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SPECIAL REPORT

CLIMATE CHANGE

The Battle Heats Up (p. 12)

Corporate Bonds Sprout Green Shoots

Why The U.S. Clean Power Plan Is Controversial

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COVER IMAGE: MARIA STENZEL/NATIONAL GEOGRAPHIC MAGAZINES/GETTY IMAGES

There is a general global consensus on the need for investment in clean energy, and the cost of key renewable technologies, including photovoltaic solar and onshore wind generation, continues to decline. This is helping to create steady—and in some markets, substantial—investment in new renewable energy projects. In the U.K., for example, the government recently awarded contracts worth US$485.8 million to 27 clean energy projects.

The current low price of crude oil and natural gas is unlikely to have a widespread impact on the credit quality of global project finance debt over the next year to 18 months. However, if prices remain in the US$50 per barrel range for a sustained period or fall further than we expect, the outlook may prove problematic for projects with refinancing risk, market exposure, or input prices.

Countries And Companies Are Taking Steps To Counter Climate Change And Natural Catastrophes

Overview

- Climate change could prove costly for economies around the world.
- Credit ratings could be affected as natural catastrophes and sea levels increase.
- Sovereigns, local governments, and businesses are looking for ways to deal with climate change, including increased use of renewable energy sources.

With near-unanimity in the scientific community about the realities of global climate change, a number of countries and companies are taking steps to address the potential ramifications they face. Simply put, the accumulation of greenhouse gases in the atmosphere, if allowed to continue unabated, will likely have extensive and costly effects on regional climates and economies around the world.

Among the most imminent—and identifiable—dangers of unchecked climate change is the potential for natural catastrophes. And while such events haven't often been a factor in negative ratings actions on borrowers we rate, we expect the effects that catastrophes will have on corporate credit quality to increase substantially if, as the evidence suggests, we suffer more frequent and extreme events. In such a scenario, corporate borrowers' insurance coverage and overall disaster-risk management could, in Standard & Poor's Ratings Services' view, become considerably less effective than it is now.

To be sure, fewer than 1% of the approximately 6,300 negative rating actions (downgrades and outlook revisions to negative) we've taken on companies around the world since 2005 have had natural catastrophes such as tropical storms, droughts, and earthquakes as the main or material factor. And while our sample is too small to draw clear conclusions, natural catastrophes can certainly result in companies' suffering property losses and disruptions in production.

Hurricane Katrina in the southeastern U.S. in 2005 and the 2011 earthquake and tsunami in the Tohoku region of Japan are the two biggest natural catastrophes of recent years, and are responsible for triggering almost one-half of the rating actions in which catastrophes were a factor. The effects of Katrina, in particular, were wide-ranging, from large direct losses to major supply-chain disruptions and price increases in a number of industries. While no sector is immune, the energy and consumer products sectors seem to be the most exposed—the former through direct effects on production and distribution, the latter through supply chain and market disruptions.

Credit Markets Go Green

In the meantime, as corporate borrowers take steps to shield protect themselves from such catastrophes, they've also become a driving force in the market for so-called green bonds—instruments used to fund environmentally friendly endeavors such as renewable energy and other projects designed to combat climate change.

Borrowers as diverse as Toyota, Unilever, and Thai oil company Bangchak Petroleum PLC have sold green bonds, and the market got a shot in the arm in March of this year when Danish wind turbine manufacturer Vestas issued a seven-year €500 million bond. This marked the first green bond of the year in the European corporate credit markets, and it's the first corporate green bond sold by a company dedicated exclusively to wind energy.

This asset class has enjoyed dramatic growth, and we expect this to continue. Based on current trends, we estimate that issuance of corporate green bonds could reach $30 billion this year, exceeding by nearly half the $19.1 billion companies raised since the market emerged at the beginning of last year *(see "Corporate Bond Market Shows Its Green Shoots," on p. 16)*. In total, the Climate Bonds Initiative, a London-based non-profit group, has said total green bond issuance—not just from corporate borrowers—has a "good chance" of reaching $100 billion in 2015, in what would be a near tripling of the amount investors snapped up last year.

With several promising areas for growth—including corporate and municipal borrowers—perhaps the biggest driver could be China, where the green bond market could grow substantially as Beijing steps up its antipollution drive and investment in renewable energy. The country now boasts the world's third-largest bond market, and about $7.8 billion in outstanding Chinese corporate bonds is linked to green themes, according to the Climate Bonds Initiative.

Revving Up Renewables

This comes amid greater global consensus on the need for investment in clean energy—a trend that has helped to bring down the cost of key renewable-energy technologies, and has thus whetted investors' appetites for such projects *(see "Standard & Poor's Approach To Rating Renewable Energy Project Finance Transactions," on p. 40)*. Globally, investments in renewable energy rebounded strongly in 2014 after two years of declines, jumping 17%, to $270 billion, according to the U.N. Environment Programme and Bloomberg New Energy Finance. The International Energy Agency, meanwhile, projects that global renewable electricity generation will increase by almost 45% by 2020, with much of the expansion in solar.

This comes as countries around the world begin to assess, and address, the economic effects of climate change. In the U.S., for example, we estimate the cost to the world's largest economy of doing nothing to be between 2.2% and 5.2% of GDP by 2100. This is more or less in line with a 2000 study by Yale University economics professor William Nordhaus and research associate Joseph Boyer, who estimated that the dire scenario of an average global temperature rise of about 11 degrees Fahrenheit by the end of the century would result in damages amounting to about 5% of U.S. economic output—and about 10% of global GDP, given substantially larger losses in a number of other countries.

That said, it's difficult to assess any potential damage because the U.S. is too diverse—geographically, socially, and economically—to truly calculate any sort of average effects. In other words, so much of the impact of climate change will be regional that it isn't easy to come up with a headline number to what it will cost the U.S. as a whole. In the Northeast, for example, rising sea levels and the possibility of Hurricane Sandy-like storm surges would threaten infrastructure that is already in desperate need of refurbishment. Meanwhile, in the Southeast, more than one-third of residents live in counties along the coast, and one-third of GDP comes from those areas—meaning that if significant coastal acreage were to slip into the sea, there would be an outsize effect on the economies of that region, through the loss of arable land, the disappearance of tourist areas, and the destruction of property.

And while we think the dangers associated with rising sea levels are unlikely be a significant ratings factor in the next five years or so, the failure of states and municipalities to prepare could leave them struggling to protect large investments in seaside infrastructure. It seems clear that rising sea levels, in conjunction with population growth, could prove catastrophic if state and local governments don't invest in the necessary infrastructure along the coast.

Perhaps the best example of this is in Florida, the most populous state in the southeastern U.S. and one of the fastest-growing states in the country. A sea level rise of 7.8 inches from 2005 to 2050 in Florida's Tampa-St. Petersburg area would boost average annual losses there to $3 billion, from $763 million (in constant 2005 dollars), according to a World Bank estimate. Under the same conditions, losses in Miami would rise to $7.3 billion, from $2.1 billion. To temper such losses, local and state authorities must prepare while there is enough time to do so.

A Long Row To Hoe

Achieving the sorts of reductions in greenhouse gases that could help to stem climate change would largely mean a migration of developed economies—including the U.S.—away from fossil fuels toward a reliance on nuclear and renewable energy. Naturally, this would come at a cost, depending on the particular measures employed. To take just one example, the Congressional Budget Office concluded that under the cap-and-trade system proposed in the American Clean Energy and Security Act of 2009—which the House passed but the Senate defeated—a 50% reduction in emissions by 2050 would have trimmed about 0.25% to 0.75% from U.S. real GDP in 2020, and 1% to 3.5% in 2050. But that didn't factor in the potential economic benefits of averting or mitigating climate change.

Meanwhile, President Obama announced in June of last year the Environmental Protection Agency's Clean Power Plan—the first federal initiative designed to reduce carbon output in the country. Whether the power industry is either eagerly anticipating the plan or bracing for the effects may be a matter of perspective. One thing opponents and advocates agree on is that the scope and substance of the rule exceeds anything done at the state or local levels so far.

At the very least, the plan promises to transform energy markets and companies of varying types—including those in generation, transmission, distribution, storage, etc. In the longer term, it's possible the plan could bring on a new era of regulation in the power industry, with the U.S. at the forefront of a worldwide effort to curb carbon emissions and turn back climate change. **cw**

For more articles on this topic search RatingsDirect with keyword:

Climate Change

Analytical Contacts:

Michael Wilkins
London (44) 20-7176-3528

Beth Ann Bovino
New York (1) 212-438-1652

Corporate Bond Market Shows Its Green Shoots

Overview

- Green bonds aimed at funding environmentally friendly investments more than tripled in issuance in 2014, to $36.6 billion.
- Corporate issuers have contributed greatly to the green bond market's expansion, though multilateral investment banks still lead in issuance.
- In particular, the Chinese corporate green bond market has the potential to experience substantial growth in coming months.
- Green bonds carry the same investor protections as regular bonds. Most green bonds now have investment-grade ratings, and investors aren't paying a premium for them.

Green bonds—one of a number of new issue trends to hit the capital markets—got a lift on March 11, 2015. That's when Danish wind turbine manufacturer Vestas issued a seven-year €500 million bond in a bid to diversify its funding base by taking advantage of the rising investor interest in green bonds. The Vestas issue marks the first green bond of the year for the European corporate bond market, and it's the first corporate green bond issued by a company dedicated exclusively to wind energy.

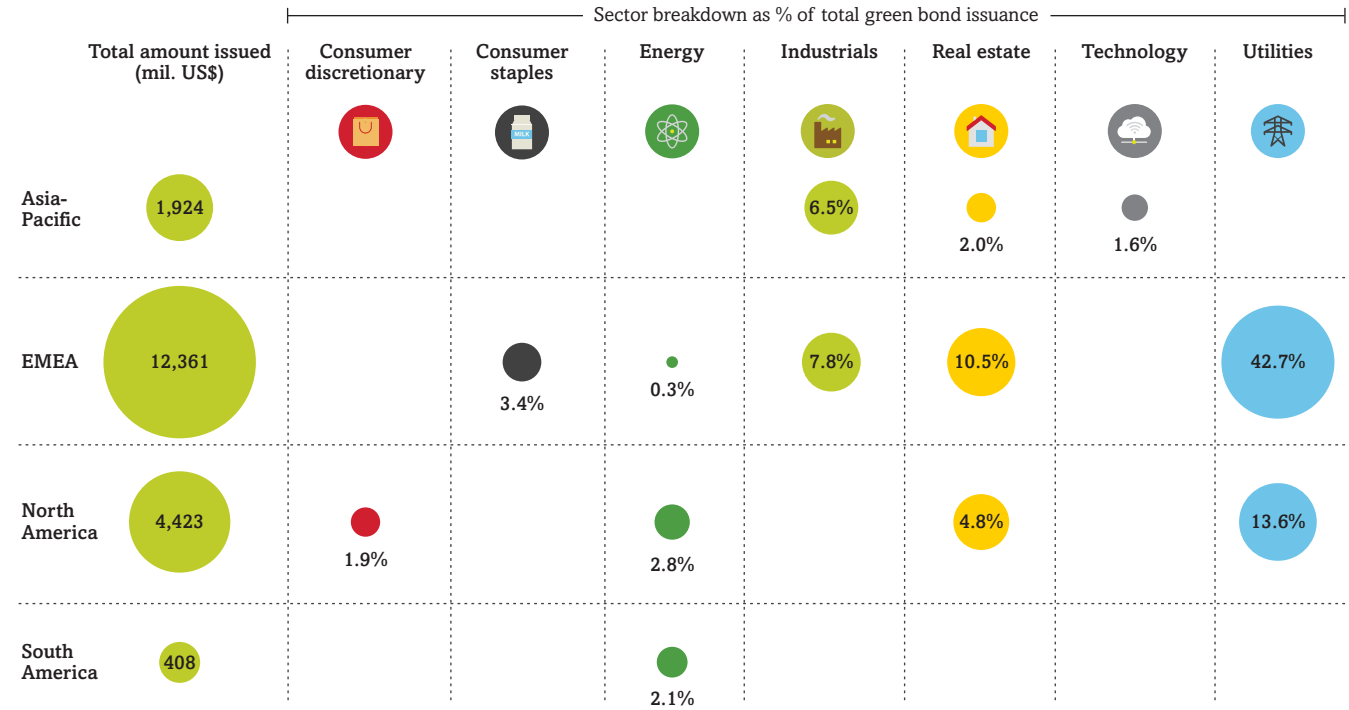
Green bonds are a new financing instrument aimed at funding a wide range of environmentally friendly investments. As an emerging asset class, they experienced dramatic growth in 2014, and expectations for 2015 remain equally healthy. Based on current trends, Standard & Poor's Ratings Services estimates corporate green bond issuance in 2015 could reach up to $30 billion, a near 50% increase on the $19.1 billion raised since the market sprung to life at the beginning of last year *(see "The Greening Of The Corporate Bond Market," published May 20, 2014, on RatingsDirect)*. In total, the Climate Bonds Initiative, a nonprofit group based in London, believes green bond issuance—not just from corporates—is likely to hit $50 billion with a "good chance" of getting to $100 billion. This compares to a tripling of the market to $36.6 billion last year *(see chart 1)*. Several promising areas for growth include further issuance from the corporate sector and from municipal bond issuers. The real game changer, however, could be when China enters the green bond market in full force.

Corporate issuers have been a driving force in the strong growth of green bond issuance over the past 18 months. Borrowers range from companies as diverse as Toyota, Unilever, Stockland (Australia's biggest real estate trust), ASE (Taiwan's technology firm), and Bangkchak Petroleum (Thai oil company). Then there's China.

The Chinese green bond market could grow substantially over the next 12 months as Beijing steps up its antipollution drive and investment in renewable energy. The municipal bond market is also accelerating. The German State of North Rhine-Westphalia (NRW) issued a "sustainability" bond this month, known as the Nachhaltigkeitsanleihe. Due to the bond's popularity with investors, NRW increased the issue by 50%, from €500 million ($569 million) to €750 million.

Green bond issuance in 2014 comprised 44% of multilateral bank issuance, 38% of corporate issuance, and 13% of municipal issuance *(see chart 2)*. The increase in the green bond market brings the total out-

Corporate Green Bond Issuance 2014 To 2015



Data as of March 12, 2015. EMEA–Europe, the Middle East, and Africa.
Source: Standard & Poor's.

standing number to $53.2 billion as of the end of 2014 *(see table)*, according to the Climate Bonds Initiative.

Corporate Green Issuance Adds Depth And Liquidity To The Market

Corporate green bonds have helped create depth in the green fixed-income market, which multilateral investment banks have so far dominated. Not only have corporates introduced scale, but they have also offered a range of currencies, geographic locations, and maturities—all great for liquidity in the market.

While a broad range of corporate sectors were represented, issuance remains dominated by utilities and real estate companies. Utilities and power generation accounted for about 17% of total green bond issuance by volume, the largest in the nonfinancial sector. The second-largest sector in volume terms is real estate. These companies have raised funds generally for upgrading buildings to various environmental and energy efficiency standards.

As well as the €500 million issue from Vestas, we recently saw the world's first green bond from an oil company, which came out of Thailand. State-owned

Utilities Lead The Way In Issuing Corporate Green Bonds In 2004 To 2015

All figures in U.S. dollars

The utilities sector issued a total of 56.3% or $10.77 bil.

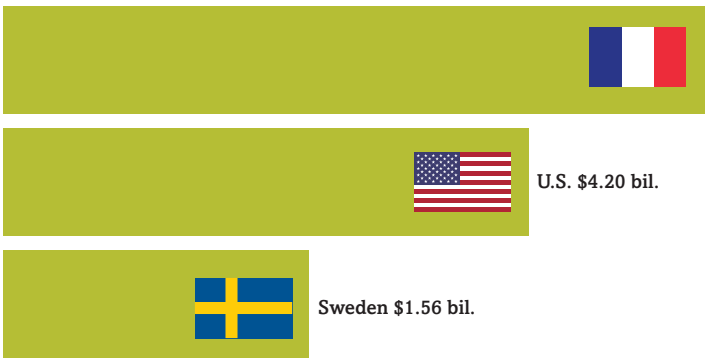
The real estate sector issued a total of 17% or $3.29 bil.

The industrials sector issued a total of 14.3% or $2.74 bil.

Data as of March 12, 2015.
Source: Standard & Poor's.

France Holds The Top Spot For Corporate Green Bond Issuance

All figures in U.S. dollars



Data as of March 12, 2015.
Source: Standard & Poor's.

Corporate Green Bond Issuance In EMEA Alone Accounts For 65% Of The Total Amount Issued Globally

All figures in U.S. dollars

*Includes North America, South America, and Asia-Pacific. Data as of March 12, 2015. EMEA—Europe, the Middle East, and Africa.
Source: Standard & Poor's.

Bangkchak Petroleum issued a Thai baht billion ($93 million) green bond to help it expand its operations in renewable and clean energy. In July last year, Taiwan's ASE became the first technology firm to issue green bonds, which also marked the first corporate green bond from Asia.

