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SPECIAL REPORT

Offshore Wind Arrives. Will Renewables Prosper?





SPECIAL REPORT

12 Renewable Energy Requires Renewable— And Plentiful—Funding To Meet Global Policy Goals

By Terry A. Pratt, New York

Not long ago, investment in renewable energy seemed like a low-risk proposition with politically supported goals of increasing energy independence and security, mitigating climate change, and creating jobs. Countries worldwide adopted policies to aid investment. Unfortunately, budget constraints and financial crises have introduced an element of uncertainty into the future of renewable energy.

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Electricity comes from many sources, but there is one source that only a few countries in Western Europe, along with China, take advantage of, and it is in growing abundance: offshore wind power. The industry began in Sweden and Denmark in 1991 but had not grown significantly until recently. Countries are increasingly relying on offshore wind power to help meet social and economic policies over the next decade, but the investment required is immense.

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Supervision's global standards for banks' liquidity and capital adequacy—will bring profound changes to the global project finance sector and the ways it pursues funding.



31 Support For Renewable Energy Inches Ahead While Global Energy Demand Grows By Leaps And Bounds

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With energy consumption worldwide projected to roughly double in the next 35 years, conventional wisdom says renewable sources of power will play a big role in meeting demand. The conventional wisdom may be wrong. Cost, feasibility, and political wrangling all stand in the way of near-term renewable-energy expansion, globally and in the U.S.



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Renewable energy sources usually produce electricity more cheaply than conventional fuels that supply most markets. Investment in renewable energy depends on government support. The U.S. wind power industry is trying to get Congress to continue the main source of federal support, the production tax credit, beyond 2012. Without the tax credit, investment drops quickly.

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40 Why Regulatory Risk Hinders Renewable Energy Projects In Europe

By Jose R. Abos, Madrid

Ambitious targets for clean energy generation in the EU have put renewable energy at the forefront of discussions about meeting Europe's energy needs. And political reactions to the nuclear crisis in Japan—which prompted Germany, for example, to shift its energy policy toward renewables and away from nuclear—are also fueling the interest in renewable energy. But regulatory risk is becoming a bigger issue for these projects.

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By Grace D. Drinker, San Francisco

The U.S. and Europe have undergone big shifts in their emphasis on renewable energy. Wind power has developed into the renewable technology of choice, given its superior economics. Comparing 10 years of these projects' actual performance to original expectations has helped us to better understand why their cash flow is so volatile.

49 Will Securitization Help Fuel The U.S. Solar Power Industry?

By Andrew J. Giudici, New York

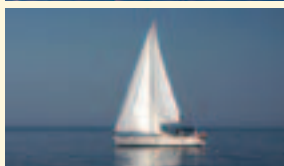
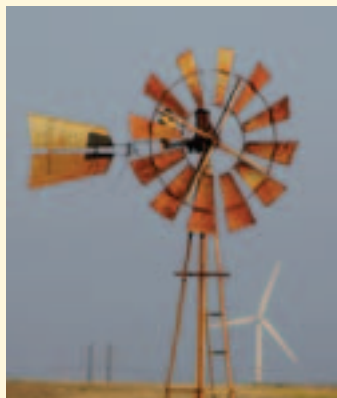
As the U.S. solar power industry expands, developers will need financing to fund their growth. Securitization—a financing technique that aggregates pools of assets, financial contracts, or loans, and through a structuring process transforms their future cash flows into a security—may be a viable option for developers that wish to monetize cash flows from future lease or power purchase agreement payments.



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Renewable Energy Requires Renewable—*And Plentiful*—Funding To Meet Global Policy Goals

Overview

- Support schemes take various forms, and all are subject to long-term fiscal constraints.
- Some asset classes will likely retain more support than others in times of fiscal constraint.
- U.S. budgetary constraints are hampering renewable projects that rely on the federal production tax credit (PTC), especially wind power.
- Standard & Poor's thinks strong growth in the renewable-energy sector will require new investment sources, such as pension funds and capital markets, and more private equity.

Not long ago, investment in all renewable-energy asset classes seemed like a low-risk proposition with politically supported goals of increasing energy independence and security, mitigating climate change, and, more recently, creating jobs. Countries worldwide have been adopting policies to aid investment in renewable-energy technologies despite strong opposition in many to the high cost of such programs. European policies have been supportive for years. The U.S. has provided more limited support for renewable energy but has recently added stimulus spending for it. China has been building such projects rapidly to counter its high reliance on coal, and Australia is about to introduce a carbon tax that will spur renewable-energy investment. Unfortunately, budget constraints and financial crises have introduced an element of uncertainty into the future of renewable energy, especially in Europe and the U.S.

Support schemes take various forms, such as subsidies (direct support) and usage requirements and carbon taxes (indirect support), all of which are subject to long-term fiscal constraints. Governments want to keep electricity rates low to help economic recovery, and many countries and U.S. states such as California are committed to mitigating climate change and creating “green” jobs, so continued investment is critical. Limitations on the government’s ability to provide support suggest that it will be reallocated to more efficient, larger-scale technologies. This greater focus might expand the investor pool and add sustainability to the industry.

Standard & Poor’s Ratings Services believes some asset classes will likely retain more support than others in times of fiscal constraint. The U.K. and Germany strongly support offshore wind to meet climate-change and jobs goals (see *“Strong Growth Of Global Offshore Wind Power Needs Substantial Investment,”* on p. 16). By 2014, the U.K. will have more than 4,000 megawatts (MW) of offshore wind capacity, up from just over 500 MW in 2008. And Germany’s decision to retire its nuclear plants, which provide about one-quarter of its electricity, will require more investment in renewable energy, particularly offshore wind. The factors that make offshore wind projects attractive globally are that they can be very large and take advantage of wind regimes that are often far superior to those on land. And, offshore projects are increasingly being built in deeper water, and therefore farther from public view.

Solar Power Has Had Some Dark Days

As relatively new as the industry is on a big scale, some segments of the renewable world have already experienced big setbacks, especially solar photovoltaic power. Solar investment in Spain, Germany, and Italy has grown rapidly in the past few years and far exceeded government goals thanks to favorable long-term subsidies. But constrained budgets in Spain and Italy have forced those countries to greatly reduce solar subsidies, which led to reduced investment (see *“Credit FAQ: Could Spain’s Halt On Renewable Energy Incentives Take The Wind*

Out Of Projects, Developers, And Utilities?” on p. 53). In Spain and the Czech Republic, we believe regulatory risk has become a bigger issue following these governments’ decisions to alter their support framework for projects that are already financed (see *“Credit FAQ: Why Regulatory Risk Hinders Renewable Energy Projects In Europe,”* on p. 40). These abrupt reductions for solar photovoltaic power have led to a large decline in demand for solar panels, resulting in numerous failures of once-prominent panel makers.

Uncertainty Is A Big Factor In U.S. Government Funding

U.S. budgetary constraints are hampering renewable projects that rely on the federal production tax credit (PTC), especially wind power. The PTC, which provides about 20% of a project’s cost over its 10-year life from the start of operations, has been the foundation of renewable-energy growth for the past decade. The current PTC expires at the end of 2012. Congress has extended the PTC several times in the past (although often after some delay), but the sheer cost of this funding in a time of record deficits could result in its discontinuation. If that happens, investment in onshore wind would decline substantially, and the nascent offshore wind industry that East Coast states favor would also be jeopardized (see *“U.S. Offshore Wind Investment Needs More Than A Short-Term Production Tax Credit Fix,”* on p. 34). Less at risk is the solar sector, whose investment tax credit runs through 2016, and prices for solar photovoltaic panels are declining rapidly.

The drop in the price of natural gas to about \$2 per million Btu adds to the debate about the cost of the U.S. renewable sector. Until recently, the high price of natural gas led to high power prices, which made renewable energy look more competitive and was a powerful incentive for Congress to provide support. But the currently low power prices now make cost parity a tougher argument to make. The continuing decline in solar panel prices might help the solar industry deal with this problem, but the wind industry faces a tougher challenge.

Still, many U.S. states, especially California, attract investment through Renewable Portfolio Standards (RPS), which require a certain share of renewable electricity in the total supply, and from other investment support programs. Two planned offshore wind projects in the U.S., in Rhode Island and Nantucket Sound, are now in the advanced stages of development thanks to RPS.

RPS standards are likely to remain in effect even if federal support for renewable energy wanes. A similar support scheme in the U.K., the Renewable Obligation program, is a major factor behind the recent burst of offshore wind power investment there.

Alternative Funding Methods Are Taking Hold In Some Regions

Indirect support through taxes on carbon also helps renewable energy by raising the cost of electricity derived from traditional fossil fuels. Denmark makes good use of this tool, and Australia will soon, creating an interesting dynamic that could open the door to significant investment (see *"Can Gas Smooth Australia's Transition From Coal Or Will Renewables Leap Ahead?"* on p. 57). The carbon tax that Australia will introduce on July 1, 2012, will curtail production from coal-fired plants that currently supply 80% of the country's electricity and would logically attract gas-fired investment to fill the gap. Australia hopes to cut its carbon emissions by 2020 by 5% from 2000 levels, with an ultimate aim of an 80% reduction by 2050. But, the 2050 reduction target could make new gas-fired investment economically unattractive in the long term, which could open the door to renewable energy to help meet demand and carbon-reduction goals.

The investor pool is another influence on the growth of renewable energy. Some countries such as Denmark enjoy wide public participation in renewable energy today because local ownership was required for projects in the early years of that industry's development. Fixed-payment systems, such as the feed-in tariff (FIT), also open the door to a wide investor pool, given the limited contractual nature of the system and good predictability of cash flow streams. Tax-based schemes

such as the U.S. PTC limit the investor pool because the credit relies on tax equity investors and complex financing structures. In addition, most renewable projects in the U.S. are financed with bank lending, which could be curtailed under proposed Basel III requirements that penalize long-term investments (see *"Basel III And Solvency II Regulations Could Bring A Sea Change In Global Project Finance Funding,"* on p. 26).

Standard & Poor's thinks strong growth in this sector will require new investment sources, such as pension funds and capital markets, and more private equity, but these investors have yet to jump into the pool in a big way. Securitization for solar power is a big option gaining a lot of interest (see *"Will Securitization Help Fuel The U.S. Solar Power Industry?"* on p. 49). Part of the problem is that the renewable sector has many risks that these investor classes are not yet completely comfortable with. These risks include potential changes in government support, technology risk, construction risk, and operational risk such as wind resource adequacy and other factors. As these investors better understand the risks in these projects, they will invest more and help industry sustainability (see *"After A Decade Of Wind Power, The Unexpected Is Still Always Expected,"* on p. 45).

There is never a dull moment in the electric power industry, and uncertainty surrounding renewable-energy investment over the next few years will only add to the excitement—for some. Government support has provided the foundation for renewable energy, but this support is now questionable in many countries and can slip away unexpectedly for a number of reasons. Some technologies, such as offshore wind, appear more poised to gain continued support than others, but there is opportunity for new investor classes to provide long-term, and hopefully more stable, financial support. **CW**

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Renewable Energy



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A photograph of several offshore wind turbines in the ocean under a clear blue sky. The turbines are white with three blades each, mounted on yellow steel platforms. A small yellow boat is visible in the water in the foreground. The background shows a vast expanse of blue water and sky.

Strong Growth Of Global Offshore Wind Power Needs Substantial Investment

Overview

- Offshore wind owes its existence to regulatory support.
- The investment potential for offshore wind through this decade is immense. But this technology is not cheap.
- We think utility funding will remain the predominant source for projects in the early stages of development for the next few years.
- Financing for U.S. offshore wind projects differs from that used in Europe, where the utility balance sheet is the most common method of funding.
- Offshore wind power is a relatively new industry with large growth potential, but many factors are impeding investment globally.

Electricity comes from many sources, but there is one source that only a few countries in Western Europe, along with China, take advantage of, and it is in growing abundance: offshore wind power. The industry began in Sweden and Denmark in 1991 but had not grown significantly until recently. European utilities and project developers have built more than 3,800 megawatts (MW) of offshore wind power capacity, according to the European Wind Energy Assn., and another 2,400 MW will become operational globally in 2012 or early 2013, mostly offshore of the U.K. and Germany and to a lesser extent China. Countries are increasingly relying on offshore wind power to help meet social and economic policies over the next decade, but the investment required globally to meet this vision is immense (*see table 1*).

The factors behind the industry's growth in Western Europe and China are fuel diversification, climate-change mitigation, and, more recently, job creation. For the same reasons, governments and stakeholders in many other countries are looking to add offshore wind power to

their resource arsenals, especially where large demand centers are near favorable locations for offshore wind farms.

Funding will be a key issue for industry growth. Utility balance sheets and state lending organizations have been the dominant sources of funding

for this relatively new asset class, but these will not be nearly enough to fund the ambitious investment needed by 2020. Standard & Poor's Ratings Services estimates that the amount needed to meet U.K. and German government goals by 2020 falls between €91 billion (\$117 billion) and €104 billion (\$133 billion).

Project financing is becoming increasingly available for European offshore wind projects as governments, project sponsors, suppliers, and lenders manage investment barriers and help the industry grow.

Favorable Regulations Are The Key To Increasing Investment

Electricity from offshore wind costs much more to produce than that from conventional fossil fuels that dominate supply in most countries. Consequently, offshore wind owes its existence to regulatory support. We do not see this

Table 1 | Total Offshore Wind Capacity By Development Status

Cumulative market, in MW				
—As of June 2011—				
	Online/under construction	Consented	Planned	Total projects
U.K.	5,894	588	42,114	48,596
Germany	1,028	8,725	21,493	31,247
Denmark	854	418	1,200	2,471
China	442	N.A.	N.A.	442
U.S.	0	468	N.A.	468
Rest of the world	1,151	7,610	49,930	58,692
Total global capacity	9,369	17,809	114,737	141,915

N.A.—Not available.
Sources: European Wind Energy Assn., Lindoe Offshore Renewables Center.

Table 2 | Comparison Of Support Schemes For Offshore Wind In Key Markets

	Germany	U.K.
Indicators of growth potential		
Share of energy from renewable sources in gross final consumption of energy	35% by 2020* and 80% by 2050 (from about 17% today); last nuclear plant shutdown by 2022	15% by 2020\$ (from about 6.5% currently) and 80% reduction in carbon emissions by 2050
Offshore wind target	10 gigawatts (GW) by 2020 and 25 GW by 2030	18 GW by 2020
Incentive schemes		
Statutory provisions/laws	Renewable Energy Act (EEG), first passed in 1991; latest amendments in force since Jan. 1, 2012	Currently: Renewable Obligation (RO) Act since 2002; proposals on consultation period under review to be passed into law in 2012: Electricity Market Reform (EMR) and ROC Banding Review (RBR)
Current incentive scheme	Fixed feed-in tariff (FIT) with a maximum term of 20 years. Initial remuneration of 15 cents per kilowatt hour (KWh) for the first 12 years or 19 cents per KWh during the first eight years if the wind farm is operational before 2018. The initial remuneration period can be extended for projects located at least 12 nautical miles from the shore by 1.7 months for every meter deeper than 20 meters. Following the initial remuneration period, the project receives 3.5 cents per KWh until completing the maximum 20-year remuneration period. FITs decrease by 7% per year beginning in 2018.	Premium pricing (renewable obligation certificates, or ROCs) combined with quota obligations. The regulator (the Office of Gas and Electricity Markets, or "Ofgem") maintains ROC prices relatively high by creating an undersupply. Currently, generators are granted 2 ROC per MWh, falling to 1.5 ROC per MWh beginning April 2014 for 20 years from the point of registration for every KWh of electricity produced from renewable sources. Electricity utilities purchase these ROCs as proof that they are meeting their quota obligations if they do not generate enough ROCs themselves.
Scheme under review	None	Currently includes 2 ROC per MWh to April 2015, 1.9 ROC MWh to April 2016, and 1.8 ROC per MWh to April 1, 2017 (when the ROC scheme will no longer be available for new projects), or a two-sided FIT CfD (effectively guaranteeing a fixed price as generators would be obliged to return money if electricity prices are higher than the agreed FIT) from April 1, 2014. Projects subject to the ROC scheme before April 1, 2017, will have such scheme grandfathered throughout the project life, variable until 2027 and fixed thereafter. Items still to be defined are: 1) FIT levels, 2) the government counterparty providing the top-up FIT, and 3) the potential priority access and route to market for power generated under CfD.

changing for years to come. Countries are investing in renewable energy not so much to provide electricity at the lowest cost, but more to meet goals of energy security, climate-change mitigation, industrial policy, or a combination of the three. Government policies have been effective in attracting offshore wind projects to the U.K., Germany, and Denmark, but not yet in the U.S. Interestingly, diverse policies result in favorable investment frameworks and rapid growth (*see table 2*).

Funding Sources And Gaps In Times Of Financial Constraints

The investment potential for offshore wind through this decade is immense. Many countries expect wind power to account for a large share of their renewable-energy investment to meet energy and climate goals. But offshore wind technology is not cheap. Estimating its average cost per MW of installed

capacity is difficult because of variations in key cost factors such as turbine size, distance from shore, water depth, sea and weather conditions, and many other factors, especially as projects move farther offshore. We estimate the average cost at roughly €3.5 million to €4.5 million per MW (\$4,500 per kilowatt), or double that of a typical onshore wind project using proven turbines. At this cost, the new capacity by 2020 envisioned by the U.K. (16 gigawatts[GW]) and Germany (10 GW) alone would require about €91 billion (\$117 billion) to €104 billion (\$133 billion). China's current five-year plan envisioning 30 GW of offshore capacity by 2020 would involve even more investment.

Most European offshore wind projects to date have been sponsored by utilities and funded on their balance sheets. Only utilities could put together funding on reasonable terms to pay for these capital-intensive projects. In addition, utili-

ties are motivated by strategic objectives and regulatory incentives. After construction and commissioning are complete, some utilities sell the project or part of it to long-term investors. But some rated utilities have limited headroom at their current ratings to accommodate the increase in financial risk inherent in the substantial upfront investments required (*see "Credit FAQ: How Electricity Market Reform Could Affect The Ratings On U.K. Generators," published May 24, 2011, on RatingsDirect, on the Global Credit Portal*). This will likely increase the incentive for utilities to develop the projects off their balance sheets through single-asset project financing and shared equity stakes with infrastructure or financial investors.

We think utility funding will remain the predominant source for projects in the early stages of development for the next few years, then gradually decline as offshore wind technology evolves and

Denmark	U.S.	China
30% of electricity consumption covered by renewable energy by 2020§	No binding target; 33 states have announced renewable energy targets (RETs).	11.4% of total primary energy consumption provided by renewable sources by 2015 and 20% by 2020
4.6 GW by 2025	10 GW in the next decade and 54 GW by 2030	5 GW by 2015 and 30 GW by 2020 (compared to about 400 megawatts (MW) currently)
None	Renewable Portfolio Standards (RPS); no special support for offshore wind	Renewable Energy Law (2005); latest revision in effect since April 2010
Fixed FIT contract for difference (CfD) for the first 50,000 full-load hours, and market price thereafter. The FIT level is set under a competitive tender.	Quota obligation for utilities (set by RPS) coupled with production tax credits (PTCs, currently about 2.2 cents per KWh) for renewable energy generation. The support scheme expires at the end of 2012.	FIT set under tender: In the first batch of five concessions tendered in October 2010, the preferred bid prices were considerably lower than market expectations, which, in our view, calls into question the economic viability of these projects. FIT guaranteed at the tender bid price for the first 30,000 full-load hours (could be as much as 10 to 15 years, depending on the capacity factor).
None	Current support scheme expires at the end of 2012.	Given the relative novelty of the offshore wind development program in China, the regulatory framework is yet to be built.

investors are better able to quantify construction and commissioning risks.

Despite the good match of long-term assets with institutional investors' long-term investment horizons, investors have so far shown little interest in these projects until they have established operations and are generating a profit. Institutional investors are typically reluctant to assume construction risk and instead focus on yield. But this is beginning to change. In 2008, a private investor group led by Blackstone Group L.P. began to develop the 288 MW Meerwind project in Germany, the first offshore wind project to be sponsored privately. This €1.2 billion project is in construction and funded with private equity and debt.

