharging of the cavern.
- A degree of power augmentation is achieved by extracting some compressed air after it does work in the first couple of expander stages and injecting this bleed air into the combustion wrapper. Also, keep in mind that the expander exhaust generally is below ambient temperature, usually about 50F. Alternatively, this cold exhaust air can be routed to the GT inlet to maintain nameplate performance levels on hot days.
- Emissions from CAES2 are minimal because the only fuel that must be burned is that in the gas turbine, which is equipped with a DLE (dry, low emissions) combustion system. GT exhaust heat is transferred to air discharged from the cavern in a recuperator before it enters the expander, eliminating the need for the external combustor shown in Fig BK1.

The CAES2 described in the drawing for a Frame 7B-E engine produces 172 MW at a heat rate of 3771 Btu/kWh. It requires only 0.71 kWh to produce a kilowatt-hour of power for the grid. Performance is better than for first-generation CAES primarily because of the recuperator.

Next, Kraft discussed the value proposition for converting to CAES a 2 × 1 F-class combined cycle seeing limited service (Fig 15). Here the 2 × 1 combined cycle is repurposed as a 1 × 1 unit with the CAES expanders coupled to the second 7FA gas turbine. Output of the 1 × 1 portion of the project analyzed would develop 238 MW without duct burners in operation, 268 MW with supplementary firing of the heat-recovery steam generator (HRSG).

Total output of the CAES portion of the plant is 388 MW—a production increase of 150 MW compared to the conventional plant with no duct firing. Kraft estimated the capital cost of the additional power at about $720/kW—including the new expander and compressor trains, conversion of the HRSG to a recuperator, construction of an underground storage cavern, and balance-of-plant requirements.

Kraft closed out the CAES portion of his presentation by comparing the cost of bulk energy storage alternatives today. Were a new 7FA-powered CAES2 plant developed from the ground up rather than converting an existing unit for energy-storage service, it would cost upwards of $950/kW—or about a third more than converting an existing plant. A new PSH facility would cost from about $2500 to $4000/kW.

Lithium-ion batteries were mentioned as an alternative to PSH and CAES2, but considered uneconomic in sizes above about 20 MW and for discharge times of more than one hour at the current stage of development. Cost estimate is $1500/kW.

Power augmentation. Kraft addressed power augmentation in the last part of his presentation—specifically ES&P's patented humid air injection (HAI) system for combined-cycle plants (access www.ccj-online.com/archives.html, click Spring 2004, click "Water injection a concern?" on cover). The system promises cold-day performance on a hot day for a nominal $300/kW depending on the specific powerplant arrangement, ambient environment, etc.

Simply put, HAI involves the injection of a steam/air mixture into the GT compressor discharge just ahead of the combustor. A standard motor-driven compressor is installed to supply the compressed air for this purpose. The extraction point for steam preferred by thermal engineers is the cold reheat line because it is thought to provide the best combination of power augmentation and heat rate.

The first commercial project is planned for a 2 × 1 7FA-powered combined cycle at PSEG Fossil LLC's Bergen Generating Station. It is expected to deliver a 50-MW net increase from the Bergen unit on a 95F day. Output of each GT increases by about 35 MW, but the steam turbine output drops by about 15 MW because less steam flows through it, and the air compressors increase the parasitic power draw.

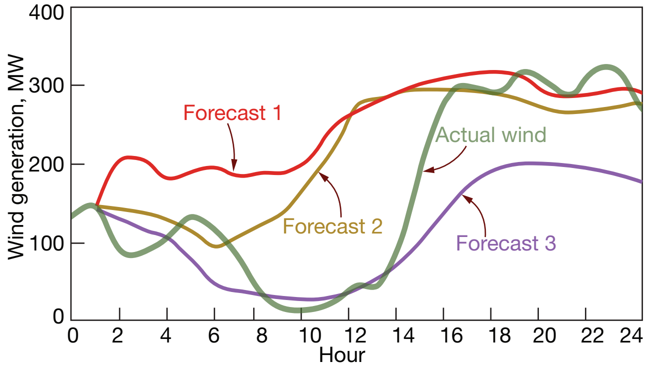
GT enhancements can facilitate renewables integration

The dozen presentations preceding Bruce Rising's made it clear that responsibility for dealing with the idiosyncrasies of intermittent renewables rested squarely on the shoulders of the balancing authority—ISO, RTO, or regulated utility. Also, that generating plants powered by gas turbines typically are best suited for filling the gaps in renewables production caused by clouds and changes in wind speed.

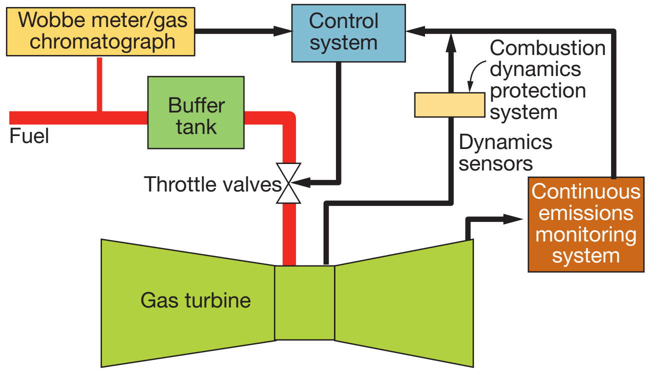
Rising's assignment was to update the group on the capabilities of the latest large frame gas turbines; plus, identify enhancements available to owner/operators for upgrading existing engines to more effectively support grid operations. The ability to provide both ancillary services—such as reactive power and voltage control, load following, etc—and energy is conducive to a stronger balance sheet.

Rising opened his presentation with a passing salute to the "traditional" power market, in which the dispatch order of conventional assets is based on the cost of generation. He then noted the uncertainty surrounding how units will be dispatched in the future in areas with a high penetration of intermittent generation.

The renewables footprint already is becoming evident in system response, Rising said. Ramps up and down are faster and starts appear more frequent. A Siemens' assessment indicates



16. One wind-forecast assessment project produced the results described. The solid green line is actual wind generation, the other three were produced by competing forecasting software tools



17. Fuel flexibility is provided by system shown above to mitigate the impact of changing gas properties—including heat content

that a significant amount of installed thermal capacity is approaching a 50-operating-year threshold and that 50,000 to 70,000 MW of old coal-fired capacity could be retired in the near term because they are of marginal value for supporting renewables, as well as other reasons.

Intermittent renewables pose forecasting challenges, Rising continued. Important to remember is that *installed* renewables capacity does not equate to *available* capacity. Tools for forecasting wind are subject to increasing error the further out in time the forecasts are made; also, significant variability exists among forecasting methods (Fig 16). Such uncertainty may force backup generating units into rapid ramp events that adversely impact equipment lifetime.

Faster ramps and more starts/stops are not the only challenges facing conventional assets once wind and solar penetration reach a critical threshold. Thinking is that increased turndown of base-load units may be required, with the need to operate units as low as 30% of rated capacity to avoid shutdowns and increasing the number of start/stop cycles.

Fast ramping also may have adverse impact on the efficiency of environmental controls, and could raise permit issues. Trying to balance fuel supply against unpredictable consumption may pose contractual challenges as well.

All gas-turbine OEMs offer or are developing technologies to mitigate the adverse effects of deep cycling and fast ramping. In addition to extended turndown capability, Rising said Siemens can provide the following:

- Fast-start units—Flex-Plant™ 10 and Flex-Plant 30.
- Power augmentation via wet compression and/or higher duct firing to help "fill in the generation gaps" when the wind slows or stops.
- Power Diagnostics® for rigorous monitoring of assets and related instrumentation to advise when maintenance shutdowns are needed to prevent equipment damage.

Note that Flex-Plant 10 refers to a simple-cycle F-class engine capable of injecting 150 MW of firm capacity into the grid within 10 minutes of being called.