Issuance to date has been met with healthy investor demand, although it is worth noting that 2014 was a year of very strong bond issuance overall. Corporate green bond issues tend to behave similarly in yield performance to the other bonds of corporate issuers, even though there is lower liquidity in the green bond market.

China's Green Bond Market Could Be The Game Changer

The corporate green bond market has the potential to experience substantial growth in China in the coming months. First, dealing with environmental issues looms high on the Chinese government's agenda. Second, the government has a strong incentive to develop a bond market and encourage corporations to raise funds by bond issuance, which would help to diversify credit risk now concentrated in the banking system.

China's bond market is now the world's third-largest at about Chinese renminbi 24.61 trillion, or about US$3.97 trillion.

Corporate Green Bond Issuance To March 13, 2015

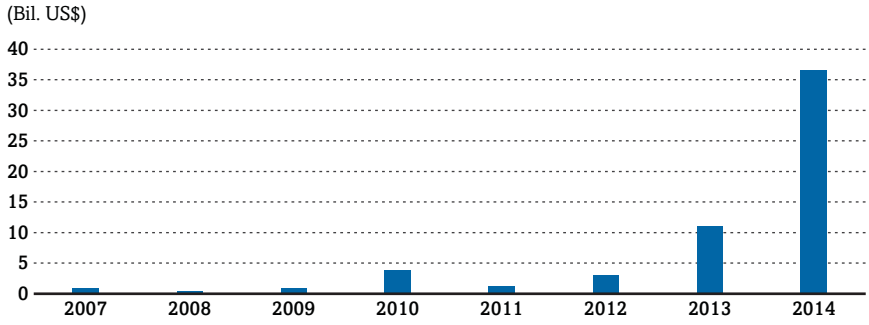
Issuer name	Coupon (%)	Maturity date	Amount issued ($)*	Price at issue ($)	Issuer rating	Sector
Vasakronan AB	0.342	5/25/2016	152,272,000	100	NR	Real estate
Vasakronan AB	1.774	5/25/2016	45,681,600	100	NR	Real estate
Electricite de France SA	2.25	4/27/2021	1,899,840,000	99.561	A+	Utilities
Unibail-Rodamco SE	2.5	2/26/2024	1,025,360,000	98.723	A	Real estate
Vasakronan AB	0.925	3/19/2019	102,283,000	N/A	NR	Real estate
Vasakronan AB	2.473	3/19/2019	55,075,600	N/A	NR	Real estate
Unilever PLC	2	12/19/2018	414,200,000	99.675	A+	Consumer staples
Svenska Cellulosa AB SCA	0.945	4/2/2019	154,240,000	100	A-	Consumer staples
Svenska Cellulosa AB SCA	2.5	4/2/2019	77,120,000	100	A-	Consumer staples
Skanska Financial Services AB	1.216	4/8/2019	130,886,000	100	NR	Industrials
Iberdrola International BV	2.5	10/24/2022	1,036,770,000	99.72	NR	Utilities
Vasakronan AB	0.531	10/24/2016	152,158,000	N/A	NR	Real estate
Acciona SA	5.55	4/29/2024	86,596,500	100	NR	Industrials
Arise AB	3.181	4/25/2019	167,087,000	100	NR	Utilities
Enna Energia SRL	5	5/16/2019	4,384,620	100	NR	Energy
Regency Centers LP	3.75	6/15/2024	250,000,000	99.482	BBB	Real estate
GDF Suez	1.375	5/19/2020	1,645,140,000	99.345	A	Utilities
GDF Suez	2.375	5/19/2026	1,782,230,000	98.494	A	Utilities
Rikshem AB	0.171	5/20/2016	15,171,700	100	A-	Real estate
Toyota	0.41	8/15/2016	560,000,000	99.999	AAA	Industrials
Toyota	0.67	12/15/2017	480,000,000	99.982	AAA	Industrials
Toyota	1.18	6/17/2019	165,250,000	99.987	AAA	Industrials
Toyota	0	4/15/2020	43,750,000	N/A	AAA	Industrials
Rodamco Sverige AB	0.798	6/3/2019	97,289,400	100	NR	Real estate
Rodamco Sverige AB	2.25	6/3/2019	127,225,000	99.906	NR	Real estate
Vornado Realty LP	2.5	6/30/2019	450,000,000	99.619	BBB+	Real estate
THP Partnership	4.394	10/31/2046	217,066,000	100	NR	Real estate
Hera SpA	2.375	7/4/2024	679,633,000	99.464	BBB	Utilities
Anstock II Ltd	2.125	7/24/2017	300,000,000	99.723	NR	Technology
NRG Yield Operating LLC	5.375	8/15/2024	500,000,000	100	NR	Utilities
NRG Yield Operating LLC	5.375	8/15/2024	500,000,000	100	NR	Utilities

Banks are the dominant Chinese investors, with a 75% market share at the end of 2011 (ADB, 2013). In March 2014, the Ministry of Environment announced a plan to integrate environmental benchmarks into credit scoring for companies in industries with heavy pollution or overcapacity. These scores will be based on their efforts to protect the environment and could directly lead to more green bond issuance.

Approximately $7.8 billion in outstanding Chinese corporate bonds are linked to green themes, according to the Climate Bonds Initiative. Many of these are high-yield notes or convertible bonds issued by solar photovoltaic and wind turbine manufacturers. These are by no means the largest or most important corporations active in China's green sectors, but they are the only ones whose proceeds are clearly linked with environmental projects. State-owned companies, large private corporations, and small and midsize enterprises are active in deploying environmental technologies and processes that may be recognized and supported through green bonds.

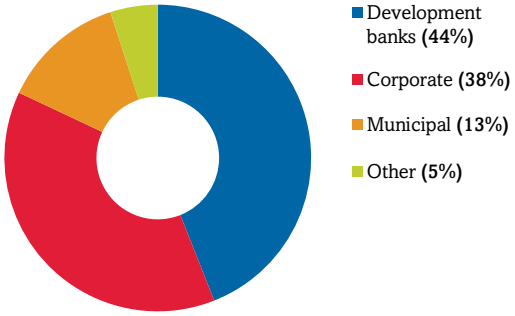
Also noticeably, the International Finance Corporation (IFC) issued a 500 million renminbi-denominated green bond (approximately $80.29 million) in June 2014 whose funds will be used to support climate-friendly investments in emerging markets. The bond is listed on the London Stock Exchange and sets a precedent as the first green bond issued by a multilateral institution offshore in Chinese currency.

Chart 1 | Green Bond Issuance By Year



Source: Climate Bonds Initiative.

Chart 2 | 2014 Green Bonds By Issuer Type



Source: Climate Bonds Initiative.

Low Oil Prices Could Test The Green Bond Market

This year may represent a test for the viability and durability of the green bond concept, given recent developments in energy markets, not to mention emerging markets. Are the fast-growing green bonds simply a product of exceptionally benign weather conditions in capital markets? Would the growth of exotic products such as green bonds stall if there is a market correction?

A recent Bank of America Merrill Lynch note argued that green bond prices were not only similar to non-green bonds but they were also "less volatile than counterparts, which may be driven by their perceived safety and longer-term investor base with lower churn rates." Apparently, green bond owners are likely to be long-term investors holding them to maturity. This is because a significant proportion of green bond investors are signatories to the Principles of Responsible Investment and have mandates to buy and hold a certain proportion of green assets in their portfolios.

Another question is whether green bonds will wither as oil prices tumble, making alternative energy investments less appealing. We believe chances are good that the market's strong growth could continue even with lower oil prices. Oil price movements, in our view, will have less of an impact on renewables than many fear due to the longevity of climate change as an investment driver relative to the short-term fluctuations in commodity prices. Moreover, green bonds don't just raise funds for renewable energy projects, they're also used to tackle pollution. Socially responsible investing also covers

housing, education, and water projects that oil prices don't affect.

At the moment, green bonds are priced based on the corporate credit of the bond issuers and investors are not paying a premium for their environmental integrity, which is not seen as an investment benchmark yet.

High-Yield Issuers Are Testing The Water

Green bonds carry the same investor protections as regular bonds. Most green bonds also have investment-grade ratings, although some speculative-grade corporates tapped into the green bond demand last year.

Three high-yield green bonds have been issued so far: Abengoa Greenfield (which Standard & Poor's rates 'B'), NRG Yield, and TerraForm Power. Altogether, these three companies issued $2 billion equivalent in aggregate principal amount.

According to the Green Bond Principles, there are four types of green bonds, including green use of proceeds bonds, green use of proceeds revenue bonds, green project bonds, and green securitized bonds. The green-use-of-proceeds category is the only one that high-yield issuers have adopted so far, and in general, high-yield bonds provide recourse to all of the assets of the issuer and guarantors, rather than recourse only to certain projects or contracts.

And the existing high-yield green bonds already incorporate the green-use-of-proceeds concept of "eligible green

Corporate Green Bond Issuance To March 13, 2015 (continued)

Issuer name	Coupon (%)	Maturity date	Amount issued ($)*	Price at issue ($)	Issuer rating	Sector
Arise AB	6.059	9/8/2017	49,313,100	100	NR	Utilities
Massachusetts Institute of Technology	3.959	7/1/2038	370,000,000	100	NR	Consumer discretionary
Abengoa Greenfield SA	5.5	10/1/2019	334,662,000	100	NR	Industrials
Abengoa Greenfield SA	6.5	10/1/2019	300,000,000	100	NR	Industrials
Abengoa Greenfield SA	6.5	10/1/2019	300,000,000	100	NR	Industrials
Abengoa Greenfield SA	5.5	10/1/2019	334,662,000	100	NR	Industrials
BKK AS	2.05	10/6/2021	169,036,000	100	NR	Utilities
Fastighets AB Forvaltaren	0.71	10/10/2019	55,375,600	N/A	AA-	Real estate
Innovatec SpA	8.125	10/21/2020	12,733,100	N/A	NR	Energy
Stockland Trust Management Ltd	1.5	11/3/2021	374,561,000	99.618	A-	Real estate
Nord-Troendelag Elektrisitetsverk Holding AS	2.19	11/12/2021	14,719,500	N/A	NR	Utilities
Nord-Troendelag Elektrisitetsverk Holding AS	2.07	11/13/2019	58,950,100	N/A	NR	Utilities
Nord-Troendelag Elektrisitetsverk Holding AS	1.88	11/13/2017	36,843,800	N/A	NR	Utilities
Vasakronan AB	0.513	11/18/2019	67,902,500	N/A	NR	Real estate
Verbund AG	1.5	11/20/2024	626,940,000	98.437	BBB+	Utilities
Rikshem AB	0.178	12/2/2016	26,607,100	N/A	A-	Real estate
Rikshem AB	0.274	6/5/2017	33,100,700	N/A	A-	Real estate
Vardar AS	3.8	12/11/2019	41,233,100	100	NR	Energy
Energia Eolica SA	6	8/30/2034	204,000,000	98.344	NR	Energy
Energia Eolica SA	6	8/30/2034	204,000,000	98.344	NR	Energy
TerraForm Power Operating LLC	5.875	2/1/2023	800,000,000	99.214	NR	Utilities
TerraForm Power Operating LLC	5.875	2/1/2023	800,000,000	99.214	NR	Utilities
Vasakronan AB	0.37	2/20/2018	47,827,400	N/A	NR	Real estate
Vestas Wind System A/S	2.75	3/11/2022	535,960,000	N/A	NR	Energy

*Exchange rate as of each issue date. N/A—Not applicable. NR—Not rated.
Source: Bloomberg Professional.

projects," despite the continuing debate around the meaning of green. Each of Abengoa Greenfield, NRG Yield, and TerraForm Power promised to use the proceeds of their issuances for eligible green projects in general, with the use of proceeds for the NRG Yield and TerraForm Power green bonds tied to the acquisition of wind power companies.

Green Standards Are Taking Root

The surge in green bond sales represents growing demand among bond buyers for green investments amid concerns about climate change. But it also highlights one major challenge facing the nascent market: What should qualify as an environmentally friendly project?

If everybody wants to be associated with being green, it raises the danger that the value of green bonds may get diluted by "greenwashing." Transparency for this developing market requires clear definitions and disclosure of how proceeds are used and how projects are managed.

In fact, the market has been making efforts at standardization. For example, since the Green Bond Principles (GBP) were produced in January last year, 77 members and 35 observers have joined. These institutions worked over the past year to improve the GBPs, and they expect to produce an updated version at the end of first-quarter 2015. Some issuers have also said they plan to report regularly to investors about how green bond proceeds are being used. More recently, the Investor Network on Climate Risk drafted a new set of guidelines for green bond issuers in February 2015. The group comprises 27 institutional investors, including pension funds, insurance companies, and asset managers.

The aim of issuers and investors alike is to have commonly agreed standards on what counts as a green bond, with sufficient transparency and monitoring to ensure funds are not misused. The emphasis is likely to remain on investors checking exactly what they are buying.

Project Bonds Offer A Deeper Shade Of Green

Among supranational organizations, green bonds have now become part of the normal funding landscape. However, among corporates, they're still a new product, and not all corporations that are eligible have decided to tap the market. That's partly because financing climate change mitigation is not part of the mandates of corporates. Also, the current market is fairly small, and a more liquid market, diversified with private placements, is yet to be developed in order for more issuers and investors to step in.

Green labeling in the corporate arena currently applies only to the category of green-use-of-proceeds bonds, which have developed around the idea of flat pricing. That is, the credit profile of green bonds is the same as vanilla bonds, reflecting the balance-sheet strength of the issuer. This deviates from green project bonds, which fund clean-energy projects and infrastructure via nonrecourse asset financing structures. Such structures link revenue and cash flow to the asset being financed and are already commonly adopted in wind, solar, and hydro power, energy efficiency, and other clean-energy projects, with cash flows from such assets acting as the primary source of bond repayments. Such assets often have long economic lives, with cash flows supported by long-term offtake contracts with strong counterparties. These asset characteristics have the potential to meet the financial objectives of institutional investors, while also providing environmental benefits.

S&P Dow Jones Indices has created a Green Bond Index and a Green Project Bond Index to capture both areas. Over time, we may see an opportunity for these two groups to converge, as the green fixed-income market increasingly evolves and focuses more on bonds backed by the credit of environmental projects rather than the corporate creditworthiness of the issuer. This convergence, in our view, would necessitate close scrutiny of the projects to ensure they meet credentials related to both creditworthiness as well as greenness. **cw**

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Green Shoots

Analytical Contacts:

Michael Wilkins
London (44) 20-7176-3528

Taron Wade
London (44) 20-7176-3661

Lawrence Lu, CFA
Hong Kong (852) 2533-3517

The U.S.'s Clean Power Plan, Rife With Controversy, Seeks To Battle Climate Change

Overview

- Climate change has remained highly controversial and politically incendiary in the U.S.
- The Clean Power Plan, which aims to fight climate change, is ambitious and, as expected, just as controversial.
- States are looking at various ways they can comply with the plan.
- The U.S. promises to be an active player in U.N. Climate Change discussions later this year.

When a youthful Senator Barack Obama announced his bid for the presidency eight years ago, he did so on a platform of sweeping change. One key issue on his platform was the environment, and, within two years of his inauguration, a comprehensive environmental plan, including a carbon "cap and trade" provision and sweeping renewable incentives, reached Congress.

But upon its failure, federal progress on environmental reform, especially regarding the power sector, stalled somewhat. During the next few years, however, that could all be changing.

In June 2014, a somewhat more aged President Obama announced the Environmental Protection Agency's (EPA) Clean Power Plan, the first federal initiative designed to reduce carbon in the U.S., and already, it's clear that the power industry is either eagerly anticipating or bracing for a considerable impact, depending on their perspective. Opponents and advocates have been vocal so far, but all seem to agree that the scope and substance of this plan exceeds anything done on state or local levels to date.

