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Climate Change Credit Survey

A Study Of Emissions Trading, Nuclear Power, And Renewable Energy

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CLIMATE CHANGE CREDIT SURVEY: A STUDY OF EMISSIONS TRADING, NUCLEAR POWER, AND RENEWABLE ENERGY

Welcome to Standard & Poor's credit survey on the impact of climate change policies on the European power industry. This publication reflects the commitment of the European Infrastructure Finance Ratings team to coverage of the topic and is intended to enhance Standard & Poor's reputation as the world's leading provider of timely, objective credit analysis.

We believe that EU climate change policies will continue to have a significant bearing on the risk profile of the European utilities sector. These policies, therefore, will continue to be a significant focus of our analysis of the sector. In the short term, the principal impact of climate change policies will be to continue to boost cash flow--and thus credit quality--of European generation companies that operate in countries in which power markets have been fully liberalized. Uncertainties about the long-term direction of global and EU climate change policies, however, are complicating the planning process for the coming cycle of new generation capacity build, which is in turn creating uncertainties about long-term power prices. This is likely to result in delays to generation investment decisions and expenditure.

The commentary articles included in this survey provide an overview of the main policy instruments that are being used by the EU to meet their commitments under the UN-brokered Kyoto Protocol as well as an analysis of the principal effects of EU climate change policies on the power generation sector. One of the most prominent effects of EU climate change policies has been the introduction of the EU Emissions Trading Scheme. This has resulted in generation companies in a number of European markets making windfall profits. The economic rationale of this effect and its long-term sustainability, particularly as the supply of emission credits from outside the EU increases, are examined.

There are also analyses of the role that nuclear generation, which is carbon dioxide “clean”, could play in helping the EU and some countries to deliver on their long-term policy goals of reducing greenhouse gas emissions. In addition, studies on the French, Spanish, and U.K. wind power markets have also been included. Renewable wind power generation, which is environmentally clean, forms a central focus of climate change policies. Further research is included on the role that clean-coal technology could play in enabling coal-based generators to lower their emission levels.

Based in London, Paris, Frankfurt, Madrid, Moscow, Milan, and Stockholm, our regional infrastructure analysts welcome your feedback. Please do not hesitate to contact me or any of the analysts if you require further information.

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TARGETS AND TRADING: THE EU'S RESPONSE TO CLIMATE CHANGE

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The future direction of EU and national climate change and energy policies will have a significant bearing on the utility sector's risk profile. In the short term, the principal impact of EU climate change policies will be to continue to boost the profitability and cash flow--and therefore credit quality--of European generation companies that operate in countries in which wholesale and retail power markets and prices have been fully liberalized, such as Germany, the U.K., and Sweden. These companies include E.ON AG (AA-/Negative/A-1+), RWE AG (A+/Negative/A-1), EnBW Energie Baden-Wuerttemberg AG (A-/Stable/A-2), Vattenfall AB (A-/Positive/A-2), Scottish and Southern Energy PLC (A+/Stable/A-1), Scottish Power PLC (A-/Stable/A-2), and EDF Energy PLC (A/Stable/A-1).

Uncertainties about the future direction of climate change policies are, however, complicating the planning process for the coming cycle of new generation capacity build because it is unclear which generation technologies will be favored. This is creating uncertainties about long-term power prices. Standard & Poor's Ratings Services believes this may also be resulting in delays to generation investment decisions and expenditure.

The EU Agenda On Climate Change

The potential social and financial costs of climate change are so significant that Standard & Poor's believes that this issue will remain high on the agenda of the EU. As 80% of "greenhouse gases", which are believed to be a significant contributor to global warming and climate change (see "Sidebar 1: What is Global Warming?" at the end of this article), are emitted through energy production or consumption, the political direction the climate change debate takes and the resulting EU and supranational climate change policies will continue to be significant drivers of risk and value for EU generation companies.

The EU, U.S., Canada, Russia, Japan, China, and India account for about 75% of greenhouse gas emissions. Standard & Poor's believes that the form and effectiveness of any agreement that replaces the Kyoto Protocol, which lasts until 2012, (see "Sidebar 2: The Kyoto Protocol" below) will be heavily influenced by the position taken by this group of countries.

Standard & Poor's believes that the future direction and economic cost of EU climate change policy, and the EU's negotiating stance regarding efforts to replace the Kyoto Protocol, will be influenced by the extent to which the Union can increase international participation in efforts toward a binding, target-based emission reduction system. If there were not a sufficiently broad level of international participation in any replacement treaty, the EU would be at a competitive disadvantage to countries that did not sign up to any replacement treaty--and therefore did not have to bear the costs of emission reduction.

The EU has estimated that in the coming decades the EU-25's share of global greenhouse-gas emissions will decline to less than 10%, while, for example, those of developing countries will expand to more than one-half of the total. Even a marked reduction in EU emissions would therefore have a negligible impact on total emissions. Consequently, if there is insufficient international participation in any replacement treaty, Standard & Poor's believes that the EU and EU national governments may reconsider whether the future direction of climate change policies should be changed to reduce the cost to the EU.

Energy Policy Measures Being Used To Meet The EU-15 Emission Target

The generation, supply, and use of power is one of the main sources of greenhouse gas emissions in the EU (the other principal sources are transport, industrial processes, waste management, and agriculture). The range of energy policy measures that have been implemented to reduce emissions from energy supply and use includes:

- The EU CO2 Emissions Trading Scheme (ETS), which has created a carbon constraint in the EU, thereby allowing the market to price CO2 emissions (see "Greenhouse Gas Regulation Creates Upward Pricing Pressure And Windfall Profits For European Utilities", published on Oct. 12, 2005, on RatingsDirect, Standard & Poor's Web-based credit analysis system);
- The Linking Directive, which links the ETS with the Kyoto Joint Implementation and Clean Development mechanisms (for more detail, see "Kyoto Catch-Up: Could Cheap Emissions Credit Imports Flood The EU Market?", published on Oct. 7, 2005, on RatingsDirect);
- A directive promoting the generation of electricity from renewable sources--the EU has set a target of generating 22% of gross electricity consumption from renewable energy sources, such as hydro, wind, tidal, wave, and solar power, by 2008-2012 (see "French Wind Power Gaining Momentum But Not Yet A Breeze", published on June 30, 2005;

"New Tariff Regime Brightens Horizon For Wind Power In Spain", published on June 14, 2005; and "U.K. Wind Power Framework Is Improving But Clouds Remain On The Horizon", published on June 6, 2005, all of which are available on RatingsDirect);

- A directive to promote combined heat and power technology, which uses significantly more of the energy generated from fuel than simple power generation; and
- A directive on the energy performance of buildings, to enhance the energy efficiency of buildings (and thereby reduce electricity demand).