Flex-Plant 30 is the product name for an F-class 2 × 1 combined cycle designed to deliver a nominal 500 MW within 72 minutes (hot start condition; 16 hours or less from last shutdown) when conventional drum-type heat-recovery steam generators are installed; five minutes faster with Benson (once-through) HRSGs. The GTs can deliver their rated capacity in 22 minutes with the Benson option; in 32 minutes with a conventional HRSG.

By contrast, a conventional 2 × 1 would require 116 minutes to achieve full output and GT power would not be available for 108 minutes.

For a warm start (up to 64 hours since the last shutdown), a conventional 2 × 1 would require 152 minutes to deliver GT power, 162 minutes to get the entire plant online. Compare these numbers to 37 and 81 minutes for the F-P 30 with drum HRSGs and 22 and 75 minutes with once-through boilers. Note that actual startup times may vary slightly because of ambient and other local conditions.

Rising spent several minutes describing Siemens' solution for expanded turndown with low CO emissions, and its fuel-flexibility option incorporating a combustion dynamics protection system with feed-forward tool to minimize power fluctuations and fast-response Wobbe meter with redundant gas chromatograph (Fig 17).

Subscribers who actively participate in the 501G, F, and D5-D5A user groups and in the CTOTF's Siemens Roundtable probably are familiar with these offerings. If not, you can get a real-world view of their implementation at www.ccj-online.com/archives.html, click 3Q/2009, click "Klamath gets better with age" on the issue cover. Or you can access Rising's presentation at www.integrating-renewables.org.

Before wrapping up, Rising allowed attendees to peek into the Siemens development pipeline at a solution currently in field validation to assure that users operating at low GT loads will not exceed CO and NO_x emissions limits. Virtually all HRSGs built in the last several years are equipped with SCR (selective catalytic reduction) catalyst to restrict NO_x emissions to the ultra-low levels required by law.

Some have CO catalyst as well, but many do not. For those in the latter group requiring expanded turndown capability, addition of CO catalyst is necessary to insure that CO emissions remain below permit limits during transients. The traditional way of doing this would be to add an oxidation catalyst bed ahead of the SCR. But oftentimes the necessary space is not available.

The Siemens answer is to replace the existing SCR catalyst with the company's Novel catalyst, which destroys NO_x and CO simultaneously. It is

Bruce Rising, *Strategic Business Manager, Siemens Energy Inc*

Rising started his career in engineering and science and moved to the business side. A former scientist in energy and environmental R&D, he served Siemens as manager of regulatory affairs, and as manager of marketing intelligence in the company's global strategy group, before accepting his current position.

designed to operate over a wide range of GT loads and, because it occupies less volume than traditional SCR catalyst, system pressure drop is lower.

Pilot test results included the following: less than 1 ppm ammonia slip; less than 2 ppm combined reduction capability for NO_x, CO, and volatile organic compounds; lower emissions of CO and VOCs; minimal formation of ammonia sulfates and bisulfates in the cool end of the HRSG.

Thomas P Mastronarde, PE, *Project Engineering Manager, Gemma Power Systems LLC*

Mastronarde provides technical analysis and support for energy-project development and is responsible for the timely and accurate completion of engineering during project execution. Emerging opportunities for hybrid solar thermal/combined cycle plants is one interest area. He spent 35 years at Alstom and its predecessor companies, rising to chief engineer for HRSGs.

Injecting solar steam into the HRSG

Tom Mastronarde, well known to the CTOTF community for his HRSG design acumen, discussed the integration of a solar thermal steam system with a conventional heat-recovery steam generator. In particular, plant and asset managers wanted to know if it were possible to retrofit a solar thermal array to an existing combined-cycle plant and what the value proposition was for doing so.

The boiler designer began by assuming that the retrofit candidate was a conventional supplementary-fired, 2 × 1, F-class combined cycle, located in the Southwest, having a nominal capacity of 500 MW with no duct burners in service. Peak capacity with supplementary firing ranged from 560 to 630 MW. Another key assumption: 235 acres were available onsite to accommodate a solar field capable of producing an incremental 50 MW of power.

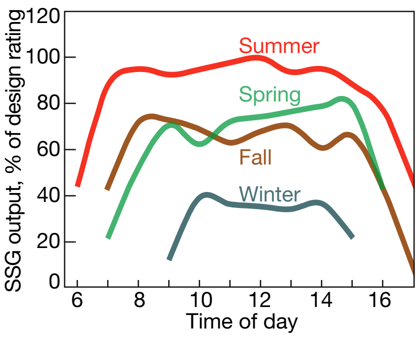
Proven solar trough technology was selected for Mastronarde's study and a DNI (direct normal irradiation, a measure of solar intensity) of 1000 W/m^2 was assumed. Nominal flow from the solar steam generator (SSG) to achieve the desired 50 MW is 450,000 lb/hr. Steam pressure floats during operation from about 1100 to 1700 psig; temperature is a relatively constant 700F.

Superheated steam from the SSG would be introduced into the HRSGs' saturated steam lines upstream of the inlet to the first HP superheater section. Feedwater would be supplied to the SSG evaporator section from the combined-cycle's HP feedpump discharge.

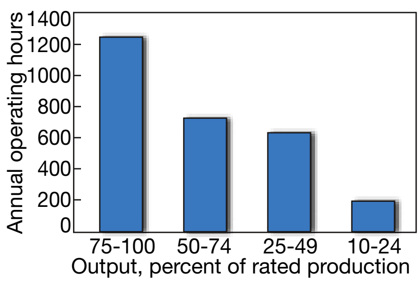
Mastronarde compared output and heat rate on a 94F day with evap coolers on and both gas turbines operating at full load (total of 335 MW) for the following system line-ups:

- Unfired combined cycle, no solar component: Plant output, 516 gross/503 net MW; heat rate (net, based on LHV), 6256 Btu/kWh. Note that steam turbine (ST) output is found by subtracting plant gross output from the 335 MW produced by the GTs—181 MW for this operating scheme.
- Unfired combined cycle with SSG producing half its rated output (225,000 lb/hr), indicative of fall and winter operation: Plant output, 541 gross/526 net MW; heat rate, 5983 Btu/kWh.
- Unfired combined cycle with SSG producing rated output (450,000 lb/hr), as it would on a clear summer day: Plant output, 566 gross/549 net MW; heat rate, 5732 Btu/kWh.
- Combined cycle with full supplementary firing and no solar component: Plant output, 615 gross/598 net MW; heat rate, 6606 Btu/kWh.

Integrating a solar-trough system into an existing combined cycle is relatively straightforward, according to Mastronarde. Plant thermal and electrical equipment and infrastructure already are in place to produce power and deliver it to the grid. Plus supplemental firing can be used to compensate for variations in solar thermal output to maintain desired plant output. Incremental staff requirements would be minimal to keep mirrors clean and maintain the thermal fluid system (often referred to as heat-transfer fluid, HTF) that transports heat from the solar field to the SSG.



18. Seasonal variation in the production of solar thermal energy is significant



19. Annual capacity factor of the solar steam system is 32% for a typical year with 2810 operating hours

He identified the following impacts on equipment capacity, performance, and operation:

- Steam turbine. HP and reheat steam temperatures are reduced when solar steam is injected at the HRSG superheater inlet. However, there is only a minimal change in moisture content at the ST exhaust.
- Station service transformer must provide about 2200 kW of medium-voltage (MV) power to support the solar operation. If the existing transformer cannot accommodate the additional load, a new 2.5-MVA 4160/480-V transformer is necessary.
- MV switchgear and motor control centers (MCCs) are required to support the solar operation (4.16-kV HTF pumps and 480-V loads).
- Plant DCS (distributed control system) requires additional I/O points and operator graphics to enable integration of the solar and combined-cycle systems.
- Additional demineralized water is needed for mirror washing.