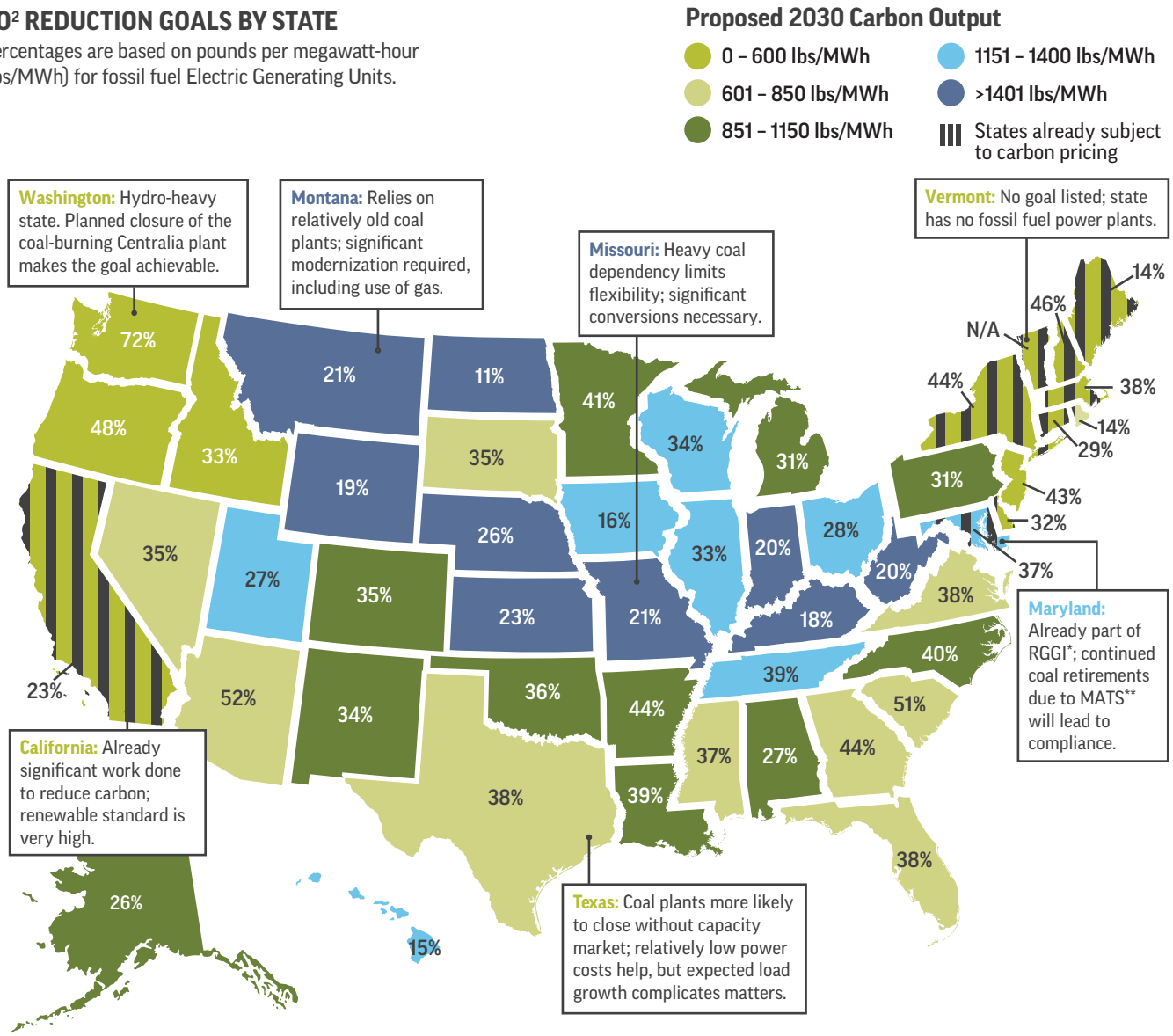
Although it won't be finalized until Summer 2015, with State Implementation Plans due in 2016 and 2017, controversy has already started swirling and the market has taken notice.

A STATE-BY-STATE LOOK AT THE IMPACT OF THE EPA'S CLEAN POWER PLAN

The plan assigns each state a carbon reduction goal, but the degree and complexity vary significantly. In general, those states that have already made strides in carbon reduction have more achievable goals. But most states will have to rely on renewables, demand-side management, and coal retirements to meet targets.

CO^2 REDUCTION GOALS BY STATE

Percentages are based on pounds per megawatt-hour (lbs/MWh) for fossil fuel Electric Generating Units.



At the very least, this plan, once finalized, promises to transform the energy market and, therefore, energy-related issuers of different types (generation, transmission, distribution, storage, energy efficiency, etc.) may face credit implications.

But longer term, it's possible that this federal plan could usher in a new era of power industry regulation in the U.S., one with sweeping effects, and one that results in the U.S. demonstrating considerable leadership in worldwide efforts to reduce carbon emissions and forestall climate change.

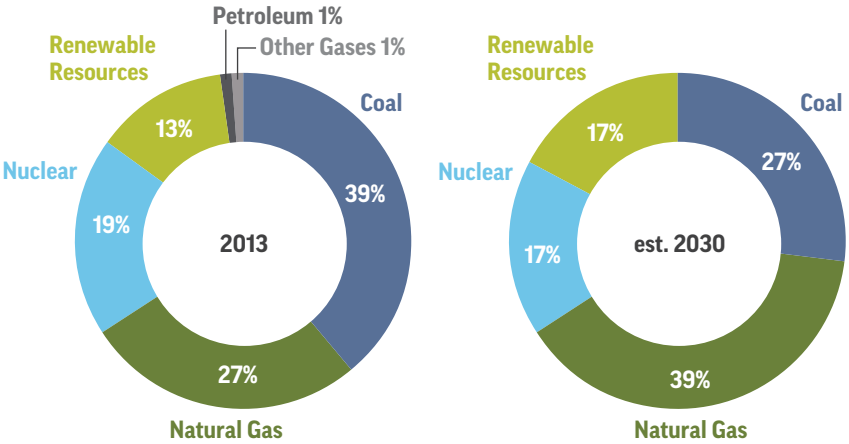
Importantly, nothing is finalized, and everything in the rule is speculative until the EPA sifts through all 3.5 million comments, presumably sometime later this year. But, after that, the changes in the industry could appear sooner rather than later, as participants seek to identify new opportunities and avoid the pitfalls of inaction.

TOTAL COAL CAPACITY RETIRED BY 2030 IN GIGAWATTS

While coal-fired generation had weakened due to the shale boom, the plan should accelerate the shift toward gas-fired generation, especially in areas with aggressive goals.

U.S. POWER GENERATION BY ENERGY SOURCE

The generation profile of the U.S. is in flux; though coal is the dominant fuel source now, its share will drop by more than 25% by 2025.



OVERALL CO^2 REDUCTION

Carbon emissions have already dropped due to a weak economy and state regulations, but a further 19% drop is likely by 2030.

*RGGI: The Regional Greenhouse Gas Initiative. **MATS: Mercury and Air Toxics Standards
Source: EPA, EIA, and Standard & Poor's Ratings Services.

The Controversies

For several reasons, climate change has remained highly controversial and politically incendiary in the U.S. during much of the past decade, so it continues to be a laggard rather than a leader in environmental regulation. Certainly, creating a political consensus on anthropogenic climate change has been enough of a challenge, even with the scientific debate settled long ago. But even beyond historic disagreements over the science, the politics of a coordinated fight against climate change, particularly funding new approaches, are inherently challenging.

Any legislation to remediate climate symptoms would inherently mean a budgetary shift, and given that this could happen largely along ideological lines, it's very likely that there would be significant, and, perhaps, prohibitive dissent. This is accentuated by politicians' inability to fully articulate the tangible benefits of remediation. One major hurdle to overcome is the socialization of funding the changes. Should the costs be borne upfront or spread over time? And, if the recent response to the rule is any indication, it seems that an executive action is less appealing still, with claims that the president is overstepping his constitutional authority (even if the Supreme Court has disagreed with this interpretation in previous rules).

The Clean Power Plan has certainly introduced new concerns in the climate action debate.

Too expensive?

The first, and perhaps loudest, complaint is that the plan will soon become untenably expensive, based partially on previous carbon abatement mechanisms. Despite the significant price decline of renewables in recent years, these can still be expensive to add to the grid because, depending on type, they may require complementary peaking capacity to ensure reliability. And while natural gas has dropped significantly in price

and promises to remain cheap for the foreseeable future, coal plants, at least at the base-load end of the dispatch curve, are still often more economical on a per-megawatt basis, even if their fixed costs are somewhat higher; furthermore, the plan may require additional transmission infrastructure.

Under the Clean Power Plan, in our estimation, coal will drop to 27% of American generation by 2026 from its current level of about 39% if the plan is finalized as is. Some coal assets that are closing would still have "stranded" costs associated with their closure that would have to be accounted for in some manner. But, these costs could well be defrayed by reliance on energy efficiency, which could depress demand and weaken prices, although critics contend that these measures may fail to take hold.

The second major concern with the Clean Power Plan is that it could, in the short term, damage economies in certain parts of the country…

Will it damage state or regional economies?

The second major concern with the Clean Power Plan is that it could, in the short term, damage economies in certain parts of the country—namely, those where coal is king. In these regions, not only does coal presently provide a cheap and reliable source of power, but extracting and transporting coal also may sustain other parts of the economy. An abrupt closure of coal plants and related infrastructure would likely hurt employment rates and local prosperity. Expectedly, local politicians in some of these areas are among the most vocal opponents of the rule, and some are even encouraging their states to simply not attempt compliance. To these actors, it may seem that the possible penalties associated with compliance are actually less severe than the economic consequences of switching to gas from coal, and, certainly, the political price tag is less. For those states that see the plan as a near-term economic benefit, they are interested in whether there will be credit for early action.

Too much uncertainty?

The third concern is the inherent uncertainty that the plan creates. If the implementations of other emissions-control plans such as the Mercury And Air Toxics Standards, Cross-State Air Pollution Rule, and National Ambient Air Quality Standards are any indication, we don't yet know for sure when this rule will ultimately come into effect, or what it will look like when it does. Accordingly, the necessary planning work and time for business to adapt is constrained. This prevents businesses, especially the capital- and labor-intensive ones in the power industry, from being able to adequately prepare for the new realities they'll have to confront when the rule is in effect, while still remaining economically competitive in the years before the rule. That said, many large utilities, generators, and midstream energy entities such as pipelines are actually perceiving this rule as an opportunity.

What about grid reliability?

The final issue is that of reliability. A new generating framework that relies heavily on intermittent renewables like wind and solar may weaken the grid's ability to handle peak loads. The great strength of coal and gas generation has been grid stability. Intermittent renewables continue to require significant complementary capacity in the absence of economical energy storage. Although there are many regions of the world with periods of high renewable power supply, these to varying degrees continue to rely on some form of thermal back-up. Accordingly, until the likely generation mix under the Clean Power Plan is understood and how this will evolve is understood, it's hard to get a solid understanding of what adequate reserve margins will be required. Without adding renewables to the mix, there are already reliability issues in the U.S., which could be accentuated by the plan, especially in the Electric Reliability Council of Texas (ERCOT) or the Southwest Power Pool markets, where we expect as many as 8.7 gigawatts and 9 gigawatts of coal plant closures, respectively. Furthermore, as the Polar Vortex of early 2014 laid bare, the gas infrastructure in the U.S. may not yet be in place in parts of the country to ensure reliability when supply is constrained. Most industry participants who cite reliability as a concern are wary that the interim goals, which begin early next decade, could be unachievable if they are to maintain reliability, because compliance would seem to rely on running gas plants at capacity factors exceeding designed rates, which could lead to unforeseen outages.

The States Respond

The rule may not yet be final, but that hasn't stopped key parties from discussing possible strategies for compliance. The plan's original draft specifies four building blocks *(see table 1)*, and we expect a three-pronged approach to satisfy these criteria and ultimately comply with the rule.

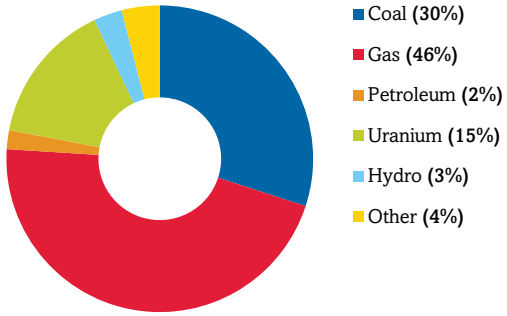
In early discussions, it appears that this rule may reinvigorate the concept of carbon allowance trading as a means for compliance. Certainly, California and the New England states have had success in reducing the carbon footprint by promoting carbon-friendly generation. And, with challenging goals ahead, states probably can't rely exclusively on renewables or on the generators' good faith. But if the aforementioned examples are any indication, scale is of great importance, and we expect that states, especially those with common social and economic interests, will create regional alliances. As such, it seems logical that existing exchanges for carbon allowances could grow in size to encompass new states, thereby improving liquidity, lowering costs, and enhancing system reliability. In all likelihood, states with considerable populations and significant burdens for carbon reduction, such as Illinois or Texas, would probably lean heavily on such a strategy,

especially if they can improve their scale by adding other states.

Next, we expect that renewable portfolio standards will be increased in the states in which they already exist, and perhaps be introduced where they haven't existed before. The rationale for this is apparent enough. First, the cost of installing renewables has dropped dramatically in the past decade, to the point where, in some instances, it is approaching grid parity. The recently signed utility-scale solar power purchase agreement by Austin, Texas at 5 cents per kilowatt-hour is an unprecedented low for photovoltaic solar and, at this price, is competitive with gas turbine projects. Besides the reliability and affordability concern, there are other macroeconomic reasons. Certain states still rely quite heavily on coal, but not just as a means of ensuring cheap power. In parts of Appalachia and beyond, coal may be the economy's lifeblood; greater incentives for zero-carbon renewables could allow states to comply with carbon reduction goals while forestalling coal plant closures, which would be severely unpopular in that part of the country. States that have limited ability to switch en masse to natural gas, such as Ohio, Indiana, West Virginia, or Kentucky, might consider providing incentives for renewable generation (which would permit them to meet the Clean Power Plan's "mass-based" goals).

Finally, energy efficiency, in some form, will likely be relied on as a means for not just reducing carbon output, but also curtailing price increases associated with the other approaches. Indeed, demand-side management has been largely successful in recent years, and some form of it can be found in nearly every state. California, in particular, has curbed power price increases associated with its own carbon rules by setting ambitious demand-side management goals. But this may be easier said than done: demand reduction was "aided" during the past decade by a relatively weak economy. In our view, demand management is likely to be more effective in economies biased more to the service sector compared with those states with greater industrial bases. When there's economic progress, restraining load growth could be more of a challenge and, certainly, some states are likely to have more robust growth patterns than California or the Regional Greenhouse Gas Initiative (RGGI) states have had. However, we acknowledge that the relationship between power demand and GDP growth is somewhat weaker than it has been in the past. Areas with lower expected economic growth in the future, such as New England or New York, might be able to effectively use this strategy and insulate themselves against rate increases. This is especially compelling where considerable coal-to-gas switching has already occurred, and where remaining coal assets are largely efficient baseload plants.

PJM Market Capacity In 2030 With $11.92 Carbon Cost



Source: Standard & Poor's.
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To be sure, the federal government is not entirely leaving states to their own devices. The Obama Administration has already earmarked $4 billion in federal funds to help willing states comply with the rules early; in those states, this could mitigate rate shock, which remains a primary focus. This could still be coupled with other incentives for early compliance, and having enthusiastic first-movers could be critical to the plan's overall success, especially if, with these incentives, they can demonstrate that end-user cost increases are not as dramatic as the plan's critics suggest they may be.

The plan may not be slated for compliance for several years, but already, certain states have been discussing their strategies, and, in reality, some combination of the above methods is probably most likely. Due to the heavily political nature of carbon regulation, we expect that like minds could merge in an effort to comply. Even among the relatively small universe

of utility regulatory commissions, there are significantly diverging thoughts on the matter, and much of this stems from the states' perceived inabilities to meet the early goals in these mandates without dramatically overhauling their generating systems. However, many are intrigued by the plan's economic prospects.

Illinois, for one, is seeking an all-of-the-above approach, embodied in a proposed Low Carbon Fuel Standard, which the state's legislature is currently debating. Although the proposal's specifics are not well known yet, it appears that load-serving entities would need to get 70% of their power from low-carbon sources, which could bolster the case for renewables, nuclear power, and energy efficiency, as well as creating challenges for coal assets. But as with any other state, economic considerations are key: the hope is that this plan could forestall nuclear plant closures and their related job losses, along with rate hikes. While this plan, in and of itself, may not ensure compliance with the state's goal, it certainly speaks to the direction the state may take in meeting the mandate.

Furthermore, Pennsylvania, which is in the PJM Interconnection power market, faces a 31% carbon reduction goal by 2030, and already leans on nuclear power for about 35% of its electricity needs *(see chart 1)*. With a relatively weak economic trajectory, energy efficiency could be one means for meeting reduction goals, but the state has also been mentioned as a possible candidate for inclusion in RGGI. Although it has more coal-fired generation than New England states, its experience might be similar to that of Maryland, which is also part of RGGI.

Finally, California's situation is a challenging one. As an explicit inspiration for this plan, the state's achievements in carbon reduction are well known. But California still has a mandate to meet, needing a further 23% reduction on top of its already considerable mitigation. And, to boot, it's already eliminated virtually all coal from its generating profile *(see table 2)*, so coal-to-gas switching is not a viable solution, and after years of demand reduction there are concerns about whether or not that approach had reached its full potential. But after the president's 2014 announcement, California Governor Jerry Brown announced that his state would seek to generate 50% of its power from renewables by 2030. While not expressly a response to the plan, this ambitious goal would bring the state in compliance.

The Price Tag

As is always the case with environmental regulation, cost is a major consideration, but there's no simple or immediate answer to "How much will it cost?"