The Emissions Trading Scheme

One of the principal policy instruments being used by the EU to try to meet its Kyoto commitments is the ETS. The Emissions Trading Directive, which came into force in January 2005, covers power and heat production, pulp and paper production, oil refining, cement, and lime and steel production. All facilities above a certain size (which varies by Member State) within each of these industries must hold emission certificates to cover their CO2 emissions. More than 11,000 plants fall under the scheme.

Emissions allowances can be transferred and traded. Any plant owner that fails to present emissions allowances equivalent to actual emissions will be fined €40 per ton of CO2 equivalent in 2005-2007 and €100 per ton of CO2 equivalent in 2008-2012.

The ETS covers two periods. The first runs from Jan. 1, 2005, to Dec. 31, 2007. This is considered a test period and covers CO2 only. Emission allowances have been distributed to plants in the covered sectors for free. The first-phase national allocations of emission allowances represent a reduction of about 2.7% from "business as usual" emission levels. This creates a carbon constraint in the EU and ensures that CO2 emissions or pollution will be priced into industrial and power production processes.

The second phase of the ETS runs from Jan. 1, 2008, to Dec. 31, 2012, the end of the Kyoto Protocol commitment period. At least 90% of emissions allowances will be distributed for free based on historical emission levels, while the remainder can be auctioned out. The 2008-2012 national allocation proposals by Member States have to be submitted to the European Commission by the summer of 2006.

European utilities that generate electricity using coal, lignite, gas, and oil have received free emission allowances covering much of their "business as usual" emissions for the period to Dec. 31, 2007. At the same time, the ETS, introduced on Jan. 1, 2005, has created a carbon constraint and a price for CO2 pollution. This is a generation cost for those utilities that emit CO2.

The Challenge Of Meeting Kyoto Commitments

Standard & Poor's believes it will be challenging for the EU-15 to meet its Kyoto target of reducing emissions of greenhouse gases by 8%. The EU has, however, invested significant political capital in the climate change debate given the importance of the issue. It has taken a global lead in publicizing and trying to counter the risks of climate change. Standard & Poor's, therefore, believes that significant effort will be made by the EU to ensure that the 8% reduction target is met.

According to "Greenhouse gas emission trends and projections in Europe 2004", published by the European Environment Agency (EEA), emissions by the EU-15 in 1998-2002, the latest five-year period for which data is available, were 2.9% below their base year level.

In addition, the emissions of CO2 and other greenhouse gases from the EU-15 grew by 1.3% in 2003 compared with 2002 due to the increased use of coal in the generation mix and higher heating demand due to unfavorable weather conditions. The emissions increased by 1.5% in the EU-25 in 2003 compared with 2002.

The latest projections on future emissions according to the EEA indicate that the EU-15 will have to rely on obtaining emission credits through the Kyoto Protocol's project-based mechanisms to meet its Kyoto target of an 8% emissions reduction. This will involve investment in emission-reducing projects in non-EU countries.

According to the EEA (based on data available for the 1998-2002 period), the EU's existing domestic policies and measures will reduce greenhouse gas emissions in 2008-2012 by 0.6%-1.0% from base year levels. The EEA believes that the effective implementation of additional planned policies and measures could allow the EU-15 to achieve a reduction of 5.4%-7.7% (the higher forecast assumes that Member States would cut emissions by more than is required to meet their national targets). The use of the Kyoto mechanisms is forecast by the EEA to allow the EU-15 to reduce emissions by a further 1.1%. This could allow the EU-15 to achieve an 8.8% reduction and meet its Kyoto target.

What is Global Warming?

"Global warming" is the increase of the average temperature of the Earth's atmosphere, land mass, and oceans. The majority scientific opinion on global warming and climate change, as expressed by the UN Intergovernmental Panel on Climate Change (IPCC) in its Third Assessment Report from November 2001 is that most of the global warming in recent decades can be attributed to human activities, such as the burning of fossil fuels--oil, coal, and gas. These fuels release the greenhouse gases that are believed to trap some of the sun's heat in the atmosphere. This view has been endorsed by the national science academies of the G8 nations (the U.S., the U.K., Germany, France, Italy, Canada, Japan and Russia), and Brazil, China, India, and Russia.

According to the IPCC, one of the foremost authorities on global warming, the Earth's surface warmed by about 0.6 degrees centigrade degrees over the twentieth century. The IPCC has projected that by 2100 the average global surface temperature could have increased further by 1.4-5.8 degrees centigrade above 1990 levels. In Europe, the mean temperature increased by more than 0.9 degrees centigrade in the twentieth century. It has been projected that temperatures in Europe could increase further by 2100 by 2.0-6.3 degrees centigrade above 1990 levels.

Global warming is expected to result in changes in the amount and pattern of rainfall. More extreme weather events could also result, including more intense hurricanes, floods, droughts, and heat waves, which could result in significant social and economic costs.

The Kyoto Protocol

The UN-brokered Kyoto Protocol aims to counter the threat of human-induced climate change by setting binding targets on its signatory nations for the reduction of emissions of carbon dioxide (CO2), nitrous oxide (N20), methane (CH4), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, the greenhouse gases. CO2, mainly created by the burning of fossil fuels, is the most significant of the gases in terms of emission volumes. It is believed that reducing greenhouse gas emissions will reduce the extent of future global warming and consequent climate change.