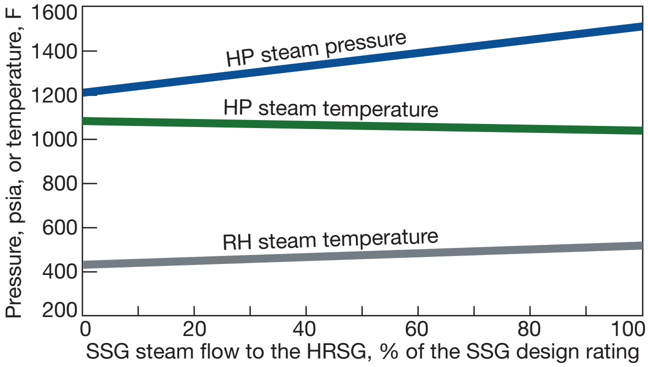
The segment of Mastronarde's presentation having to do with the behavior of solar thermal plants was perhaps of greatest interest to the audience because very few, if any, in the room had any experience with them. He began by saying that SSG output is variable and is affected by the season, time of day, weather conditions, and intermittent cloudiness on sunny days. Certainly no surprise there.

Mastronarde added that plant electric output from solar steam is variable and affected by the number of hours per day that the solar field can absorb the sun's energy, as well as by the proportion of sunny days to cloudy days. Also no surprise.

The "meat" of what the boiler design expert had to say was presented in a series of slides—including Figs 18-20. He also showed in other slides how steam flow and temperature varied on a given day with intermittent clouds (up and down) and how smooth flow and temperature curves were on a clear day (view at the web address noted above).

Most instructive perhaps where the results of a model run to show how solar thermal and electric variables were affected by intermittent clouds that took from 15 to 20 minutes to cover the entire array of collectors. Here are some numbers to keep in mind:

- 95% reduction in incident solar radiation in 12 minutes.
- 50% reduction in SSG steam output in 20 minutes.
- 10% reduction in ST throttle flow in 20 minutes.
- 4% reduction in plant net power output in 20 minutes.



20. Steam conditions at the steam turbine's HP and IP inlets show little variation, except for HP steam pressure, over the full range of SSG outputs

Not worrisome, Mastronarde told the group. The decrease in HRSG steam flow as clouds move over the solar field can be offset by firing duct burners. The rate-of-change of thermal input required from the supplementary firing system (approximately 50% to 60% of burner rated output) within 20 minutes is well within the capability of the duct burner and the HRSG.

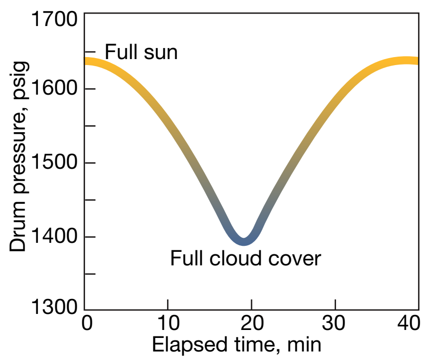
Last segment of the presentation was an analysis of potential fatigue effects from intermittent cloud cover. Mastronarde ran through a quick exercise to show why he believes an HRSG could be subject to 60,000 thermal cycles from intermittent cloud cover over a 25-year life. He then showed a curve to illustrate the pressure swing that occurs during one "solar cycle," which with full sun, proceeds to full cloud cover, and then returns to full sun within 40 minutes (Fig 21). Pressure varies over the cycle by 240 psi, or 11% of the HP drum's 2200-psig design pressure.

The design engineer said that according to Section VIII of the ASME *Boiler & Pressure Vessel Code,* "Cycles in which the pressure variation does not exceed 20% of the design pressure are not limited in number." The screening criterion for temperature cycles: "Cycles in which the metal temperature differentials between any two adjacent points in the pressure vessel are less than 50 deg F are not limited in number.

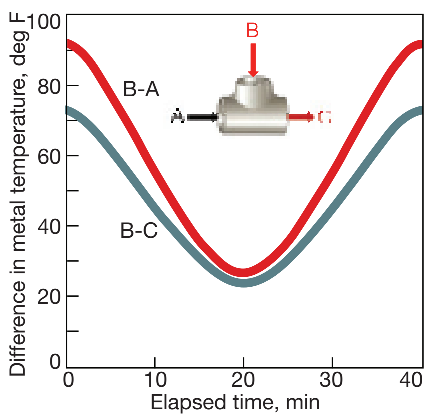
The HP drum satisfies both these criteria and its service life is unaffected by pressure or temperature cycles caused by intermittent cloud cover. Thus a fatigue analysis was not required.

Evaluation of the tees that combine superheated steam from the SSG and saturated steam from the HRSG drum before the mixture enters the HP superheater produced a different result for a 60,000-cycle lifetime. During the cloud-induced transient, the 6-in.-diam (Sch 120) SA 106B pipe delivering superheated steam from the SSG at 1600 psia/700F (branch B in Fig 22) experiences a temperature drop of 80 deg F at full cloud cover and then rebounds to 700F within the next 20 minutes.

Branch A, with 1637 psia/608F saturated steam from the HP drum experiences a cyclic temperature variation of 15 deg F during the 20 minutes it takes to go from full sun to full cloud cover. The 1627-psia steam in branch C (HP superheater inlet) goes from 627F to 596F in the first 20 minutes of the cycle.



21. Variation in HP drum pressure during a severe intermittent cloud-cover event does not adversely impact drum life



22. Temperature variation in mixing-tee metal temperature during solar transient suggests a fatigue analysis

Thus, the mixing tee fails the temperature screening criterion, requiring a detailed fatigue analysis. Disappointing as that might sound, Mastronarde said it was likely that a detailed analysis would demonstrate the expected number of thermal cycles are acceptable. If not, the magnitude of the thermal cycles could be reduced by addition of a thermal sleeve to the mixing tee.

For a backgrounder on "Integrating solar, conventional energy resources," visit www.ccj-online.com, access COMBINED CYCLE Journal archives, 2Q/2010 issue, click article title on magazine cover.

Materials considerations for equipment seeing increased cyclic duty

Steve Gressler followed Mastronarde at the podium and focused on the subject that the boiler designer had introduced a few minutes earlier: materials-life considerations for cycling plants. Gressler, a metallurgist, opened his presentation with these three thoughts regarding equipment lifetime management to assure personnel safety and optimal reliability:

- Materials and equipment have finite lives that vary with application and local conditions.
- More rigorous service duty—cycling, for example—accelerates damage rates.
- Fabrication defects and design shortcomings that were benign and tolerable under steady-state conditions increase uncertainty and risk under more demanding cyclic duty.

What owner/operators basically want to know, Gressler said, are the answers to these two questions: (1) Where are the highest risk locations on critical equipment? (2) When will failure occur?

He recommended an iterative process based on well-established phased methodology to get the answers. First identify weak links and their contributing factors. Then selectively progress through more quantitative analyses. Finally, integrate multiple disciplines—such as materials, NDE (nondestructive examination), analysis, monitoring, instrumentation, data management, and economics.

Critical to success, Gressler continued, are an early start (gather knowledge of current condition to serve as a baseline for comparison), consistency, and an increase in prediction accuracy when the expected time of failure nears. To accomplish the last goal, you must know what constitutes "failure" (crack, distortion, risk level, etc), what the active failure mechanisms are, and what the rate of damage is.