We expect that, in the near term, the Clean Power Plan will generally drive cost increases, but how high will vary sharply by state, and several factors could mitigate them. In general, those states that have already taken big steps to reduce their collective carbon footprint, such as California and Colorado, will probably see more modest price increases, especially if they can reduce demand. However, those states that haven't made much progress are likely to see higher costs; ERCOT, especially, comes to mind. The post-carbon-generating world will likely require more emphasis on reliability and transmission, and the costs of ensuring these are likely to accrue, at least partially, to the end-user. Capacity pricing might increase sharply in response, as reliability products are introduced. And, despite significant advances, renewables may still be relatively expensive, especially if they're in low-resource areas.

What's less frequently discussed in tandem with this, however, are the benefits, which we believe are still twofold. First, we anticipate that, much as building new plants has in the past, these developments could stimulate the economy to create jobs and increase the tax base. Incidentally, many regions of the country that have the most ground to cover suffer from weaker economies as it is *(see charts 2 and 3)*. Whether renewables or natural gas are used to satisfy the carbon mandate, construction jobs are likely to follow, not just for the plants themselves, but for related infrastructure, such as gas pipelines. Furthermore, and perhaps more distantly, we have stressed that an inability to contain climate change through collective carbon reduction could result in considerable weather-related consequences; the avoidance of these would be considered a long-term benefit to the Clean Power Plan. Of course, these benefits are

Table 1 | Clean Power Plan's Proposed Methods For Carbon Reduction

Building block	Challenges
Heat rate improvements	Limits of effectiveness, rebound effect (more efficient coal plants leading to more frequent coal dispatch)
Running lower-emitting electric generating units (coal-to-gas switching)	Cost of building new capacity, transmission constraints, pipeline capacity constraints, operational challenges of running combustion turbines more, stranded costs of coal plants
Zero emitting sources	Very high cost of new nuclear plants, high cost of renewables (including complementary peaking capacity), reliability, transmission
End-user efficiency	Creating proper incentives for end-users and utilities, possible saturation

Sources: EPA; Standard & Poor's.

Table 2 | Electric Generating Capacity Additions 2013 To 2040 (Gigawatts)

Timeframe	Coal	Nuclear	Renewables/other	Natural gas
2013 to 2015f	2.16	1.12	30.73	16.63
2016 to 2020	0.33	4.40	6.37	25.07
2021 to 2025	0	0	5.25	44.41
2026 to 2030	0	0.33	7.92	56.51
2031 to 2035	0	0.60	11.76	58.63
2036 to 2040	0.13	3.27	21.93	54.00

f–Forecast.
Source: U.S. Energy Information Administration.

still somewhat more difficult to quantify than the related costs, which are certainly more immediate, and the timing difference makes this a harder sell politically.

The Next Steps

A recurring criticism of the American policy on energy and the environment is that, to date, there hasn't really been a coherent plan with tangible goals and compliance penalties, and that's caused its participation in wider, global environmental accords to seem half-hearted. But, here in 2015, much of the community that is engaged in climate change has acknowledged that without the participation of the world's major economies, efforts to stem global temperature increases to manageable levels can only go so far. Although the U.S.'s 2014 bilateral agreement with China on increasing renewable penetration and reducing carbon emissions is an encouraging step, the next year or two will be more telling. During this time, three pivotal events will unfold.

First, we expect the Clean Power Plan to be finalized during the summer of 2015 *(see table 3)*. Although litigation has been threatened and is fully expected upon finalization, we nonetheless believe that the carbon goals promised in last year's rollout will be affirmed, and that the timing for final compliance will be unmoved.

More importantly, the U.N.'s next Climate Change Summit will take place in Paris in December. It's not yet clear how these events will unfold, but we expect the U.S. to actively and positively participate in these discussions. A key criticism of the Clean Power Plan is that while it's ambitious, it may mean little for reversing climate change without buy-in from the world's other large economies, which have the capacity to emit carbon at even greater levels due to less advanced generating profiles. The recent accord with China is considered a positive, initial step in solving this problem. The U.S. economy's size means that the Clean Power Plan is more likely to result in a more meaningful outcome at the summit. In turn, we expect this to provide more support for the plan.

Finally, we expect that the 2016 U.S. presidential election could be the next philosophical battleground on climate change. Although it's still very early in the process, potential contenders have already been quite vocal on the subject, and the rhetoric has been as divided as ever among these key participants. With several key Senate races decided on energy and environmental issues in 2014, it's clear that the public has an appetite to hear the candidates' views on these subjects, especially as the effects of climate change continue to be borne out in plain view. This discussion will not just require candidates to respond to the Clean Power Plan, but also to conjecture about what's next, because domestic power generation is but one part of the climate change puzzle.

Although uncertainties remain as to the Clean Power Plan and its place among global carbon abatement schemes, it's clear to us that the Obama administration is intent on making the sustainability of the American power grid a part of its legacy. While the next Administration may not share these sentiments, the wheels are already in motion, and it appears that the U.S. is now demonstrating some commitment to a tangible federal plan for the first time. As domestic and international plans materialize in coming months, we'll be watching closely to see to what extent the plan really will have significant credit impacts. **cw**

Table 3 | **Plan Timeline**

Stage	Approximate time frame
Clean Power Plan finalized	Summer 2015
State Implementation Plans submitted (individual states)	June 2016
State Implementation Plans submitted (collective states)	June 2017 to 2018
Interim compliance goals begin	2020
Final carbon-reduction goals to be met	2030

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Analytical Contacts:

Michael T. Ferguson, CFA, CPA
New York (1) 212-438-7670

Trevor J. D'Olier-Lees
New York (1) 212-438-7985

Climate Change Will Likely Test The Resilience Of Corporates' Creditworthiness To Natural Catastrophes

Overview

- Generally, companies have so far managed to mitigate the effects of natural catastrophes through liquidity management, insurance protection, natural disaster risk management, and post-event recovery measures.
- However, the more frequent and extreme climatic events many scientists predict could adversely affect companies' credit profiles in the future.
- Greater disclosure of firms' exposure to extreme natural catastrophes should, in our opinion, encourage them to bolster their resilience to these events and thereby aid transparency.

While recent history shows that natural catastrophes may have not been a major rating factor on corporate credit quality in the past, their effect in the future may increase considerably if, as scientific evidence suggests, we experience more frequent and extreme climatic events. If such extreme events were to occur, companies' existing insurance and overall disaster risk management measures could, in Standard & Poor's Ratings Services' opinion, become considerably less effective. Therefore, we see improvements in companies' disclosure about their exposure to natural catastrophes becoming more relevant to our ratings analysis.

The economic cost of natural catastrophes has risen significantly over the past 10 years *(see chart 1)*. Yet, through a combination of existing preventive measures, most companies we rate have managed to mitigate the impact of such events on their corporate credit profiles. Nevertheless, with scientists predicting an increase in extreme climatic events, firms' vulnerability to natural catastrophes is in our view likely to be sorely tested.

Catastrophes Seldom Trigger Rating Actions—Yet

Although natural catastrophes can result in companies experiencing property losses and production and market disruptions, such events are not frequently a factor behind our negative rating actions. Since 2005, we have identified natural catastrophes (tropical storms, floods, droughts, and earthquakes) as the main or material contributing factor for at least 60 negative rating actions (comprising downgrades and outlook revisions). This compares with about 6,300 corporate credit downgrades on companies in total over that period. In addition, we revised our outlook on less than five companies to stable from positive as a result of natural catastrophes. Overall, we find that companies' liquidity management, insurance protection, natural disaster risk management, and post-event recovery measures were adequate in mitigating the impact of natural catastrophes on their rating profiles during the period.

Energy And Consumer Products Sectors Most At Risk

While our sample of negative rating actions is too small to draw robust statistical conclusions, our analysis provides insights into how and when natural catastrophes can affect companies' creditworthiness.

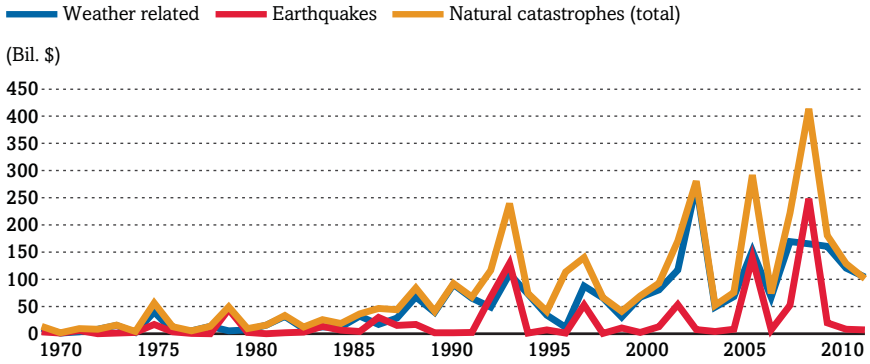
No sector is immune to the effects of natural catastrophes. However, the energy sector (through a direct impact on production and distribution facilities and market dislocation) and the consumer products sector (through supply chain and market disruptions) appear most exposed, together representing more than one-half of the affected sample. This is about double the proportion of rated companies that make up each of those sectors.

In around 40% of cases, natural catastrophes led to a one-notch downgrade. In a further 30%, we assigned a negative outlook that we subsequently resolved by affirming the rating. However, on average it took about 15 months for the credit profile of these latter companies to recover sufficiently for us to revise the outlook to stable. Across the rest of the sample, natural catastrophes contributed to multi-notch downgrades, and in about 10% of cases to default. Overall, this affected nearly twice as many speculative-grade than investment-grade companies because the former are more vulnerable to a downgrade, as our default statistics illustrate.

In one-half of cases in our sample, a natural catastrophe was the main trigger for the rating action. In the remainder, it was a contributing factor: Often, other more material negative developments had already weakened the credit profiles of companies affected by a catastrophe. As a consequence, the natural catastrophe led to downgrades in the vast majority of those cases. By contrast, in 50% of cases when the natural catastrophe was the main trigger, the negative rating action was a revision of the outlook to negative, which was resolved with a rating affirmation.

In about 40% of cases, natural catastrophes directly affected the operations of the company by physically disrupting its opera-

Chart 1 | **Economic Losses Caused By Natural Catastrophes**



Source: Sigma World Insurance Database.
© Standard & Poor's 2015.

tions. For one-third of cases, the main negative effects were indirect and focused mainly on the company's supply chain. In the remaining cases, the widespread market and economic disruptions caused by natural catastrophes adversely affected the company's credit profile. This caused unfavorable price movements and increased price volatility. In certain cases, the market and economic disruptions led to simultaneous negative rating actions on several companies operating within the affected sectors, two examples being power companies and automakers in Japan.

Katrina And Tohoku Took Their Toll

Hurricane Katrina in 2005 and the Tohoku earthquake and tsunami in 2011 constitute the two biggest natural catastrophes of the past 10 years. They are also responsible for triggering almost 50% of rating actions in which natural catastrophes were a factor. Katrina, in particular, was behind almost all of the cases that ended in default. The effects of Katrina were wide-ranging, from large direct losses to major supply chain disruptions and price increases across a wide variety of industries.

The most notable company that the Tohoku earthquake and tsunami affected was Tokyo Electric Power Co. Inc. (TEPCO), the owner of the Fukushima nuclear power plant that was severely damaged by flooding caused by the tsunami. The government's subsequent request to shut down nuclear reactors for safety inspections following the Fukushima disaster exacerbated the tsunami's effect on TEPCO's business. As a result, we lowered our long-term corporate credit rating on TEPCO to 'B+' from 'AA-' between March and May 2011. Other power companies with nuclear operations that we rated in Japan similarly suffered multinotch downgrades. The earthquake also caused widespread market disruption, which led us to revise our outlook on several Japanese automakers.

Natural catastrophes don't cause disruptions for all companies. Those whose business focuses on providing assistance during natural catastrophes could benefit, for example. By contrast, fewer-than-expected natural catastrophes could adversely affect such firms. In such instances, this has contributed toward negative rating actions. Other companies can benefit from higher prices as a result of natural catastrophes or because of reduced market competition if their peers suffer losses. However, these positive effects are rare.

Climate Change And Global Trade Links Raise The Stakes

Looking ahead, however, the picture is less certain. Growth in exposure in areas

Chart 2 | Rating Actions By Peril (2015–2014)

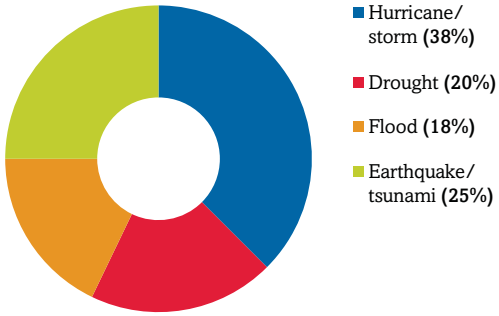


Chart 3 | Rating Actions By Sector (2005–2014)

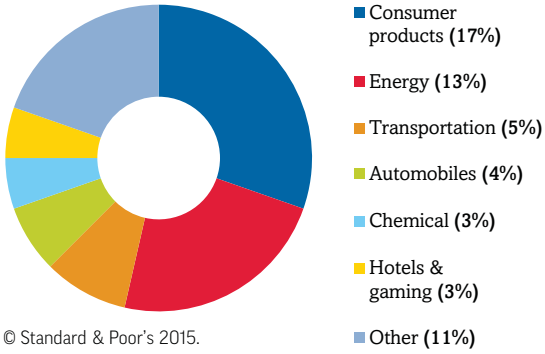
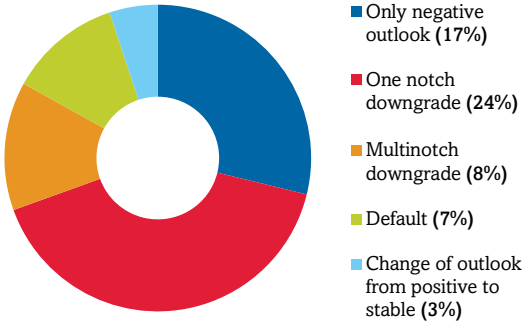


Chart 4 | Rating Actions By Type (2005–2014)



with high risk for extreme events, coupled with increased integration of the world economy through complex global supply chains, may exacerbate the impact of natural catastrophes. At the same time, the effects of climate change may increase in severity and frequency. Scientific evidence, as summarized in the Intergovernmental Panel on Climate Change (IPCC) Climate Change 2014 Report *(see note 1)*, points in that direction. In essence, higher temperatures will lead to more heat waves and droughts. Because warmer air can hold more moisture, the likelihood of extreme rainfall and subsequently floods will increase. Furthermore, rising sea levels caused by global warming are likely to increase the impact of coastal flooding during storms and high tides.

If such extreme events were to occur, companies' catastrophe insurance and overall disaster risk management could, in our view, become considerably less effective. The Japanese earthquake of 2011 provided a glimpse of what could happen when the magnitude of the event exceeded the levels assumed in the design of some of the tsunami protection measures, which as a consequence proved inadequate.

In an increasingly interconnected world, a major local natural catastrophe affecting an important link in the global economy is likely to have a worldwide and long-lasting impact. Moreover, certain risks may become difficult and costly to insure as the likelihood and cost of natural catastrophes events increases. For instance, following large insurance losses from contingent business interruption (CBI) resulting from the Tohoku earthquake and the Thai floods in 2011, insurers tightened up insurance policy conditions; increased rates; and, in some cases, reduced the insurance coverage for some companies. (CBI is an important tool for companies to protect themselves against losses as a result of supply chain disruptions.)

It's unlikely that any company on its own can take adequate risk measures or purchase sufficient insurance to protect itself in the event of extreme natural catastrophes. Therefore, we consider that the international community as a whole will need to improve the resilience of the global economy to natural disasters so that their impact on companies is manageable. Climate change will, in our opinion, only add to this challenge.

Because we expect the frequency of natural catastrophes, along with their economic effects, to increase in the future, companies will, in our view, need to improve their level of disclosure about their exposure to such events. This will allow investors and analysts to assess how material natural catastrophe is for the companies they invest or analyze. In that regard, we consider that the 1-in-100 Initiative should provide more insight into the resilience of companies to such events. The aim of this initiative is to promote companies' disclosure of their exposure to natural catastrophes. It looks to participating companies to disclose the maximum probable annual financial loss that they could expect once in a hundred years (that is, with a 1% chance of occurring; *see note 2*).

So Far So Good, But The Future Could Be Very Different

Generally, companies have managed to adequately withstand the effects of natural catastrophes over the past 10 years through a combination of liquidity management, insurance protection, disaster risk management, and post-event recovery measures. In the future, however, the world could be hit by events that are significantly more devastating than recent ones. We believe such events could lead to a more widespread weakening of corporate credit profiles and subsequently to more downgrades than in the past. **cw**

NOTES

1. Further details of the IPCC Climate Change Report 2014 are available at http://ipcc.ch/pdf/assessment-report/ar5/syr/AR5_SYR_FINAL_SPM.pdf
2. More details on the 1-in-100 Initiative can be found at http://www.un.org/climatechange/summit/wp-content/uploads/sites/2/2014/09/RESILIENCE-1-in-100-initiative.pdf

For more articles on this topic search RatingsDirect with keyword:

Climate Change

Analytical Contacts:

Miroslav Petkov
London (44) 20-7176-7043

Michael Wilkins
London (44) 20-7176-3528

How Will California Water Utilities Fare Amid The Long Drought And New Conservation Mandates?

