U.S. POWER INDUSTRY 2014 FORECAST

TURNOVER OF THE GENERATION FLEET SPEEDS UP; GAS PROJECTS DOMINATE PLANS FOR NEXT FIVE YEARS

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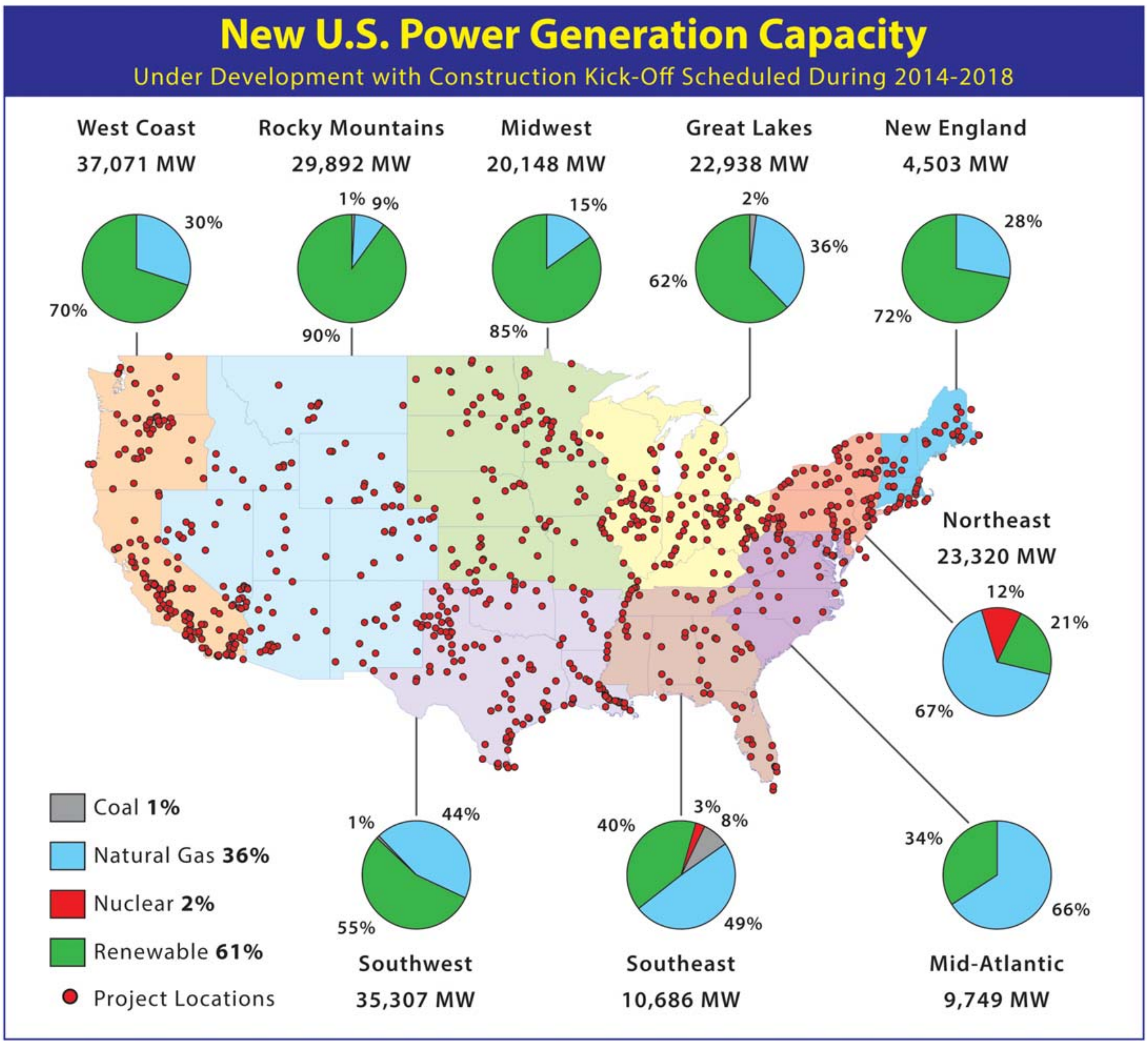
The U.S. power business had a particularly lively and litigious year in 2013, and signs point to more of the same in 2014. Inside the Washington Beltway, the U.S. Environmental Protection Agency (EPA), Congress and the federal courts continue to tussle over energy and environmental policy, forcing industry participants to make expensive decisions about fuel, equipment and strategy in a policy environment where questions outnumbered answers.