On the debt side, the handful of European projects using nonrecourse debt have been financed exclusively with loans, and commercial banks have par-

ticipated with multilateral or state lending organizations in most cases. Negotiating acceptable terms for such a large and heterogeneous group of investors would seem to be a barrier to lending, but the use of such financing is accelerating. This was evident in 2011: Meerwind secured €822 million in loans under the auspices of the German state-owned agency KfW Bankengruppe, which established a €5 billion support scheme to help build out offshore wind projects to replace generation from retiring nuclear plants over the next decade. Also, the German Global Tech 1 project secured €280 million from KfW's facility and €270 million from a group of commercial lenders that also guaranteed €400 million of an additional €500 million loan granted by the European Investment Bank.

One kink in the works could be the gradual application of the Basel III regu-

lation, which increases the capital charge for long-duration loans and thus provides an incentive to rotate capital. We think Basel III combined with the trend of bank downgrades could reduce the amounts and increase the costs of long-term bank lending. This could result in a "flight to quality," whereby banks could restrict their lending to projects with the strongest credit quality and short tenors spanning the construction phase or the typical five- to seven-year mini-perm period (a mini-perm loan is initially a temporary loan that is later made permanent). If that happens, meeting industry growth targets will depend heavily on attracting other investor pools beyond private equity, such as pension funds and capital markets.

Financing for U.S. offshore wind projects differs from that used in Europe, where the utility balance sheet is the most common method of funding.

Table 2 | Comparison Of Support Schemes For Offshore Wind In Key Markets (continued)

	Germany	U.K.
Incentive schemes (continued)		
Incentive counterparty	FIT is paid by the relevant grid operator.	Currently: Utilities entering into bilateral contracts with renewable energy generators for the ROCs. Proposed: Counterparty for the FIT or alternative scheme still to be defined.
Capital grants/subsidies	No	Yes
Tax incentives: electricity generated from renewable source eligible for tax relief?	No	Yes, all renewable energies (including offshore wind) are exempted from the climate change levy on electricity.
Priority grid access and dispatch for renewable power?	Yes	No; pending issue under the ongoing EMR
Transmission responsibility and up-front investment assumed	Transmission operators are remunerated to cover the investment plus a return on capital over the life of the asset.	Project developer is responsible. However, the assets are expected to be sold to an Offshore Transmission Owner (OFTO) under a competitive tender regulated by gas and electricity regulator Ofgem.
Other support	In June 2011, KfW Bankengruppe approved its Offshore Wind Power Programme, providing a dedicated €5 billion debt facility available to the first 10 German offshore wind projects on a first-come, first-served basis.	£3 billion budget for the Green Investment Bank to make direct investments in "green infrastructure" projects beginning in 2015.

Notes: Fixed FIT—Fixed payment that generators receive instead of revenues from selling electricity in the market. Premium FIT—Fixed premium on top of the variable wholesale electricity price. FIT CfD—FIT with a Contract for Difference. Contract between the electricity generator and the government or public energy agency with a fixed "strike" price, whereby payments equal the difference between the average price at which electricity is sold in the market and the agreed price.

*Renewable Energy Act (EEG) 2012. §As defined under the European Union Directive 2009/28/EC.

Sources: (U.K. wind target) Electricity Market Reform white paper; (U.S.) "Pushing Forward: The Future of Offshore Wind Energy" paper by Roland Berger Strategy Consultants; (China) last five-year plan from the National Energy Administration, E&Y Renewable Energy Country Attractiveness indices, February 2012.

Prospects are good for nonrecourse project financing, and small firms or those with limited balance sheets are developing most projects. Equity funding could involve numerous parties, leveraged equity from sponsors, or large private infrastructure funds.

Debt funding is just as challenging as it is in Europe. Bank lending is typically the initial option, as it has been for most U.S. wind projects in the past decade. But U.S. banks are unfamiliar with offshore wind project risks. European banks that understand and can quantify the risks are likely to be major participants—and they already know the U.S. market issues well. But for the bank sector overall, Basel III provisions that penalize long-term assets could make this traditional source of financing less attractive (see “*Basel III And Solvency II Regulations Could Bring A Sea Change In Global Project Finance Funding*,” on page 26.)

Investment Incentives And Barriers

Offshore wind power is a relatively new industry with large growth potential, but many factors are impeding investment globally.

Regulation

The reliance on government support for offshore wind makes the cost of support the central issue, whether it is passed on to end users in higher tariffs or borne by the public through higher taxes. As costs rise, favorable public sentiment wanes, and opposition increases. If the investment greatly exceeds goals, governments can sometimes quickly reduce support, which could harm long-term industry stability in several ways.

Incentives are commonly reduced for future projects as a new technology becomes cheaper, but investors expect

Denmark	U.S.	China
None	Utilities entering into bilateral contracts (purchase-power agreements) for the supply of energy and the acquisition of PTCs.	Grid operators
No	U.S. Department of Energy's Offshore Wind Initiative is investing \$43 million in 41 projects across 20 states over the next five years. It also initiated a six-year (2012 to 2018), \$180 million support program to cover a share of design, hardware, and construction costs.	Renewable Energy Fund, sustained through a national surcharge on electricity prices, is paid twice a year to grid companies by the government to subsidize the difference between wind power tariffs and coal-fired electricity tariffs.
No	Yes: Production tax credits and tax depreciation	A tax refund of 50% of the value-added tax levied on electricity generation from wind power. In addition, wind power operators are entitled to a three-year tax holiday and a three-year, 50% reduction of the 25% enterprise income tax.
Yes	No	Yes
Transmission system operator	Project developers	By law, grid operators have obligations to build transmission lines to connect wind sites and purchase all the electricity generated from wind. In practice, transmission lines for more than half of the projects were constructed by project developers.
None	None	Approved Clean Development Mechanism (CDM), by which carbon-free generators can sell Certified Emission Reduction certificates (CERs) under Kyoto Protocol.

existing projects to be exempt from such reductions. There have been recent cases of countries reducing incentives that had been promised for projects already financed. Gauging the integrity

and sustainability of regulatory support over a project's life is more art than science (see "Credit FAQ: Why Regulatory Risk Hinders Renewable Energy Projects In Europe," on page 40).

Technology and design

The ability of offshore wind turbines and foundations to meet production forecasts over their design life and within operation and maintenance

Policy Framework Background For Key Countries

In much of the world today, wind power is viewed primarily as a tool to mitigate climate change. But energy security concerns that arose after the oil crisis in the early 1970s were the primary impetus behind the contemporary development of the onshore industry, especially in Denmark. Offshore wind power subsequently emerged as a viable renewable-energy resource to meet energy security, climate, and, more recently, industrial development goals, given the better offshore wind resources and turbines that cannot be seen from shore.

Government policies for offshore wind projects have evolved in nearly every case from those for onshore wind.

Denmark Was A Pioneer And Is The Largest Producer Of Wind Electricity Per Capita

Denmark's continuing quest for energy independence surpasses that of any other nation, and wind power has played a major and increasing role since the mid-1980s, providing various forms of support along the way as well as a lot of fervent debate about the costs. According to the Danish Energy Agency, onshore and offshore wind power production in 2010 equaled nearly 22% of the domestic supply of energy, up from about 2% in 1990. Part of this wide and growing acceptance is that early on, those who invested in wind projects had to live near them, thus establishing early a wide lending and ownership base.

Offshore wind came into the resource mix in the early 1990s with two government-directed projects, one of which, in 1991, was the world's first multi-turbine project, located about one kilometer off the coast near Vindeby. About a decade later, the government accelerated development by opening up a competitive tender process for much larger projects to support stronger energy security and carbon-reduction goals. The tender process adds a measure of market discipline that remains a key aspect of offshore wind project compensation. At the same time, the government assumed control of the transmission grid and gave the grid operator the responsibility to build it out to support renewable energy, a key policy incentive that has encouraged investment. As security and climate goals strengthened, offshore tenders have continued. By year-end 2011, Denmark had 857 MW of offshore capacity, according to the European Wind Energy Assn. (EWEA).

In 2011, the government adopted a policy to supply 50% of its energy demand in 2020 with renewable resources, which resulted in the 600 MW Kriegers Flak project that will become operational between 2018 and 2020. In addition, the government announced in March 2012 that wind power alone should supply 50% of the demand by 2020, and another 900 MW of installations will be built before then.

Offshore Wind Should Help Germany Fill The Gap Left By The Nuclear Shutdown

The German response to the 1973 oil crisis was, like Denmark's, geared toward energy security with an emphasis on coal and nuclear investment. Germany initially lagged behind Denmark in developing policies to promote wind energy, but times have changed. Although Germany inaugurated its first large-scale offshore wind project seven years after Denmark did, Germany's policies will require greater investment and thus project finance potential.

Germany has supported renewable-energy investment since the oil crisis, but it did not form intensive policies until the late 1980s. Policy drivers included the 1986 Chernobyl disaster and the rise of climate-change concerns, especially given the country's high use of coal in power production. Its policies have resulted in the development of a formal feed-in tariff (FIT) in use since the early 1990s that has been the foundation for renewable-energy investment, especially for offshore wind. The FIT varies by asset class depending on government interest, and offshore wind was added in 2000 when the government adopted policies to greatly expand electricity supply from renewable resources.

Thanks to the FIT, offshore wind investment has grown from zero in 2009 to 120 MW today. Another 800 MW is in construction, and more than 8 GW has been authorized (see table 1). Investment will grow even more in the decade ahead as Germany shuts down its nuclear power plants in response to the Fukushima nuclear catastrophe in Japan in 2011.

To support this rapid exit from nuclear power, the German government revised investment incentives for its preferred replacement candidate, offshore wind, to realize 10 GW of capacity by 2020. Offshore wind developers can choose between the existing FIT or a higher FIT over a shorter period for projects that are operational before 2018 (see table 2). In addition, the reduction in the original FIT was postponed to year-end 2018 from 2015. Finally, the German state-owned agency KfW Bankengruppe offered a €5 billion loan scheme to help fund the construction of the initial 10 offshore wind projects, on a first-come, first-served basis. Meerwind was the first.

This abrupt change in policy is favorable to offshore wind but introduces risk by rapidly expanding industry demand beyond the supply available.

The U.K. Has Ambitious Offshore Wind Targets And Ongoing Regulatory Reform

The U.K. is the uncontested world leader in offshore wind power, with more than 2 GW of capacity online at year-end

(O&M) expectations in harsh conditions is the key technology risk. Most turbines in use today range from about 2 MW to 5 MW. Small ones have operational histories of about 10 years, but

large ones have been in use for only a few years. The newer turbines of about 5 MW that are increasingly preferred for offshore projects have not been in use long enough to enable

developers to soundly gauge long-term performance.

Offshore wind turbines generally experience the same problems that onshore ones have—electrical and

2011 (according to the EWEA)—essentially double the amount in the rest of the world (see *table 1*). More than 4 GW are in construction, and there is vast potential for more. But, the key policy issue is that this growth comes at a high cost, and so has considerable opposition.

Government support and the U.K.'s natural advantages—a long coastline, shallow waters, and heavy winds—have enabled it to achieve this leadership position. The U.K. also has substantial incentives in the form of Renewable Obligation Credits (ROCs) that it grants to eligible renewable-energy generators for each megawatt hour (MWh) they produce. ROCs also provide a premium to the market price (see *table 2*).

The Department of Energy and Climate Change is proposing energy sector reform to increase private-sector investment in low-carbon energy sources to meet goals of 15% renewable-energy supply share by 2015 and an 80% carbon reduction by 2050. The proposal is scheduled to go to Parliament this year, so we do not expect implementation until 2013.

The proposal targets 18 GW of offshore wind installed capacity by 2020. Incentives include higher ROCs for offshore wind projects built between 2014 and 2017. Afterward, ROCs will be phased out and replaced by a fixed-price remuneration system in the form of FIT Contract for Difference (CfD), by which renewable-electricity generators will enter bilateral contracts to sell electricity into the wholesale market and receive a supplemental payment from the government (or a government agency) for the difference between the wholesale price and the agreed tariff. Renewable-energy generators may choose between both remuneration schemes in the transition period from April 2014 through March 2017. This seems good for investment: The ROC price varies with market prices, but the CfD is fixed.

Still, key questions remain. One is, will power generated under FIT CfDs have priority access to the grid and dispatch? This is a key credit feature for an intermittent fuel source such as wind (see the “Interconnection” section). Another key question is which counterparty will pay the FIT CfD.

And there is always that pesky issue of how much of the cost the consumer must ultimately bear. The regulator, the Office of Gas and Electricity Markets, estimates that user bills could go up by 14% to 25% between 2010 and 2015 to fund the estimated £200 billion investment involved in the proposed Electricity Market Reform. This hit on the wallet could lead to a lack of support for offshore wind, especially if the current economic conditions persist.

The U.S. Is A Late Adopter With A Long Way To Go

Onshore wind investment in the U.S. has been a big success, primarily because of federal production tax credits (PTCs) and some state mandates that require utilities to provide a certain share of the supply from renewable-energy sources. Wind technology is generally the most economically attractive. But offshore wind investment remains constrained by an emerging permitting process, high costs, and a long development cycle, despite having support schemes similar to those of Europe. The industry is active, though, and may soon begin one or more projects along the East Coast, given the proximity to large load centers with high electricity prices, shallow waters, and limited storm risk.

The federal and state permitting processes for offshore wind projects are in their infancy and doubly challenging when both state and federal jurisdictions are involved. It was not until 1995 that the Department of the Interior obtained authority to approve and grant leases in federal waters for offshore wind projects. Cape Wind Associates, developer of a 468 MW wind project in Nantucket Sound, obtained a lease in April 2010, nearly 10 years after the project's initial submittal. Few developers can stomach 10 years of expense just to get a permit, much less construct and start up a plant. Regulatory processes must be streamlined, shortened, and more predictable for the U.S. to tap into offshore wind power potential.

The U.S. subsidy framework is much weaker than the Danish, German, and U.K. regulatory schemes. Federal financial support for wind power is largely limited to a PTC per kilowatt hour over 10 years, which covers about 20% to 25% of a project's cost. This has two big drawbacks for investment. First, the PTC program is usually mandated for only a few years and is therefore subject to continuing renewal risk. The current program ends near year-end 2012. Congress's failure to renew it several times during the past decade has led to huge investment reductions each time. Given current budget constraints, no one knows whether Congress will renew the program. The problem for offshore wind projects is that the development cycle spans many years, beyond which the PTC may not be authorized. For example, the promising 450 MW Bluewater project in Delaware recently cancelled its long-term purchase-power agreement, citing an inability to finance the project, partly because of the uncertainty of PTC support.

The second drawback is that most renewable-energy projects cannot fully realize the tax benefits of the PTC because of low tax exposure. This requires tax equity participation in most projects to make efficient financing possible. This adds complexity and cost to transactions, but more important, it limits the investor pool.

control systems, gearboxes, blades, and especially foundations. The foundation represents a much higher share of the total cost than it does for onshore projects. Sea and wind conditions add considerably to load fatigue and materials degradation. In addition, the integrity of the connection between the turbine and foundation has emerged as a problem in some designs, leading to unexpected outages and repair costs for some projects.

Operating experience will help put technology risk in better perspective. But such risk will always be present in offshore wind projects as long as developers want to use larger turbines in deeper waters where wind regimes are stronger to gain economies of scale and reduce costs.

Construction

Construction risk is much greater for offshore wind projects than onshore ones, given the special boats, cranes, and highly skilled personnel required to complete construction on schedule, on budget, and to performance requirements—under sometimes precarious sea and wind conditions. Success with offshore projects requires proven contractors, sound project management, and solid logistics skill, as well as contingencies for unexpected weather conditions. Several firms have cited weather delays, installation vessel unavailability, cabling difficulties, and materials problems as causes of massive cost overruns.

The highly complex nature of offshore wind project construction requires strongly structured engineering, procurement, and construction (EPC) contracts that allocate price, schedule, and performance risks to a single party. But the diverse nature of the construction involved—foundation installation, turbine supply and erection, vessels, and undersea transmission cabling—makes it difficult to arrange single-point EPC contracts. Therefore, projects often hire multiple contractors. But this decreases the likelihood that any single party will accept overall construction risk; one

contractor's poor performance could lead to delays or other problems for another and disagreement about who was responsible.

The allocation of responsibilities and penalties for nonperformance must be clear, especially given the vagaries of weather and the overly complex nature of the construction. Successful projects require strong contractors that have favorable experience in performing their specific activities and an absolutely sound interface plan. Projects must also have effective contract provisions to mitigate the risk of a contractor's nonperformance.

Interconnection

In Denmark and Germany, transmission system operators are responsible for the construction and financing of transmission infrastructure to hook up offshore projects. This has good and bad implications. It substantially reduces the project's cost, and hence funding needs, but it also forces the project to rely on an external party for a critical item. Being able to manage unexpected events is critical.

In Germany, the rapid growth in offshore wind projects has exceeded the independent grid operator's ability to build out the transmission system quickly in some areas to support them. Offshore projects under construction could experience start-up delays, and those in development may not be able to get financing until the supply chain catches up.

Risk remains during operations, too, if large demand centers face grid constraints, or if jurisdictions do not grant priority grid access and dispatch for intermittent renewable energy. In these cases, the grid may be unable to accept the entire wind project's output at all times, especially during off-peak periods when wind capacity may be highest.

Operations and maintenance

As with most projects, O&M for offshore wind energy focuses on turbine availability and cost certainty. An offshore wind project will lose cash flow if a turbine becomes unavailable.

Turbines can be hard to maintain, especially in bad weather and rough seas, and even more so if a boat and crane are not available. Many offshore turbine technologies were developed with special emphasis on resolving availability problems remotely, but sometimes personnel are required to implement repairs. So, the better projects have a sound O&M plan to deal with these issues.

Many wind projects typically mitigate O&M risk for the first two to five years of operation (the typical start-up period) through an agreement with the equipment supplier that enhances the technology warranty. Projects may extend an O&M agreement thereafter, but O&M for offshore wind is far more complex than that for onshore wind. The better projects performing their own O&M will be able to obtain the vessels, cranes, and personnel at expected rates. This can be hard to do well for a long period, given the lack of long-term O&M data on newer turbine technologies and foundations.

Wind resource

Revenue schemes for most, if not all, offshore wind projects provide a payment for electricity provided, but not for capacity. Therefore, revenues are linked directly to the wind resource and how it is modified as it travels through the wind turbine array (called the “array effect”). A lot of actual and modeled data is available on the various offshore wind farms in Europe. The best data is that collected at the height of the turbine nacelle, but this is often limited for most projects, especially those slated for deeper waters. This introduces uncertainty of production, and thus of cash flow, which can dampen investor sentiment. Successful financing of offshore projects in the U.S. will have to overcome an even weaker data set.

Onshore wind resources can be much more variable than experts initially expect, and we believe the same is true for offshore wind. Many European onshore wind projects have experienced much weaker production than expected, despite often having

two or three assessments from independent technical experts that factored in much long-term data from operating plants and ground locations, such as airports and weather stations. (*See “After A Decade Of Wind Power, The Unexpected Is Still Always Expected,” on page 45.*) Because offshore wind projects have less data available, one or two years of onsite data at hub height cannot provide reliable projections of offshore wind resources for a 20- to 25-year debt term. More data will gradually become available, resulting in better estimates, but the wind resource will remain a key risk to offshore wind projects.

Capital structure

The revenue support mechanism for offshore wind projects can vary, and lending arrangements need to take this into account. The Cape Wind project in the U.S. in Nantucket Sound secured a purchase-power agreement (PPA) with a price that is fixed initially and escalates with inflation, so one can reasonably forecast PPA prices. In Germany, a project earns the feed-in tariff (FIT) price for 20 years and so can establish a 20-year debt tenor to match. However, the pricing mechanism may have step-downs at times and further adjustments if energy production differs from expectations. In the U.K., revenues are exposed to market electricity and emissions credit prices, in addition to wind risk. In Denmark, an offshore project earns a fixed price up to a maximum amount of energy production. If the actual production exceeds (or falls short of) initial expectations, the revenue stream will end before (or extend beyond) debt maturity. **CW**

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Basel III And Solvency II Regulations Could Bring A Sea Change In Global Project Finance Funding

Overview

Possible changes include:

- Higher costs to obtain project finance loans,
- Ongoing changes related to which banks offer project loans,
- A change in how banks structure such loans,
- More refinancing risk for some bank loan financings,
- A shift to more capital market funding of project finance transactions, and
- The creation of innovative financing solutions such as effective targeted risk transfer techniques to improve projects' credit quality.