In light of the fourth consecutive year of drought conditions in California, concerns about the reliability of the state's water supply have spiked, as have worries about the effects of Governor Jerry Brown's recent statewide water conservation mandate. Standard & Poor's Ratings Services seeks to explain the effects of the persistent drought on California water utilities' financial performance and credit quality.

Q. ***What is the credit impact of the drought on California water utilities?***

A. The financial and credit impact of the drought and required conservation levels vary across water utilities. Rate-setting flexibility, sources of supply, supply costs, and management's actions—either proactive or reactive—all factor into the degree of credit impact, and thus we are analyzing the impact of the drought case by case. Many of the California water utilities we rate entered this drought period with good to strong debt service coverage and solid liquidity positions, which can somewhat mitigate the impact of lower water sales volumes for a time. Also, many water utilities plan in advance for droughts from both an operational perspective and a financial perspective. We are closely monitoring how our rated water utilities respond to Governor Brown's executive order, including how they plan to adjust rates given the required conservation. Complicating the matter is the ruling by the 4th District Court of Appeal on April 20, 2015, in the case of Capistrano Taxpayers Association Inc. v. City of San Juan Capistrano(1) that struck down certain tiered-rate structures, which are a common tool to encourage water conservation. If the regulatory framework the state adopts on May 5 or 6 differs significantly from the current proposal (which we describe below), then we will again comment on the potential for credit impacts.

Q. ***Can you explain the executive order Governor Brown issued this month in response to the drought?***

A. On April 1, 2015, California Governor Brown issued an executive order(2) mandating statewide water conservation. This is the first time in California's history that water use restrictions have been mandated, and it represents a departure from prior requests for voluntary statewide water conservation. The governor issued the order following three consecutive years of drought and against a backdrop of historically low water supply: Snowpack in the Sierra Nevada Mountains—a critical source of water for the state during the spring and summer periods—was a mere 5% of the historical average(3) for April 1. The National Drought Mitigation Center estimates that about 67% of the state is experiencing either extreme or exceptional levels of drought(4), and virtually the entire state is experiencing some level of drought.

The objective of the order is to reduce statewide urban potable water usage by 25% through Feb. 28, 2016, but the order does not affect other water use categories, such as water used for agricultural production. If achieved, the State Water Resources Control Board (SWRCB) estimates that this level of water conservation would total about 1.5 million acre-feet(5), or roughly the volume of water currently held in Lake Oroville(6), one of the state's largest reservoirs with a capacity of 3.5 million acre-feet.

Q. ***How does the executive order affect California water utilities?***

A. For urban water suppliers, the impact of the executive order varies primarily depending on 1) the service area's per capita water usage and 2) the level of water conservation already achieved during the past year. Although the executive order targets a 25% statewide reduction in water usage as compared to 2013, state officials do not expect to achieve the water savings through a uniform reduction in water usage across the state. Instead, the revised regulatory framework(7)—which SWRCB published on April 18 and is subject to board adoption on May 5 or 6(8)—contemplates nine conservation tiers ranging from 4% to 36% reductions, stepping up in 4% increments(9).

Each urban water supplier's conservation standard is based on the service area's residential per capita water use during July through September 2014, three summer months when water demand for outdoor irrigation is typically high. The conservation standard is lower for service areas with lower residential per capita usage and higher for service areas with higher residential per capita usage. Notably, the conservation standard is measured relative to water usage during a benchmark period from June 2013 through February 2014. Some urban water suppliers have already achieved the required conservation level or are nearly at the required level, and we don't expect the modest additional conservation to significantly affect those suppliers' operations or finances relative to their prior-year performance.

For example, of the 413 urban water suppliers subject to the executive order, San Francisco Public Utilities Commission (SFPUC) had the ninth-highest total water production during the benchmark period (20.4 billion gallons), but the service area had the second-lowest residential per capita water use during July to September 2014, at 45.4 billion gallons. Based on this residential per capita use, the assigned conservation standard is 8%; however, because SFPUC already achieved 8% water conservation in 2014 relative to the benchmark period, no additional conservation would be required to comply with the executive order. In contrast, Coachella Valley Water District (CVWD) had the seventh-highest total water production during the benchmark period (28.3 billion gallons), and the service area had the seventh-highest residential per capita water use during July to September 2014, at 475.1 billion gallons. Based on this residential per capita use, the assigned conservation standard is 36%. Given that CVWD achieved only 4% water conservation in 2014 relative to the benchmark period, significant additional conservation of 32% for 2015 is required to comply with the executive order.

The SWRCB plans to assess a water supplier's compliance with the executive order by examining monthly reports that the suppliers will file. Enforcement actions for noncompliance may include informal enforcement, such as warning letters, or formal enforcement, such as

cease and desist orders accompanied by administrative civil liabilities of up to $10,000 per day.

Agricultural water suppliers are not subject to the executive order; however, low river flows and low allocations from the two major water projects in the state have cut into their surface water supplies.

Q. ***What impact does Standard & Poor's expect the drought and the executive order to have on water utility revenues?***

A. Although reduced volume of water sales seem likely to cause a corresponding reduction in operating revenues and net revenues, we understand that the financial performance of urban water suppliers also depends on other factors. For most retail water systems that have a volume-based component to their rate structure, reduced volume of water sales would indeed correspond to lower revenues (barring an increase in rates). However, the relationship between the percent reduction in the volume of water sales and the percent reduction in operating revenues is not necessarily one to one. User rates for most retail water systems have a fixed component, which lower sales volume would not affect.

Many rate structures also have tiered pricing, with higher water use leading to a higher per-unit rate. In these cases, the impact of lower water sales is more complex, with the loss of revenues determined in part by the water rate tiers and the amount of usage within each tier. Even further complicating the matter is the April 20 ruling on Capistrano Taxpayers Association Inc. v. City of San Juan Capistrano. In that ruling, the 4th District Court of Appeal struck down certain tiered-rate structures; specifically, those for which the water utility has not demonstrated that the tiers closely correspond to the actual cost of providing service at a given level of usage. We understand that the case has been remanded for further proceedings related to another issue in the case. Water utilities could also offset the volume lost with increased rates, as we address below.

Q. ***Can California water utilities increase rates to offset any decline in water sales volume?***

A. In general, California water utilities have the ability to adjust rates to offset lower sales volume. However, to increase rates, they must meet the public hearing and protest requirements under Proposition 218. The requirements include a public notice and a public rate hearing at least 45 days after the notice. The rate increase can be prevented if a majority of the parcel owners within the utility's service area protest at the public hearing or in writing. In our experience, it is rare for a rate increase to be outright prevented due to this provision, although significant opposition from a vocal minority of the customer base may sway decision makers from the recommended course of action.

Some utilities already have the ability to increase rates in a drought because they have been through a previous Proposition 218 process. These utilities can likely increase rates up to the preapproved level through a governing board action. If a utility has not yet gained this ability, it would likely need to undertake a public notice process to comply with the procedural requirements of Proposition 218. This process could cause a lag between required conservation and the implementation of higher rates. In particular, if the ruling on Capistrano Taxpayers Association Inc. v. City of San Juan Capistrano is left to stand, then the timeline to adjust rates may be significantly extended if the water utility is required to conduct a new cost-of-service study to demonstrate compliance with the ruling.

Q. ***Could a reduction in water sales volume lower a utility's operating expenses?***

A. Yes. In many cases lower water sales will lead to lower operating costs, although the impact will vary among utilities depending on their water supply sources and the marginal cost of additional supply. A water system relying exclusively on groundwater from its own wells would likely save on pumping costs if it sells less water. However, the savings may only be modest relative to a utility's operating budget because high-quality groundwater tends to be a relatively low-cost supply. If a utility directly purchases imported water on a per-unit basis, on the other hand, the lower water use will of course reduce water costs, and these savings could be substantial if imported water represents a significant portion of the utility's budget.

Although utilities could see some expense reduction, many of their costs—including fixed payments to suppliers, rents, leases, and debt service—are independent from the volume of water sold and likely wouldn't change. A decline in water sales would likewise have little short-term impact on salaries, benefits, and maintenance costs. **cw**

FOOTNOTES

(1) http://www.courts.ca.gov/opinions/documents/G048969.PDF
(2) http://gov.ca.gov/docs/4.1.15_Executive_Order.pdf
(3) http://www.water.ca.gov/news/newsreleases/2015/040115snowsurvey.pdf
(4) http://droughtmonitor.unl.edu/Home/StateDroughtMonitor.aspx?CA
(5) http://www.water.ca.gov/waterconditions/waterconditions.cfm
(6) http://cdec.water.ca.gov/cdecapp/resapp/resDetailOrig.action?resid=ORO
(7) http://www.swrcb.ca.gov/waterrights/water_issues/programs/drought/docs/emergency_regulations/fact_sheet_implementing_25.pdf
(8) http://www.waterboards.ca.gov/waterrights/water_issues/programs/drought/docs/emergency_regulations/regulations_fact_sheet.pdf
(9) http://www.swrcb.ca.gov/waterrights/water_issues/programs/drought/docs/emergency_regulations/draft_usage_tiers.pdf

For more articles on this topic search RatingsDirect with keyword:

California Water

Analytical Contacts:

Tim Tung
San Francisco (1) 415-371-5041

Robert L. Hannay, CFA
San Francisco (1) 415-371-5038

Standard & Poor's Approach To Rating Renewable Energy Project Finance Transactions

There is a general global consensus on the need for investment in clean energy, and the cost of key renewable technologies, including photovoltaic (PV) solar and onshore wind generation, continues to decline. This is helping to create steady—and in some markets, substantial—investment in new renewable energy projects. In the U.K., for example, the government recently awarded contracts worth US$485.8 million to 27 clean energy projects under the first round of its new "contracts for difference" auction regime, consisting of agreed strike prices under 15-year contracts.

Globally, according to the United Nations Environment Programme and Bloomberg New Energy Finance, investments in renewable energy rebounded strongly in 2014, registering a 17% increase to $270 billion after two years of declines and brushing aside the challenge from sharply lower crude oil prices(1). There were $7 billion-plus financings of offshore wind projects, boosting the investment totals for tthe Netherlands, the U.K., and Germany. These included, at the euro equivalent of $3.8 billion, the largest single renewable energy asset finance deal ever outside large hydro—that of the 600 megawatt (MW) Gemini project in Dutch waters. The International Energy Agency, meanwhile, projects that global renewable electricity generation will increase by almost 45% by 2020 (roughly 5.4% per year). Much of the expansion is likely to be in solar generation, and we anticipate growing demand for ratings as capital market financing for solar projects increases.

Standard & Poor's Ratings Services currently rates 19 renewable project financings *(see Appendix)*, but we expect to rate more as the market grows. We frequently receive questions from market participants about how we assess the credit risk of renewable energy projects; this article addresses these questions and outlines the key issues we consider in assigning ratings to renewable project financings. We focus on wind and particularly solar, which has been the subject of many of the inquiries we've received.

Question 1 serves as a primer for our project finance rating process in general, and question 2 outlines the key credit issues for renewable energy ratings in particular. Questions 3 through 18 look at these issues in detail: questions 3, 4, and 5 address construction risk, questions 6 through 9 address business risks in the operations phase, questions 10 through 17 address financial risks in the operations phase, and question 18 addresses a final modifier in the operations phase.

1 *What is Standard & Poor's general approach to rating power project financings?*

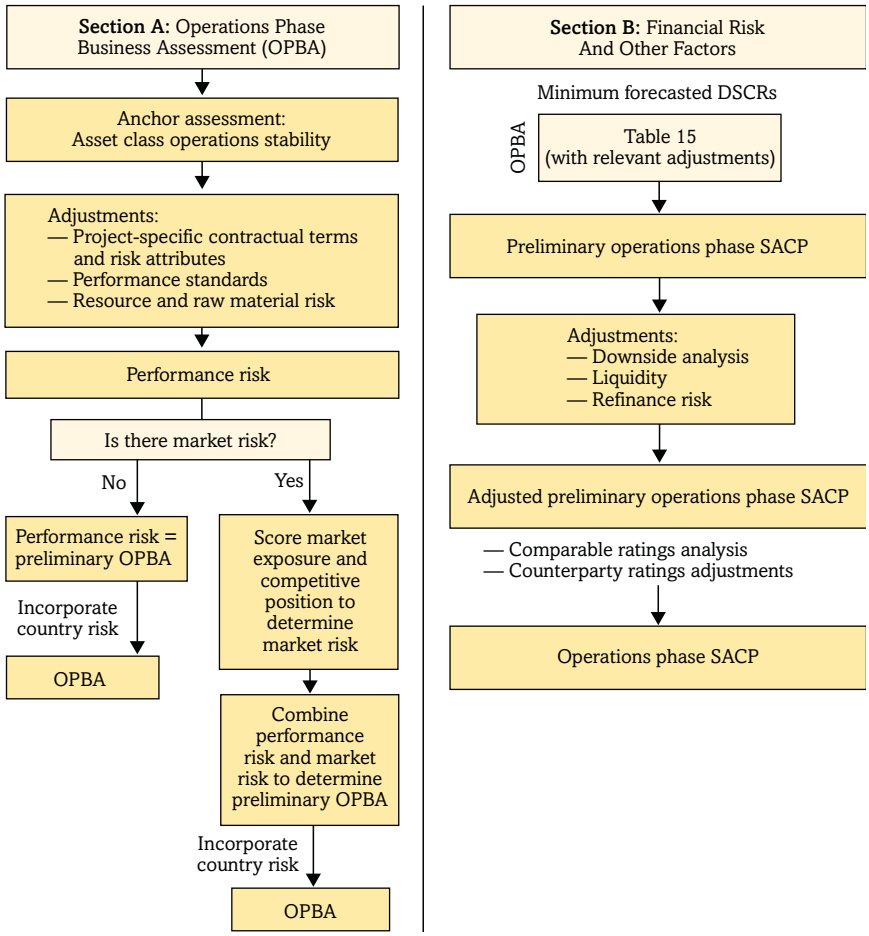
Our methodology for rating project financings, including those related to renewable energy, is outlined in the following criteria articles, published on RatingsDirect:

- *"Project Finance Construction Methodology,"* published Nov. 15, 2013;
- *"Project Finance Operations Methodology,"* published Sept. 16, 2014;
- *"Project Finance Construction And Operations Counterparty Methodology,"* published Dec. 20, 2011;
- *"Project Finance Transaction Structure Methodology,"* published Sept. 16, 2014; and
- *"Project Finance Framework Methodology,"* published Sept. 16, 2014.

For rating debt that finances energy projects, we also apply our *"Key Credit Factors For Power Project Financings"* (KCF), published Sept. 16, 2014. This provides more specific guidance for rating both conventional and renewable power project financings.

The key steps in our project finance rating process are summarized in paragraphs 10, 11, and 12 of our framework methodology. First we establish a project's stand-alone credit profile (SACP)—an assessment of its intrinsic creditworthiness. The SACP is the lower of our assessments of the project's construction phase SACP and operations phase SACP *(see chart 1)*. To arrive at the final rating, we adjust this project SACP according to our assessment of factors related to the transaction structure, extraordinary government support, rele-

Chart 1 | **Operations Phase SACP**



vant sovereign ratings, and any full credit guarantee, if there is one.

In terms of construction risk, we typically focus on technology and counterparty risks for most of the renewable projects we rate, such as PV systems and wind farms. In addition, there are other construction risk factors that can differentiate solar PV and wind projects from more complex renewable and traditional fossil fuel projects.

When we assess the operations phase SACP, we first determine its business risk profile, which we call the operations phase business assessment (OPBA). The OPBA can be thought of as a measure of how risky a project's operations are. It ranges from '1' to '12', with '12' representing the highest risk.

Then we evaluate the financial risk and other factors such as counterparty risk.

As outlined in our operations methodology, the main factors to determine the OPBA are:

- *Performance risk assessment:* We determine this by analyzing asset class operations stability and then adjusting for several factors including resource risk.
- *Market risk assessment:* Market risk only applies when a project's cash flow available for debt service (CFADS) has the potential to decline by more than 5% from our base case to our downside case due to market risk. In such cases, we then assess the project's market exposure (an assessment of its CFADS volatility due to market forces) and its competitive position.
- *Country risk*. For projects with no market risk, the preliminary OPBA is the performance risk assessment. The OPBA is post country risk adjustment. We then assess a project's future financial performance by forecasting the minimum debt service coverage ratios over its life. Combined with the OPBA, this results in the preliminary operations phase SACP, which ranges from 'aa+' to 'b-' *(see table 15 of our operations methodology, reproduced here)*.