For 2014, renewables and gas-fired generation look to be the clear winners, while coal and nuclear are the big losers. We see that trend continuing for several more years. But around 2017, some wonder if federal efforts to clean and decarbonize the nation's power supply will create, once again, a competitive opening for nuclear power.

In the U.S., Industrial Info Resources is tracking 1,608 new-build electric generation projects that are scheduled to kick off between 2014 and 2018. These projects represent about 194 GW of new generating capacity, with a total investment value (TIV) of several hundred billion dollars. We do not expect all of those projects to begin on schedule. In fact, based on historical construction starts data for the power generation industry, less than half of these projects will begin turning dirt over the next five years.

In that period, developers plan to begin construction on: 119 GW of renewable generation; 69 GW of gas-fired generation; 3.1 GW of nuclear generation; and 2 GW of coal-fired generation. Our project data covers new-build generation of all types, unit additions, industrial energy projects and pollution-control projects.

As in prior years, renewable energy accounts for the majority of planned new-build generation projects over the next five



years. Between 2014 and 2018, renewable energy projects account for about 62% of all new-build generation projects. Although all U.S. regions plan to add renewables, regions such as the Rocky Mountains, Midwest, New England, West Coast and Great Lakes show a proclivity for green power. Other regions, including the Northeast, Mid-Atlantic and Southeast, plan to rely more heavily on natural gas.

Coal outlook

New-build coal generation has been severely curtailed in recent years. As recently as 2006, developers had planned to rely on coal for 43% of new-build generation projects over the next five years. But now, coal is expected to account for only about 1% of new-build generation in the U.S.

By mid-2014, the power industry will know the fate of the EPA's decade-long effort to control interstate migration of power plant air emissions. That is when the U.S. Supreme Court is scheduled to issue its decision on the EPA's Cross-State Air Pollution Rule (CSAPR), the latest in a long series of efforts by the agency to control power plant emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NOx) that move across state lines.

Meanwhile, the Obama administration has continued efforts to decarbonize the electricity business, announcing an aggressive climate change policy last June that included a commitment to lower emissions of CO_2 from new and existing power plants. In late September, the public got a look at the EPA's draft rule on carbon pollution for new fossil-fueled power plants that will be larger than 25 megawatts (MW).

For new coal-fired units, the EPA proposes to limit CO_2 emissions to between 1,000 and 1,100 pounds per MWh. The proposed standard is about half the current emissions level of a new coal-fired plant without CO_2 controls. Operators will be given the choice of meeting standards over one year or seven. This effectively mandates installing carbon capture & sequestration (CCS) equipment on an integrated gasification combined cycle (IGCC) power plant.

The coal and power industries assert that CCS is an expensive technology that has not been commercially deployed. The construction cost for an IGCC plant has ramped up to between $4 billion to $5 billion for a 400 MW to 500 MW facility about $10,000 per installed kilowatt of capacity, higher than nuclear power.

It is not clear when the EPA expects to finalize its CO_2 regulation for new coal-fired power plants. But by mid-2014, the agency is planning to drop the other shoe: a new rule regulating CO_2 emissions from existing coal-fired generators, something that could increase the speed at which the U.S. generating fleet is being turned over.

The EPA is the point agency for another regulation affecting coal-fired power: the Mercury and Air Toxics Standards (MATS), which the agency finalized in April 2013, though the EPA took an additional 60 days of public comment over the summer on issues relating to plant startup and shutdown. Formerly known as the Utility Boiler MACT, MATS limits power plant emissions of mercury, acid gases and toxic metals. It has an effective date of 2015, though one-year extensions are available . The industry may choose to litigate MATS, but we note that rule has aroused far less vehement and widespread opposition than CSAPR.

Dozens of coal plant owners across the country have announced the closure of plants where it did not make sense to install pollution-control equipment.

The decision to close a coal unit typically is driven more by the size of a unit than its age. Utilities are considering retrofitting units that are 450 MW or larger, but units smaller than that typically are being closed. Also, coal plants that are 50 or more years old are good candidates for shutdown, though we expect some of these older plants will remain open to ensure regional electric reliability.