Banking institutions have traditionally dominated global project finance lending (*see chart*). While traditions can be tough to change, we believe stricter regulations governing bank lending under Basel III—the Basel Committee on Banking Supervision's new global standards for banks' liquidity and capital adequacy—will bring profound changes to the global project finance sector and the ways it pursues funding.



Banking regulators are putting Basel III into effect country by country (with an official target for completing the rollout by 2018), and each nation's regulatory body has its own interpretation of how to apply the rules. Standard & Poor's Ratings Services expects Basel III standards to require banks to significantly increase their capital reserves, particularly common equity. This could threaten banks' return on equity and, in turn, their market values. Banks' opposition to Basel III is growing as they continue to deal with increasingly difficult business conditions such as the eurozone crisis and sluggish economies. Variations in how national regulators might implement and interpret Basel III—including heated debates over risk weighting—are adding to the bank industry's angst.

The EU's Solvency II directive—which some call “the Basel III of the insurance industry”—could also directly shape project finance because it imposes, for the first time, capital requirements on the asset risk of insurance companies (see “Why Basel III And Solvency II Will Hurt Corporate Borrowing In Europe More Than In The U.S.,” published Sept. 27, 2011, on RatingsDirect, on the Global Credit Portal). Like Basel III, Solvency II imposes higher capital charges for lower-credit quality and longer-dated financial instruments. Given that project financings are typically highly leveraged, any change to the cost or availability of debt

or swaps is a potential challenge to the viability of some projects.

The Form Of The Basel III Rollout Remains Hazy

There is still-significant debate as to how Basel III will be implemented in each country, and many banks have begun lobbying against Basel III in earnest. In September, the Institute of International Finance (IIF, a global association of about 400 large commercial and investment banks) published a report titled, “The Cumulative Impact On The Global Economy Of Changes In The Financial Regulatory Framework,” stating that given the weakened economies in the U.S., the eurozone, Japan, the U.K., and Switzerland, Basel III could lead to the loss of 7.5 million jobs and a 3.2% reduction of GDP by 2015 in those economies (thereafter, the IIF believes such negative effects will fade).

New Regulations Could Complicate Refinancing Of Current Loans

Most bank loans to projects have to be refinanced during the life of a project and this introduces refinancing risk. Because a project's revenues are often largely fixed, refinancing risk—the risk that existing project debt with a bullet maturity cannot be repaid from a new borrowing or other refinancing because the terms of such new borrowing or refinancing are uneconomical—can be

material. As we note in “Summary Of Standard & Poor's Criteria Methodology For Refinancing Risk In PPP/PFI Projects,” published Oct. 28, 2009, a project with no refinancing risk is more likely, all other things being equal, to have a stronger credit profile than one exposed to refinancing. In a limited life concession typical of project finance transactions, there is an additional time pressure to undertaking the refinancing. And amid the continuing sluggish global economy, Basel III and Solvency II could introduce further uncertainty about refinancing and hence increase credit risk—particularly for those project finance loans whose business risks have changed.

Banks made many of these loans when market conditions were better or business prospects for the future were rosier. For instance, in the U.S., tax incentives helped spur a solid stream of wind power financings from about 2000 onward. Many of the deals in the period 2000 to 2006 relied on wind resource forecasts that have since proved to be overly optimistic, thus increasing refinancing risk. Further complicating matters are the likely higher funding costs and lower availability of long-term bank credit due to these new regulations. Hence, a capital markets bond financing to replace the bank debt might be an increasingly attractive option to banks. However, banks have been aggressive in structuring many current project loans. As such, these loans were not necessarily structured to readily facilitate an investment-grade bond market issuance to fund the refinancing. And for many capital market investors, investment-grade is their preference. Furthermore, the proposed new capital charges under Solvency II discourage long-term investing by insurance companies.

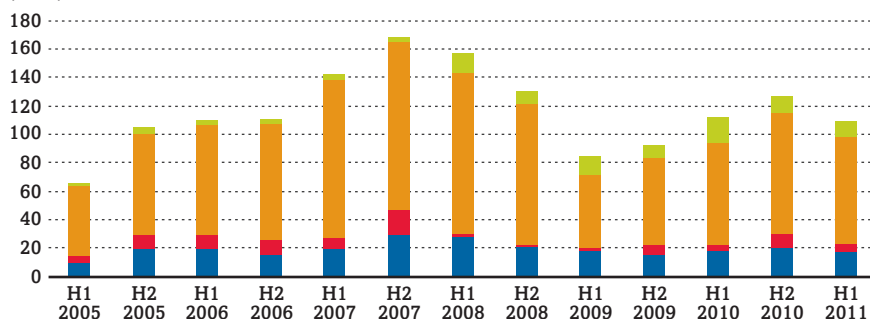
Changes Could Usher In New Funding Types, Business Models, And Providers

The general sentiment among bankers is that adopting Basel III “as is” would discourage banks from holding longer-term loans on their balance sheets, due to the net stable funding requirement (NSFR;

Global Volume By Source Of Funding

Equity Bonds Loans IFI support

(Bil. \$)



IFI—International financial institutions (including multilateral and development bank support).

Source: Infrastructure Journal.

© Standard & Poor's 2011.

see Appendix). In fact, some banks have or will significantly reduce or exit the project finance business and some other product lines because of this and other Basel III requirements. Increasingly, banks are distributing lists of project assets for sale to get them off their balance sheets. Moreover, we're seeing signs that some banks that depend more heavily on government support are getting encouragement from those governments to focus the use of bank capital on lending in their domestic markets, with a view to preserving jobs.

We believe banks may try to encourage sponsors to borrow for shorter terms and to accept refinancing risk. In Australia, the use of shorter terms with refinancing is widespread. If this happened, we anticipate seeing increased use of project features such as interest rate step-ups and cash sweeps that can reduce refinancing risk. Two-phase financings might become en vogue again, e.g., construction financing funded by banks loans then takeout through bonds.

An increase in shorter-term refinancing may require changes in how revenue agreements (such as a power purchase agreement or government concessions) are structured. Such arrangements are widely used in project financings and often support a stronger credit quality. Revenue contracts are often 30 years or longer for government concessions and some power projects, and even commodity-linked projects often have more than 10-year terms. Such agreements might need to be designed to accommodate more frequent and shorter-term refinancings that could be on different financial terms and conditions than originally projected.

Some banks are also considering increasing their presence in the capital markets. Basel III considers project bonds favorably, from a capital coverage perspective. In some regions, programs such as the EU's Project Bond Initiative (see "How Europe's Initiative To Stimulate Infrastructure Project Bond Financing Could Affect Ratings," published May 16, 2011) has been developed to encourage institutional investors to participate

more in this asset class. We are observing an increase in the number of new debt funds. In addition, we are recognizing the appetite of bond investors for instruments with stronger credit quality; financial innovations, such as effective targeted risk transfer techniques to enhance credit quality of projects, are being developed.

Liquidity Requirements May Threaten Certain Project Finance Credit Facilities

Basel III introduces new liquidity requirements for banks through its liquidity coverage ratio (*LCR*; see Appendix). In its current form, the *LCR* could penalize undrawn revolving credit facilities made to special-purpose vehicles by requiring 100% coverage. However, the effect on banks will be minimal because, as the law firm Linklaters points out, these facilities represent a relatively small percentage of banks' debt exposure. On the other hand, the *LCR* could threaten the use of letters of credit, which are prevalent in project finance. Local country regulators can set the Basel III liquidity coverage ratio requirement, and Linklaters has indicated that a coverage level of 25% or higher might make letters of credit economically unattractive to banks unless they were tied to concessions from sponsors (See "Basel III and Project Finance," published in *Project Finance International*, June 29, 2011, Issue 460).

New Paradigm In Global Project Finance Funding Is Still Being Defined

The end game for what might be the new paradigm in global project finance funding is hard to predict, as the powerful forces of politics, regulations, and business are still crossing swords. At this point, we are considering various scenarios arising from these new regulations and evaluating what potential credit implications there could be for project finance transactions. We are also applying existing criteria or will develop new methodologies to assess credit risk for financing innovations that the market might devise.

Appendix: Basel III And Solvency II—A Primer

The main changes to bank regulation proposed in Basel III

The Basel III bank regulatory regime, agreed on by the members of the Basel Committee on Banking Supervision, is the successor to Basel II, implemented at the start of the past decade. This, in turn, was the successor to the Basel Accords of 1988 on minimal capital requirements for banks, known as Basel I. By establishing tighter capital requirements and introducing liquidity, funding, and leverage guidelines, the most recent proposals in our view indirectly recognize the shortcomings of Basel II in these areas in light of the recent financial crisis.

The key regulatory changes, to be implemented in stages between 2013 and 2018, are as follows:

Increased capital requirements. These aim to provide a large enough buffer to absorb losses by banks during periods of stress, and increase the risk weights placed on market activities. The regulatory changes related to market risk capital requirements are better known as Basel 2.5 and will be implemented in January 2012, one year before the Basel III package. The Basel III regulations will raise minimum total capital requirements in a step-by-step process until 2018, at which time they should reach 10.5% from the current 8%. This includes the so-called capital conservation buffer, which creates constraints on banks' capital and shareholder distribution policies. The regulations impose further minimum capital requirements for systemically important financial institutions, with a capital surcharge of up to 350 basis points (bps). On top of this, the Basel Committee is discussing imposing a countercyclical capital buffer of up to 250 bps for all banks. It increases not only the quantity of capital, but also its quality, with minimum common equity more than doubling to 4.5% by 2015, including the capital conservation buffer, and to 7% by January 2019 from the current 2%. The new capital charges also aim to reflect counterparty credit risk in light of the Lehman

default and its aftermath. We anticipate that those most affected will likely be financial institutions with large derivatives and trading businesses.

New liquidity and funding ratios. By introducing these ratios in 2015 and 2018, respectively, banking supervisors aim to prevent run-offs on banks perceived to be vulnerable. The liquidity coverage ratio tests the stock of high-quality liquid assets relative to net cash outflows over a stressed period of 30 days. The funding ratio—known as the net stable funding ratio—tests the amount of stable funding relative to the required amount of stable funding over one year.

The introduction of a leverage ratio. As a supplementary measure, the leverage ratio should identify outlying banks relative to their peers and prevent institutions from subverting capital requirements. The ratio will measure high-quality capital relative to a total exposure or asset measure.

The key changes to insurer regulation in Solvency II

The Solvency II EU directive that codifies and harmonizes the EU insurance regulation promises to transform the industry (*see "Solvency II Implementation Looms, But European Insurers Still Face Uncertainty After Fifth Quantitative Impact Study," published April 6, 2011*). The predecessor regime, Solvency I, dates back over 30 years and generally is no longer regarded as fit for its purpose. Per draft legislation, the effective date for Solvency II is January 2013, although it may be deferred by up to one year. Furthermore, transitional measures over as much as 10 years will cushion the initial impact.

The implications for insurers are huge, in our view, and will significantly weigh on insurers' investing activities, which currently attract no capital requirements at all, regardless of risk characteristics. Based on the fifth Quantitative Impact Study, the risk-based capital regime of Solvency II will introduce shorter dated and highly rated debt instruments over longer-dated and lowly rated instruments. The European insurance industry

currently holds investments valued at about €7 trillion, 40% of which is held in debt securities.

Solvency II consists of three pillars: quantitative requirements; qualitative requirements, including risk management; and disclosure requirements. Like Basel III for banks, the introduction of solvency and minimum capital requirements should, in our opinion, lead to increased regulatory consistency across jurisdictions—within the EU at least—particularly in the area of risk-based capital adequacy relative to economic risk.

Introduction of a solvency capital requirement. The centerpiece of the first pillar of Solvency II is the introduction of a solvency capital requirement. It aims to provide a standard measure for market, underwriting, and noninsurance risks, as well as counterparty default risks. The measure reflects the aggregate effect of stresses reflecting these risks, focusing on a market-consistent value of the assets and liabilities. Insurers that breach the requirement would not face automatic regulatory intervention, but will require management to submit to the regulator a plan demonstrating how it will rectify the breach.

Introduction of a minimum capital requirement. The regulation also introduces a minimum capital requirement, which should be an absolute minimum level of capital, a breach of which would result in ultimate regulatory intervention. Market participants expect that the corridor for the requirement will range between 25% and 45% of the solvency capital requirement. **CW**

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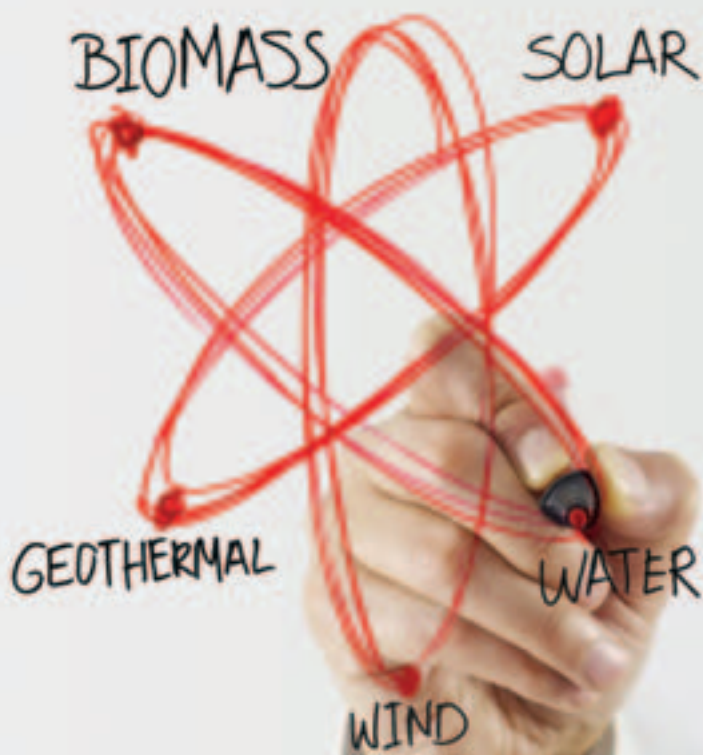
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Support For Renewable Energy Inches Ahead While Global Energy Demand Grows By Leaps And Bounds

Overview

- Global energy consumption is estimated to increase roughly 2% a year through 2030. At this rate, energy use would double every 35 years.
- Wind power represented just 1.5% of global electricity production by the end of 2008.
- The U.S. will need significant investment, possibly as much as \$93 billion, in transmission lines to carry electricity from regions that generate the most wind power to areas where demand is highest.
- If the U.S. is to reach any of its milestones, states will have to play an important role.
- Solar power may provide a more cost-effective alternative to wind power.

With energy consumption worldwide projected to roughly double in the next 35 years, conventional wisdom says renewable sources of power will play a big role in meeting demand.

The conventional wisdom may be wrong.

Cost, feasibility, and political wrangling all stand in the way of near-term renewable-energy expansion, globally and in the U.S. The sputtering economic recovery in the U.S. (combined with historically low natural gas prices) and a wave of austerity sweeping through Europe's legislatures are not fostering a celebratory mood when governments propose spending on renewable-energy infrastructure. Even fast-growing economies in Asia, where energy consumption looks set to far outpace that in other regions, seem content to rely on fossil fuels for the time being.

Global energy consumption will increase roughly 2% a year through 2030, according to estimates by the International Energy Agency (IEA). At this rate, energy use would double every 35 years. The IEA predicts that the highest growth will be in Asia, at about 3.7% a year, and countries outside the Organization for Economic Cooperation and Development, at approximately 3%. The lowest growth in consumption will likely be in Europe, at about 1% per year.

Now consider that about 80% of the world's energy needs are met using fossil fuels. In the U.S., for example, nearly half of the electricity production comes from coal. Yet, wind power, which is among the world's fastest-growing sources of renewable energy, represented just 1.5% of global electricity production by the end of 2008. Europe is light years ahead of the rest of the world in using it.

Europe accounts for more than half of the world's total wind energy capacity and boasts seven of the world's 10 biggest markets for wind-powered electricity. Wind power generation in Europe will increase roughly 9% a year until 2030, according to the *Wall Street Journal*. By contrast, the U.S. accounts for only about 2% of global generation and produces enough wind-powered electricity for just 13 million of the country's 115 million homes.

The U.S. Department of Energy (DOE) plans to narrow that gap significantly in

the next two decades. The DOE says wind power could meet 20% of total U.S. electricity demand by 2030, up from about 3% now. This new capacity would replace half of the natural gas-powered generation and 18% of the coal-fired generation. The National Renewable Energy Laboratory (NREL), which is funded by the DOE, is even more ambitious. It suggests that the Eastern U.S., where onshore-wind resources are in short supply, could meet 20% of the total demand by 2024.

Money For Wind Power Doesn't Grow On Trees

Clearly, costs come into play with plans of this magnitude. The country would need significant investment in transmission lines to carry electricity from regions that generate the most wind power to areas where demand is highest. The cost to achieve the NREL's target could run to \$93 billion, the group says.

In addition, reaching the 20% goal would probably require substantial investment in offshore wind power infrastructure, which doesn't currently exist in the U.S. The DOE predicts offshore wind could deliver about 17% of the total supply in the U.S. And although offshore wind power generation is generally more reliable than onshore power generation, offshore power is also more expensive.

Generally, environmentalists welcome the focus on renewable-energy sources because of the promised reduction in fossil fuel pollution. But, some groups oppose offshore wind farms because of concerns about their effects on marine life, potential impediments to fishing and boating, and, perhaps most vehemently, what some consider the "visual pollution" that acres and acres of windmills would create. Such disputes are not confined to local residents. American real estate tycoon Donald Trump has threatened to sue Scotland if



Many of the studies showing the economic and environmental benefits of renewable energy may, however, be little more than mathematical exercises.

the nation continues its plan to build a wind farm off its east coast, less than a mile from a luxury golf course Trump recently built—a plan, he says, he was promised would not come to fruition.

In any case, the economic feasibility of pouring federal money into renewable energy, especially with Washington's continual bickering over the U.S. deficit, is a matter of debate. Proponents cite national security interests for their support for increasing investment. They see decreasing—or ideally eliminating—U.S. reliance on energy-producing materials from other countries as a top priority. Other proponents say the industry could generate tens of thousands of jobs and pump billions of dollars into the economy. Opponents suggest these numbers are inflated, at best, and fail to recognize the substantial initial investment required. Nonetheless, the U.S. wind power industry received 42% of all federal subsidies for electricity generation in 2010, according to the Energy Information Administration (EIA).

If the U.S. is to reach any of the aforementioned milestones, states will have to play an important role. California, often in the vanguard of renewable-energy advancements, has more than doubled its wind-power capacity in the past decade, and wind now supplies about 5% of the state's electricity needs. On the other side of the country, a study by the Community Foundation for the Alleghenies showed that boosting the renewables portion of Pennsylvania's so-called alternative-energy portfolio standard would be a boon to the state's economy. Increasing renewable-energy sources there to 15% by 2026 from the current target of 8% could create more than 125,000 new jobs and add more than \$25 billion to Pennsylvania's economy.

Greater Use Of Solar Power Could Make More States "The Sunshine State"

Solar power may provide a more cost-effective alternative to wind power. Although installing a solar energy system is often expensive, the capacity for generation is, theoretically, limitless, and the cost of energy from it is, essentially, zero—thus producing savings that would continue long after the system's cost has been recouped. Again, the latter point is debatable, considering that the lifespan of solar-energy systems is finite, and replacing them carries significant costs.

Currently, solar power contributes only about 0.1% of U.S. electricity production, according to 2009 figures from the IEA. But, U.S. solar capacity is growing quickly, increasing 17% in 2007 alone, according to the Solar Energy Industries Assn. trade group. Other industry groups predict solar power use will meet 10% of the country's energy needs by 2025.