Under the Kyoto Protocol, developed countries who signed up to the treaty committed to an overall 5% reduction from the 1990 level of greenhouse gas emissions by 2008-2012. The EU's overall commitment is to reduce greenhouse gas emissions, averaged over 2008-2012, to 8% below the base year level of emissions. The base year level of emissions is calculated by using the 1990 emission levels of CO2, CH4, and N2O of all member states and the 1990 or 1995 emission levels for fluorinated gases depending on the member state.

This 8% reduction target has been redistributed by the EU "burden-sharing" agreement between the EU-15 Member States. Individual targets have been set for each EU Member State. Some countries, such as Portugal, Spain, and Greece, whose economies were less developed and greenhouse-gas intensive in 1990 compared with the EU average, were allowed an increase in emissions, while more economically mature and carbon-intensive Member States such as Denmark, Germany, and the U.K. had to reduce their emissions. ■

EU CLIMATE CHANGE POLICY: THE EFFECTS ON GENERATION COMPANIES

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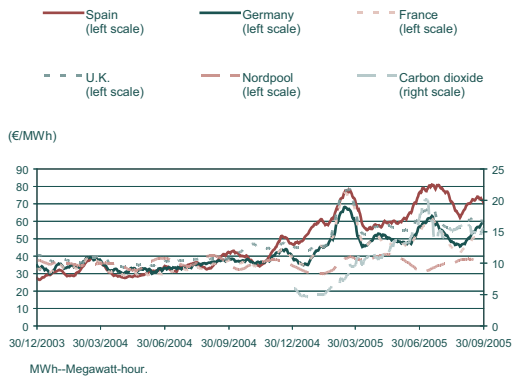
EU climate-change policies will continue to have a significant bearing on the risk profile of the utilities sector. In the short term, Standard & Poor's Ratings Services expects the principal policy impacts to be a continued boost to the profitability of European generation companies that operate in countries in which power markets have been fully liberalized, and delays to some generation capacity investment decisions, given the long-term uncertainties about how climate-change policies will affect the relative economics of different generation technologies. Given current policy, however, Standard & Poor's believes that new-build renewables (such as wind, solar, and biomass) and gas will be favored given their better carbon dioxide (CO2) emission performance than coal and- oil-based generation, albeit that the relative economics of these competing generation technologies will also be heavily influenced by the cost differential between gas and coal.

Coal-based generation will, however, continue to be important in some markets like Germany, where research efforts will focus on technologies such as clean-coal technologies and carbon capture and storage, which can reduce the CO2 emissions that reach the atmosphere. Standard & Poor's also expects the debate about the long-term future of nuclear power to intensify. Although new-build nuclear continues to face social and political challenges, and there are uncertainties about how nuclear waste will be managed, nuclear generation has the advantage--in the context of the climate change and security of supply debates--that it is relatively CO2 "clean" and is a "homegrown" source of power.

European Power Market And Carbon Dioxide Price Developments



MWh--Megawatt-hour.

A key longer-term angle of the emission reduction debate, which Standard & Poor's will continue to monitor, will be how climate-change policies affect power demand. Demand-side measures to improve energy efficiency offer one of the most effective means of reducing emissions. In addition, sustained high power prices (in part reflecting the impact of climate change policies) in liberalized markets will negatively affect demand and growth and could cause an increase in self-generation.

The EU's policies will continue to evolve into the long term, however, and uncertainty about significant elements of them could have a credit impact on the European energy generation sector. This article discusses how rated generators have been affected by the EU's climate change abatement and mitigation policies, and considers the potential impact of future developments.

The Short-Term Impact

Higher profits for generation companies in liberalized markets

Although the EU CO2 Emissions Trading Scheme (ETS), introduced in January 2005, requires generation companies to hold tradable allowances to cover their CO2 emissions, EU generators who use generation technologies that emit CO2 have and will receive free allowances covering a very significant share of their emissions. Consequently, even though the introduction of the ETS in Europe has imposed limits on emissions of, and a price for, CO2, which has contributed to higher wholesale power prices in markets such as Germany and the U.K., generators in these markets who emit CO2 have generally not experienced an increase in their marginal cash generation costs. For generators in these markets that do not emit CO2 (hydropower and nuclear generators, for example), higher wholesale power prices have fed straight through to higher profitability, because they bear no increased marginal generation costs.

In competitive markets, generators are likely to benefit from windfall profits unless the marginal generation fuel is nuclear, wind, or hydro, or unless a coal facility is granted less than one-half of the allowance required for its normal production level. At this stage, Standard & Poor's believes that we are unlikely to see these conditions in any EU-15 markets in 2005-2007 (see "Greenhouse Gas Regulation Creates Upward Pricing Pressure And Windfall Profits For European Utilities", published on Oct. 17, 2005, on RatingsDirect, Standard & Poor's Web-based credit analysis system).

The earning of windfall gains by EU generation companies is controversial. Political and regulatory risk does, therefore, exist for generators, although the inclusion of the opportunity cost (or market price) of freely awarded emission allowances in wholesale power prices in liberalized power markets is economically logical and is the outcome that would have been expected when the EU ETS was designed.

Short generation means a weaker competitive position

Companies that operate in a competitive retail market but are short in generation relative to their competitors will become competitively weaker. U.K. electricity and gas supply company Centrica PLC's (A/Stable/A-1) competitive position, for example, will weaken compared with its U.K. competitors, such as Scottish and Southern Energy PLC (A+/Stable/A-1) and Scottish Power PLC (A-/Stable/A-2), which are long in generation (i.e. their own power generated exceeds the amount of power to be supplied to retail customers) and will therefore benefit from the introduction of CO2 trading and rising wholesale power prices.

Centrica has a short power generation position (i.e. it has less owned generation output than customer demand) in the U.K. compared with its competitors, which means that it is more vulnerable in a rising wholesale price market. Standard & Poor's expects Centrica to continue to look for opportunities to acquire further upstream assets to reduce its short position.

The impact of ETS on markets that have not been fully liberalized

In countries such as Spain and France, where end-user power prices have not been fully liberalized, the impact of the introduction of CO2 pricing on generation profitability is more complex. It will ultimately depend on whether the regulatory environment enables the generation companies to recover their higher opportunity costs of generation through higher regulated end-user tariffs.