Year	Capacity (MW)
2010	4,062
2011	4,134
2012	11,323
2013	10,393
2014	6,875
2015	18,039
2016	2,926
2017	1,780

Table 1: Recent and planned coal plant shutdowns.

In 2013, construction started on several billion dollars of pollution-control projects at coal-fired power plants across the U.S., and that spend should grow between 2014 and 2018. We expect construction of approximately $23.7 billion of pollution-control projects to begin at U.S. power plants over the next five years.

Aside from closures and environmental retrofits, we see a decline in scheduled maintenance outages at coal plants and an increase in unit cycling, mainly driven by low gas prices.. Gas prices are expected to stay low for the foreseeable future, leading to more coal-plant cycling, which eventually will lead to equipment failure and unplanned outages.

Another emerging U.S. regulatory issue is an update of the Clean Water Act's section 316(b) on cooling water intake systems, whose impact would go beyond coal to nuclear and even gas plants that cool their equipment with water from rivers, lakes and streams. The EPA was scheduled to publish its final rules updating this section of the CWA by November 2013. Section 316(b) requires that the location, design, construction and capacity of power-plant cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

All of this regulatory activity and uncertainty has all but ended development of new-build coal-fired generation. Last year saw the completion of two coal-fired plants the Edwardsport IGCC plant in Indiana and the Sandy Creek project in Texas leaving only a small handful of projects still under construction. Over the next five years, we see about 2 GW of new-build coal plants kicking off construction.

While coal advocates rightly point to EPA regulations as a primary reason why new-build coal plant development has been stymied, market forces also play an important role. Overwhelmingly, utilities that need new generating capacity are building natural gas power plants, which were cheaper and faster to build and less expensive to run. Also, gas plants have a smaller physical footprint compared with coal plants.

Industrial Info predicts that gas prices would have to more than double from their current level of about $4 per million British thermal units (MMBtu) for coal to compete economically with gas.

Natural gas outlook

Through the first nine months of 2013, construction began on 4.5 GW of gas-fired generation in the U.S. New-build natural gas-fired power had a far brighter 2013 than coal, and we see that trend continuing over the next five years, driven by a variety of factors:

- EPA regulation has added and will continue to add costs and operational restrictions to the nation's aging fleet of coal-fired generation
- The shale revolution has dramatically expanded the nation's supply of natural gas, lowering its price. Gas briefly fell below $2 per MMBtu in early 2012, and yearend 2013 prices were under $4 per MMBtu
- Repowering coal-fired units with gas has proven to be an attractive option for some utilities

• Intermittent resources like wind and solar need to be backed up by dispatchable resource, and gas-fired generation has been the backup generation technology of choice for some time

• Nuclear power remains a "bet the company" proposition, as shown by construction of Vogtle units 3 and 4, which are significantly over cost

Over the 2014 to 2018 period, developers plan to begin building about 69 GW of new-build, gas-fired plants, representing up to about $60 billion TIV. Again, Industrial Info does not expect all of those projects to start construction according to plan. But historically, gas plants have had a relatively high percentage of on-time completions: about two-thirds of them are started, and completed, according to schedule. That is another reason why we continue to see natural gas as a leader in new-build power construction over the next five years.

While all regions plan to build some gas-fired generation over the 2014 to 2018 period, regions expecting to see the greatest reliance on gas in their new-build markets include the Northeast, Mid-Atlantic and Southeast. Other regional markets, including the Rocky Mountains, Midwest and Great Lakes, are expected to face more modest, though still active, levels of gas plant development. Overall, gas is expected to claim about 36% of the new-build market between 2014 and 2018.

Building a gas-fired generator costs between $700,000 and $1.2 million per MW, far less than coal or nuclear units. Given that, plus the smaller footprint required for a gas plant compared to other generation technologies, it is easy to see why utilities and power developers across the country have turned to gas as the fuel of choice for new generation. Duke Power, Florida Power & Light, Tennessee Valley Authority and Southern Company are only some of the utilities relying heavily on gas for new generation, both to replace capacity that is being retired and to meet new customer demand. The "dash to gas" also is a dominant feature of power-plant development in markets where asset owners are paid only for actual energy produced, not for capacity.