Many of the studies showing the economic and environmental benefits of renewable energy may, however, be little more than mathematical exercises. Both the EIA and IEA predict that the biggest increases in global energy consumption will come in fossil fuels: oil, coal, and natural gas. Although the groups say the generation and use of renewable-energy sources will also grow, they will pale by comparison. In fact, the groups say consumption of fossil fuels will be twice as high in 2020 as it is today. **CW**

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U.S. Offshore Wind Investment Needs More Than A Short-Term Production Tax Credit Fix

Overview

- Offshore wind projects offer a potentially vast source of clean energy. But this technology is much more expensive than onshore applications, and it has a long and costly development cycle.
- Financial support, direct and indirect, can take many forms and can vary by the type of technology to be used.
- Federal production and investment tax credits (PTCs and ITCs) are the key support mechanisms for attracting investment in renewable energy.
- The PTC as enacted is more helpful to onshore wind projects than offshore ones.
- Cash grants and state Renewable Portfolio Standards (RPS) are other viable sources of support.

Renewable energy sources usually produce electricity more cheaply than the conventional fuels that supply most markets. Investment in renewable energy depends on direct and indirect government support. Support programs have been successful in encouraging investment, but they involve a public cost, are subject to politics, and can have positive and negative effects on supply markets. Until recently, many countries considered the cost acceptable, but the recent financial crisis in Europe and record budget deficits in the U.S. have put such support under the public microscope. The outcome may not be favorable for achieving sustainable growth, a key characteristic of any successful industry.

The U.S. wind power industry is dealing with the same issue and trying to get Congress to continue the main source of federal support, the production tax credit (PTC), beyond the end of 2012. This support has enabled rapid industry growth in onshore wind during the past decade. Without the PTC, investment drops quickly. A new element to the debate is how to provide support for investment in offshore wind projects, which can provide substantial amounts of clean energy but at a high cost. The difficult permitting process and long development cycle of offshore wind do not match well with a short-term PTC extension. Policymakers need to consider other options of funding if they want to see the role of offshore wind expand.

Offshore wind projects offer a potentially vast source of clean energy, especially near large northeastern population centers. Many states along the Eastern Seaboard are very interested in exploiting this energy potential and reaping the benefits from the port, marine, and supply industries that would follow. But, offshore wind technology is much more expensive than onshore applications and has a long and costly development cycle that is not well-suited to short-term federal support schemes. Offshore wind in the U.S. also lacks a well-functioning and timely regulatory approval process (*see "Policy Framework Background For Key Countries," in the article titled, "Strong Growth Of Global Offshore Wind Power Provides Big Opportunities For Project Finance," published May 16, 2012, on RatingsDirect, on the Global Credit Portal*).

In sharp contrast, several European countries have adopted a number of policies that have led to large growth in offshore wind, and the U.K. and Germany have the most new construction and potential (*see chart*).

Government Support Takes Many Forms

Support for renewable energy globally has developed in three phases, and a fourth has emerged recently in Germany. Initial support was to achieve energy dependency, especially since the oil crisis of the 1970s. The next phase came in the 1980s, when renewable energy emerged as the best way

to meet climate-change goals. More recently, renewable energy policy has been geared toward the creation of "green technology" manufacturing jobs that will hopefully jump-start economies. Finally, a large increase in renewable energy sources will be the only way Germany can successfully retire its nuclear energy plants within a decade, and offshore wind will play an important role there.

Support, direct and indirect, can take many forms and can vary by the type of technology to be used. Direct support includes feed-in tariffs (FITs), which Canada, Germany, Spain, and other countries use in various forms. Denmark uses a long-term agreement based on tender offers. And the U.S. government attracts investment through production and investment tax credits and favorable accounting treatments.

At the other end of the spectrum is indirect support, which usually involves regulatory mandates that require utilities to include a certain share of their total supply from renewable energy. There are usually penalties for not meeting the requirements. The U.K. Renewables Obligation and U.S. state Renewable Portfolio Standards fall into this category. Another form of indirect support is a carbon tax on carbon-intensive users, which raises the cost of fossil fuels and makes renewable sources more price-competitive. Australia is implementing a carbon tax in July 2012.

U.S. Tax Credits Highlight The Incompatibility Of Short-Term Support And Long Project Development

Federal PTCs and investment tax credits (ITCs) are the key support mechanisms for attracting investment in renewable energy. U.S. onshore wind capacity has grown tenfold since 2002, from about 4,700 MW to nearly 47,000 MW today, largely because of the PTC.

A wind project earns the PTC for each kilowatt hour of production for the first 10 years of operation. A project must be operational before the PTC enactment period expires. At about 2.2 cents, the PTC can provide about 20% of the installed cost of an onshore wind project.

PTCs cannot be sold to third parties but must remain with the project.

The PTC has several favorable elements. Remuneration is based on production, which encourages using the best wind resources available. It also requires investment discipline. No one is forced to buy a project's power, so the project must make itself attractive to purchasing utilities and allocate risk appropriately through power-purchase agreements (PPAs) or other means. Remuneration also does not rely on a government outlay, but rather on a reduced payment to the government—always a plus. This better ensures that the project can realize the full PTC value over 10 years, though some risk remains. Lastly, as a federal tax break, the PTC essentially transfers much of the higher cost of renewable energy to the federal taxpayer and away from the local utility and thus customers.

But the PTC as enacted is not as helpful to offshore wind projects. One major drawback of the PTC is the uncertainty of its availability. The PTC is usually enacted for a short period, usually about two years. Sometimes, Congress extends it before it expires, but Congress has also let it lapse and then renewed it a few months later. In effect, the PTC is more unpredictable than wind itself. Onshore wind projects can deal with this short tenor because of quick approval and short construction times. But, this uncertainty leads to rapid project development and construction before the PTC's expiration, which introduces some risk about how well construction was performed and whether it went over budget in the rush to chase scarce resources. It also leads to boom-and-bust investment cycles that discourage major foreign equipment suppliers from investing in domestic manufacturing and spare parts, which then results in continued reliance on import availability and foreign exchange risk. This keeps costs high when they need to decline.

The uncertainty aspect also leads to massive spending on lobbying the government every couple of years to continue the program rather than on R&D to improve technology and reduce unit costs, which would then reduce reliance

on subsidies. Finally, if the wind resource falls short of expectations, the PTC value does too, creating uncertain returns to investors.

Another limitation of the PTC is that it limits the developer pool and, more important, the investor pool. The boom-and-bust nature of the industry results in large firms, which can withstand bust cycles, crowding out small developers that often initially develop the deals that are then sold to larger players.

The investor aspect is more complex. Projects usually do not have enough tax exposure to gain the full value of the PTC. So, projects turn to—and become dependent on—tax equity investors. This limits the investor pool to entities with tax exposure, which eliminates a much-needed wider investor base. The early Danish model required local investment, a key reason behind wind power's wide acceptance there now. The financial crisis in the U.S. led to a great reduction in tax equity investment pools because wind projects were not willing to pay the higher returns the tax equity pools wanted. When the PTC expires, the tax equity pool dries up, and investment declines. When financial markets contract, most tax equity evaporates, and the same thing occurs. Tax equity monetization also creates additional legal and structural complexity for wind projects, which costs time and money and adds to cost. It is also not so attrac-

tive to capital market investors, who want stable cash flow allocation.

The investment tax credit has similar strengths and weaknesses. A project gets an ITC up to a certain amount based on the actual cost of the project. This support scheme has been used recently as a temporary stimulus tool for wind projects. An advantage of the ITC is that it provides a known tax value, which can be beneficial for offshore wind, given its greater uncertainty of production (and therefore PTC value) because of new turbine technology and uncertain wind farm performance. Ironically, the ITC is the current federal support scheme for solar projects, which have more predictable revenue streams than wind power.

The downside of the ITC is the uncertainty of its availability over the long term and the reliance on the tax equity base. The ITC also does not encourage use of the best wind resources.

Cash grants and state support are other options

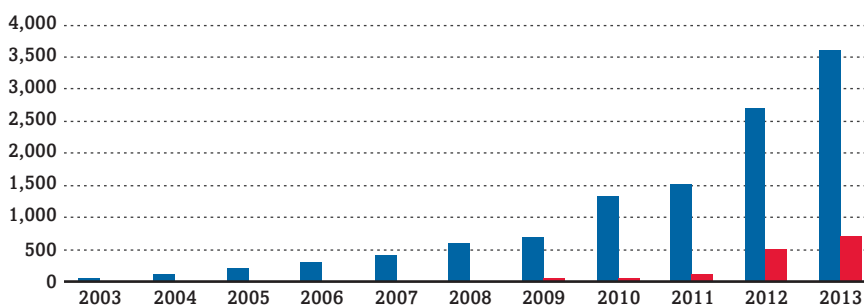
The cash grant is the third tier of direct federal support, but its longevity is also in question. The federal government used this tool as part of the federal stimulus program. After completion of construction, it provides a nontaxable cash grant equal to 30% of the project costs in lieu of, if desired, the PTC. Advantages of this tool, beyond its large size, are that it is predictable and trans-

Offshore Wind Capacity In The U.K. And Germany

Cumulative installations

■ U.K. ■ Germany

(MW)



MW—Megawatts.

Source: 4C Offshore.

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parent because it is based on investment, and the project does not have to rely on tax equity, so the developer and investor pools are expanded.

Disadvantages are the grant's reliance on the federal government. Risk is higher for projects with long development and construction periods, such as offshore wind. Second, because offshore wind projects will probably be large, grants would be, too. This could lead to so-called "headline risk" like what occurred with solar panel maker Solyndra. The potential public backlash could hurt the nascent industry.

The fourth tier of support is the state Renewable Portfolio Standard (RPS), whereby utilities are required to provide a share of electricity supply from renewable resources by a certain date, and noncompliance is subject to penalty payments. According to the Database of State Incentives for Renewable Energy, 29 states and the District of Columbia have RPS requirements, and eight others have RPS goals. All states along the Eastern Seaboard, where offshore wind potential is greatest, have RPS requirements except Virginia, which has a goal. Some programs include measures for specific technologies, but offshore wind is not among them.

The RPS scheme has attracted investment. Largely to meet their RPS goals, utilities in Massachusetts have agreed to purchase a large portion of the output from the planned 468 MW Cape Wind project in Nantucket Sound. A Delaware utility agreed to buy output from the recently cancelled 450 MW Bluewater Wind project. The lack of PTC certainty undermined this project.

Other state support schemes can be beneficial, too. A Rhode Island contracting standard for renewable energy resulted in the PPA for Deepwater Wind's planned 30 MW Block Island offshore project.

Germany Is FIT For Growth

Germany has been very successful using the FIT scheme to greatly expand onshore and now offshore wind projects. The FIT has many variations, but it generally guarantees a set price for energy

fed into the grid. The price can be market-independent—such as fixed, or fixed with an inflation adjustment—or be market-dependent—such as a spread over the market rate. The German system is market-independent. Suppliers are required to take the electricity supplied, and rate payers (business and residential electricity customers) pay increased electricity costs per kilowatt hour (kWh) on their monthly bills.

Advantages of the FIT are ease of administration, providing developers a known price for a known period, and eliminating the chore of negotiating a PPA with the buyer. In some countries, the FIT is combined with the requirement that the electricity grid operator build out the system to accommodate renewable projects feeding in. This greatly reduces the cost of offshore wind projects and makes them easier to finance. This arrangement also leads to a wide pool of developers and investors and has been highly successful—thus far. Germany declines the FIT prices for future projects to force cost reduction. The U.S. federal PTC works just the opposite.

Disadvantages of this scheme are potentially very big. The FIT relies on the government to set the price to bring in the amount of electricity needed, a role governments do not excel at. If the price is set too high, investment is rapid and far exceeds the supply chain, leading to industry imbalance. When overbuilding occurs or appears imminent, the government lowers the incentives. If the reduction in support is large, investment plummets and the supply chain is damaged. This happened recently with the solar photovoltaic industries in Spain and Italy. Right now, the German government offers favorable support for offshore wind to help fill the supply gap that will result as it retires its nuclear plants over the next decade. The risk is whether the current terms are sustainable.

The U.K. ROCs On

The U.K. has quickly become the world leader in offshore wind power thanks to the Renewable Obligation program and favorable subsidies. Like most support programs, though, the cost is high and a

continual topic of intense debate. The program was created in 2002 to help the U.K. meet its climate-change goal, which now is to use wind power to supply 20% of its electricity by 2020. The program obligates licensed electricity suppliers in the U.K. to purchase an increasing proportion of electricity from renewable sources, similar to a U.S. state RPS. Failure to meet the requirement results in a penalty for the supplier.

The program supports renewable energy with a production-based subsidy called the Renewable Obligation Credit (ROC). A project earns for 20 years the wholesale price of electricity plus the ROC price for every megawatt hour (MWh) of electricity delivered, plus other levy reductions. The ROC price is market-based but influenced by policy. To encourage use of different technologies, the program may allocate more than one ROC for each MWh of production. For example, offshore wind projects receive 1.9 ROCs per MWh production. The variation in ROC valuing is known as “banding.”

The ROC scheme has many positive attributes, depending on one’s point of view. Projects benefit from two revenue streams, the market price and the ROC price, much like a U.S. merchant energy project. Because the price is not fixed, equity holders could earn a higher profit margin than those in Germany, for example, where the FIT price is fixed for 20 years. This may result in exploitation of superior wind resources or just bigger equity bets. Finally, the scheme does not rely on a government payment.

One disadvantage of ROCs is that remuneration is based on two variable revenues streams, which might lead to larger firms dominating the market because they are better able to mitigate their market exposure than small firms. As with FITs, the government sets the banding value. If too high, too much investment occurs; if too low, the government loses credibility. It is much easier for the government to change the scheme to meet ever-changing goals than for the industry to respond, which, again, puts the stability of long-term industry growth at risk. Recently, the government changed the banding value

for offshore wind, favorably, to 1.9 from 2.0. But, the very rapid growth in offshore wind projects in the U.K. introduces the risk that the government could change the pricing scheme appreciably and damage industry sustainability.

The U.S. Has Far To Go To Catch Up With European Wind Energy

The U.S. wind industry is in the same situation today that it faced in 2001, 2003, and 2005: lobbying the public and Congress to extend the PTC, which expires at the end of this year. House and Senate bills are in play that would extend the PTC four years and two years, respectively. Any extension would lead to more investment in onshore wind projects, at least until the next expiration date looms and uncertainty again slows down investment.

An extension might be helpful to offshore wind projects that are in an advanced stage—especially Cape Wind, which does not have PPA coverage for all capacity—if they can begin commercial operation before the new PTC term ends. But an extension would provide little support to offshore wind projects in early stages of development; it is hard to stomach spending millions on development when a key source of federal support is needed but highly questionable. This is why the PTC program in its current form does not effectively support offshore wind investment.

The European experience illustrates three things: Offshore wind projects are feasible, the industry’s investment potential is vast, and some long-term support schemes have been effective in attracting investment, at least so far. Support schemes can change quickly and badly, as the solar photovoltaic industry has discovered. European programs provide far more long-term revenue certainty than U.S. programs, and that is one reason why offshore wind investment is growing rapidly there and not here. **CW**

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Credit FAQ

Why Regulatory Risk Hinders Renewable Energy Projects In Europe

Ambitious targets for clean energy generation in the EU have put renewable energy at the forefront of discussions about how to meet Europe's future energy needs. And political reactions to the recent nuclear crisis in Japan—which prompted Germany, for example, to shift its energy policy toward renewables and away from nuclear—are also fueling the interest in renewable energy.

But despite the momentum behind renewables, Standard & Poor's Ratings Services sees signs that regulatory risk is becoming a bigger issue for these projects. One example is the recent decision by the Spanish and Czech governments to adjust their regulatory support frameworks, including subsidies, for existing renewables projects, in part retroactively. Because we consider regulation to be a key rating factor in our assessment of renewable energy projects, alongside technical factors such as efficiency and fuel sources (sun, wind, or hydro), we've been watching these developments closely.

In this FAQ, we answer investors' frequently asked questions about our assessment of regulatory risk in renewable energy projects and identify potential areas of credit concern.

Q. *What is Standard & Poor's approach to analyzing renewable energy projects?*

A. As for any other single-asset nonre-course financing, we analyze renewable energy projects using our project finance criteria, which we supplement with a

review of the key credit factors specific to the renewable technology in question.

In essence, we evaluate projects case by case, taking into account the predictability of a project's cash flow and comparing this cash flow with the project's debt repayment profile.

Q. *Why has regulatory risk become more significant for European renewable energy projects?*

A. In our opinion, budgetary constraints in the public sector and the need to implement severe austerity measures in some countries are calling into question the sustainability of financial support for renewable-energy development in Europe.

Regulated incentives for renewable energy projects often underpin their financial viability: For instance, subsidies for solar power projects in Europe can account for up to 85% of their initial revenues. This, in our view, illustrates the importance of predictable, ongoing financial support for renewable energy projects, and highlights the credit risk associated with any changes to this support.

Q. *How does Standard & Poor's determine whether the regulatory system is likely to support a project's credit quality?*

A. We aim to determine the contractual and regulatory arrangements under which the renewable energy project will operate, and assess their supportiveness at the outset of the project and over its lifetime.

In analyzing the regulatory framework for a given asset, we start by evaluating the form of support commitment. Regulatory support to any given project in any given country normally can be in the form of either a decree or law approved by the government or parliament, or a power purchase agreement or other offtake agreement with a utility managed by a specific industry sector regulator, or administered through a con-

tract between an offtaker or clearing entity (that is, the contracted purchaser of the electricity, possibly state-owned) and the power generator. We then analyze the credit quality of the counterparty of such support, which may impose a cap on the project rating.

Given the importance of regulatory incentives to a renewable energy project's total revenues, we look for this support—which may be constant or decline over time—to ensure that the project's cash flows meet the established debt service repayment profile over the life of the project.

Q. *How sustainable is the financial support for renewable energy in EU countries, in Standard & Poor's opinion?*

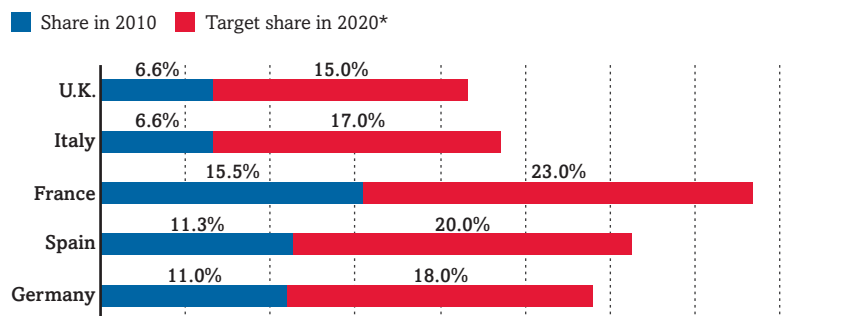
A. EU member states have committed to ambitious targets for the replacement of fossil fuels with renewable energy under EU Directive 2009/28/EC. Although feed-in tariffs (FITs) have proved effective in boosting investors' appetite for renewable energy assets in the past few years, there is still some way to go to meet the 2020 targets for energy generation from renewable energy sources (*see chart 1*). We believe governments might therefore continue to provide a high level of financial support to plug the gap until they are reassured about reaching the targets.

However, we believe this generous support—which creates direct costs for governments and consumers—could ultimately prove unsustainable, especially in light of the current subdued economic growth and strict public and private sector budgetary constraints.