We generate the debt service coverage ratio from our base-case financial forecast. We develop this scenario based on our expectations for a project's contractual performance, plus operational, financial, economic, industry, and project-specific considerations.

Discussions with independent experts can inform the assumptions that underpin the base-case scenario. The KCF provides guidance on our key assumptions.

The base-case scenario factors in contracts that effectively mitigate risk for the stated minimum duration of the contract. For contracts with renewal extensions, we do not assume extension unless the project has the unilateral right to extend the contract and we conclude that the project would do so.

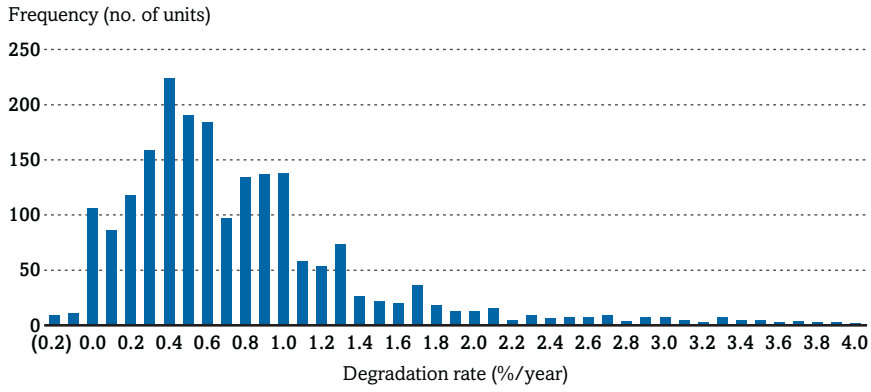
When we determine the operations phase SACP, we assess the likelihood that a project will be able to meet its financial obligations in a downside-case scenario. We define this as the market downside case *(see paragraphs 47 through 50 of our operations methodology)*, coupled with project-level operating stresses and macroeconomic and financial stresses *(see paragraph 68 of our operations methodology)*. If the project has no market risk, then the downside case consists only of operational stresses as well as macroeconomic and financial stresses where appropriate. How the project performs under the downside case may lead to a higher or lower operations phase SACP.

Table 15 | Preliminary Operations Phase SACP

	—Preliminary operations phase SACP outcome in column headers— —Minimum DSCR ranges shown in the cells below*—				
OPBA	**aa**	**a**	**bbb**	**bb**	**b**
1-2	=> 1.75	1.75-1.20	1.20-1.10	<1.10§	<1.10§
3-4	N/A	=> 1.40	1.40-1.20	1.20-1.10	<1.10
5-6	N/A	=> 2.00	2.00-1.40	1.40-1.20	<1.20
7-8	N/A	=> 2.50	2.50-1.75	1.75-1.40	<1.40
9-10	N/A	=> 5.00	5.00-2.50	2.50-1.50	<1.50
11-12	N/A	N/A	N/A	=>3.00x	<3.00

*DSCR ranges include values at the lower bound, but not the upper bound. As an example, for a range of 1.2x-1.1x, a value of 1.2x is excluded, while a value of 1.1x is included. §In determining the outcome in these cells, the key factors are typically the forecasted minimum DSCR (with at least 1.05x generally required for the 'BB' category), as well as relative break-even performance and liquidity levels. SACP—Stand-alone credit profile. DSCR—Debt service coverage ratio.

Chart 2 | Photovoltaic Solar Panels: Histogram Of Published Degradation Rates



Source: Technology and Climate Trends in PV Module Degradation, D.C. Jordan, J.H. Wohlgemuth, S.R. Kurtz; National Renewable Energy Laboratory.

2 *What are the typical key credit issues when rating renewable projects?*

The critical credit factors vary depending on the type of renewable energy project.

As the mix of renewable projects that we rate changes over time, we expect the nature of these issues to change.

Construction phase risks. Renewable projects with more challenging construction tasks include mega hydroelectric projects, which can have significant tunneling and dam construction risk; solar collecting tower power plants, which we view as having similar construction difficulty to supercritical coal-fired plants; and offshore wind plants in harsh sea environments. Other renewable energy projects employ new or unproven technology, which can also be significant to our analysis.

For projects with relatively simple building tasks, such as small-scale solar photovoltaic (PV) projects, or those whose construction is complete, our main considerations are operational (in our criteria terms, this would be reflected in the construction phase SACP being higher than the operations phase SACP).

For PV solar and onshore projects, our construction analysis typically focuses on technology and counterparty risks. In addition, there are construction risk factors that can differentiate solar PV and wind projects from more complex renewable and traditional fossil fuel projects *(see questions 3 and 5)*. Question 4 addresses differences in construction risk assessments typically seen with PV projects and wind projects and those with more conventional power assets or complex renewable projects.

Operation phase risks. The main operational factors we typically focus on in determining the OPBA are the performance risk (such as the asset class operations stability) and the project's resource risk. We discuss these in more detail with questions 6, 7, and 8. Given most rated renewable projects are contracted through the term of the debt or supported by feed-in tariff regimes, market risk analysis is generally only applicable for a small number of renewable projects we rate *(see question 9)*.

An example of a renewable energy project with low operational risk would be a fully contracted geothermal project with creditworthy counterparties; on the other hand, a merchant wind project, built without a contractual agreement with another party to purchase the plant's output, would have higher operational risk.

In our financial analysis of the operations phase, the key assumptions we typically focus on include degradation rates and operations and maintenance expenses, including reserving for equipment replacement or refurbishment.

3 *How do we assess technology risk?*

Technology risk is an important credit factor for renewable projects, especially PV projects, because most technologies are innovative and rapidly changing, and often owned by start-ups or young companies. Our approach to assessing technology risk is described in our construction methodology criteria *(see also paragraphs 13 through 17 of the KCF)*.

Solar panel technologies have varying track records of performance and field experience. For example, we typically assess conventional polysilicon and monosilicon solar PV panel technology as "commercially proven" because the commercial period exceeds two decades in numerous locations globally; the panel's degradation performance over a 25-year period is predicable, based on substantial and reliable commercial degradation rate data over the same length of time; and maintenance is easy, with costs well established by the industry. If a "commercially proven" technology does not have a track record in the operating conditions of the project being rated, we typically assess it as "proven" or weaker.

In contrast, so-called "thin film" technologies such as copper indium gallium selenide and amorphous silicon have no meaningful commercial track record. Cadmium telluride thin-film has established a good reputation based on a few years' track record with a single vendor, and we consider this to be proven technology.

We consider central and string inverters used on solar projects to be proven technology, albeit with shorter useful lives than panels *(see question 15)*.

We consider the technologies that are used on onshore wind farms, such as the turbines and gear boxes, as proven.

If we rate a project that uses technology that we have not yet evaluated, we will need to form an opinion on how we classify it based on information provided to us—including field data, testing results, and any independent engineer opinions. For example, we recently assessed a particular type of DC power optimizers for inverters, and concluded that these

Table 1 | Base-Case And Downside-Case Scenarios For Two Renewable Energy Projects

Continental Wind	Base case	Downside case
Resource risk/production	P90 one-year	P99 one-year
Availability	94%	91%
Operations and maintenance	5% increase over pro forma costs beginning in 2030	12% increase
Inflation	2%	3% for five years
Solar Star		
Resource risk/production	P90 one-year	P99 one-year
Availability	98.5%	95.5%
Operations and maintenance	10% increase over pro forma	12% increase
Inflation	2%	3% for five years
Degradation	0.50%	0.63%
Economic curtailment	Economic curtailment up to the cap of 50 hours	Same as base case

are "proven but not in this application or arrangement" *(see also paragraph 17 of the KCF)*.

One of the important observations is that although we consider conventional polysilicon and monosilicon solar photovoltaic panel technology to be "commercially proven," panel quality can vary by manufacturer and even per run by the same manufacturer. We typically capture this risk in the degradation assumptions we form for our base-case and downside scenarios *(see question 12)*.

4 *Which construction risk factors differentiate solar PV and wind projects from more complex renewable and traditional fossil fuel projects?*

Features of wind and PV solar projects that differentiate them from other more complex renewable projects and traditional fossil fuel projects include:

Technology performance match to contract requirements and expectations: We assess many of the solar PV projects in the U.S. as "exceeds" contractual requirements, given the power purchase agreements have significant cushion with respect to performance requirements versus our expectations. By comparison, we typically assess traditional fossil fuel plans as "meets" contractual requirements.

Construction difficulty: Depending on size and logistics management expertise, we would typically assess a smaller PV project as a "simple building task." A larger PV solar project with weaker logistics management, or an onshore wind project, we would typically assess as a "moderately complex building or simple civil engineering task." These power projects involve more sophisticated works and specialized equipment than simple building projects, and include cranes and rigs that require skilled operators. In comparison, we normally assess a combined-cycle natural gas-fired plant as a "civil or heavy engineering task."

Design complexity: We assess simple solar or wind power plants with simple support foundations that have been installed in numerous ground conditions globally as "proven design." By comparison, we typically assess traditional generating facilities as "modified proven design" or riskier.

The KCF provides greater detail on these above factors *(see paragraphs 18 through 34 of the KCF)*.

Nevertheless, we see solar PV as a relatively new type of power-generating asset, and we have observed globally PV projects encountering challenges during construction, including delays in acquiring permits; problems with the installation of equipment; and the bankruptcies of engineering, procurement, and construction contractors and equipment suppliers. Hence, although construction risk may not constrain existing ratings on PV solar projects, it could be a key factor for solar projects that do not have sufficiently strong measures to mitigate construction risk.

5 *Can counterparty risk be a limiting factor for renewable projects during construction?*

Yes, in some cases. We assess whether contractor and equipment suppliers can

Table 2 | Standard & Poor's Global Project Finance Renewables Ratings*

Issuer	Subsector	Rating	Country
Alta Wind Holdings LLC	Wind	BBB-/Stable	U.S.
Alte Liebe 1 Ltd.	Wind	CCC+/Negative	Jersey
Breeze Finance S.A.	Wind	B- (SPUR)/Stable (senior secured) D (subordinated)	Luxembourg
CE Generation LLC	Geothermal	CCC/Negative	U.S.
CE Oaxaca Cuatro, S. de R.L. de C.V.	Wind	BBB-/Stable	Mexico
CE Oaxaca Dos, S. de R.L. de C.V.	Wind	BBB-/Stable	Mexico
Confederated Tribes of the Warm Springs Reservation	Hydro	BBB/Stable	U.S.
Continental Wind LLC	Wind	BBB-/Stable	U.S.
CRC Breeze Finance S.A.	Wind	B-/Stable (senior secured) D (subordinated)	Luxembourg
CSolar IV South LLC	Solar	BBB/Stable	U.S.
ExGen Renewables I LLC	Wind	BB-/Stable	U.S.
FPL Energy American Wind LLC	Wind	BB/Stable	U.S.
FPL Energy National Wind LLC	Wind	BB/Negative	U.S.
FPL Energy National Wind Portfolio LLC	Wind	B-/Stable	U.S.
FPL Energy Wind Funding LLC	Wind	B-/Stable	U.S.
Harper Lake Solar Funding Corp.	Solar	BBB/Stable	U.S.
Salton Sea Funding Corp.	Geothermal	B-/Stable	U.S.
Solar Star Funding LLC	Solar	BBB/Stable	U.S.
Topaz Solar Farms LLC	Solar	BBB/Stable	U.S.

*Ratings as of April 20, 2015.

Table 3 | Recent Renewable Ratings (Alternative Structures)

Issuer	Subsector	Rating	Country
TerraForm Power Inc.	Solar/wind	Corporate	U.S.
Terra-Gen Finance Co. LLC	Solar/wind/ geothermal	Corporate	U.S.
SolarCity LMC Series I LLC (Series 2013-1)	Rooftop solar	Securitization	U.S.
SolarCity LMC Series II LLC (Series 2014-1)	Rooftop solar	Securitization	U.S.
SolarCity LMC Series III LLC (Series 2014-2)	Rooftop solar	Securitization	U.S.

be considered replaceable or not. If they are replaceable, subject to the amount of available liquidity, a project can have a higher rating than the creditworthiness of the construction and equipment suppliers *(see our counterparty criteria for further details)*. In other cases, the counterparty risk can be a key factor—as in the case of Solar Star, which would have a construction phase SACP of 'a-' without a counterparty-related constraint.

6 *How does Standard & Poor's rating analysis incorporate asset performance risk?*

For all projects, our starting point for assessing performance risk is to form a view of the project's "asset class operation stability"—the risk that a project's cash flow will differ from expectations due to operational issues. The asset class operations stability assessment ranges from '1' (the most stable) to '10' (the least stable). *(For more information, see table 2 and paragraphs 23, 24, and 25 of our operations methodology.)*

Generally speaking, the more complex the project's operations and technology, the higher (i.e., weaker) the asset class operations stability assessment. We typically assess the asset operations stability of solar PV projects as '2', the strongest score of all power technologies, as its operations are relatively simple. By contrast, a typical wind project would have an asset class operations stability assessment of '4' if it is onshore and '5' or more if it is offshore. A conventional combined cycle gas turbine would have a score of '5' *(for more information, see table 2 of our operations methodology and paragraph 48 of our operations methodology)*. We then adjust this assessment according to our view of factors such as resource risk *(see question 8)*.

The asset class operations stability assessment is an important input in determining the overall level of debt service coverage that we consider commensurate with a particular rating. Our assessments of asset operations stability under the revised criteria we published last year led us to upgrade two large U.S. renewable energy projects, Solar Star and CSolar, by one notch to 'BBB' *(see "Solar Star Funding LLC Rating Raised To 'BBB' On Assessment Of Operations Phase Risk; Outlook Stable," and "CSOLAR IV South LLC Senior Secured Note Rating Raised to 'BBB' On Revised Project Finance Criteria; Off CreditWatch," both published Oct. 6, 2014)*. We could have upgraded a third solar farm under construction, Topaz Solar, but the rating is constrained by its offtaker (the utility buying the project's electricity under a long-term contract).

The asset class operations stability assessment is then further adjusted by various project-specific contractual terms and risk attributes and this can lead to a higher or lower assessment (the highest being '12'). The questions below address some of the typical adjustments we consider for renewables.

7 *How does Standard & Poor's rating analysis incorporate the benefits of geographic diversification for a portfolio of renewable energy assets?*

We typically consider a project that has a portfolio of independent assets providing meaningful diversity and low correlation risk as having "positive" performance redundancy in our operations phase assessment *(see table 4 of our operations methodology)*. This assessment would lead to a positive adjustment to the asset class operations stability assessment. For example, Continental Wind LLC has an asset class operations stability assessment of '3' after the performance redundancy adjustment. It would be '4' otherwise.

Portfolios of assets can also benefit from a more favorable resource assessment.

8 *How does Standard & Poor's rating analysis incorporate resource risk?*

Resource risk is one of the biggest risks for renewable energy power projects because, with rare exceptions, the renewable power purchase agreements or feed-in tariffs provide that they are paid only for the volumes they deliver.

Our resource and raw material assessment for renewable projects focuses on the characterization of the natural resource to determine if the resource or raw material will be available in the quantity and quality needed to meet production and performance expectations.

Our resource and raw material risk assessments range from "minimal" to "high."

We typically assess a solar project's resource risk as "modest" (one step above "minimal") when we have a high level of confidence in the project's resource estimates, based on reliable analysis from multiyear resource data at the site that supports a long-term view of resource availability.

Geothermal technologies may be able to attain a modest resource risk assessment in situations where the geothermal resource is characterized by solid and reliable data on the resource's actual performance, provided that analysis indicates that the proven resource life will comfortably supply the power project's expected needs.

Our KCF states that if we view the resource as likely to vary from a baseline amount by 10% to 20% over the long term or 20% to 30% in the short term, we would typically assess the resource as "moderate" and apply a +2 adjustment to the asset class operations stability assessment. If we forecast higher long-term variation, generally between 20% to 30% from a baseline amount, or higher short-term variation, generally 30%-40%, we would typically still assess the resource risk as moderate but here apply a +3 adjustment to the asset class operations stability assessment. We tend to assess the resource risk of wind projects as moderate.

Some renewable projects consist of a portfolio of several individual projects of generally similar size, in which each project relies on a separate, independent natural resource regime to generate cash flow. By independent, we mean that variation of energy generation in one project location is not

strongly correlated to the variation in another, based on analysis of historical data. This would lead us to expect that overall variation would be less than the production from any single project in the portfolio. In such a case, we typically assess the project one level better than the lowest assessment among the individual projects in the portfolio. For example, if each of the projects in a portfolio had a resource assessment of moderate, with a +2 adjustment, we would be likely to assess the overall power project portfolio's resource risk as modest.

For example, FPL Energy American Wind consists of six U.S. wind power projects in different wind regimes, with a total output of 683 MW. Based on historical performance, we consider American Wind to have benefited from the portfolio effect described here and therefore we assess resource and raw materials risk as "modest," adding a +1 adjustment to arrive at an asset class operations stability assessment of '5'.