The French generation market is dominated by Electricite de France (EDF; AA-/Negative/A-1+), which has an 87% generation and supply market share. It is heavily dependent on CO2-clean nuclear generation--87% of its production in France in 2004 was nuclear and 9% was hydro. Given that most French end-user prices continue to be regulated, the principal means by which EDF can benefit from CO2 pricing is through the export of power to markets such as Germany where prices are not regulated.

Uncertainty delays investment

Uncertainty about the emission allowances that CO2 generators will receive in the second phase of the EU ETS, long-term global and EU climate change policies--specifically, whether the Kyoto Protocol will be replaced with a further target-based emission reduction system and whether the EU ETS will continue beyond 2012--and the future of nuclear power has created significant planning difficulties for existing and prospective new EU generators as they consider future investment. Standard & Poor's believes that this uncertainty has and will result in delays to investment decisions. This may temporarily reduce capital expenditure, thereby boosting the cash flow of generation companies. This improvement will not, therefore, be sustainable over the long term.

There is, therefore, a strong need to clarify long-term global and EU climate-change policies and thereby to create long-term regulatory certainty, which will allow companies to plan their long-term generation investments more effectively. Such policies will affect emission costs beyond 2012 and the relative economics of different generation technologies. According to the International Energy Agency (IEA), EU generators will invest about €1.2 trillion in 700 gigawatts of new generation capacity to 2030. These investments will have very significant asset lives of up to 40 years, and so will have a significant long-term bearing on greenhouse gas emission levels.

The future of nuclear power

Nuclear generation does not emit CO2. If the EU had no nuclear generation capacity, the European Commission has estimated that CO2 emissions would increase by 300 million-700 million metric tons of CO2--7.0%-16.5% of expected EU CO2 emissions--in 2008-2012. As a result, debate about the long-term role of nuclear generation in the EU has been renewed (see article titled "European Nuclear Power Shows Signs Of Surging Back, But It's No Renaissance", published on Oct. 12, 2005, on RatingsDirect). The EU-25 generation mix in 2004 was: 32% nuclear; 30% coal; 18% gas; 11% hydro; 6% oil; and 3% renewable energy.

Standard & Poor's believes that the climate change debate and concerns about security of supply could result in changes to nuclear policies, including an extension of the lifetimes of existing nuclear plants in Germany, Sweden, and the U.K. This could have a positive impact on nuclear operators such as E.ON AG (AA-/Negative/A-1+), EnBW Energie Baden-Wuerttemberg AG (A-/Stable/A-2), British Energy Group PLC (BB+/Stable/--), Vattenfall AB (A-/Positive/A-2),

and RWE AG (A+/Negative/A-1). High-margin nuclear revenue would be prolonged, while capital expenditure for replacement generation capacity and the point at which significant nuclear decommissioning liabilities need to be funded would be delayed, thereby significantly boosting cash flow. In some countries, such as the Netherlands, Poland, and the U.K., politicians have even opened discussion about the potential for investing in new nuclear generation. At the same time, the political support for nuclear power has remained strong in France, Finland, and several East European countries.

Gas versus coal

All other things being equal, the implementation of the Kyoto Protocol and the EU ETS is likely to reduce the competitiveness of traditional coal- or oil-fired power plants and result in a greater use of natural gas, which emits less CO2. The relative economics and attractiveness of these competing generation technologies will, however, also be heavily influenced by the cost differential between gas and coal--gas prices continue to be linked to the price of oil, and as a result, are high. Other energy policy goals will also be important, for example the need to maintain a diversified generation mix to reduce excessive reliance on any one fuel or supplier and the continued need for large-scale base load capacity.

The Medium Term

Markets' ability to meet emissions targets

In 2002, according to "Greenhouse gas emission trends and projections in Europe 2004", published by the European Environment Agency, the U.K., Sweden, and Germany were the best positioned countries to meet their 2008-2012 emission reduction targets. Generators in these markets may in principle, therefore, benefit from more generous emission allowances for the 2008-2012 phase of the EU ETS than generators in the other EU-15 countries, and in particular generators in Spain, Portugal, Denmark, and Italy. This is unless, for example, national governments have additional higher domestic targets. According to the EEA, these countries were neither on track to meet their emission reduction targets in 2002 nor projected to reach their final targets for 2008-2012.

Power demand following sustained high prices

Higher wholesale power prices will result in lower demand and demand growth. This outcome of EU climate change policies and the ETS is both predictable and desirable in the context of reducing CO2 emissions. High prices will also prompt changes in consumption patterns. If sustained over the medium term they may even cause the relocation of businesses--particularly those in the traded goods sector (for example, smelting)--to regions with lower energy prices and a material increase in industrial self-generation. Industry organizations in several European countries have voiced concerns that higher electricity prices and curbed emissions rights will have a negative impact on the competitiveness of European industry, particularly in those industries, such as steel, refining, and aluminum, in which it will not be possible for industry to pass through full power-price increases to end users.

Increasing energy efficiency

The IEA, in its 2004 World Energy Outlook, presented a World Alternative Policy Scenario that focused on means by which energy-related CO2 emissions could be reduced over 2002-2030. In the forecast scenario, demand-side measures to improve energy efficiency, which would lower demand and the size (and profitability) of the EU generation market, accounted for almost 60% of the reduction in CO2 emissions. Increased nuclear and renewable (which had a 3% share of the EU-25 generation market in 2004 that the EU aims to increase to 22% in 2008-2012, driven by continued policy-based subsidization) power generation accounted for most of the rest of the reduction.

Energy efficiency is a key priority for the European Commission given the significant contribution it can make to the achievement of the EU's emission reduction targets. Measures the EU is encouraging include the promotion of the wider use of combined heat and power, in which heat and power are simultaneously produced, thereby offering energy savings, and the promotion of increased energy efficiency in buildings. The use of energy in buildings accounts for about 40% of the EU's energy requirements and offers, according to the EU, the largest single source of energy efficiency through the application of tighter design standards for new and refurbished buildings.