In our view, a sustainable regulatory system is one that balances the promotion of renewable energy against the costs to the government and consumers. In evaluating this balance for individual projects, we focus on the following factors for each particular regulatory regime:

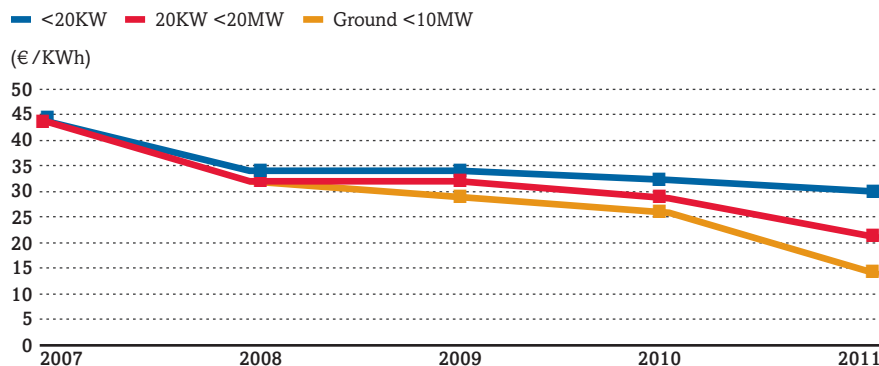
- The size of the financial support and incentives. This is illustrated by the gap between the tariff paid to energy producers and the market price end users pay (*see table 1*). We view FITs and other incentives that are consider-

Chart 1 | Share Of Energy Consumption From Renewable Energy Sources Within Selected European Countries Versus EU 2020 Target



*As defined under EU Directive 2009/28/EC.
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Chart 2 | Evolution Of Spanish Feed-In Tariffs 2007 To 2011



KWh—Kilowatt hour. MW—Megawatt.
Source: Standard & Poor's and MICyT.
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ably above market cost to be at the greatest risk of cutbacks, especially in times of economic stress and budgetary controls. Furthermore, the gradual decline in production costs as a technology matures may exacerbate the political pressure to reduce visible incentives such as FITs. Although the rate of return of a project is not a key factor in our analysis of creditworthiness, we've observed that very high expected returns (exceeding 20% to 25%), which have been common for renewable energy projects in the past few years, may also indicate a high risk of regulatory changes. When the electorate perceives that the returns for well-established and low-risk projects and technologies are high, it can erode the political support for regulatory frameworks allowing such returns. We witnessed such an effect in the Czech Republic.

- **Affordability.** We compare the direct cost to the government of the FITs and tax incentives with the government's current and expected budgetary and debt positions in relation to its budgetary and debt targets. Those countries in which this support represents a higher proportion of GDP are the most at risk of regulatory changes, in our view, especially if they are under budgetary pressure. We believe that a government's incentive to reduce subsidies on future projects (or even those that are already operational) will increase in line with its budgetary constraints and will be higher if the potential cuts yield significant savings (we discuss this further in the final question). Continued subsidies in those countries where there is already a deficit of funding for energy tariffs, such as Spain, are also more at risk, in our opinion.
- **Control mechanisms.** We view a cap on installed capacity as credit positive in any regulatory regime, insofar as it may prevent unsustainable growth of subsidies. The absence of caps in the regulatory framework allow for uncontrolled growth, which then translates into subsidy payments that may be too high for the economy to uphold. This was a significant factor behind the

recent revisions by Spain and the Czech Republic of their solar PV regulatory frameworks.

- The effectiveness of the grid management. Ineffective management of the electricity grid may increase the cost of back-up energy supplies considerably, in our view.

Q. Are FITs the only incentive Standard & Poor's considers when assessing regulation and regulatory risk?

A. No. When evaluating the credit quality of a renewable energy project, we look at all incentives the regulatory framework provides to the project from the outset. FITs are just one aspect of the support regime in Europe, albeit a more visible and potentially controversial one, because they are paid directly to the generator. Other features of European regulatory frameworks, the revision of which may affect the economic viability of a project, include:

- Providing priority access to the market and/or distribution grid for electricity produced from a renewable source;
- Providing green certificates to generators for the electricity they produce

from renewable sources. These certificates can be traded, usually to firms that do not have sufficient renewables in their energy mix; and

- Favorable tax treatment for the initial project investment, or for profits linked to renewable energy production.

Q. When analyzing renewable energy projects, does Standard & Poor's assume that regulatory support will remain constant?

A. No. We would anticipate that the support for a given transaction, as defined at the outset, would be honored and remain stable over the life of that transaction. However, the regulatory regime within a country will evolve over time: In our experience, transparent regulations will explicitly mention a fixed level of subsidies to projects over a certain period or until, say, a target level of installed capacity is reached. At that point, a new regulation (in the form of a decree or law) replaces the old one and new, possibly lower, subsidies will apply to any new projects.

Over the past few months, for instance, regulatory revisions across

The absence of caps in the regulatory framework allows for uncontrolled growth...

Table 1 | Comparison Of Consumer Electricity Prices And Tariff Rates Paid To Generators In Europe In 2011

Average electricity rates in 2011 (€/KWh)	Germany	Spain	France	Italy	Czech Republic
Household electricity rate	25	19	13	21	16
Industrial electricity rate (at a consumption level of 2,000 MWh/year)	12	12	7	13	12
Industrial electricity rate (at a consumption level of 24,000 MWh/year)	9	9	6	11	10
Tariffs paid to generators (€/KWh)					
Wind (onshore)	5–9	7	8	30	11
Wind (offshore)	13–15	7	31–58	30	11
Solar PV	32–43	14–30	27–58	36–44	23
Solar thermal	—	28	—	—	—

KWh-Kilowatt hour. MWh-Megawatt hour. Solar PV-Solar photovoltaic.
Source: Europe's Energy Portal.

Europe have led to reductions in the solar photovoltaic (PV) tariff ranging from 15% in Germany to 70% in the U.K. In Spain, subsidies to solar PV projects have fallen over the past four years as the government revised its FIT framework (see chart 2).

In our view, the regulatory support for renewable energy will continue to erode in all main EU markets as the technology matures and the price per unit of power generated drops. We believe it's likely that there will be a point at which support is no longer necessary, specifically when the unsupported cost of electricity generation from a given renewable source matches that from fossil fuels. However, we think this so-called "grid parity" price point is probably five or more years away, and will depend on the level of support in a given jurisdiction, the availability of the natural resource (wind or sun, for example), and the amount and speed of technological progress. That said, the implementation of carbon taxes and costs on the carbon-generating industries should hasten this grid parity.

In the near term, we believe the policy choices of individual governments—many of which face an immediate period of financial austerity—will continue to determine the level of regulatory support.

Q. How does Standard & Poor's assess uncompensated reductions in the regulatory support or incentives that were promised to a project at the outset?

A. We anticipate—but do not automatically assume—that the support and incentives available at the start of a project will be sustained in line with the original documentation, which usually means over the life of the transaction. We view recent uncompensated revisions as evidence that there is an increased risk of future retroactive changes, and take this into account when assigning a new rating in a particular legislation.

In evaluating the remedies a government or regulatory body puts in place to compensate for reductions in support for projects that are already operational, we focus on their impact on the credit quality of the transaction. First, we assess how the reduction in support affects the project's ability to meet its debt service in full and on time. We then analyze whether the remedies will restore cash flow to the level expected at the outset of the project in each and every debt service payment period, or whether they aim only to restore the expected return over the life of the asset. While the

former would preserve the project's credit quality, the latter may not.

Q. Does Standard & Poor's apportion a similar level of regulatory risk to all renewable energy projects in a given jurisdiction, irrespective of fuel source?

A. Not necessarily. For renewable energy projects in the same jurisdiction, we take into account each separate renewable energy source (wind, solar PV, solar thermal, or biomass, for example) and its specific regulation. Different regulations for different technologies or fuel types normally reflect variations in production costs and growth targets. These factors translate into different levels of sustainable financial support and, hence, variations in credit quality.

For example, we observe that solar PV projects in Spain accounted for about 37% of the almost €7 billion in total subsidies granted to renewable energy projects in 2010, compared with about 2% for solar thermal (see table 2). This may explain why the regulatory changes Spain implemented at the end of 2010 were more onerous for solar PV projects than for solar thermal projects. Furthermore, solar thermal technology lags considerably behind that of other renewables like wind or solar PV. This highlights to us that the regulatory support available to solar thermal projects in Spain is more sustainable than that for solar PV projects.

On the other hand, in most EU countries, wind projects account for a higher share of electricity generation than to other renewable energy sources, while receiving a considerably lower share of financial support. This makes wind less demanding on the public purse and its support more sustainable, in our view. **CW**

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Renewable Energy



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Table 2 | Breakdown Of Feed-In Tariff Subsidies Paid To Renewable Energy Projects In Spain In 2010

(Mil. €)	Wind	Solar PV	Solar thermal
Jan.	183	140	3
Feb.	196	103	2
March	207	119	2
April	206	135	2
May	213	209	10
June	134	247	6
July	172	289	17
Aug.	117	276	21
Sept.	124	318	30
Oct.	133	293	29
Nov.	118	261	29
Dec.	187	222	23
Total	1,990	2,612	174
Share of total*	28%	37%	2%

*The remaining 33% share of FITs, which takes the total subsidy for the year to €7 billion, is for other renewables such as hydro and biomass. Solar PV-Solar photovoltaic.

Source: Comisión Nacional de Energía.



After A Decade Of Wind Power, The Unexpected Is Still Always Expected

Over the past decade, the U.S. and Europe have undergone big shifts in their emphasis on renewable energy. Government policies and public perception have increasingly recognized the need for renewable energy to promote energy security, combat climate change, and, more recently, to create jobs. Wind power has developed into the renewable technology of choice, given its superior economics compared with most other renewable options. In addition, a long track record of operating performance helps investors to better evaluate the risks in wind power projects.

Overview

- The use of wind power continues to grow in the U.S. and in Europe.
- All but one of the wind projects we rate have fallen to speculative-grade from investment-grade over time.
- Technology and design problems, wind resource deficiencies, and certain problematic financial structure features are all weighing on these projects' creditworthiness.

In 2001, U.S. and EU wind capacity totaled about 22,000 megawatts (MW)—by 2010, it had reached more than 124,000 MW, and it continues to escalate. Throughout this period of tremendous growth, Standard & Poor's Ratings Services rated and maintained surveillance on several portfolio and single-asset wind projects' debt issues. Initially, we rated the senior debt from all of these portfolios—three in the U.S. and four in Europe—investment-grade ('BBB-' or higher), albeit on the lower end of the scale. All but one of these ratings have since fallen to speculative-grade ('BB+' or lower), and some ratings have dropped much farther than others.

Comparing 10 years of these projects' actual performance to original expectations has helped us to better understand why their cash flow is so volatile. The main reasons are wind resource deficiencies (which arise when the wind isn't blowing hard or often enough), higher-than-expected operating and maintenance costs, and features in the projects' cash flow structures that prevent the use of excess cash to meet debt service.

Portfolio Projects Came First

All of the wind projects we initially rated between 2003 and 2007 in the U.S. and Europe were portfolios of a number of smaller projects, structured to benefit

from diverse wind resources in different regions. These portfolio projects, all of which had investment-grade ratings at issuance, have since fallen to speculative-grade for various reasons.

The main stresses leading to the downgrades in Europe were electricity production that significantly lagged our base case forecasts due to a poorer-than-expected wind resource and prolonged periods when turbines were unavailable. In contrast, our downgrades of U.S. projects primarily resulted from weak debt service coverage ratios (DSCR) due to operational and maintenance expenses that far exceeded the projects' expectations.

In 2010, we rated our first single-asset wind project, Alta Wind Holdings LLC. We assigned investment-grade ratings to all of its senior debt because initial pro forma financial forecasts under our base case demonstrated decent stability under a conservative evaluation of the project's wind resources. Alta Wind is the only wind project that still maintains an investment-grade rating (*see table*).

To illustrate the primary components of the initial analysis of an investment-grade wind project, we look to our first rated portfolio. In June 2003, we assigned a 'BBB-' rating to FPL Energy American Wind LLC's \$380 million senior secured debt due 2023. Later, FPL Energy (now NextEra Energy Inc.) issued additional debt at holding com-

pany FPL Energy Wind Funding LLC that it repays with distributions from American Wind, a portfolio of seven wind projects located in various regions throughout the U.S.

Our initial investment-grade rating on the American Wind projects reflected several factors, including:

- Geographic diversity;
- A reserve to mitigate performance risk at its then-new Vestas V-80 turbine, which would derive about one-third of cash flow from a single wind farm, High Winds;
- The strong operational and maintenance performance of FPL Energy, a major developer of wind projects in the U.S.; and,
- A strong DSCR of about 1.4x under a "P90" one-year confidence level for electricity production (which indicates that every year, there is a 90% probability that the portfolio will produce at least the projected amount of electricity, based on the wind resource).

The cash flow from this portfolio of projects was fully cross-collateralized, which means that favorable performance at one project could offset a shortfall in cash flow at another. This turned out to be a good thing, as High Winds, the portfolio's expected major breadwinner, had various availability issues and a low wind resource. Other wind farms in the portfolio, however, performed above expect-

Wind Power Projects' Rating History

	2011	2010	2009	2008	2007
Alta Wind Holdings LLC	BBB-/Stable	BBB-/Stable			
Alte Liebe 1 Ltd.	NR	BB-/CW-Neg (BB- SPUR)	BBB-/Neg (BBB- SPUR)	A/Neg (BBB- SPUR)	AAA/Neg (BBB- SPUR)
Breeze Finance S.A.	B+/Neg (B+ SPUR)	BB+/Neg (BB- SPUR)	BB+/Neg (BB SPUR)	AA/CW-Neg (BBB SPUR)	AAA (prelim.)/ CW-Neg (BBB SPUR)
Breeze Finance S.A.—Sub	C/Neg	C/Neg	CC/Neg	BB-/CW-Neg	BB- (prelim.)/CW-Neg
CRC Breeze Finance S.A.	B-/Neg	B-/Neg	B+/Neg	BBB/Neg	BBB/Stable
CRC Breeze Finance S.A.—Sub	C/Neg	C/Stable	C/Stable	BB+/Neg	BB+/Stable
FPL Energy American Wind LLC	BB/Neg	BBB-/Neg	BBB-/Stable	BBB-/Stable	BBB/Stable
FPL Energy National Wind LLC	BB/Neg	BBB-/Neg	BBB-/Stable	BBB-/Stable	BBB-/Stable
FPL Energy National Wind Portfolio LLC	B/Neg	B+/Neg	BB-/Neg	BB-/Stable	BB-/Stable
FPL Energy Wind Funding LLC	B/Neg	B+/Neg	BB-/Neg	BB-/Stable	BB/Stable
Max Two Ltd.	NR	NR	BB-/Neg	BB+/Stable	BB+/Neg

SPUR—S&P underlying rating. NR—Not rated.

The European experience shows that accurately gauging long-term wind risk in some parts of the Continent remains challenging...

tations, thus offsetting the underperformance at High Winds.

Wind Resources Are Tough To Predict

The initial wind portfolios intended to use geographically diverse, independent wind sources to mitigate site-specific wind risks and achieve more stable cash flow. Our investment-grade rating on Alta Wind Holdings, the first single-asset project we rated, reflected a robust liquidity package and the strong history of wind production in the region.

We assess wind resource risk by the strength of the wind resource analysis from independent experts. However, we take a conservative view given that solid long-term wind data at a particular site is rarely available, and Mother Nature is fickle. Moreover, wind patterns can change unpredictably while flowing through a wind turbine farm (the “array effect”).

In 2007 and 2008, it became clear that the wind resources the European portfolios had predicted were not materializing. Before assigning our first rating on a wind power project in 2003, European countries had been establishing lots of wind capacity and so had significant data to gauge wind regimes. For example, Germany had established more than 14,000 MW of measurable power in wind farms by 2003. Most of the data, however, were not site-specific—rather, they were extrapolated from regional data that did not necessarily indicate on-site performance. Even so, the view of leading wind experts at the time was that wind resources were highly unlikely to fall below the average historical production levels in a region for more than two or three years. In actuality, meager winds persisted for some time, forcing some projects to use their full liquidity facilities to service debt. As the poor wind condi-

tions continued, these projects couldn’t replenish their liquidity facilities, giving them little cash flow flexibility.

The European experience shows that accurately gauging long-term wind risk in some parts of the Continent remains challenging, despite the wide array of data available and the large number of wind regime experts. Wind analysis continues to evolve, and it will always be a learning process. A proven methodology for evaluating a wind regime on one continent, or even in one wind region, may not work for another if the measured data is not comparable with specific conditions at the site.

The two portfolio projects in the U.S. have also suffered from poor wind conditions, but not to the same extent as in Europe. U.S. wind resources hit an all-time low in the past two years, but still remained in line with our base case. Still, the lower wind performance has given us a better sense of the variability of the wind resource, and we now take that into greater consideration in our analysis.

Operational, Design, And Construction Issues Also Come Into Play

Operations and maintenance

While the two rated portfolios in the U.S. have endured low wind resources at times, their cash flows have declined primarily because of operations and maintenance (O&M) costs that far exceeded initial estimates. O&M costs for wind are generally considered small in relation to revenues, which led many market participants to conclude that an increase of 5% or 10% in those costs would only modestly affect a project’s performance. The O&M costs for the U.S. wind deals, however, stabilized at rates that were 30% to 40% higher than forecast by 2012. This

led to a significant decline in DSCRs and, subsequently, several downgrades.

The reason for the unexpected rise in costs, was simply, that demand for labor and parts far exceeded what the immature U.S. supply chain could deliver. In contrast, European projects' O&M costs have stayed in line with forecasts, partly because the supply industry there is mature, making long-term predictions more viable. In the U.S., labor and crane costs in particular have risen dramatically over the past three years, and are not likely to drop back to forecast levels. The staffing levels required to maintain the projects are much higher than the projects anticipated. On top of this, the significant growth in the U.S. wind industry over the past 10 years has led to an undersupply of skilled labor, which has pushed wages up. Moreover, the cranes needed to perform necessary maintenance are in high demand. Lease rates have skyrocketed, and long lead times (in some cases up to six months or more) to lease a crane can result in lost revenues while a turbine is down and awaiting maintenance.

In our ongoing surveillance of the U.S. projects, we now assign greater importance to the risk of increasing O&M costs, especially in jurisdictions where wind development is growing rapidly and the supply chain is weak. It may take time for the supply of labor and cranes to catch up with demand in growing markets. We also take a harder look at the assumptions behind O&M costs: Is each wind farm sufficiently staffed? How experienced is the operator? Are cranes easily accessible to the project? The answers to these questions have become a crucial part of our analysis.

Design and construction

In both Europe and the U.S., cracked blades and foundations for many turbines, along with construction delays, contributed to availability issues at certain projects. Most projects can expect lower availability during the first years of operations as the wind farm settles and operators get more comfortable with maintaining the facility. But even so, given the large number of wind turbines in operation before we began rating these transactions, the big problems with founda-

tion design—which we don't consider to be a “complex” technology in our project finance analysis—came as a surprise. Fixing the foundations was expensive and even caused some portfolios to drop their insurance coverage, which significantly adds to a project's risk.

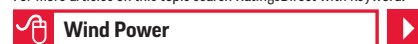
Cash flow structure features

The structure of a portfolio's cash flow has proven to be a critical determinant of wind projects' overall risk. To benefit from the portfolio effect (geographical diversification, in particular), the cross-collateralization of the wind projects in the portfolio is crucial. The Max Two Ltd. transaction, a portfolio of wind farms in Europe, provides a good example. The different farms in this portfolio were not cross-collateralized, which meant that when the financial performance of one project declined, it could not get support from the stronger performance of another. Thus, the overall portfolio received no benefit from its geographic diversity.

The Industry Is Still Evolving

As the wind power industry has matured over the past 10 years, developers and lenders have gained a better understanding of the risks involved with these projects. The key credit considerations of wind projects, namely exposure to an unpredictable wind resource and increased operations and maintenance costs haven't changed. However, these factors have turned out to be more volatile than we expected. Our original focus—on a relatively conservative base case for production, including a one-year P90 probability—has thus proven prudent, although in some cases, wind resources have underperformed even that cautious scenario. We will continue to monitor this evolving industry and to consider what we've learned in our rating analysis. **CW**

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Will Securitization Help Fuel The U.S. Solar Power Industry?

Overview

- Securitization may be a viable option for solar developers that wish to monetize cash flows from future lease or power purchase agreement payments.
- The primary risks of these transactions include a lack of historical performance data, a limited number of potential servicers, and ongoing downward pressure on solar panel prices.

As the U.S. solar power industry continues to expand, developers will need various financing outlets to fund their growth. Standard & Poor's Ratings Services believes securitization—a financing technique that aggregates pools of assets, financial contracts, or loans, and through a structuring process transforms their future cash flows into a security—may be a viable option for developers that wish to monetize cash flows from future lease or power purchase agreement (PPA) payments. Such transactions could provide the issuers' parents with a significant amount of upfront cash for capital spending or other business ventures.

While Standard & Poor's hasn't rated any solar securitizations to date, we have determined what, in our view, may be their key credit concerns. Generally these risks fall into three broad categories: limited performance data, a lack of large scale services, and declining panel prices. Throughout this article we will discuss these risks in great detail, while also identifying additional credit risks that are specific to securitizations.