Project diversification does not lead to a better resource risk assessment in all cases. For example, Continental Wind LLC is a portfolio of 13 wind power projects in various locations across the Midwestern U.S., but more than 55% of the project's capacity has an operating history of less than two years. We therefore view its wind resource risk as "moderate," which adds +2 to the asset class operations stability assessment, leading to an assessment of '5'.

Other relevant adjustments (such as high exposure to seasonality or limited experience of the independent expert) are detailed in table 10 of the KCF.

In determining the likely accuracy of the resource data available for a given renewable energy project, we generally evaluate the independent engineer's assessment of the data used to estimate the resource potential of the project. We also look at research produced by institutions. For example, in the case of solar energy, the U.S.-based National Renewable Energy Laboratory maintains a National Solar Radiation Database that includes data from two different kinds of solar energy collection (called "insolation"): direct normal insolation (DNI) and direct and indirect insolation (or global horizontal insolation [GHI]). There is some uncertainty in solar resource measurements and there could be greater or lower insolation than the data suggest. For DNI, the range of uncertainty is up to about 15% and for global insolation it's up to about 9%. Greater uncertainty in the data means that there could be greater uncertainty for cash flows. This is therefore more significant for solar thermal projects that rely on DNI than PV projects that use GHI.

For most projects, multiple sources of resource data are available, with different modeling techniques and resulting measurements.

For most projects, multiple sources of resource data are available, with different modeling techniques and resulting measurements. Certain ways of measuring natural resource amounts are known to be more precise than others—for example, measurements of sunlight at ground level are generally more accurate than satellite data. A lack of ground data or other factors that negatively affect data integrity would lead us to conclude that the resource is more variable.

9 *How does Standard & Poor's rating analysis incorporate market risk?*

Our view of market risk reflects the extent to which a project is exposed to market changes, for example if the pricing of the power generated is linked to commodity market pricing. For the majority of renewable energy projects that we have analyzed, this risk is minimal because power purchase agreements tend to be structured to cover the life of the debt and provide the project with a fixed price for output, fully hedging against market risk. However, for a small number of renewable projects with market risk, it can be a ratings driver.

Where we perceive market risk, we adjust the OPBA if a project's CFADS has the potential to drop by more than 5% from our base-case forecast levels because of price changes, volume fluctuations, or both.

For example, Salton Sea—a geothermal project in Southern California—is exposed to market risk because the project is paid by its long-term offtaker based on a formula set by the state regulator that is linked to gas prices and updated monthly. In our view, this means that its revenues and expenses can be mismatched during periods of low gas prices. We view the potential market price changes as substantial and have assessed its market exposure as "high." The "high" assessment reflects our expectation that a significant drop in gas market prices could lead to the project's cash flow available for debt service declining by more than 50% compared with our base case. As a result, its OPBA is '10', the highest OPBA assessment we have for a renewable project in our portfolio.

When market risk is present we also consider how competitive the project's ability to generate electricity is. *(See tables 11 and 12 and paragraphs 43 through 53 of our operations methodology.)*

Our competitive position assessment of renewable projects comprises our analysis of regulation support and predictability, barriers to entry, delivery cost relative to peers, fuel supply, and transmission access.

If a project has a period of no market risk followed by a period of market risk, then we would typically assess these two periods independently

to produce a SACP for each. We would then use the lower of the two SACPs to determine debt ratings. Periods of contracted revenue usually have a higher SACP than periods of uncontacted revenue, but not always.

10 *How does Standard & Poor's develop base-case and downside-case financial forecasts?*

The base-case financial forecast is our expected scenario. Table 7 of the KCF outlines our process for developing assumptions such as operational performance availability and operations and maintenance costs. Initially, we consider performance that is likely to be typical for the asset class in the relevant market, and then adjust by factoring in particular project attributes, the performance of the power project's peers in the relevant market, our experience, and independent expert opinion where available. Over time, our base case also takes into account actual operating results.

Our downside case combines our market downside case *(see table 4 of the KCF)* with our operational downside assumptions and financial stresses linked to any refinancing, where relevant. We develop our downside case in line with the guidance in tables 8 and 10 of the KCF.

Factors that we tend to focus on in our financial analysis include:

- Production forecasting,
- Degradation (solar PV only),
- Curtailment,
- Operations and maintenance expenses,
- Reserving for equipment replacement/refurbishment, and
- Warranties.

We elaborate on these factors in the questions below.

11 *How does Standard & Poor's develop a production forecast based on resource availability?*

Base case. We typically base our initial assessment on the expected average availability of the resource at the project's site, when sufficient on-site data are available, and adjust for likely long-term regional trends in resource variation, for example due to known long-term weather cycles.

> *Solar or wind resource forecasting tends to be based on a statistical analysis of resource data relevant to the project's location and site conditions.*

For example, our base-case forecast for FPL Energy National Wind LLC is based on analysis of the year-on-year variation for the nine years of historical data. Our assumption for the forecast period through the life of the debt is the average over the past nine years with a 5% haircut for the variation observed over that period.

A project that relies on sunlight or wind may have limited or no operating data. In these cases, our assessment of resource and raw materials risk takes into account information that can provide us with a long-term view of resource adequacy. This includes reliable data available for the project site, and, if available, an experienced independent expert's statistical assessment of the resource and the likely electricity production.

For projects of this type, solar or wind resource forecasting tends to be based on a statistical analysis of resource data relevant to the project's location and site conditions. For solar and wind projects, the typical base-case assumption for power production probability of exceedance value is P90—an electricity production amount that would be exceeded 90% of the time when assessed statistically over a one-year period. We tend to use a one-year average period, rather than 10 years or longer, because projects generally have a structure that requires them to service debt once or twice a year.

The independent expert should be experienced *(see "Credit FAQ: Provision Of Information For Assessing Project Finance Transactions," published Dec. 16, 2013)*. We typically expect the independent expert report to include a review of the resource risk that should ideally describe the sources of the data on which the forecast is based, the embedded uncertainties, why they chose one source of data over others, and, for wind or solar, how they factored in any on-site measurements.

Downside case. For the downside case, we model a scenario for delivery volume and quality based on the worst level we expect in our base case over a 20-year period. For example, for a run-of-river hydro plant that has been operating for many years and sees annual variation in water supply, our downside case would forecast water flow near the low point of its historical performance.

For assets with a limited operating track record, the downside scenario generally stresses resources according to a P99 one-year average rate of production (that is, we assume an electricity production amount with a 99% probability of being exceeded in a given year).

12 *What is Standard & Poor's approach to degradation rate assumptions for PV solar projects?*

Base case. Solar panel degradation refers to the reduction in production over time as a function of the panel's reduced ability to convert sunlight into electricity, typically expressed as a percentage of total output per year. It directly reduces our base-case and downside assumptions for production, and thus cash flows. Our view of degradation depends on many things, including quality of materials used, the manufacturing process (the more manual this is, the higher the

risk of performance issues such as soldering problems), the choice of technology, the quality of installation, and our assessment of operations and maintenance (O&M).

For technology we assess as "commercially proven" or "proven" *(see paragraphs 13 through 17 of the KCF)*, we assume the degradation rate is linear. Annual degradation rates we have used in our ratings to date vary from 0.5% (in the case of proven monocrystalline technology from a high-quality supplier) to 1.3% (for the first securitization of residential rooftop solar PV systems). For thin-film technology, supplied by First Solar, we currently assume an annual degradation rate of 0.9%, reflecting both the different technology and shorter field experience. However, these assumptions may change over time, as more data become available.

The degradation rate of PV solar panels is a contentious subject in the industry. According to the study by Kurtz and Jordan, *"Technology and Climate Trends in PV Module Degradation,"* there is a wide range of actual long-term degradation rates experienced by PV technologies in the field *(see charts 2 and 3)*. The average degradation rate was less than 1% per year for most products manufactured after 2000. Different technology types (such as thin film) have statistical differences in degradation, particularly before 2000.

In assessing what degradation rate we will use, we view it as important to consider not just the panel manufacturer but the quality of the actual panels coming from a specific production run. As a result, we review information from the independent engineers to take a view of the quality assurance and quality control procedures.

To date, defects that have been encountered include damaged interconnections, soldering issues, or encapsulate discoloration or delamination. Recognizing the potential risks to long-term performance that quality issues introduce, third-party companies are now offering quality assurance services to monitor the manufacturing process or post manufacturing tests for defects.

Quality issues that affect degradation are not limited to the manufacturing process but also include installation and operations of the PV system, given that there is a wide range in the skill base of installers and operators, particularly as new markets open up to solar. As with manufacturing, there are third-party companies offering quality assurance services to inspect installations.

Our degradation assumptions may change as more information becomes available. For example, data from Germany—where the operating track record is longer than those of most countries—reveal that not all installation defects that impair performance are identified in the first year, but can materialize at least four or five years later when the degradation relates to issues like wiring. For the solar projects we have rated investment-grade (i.e., 'BBB-' or above), we have concluded based on detailed information provided that the projects have taken a rigorous approach to validating quality controls.

Downside case. For solar power projects, most of which experience an annual decline in output due to panel degradation, our downside case normally assumes 25% greater annual degradation than in the base case. These types of projects typically do not perform periodic maintenance on the solar panels to recapture lost efficiency. For example, if the base case assumes an annual solar degradation of 0.9%, we would assume an annual degradation of 1.125% (that is, 0.9% x [100% + 25%]) in the downside case.

13 *How does Standard & Poor's evaluate curtailment risk in its analysis?*

Our analysis incorporates the risk of curtailment (the reduction of a facility's power generation, for example due to transmission capacity that is insufficient or out of service).

Base case. Per table 7 of the KCF, we develop our assumptions based on the curtailment history for the site and adjust to reflect any changes to the transmission system that would likely result in smaller or greater outage going forward. We would assume that there is no transmission curtailment if the project is in a well-established power market—one that is centrally administered with a proven track record of very high reliability—and the transmission system for example is not undergoing significant expansion.

Economic curtailment. Curtailment can occur in different ways. In one PV solar project we rate in the U.S., the offtake contract permits the offtaker to curtail acceptance of production from the project for up to 50 hours annually for economic reasons. Given the pricing of the project is above market, we capture this risk in our base-case financial forecast by assuming that this curtailment occurs for the full 50 hours each year.

Downside case. Per table 4 of the KCF, the downside case is typically a 2% increase from our base-case assumptions. We would typically assume no transmission curtailment if the project is in a well-established power market and the transmission system, for example, is not undergoing significant expansion.

14 *How do we factor operations and maintenance expenses and reserving into renewable project ratings?*

Base case. Initially, we consider performance that is likely to be typical for the asset class in the relevant market and then adjust by factoring in particular project attributes, the performance of the power project's peers in the relevant market, our experience, and independent expert opinion where available. Over time, our base case also takes into account actual operating results *(see table 7 of the KCF)*.

One of our important observations from rating renewable projects is that, when markets open up, initial O&M expenses are usually estimates with limited comparable benchmarks. As the industry grows, which can be very rapid, demand for specialist labor and crane hire can significantly push O&M expenses upward. This was the case in the U.S. wind industry, where O&M expenses increased by about 30% to

40%, resulting in downgrades of the two FPL Energy wind projects we rate.

15 *How does reserving for equipment replacement/refurbishment factor into renewable project ratings?*

Table 9 of the power project KCF lists our view of the typical useful asset life for different types of renewable projects (for example, up to 25 years for land-based wind turbines). However, some of the equipment used in renewable projects has a shorter life than the project as a whole, such as inverters used in solar projects.

In such cases, we see if the transaction structure provides for reserves that are built up over time and are sized to fund the replacement or refurbishment of the equipment at a certain time (without incorporating any benefit from a warranty). We determine the appropriate time of replacement or refurbishment based on industry data, including independent engineer reports from our rated projects. In the case of solar inverters, we have concluded for our base-case assumption that at year 10 central inverters should be refurbished and string inverters should be replaced.

16 *How does Standard & Poor's assess equipment warranties related to renewable energy projects?*

Market participants often ask us about the role of warranties for equipment in our credit analysis of renewable projects.

To date, rated renewable projects have not received any type of credit uplift from equipment warranties, although theoretically a strong supporting warranty could provide a credit benefit by mitigating the risks we may associate with a newer technology. This has not yet been the case because the entity providing the warranty often has lower credit quality than the project; the conditions attached to the warranty can be murky; and the warranties don't typically extend to the life of debt, and thus may not be available when the project needs them.

These concerns are particularly relevant for warranties in the solar industry, where there have been multiple bankruptcies among warranty providers, including engineering, procurement, and construction contractors and manufacturers of panels, inverters, and racking. In addition, equipment suppliers in the wind industry have also experienced some distress, such as Clipper Windpower.

For projects where production downtimes could be longer than industry norms because the project does not have spare parts on site or available from a predictable supplier we may apply a negative adjustment for our O&M assessment, leading to a weaker OPBA.

If we were to view a warranty as providing credit enhancement to the project, the project's credit profile would be tied to that of the warranty provider.

17 *What do typical base-case and downside-case assumptions look like for the projects we rate?*

Table 1 compares our base- and downside-case scenarios and assumptions for a rated wind project, Continental Wind, and a rated PV solar project, Solar Star. Both of these projects have relatively limited operating history, so we use a P90 production rate for the base case and a P99 rate for the downside case.

Continental Wind has an asset class operations stability assessment of '3' (after adjustments for project-specific contractual terms and risk attributes), which means we adjust our base-case availability down by 3 percentage points for our downside scenario. Solar Star's adjusted asset class operations stability assessment is '2' and so the availability stress is 3 percentage points.

Both projects have neutral O&M and technological performance assessments, and therefore our downside stress for O&M costs is a 12% increase.

Our base-case degradation rate is stressed by 25% for Solar Star, which is our general approach for solar power projects *(see table 8 of the KCF)*. Degradation rates are specific to solar PV systems and are not applicable to wind projects.

Common to both projects are macroeconomic stresses such as inflation. We apply a 100-basis point shock in each of the first five years for the downside case, in line with our *"Common Macroeconomic Assumptions Used In Project Financings,"* published Sept. 16, 2014. Currently, our long-term base-case inflation assumption for both projects is 2%.

18 *Can counterparty risk be a limiting factor for renewable projects during operations?*

Yes, in situations where we consider the pricing of the power purchase agreement or tariff to be higher than merchant power prices. In that case, we consider the energy offtaker to be irreplaceable; i.e., if the rating on the offtaker falls below that on the project, we would lower the project rating. Although the project may be able to sell in the spot market or recontract with another offtaker, there is no assurance that the project would be able to get the same favorable pricing above market levels.

(1) See *"Global Trends In Renewable Energy Investment 2015,"* at http://fs-unep-centre.org/sites/default/files/attachments/key_findings.pdf.

Appendix: Standard & Poor's Global Project Finance Renewables Portfolio

Globally, we rate 19 renewable project finance issues *(see table 2)*.

As the market grows more comfortable with solar technology, there has been increased rating activity related to alternative financing vehicles for small to midsize PV solar. In the last year, we've rated several new kinds of corporate structures for financing renewable energy projects, including "yieldcos" (a vehicle predominantly distributing its cash flows from owned operating assets as dividends) and securitizations, which are summarized in table 3. **cw**

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Analytical Contacts:

Trevor J. D'Olier-Lees
New York (1) 212-438-7985

Luisina Berberian
London (44) 20-7176-3276

Anne C. Selting
San Francisco (1) 415-371-5009

Michael Wilkins
London (44) 20-7176-3528

Low Oil And Gas Prices Are Unlikely To Dent Most Global Project Finance Ratings, For Now

Standard & Poor's Ratings Services believes the current low price of crude oil and natural gas is unlikely to have a widespread impact on the credit quality of global project finance debt over the next year to 18 months. However, if prices remain in the US$50 per barrel range for a sustained period or fall further than we expect, the outlook may prove problematic for projects with refinancing risk, market exposure, or input prices.

Nevertheless, as of March 2015, 71% of our 282 rated global project financings, including most of those for oil and gas projects, carried investment-grade ratings ('BBB-' or higher). We expect many of these projects will continue to benefit from long-term contractual agreements, break-even points that were designed with low oil and gas prices as a base, the presence of substantial available liquidity to the issuer, or varying degrees of sovereign support. Low oil and gas prices also make transportation project financing more attractive, as lower fuel prices encourage more highway and air travel and, indirectly, more train travel through the effect on power prices. Lastly, the effect of sustained low oil and gas prices on some power projects will vary depending on the complex interaction of regulation, contractual obligations, and fuel costs.

The largest share of our rated project finance issues, at 31%, are power projects, with transportation-related projects comprising 21%, oil and gas projects 9%, and energy projects representing 2% *(see chart)*. The latter four sectors are the ones that have attracted heightened interest since oil and gas prices began their precipitous decline from about $108 per barrel in the summer of 2014 to between US$50 and US$60 per barrel over the past few weeks. The current price of crude could make some lenders more cautious in underwriting new, long-term projects until there is more visibility about the depth and length of the oil price slump. A longer-than-expected slump will also, in our opinion, cause issuers to be more discerning in the selection of projects they undertake, forcing them to decide between urgent projects and those that are desirable but which can be put on hold. It's also likely that some projects will increasingly seek to offset part of the volatility risk of oil and gas prices through the use of private-sector partners and increased credit enhancement from supranational lenders.