The Long Term

Policymakers' focus

Standard & Poor's believes that, subject to the outcome of global negotiations on the replacement of the Kyoto protocol, the focus of long-term EU climate change policies that will directly affect the power sector will include:

- The continuation of the EU ETS;
- Demand-side measures to improve energy efficiency;
- Policies to encourage further investment in CO2-neutral nuclear energy and renewable power;
- Increased thermal and carbon efficiency through an increased market share of natural gas generation, at the expense of coal, and the wider and more effective application of clean-coal technologies; and
- Carbon capture and storage.

Technological advances

Alongside emissions reduction, technological advances that reduce the level of fossil fuel greenhouse gas emissions reaching the atmosphere are expected to play an important role in combating climate change. This is because fossil fuel-based generation technologies will remain central to power generation markets in both developed and developing countries over the long term for reasons of security of supply and social policy. Germany, for example, has significant reserves of lignite, but negligible reserves of oil and gas, and consequently has an economically and socially important lignite mining industry. Lignite generation is an important component of the generation mixes for both RWE and Vattenfall. As a result, significant CO2-intensive coal and lignite generation will continue in Germany.

Some of the technologies that could affect the level of emissions include carbon capture and storage and a number of “clean” coal technologies (see "What Role Will Clean Coal Technology Play For European Utilities?", published on Oct. 7, 2005, on RatingsDirect). The IEA has estimated that carbon capture and storage technology could store several decades of CO2 emissions, at a minimum. The technology is, however, still immature, and is not yet economically viable.

Scottish and Southern Energy, together with partners, recently announced that it had begun the design of an industrial-scale project to generate “carbon-free” electricity from hydrogen. The planned project would convert natural gas to hydrogen, which would be used to fuel a power station, and CO2, which would be exported to a North Sea oil reservoir for storage. It is hoped that the project could begin commercial operation in 2009, although the partners still need to confirm the economic feasibility of the project and have noted that it will require “an appropriate policy and regulatory framework”. ■

KYOTO CATCH-UP: COULD CHEAP EMISSIONS CREDIT IMPORTS FLOOD THE EU MARKET?

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A key element of the UN Kyoto protocol on climate change is the trading of allowances on greenhouse gas emissions (mainly carbon dioxide). In the EU, this is implemented under the Emissions Trading Scheme (ETS), which applies to almost all energy utilities. To help utilities meet targets in an economically viable way, the Kyoto protocol contains flexibility mechanisms such as the Clean Development Mechanism (CDM), Joint Implementation (JI), and the purchase of so-called "hot air."

Standard & Poor's considers that regulatory hurdles, project-specific risks, and political resistance to using hot air are likely to constrain the development of these flexibility mechanisms. They are therefore expected to have little impact on utilities before 2008. CDM, JI, and hot air are, however, likely to have some direct and indirect positive effect on the additional supply of emissions reduction credits and should drive down the price of emissions allowance. The CDM program, the JI program, and their interaction with hot air are extremely complex and their effects are uncertain. Over time, however, the use of these mechanisms could become more widespread, particularly if the costs for meeting emissions reduction targets in the EU prove higher than expected. Standard & Poor's will continue to monitor developments in this area.

Imported Emissions Allowances: Big Potential, Little Actual Impact

Due to the risks associated with the Kyoto flexibility mechanisms, Standard & Poor's does not expect European utilities to rely heavily on CDM credits to meet their emission reduction requirements, although some utilities, such as Sweden-based Vattenfall AB (A-/Positive/A-2) and Germany-based RWE AG (A+/Negative/A-1), have reported participation in the CDM program. Until these mechanisms have more of an impact, Standard & Poor's considers that the switch to gas from coal will continue to be a major way for power generation utilities to reduce their carbon emissions. Consequently, the price of gas relative to coal will continue to have an important influence on the price of emissions allowances.

How CDMs work

The EU ETS system was conceived of as a cap-and-trade system, whereby the total emissions produced by regulated facilities are in effect capped by a limited allowance. There is a major caveat to this cap, however: a utility in the EU may import emissions reductions achieved outside the EU to help meet emission targets. These imports would in effect raise the cap and potentially drive down the price of EU ETS allowances.

The import of emissions reductions is carried out under the CDM or JI programs. CDM applies to countries that have signed up to Kyoto but that do not have targets, such as China, India, and Brazil. JI applies to Kyoto signatories with targets, such as Russia and Ukraine. The idea behind these programs is to ensure cost-effectiveness in investments to reduce emissions, as it can be considerably less expensive to reduce or avoid emissions via projects outside the most developed industrialized nations.

Lots of planned CDM projects, but few implemented

The JI program has seen very little take-up, as credits from this program will not be effective until 2008 and the regulatory infrastructure for the program is still in its infancy. At first glance, however, the potential impact of CDM programs appears to be huge. Planned CDM projects (at the project design document stage) represent a total of 693 million tons (Mt) of potential emissions reduction credits by 2012. Moreover, potential credits are growing at rate of 454 Mt per year. By way of comparison, the reduction currently required of facilities affected by the EU ETS from their business-as-usual scenario is only 113 Mt/year (average deficit from 2005 to 2008). Moreover, CDM reduction credits are trading at only €5-€10/ton, while EU ETS allowances are currently trading well above €20/ton, occasionally reaching more than €30/ton.

Reality, however, does not currently reflect the suggested potential, owing to the slow process of registering CDM projects. The project developer, which is usually a private enterprise, seeks to register a project with the CDM executive board. The board, which is comprised of 20 members of the UN's climate change program, appoints an independent auditor to ensure that the project will actually reduce greenhouse emissions, and that it would not have otherwise been carried out simply as a result of existing economic incentives or regulatory requirements. Following a review of the auditor's findings, and a 30-day consultation period during which stakeholders can comment, the board registers the project.

Because of the amount of administration involved and the constrained capacity of the UN's climate change unit, the overwhelming majority of proposed methodologies are still awaiting approval. To date, only 363 Mt (from now to 2012) has been validated, while only 6.09 Mt/year has been validated and has passed

through the public comment period. While the risk of non-approval of any particular methodology is significant, indications are that most of the projects that have been validated will eventually be registered, but it may take some time.