Solar Power Installations Continue To Grow

Demand for renewable energy has grown considerably during the past three years as a greater proportion of the general population became concerned about reducing their carbon footprints. According to the Interstate Renewable Energy Council, annual installed grid-connected photovoltaic (PV) capacity grew by almost 300% from 2008 to 2010. About one-third of total installations in 2010 came from utility-scale projects. The remaining capacity encompassed small installations at residential proper-

ties, government buildings, commercial entities, and military stations.

Installations on residential and non-residential properties also grew significantly during the past three years (*see chart*). Total installed capacity for residential and nonresidential buildings in 2010 topped 600 MW, an increase of more than 200% when compared with 2008. A drastic decline in panel prices, along with flexible financing options and tax incentives, contributed to the rapid growth in this sector.

The installation of solar panels requires substantial capital investments by the developer—and with some of the financing options, such as solar lease agreements and PPAs, it may be several years before a developer recoups its initial investment. Solar leases and PPAs are financing transactions between an off-taker (i.e., a home owner, small business, etc.) and a solar developer. Under these agreements, the offtaker receives solar electricity for a certain number of years at a predetermined price. The developers retain most of the federal tax incentives

and renewable energy credits because the oftakers do not own the solar systems. In return for electricity at below-market rates, the developer will receive periodic payments from the oftakers. While PPAs and solar lease payments provide developers with steady revenue streams, they may also result in near-term funding issues that could hinder future growth.

Due To Limited Data, Default Rates May Be Difficult To Determine

The rooftop solar industry has only been operating on a significant scale for the past three or four years. The drastic increase in such installations can be seen in the chart. Because the solar industry is still in the nascent stages of development, there is limited data from which to draw conclusions regarding the likelihood of oftaker defaults under a lease or PPA agreement. Given that the length of these agreements may run up to 20 years, we believe that reliance on short-term data may not accurately reflect how an oftaker will behave over an extended period of time. In addition, we believe early adopters of this technology will be less likely to default because their reasons for entering into a lease or PPA may go beyond the more straightforward economic motivations. As such, we expect that defaults would be relatively low among the first generation of adopters and increase as the second and third generations move into the industry.

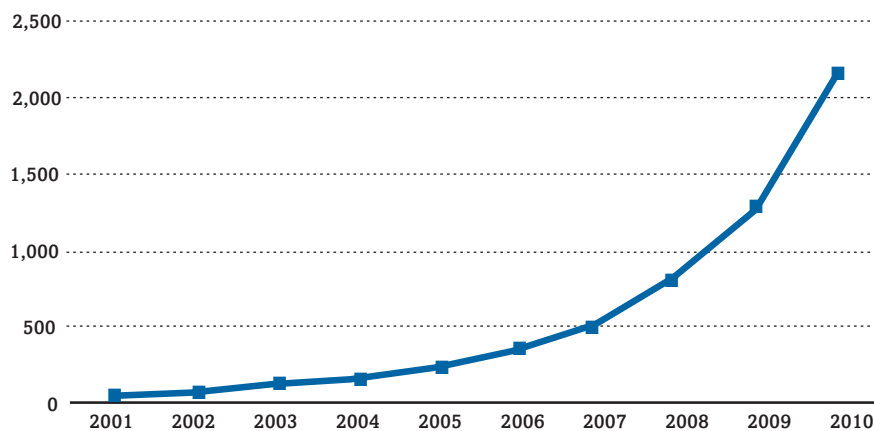
At first glance, utility default rates might seem to be a useful proxy for evaluating PPA or lease default rates, but there are several issues with using this data set. First, utility default rates are typically presented on a nationwide basis and do not break down the results according to classifications of customer credit quality (i.e., FICO scores). Second, virtually all customers participating in the small-scale solar programs that would be securitized remain connected to the grid and draw some of their power from a utility. It is possible, therefore, that those customers would be more likely to default on their solar bills than their utility bills.

Given the nature of the oftakers and their obligations, it seems that existing methodologies could be used as a proxy

The installation of solar panels requires substantial capital investments by the developer—and...it may be several years before a developer recoups its initial investment.

Cumulative U.S. Grid-Tied Photovoltaic Installations (2001 To 2010)

(Megawatts)



Source: Interstate Renewable Energy Council.
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to evaluate the default risk in a solar portfolio. Existing models and approaches for analyzing residential or corporate credit, such as those used to analyze residential mortgage-backed securities or collateralized loan obligations, could be leveraged for this analysis.

Lack Of Large Operation And Maintenance (O&M) Providers Can Create Additional Risks

We believe there are currently few O&M providers that have the geographic reach necessary to service a diverse securitized pool. Due to the limited number of national O&M providers, we believe it may be difficult for a transaction to quickly find a replacement if the original servicer were to default on its obligations. This risk could pose a challenge to securitizations seeking ratings higher than the rating of the O&M provider.

The limited number of O&M providers can affect the transactions in a number of ways. For example, if an extended period of time is required to replace the provider, the transaction's cash flows could decline as systems are not maintained during this period of time and the forecast amount of energy is not produced. While solar systems do not require extensive maintenance, they do need to be continuously monitored to address issues as they arise. The performance of a securitization may also be hurt if the O&M rate required by a new provider is higher than the previous rate. Rising expenses would most likely reduce future cash flows, which in turn, increase the transaction's credit risk profile.

Declining Panel Prices May Result In Additional Credit Risks

Over the past several years, prices of PV solar panels have drastically declined, and in some markets, installed costs are approaching grid parity. We believe the price of solar electricity is strongly correlated with panel prices and tax incentives. As the price of solar systems decline, it's likely that solar lease and PPA rates will fall as well. However, the elimination of certain tax incentives may offset the decrease in panel prices. Many market participants are now expecting panel

prices to reach \$1/watt in the immediate future. To put this reduction in perspective, in 2009, many industry participants believed panel prices would fall to \$1 per watt in 2014 or 2015 (*see "Regulatory And Political Headwinds May Slow Renewable Energy Growth," published Sept. 8, 2011, on RatingsDirect, on the Global Credit Portal*). While there are signs that the sharp reduction in panel prices may not continue, further declines could leave many PPAs being underwritten today to be above market contracts.

In addition to falling PPA and panel prices, offtakers are also benefiting from technological changes in the solar sector. As solar technology continues to improve and panels become more efficient, it's likely that panels being used today may become outdated. While technological advances and falling prices may benefit the solar industry, significant improvements in panel prices and efficiencies may result in a number of original offtakers feeling buyer's remorse as they may have entered into above-market contracts and leased obsolete solar systems. We believe declining prices and technological advancements may increase the risk that offtakers will try to renegotiate their rates after signing their initial agreement in an effort to reduce their PPA or lease payments. It's also possible that offtakers who can't renegotiate may selectively default on their PPA or lease obligations. We believe this risk is particularly high in situations where panels change hands, either in the event of a property sale or an insolvency of the owner (i.e., foreclosure).

Depending on the agreement, the outgoing offtaker may be required to find a replacement who will assume the existing agreement or otherwise purchase the system at a fixed price. While we recognize that this contractual obligation exists, we think that offtakers that have recently defaulted on their mortgage or other financial obligations may have little incentive to fulfill the terms and conditions of their PPAs or lease agreements. We believe that to attract a new offtaker, the lease rate may have to go down or rate escalators be lowered or suspended for a period of time, which

could materially affect the securitization's future cash flows.

Recovery Rates Vary

The recovery amount following an event of default may vary depending on the recourse available to the transaction. The securitization's recourse may not, for instance, extend beyond the right to remove the panels or take legal action against the offtaker for missed payments. We believe such limited recourse increases the offtaker's risk profile, as it would have little incentive to avoid a default. Furthermore, limited recourse in conjunction with a depreciating asset may result in extremely low recovery rates. We believe that under a default scenario, there will likely be a periodic reduction in cash flows to account for the time needed to attract a new offtaker. We also believe that a reduction in rates will be necessary to attract a new offtaker due to technological changes and falling PPA prices as discussed earlier.

Utility Rate Projections Have A High Margin For Error

For the most part, offtakers in a solar securitization will be responsible for purchasing all power that a specific solar system produces. Typically, the securitization bills the offtaker a lower percentage of the applicable utility rate for the solar power generated, creating an economic incentive for the offtaker to maintain the contract. Most agreements include an annual billing rate escalator on the generated solar power for the remaining term of the lease or PPA. Depending on how the parties establish the differential between standard utility rates and the solar rates, the economic incentive may erode over time.

We believe that, trend analysis aside, projecting a utility's billing rates is a difficult exercise and that the longer the projection period, the higher the margin for error. Aggregated forecasts across different regions and utilities may underestimate or overestimate, depending on many variables.

Any forecast of utility rates requires an in-depth understanding of the relevant utility's operational strategy to establish

acceptable base case and stress case scenarios for that particular region. The region's regulatory environment is also a critical factor to consider. Other factors to consider are the source and reliability of the data, the type of data (residential retail rate, usage assumptions, etc.), and assumptions for competitive versus regulated markets and municipal versus investor-owned and retail marketers.

Energy Sales To The Grid

In a situation where the offtaker is defaulting on its contractual arrangements, the securitization may rely on recovery from the utility by way of a sale back to the grid. Typically, such sales rely on the provisions under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), whereby the solar project, as a qualifying facility (QF), sells the power to the utility. Under PURPA, the utility may be required to purchase the power at its avoided cost, which is the cost the utility would have incurred to produce the same quantity of power (the so-called "must-take" provisions).

Some of the questions that arise in connection with the assumption that the securitization can sell back to the grid are:

- Is the utility subject to PURPA's must-take provisions? Is the project an eligible QF? There may be applicable exemptions for the utility, as well as eligibility assumptions for the project's "qualifying" status.
- Is there, in fact, a market for the sale? A visible, active local transmissions market would give credibility to the recovery analysis.
- Does the solar project have the mechanical capability to deliver the power to the grid? Where applicable, clearly delineated servicing procedures, in the securitization documents together with any necessary mechanical adjustments, would facilitate execution of the delivery.
- What are the assumptions made for projecting the utility's avoided costs? We may evaluate the utility's procurement strategy and power mix, for example, in states that do not have Federal Energy Regulatory Commission guidance on establishing the calculations.

Diversification Informs Our Solar Resource Analysis

The solar resource—which refers to the amount of sunlight a given geographic area receives—is generally quite stable for PV panels, but there is some risk, due to measurement errors and a small inherent variability, that actual sunlight will be less than the forecast amount. The amount of sunlight also varies by location and time of year, which may result in the securitization having a volatile cash flow profile. For this reason we believe it's imperative to base the solar resource forecast on monthly data so that it incorporates such seasonal variations.

Solar securitizations will mostly likely benefit from a geographically diverse collateral pool across the U.S. This reduces the transaction's operating risk profile because the securitization doesn't depend on one area for most of its future cash flows. For example, the transaction's performance is less likely to suffer if one region has, say, a long string of cloudy days. As such, most independent solar resource consultants account for diversification by reducing the collateral pool's interannual variability, which measures the change in the solar resource from year to year.

However, some securitizations may have a ramp-up phase where the collateral pool may not be complete at issuance. This could occur because the sponsor has not installed or acquired all of the solar systems and executed corresponding PPAs or lease agreements. Therefore, in such an instance we believe the full benefit of the reduction in interannual variability due to geographic diversification may not be appropriate during the ramp-up phase.

Liquidity Can Pose Some Challenges

Maintaining adequate liquidity in a solar securitization can be difficult due to several factors.

Ramp-up risk

Depending on the ramp-up strategy, the securitization's credit risk profile may become more volatile if the sponsor has

difficulty managing a large number of simultaneous installations across multiple geographic locations.

The ramp-up needs to be fast enough and diverse enough to ensure that there is sufficient liquidity and that the portfolio does not become overly concentrated. We would expect the securitization to have mechanisms in place to address the potential for increased concentrations if the installations occur at an uneven pace among various locations, along with other measures of diversification.

Dividends or other equity payments

Dividends or other forms of cash payments to equity holders usually raise a transaction's credit risk. Cash leakage, in conjunction with the seasonality of solar production, could hurt a transaction's creditworthiness. If cash flow from the high-production summertime months leaks out of the deal, the amount available for debt service in the winter might prove insufficient.

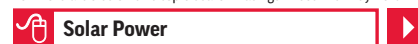
Regular maintenance expenses

Inverters and other equipment require periodic replacement. Usually, reserve funds or dedicated cash flow are needed to account for these expenses.

Securitization Is A Viable Funding Strategy

We believe securitization of solar systems could be a feasible financing tool for developers who wish to monetize future cash flows. Securitization may reduce a developer's financing cost as the creditworthiness of the transaction is dependent upon the collateral pool and not the credit quality of the issuer, which in most cases is in the speculative-grade category. **CW**

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Credit FAQ

Could Spain's Halt On Renewable Energy Incentives Take The Wind Out Of Projects, Developers, And Utilities?

Spain's newly elected government recently announced the temporary suspension of economic incentives for electricity production from new clean energy installations included in the so-called special regime. Under this scheme, renewable energy facilities (renewables) have benefited from regulated rates above market prices for their electricity production, with solar and wind technologies absorbing the largest share of premiums.

Electricity tariffs in Spain have not fully covered costs since 2000. As a result, utilities have financed a significant share of these costs—which include special regime premiums—although, in principle, these costs should be passed on to end-consumers through the electricity tariffs. The Spanish government has indicated that its moratorium on special regime premiums will help it control this electricity tariff deficit, which generated about €22 billion in cumulative debt by year-end 2011.

(For further information, see "Credit FAQ: How The Spanish Electricity Tariff Deficit And Political Uncertainties May Affect The Ratings On Spanish Utilities," published Jan. 12, 2012, on RatingsDirect, on the Global Credit Portal.)

Standard & Poor's Rating Services recognizes that market participants may be wary of the potential effect the legislation passed by the Spanish government (Royal Decree 01/2012) could have on a number of players in the Spanish energy market. Here, we address these concerns and answer investors' frequently asked questions about how the new measure may affect Spanish renewable energy projects, project developers, and utilities.

Q. What effects could the moratorium have on the creditworthiness of renewable energy projects in Spain?

A. We don't believe it will have any credit effect on projects already in operation and projects that, although not in operation, have already been granted the right to receive special remuneration (registered projects). This is because we understand that the measure will not alter the special remuneration framework for these projects.

Although we do not have any public ratings on renewable energy projects in Spain, we continue to review their credit quality as part of our evaluation of the underlying collateral provided for various other transactions. These various renewables projects include wind, solar photovoltaic (PV), and concentrated solar power (CSP) projects.

Q. How could the halt on premiums affect the development of new renewables projects in Spain?

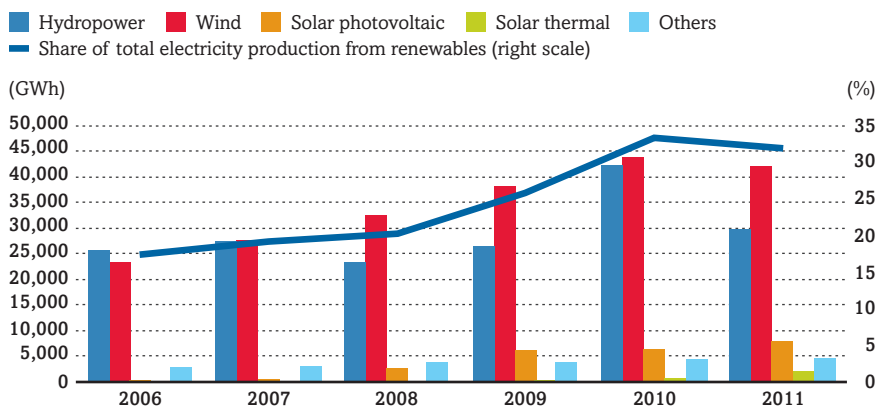
A. We expect the moratorium will likely freeze the development of unregistered wind and solar projects in Spain. The measure will, for example, prevent 550 megawatts (MW) of PV installations from obtaining special remuneration rights in 2012, and will bar already authorized wind projects in excess of 9,000 MW from obtaining registration. We believe that, without special financial incentives, solar-based energy projects will remain uncompetitive in the liberalized Spanish electricity market. We also think that onshore wind farms in Spain that no longer benefit from the incentive scheme will not provide returns consistent with sponsors' expectations for the time being. This is because, in the absence of economic incentives, only those wind projects with load factors well above the segment average—meaning those placed in the highest-wind sites in Spain—will be economically viable. Such high-load locations are very limited because most of them already host operational projects. That said, we believe that onshore wind projects could become economically viable in the future, depending on the evolution of electricity pool prices in Spain, as well as fast-evolving cost factors such as wind turbine prices.

In light of the Spanish government's commitment to eliminate the electricity tariff deficit by 2013, together with the declining cost of inputs for renewable energy installations, we consider it unlikely that any future special remuneration scheme would be more advantageous than the present one. We therefore see little practical incentive for sponsors of registered projects to hold back on their development in the hope of benefiting from a more favorable remuneration regime.

Q. Does Standard & Poor's consider that the decree signals the end of the "renewable-friendly" energy regime in Spain?

A. No. In the long term, we think the Spanish government will eventually have to restore an incentive scheme if it is to meet the ambitious targets to increase

Breakdown Of Electricity Production From Renewables In Spain



GWh—Gigawatt hour.

Sources: Ministerio de Industria, Turismo y Comercio (2006 to 2010); Red Eléctrica de España (2011).

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renewable energy consumption, as laid out in the 2009 European directive on the promotion of clean energy (Directive 2009/28/EC).

In 2010, Spain derived 11.3% of total energy consumption from renewable energy sources. This was twice as much as in 2005 but still some way off the EU's target of 20% by 2020. In our view, some market participants understand that disincentivizing the development of renewables projects is incompatible with Spain's stated target, and could consequently hold back from developing new projects until a more favorable regime is put in place.

Q. How will the government's latest action affect Standard & Poor's view of regulatory risk for renewable energy projects in Spain?

A. We think it could help dispel existing concerns regarding other immediate and retroactive detrimental regulatory changes that market participants had feared since the Spanish parliament passed legislation in 2010 effectively

capping the revenues that operational PV plants were receiving.

However, we don't completely rule out the possibility that the government could take adverse regulatory actions in the future. We acknowledge that, if the economic environment further deteriorated, the government could once again seek financial relief from the renewable energy sector. Under such a scenario, we believe renewable energy projects would be particularly exposed to regulatory risk or, perhaps, financial penalties such as a tax levy as was the case in the Czech Republic (AA-/Stable/A-1+).

On the other hand, we also think that the Ministry's announcement should be viewed in the context of a wider reform of the Spanish electricity market heralded by the new government. Although announced as a "temporary suspension," we believe that this interruption in economic incentives may be the prelude to an overhaul of the Spanish special remuneration system for energy producers. We believe this, in turn, could reduce future regulatory risk for Spanish renewable projects in the long term. A redefined remuneration regime designed under economic sustainability

principles—as expressed by the government—could offer a more stable regulatory framework under which the renewable energy sector could expand. In our view, this would help attenuate investors' wariness against supporting the development of new projects. In any event, we will assess the sustainability of any new framework for renewable energy once it is presented.

Q. How could the initiative affect Spanish project developers' creditworthiness?

A. We think larger Spanish project developers should successfully weather any negative effect resulting from having to suspend or postpone a number of their planned operations. On the other hand, smaller developers may not have the means to withstand such a setback.

In general terms, we consider that the most significant Spanish developers can be classified into two main groups. On the one hand, diversified industrial conglomerates such as Abengoa S.A. (B+/Stable/—), Acciona S.A. (not rated), or ACS Group (not rated) act as sponsors and engineering and construction (E&C) providers for incentivized energy projects. On the other, vertically integrated utilities such as Iberdrola S.A. (A-/Stable/A-2), Gas Natural SDG S.A. (BBB/Stable/A-2), or Endesa S.A. (A-/Watch Neg/A-2) cover a share of their generation capacity through the development of renewables projects, particularly those based on wind technologies.

For developers in both categories, we believe that postponing or abandoning their planned projects should not have material credit rating implications.