Dash to gas

Recently, several utility CEOs have warned about the potential dangers of an "all gas, all the time" strategy, which the industry first experienced about a decade ago when a near-exclusive reliance on gas led to a significantly over-built market. However, as long as regulators and corporate leaders make their primary consideration the construction cost for new generation, we see the "dash to gas" continuing. Utilities have a deeply held commitment to fuel diversity, but the market and regulators are combining to push them to ever-heavier reliance on generating electricity from gas.

Switching coal-fired generators to burn gas whether repowering or converting is another trend driving increased reliance on gas in the power sector. A repowering decision is highly dependent on the original equipment: if the generator does not require a complete revamp in order to burn gas, then asset owners tend to look favorably on repowering.

As long as natural gas prices remain relatively low, around $5 per MMBtu for electric generators, and the science is still out on the environmental impacts of producing gas by hydraulic fracturing, it is difficult to see any alternative to gas capturing an ever-rising share of the U.S. new-build electric generation business over the next five years.

Gas generation backs up a lot of intermittent generation such as renewables. Gas prices can be volatile, but since 2008 prices have moved steadily down. A surge in gas prices could slow gas plant development activity, but stopping it seems unlikely.

Nuclear outlook

The nuclear power industry suffered several setbacks in 2013, and Industrial Info does not see anything that would reverse the industry's fortunes over the next five years.

Nuclear's new-build future looked so bright back in 2008, when the Nuclear Regulatory Commission (NRC) received 24 applications to build new nuclear power plants. The NRC's approval of a Westinghouse AP1000 nuclear reactor in late 2011 was supposed to herald a new era of nuclear power construction.

But in recent years, developers have dropped new-build nuclear projects, citing high costs, regulatory uncertainties and difficult competitive pressures. Congress' inability to enact climate-change legislation in 2010 removed an important driver for new-build nuclear.

The Fukushima accident in early 2011 further clouded the outlook for building new nuclear generators, as the NRC promulgated several rounds of new safety upgrades for existing and planned reactors. And low natural gas prices have posed a big competitive challenge to new-build nuclear.

But in the end, the nuclear renaissance has been slowed, if not killed, by the breath-taking costs of the technology. In this way, the industry has been reliving the 1970s, when escalating costs and construction delays killed nuclear power years before the general public ever heard of Three Mile Island.

Over the 2010-to-2012 period, NRG Energy and Exelon ended efforts to build a total of five nuclear units. The NRC is continuing to process new-build construction & operating license applications. But the estimated cost to build a nuclear generator suggests that any licenses issued by the NRC will remain unused, at least for the foreseeable future.

Across North America, about $705 billion of nuclear capital construction or plant upgrades, additions and improvement projects, including $1.15 billion of plant uprate projects, have been cancelled or placed on hold since the start of 2011.

Looking forward, two new-build nuclear units are scheduled to kick off in 2017 — one in New Jersey and one in Pennsylvania. Two uprate projects, both in Tennessee, also are scheduled to begin turning dirt that year.

Among existing generators, market economics have led to the closure of two nuclear plants in 2013: Kewaunee in Wisconsin and Vermont Yankee in Vermont. We expect more closure announcements, driven by difficult economics (resulting from low gas prices and absence of capacity markets), as well as regulations such as the not-yet-finalized Clean Water Act section 316(b) rule. The plants we see as most at risk for premature closure are single-unit plants operating as merchant generators, without a captive customer base, or plants located in states such as New York, where political leaders have turned against nuclear power.

The estimated cost to repair damaged units has forced the closure of Crystal River in Florida and the San Onofre Nuclear Generating Station (SONGS) in California last year. And rising costs coupled with slower demand growth for electricity has caused Duke Energy to cancel one planned plant (Levy) and push back another (Harris). Tennessee Valley Authority's effort to complete construction of its Watts Bar Unit 2 plant is years late and significantly over budget.

New-build nuclear

Southern Company's Vogtle units 3 and 4 and SCANA's Summer units 2 and 3 are the industry standard-bearers for new-build nuclear construction. Both began construction in 2012. The Vogtle units are scheduled to begin operating in 2017 and 2018, while the Summer units have scheduled in-service dates of 2017 and 2018 as well.

Southern Company has experienced significant cost overruns for its Vogtle project. Although the Vogtle and Summer unit expansion projects are using the same reactor technology, the Westinghouse AP 1000, reports out of the Summer project are less troubling than what's coming out of the Vogtle project.