The materials expert told the group that damage can be caused by an independent mechanism, by several in unison, or by several having compounding effects, and then reviewed the failure mechanisms of greatest interest to personnel at generating plants:

- **Fatigue** is a progressive damage mechanism that develops over time because of repetitive and fluctuating thermal and/or mechanical loading. Extent of damage depends on the number of cycles, local stress, and temperature.
- **Creep** is a progressive damage mechanism that develops over time because of the sustained application of stress at high temperature (over 800F). Extent of damage depends on time, temperature, stress, and material. To illustrate: A 16% increase in stress (from 6 to 7 ksi) halves the expected lifetime; a 4% increase in metal temperature from 1000F to 1040F reduces material life by a factor of four.
- **Creep-fatigue** is of concern because the interaction of the two damage mechanisms can reduce material life to 20% of that predicted independently.
- **Corrosion-fatigue,** sometimes called corrosion-assisted fatigue, is characterized by crack initiation from fatigue and the acceleration of crack growth by corrosion and oxidation.
- **Flow-accelerated corrosion,** known simply as FAC, is the thinning of metal by dissolution of the protective oxide layer under certain chemical and flow conditions. It is found most often in boilers (cold-end heat transfer bundles), air-cooled condensers, and condensate systems.
- **Over-stress conditions** result from unintended movement or loading—for example, from water hammer, bending, etc.

To reduce the uncertainty in your predictions of remaining materials life, it's important to know the current condition of your equipment. Accurate documentation is critical to this effort—specifically material specifications and fabrication and installation records.

Sounds simple, but many combined-cycle plants—particularly those built during the bubble years 1999-2004—are missing much of their important paperwork.

If that has occurred at your facility, it's important to conduct the appropriate inspections and compile the needed information. You may find that the requisite materials identification tests reveal the materials specified in construction documents are not the ones installed and achieving the expected equipment lifetime may not be possible—even with flawless operation.

Example: Gressler and his colleagues at Structural Integrity Associates Inc found inappropriate weld material and heat treatment procedures while investigating the condition of high-energy

Steven P Gressler, *PE, Senior Associate, Structural Integrity Associates Inc*

Gressler has more than two decades of experience performing life assessment, failure analysis, and materials evaluation of fossil-power generation equipment—with an emphasis on high-energy piping, boilers, and headers. He spent the first 10 years of his career at Ohio Edison Co in the company's engineering offices and plants. Gressler has contributed to the development of custom inspection techniques, risk-based assessment tools, and evolving methods assessing creep-strength-enhanced ferritic steels.

piping systems at the New Harquahala Generating Co LLC, Tonopah, Ariz. Extensive work was required to correct deficiencies in the main and hot-reheat steam systems. The case history presented in the 2Q/2010 issue of the COMBINED CYCLE Journal, "P91 commands respect," should be required reading for all plant supervisory personnel.

Once true baseline conditions have been established, it's important to continuously monitor plant operations for such anomalies as temperature and pressure excursions, fast ramp, fast startup, turbine trips, etc. Only with this information is it possible to calculate remaining life accurately.

Recall from your gas-turbine experience how OEMs determine when engine inspections are necessary and when critical parts must be repaired/replaced. The same methodology must be applied to other equipment—piping, valves, high-temperature/high-pressure pumps, heat-recovery steam generators (HRSGs), etc.

To better understand the impacts of poor operating practices on equipment life, review the experience of Southern Company Generation with a new software tool designed to track the life remaining in critical HRSG parts. Access www.ccj-online.com/archives, click 3Q/2009, click "New software . . ." on the cover.

Smart grid

Smart grid: An idea for the future

Scott Matlock presented "Smart power," describing Alstom's vision of how to reduce the electric-power industry's carbon footprint and maximize energy-use efficiency through better information management and the application of emerging technologies—such as carbon capture and storage. However, after listening to several transmission experts discuss the challenges associated with integrating renewables into the generation mix, it became obvious that "smart grid" was not in contention as a viable solution—at least not today.

Alstom's premise is that the global electricity sector faces a significant three-fold challenge: satisfy soaring demand, curb emissions, and develop carbon-free energy resources. The company believes smart grid will help meet this challenge. In its view, "smart grids are set to revolutionize the way we produce, distribute, and consume electricity, delivering major benefits in terms of cost, quality of life, and environmental footprint."

Here, smart grid is defined as an energy transmission and distribution network with embedded control, information technologies, and telecommunications capabilities that can provide real-time information to all stakeholders in the electricity value chain—from the generating plant to the home.

Alstom says that to maximize its return, a smart grid must expand its "smartness" from the end user upwards towards generation resources, allowing independent generators and load-serving utilities to optimize their assets to exactly match demand.

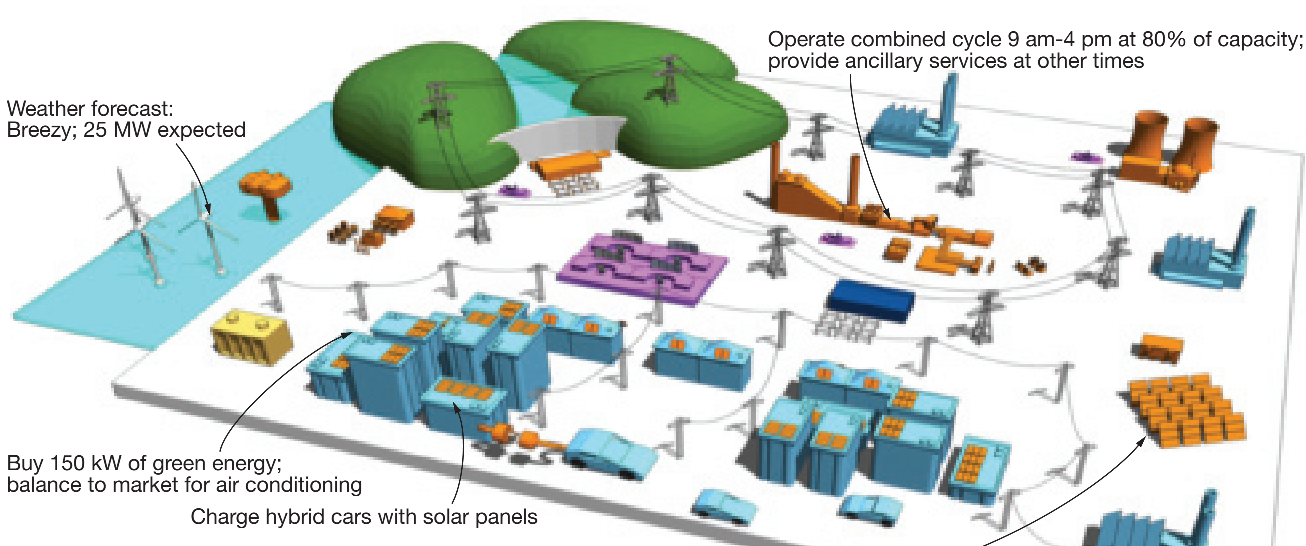
In a few years, the company believes, smart metering and demand management technologies in homes and commercial buildings will extend real-time control of energy use down to consumers. Expectation is that the smart grid would reduce the overall cost of generation and enhance grid stability, thereby facilitating the integration of intermittent renewables.

Smart meters and energy gateways would enable dynamic time-of-day pricing by giving consumers the ability to link up their smart critical appliances—such as hot-water heaters, hybrid cars, solar panels, etc—to local storage units and start operating or recharging automatically when signaled by the smart grid (Fig 23). Consumers also would be able to adjust their appliance settings remotely based on pricing information received on their computers, smart phones, etc, thereby contributing to a reduction in peak-time energy consumption.

Alstom's visionaries say future electricity networks will embed

Scott Matlock, *Western Regional Manager, Alstom Power, Automation and Controls*

Matlock has broad experience in electrical engineering. Before joining Alstom, he was VP operations for a Colorado-based engineering organization, regional manager for an electrical distribution company, and engineering manager for a technical customer support team.



23. Future vision of an energy ecosystem capable of reducing CO_2 emissions and integrating renewable and conventional generation resources new software applications to better assess risks related to generation intermittency and to allow grids to self-heal in emergency conditions and resist cyber and physical attacks. Such capability would enable operation of grid assets closer to their physical limits thereby reducing the need for capital investments in redundant systems and equipment.