Table 1 | Spain's Special Regime Premiums And Electricity Tariff Deficit

	2007	2008	2009	2010	2011*	2012§
Total special regime premiums (bil. €)	2.8	4.1	6.5	7.1	6.1	7.2
Special regime premiums (% of total regulated costs)	14.0	16.7	33.9	38.8	39.5	39.3
Regulated costs liquidation deficit (bil. €)	1.4	5.8	4.6	5.6	3.3	3.0
Special regime electricity production (% of total electricity production)	20.6	24.0	30.5	33.3	34.6	35.6

*Provisional liquidation as of October 2011. §Comisión Nacional de Energía (CNE) forecast, Report 39/2011, published Dec. 28, 2011.

Sources: CNE, Regulated Costs Liquidation Report.

Table 2 | Expected 2011 Statistics For Spain's Special Regime Energy Sources

	Solar photovoltaic	Solar thermal	Wind	Hydropower*	Cogeneration	Biomass	Other	Total
Installed capacity (MW)	4,188	856	20,658	2,045	6,182	752	1,230	35,911
Annual production (GWh)	6,180	1,640	43,541	5,980	24,907	3,681	7,470	93,399
Total premiums (mil. €)	2,405	394	1,800	234	1,352	271	421	6,877
Unitary equivalent premium (€/MWh)	389.1	240.0	41.3	39.2	54.3	73.5	56.4	—
Special regime production share (%)	6.6	1.8	46.6	6.4	26.7	3.9	8.0	100.0
Special regime premiums share (%)	35.0	5.7	26.2	3.4	19.7	3.9	6.1	100.0

*The special regime only comprises 10.4% of total national hydropower capacity as of year-end 2011 (source: Red Eléctrica de España). Note: The average final market price of electricity in 2011 was 60.09 €/MWh (source: Red Eléctrica de España).

Sources: Comisión Nacional de la Energía, Report 39/2011, published Dec. 28, 2011. MW—Megawatt. GWh—Gigawatt hour.

Companies in the first group generally have widely diversified revenue sources, whereas companies in the second group have particularly solid revenues streams and significant financial flexibility. Many developers, especially those in the first group, have already entered into other less-saturated international markets like the U.S. and Latin America that could absorb a share of their future untied operating capacity. In addition, companies in both groups have large balance sheets that should allow them to dilute any adverse effect following the moratorium.

Conversely, we believe that smaller developers might not have the operational and financial strengths needed to cope with the moratorium. As a result, they will likely be hit harder than their larger counterparts.

Q. How could the initiative affect Standard & Poor's assessment of Spanish utilities' creditworthiness?

A. We believe that material efforts to control and reduce the existing tariff deficit, such as the moratorium, could provide Spanish utilities with greater operational and financial flexibility (see *"Credit FAQ: How The Spanish Electricity Tariff Deficit And Political Uncertainties May Affect The Ratings On Spanish Utilities,"* published Jan. 12, 2012). That said, we also recognize that the measure could be the prelude to other regulatory changes that could further alter utilities' credit profiles.

We view the deteriorating tariff deficit as one of the key financial and business risks that Spanish utilities confront. Given that the moratorium only suspends the allocation of new remuneration rights to projects still pending official registration—and therefore relatively far from being operational—we believe that the announced moratorium will only marginally help alleviate the pressure over the tariff deficit in 2012. In 2012 and 2013, our base-case scenario factors in a continued accumulation of tariff deficit receivables on the affected utilities' balance sheets, but at a slower pace compared with 2010 and 2011, as the government gradually implements further structural measures to address the imbalance

between electricity tariffs and costs. However, we still believe it will be politically difficult to reach the stated target to eliminate the tariff deficit by 2013.

We also believe that measures directed toward sustainable cost-reflective tariff schemes could facilitate the securitization of accumulated and future tariff deficits. If the government takes steps in that direction, we think it could help limit potential investors' wariness against securities issued by the Fondo de Amortización del Déficit Eléctrico (FADE), the national securitization vehicle that ultimately transfers tariff deficit receivables off utilities' balance sheets to the capital markets. Nevertheless, we will continue to be cautious about including proceeds from such a financing source in our forecasts for Spanish utilities given their high dependence on capital market conditions.

We will monitor potential further regulatory changes that could alter utilities' operating framework, particularly in the context of intense sovereign stresses and a deteriorating economic environment. For example, we think it is possible that the announced wide-ranging revision of the electricity market might expose regulated transmission grid and distribution network operators to adverse changes in their supportive remuneration regimes. Similarly, we also think there is a risk that the Spanish government could resort to ad hoc taxation of utilities' "windfall" profits, obtained from operational hydropower and nuclear installations that were already amortized under the pre-liberalization regime. In any case, we will assess the specific effects of any future structural measures on the utilities' business risk and financial risk profiles if and when they materialize. **CW**

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Overview

- Australia's carbon tax is to be implemented on July 1, 2012. It will include a fixed carbon price for three years, before permits can be traded in international markets.
- Gas appears to be the likely transition fuel in the move away from coal-fired generation.
- However, several key factors remain uncertain and could influence the economics of gas as replacement fuel: gas prices, carbon price volatility, plant capital costs, and the expected useful lives of new plants.
- Moreover, investment prospects for new gas base-load stations seem limited because of a lack of potential investors and possibly shortened economic lives of new plants.

Can Gas Smooth Australia's Transition From Coal Or Will Renewables Leap Ahead?

Australia's looming carbon tax could provoke a dramatic change to the power sector. As the country weans itself from reliance on coal to generate its power, gas production is set to boom with several planned projects in the coal-seam-gas to liquefied natural gas (LNG) industry. The expected surge suggests that gas is the most logical choice to smooth the long-term transition in Australia to clean energy because of its lower carbon intensity. But the winner of this carbon race is not so clear-cut.

Executive Summary: Limited Prospects For New Base-Load Power

Potentially higher gas prices and carbon price volatility throw some doubt on the competitiveness of gas to challenge the dominance of coal-fired generation. The forecast boom in gas production would link prices to international benchmarks, potentially spurring steep rises. And the recent volatility in carbon prices in the European markets demonstrates that the jury is out as to whether the carbon tax is enough to offset coal's cost advantage.

Fueling the uncertainty is what we consider to be a short window for new gas base-load investments. Construction of new plants spans over extensive periods, while investors face long pay-back periods. Furthermore, the economic lives of new plants may be reduced. Beyond the initial 5% cut by 2020 from carbon emissions levels in 2000, the Australian government has set an ultimate aim of 80% in emissions reduction by 2050. As the ultimate target is less than 40 years away, new gas plants therefore may see shortened eco-

nomic lives—even if investment decisions were made today.

Continuing weak base-load demand also dims the prospect for investments in new gas base-load power. Conversely, demand for peak energy is rising. Standard & Poor's Ratings Services therefore believes the main role of gas will be supplying peak rather than base-load power.

What's more, we consider the pool of investors to undertake such large and capital-intensive investments to be small. Only the big three integrated energy companies—Origin Energy Ltd. (BBB+/Stable/A-2), AGL Energy Ltd. (BBB-/Watch Neg/—), and TRUenergy Pty Ltd. (BBB/Stable/—)—are best placed to invest or sponsor investments in generation through offtake contracts. These companies have led the consolidation in the retail sector, capturing 80% of the market after New South Wales' privatization in 2011. Likewise, the generation sector is set to merge in coming years as the companies seek greater vertical integration to manage their retail loads. AGL's conditional announcement to acquire the Loy Yang A power station is in our view consistent with this trend.

Owners of stand-alone base-load coal plants, however, are unlikely to invest in new generation, in our opinion. In particular, sponsors of highly leveraged project-financed vehicles that are struggling financially and facing truncated lives of existing plants are unlikely to have the surplus cash flow to compete with the "big 3" for new investments (see *"Prospects Dim For Australian Power Generators As Weak Pricing And Carbon Uncertainty Stifle Outlook,"* published June 28, 2011, on RatingsDirect, on the Global Credit Portal). Moreover, the incentive to provide fresh equity without a retail offtake agreement is limited, and without such an agreement, financiers are unlikely to be attracted to provide capital.

Nevertheless, government support could ignite new investments, especially in the renewables sector. The federal government's A\$10 billion Clean Energy Finance Corp. could be a major player in promoting renewable solutions. A material build-out of renewables is likely under the government's requirement that

Table 1 | Possible Trajectory Of Cuts In Carbon Dioxide Equivalent Emissions

Scenario	2020 to 2030	2030 to 2040	2040 to 2050
Severe back-ended reduction (% per year)	1.0	2.0	4.5
Back-ended reduction (% per year)	2.0	2.5	3.0
Straight-line reduction (% per year)	2.5	2.5	2.5

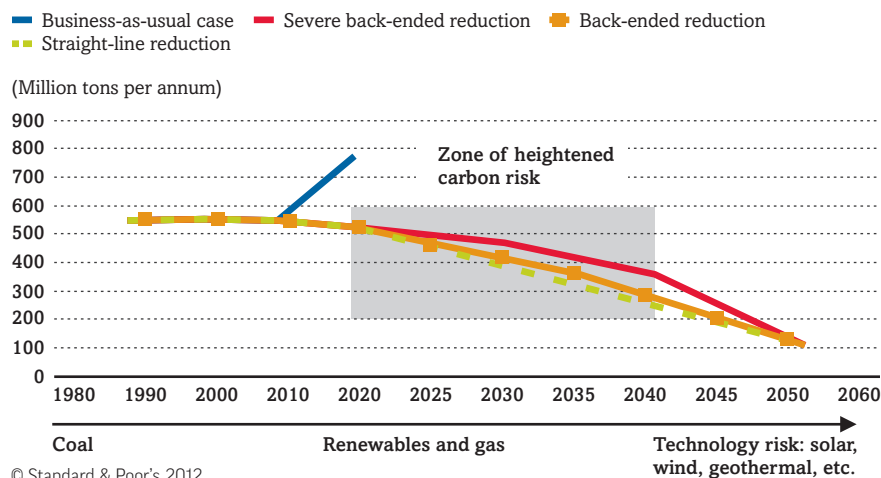
Business-as-usual projections by Department of Climate Change and Energy Efficiency.

Table 2 | Carbon Intensities Of Different Plant Fuel Types

Plant fuel type	Approximate CO ₂ intensity (t/MWh)
Brown coal (Loy Yang A & B)	1.20
Black coal	1.00
Open cycle gas turbines (peak load)	0.65
Closed cycle gas turbines (base load)	0.45
Approximate current NEM average	0.90

CO₂—Carbon dioxide. NEM—National Electricity Market. t/MWh—Terajoules per megawatt hour. A terajoule is equal to one trillion joules; one joule is a unit of energy.

Chart 1 | Emissions Trajectories



retailers source 20% of electricity from renewables by 2020.

Once built, renewable generation with its negligible operating costs appears to have a clear cost advantage. A major build-out of renewables is likely to pressure the usage (capacity factors) of existing stations and wholesale prices. This, in turn, could mount the strain on highly leveraged thermal plants—in particular, older more carbon-intensive plants and those further up the merit order.

So, while much of the existing coal-fired fleet is likely to continue to be necessary for system security and reliability for decades to come, their profitability is not assured. The development of renewables as a major source of generation could further erode the business case for new gas base-load power.

The Government's Carbon Abatement Objectives

The government's carbon-abatement program will be implemented in several phases (*see Appendix I for a summary of the scheme*). The ultimate objective is to slash greenhouse gas emissions by 80% by 2050, compared to levels in 2000 of about 550 million tons (mt) of carbon dioxide (CO₂) emissions, according to the state of Victoria's Environment Protection Authority. With electricity generation being the single largest source of carbon emissions in Australia at 37%, this sector is clearly at the front-line of any plans to cut carbon emissions.

Under the clean energy legislation, Australia has unconditionally committed to shave off 5% of its comparative 2000 greenhouse gas emissions by 2020, to about 524 mt CO₂ emissions. This is equivalent to a 9% (56 mt CO₂ emissions) cut to current emissions, based on the Department of Climate Change expectations of average annual emissions of 580 mt CO₂ emissions from 2008 to 2012.

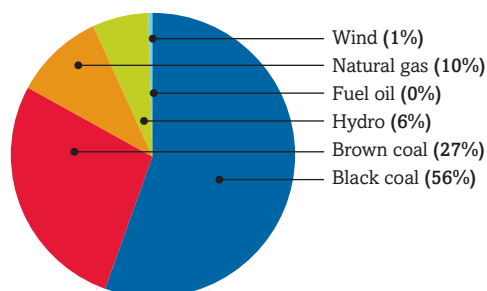
The 5% target by 2020 is actually more challenging than it appears. On a normal case for the Australian economy, the Department of Climate Change expects average annual emissions to increase to 686 mt CO₂ emissions by 2020. Hence, the 5% cut could actually involve restructuring the carbon inten-

sity of the economy to achieve a reduction of 162 mt CO₂ emissions or 29% to a business-as-usual case.

Given its proximity, the 2020 target is not surprisingly the focus of debate about emission reductions. Nonetheless, in our view, the next 10 to 15 years will also be key toward achieving the ultimate goal in 2050. Delays in investments to materially replace the current generation fleet beyond this period are likely to increase the risk of stranded thermal assets (*see chart 1*).

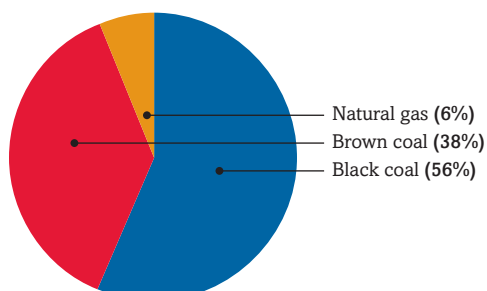
Such a scenario elevates the technology risk to develop viable alternatives. In the past half-century, a well-maintained coal-fired station typically was expected to have a useful life of up to 50 years or even longer. But because of the 2050 target, the economic lives of new thermal stations, in the absence of carbon capture and storage, are likely to have significantly shorter economic lives

Chart 2 | Historical Generation By Fuel Type For 2009 And 2010



Source: RepuTex Carbon Analytics, 2012.
© Standard & Poor's 2012.

Chart 3 | Historical Emissions By Fuel Type For 2009 And 2010



Emissions are calculated as per metric ton of carbon dioxide.
Source: RepuTex Carbon Analytics, 2012.
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(stranded asset risk). As such, it is difficult to see thermal capacity replacing the current fleet of plants. Nuclear power is seen to be a politically difficult solution for ensuring energy supply. And current low-carbon technologies are generally considered unable to provide reliable supply at a cost commensurate with current thermal technologies that have lower carbon-intensity.

Abundant And Relatively Cheap Coal Entrenches Reliance On The Fuel

Australia's endowment of abundant and cheap coal means that the country is largely reliant on this fuel for its electricity supply. About 80% of power is being sourced from carbon-intensive black and brown coal plants located close to the mines, making it among the cheapest sources of energy supply (*see charts 2 and 3*). The stations typically

have a 40 to 50 year physical lifespan. The balance is generated from a combination of gas, fuel oil, and renewables such as hydro and wind. However, much of the gas generation is for peak load rather than base load.

Gas May Take Up The Slack As Coal Reliance Reduces

At first glance, it would seem logical that the carbon tax would result in gas being the favored choice. Gas base-load generation emits about half the emissions of comparable coal-fired plants (*see table 2*). However, the economics of gas as a replacement fuel are subject to a number of factors. These include relative fuel costs, carbon prices, relative carbon intensities, plant capital costs, and expected plant useful lives.

RepuTex Ltd., a Hong Kong-based firm specializing in carbon risk analytics, has modeled three scenarios to examine the sensitivity of the price of carbon permits and gas on the fuel mix beyond 2020 (*see table 3*). The proportion of gas generation in the fuel mix rises under all three scenarios. It increases from historical levels of about 10%, to slightly more than 30% in Scenario 1 and to less than 20% in Scenario 3, subject to gas and carbon prices (*see chart 5*). Under Scenario 1, coal's contribution to the fuel mix drops to about half from 80%, with most of the gap being filled by gas.

Table 3 | Scenarios Based On Changing Carbon And Gas Prices

	Carbon price	Gas price per GJ
Scenario 1	Per Treasury modeling*	A\$4.50
Scenario 2	Per Treasury modeling*	A\$7.50\$
Scenario 3	Hits a floor in 2015 and stays low	A\$7.50\$

GJ—Gigajoule, or one billion joules (one joule is a unit of energy). *Per the Australian Energy Market Operator's historical expectations of steady growth in electricity demand of about 2% per year. \$Higher gas prices in 2015 to reflect international gas pricing following commencement of liquefied natural gas exports. A crucial assumption, particularly for Scenario 2, is that black coal prices do not increase to the extent that the carbon price shifts the relativities back toward gas as in Scenario 1. Additional assumptions are contained in Appendix II.

Table 4 | Major Terms Of The Clean Energy Legislation

Scheme coverage	Stationary energy, industrial processes, non-legacy waste, fugitive emissions, and transport (except household transport fuels, light vehicle business transport, and off-road fuel used by the agriculture, forestry, and fishing industries). In terms of waste exposure, only landfill facilities with direct emissions of 25,000 tons CO ₂ emissions per year or more will be liable.
Fixed price period	Three years from July 1, 2012, with a starting price of A\$23 per ton rising at 2.5% per year in real terms. Hence, if inflation is at 2.5%, the price will increase by 5%.
Emissions trading scheme	From July 1, 2015, with a price ceiling and floor for the first three years. • <i>Ceiling</i>: Set at A\$20 above the expected international price, rising by 5% in real terms each year. • <i>Floor</i>: Set at A\$15, rising by 4% each year in real terms. Permits under the scheme can be sourced from "credible" international carbon markets, but a minimum of 50% of the liability must be met from domestic permits.
Timeline for setting pollution caps	
Deadline to set pollution cap	Pollution cap announced for financial year(s) beginning:
5/31/2014	2015 to 2019 inclusive
6/30/2016	2020
6/30/2017	2021

The pollution cap is intended to be reset annually to maintain five years of known caps at any given time.

Renewables growth is limited in all three scenarios and fails to meet the 20% 2020 target. Wind begins to appear in a material way in the fuel-mix picture, while hydro somewhat maintains its share (see chart 5).

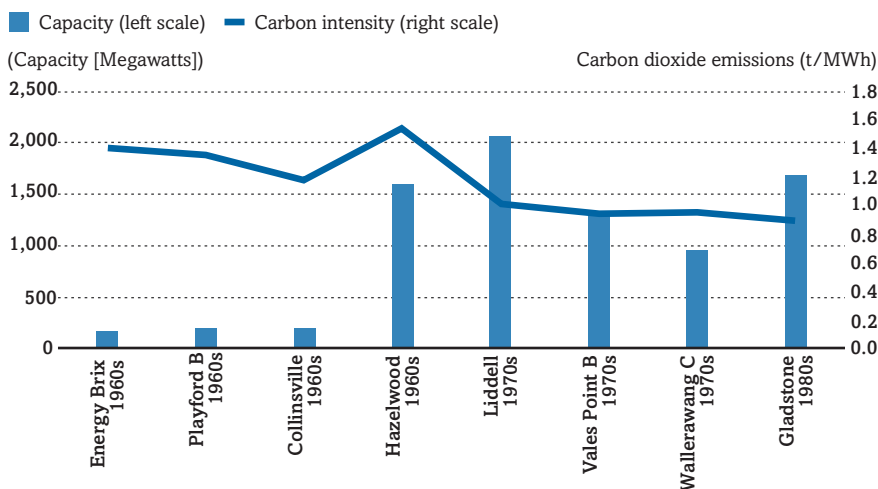
However, when gas price spikes to A\$7.50 per gigajoule (GJ; or one billion joules, a unit of energy), the build-up in gas slows considerably. Scenarios 2 and 3 illustrate the sensitivity of fuel costs to the evolution of the fuel mix despite there being a carbon price. Brown coal's share would be largely taken up by gas, but also to some extent by black coal in Scenario 3. For the third scenario, the low price of carbon permits does not offset the cost advantage of coal as much compared to Scenario 2 if gas prices stayed at A\$7.50 per GJ.