Validation and registration is only the first step, however, as they only allow a project to go forward from a regulatory perspective. The project will still have its own economic and technical hurdles to get over before emission reduction credits can be produced. These risks include construction, funding, commissioning, general market risk, operation, legal, and financial risks.

Most CDM projects are highly speculative, simply because they are located in countries such as China, India, and Brazil, where the local legal structure and other developing country risks are major concerns. Compounding the financial risk for developers, the vast majority of the projects could only start producing emissions reduction credits by 2008 at the earliest, and if the ETS and the CDM program are not renewed after 2012, a project will only have a few years to recover its costly capital investment.

The project uncertainties are reflected in the low price of CDM reduction credits. As the credits do not yet reflect actual production, what are currently being traded are potential reduction credits that may or may not be produced. These CDM reduction credits therefore trade well below EU ETS allowance low prices, as they carry delivery risk, and, in some case, regulatory approval risk. Once in production, however, the price of these credits should trade very close to EU ETS allowances.

National governments will present competing demands for CDM credits

Assuming that the number of potential projects continues to grow at the current pace and that only one half of all the projects eventually come into production, this would still create 227 Mt of credits per year. This is double the 113 Mt/year shortfall that currently exists in the EU ETS system. This comparison, however, can be quite misleading: although CDM reduction credits can be used by a EU ETS facility to offset its greenhouse gas emissions, these credits can also be purchased by a national government to offset emissions from a non EU ETS source in order for the country to meet its Kyoto targets.

There will be competing demand for these CDM credits from national governments. If national governments purchase CDM credits to offset emissions from non-EU ETS sources, for example transportation and domestic sources, then fewer credits will be available for EU ETS facilities. For EU countries, the shortfall from non-EU ETS sources is estimated to be 138 Mt/year. Indications are that Canada and Japan are significantly behind their reduction targets and could also have a large appetite for CDM credits. Japan and Canada are estimated to require a reduction of 154 Mt/year by 2006.

Hot Air: A Controversial Way Of Meeting Kyoto Targets

To meet Kyoto targets, countries are allowed to purchase Kyoto allowances from other countries. Countries such as Russia and Ukraine have a lot of surplus allowances to sell, since their emissions decreased as a result of the economic downturn in the 1990s, while the baseline for greenhouse gas reductions was based on emission levels in 1990. This surplus is usually called "hot air". Standard & Poor's estimates that about 680 Mt/year of hot air could be available from Russia and former Soviet countries (this estimate is based on the Third National Communication of The Russian Federation, and The First National Communication On Climate Change from Ukraine).

Hot air can be purchased by national governments to meet their Kyoto targets, but it cannot be purchased by companies to be used in place of EU ETS allowances. The connection between hot air and the impact on the EU ETS market is not direct. Hot air could effect the supply of EU ETS allowances indirectly if national governments were to start buying hot air in large quantities, as this would reduce the demand for CDMs, leaving EU ETS facilities with a greater supply of CDM credits.

Although the purchase of hot air to meet Kyoto targets is legal, the current political environment is heavily against this practice. This is largely because this would mean spending taxpayers' money on simply meeting a legal requirement rather than on actually reducing emissions. Moreover, the Kyoto protocol states that member states should achieve reductions significantly through domestic sources, although it does not specify any quantifiable requirements. Nevertheless, if countries find themselves falling behind targets closer to the deadline of 2012, purchasing hot air may become a more likely option. ■

GREENHOUSE GAS REGULATION CREATES UPWARD PRICING PRESSURE AND WINDFALL PROFITS FOR EUROPEAN UTILITIES

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Executive Summary

The EU Emissions Trading Scheme (EU ETS), which came into force on Jan. 1, 2005, was conceived of as a cap-and-trade system to allow market forces to determine the most efficient way of reducing greenhouse gas emissions. It is similar to sulfur dioxide emissions trading in the U.S., where total emissions are capped by limiting the total allowance granted to emitting facilities. Facilities can intertrade allowances, thereby enabling the market to determine the most efficient way of reducing emissions.

The EU ETS has, however, created an issue that was not much discussed in the U.S. system, that of windfall profits. The profits of some generators in the major European markets (the U.K., Nordic countries, Germany, and Italy, but not the domestic markets of France and Spain) are increasing due to the upward pressure greenhouse gas regulation has on power prices. This benefit applies not only to nonemitting facilities but to all facilities--including coal plants, which emit the most greenhouse gas.

Many industrial end users, particularly the aluminum smelters, have voiced their discontent. They maintain that while end users suffer from the higher cost of electricity due to the incremental cost of greenhouse emission, the power suppliers--those actually releasing the greenhouse gas--are gaining incremental profits.

Standard & Poor's Ratings Services will consider how this situation has arisen and ask if regulators and politicians are likely to allow windfall profits to continue.

The Role Of Opportunity Costs In Creating Windfall Profits

To understand why windfall profits exist, we first need to assess the role of opportunity costs in generators' pricing decisions and in the price formation of the power market.

Fossil fuel generators are grandfathered a certain amount of free carbon dioxide emission allowances. On the whole, allocations for the first EU ETS trading period (2005-2007) are similar to historical generation volumes and in some cases allocations have been somewhat lower than historical volumes.

When generators bid their plants into the wholesale market, their pricing strategy is based on the marginal cost of generation. This includes fuel, variable operating and maintenance expenses, and emission costs. Although a generator may have received a grandfathered allowance, it still prices emission costs as if this allowance had been purchased from the market. As a result, introducing emission costs to a generator's cost structure raises wholesale power prices, regardless of the amount of free allowance the generator is grandfathered. For many generators, the higher wholesale prices drop directly to the bottom line as windfall profits, either because the allowance has never had to be purchased or because the generator does not emit greenhouse gases (nuclear and hydro generators, for example).

Treating the free allowance as an opportunity cost is a well-established economic rationale applied by most, if not all, major generators in Europe. The emission allowance is effectively considered as another fuel: a coal facility needs a certain allowance to generate power just as it needs coal to generate power. Given a certain amount of coal free of charge, a generator would continue to price its power as if it had purchased the coal. This is because the alternative use of the coal, simply selling it to the market, would generate revenue. For the same reason, a generator who has received a free emission allowance will price its power as if it had purchased the allowance on the market.