Software applications at the distribution level promise to improve grid connection availability, avoiding costs incurred by businesses and consumers for power fluctuations and outages. The ability to share real-time data across the distribution system would further increase the transparency and liquidity of the energy wholesale market, bringing new storage and demand-response resources to reduce the need for standby generation. The expected result: A safer, more reliable, more efficient electric grid.

Injecting renewable energy into the distribution system

Jonathan Hawkins focused on PNM Resources' work to integrate renewables generation with the distribution system (Sidebar 5). One motivator for this effort is New Mexico's RPS, which requires that 1.5% of the company's green electricity be produced by distributed generation facilities in 2011, rising to 3% by 2015.

PNM Resources currently gets most of its renewable energy from the 200-MW New Mexico Wind Energy Center, which has been operating since early 2003. The 136-turbine facility remains among the largest wind plants in the country.

New Mexico is said to have more than 300 "sunny" days a year, making PNM Resources the perfect partner for DOE in a Smart Grid Demonstration Project that would incorporate a utility-scale battery (2 to 4 MWh) with a 500-kW solar (photovoltaic) installation.

Energy storage makes good sense, Hawkins said, because peak electric production from PV does not align with peak usage (Fig 24). Note that summertime peak demand occurs about two hours after the peak solar time. In winter, the separation between peak electric production and demand is greater. A battery allows electricity produced at the peak solar times to be used when customer demand peaks.

5. PNM Resources facts

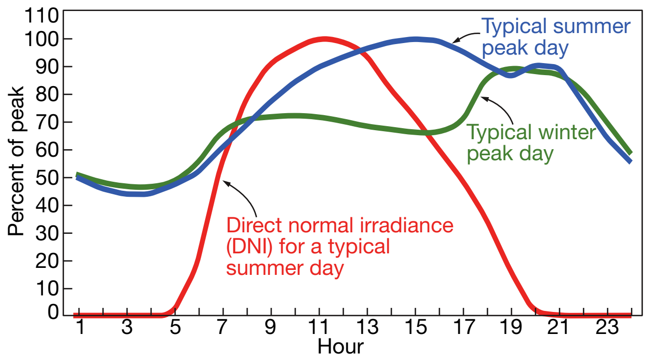
Regulated utility
Service territory: Parts of New Mexico and Texas
Customers: 859,000
Generation: 2717 MW (40% coal, 37% natural gas, 15% nuclear, 8% renewables)

A 200-MW wind farm represents more than 90% of the company's renewables portfolio. New Mexico's RPS requires that 20% of the kilowatt-hours (retail) the company produces in 2020 come from renewable resources. Other milestones: 10% in 2011, 15% in 2012

Jonathan Hawkins, *Manager of Advanced Technology and Strategy, PNM Resources*

Hawkins is responsible for new-technology R&D—including smart-grid technologies and strategy, integration of distributed energy resources, and energy storage. He is the company's advisor to EPRI programs on integration of distributed renewables, IntelliGrid, and smart-grid demonstrations, and is a voting member on the National Institute of Standards and Technology's Smart Grid Interoperability Panel.

Based on work done thus far, Hawkins continued, simple arbitrage alone would not produce a large enough benefit stream. However, by monetizing other benefits—such as carbon reduction, deferred fuel, deferred T&D system build-out, enhanced reliability, etc—a battery might be justified financially. A battery also adds value by smoothing fluctuations in distribution voltage normally caused by intermittent sources such as PV.



24. Solar power produced at maximum DNI is stored in a battery and released later in the day when demand is highest

Much work remains before the PV/battery system can be considered a firm, dispatchable renewable resource and achieve the stated goal of reducing peak demand by a minimum of 15%. Areas of ongoing development work include these:

- Develop and test computer-based modeling tools capable of simulating the behavior of distributed generation and storage interconnected with the distribution system. The use of computer-based models can allow PNM to scale aspects of the project virtually to investigate other scenarios. As an example, the utility can look at the effects of larger PV installations or larger battery storage by scaling actual data.
- Optimize the intelligent control algorithms that will operate battery installations on utility grids.

Other project objectives are the following:

- Demonstrate mitigation of voltage fluctuations by the battery system.
- Quantify and refine associated performance requirements, operating practices, and cost/benefit.
- Reduce greenhouse-gas emissions through the expanded and more beneficial use of renewables.
- Extrapolate, where possible, the benefits of storage when coupled with renewables.

The DOE-funded demonstration project involves many organizations in addition to PNM Resources, including the following:

- Sandia National Laboratories: system integration and design support; testing and evaluation.
- University of New Mexico: system modeling and analysis; battery control algorithm development.
- Northern New Mexico College: data analysis.
- EPRI: Analysis and modeling using the research organization's Intelligrid methodology. The PNM/DOE project benefits from the utility's selection by EPRI as one of 11 worldwide hosts under its Smart Grid Demonstration Program. Under this program, PNM and EPRI are currently engineering the design and operation of commercial smart-grid systems.
- Industry vendors, such as manufacturers of batteries and PV systems.

Finally, Hawkins said that knowledge gained by PNM Resources' personnel is being shared with the industry and the nation by participation in these programs.

Case studies

Renewables already impacting NV Energy's grid operations

NV Energy, which worked with CTOTF in developing the Integrating Renewables Workshop, brought its "A" team to the meeting to explain the challenges it faces and how it expects to satisfy the requirements of the state's demanding RPS (Sidebar 6).

Senior VP of Energy Supply Jeff Ceccarelli welcomed attendees to Reno and gave a quick review of the utility's history. NV Energy and its predecessor companies have been a catalyst for Nevada's economic development since before the 20th century.

The first electricity the utility produced was in the Reno area, host city for the workshop. It was used for lighting the mining town of Virginia City and for pumping water from the deep shafts of the area's world famous silver mines. Thomas Alva Edison personally designed Virginia City's first electric distribution system.

VP Generation Kevin Geraghty set a positive tone for the workshop and explained the integration challenge the company has in its northern territory. Note that NV Energy operates two independent grids today. Sierra Pacific Power Co built the northern grid and Nevada Power Co the southern grid before the companies merged in 1999. A north-south transmission line linking the two systems, named the One Nevada Transmission Line (or the shortened ON Line), is under construction and expected to be in commercial service at the end of 2012.

Geraghty began with his thoughts on change. "There has never been a time in this industry when there wasn't change," he said. The challenge, the executive continued, is to embrace change and accomplish the specified goals with minimum cost impact while maintaining service quality and making electricity production and delivery cleaner and safer.

Tall order for sure. But Geraghty reminded the group of how the industry had successfully adapted to wrenching change in the past. The Clean Air Act was one example. It dramatically changed coal-fired plant design and operation, first requiring unheard of (at the time) levels of particulate removal, then SO_2 removal, then NO_x destruction, then mercury removal, and so on.

The Clean Water Act again proved the industry's capability to adapt to change. Plants built before the 1970s typically discharged water—except perhaps for oily drains—through a big pipe directly into a natural watercourse. Today many generating facilities discharge no liquids whatsoever beyond the plant boundaries.

Accommodating intermittent renewables, Geraghty said, was simply the generation industry's next challenge.

Customer attitudes have changed over time as well. The VP recalled for the group "the early days," when the customer requirement simply was "hook me up." Next, customers wanted lower rates, more reliable service, faster hook-ups. Today many customers view the utility as a "safety net" for solar PV and other distributed generation tied to home and business operations.

Geraghty called for the industry "to rise and meet a new level of customer requirements." Customers don't want to hear about "intermittency," power-quality issues, or any of the industry's other challenges, he said. The electricity supply business was relatively easy in the "old days" Geraghty continued. Utilities had to grow the market, attract new customers, increase electric consumption. Today, "we're selling efficiency, to help the customer reduce the cost of energy."