...But Gas Is Unlikely To Be A Runaway "Winner"

While gas is expected to be a "winner" under the carbon plan, the extent of the "victory" could be muted. The opening up of the east coast of Australia from 2014, as the coal seam gas (CSG)-to-LNG projects begin to export, is expected to push up gas prices, reflecting export parity pricing. RepuTex's modeling suggests this impact on gas, particularly if carbon prices are low, will help preserve coal's competitiveness. This expectation stands in marked contrast to that in the U.S. The advent of large exploitable amounts of shale gas has recently seen U.S. natural gas prices test new lows, leading to many utilities switching from coal to gas.

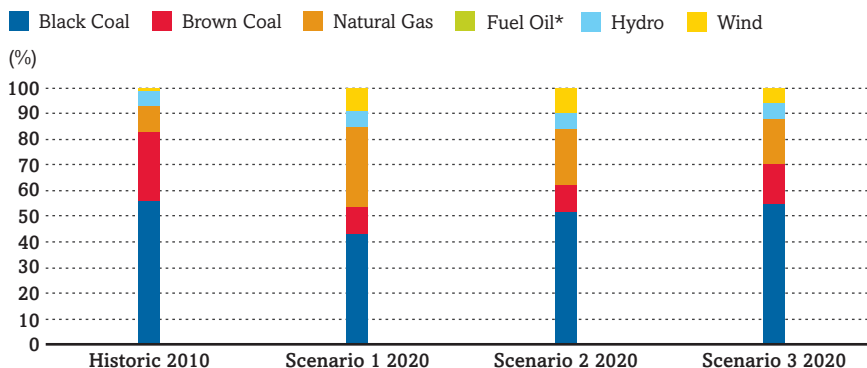
Indeed, if gas prices were to steeply rise, we believe coal could still have a superior cost advantage. This is even though we expect new thermal coal prices will increase when long-term low price contracts are to be renewed at the higher levels of the past few years (to about US\$100 to US\$120 per metric ton from less than US\$30 per ton 10 years ago). The successful development of the Cobborra mine by the New South Wales government—prices reported to be about A\$30 per ton—could help offset any climb in coal fuel costs. Also, we expect fuel costs for the brown coal plants in Victoria to remain low with no

Chart 4 | Selected Coal-Fired Generators In Australia—Commissioned Prior To 1981



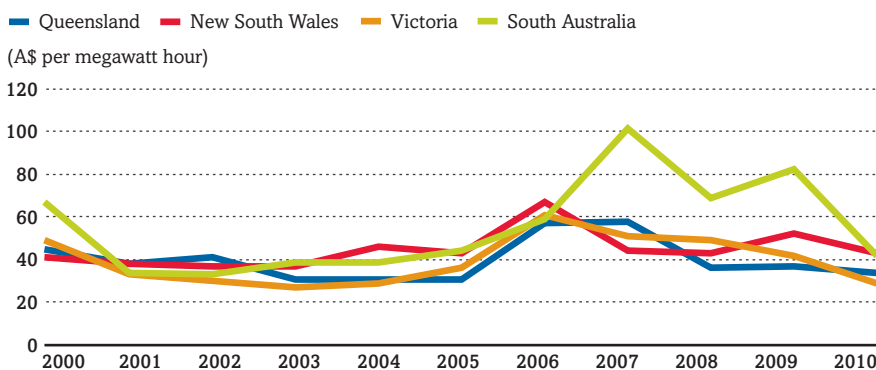
Note: It is assumed that during 2012, the following power stations will be retired: Swanbank B Power Station (4x120 MW, coal fired, Queensland) and Munmorah Power Station (2x300 MW, coal fired, New South Wales).
Sources: RepuTex Carbon Analytics, Australian Energy Market Operator, and Standard & Poor's.
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Chart 5 | Fuel Mix Changes From 2010 To 2020 Under Scenarios 1, 2, And 3



*No change.
Source: RepuTex Carbon Analytics, 2012.
© Standard & Poor's 2012.

Chart 6 | Mainland Volume Weighted Average Spot Electricity Prices



Source: Australian Energy Regulator.
© Standard & Poor's 2012.

export parity pricing. In fact, the Loy Yang plants in Victoria have the lowest short-run marginal costs in the National Electricity Market.

The prospect of uncertain returns on new power stations would make attracting investors to new gas plants a major hurdle. This issue would become more acute when the government's contract to close 2000 megawatts (MW) of carbon-intensive plants by 2015 is implemented. The RepuTex scenario outputs, particularly Scenario 1, are more theoretical possibilities if there was clarity and certainty about market dynamics, rather than a likely outcome we expect.

Limited Near-Term Prospects For New Base-Load Generation

Further clouding new investment prospects are the current demand and supply dynamics. Average wholesale prices for the past 10 years have been relatively flat once the impact of the drought in 2007 is removed (*see chart 6*). They also have consistently underperformed the forward price curve. Hence, we see limited reliable price signals that the market is in need of significant new supply.

What's more, actual energy dispatched in the past few years has declined (*see chart 7*). This trend has been contrary to Australian Energy Market Operator's (AEMO) historical

expectations of about 2% base-load growth. However, AEMO has more recently scaled back its future growth to be more in line with recent trends.

We consider headwinds for electricity demand growth include:

- Introduction of material demand-management programs particularly through smart meters such as those being rolled out in Victoria.
- The impact of network-related price rises prompting consumers to actively monitor and reduce consumption through the use of more efficient appliances.
- Continued "hollowing out" of Australia's industrial base as manufacturing production plants relocate offshore. We note Alcoa is reviewing the future of its Point Henry Aluminium smelter, which if closed could add 200 MW supply to the market.

However, there is an expectation of electricity demand rising to power the CSG to LNG plants in Queensland. RepuTex estimates that this development could spur a rise of as much as 1,000 MW from 2014. Over the very long term, the pace of any electrification of the road transport fleet, if this ever becomes material, is likely to be the main driver of demand.

As such, we see the supply demand equation remaining in balance for some

years. There is little impetus for demand increasing to soak up any additional supply from any new base-load plants. With base-load demand likely to remain flat, current coal plants would need to be displaced in order to meet carbon emissions targets. But investors will have to be convinced of the adequacy of returns from alternative base-load power sources to undertake the large capital investment required.

But we do envisage some additional investment in peaking plants. Trends show the market is becoming more skewed toward "peak" events, supporting AEMO's 2.6% forecast for annual peak demand growth. Nevertheless, such instances can pressure system supply and cause price spikes. We expect near-term investments would more likely be in cheaper, smaller-scale gas peaking generation.

It is likely that the removal of 2,000 MW under the government's contract will call for new plants to fill the gap. That said, we expect any closure to be done gradually, thereby dampening any potential price signal from such a large withdrawal of system supply. For example, if Hazelwood were chosen, it would make sense for a gradual shut-down of its eight 200 MW units—even as low as one unit per year—in order to maintain system robustness. Any such gradual change could well be filled with small units including renewables, which are being promoted under various government-sponsored schemes.

New Base-Load Generation Faces Challenge From Renewables

Various renewable energy schemes implemented could dull the shine for new base-load investments. RepuTex estimates that rooftop solar installations over the past half dozen years or so have taken as much as 500 MW from demand as of the end of 2011. In addition, mandatory renewable schemes that require retailers to source 20% of power from renewable sources by 2020 could trigger sufficient incremental supply to meet any modest increase in demand.

But new renewable generation effectively "lengthens" the queue of generators to be displaced (or the bid stack).

The prospect of uncertain returns on new power stations would make attracting investors to new gas plants a major hurdle.

Table 5 | Expected Plant Closures Under Carbon Abatement Scheme*

Power station	Capacity (MWh energy)	Emissions intensity (Tons CO ₂ /MWh)
Playford power station	1,216,818	1.36
Energy Brix	938,369	1.40
Hazelwood power station	10,100,000	1.14
Collinsville power station	964,912	1.39
Yallourn power station	11,500,000	1.11

*RepuTex statistics used.

The addition of so much generation with negligible operating costs could also adversely affect the volume dispatched and energy price for thermal base-load plants. Such a trend could impede any near-term improvement in the financial conditions of stand-alone base-load generators that are highly leveraged.

Renewables To Fall Short Of 2020 Target

The three RepuTex scenarios expect renewables to fall short of the government's requirement that 20% of energy sourced should be derived from renewable generation by 2020. RepuTex's modeling suggests renewables generation's market share would range from 14% to 17%.

To reach the government target, a considerable leap in current renewable generation is required. Installed capacity of wind farms would have to increase by between 4,750 MW and 5,000 MW (at an average 30% capacity factor) from 1,842 MW at June 30, 2010, to reach the 2020 target, based on RepuTex's estimates. This means about 25 terawatt hours (TWh) of large-scale renewable energy, compared to 10.4 TWh in 2011.

Judging by the currently small size of the renewables pipeline, meeting the 2020 target could be a stretch (*see charts 8 and 9*). The weak price and surplus of renewable energy certificates have affected investments in renewables. AGL's 420 MW Macarthur wind farm is really the only project of scale under construction. In addition, projects under the government's "Solar Dawn" project have thus far been unable to obtain power purchase agreements from credit-worthy counterparties.

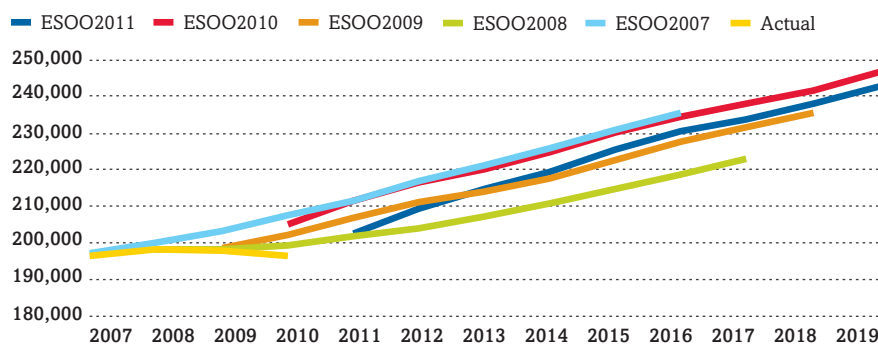
On the other hand, energy retailers have a strong incentive to meet the government's objective. Under any renewable shortfall, retailers face the imposition of large penalties of a flat A\$65 per megawatt hour (MWh; which rises to A\$92 per MWh if grossed up for its non-deductibility). As such, the penalties could spur investments in renewable generation to bridge the gap between RepuTex's modeled contributions to the government target. Energy retailers may

be at a competitive disadvantage if their rivals were able to avoid these potentially onerous costs and increase market share as a result of better pricing.

However, a key caveat is that if wholesale power prices remain weak, it may be cheaper to pay the market penalty on the shortfall. The penalty is set at a flat rate with no escalation for continued noncompliance. In the overall scheme of things, it may be more efficient to absorb some uplift in the average cost of supply than to incur potentially large capital costs on relatively expensive renewable technology over a relatively compressed time frame.

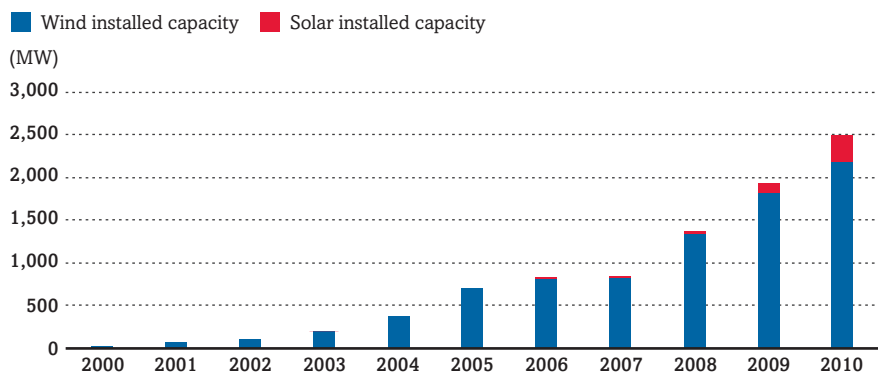
Gas could lose out if renewables, with their negligible operating costs, approach closer to the 20% mandatory renewable energy target. Particularly, in the absence of substantial system

Chart 7 | Actual NEM Generation Output Versus AEMO Demand Projections



NEM—National Electricity Market.
Source: AEMO: Australian Energy Market Operator forecasts from various annual Electricity Statement Of Opportunities (ES00).
© Standard & Poor's 2012.

Chart 8 | Australian Installed Solar And Wind Capacity As Of May 2011



MW—Megawatts.
Source: RepuTex Carbon Analytics, 2012.
© Standard & Poor's 2012.

demand, the small discrete size of many wind-farm projects could fill in any supply shortage, in our view. This further alleviates the need to build out large-scale base-load gas plants.

Toward 2050: Carbon Price Paradox And Increased Stranded Asset Risk

In the longer term, the price of carbon would have to rise significantly to change the relative operating costs of coal and gas. In our view, the projected carbon price trend of the Treasury's forecasts is highly uncertain. Furthermore, the certainty provided in the fixed carbon price period is just for three years, which is not very long in the scheme of new investments.

What's more, the flexible price period for 2015 to 2018 (with its price cap and floor) before moving to a market price, is likely to introduce carbon price volatility. Carbon prices collapsed in the European carbon market to about €7.30 (A\$9.73) per ton of CO₂ at the end of 2011, after fluctuating between €15 (A\$20) to as much as €25 (A\$33) for the past several years (see chart 10).

Paradoxically, higher carbon prices would not necessarily trigger new investments. The timing of such rises is key. Should carbon prices rise substantially only some time after 2020 to 2025, the window for gas as a transition fuel could be relatively short. The potential for stranded asset risk of new gas plants will intensify when seen in the context of the government's longer term 80% carbon abatement target. Thus, if material investment in gas does not occur in the next 10 years, there is a risk that gas may

not be as big a "winner" as expected in the transition to a lower carbon-intensity energy base. The later investments are delayed, the higher the risk of stranded assets.

Another headwind for gas in the longer term is the development of renewable technologies. As advancements are made in renewable technologies and carbon price increases, renewables are likely to become more attractive to investors relative to gas.

A Leap To Renewables Could Occur

Globally, gas may be in store for a golden age. But in Australia, the bias toward coal and limited available base-load gas may trigger a different dynamic. The near-term prospects for gas as a transition fuel are limited. We expect gas prices to increase, thus offsetting the impact of a higher carbon price.

Schemes supporting renewable technology would also result in gas being less favored to take over coal. In the longer term, potential stranded asset risk is likely to see financiers being reluctant to commit to long-term stand-alone gas plants.

If these predictions were to come true, meeting carbon emission targets may well hinge on renewables. We believe that if renewable technologies were to significantly improve the efficiency and cost of large-scale base-load renewable generation, they could effectively bypass gas. However, the technological potential remains uncertain, and unless renewables prove themselves in the next decade, the transition to clean energy could be a dramatic leap. Such a step-change needed further fuels doubts

Table 6 | RepuTex Ltd. Carbon Price Forecasts

Year	A\$ per ton of CO ₂ emissions
2012	23.00
2013	24.15
2014	25.40
2015	29.00
2016	31.90
2017	35.09
2018	38.60
2019	42.46
2020	46.70

Table 7 | RepuTex Ltd. CCGT And OCGT Capital Cost Assumptions

Plant type	Typical size (MW)	Project Cost (2011\$/KW)
CCGT	700	1,268
CCGT	430	1,005
OCGT	160	900

CCGT—Base-load gas transmission. OCGT—Peak-load gas turbines. MW—Megawatt. kW—Kilowatt.

Table 8 | Long Run Marginal Cost: Coal, Gas, And Wind

	Avg LRM (A\$/MWh)	Avg emission intensity	Carbon price (A\$)	Adjusted LRM (A\$)
Brown coal	\$48	1.3	\$23	\$77.90
Black coal	\$54	1.1	\$23	\$79.30
CCGT	\$60	0.48	\$23	\$71.04
OCGT	\$88	0.65	\$23	\$102.95
Wind	\$105	0	\$23	\$105

Future capital costs are also scaled down by 30% of CPI for future years to reflect the technology cost downward trends. CCGT—Base-load gas turbines. OCGT—Peak-load gas turbines. LRM—Long-run marginal costs. MWh—Megawatt per hour.

about the investment prospects in the Australian generation sector.

Appendix I: Scheme Summary*

*Source: *Securing A Clean Energy Future: The Australian Government's Climate Change Plan 2011*.

While the federal opposition's policy is to repeal the current scheme, they support the principle of a 5% cut by 2020 using alternative mechanisms. Hence, we consider that management of the issue of future abatement will continue to apply (see table 4).

Transitional assistance for stationary energy

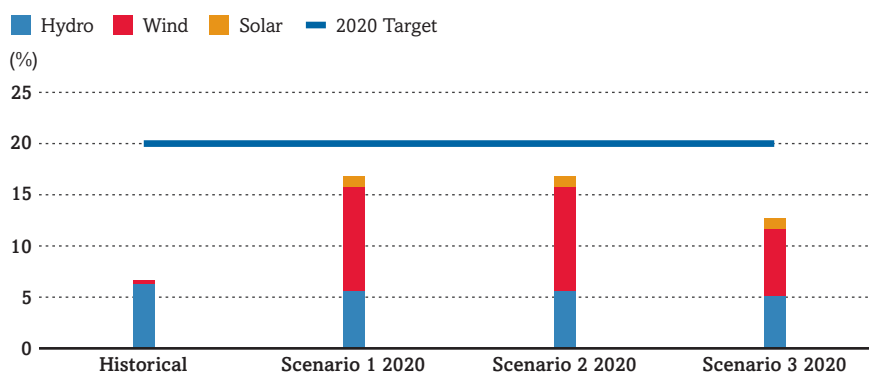
To ease the transition under the scheme, the government has set up a compensation scheme of A\$5.5 billion for coal-fired generation with emissions intensity that exceeds one metric ton of CO₂ emissions per megawatt hour (effectively this will be for brown coal generation). This is broken down into A\$1 billion in cash to be distributed before June 30, 2012. About A\$4.5 billion of free permits will be issued over four years starting from fiscal year July 1, 2013. Therefore, the liability for fiscal 2013 will need to be covered from the cash compensation and working capital.

The government has also initiated a contract for closure of up to 2,000 MW of capacity with emissions exceeding 1.2 metric tons of CO₂ emissions per megawatt hour. Effectively this scheme is restricted to five power stations (see table 5) with the Commonwealth's preferred timing of closure to progressively occur from July 1, 2016 to June 30, 2020 (subject to energy security). Negotiations regarding "contracts to close" are expected to be completed by June 30, 2012.

Investment in renewable energy

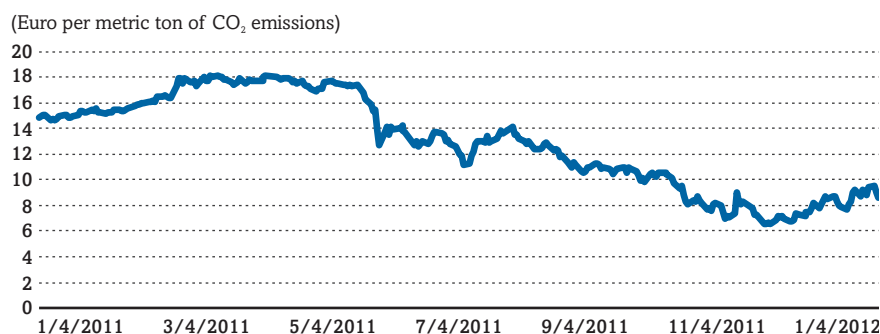
To promote investment in clean energy, the government will directly invest A\$13 billion in clean energy projects. About A\$10 billion would be via the Clean Energy Finance Corp., which is to commercialize "clean" technology and A\$3.2 billion in research, development, and commercialization of early

Chart 9 | Forecast 2020 Renewable Generation Under RepuTex Modelling



Source: RepuTex Carbon Analytics, 2012
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Chart 10 | EU Allowance Price For December 2012 Delivery



Source: Platts.
© Standard & Poor's 2012.

stage renewable technologies via the Australian Renewable Energy Agency.

Appendix II: RepuTex Modeling Assumptions

The carbon price trajectory (real prices), assuming the Treasury's price path, is shown in table 6. This price path is used as it is considered necessary given that gas CCGT's (base-load gas turbines) long-run marginal cost is about 50% more than coal's, and is considered necessary to make gas competitive and drive the government's outcome (see tables 7 and 8). **CW**

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