Which Technology Benefits Most?

When assessing windfall profits for any particular facility, the characteristics of the market's marginal plant need to be considered. This plant is important because it has an overwhelming influence in establishing the clearing price of a competitive wholesale market.

If the marginal plant does not produce any greenhouse gas and, therefore, does not have allowance costs--as is the case with nuclear, wind, and hydro facilities--wholesale prices will not rise. In this case, other generators will not benefit from windfall profits.

On the other extreme, if the marginal plant is fueled by coal--the electricity generation technology that produces the most greenhouse gas--wholesale prices will rise more than if the marginal plant had been fueled by any other technology. The rise in wholesale prices will likely be more than sufficient for all other less-polluting technologies to pass on their emission costs. If the free allowance of these generators means that they have not had to incur emission costs, the higher wholesale prices will drop to the bottom line as windfall profits. Coal plants can also pass on their emission costs to the wholesale market, meaning that their free allowance will represent a

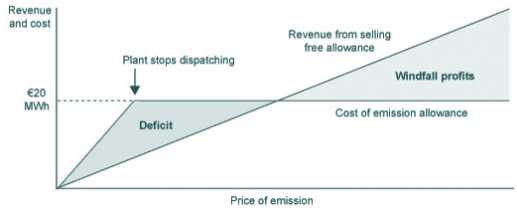
windfall profit. Nonemitting plants, such as hydro and nuclear facilities, do not have a free allowance and will receive windfall profits simply from higher wholesale prices--without an offsetting emission cost.

The most interesting scenario is when the marginal plant is fueled by gas, and the consequent impact on coal plants. In this case, power prices rise due to the gas plant's emission costs. However, the rise in power prices will be only half as much as is needed for coal generators to pass on their own emission costs. The other half must be covered by the free allowance. As a result, if a coal generator is granted less than one-half of the allowance required for production, emission costs will hurt the bottom line.

If a coal plant has a deficit, as opposed to generating windfall profits, this deficit will grow as the allowance price increases (see hypothetical scenario in chart). As the allowance price continues to increase, however, the deficit will start to shrink, eventually becoming a surplus that generates windfall profits for the plant. This U-turn in profitability is due to the rise in the allowance price leading the generator to withhold dispatch because its variable cost has exceeded the market price, thus limiting the impact of emission regulation. Yet, as the price of the allowance rises, the value of the free allowance will continue to grow, eventually exceeding the emission cost and more than compensating for the opportunity cost of not dispatching.

In a competitive market, therefore, generators are likely to benefit from windfall profits unless the marginal fuel is nuclear, wind, or hydro, or unless a coal facility is granted less than one-half of the allowance required for its normal production level. We consider both these scenarios as quite unusual at this point.

Coal Plant Granted Less Than One-Half Of Allowance Required For Production When Gas Is On The Margin*



*Hypothetical scenario.

Windfall Profits And The Role Of Regulation

Whether a generator will benefit from windfall profits also depends on the regional market it operates in. Windfall profits are most likely in the deregulated and competitive markets of the U.K., Nordic countries, Germany, and Italy, and less likely in the more regulated domestic markets of France and Spain.

In a competitive market, there is a clear connection between the marginal generation cost, the wholesale market's clearing price, and the retail price. An open and competitive market allows rational economic behavior to translate into price signals, regardless of the actual price and ultimate beneficiary of the price signal, with market participants seeking to minimize opportunity costs. In a less liberalized market, retail prices may still be regulated. So, even if a utility is able to make windfall profits from the wholesale market, it might not be able to pass on the increase to the retail market.

Will Regulators And Politicians Allow Windfall Profits To Continue?

Complaints from industrial end users and environmental advocacy groups have made regulators aware of the contention surrounding windfall profits in the utilities sector. Reactions in countries such as Germany illustrate that the issue is highly politically sensitive, causing controversy over pricing policies. But what can regulators and politicians do to change the current situation, and how might any change affect Europe's utilities?

Market liberalization, such as the European Commission's effort to facilitate cross-border trade and curtail the dominance of incumbent players, may put pressure on power prices and provide market-based incentives to reduce both emission and other costs. This will not have much impact in the short term, however, as generators will continue to count emission costs as part of their marginal costs, thereby pushing up wholesale prices. More regulation, including the possibility of a price cap, is unlikely because it would mean turning back years of deregulatory effort on the part of the EU and the governments of the member states.

The introduction of a windfall tax is possible, but would create an odd situation whereby windfall profits generated by the government's granting of a free allowance would effectively be taken back by the government. Although still in its infancy, this potential political development is worth monitoring, as it would remove the political sensitivity created by windfall profits.

National governments could try to lower the

power sector's free allowance in the next phase of the EU ETS, although a government's ability to do this is somewhat limited by the current EU directive. Under this directive, each member state has to give out 90% of the allowance it creates as free allocations in the second phase of EU ETS (2008-2012). Reducing allocations to the power sector--usually the largest sector, often accounting for about 50% or more of emissions released by EU ETS facilities--would mean that the total allowance supplied to the system is much less, potentially creating an insurmountable shortage for the system as a whole. Nevertheless, there is some room for maneuver under the EU directive, and power companies could therefore see some reduction in their free allowance in the second phase of the EU ETS.

Standard & Poor's considers that generators operating in the U.K., Nordic countries, Germany, and Italy will continue to generate windfall profits in the first phase of the EU ETS (2005-2007), with higher emission prices translating into higher windfall profits in most cases. In the second phase (2008-2012), utility companies may see some reduction in free allowance allocation because of concerns related to windfall profits. A windfall profit tax remains an option, and could come into force should political pressure continue to grow. ■

WHAT ROLE WILL CLEAN COAL TECHNOLOGY PLAY FOR EUROPEAN UTILITIES?

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This article looks at two main types of "clean coal technology" that are being considered by European utilities in their drive to reduce carbon dioxide (CO2) emissions while maintaining plant economics. Although these new technologies will help reduce CO2 emission levels, these levels will either remain higher or the cost will be greater than for other generation technologies such as gas, hydro, and nuclear.