Setting the stage for the next

three NV Energy speakers, Geraghty reviewed challenges facing the company on its northern grid regarding integration of "must take" intermittent renewables at a time when demand is decreasing. The whole idea of "must take" can be viewed as a contradiction because a utility sometimes is obligated to take wind energy when no customer needs or wants it.

Richard Salgo, the company's director of electric-system control operations, offered his perspective as a "grid operator." He began with an overview of reserves, regulation, and balancing, some of which had been covered earlier by Clyde Loutan of the CalISO.

The basic function of a balancing authority (BA) is to continuously balance loads and resources within a metered boundary, he said. It must ensure that grid frequency is controlled and that all interchange is properly transacted. Also, that the BA does not become a burden to interconnected neighbors by over- or under-generating.

Salgo next put up the area-control-error equation (too detailed for this presentation; access www.integrating-renewables.org), calling it the "barometer of balancing performance." You want the ACE to be zero, he said; if it's negative (positive) number you must increase (decrease) generation.

Area load demand, satisfied by BA generation and interchange, traditionally has been considered out of the grid operator's control. But that may not be true going forward, Salgo said, because the smart grid may enable load control at the customer—at least in some instances. Integration of intermittent renewable resources certainly will make BA generation far less predictable than it is today and complicate the management of interchange.

Spinning reserves, which provide both a portion of the BA contingency reserve requirement and the regulation room for preserving balance as load fluctuates, will have to meet more demanding requirements to accommodate the variability and/or intermittency of renewables. Ramp rates generally will have to be faster and operating ranges extended compared to spinning reserves serving conventional generation.

Operation of NV Energy's northern grid is already constrained and renewable generation is only a fraction of what it will be in 2025. Example: Nighttime minimum demand can be as low as 700 MW to 750 MW and total production from required thermal assets operating at minimum load and "must-take" renewables already is at that level.

With demand flat, at best, given the economic slowdown, and the need to keep adding more renewables capacity to satisfy the RPS, the challenge is clear. Salgo said the only apparent solution today is to curtail wind production as needed during low-demand periods. Smart grid can't help much, if any, because there's little load that can be curtailed.

What the grid operator expects of the generation fleet is more cycling capability, faster ramps, lower minimum loads, and the ability to make more frequent load adjustments. Demand-side expectations include improved load forecasting (a smart-grid deliverable), demand reductions to compensate for sudden dips in output from solar and wind resources (robust DSM capability), and load-shaping to approximate the expected renewable-portfolio supply curve.

Gary Smith, the company's director of smart technologies just smiled at Salgo's demand-side expectations as he walked to the podium. Smart-grid development is moving forward quickly under Smith's direction as evidenced by the recent rollout of the utility's Advanced Service Delivery (ASD) program. Foundation of this $301-million program, approved by the Nevada PUC last July 30: advanced metering and a 900-MHz communications network supported by 144 towers statewide.

NV Energy is a DOE grant recipient, so the federal government is chipping in $138 million for the purchase and installation of 1.3 million electric meters and 150,000 gas modules statewide. Meter installation is expected to take up to three years.

The ASD system—reliable, scalable, and secure—will enable customers to take ownership of their energy consumption eventually by scheduling energy purchases and taking advantage of off-peak discounts, etc. Smith showed the cutaway of a home a few years from now with solar PV on the roof, electric vehicles, home area network, demand-response capability, advanced metering, automated gas modules, etc. You can see it at www.integrating-renewables.org.

Operational benefits of ASD are estimated at about $35 million annually. Big savings are expected from eliminating about 17 million manual meter reads annually and from

6. NV Energy backgrounder

Customer base: 2.4 million Nevadans, 93% of the state's residents

Service territory: 54,500 mi^2

Demand: 5500 MW in the south, 1800 MW in the north

State RPS: Now at 12% of kilowatt-hour sales; ramps to 25% by 2025 with at least 6% from solar resources. Conservation can be 25% of the RPS

Nevada is ranked No. 1 in installed solar energy capacity per person

Nevada is ranked No. 1 in installed geothermal energy capacity per person

Renewables capacity totals 1241 MW (44 projects) and includes geothermal, solar PV, solar thermal, waste-heat recovery; solar thermal with storage, biomass, and wind either in production or under development.

Dariusz Rekowski, *Generation O&M Director, NV Energy*
Rekowski joined NV Energy in 2006 after 14 years with Destec Energy Inc and Dynegy Generation in various engineering, construction, commissioning-support, and management positions. First assignment at NV Energy was as plant director for the Clark/Sunrise complex.

Richard J Salgo, PE, *Director of Electric System Control Operations, NV Energy*
Salgo is responsible for the interconnected operation of NV Energy's transmission grid and balancing areas in northern Nevada and the Las Vegas area. His experience includes electric system design, system protection, construction and field operations, and grid operations.

Gary Smith, *Director of Smart Technologies, NV Energy*
Smith is responsible for the company's Smart Grid program development—including vision, strategy, investment grant, and regulatory interface. He also manages the implementation of NV Energy's advanced meter infrastructure and meter data management.

Inequality among renewables

Most generation professionals in the electric power industry are relatively unfamiliar with how hydroelectric projects *really* work. The prevailing view that flowing water turns a generator shaft to produce electricity, while true, does not acknowledge the complexities associated with the operation of these facilities.

Consider the Bonneville Power Administration, which markets power from federal dams along the Columbia River system within the constraints and requirements for other river purposes. Flood control, protection of fish listed in the Endangered Species Act, compliance with the Clean Water Act, etc, take precedence over power production.

And now there are "must take" renewables to accommodate. As part of its mission to market federal hydropower, BPA is the primary high-voltage transmission provider in the Columbia River Basin, home to more than 3000 MW of wind-powered generators. Consistent with FERC (Federal Energy Regulatory Commission) policies for open-access, non-discriminatory transmission, BPA integrates new power sources into its grid as requested.

Wind capacity in the area served by BPA is being developed well ahead of regional power demand growth because of the challenging Renewable Portfolio Standards promulgated by the western states. In fact, 80% of the wind power generated along the Columbia River is delivered to utilities located outside BPA's balancing authority area.

The rapid increase in wind power production in the Northwest (along the Columbia River and elsewhere in the region) has increased the power system's maximum output by a significant amount. Meanwhile, the balancing reserves needed to accommodate wind have consumed a major portion of the Federal Columbia River Power System's operating flexibility.

To illustrate: Columbia River gorge wind patterns are extremely variable and storms cause large up and down ramps that are hard to predict with precision. To accommodate the 3000 MW of wind power currently interconnected to the federal system, BPA now sets aside about 850 MW of hydro capability to provide incremental (INC) reserves and about 1050 MW to provide decremental (DEC) reserves.

Translation: BPA runs hydro generation 1050 MW higher than minimum generation at all times so it can reduce hydro production (DEC) if the wind picks up and suddenly increases above its schedule. In addition, hydro generation is run 850 MW below maximum generation at all times so BPA can increase hydro output (INC) if wind dies and wind generation falls below its schedule within an hour.

One impact of rampant growth in renewables generation is illustrated in a recent report, "Columbia River high-water operations," DOE/BP-4203, September 2010. BPA had been aware for some time that a combination of high stream flows and high wind could pose new challenges for its Columbia River system operations.

Such a "perfect storm" occurred during the first two weeks of June 2010, in an otherwise low-water year. BPA considers this event a likely preview of situations the organization and region will face again, and for longer periods during years of heavy snow.

Simply put, this was the conundrum caused by the freak weather system: Maximum wind and hydro generation together exceeded demand; reservoirs behind dams along the Columbia rapidly filled to maximum capacity; a need to control "spill"—that is, dumping water downstream without generating power—to control the amount of nitrogen in the river water. High amounts of nitrogen can be lethal to fish.