Standard & Poor's benchmark assumptions for 2015 are US$55 per barrel for Brent and US$50 per barrel for West Texas Intermediate, with prices for each rising by US$10 per barrel in 2016 and by the same amount again in 2017 *(see table and "Standard & Poor's Revises Its Crude Oil And Natural Gas Price & Recovery Assumptions," published March 26, 2015, on RatingsDirect)*. We also lowered our revisions on Henry Hub natural gas on March 26, 2015, to reflect the continued shift in gas production to lower-cost and highly productive reserve basins such as the Marcellus and Utica shales in North America.

Q. ***Who are the largest sponsors of oil and gas project finance in Europe, the Middle East, and Africa, and how does this oil price decline affect them?***

A. The big sponsors of oil and gas projects in EMEA are large national oil majors—such as Qatar Petroleum, Saudi Aramco, and Statoil ASA in Norway—as well as national utilities and large diversified conglomerates.

At this level, low oil prices have reduced the amount of project activity for some participants. Governments that rely heavily on oil and gas exports have already deferred those projects that are not deemed economically essential. We've seen this dynamic play out in Statoil's decision to abort the Alberta Oil Sands Project in September 2014, or Qatar Petroleum's decision to defer the Al Karaana and Al Sejeel multibillion-dollar petrochemical projects in Qatar.

At the same time, some projects are no longer feasible in light of rising construction costs paired with depressed oil and gas revenues. The combination of plunging oil prices and the high cost of deep-sea drilling, for instance, has prompted Statoil to reconsider its plans for expansion in the North Sea. Meanwhile, U.S. oil giant ConocoPhillips is cutting 230 jobs from its 1,650-strong workforce in the U.K. and announced a 20% reduction in its capital expenditure budget in March. Other big oil firms are expected to make similar cuts to their drilling and exploration budgets. We consider that some of the big oil firms may need to cut capital expenditure by up to 30% to restore profitability at current prices. The U.S. Energy Information Administration forecasts a 3% decline in U.S. crude production between May and September of this year, although it still expects the U.S. to produce more oil than last year, and more in 2016 than in 2015.

There are also cutbacks in U.S. shale oil production despite the country becoming a major producer over the past few years. But because it is more expensive to extract than oil from traditional wells, the number of shale oil projects in the U.S.—often undertaken by a combination of major domestic oil companies and smaller exploration and production firms—fell 15% from its recent peak in October 2014, through January 2015.

The sharp drop in oil and gas prices could well affect some planned project finance ventures, because we expect prudent sponsors and lenders will become increasingly wary of entering into finance structures with long-term market exposure. We also expect projects with limited price risks will become more popular in the current climate and that many sponsors, both corporate and sovereign, will reevaluate the urgency and necessity of specific projects. But we don't expect to see a significant number of defaults or downgrades in the near term.

Q. ***What types of high-exposure oil and gas projects appear relatively unaffected by these low prices?***

A. Many projects with the highest oil and gas price exposure, including RasGas in the Middle East, or Phoenix Park Gas Processors Ltd. operating in the Caribbean, will likely remain immune to the decline because they've been structured with compellingly low break-even rates of per-barrel oil prices in the mid-teens. These deals were either financed before 2008, and thus have stronger buffers against low oil prices, or they've been more recently structured with a significant cushion against low or

falling prices. Phoenix Park, for instance, continues to have considerable liquidity, which now offsets historically low natural gas liquid (NGL) prices.

While some projects may see cash flow pressure over the next few years, the best structured projects will be able to weather the decline. RasGas's average debt service coverage ratio (DSCR) is now closer to 6.7x, in our view, compared with our forecast early last year of 8x. The project's ability to withstand our downside assumptions for oil and gas prices (of US$50 per barrel) and still achieve minimum DSCRs of 2.6x is a key driver for the rating outcome, along with the ability of the project to continue to maintain average ratios above 5x. Similarly, Phoenix Park has seen its average and minimum DSCRs drop considerably in our base case to around 4.6x in 2015, but they will still need to drop somewhat further for us to consider a rating action and, even in our downside case, NGL prices are already likely near the bottom.

Under our updated project finance criteria, average and minimum coverage ratios, along with a project's resilience to downside pressures, are key considerations in assessing a project's financial risk—and our oil and gas exposed projects broadly exhibit such characteristics.

Q. ***How are the ultra-deep-water drill ships being affected by this price slump?***

A. We believe the current pressures on ultra-deep-water drill ship rates, with levels reaching US$375,000-US$500,000 per day, will not have a material impact on our rated portfolios globally. Most of our rated ultra-deep-water drill ships operate in Latin America. We expect the impact of low prices to be neutral on our rated drillers' credit quality in the short to medium term, mainly because of contracts that guarantee a fixed day rate for a distinct period of time. All these transactions were structured around the off-taker credit quality of Petroleo Brasileiro S.A. (Petrobras).

None of these projects will face re-contracting risk until 2019, when they may be exposed to higher charter rates that evolve in line with oil prices and local supply and demand dynamics. However, by then, we expect the amount of debt outstanding will be significantly lower for these projects, potentially enabling them to successfully operate with break-even day rates of approximately 50% of the current market day rate.

A pick-up in the price of energy to US$70 to US$75 per barrel after 2017 is supportive for many of the projects we look at, and is consistent with the type of medium- to long-term oil price budgeting undertaken by these project sponsors up until the oil prices began their slide. Nevertheless, many of the well-rated projects may now have to revise their budgets for the next two to three years. New budgets could be as much as 30% lower than when first constructed between 2012 and 2014 before oil prices fell.

Q. ***How will transportation projects benefit from plunging oil prices?***

A. Lower oil, gas, and diesel prices will have a positive impact on volume-based transportation and logistics projects because low fuel prices are directly correlated with more travel.

As such, we expect some benefit in terms of increased volumes on North American rated toll-road projects such as Ontario, Canada's Highway 407, Puerto Rico Highway 22, 95 managed lanes in Virginia, and NTE managed lanes in Houston—although the benefit to Houston may be offset if lower energy sector activity generates higher local unemployment. And according to the Middle East Economic Digest, which tracks project construction in the Middle East and Africa, countries in those regions are planning about US$300 billion of transportation projects over the next 20 years.

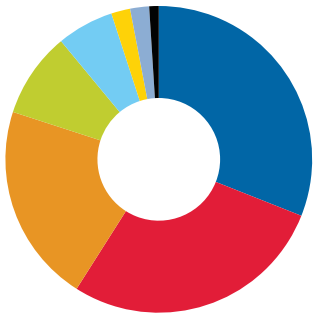
We also see one of the key beneficiaries of the oil price decline as being aviation-related project financing. Large government-backed airlines, including Emirate Airlines, are entering into a period of expansion and further capital raising amid the cheaper fuel environment.

Standard & Poor's Oil And Natural Gas Price Assumptions

	—New prices*—			—Old prices*—		
	Brent $/bbl	WTI $/bbl	Henry Hub $/mil. Btu	Brent $/bbl	WTI $/bbl	Henry Hub $/mil. Btu
2015	55	50	2.75	55	50	3.5
2016	65	60	3.25	65	60	3.75
2017 and beyond	75	70	3.5	80	75	3.75

*Prices rounded to the nearest $5/bbl and $0.25/mil. Btu. New prices as of March 26, 2015. bbl—Barrel. WTI—West Texas Intermediate.
Source: Standard & Poor's.

Global Project Finance Ratings By Sector*



*As of March 19, 2015.
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Q. ***What are the prospects for U.S. power projects because of low oil and natural gas prices?***

A. Some North American gas-fired generating projects may see minimal cash flow impacts from sustained lower oil gas prices. A lower natural gas price, which we have included in our revised assumptions, could result in incrementally lower power pricing, as most regions in the U.S. have gas plants as their marginal units. However, many rated gas-fired generating projects operate under tolling agreements that mitigate potential price decreases. The impact of lower electricity prices due to persistently lower gas prices would be limited to those few projects with exposure to merchant price risk. In California, power projects will likely see a limited impact, with many using short-run avoided-cost pricing, which incorporates natural gas as one of its power pricing components. Without hedges, however, margins for merchant commodity facilities may shrink. That being said, in purely competitive markets, the economics of natural gas-fired plants have improved, and they should dispatch with more regularity compared with coal plants, for which we haven't changed our pricing assumptions.

While the era of baseload oil plants has long since passed in the U.S., dual-fuel projects, which can use oil or diesel as an alternative to natural gas, like Astoria Energy LLC (BB/Stable) or Bayonne Energy Center LLC (BB-/Stable), may have more frequent arbitrage opportunities due to low oil prices meeting temporarily high gas prices. In certain parts of the country that have natural gas pipeline constraints, including New York and New England, using this option has proven beneficial during the past two colder-than-average winters as higher gas pricing has forced a rise in power pricing. But this isn't an unlimited opportunity. In some states, environmental rules cap the frequency with which this option can be exercised. Plus, storage capacity is finite. But we suspect that pipeline constraints could abate in coming years due to new environmental rules and significant gas supplies being available at low prices. We previously used a threshold price at which natural gas becomes less economical than oil of around US$20 per mmBtu in such scenarios. Now we expect that price to drop somewhat and, all things being equal, lead to higher capacity factors for oil-fired units.

For most contracted coal plants, rail transportation costs are reimbursed and, with cheaper oil, the price of diesel fuel is likely to fall. We will continue to evaluate the mechanism for reimbursement to see if existing fees now exceed transportation costs. That could signal positive credit implications, and we can look for these features in projects like the Colver Power Project (BBB-/Stable).

In some large U.S. power markets, however, we expect the positive fallout from lower oil and gas prices will be muted. There are unlikely to be any winners in Texas where, in our opinion, Electric Reliability Council of Texas (ERCOT)-based power providers will see little short-term benefit. For one, these power plants do not have the option of some other U.S. regions to earn revenue solely by having the capacity to sell power during peak periods of demand. And when these generators do sell available power, they are facing the prospect of lower revenues because cheaper gas has reduced the cost of peak power. Texas may also face modestly lower demand for power in 2015 as a result of less robust oil drilling—which plays a big part in the local economy. While this could depress power prices, we already forecast that 2015 would be comparatively weak. But a second weak year in a row could cause us to lower our ratings on plants that aren't adequately hedged against weak margins.

Q. ***What are the prospects for rated renewable energy projects in this environment?***

A. The rapid decline in Brent crude oil prices and the U.S. benchmark is unlikely to hurt the bankability of renewable energy projects, and could even be a boon for some of them, especially wind power. Most of our rated wind and solar projects have fixed-rate offtakes for all energy generated. For the small number exposed to market prices, lower gas prices could be detrimental as the project could generate lower revenues when natural gas plants are the marginal generator at the local price hub.

We think that in certain jurisdictions, the oil price decline could lead to an increased focus on renewables and other means of securing energy supplies that are less dependent on the cyclicality and volatility of oil prices. An example would be the fiscal pressures Gulf sovereigns are facing as a result of recent commodity price declines, and the consequent potential for energy subsidy reform that could pave the way for more renewable projects in Gulf Cooperation Council (GCC) markets.

Historically, power plants using subsidized fossil fuels have had an economic advantage over renewable projects, typically wind or solar. However, lower government revenues stemming from cheaper oil and natural gas have prompted some administrations to rethink their energy subsidies. Oman, Qatar, and Bahrain have all raised the price of gas supplied to downstream industries. And any change in energy subsidies to the power sector that paved the way for more cost-reflective tariffs will, in our view, improve the regulatory environment for renewable power projects in the region.

Dubai's Supreme Energy Council, for example, supported by the Dubai Electricity and Water Authority (DEWA), plans to diversify its fuel energy mix so that by 2020 renewable sources generate 7% of the Emirate's energy needs. In March, DEWA announced the launch of Shams Dubai, a public-private partnership (PPP) aimed at encouraging and regulating the development of commercial and residential solar power projects.

Abu Dhabi's Masdar led the way in the region with the first 100 MW concentrating solar PPP (Shams 1), achieving financial close in 2011. Under the model, we think the project company will sell power to state utility Abu Dhabi Water and Electricity Co. (ADWEC) under a power purchase agreement. An impor-

tant feature of the Shams 1 solar project was the introduction of a "green payment," under which the Abu Dhabi Ministry of Finance compensates ADWEC the cost difference between average domestic power generation and Shams 1 generation.

In our opinion, the independent water and power producer model could be replicated relatively easily in renewable energy project financing. What's more, the addition of the green payment addresses an aspect that we consider critical: providing political support in the form of this payment, which enhances the long-term viability of renewable transactions.

In March, Masdar and ACWA Power signed an agreement with Egyptian Electricity Holding Company to develop 2 GW of renewable energy capacity, including 1.5 GW solar power and 500 MW wind energy capacity. The companies are expected to start capacity development with a 200 MW solar photovoltaic power plant. Egypt plans to aggressively expand its renewable energy capacity, aiming to get 20% of its electricity from renewable sources by 2020. The government has also launched an attractive feed-in tariff scheme to boost investments in the solar power sector, mirroring Jordan last year.

Q. ***Why is it likely that oil and gas projects will continue?***

A. Despite the pressure of low oil prices, many governments have a commitment to use project finance as an effective tool to meet essential infrastructure needs, both within and outside of the oil and gas industry. They take the long-term view and have not allowed the recent price drop to influence capital spending. Saudi Arabia, Kuwait, and the UAE have all announced limited changes to their capital budgeting plans for 2015-2016, despite low oil prices.

The dip in oil and gas prices has encouraged Gulf producers to reorient their focus on downstream projects, rather than curb spending altogether. Gulf states are expanding their refineries to develop a downstream industry and export more value-added products, diversify away from oil and gas income, and meet rising domestic needs for fuel. We expect the total capacity of Gulf refineries to increase to approximately 7.4 million barrels per day (bpd) by about 2022—70.5% more than the current 4.3 million bpd, according to consultants Frost & Sullivan. Saudi Arabia is expected to remain dominant, with a 45% market share. Sadara Chemical Co., a US$20 billion petrochemical joint venture between the Saudi Arabian government-owned Aramco and U.S. multinational Dow Chemical, will use both gas and naptha, derived from crude, to produce petrochemicals this year.

Sadara Chemical is an example of the integrated downstream cluster model increasingly being used in the Gulf. GCC countries are creating downstream energy clusters with the aim of finding a profitable way to use their crude and natural gas regardless of price. Saudi Arabia, for example, has developed clusters in Jubail and Yanbu, where refineries and petrochemical plants are built side by side. If significant shale oil production, for instance, caused a long-term decline in oil prices, Saudi Arabia's own oil could supply these refineries with the fuel its petrochemical plants need to produce enriched end products. This not only guarantees a way to use oil if prices stay low, but also generates jobs and diversifies production. We understand that several other GCC countries may emulate the Saudi model.

The commodity price dip has also encouraged Gulf producers to explore shale opportunities. Speaking at an investment conference in Riyadh in January 2015, Khalid A. Al-Falih, chief executive officer of Aramco, said publicly for the first time that the company had already earmarked US$3 billion for shale gas exploration. Historically, investment in shale projects has required high oil prices because of the significant development costs associated with the exploratory phase. However, countries which built up fiscal reserves when oil prices were high, like Saudi Arabia, have a compelling reason for a presence in the shale sector, especially given recent technological advances in extracting oil and gas from shale. Market estimates put Saudi Arabian shale gas reserves at about 600 trillion cubic feet, and we understand that Saudi Aramco is in talks to secure 40 extra rigs to cover shale gas operations, indicating that it expects large-scale production over the medium term.

Because of lower prices, however, some Middle Eastern and African countries have revised the subsidies they bring to certain projects. This, in turn, has elevated the importance of cost-reflective tariff arrangements and market-based pricing. We think this will pave the way for more private-sector participation in some emerging markets in the utilities sector, particularly by way of participation through PPPs in competing generation plants. In Oman, PPPs undertake almost all power and water generation. Abu Dhabi's recent review of its subsidies for power and water bills is also a case in point. In South Africa, there has been some discussion in the market about how best to attract private-sector participation through PPPs in the power generation segment to reduce the infrastructure expansion burden from government-owned utility Eskom. Ultimately, we think sovereigns, when considering the effect of projects on the macroeconomic level, will have to differentiate between projects that are "nice to do"—such as some of those in the transportation or petrochemical space that help to diversify the economy—from those that are essential and more urgent, such as power and water-related projects. **cw**

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Analytical Contacts:

Karim Nassif
Dubai (971) 4-372-7152

Michael T. Ferguson, CFA, CPA
New York (1) 212-438-7670

Candela Macchi
Buenos Aires (54) 114891-2110

Ben L. Macdonald, CFA
San Francisco (1) 415-371-5005

Watcharee Corkill
London (44) 20-7176-3989