Extended power uprates (EPUs) slowed in 2013 compared to a few years back, and we expect to see a further slowdown over the 2014-2018 period. Last August, the Nebraska Public Power District pulled a plan to uprate the Cooper Nuclear Station. It is not alone. Rising cost estimates and low natural gas prices are undermining the econom-

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ics of some uprate projects. Flat or sluggish electric demand growth also is a factor. Fukushima-related safety upgrades from the NRC have made a difficult situation worse.

Probably the most significant factor in determining the future of U.S. new-build nuclear plants is the industry's ability to build plants according to schedule and at budget. For now, all eyes are on the Vogtle and Summer projects.

Renewables outlook

The renewable energy industry mainly wind and solar had an active 2013, and an equally active 2014 is expected. Across the U.S., developers plan to kick off construction of 119 GW of renewable generation projects between 2014 and 2018. Wind power accounts for the majority of planned construction starts, followed by solar power.

As with other fuel types, we do not expect all of these projects to begin according to schedule. Historically only about 25% of renewable energy projects start construction according to their schedule, owing to problems with financing, regulation or transmission.

At this point, the U.S. regions with the greatest percentage of new-build renewable generation scheduled to kick off over the 2014 to 2018 period include the Rocky Mountains (90% of all new-build generation is scheduled to be renewables), Midwest (85%), New England (72%) and West Coast (70%).

Over the next five years, on a GW basis, the Rocky Mountain and West Coast regions are co-leaders, with each scheduled to begin construction of about 26 GW of new renewables, followed by the Southwest (19 GW) and Midwest (17 GW).

Federal tax credits and state Renewable Portfolio Standards (RPS) regulations continue to play a role in determining renewable fortunes. About 30 states have enacted an RPS, which mandates a specific portion of a state's electricity come from renewable resources by a certain date.

RPS mandates

In some states, there are efforts under way to curtail or repeal an RPS, though none has succeeded as of yet. The absence of a federal RPS has led to a checkerboard pattern of renewable energy development across the country. In states where utilities are close to satisfying their RPS mandates, development of new renewable generation has slowed.

The outlook for renewable energy construction also is critically affected by the ability to site and construct high-voltage transmission projects. As most utility-scale renewable generation is located far away from urban load centers, new transmission lines are needed to bring power from rural areas to urban customer centers.

However, during 2013 we saw several transmission projects delayed by a combination of federal licensing, local opposition and inability to secure financing. There is no reason to think that will change during the 2014 to 2018 period.

Through the third quarter of 2013, wind developers signed power purchase agreements (PPAs) with 12 utilities for more than 7,500 MW of new generation. But ground was broken for only about 1,800 MW as of September 30, suggesting the fourth quarter will be a frenzied blur of construction activity.

Under the Internal Revenue Service's current interpretation of the Production Tax Credit (PTC) extension language, a project may qualify for the credit if "a certain level of investment is made by year's end." That will count in lieu of breaking ground. Developers are racing to meet the requirements of the extended PTC by the end of 2013. The renewed PTC provides asset owners a federal tax credit of 2.2 cents for each kilowatt-hour of electricity produced for 10 years.

Wind power

A lot of wind development is under way, but we expect most of the real construction will take place in 2014 and 2015. Outside of the West Coast, most utilities are ahead of the curve in meeting state RPS requirements. Weak electric demand growth means that renewables in general must increasingly rely on cost competitiveness, rather than legislated demand or tax credits, to be economically viable.

We see that happening: PPAs are being signed right now with wind energy developers where power is priced at $25 to $40 per MWh. Wind energy development hot spots include the Midwest, Southwest, Texas and Oklahoma. We estimate the extended PTC will lead to the construction of 13 GW of new wind power by 2016.

Beyond 2016, barring another renewal of the PTC, we see a sharp drop-off in new-build wind generation. At this point, another renewal of the PTC seems highly unlikely, though dramatic changes in the 2014 congressional elections could change that. If the PTC is not extended beyond yearend 2013, the new-build wind industry is likely to find itself at a competitive disadvantage vis-à-vis other new-build technologies.

In 2014, project developers have announced plans to begin construction on about 15 GW of new wind capacity worth an estimated $41 billion. But historically, wind power projects have had a higher level of delays and cancellations compared to natural gas projects. Therefore, we expect no more than about 5 GW of wind projects worth something north of $10 billion will actually begin turning dirt next year — about one-third of what the industry as a whole plans.