To minimize excess spill, federal hydro facilities produced, at times, more than twice as much power as needed to meet BPA demand. Since generation must equal demand, BPA was forced to sell its power at prices down to $0/MWh to reduce excess spill and manage total dissolved-gas levels. During the first two weeks of June, BPA disposed of more than 50,000 MWh for free, or for less than the cost of associated transmission.

But maximizing hydro generation was not enough to manage the high flows and prevent reservoirs from overfilling; spill flows had to be increased. Such additional spill is termed "lack-of-market spill" since it would not have been necessary had there been additional markets for power.

All thermal facilities in BPA's balancing authority area were reduced to the minimum loads necessary to keep them connected to the grid during the weather anomaly. For example, the nuclear plant known today as the Columbia Generating Station was operated at less than 20% of its rated output for a few days to avoid a shutdown.

Grid impacts. Finally, because federal hydro generators were producing far in excess of BPA demand, and wind power and other resources also required transmission, the grid was stressed. Transmission availability significantly limited opportunities for increasing hydro generation to reduce dissolved-gas levels in the river.

improved energy-theft detection. DSM programs also are expected to reduce generation requirements by 245 MW by the end of 2012, including commercial and industrial. Load control in residences and small commercial operations, peak-time rebates, programmable thermostats, and home-area networks are reducing demand by nearly 150 MW today. Goal is to double that number within a few years.

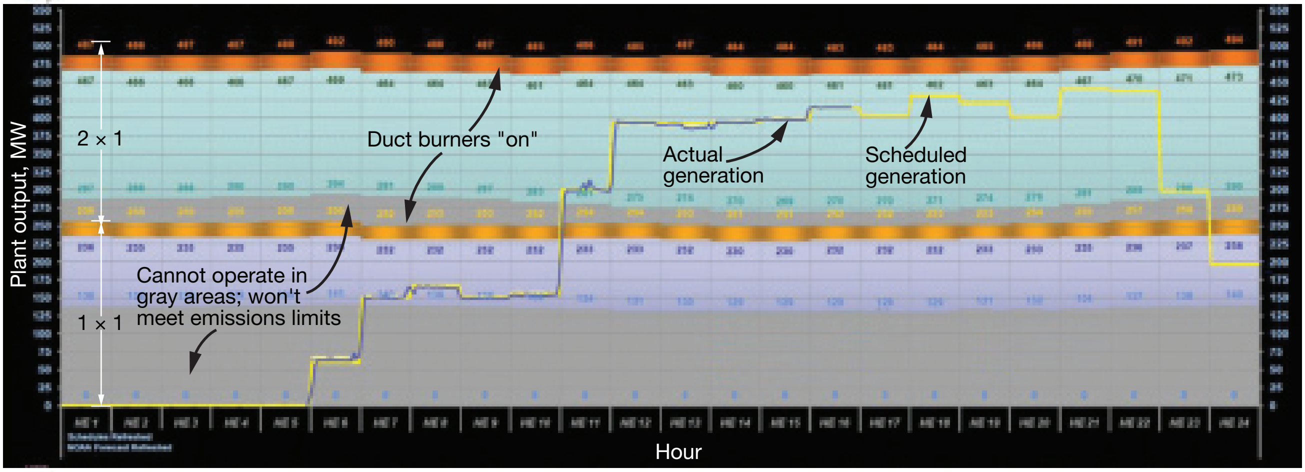
Dariusz Rekowski, director of fleet O&M and the last of NV Energy's presenters, opened by acknowledging the grid operator's expectations of generation and noting that providing dispatch flexibility to support grid stability and demand is conducive to lower operating efficiency, faster ramps, and more stop/start cycles.

They, in turn, contribute to lower capacity factor, increased wear and tear on parts, and a higher number of maintenance cycles. The result: higher O&M costs and outage timing adjustments. Rekowski said it was clear that the company had to spend its O&M dollars more wisely by adopting condition-based, rather than time-based, maintenance and to make better use of its workforce by moving people among plants for planned maintenance.

The former plant director of the company's Clark, Sunrise, and Higgins generating plants said the challenges of running conventional assets to support renewables included the following:

- Higher emissions per megawatt-hour produced.
- Part-load operational issues.
- Transient-mode operation.
- Higher fuel consumption (higher heat rate).

Rekowski cautioned that more frequent cycling of conventional assets might introduce issues not seen in base-load service. Specifically, he was concerned about water chemistry/treatment effects, turbine water induction, safety, high-energy piping issues, etc.



25. Startup and loading of the Klamath combined cycle for a typical economic-dispatch scenario shows five hours of operation with one gas turbine in service before firing the second unit

Flexibility of conventional resources underpins renewables development

Mike Roberts stressed early in his presentation that one of Iberdrola Renewables' goals is industry leadership in optimizing the flexibility of existing resources to enable more renewables development (Sidebar 7). The ability of a generator to balance its renewable and conventional resources within someone else's balancing authority reduces wind-integration charges—a drag on the bottom line.

Roberts is well versed in such matters. He was the plant manager of the company's gas-turbine-based generating facility in Klamath Falls, Ore, from before the 2 × 1 F-class combined cycle at the site was commissioned in July 2001 until it—and the plant's 100 MW of fast-start peaking capcity—was purchased by Iberdrola in 2007.

Shortly thereafter, Roberts turned over the Klamath keys to Ray Martens, an active participant in CTOTF and the 501F User Group, and moved up to Portland to manage the company's power assets and their operation.

Iberdrola Renewables wanted the ultimate in flexibility at Klamath: A base-load unit capable of daily cycling. Roberts and Martens made that happen by implementing a cornucopia of best-in-class performance upgrades from Siemens Energy that had satisfied the OEM's rigorous commercial test criteria but collectively had never been installed on one engine.

In combination, the upgrades demonstrated these operational benefits:

- Increase in generating capability of up to 6% at base load.
- Improvement in base-load heat rate of up to 2%.
- Better part-load heat rate.

Other benefits included the following:

- Turndown to 50% of rated capacity without exceeding 10 ppm CO when ambient temperature is between 59F and 95F. Operation at lower load off-peak saves fuel and reduces wear and tear on parts.
- Opportunity to reduce total emissions during engine startup.
- Increased SCR efficiency at low load.
- Extended intervals between overhauls.

For details on the Klamath upgrade, access www.ccj-online.com/archives.html, click 3Q/2009, click "Klamath gets better with age" on the cover.

Roberts followed Makansi at the podium and supported the previous speaker's contention that gas turbines were likely to have a major role in integrating renewables. He said that rapid wind development presented challenges to balancing authorities and that GT resources were well suited to provide flexible capacity, as the Klamath upgrade attests.

That wind development is both rapid and challenging in the region supported by the Western Electricity Coordinating Council (WECC), where Iberdrola Renewables is approaching 2000 MW of total installed capacity, was reflected by two bullet points in Roberts' presentation:

- Wind capacity in the WECC could more than double to 14,000 MW by the end of 2012.
- The statement by Bonneville Power Administration on September 6 offering wind developers a choice: "BPA can carry more reserves (with fewer curtailments) and charge higher wind-integration rates, or carry fewer reserves (with more curtailments) and level lower rates."

Recall that BPA markets wholesale electric power from federal hydro projects in the Columbia River Basin and a handful of non-federal nuclear and hydro generating facilities. It operates about 75% of the high-voltage trans-

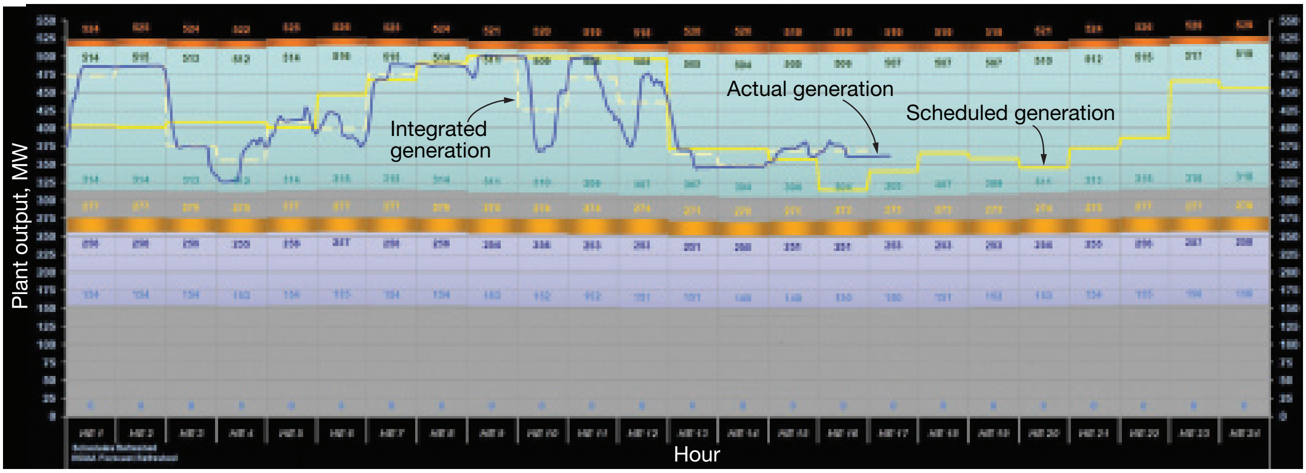
Michael Roberts, *Managing Director of Power Asset Management and Operations, Iberdrola Renewables*

Roberts has held increasingly responsible positions in his 25-year industry career, including plant engineer, O&M manager, and/or plant manager positions at four gas-turbine-based and three biomass generating facilities. He was on the management teams for construction, startup, and commissioning of both the Crockett and Klamath Cogeneration Plants.

7. Iberdrola Renewables backgrounder

Iberdrola Renewables is the world's leading wind generator with 12 GW installed and more than 58 GW in the pipeline. The company ranks second in the US, with wind turbines currently producing 3800 MW. Half of Iberdrola Renewables' planned projects are in the US, where the company earns about one-third of its revenue.

The US operation also has 636 MW of combined-cycle and peaking capacity in southern Oregon. Plus, 155 billion ft^3 of owned and contracted natural gas storage positions Iberdrola to successfully accommodate a volatile future.



26. Integrating wind requires flexible assets to ramp up and down throughout the day

mission capacity in its service territory which includes Idaho, Oregon, Washington, and western Montana, and extends into four other states.

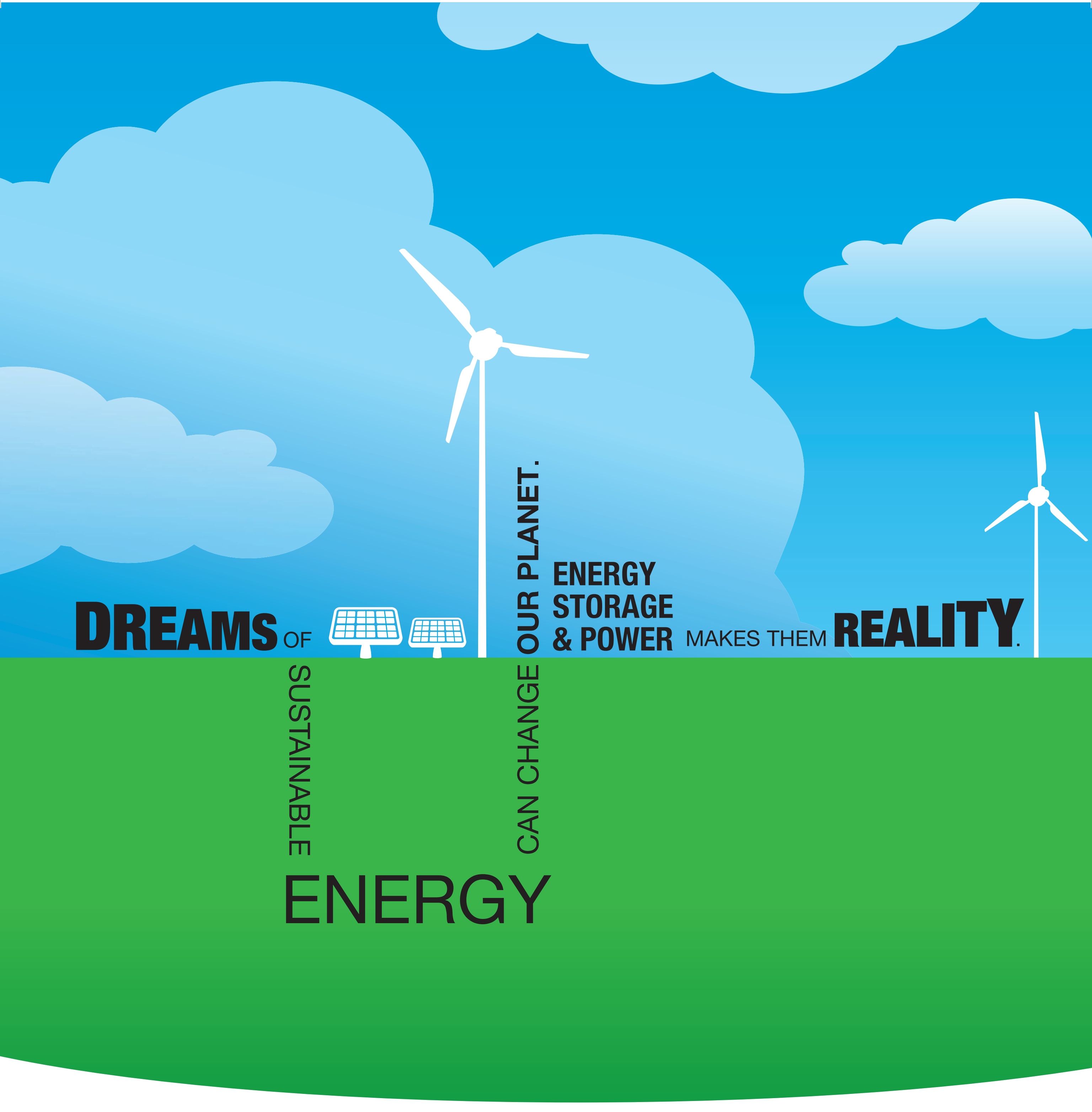
BPA has unique challenges posed by integration of intermittent renewables because the region served is dominated by hydro resources, the operation of which are impacted by regulations to insure protection of fish and wildlife, flood control, navigation, and irrigation as well as load-following and regulation (BPA sidebar).

Dynamic turbine operation, Roberts said, was likely to emerge in the future as the demand for flexible capacity grows; there is no formal market for flexibility today. He foresees the possibility of sub-hourly products that allow owners of flexible generation to bid INC and DEC capacities. Flexible capacity, he continued, would create *additional* revenue opportunities and would not adversely impact the delivery of scheduled energy.

"Optimizing a mixed portfolio of renewable and flexible resources is more difficult than either is alone," Roberts added. However, the payback of intra-company balancing to suit grid needs is that it minimizes wind-integration charges.

Looking ahead, Roberts noted that decision-making tools are critical to integration success, but that the maintenance implications of intermittent renewables on conventional assets would be difficult to define. He suggested that complex computer modeling of the "resource stack" would be needed and that it had to be reliable, fast, and user friendly to real-time traders, plant operators, wind forecasters, and others alike.

Roberts showed the group two slides to illustrate how the Klamath combined cycle was operated in the "old world" of economic dispatch (Fig 25) and in the "new world" requiring the balancing of wind resources within the hour (Fig 26).



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