Last year's largest wind power announcements included MidAmerican Energy's commitment to build about $1.9 billion of new capacity in Iowa and Austin Energy's signing of PPAs totaling about $1.4 billion to support construction of about 570 MW of new generation. In addition, large wind power projects began construction last year in Minnesota, Kansas, Nebraska and Oklahoma, among other states.

The PTC is not available to developers of solar power, but they can still access a federal Investment Tax Credit (ITC). The availability of ITCs helped the industry schedule the start of about 3 GW of solar projects last year. In 2014, we predict the industry's fortunes will shine even more brightly, with about 3.7 GW of projects scheduled to break ground.

The U.S. regions with the highest level of utility-scale (greater than 1 MW) solar power development in 2013 were the traditional hot spots: the West Coast and Rocky Mountain regions. For the next three years, we expect these two regions to continue leading the new-build, utility-scale solar market. The scheduled expiration of the ITCs in 2016 likely will put significant additional pressure on the economics of utility-scale solar power.

In late 2013, Ivanpah, the world's largest concentrating solar power (CSP) project, began generating electricity. The three-unit project, rated at about 365 MW, will sell its power to Southern California Edison and Pacific Gas & Electric. We expect to see a few more large CSP projects move through the construction process over the next five years, but the high cost of the technology will make CSP a less attractive option than photovoltaic (PV) technology.

Solar panels

In 2012 and 2013, dramatic declines in the cost of solar panels manufactured in China helped spur solar power development. Whether similarly dramatic price declines will continue into 2014 and beyond is unclear. Privately, some operators are grumbling about equipment failures at solar farms that use Chinese-made equipment.

The U.S. has asserted Chinese manufacturers benefit from unfair trade practices that have artificially lowered the price of their goods in this market. Those claims may be sorted out in 2014 by international trade organizations. We also expect to see growing industry attention on the quality of Chinese-manufactured solar panels.

In many ways, hydroelectricity has been the poor stepchild of renewable energy, but industry insiders hope passage of federal legislation in 2013 streamlining hydro project licensing is a first step toward realizing a future where more power is generated from water.

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The old view of hydro is that it is a mature technology with limited prospects and a tendency to kill fish. But hydro enthusiasts say a new view on hydro is gradually emerging: an exciting new technology eager to be deployed at sites across the country in ways that enhance, not endanger, local fish populations.

The U.S. has about 80,000 dams, but only about 3% of them have hydroelectric generators installed. Most of the dams were built early in the 20th century for flood-control purposes. Developers estimate up to 60,000 MW of new hydro generation can be economically built, an estimate that includes building new pumped-storage projects and adding hydroelectric generators to dams already in place.

Legislation passed by Congress and signed by President Obama in 2013 is expected to speed up licensing of new hydro generation. But state RPSs tend to not count hydroelectric generation, a point the industry continues to try to change.

Beyond legislation and regulation, the hydro industry has faced the formidable challenge of cheap gas-fired power. Experts keen to tout the potential of new hydro also acknowledge that a lot of it will not get built as long as utilities can generate electricity for about 3.5 cents per kilowatt-hour using gas.

Across the U.S., the regions with the largest amount of hydro power under development are the West Coast, Rocky Mountains, Southwest and Southeast. The vast majority of these projects are in an early stage of development, which carries higher risks of deferment or cancellation compared to projects that have secured funding. Still, at yearend 2013, about $5 billion of capital and maintenance projects were under construction in the U.S.

Looking forward

As we start 2014, the outlook for the U.S. power industry is gassier and greener than any year in recent memory. Inside the Washington Beltway, development of energy and environmental policy reminds us of the old adage, "those who enjoy sausage should not watch it being made."

As Congress, the EPA and the federal courts continue to wrestle over U.S. energy and environmental policy, the industry is being forced to make billion-dollar bets on the fuels and technologies that will keep our lights on for the next 50 years.

Given the consequences of a wrong decision, it is easy to see why the power industry continues to embrace natural gas as a fuel of choice for new-build generation. Information technology (IT) professionals used to say no one ever got fired for buying equipment from IBM. Highly uncertain times in the power business have made natural gas the new IBM — prominent, established, trusted and ubiquitous. TI

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