Pollution Effects Override The Many Benefits Of Coal

Coal has many attractive features as a fuel for generation facilities but one major drawback: high pollution levels. It emits more airborne particulates, sulfur dioxides (SOx), and nitrous oxides (NOx) than other major generation technology. In addition, the pressure on coal plants is mounting with growing concerns over global warming, because a coal plant also emits more CO2 than any other major technologies. Even when compared with a gas plant, a coal plant emits twice as much CO2 because coal contains more carbon and burns with worse fuel efficiency.

Coal is relatively cheap and plentiful, however. In addition, compared with natural gas, the price of coal is considerably more stable. Europe has large coal reserves, and the use of coal does not exacerbate Europe's dependence on energy imports from Russia, the Middle East, or Africa. Coal also does not pose the kind of safety and waste disposal concerns of nuclear generation.

European coal utilities, therefore, would prefer to continue to generate power from their existing coal plants but in a manner that is more fuel efficient and beneficial for the environment. The idea of making coal more environmentally friendly has received growing attention in the past few years. The Bush administration in the U.S. has made the research and development of clean coal technologies a key strategy in combating global warming. RWE AG (A+/Negative/A-1), the German utility that is a heavy user of lignite, has also made it clear that it will continue to build coal plants, but with the help of clean coal-technologies to help it achieve CO2 reduction requirements. Swedish utility Vattenfall AB (A-/Positive/A-2) has similar plans.

Overall, clean coal generation would certainly reduce the environmental pressure on European generation companies that rely on the fuel. Several of these companies also operate coal mines, such as RWE, Vattenfall, CEZ a.s. (BBB+/Positive/--), and Public Power Corp. S.A. (BBB+/Stable/--).

European Utilities Focused On Two Clean Coal Technologies

Clean coal technologies generally refer to a host of technologies that are designed to make coal-based generation more environmentally friendly. In the context of greenhouse gas reduction, there are two relevant clean coal technologies: supercritical technology and integrated gasification combined cycle (IGCC) technology.

Supercritical technology

Supercritical technology works on the principle that the fuel efficiency of a traditional steam coal plant can be raised if it is operated at a higher temperature and pressure. The limiting factor is usually fabricating the kind of construction material that can withstand the higher temperature and pressure and still function normally. The improved efficiency will mean less fuel consumed and less CO2 emitted per unit of electricity produced. Obviously plant economics would benefit from consuming less fuel, regardless of the benefit of CO2 reduction.

In the past decade, great advances have been made in coal plant efficiency. A traditional steam coal plant operates at about 33% efficiency (or

Table 1: Cost Of CO2 Capture

($/MWh)	IGCC	Traditional coal	Natural gas	Nuclear and hydro
Capital cost	10	20	10	0
Operating cost	3	8	3	0
Energy penalty	13	28	10	0
Total cost of carbon capturing	26	56	23	0

CO2--Carbon dioxide. MWh--Megawatt hour. IGCC--Integrated gasification combined cycle.

10.3 million BTU [MMBtu] per megawatt hour [MWh]). A state-of-the-art plant now operates at 600 degrees Celsius and at 43% efficiency (7.9 MMBtu/MWh), achieved without significant sacrifice in plant economics or reliability. In the development stage is technology that is expected to operate at 700? Celsius with an efficiency of 50%. A demonstration unit using this "700 technology" in Germany is being planned to be operational in 2012.

If a traditional coal plant was to be replaced with the latest technology, the emission level would decline by 20%, to 0.8 ton (t) of CO2 per MWh from 1.0 tCO2/MWh. Although the 700 technology is still many years away and entails development risk, it could eventually allow for 30% lower emission levels compared with traditional subcritical coal plants.

The reduction can be meaningful and substantial relative to existing emission levels if generators aggressively replace their existing fleet with new technologies. The impact of this approach would be even more powerful if the technology is used to replace very old and inefficient coal plants, many of which are located in central and eastern Europe.

It is important to keep in mind, however, that the reduction is relative to existing emission levels for coal plants. Even with 700 technology, the expected emission level would still be 75% higher than gas plants.

Integrated gasification combined cycle (IGCC)

The aim of IGCC technology is to make the burning of coal less polluting and at a price more acceptable than steam-coal plants. IGCC technology is fundamentally different from steam coal technology in that it does not burn coal directly. Instead, it turns coal into gas (usually hydrogen and other byproducts) first and then burns this gas in a traditional gas-fired combined-cycle unit (with some modification to accommodate the burning of hydrogen).

The attraction of IGCC technology for utility companies is that it can capture CO2 more cheaply than a steam-coal plant (as shown in the table below). For an IGCC plant, the CO2 is captured when the coal has been turned into various gases, prior to combustion. Capturing the CO2 in this intermediate stage is cheaper because, among other factors, the CO2 is more concentrated. CO2 can also be captured in steam-coal plants, but it has to be done at the end of the pipe (that is, from flue gas), making it twice as costly. If not for its ability to capture CO2 more cheaply, IGCC plants generally would not be built. Indeed, none have been built so far without subsidies. This is because they have higher capital costs than steam-coal plants (prior to carbon capture) but are less reliable. There are four IGCC plants currently operating. They include two plants in the U.S. and two in Europe. In Europe, the IGCC plants are Dutch utility N.V. NUON's (A+/Negative/A-1) Buggenum plant in The Netherlands and the Puertollano plant in Spain, which is owned by Elcogas.

Reducing CO2 using IGCC technology at a coal plant, however, is not any cheaper than reducing CO2 at gas plants. Although the capturing approach at gas plants is similar to steam-coal plants, it is less than one-half of the cost because gas plants release only about half of the CO2 that leaves steam-coal plants. Furthermore, this cost is nonexistent for nuclear or hydro plants due to the fact that these plants do not emit any CO2.

Utilities Unlikely To Choose Coal Over Other Fuels Based Solely On The Benefits Of New Technology

When building new plants for the future utilities will have to consider whether they are willing to pay the cost of this new technology or choose another fuel that produces less or no CO2 to begin with. It is clear that clean coal technologies can make burning coal less polluting in terms of CO2 emission levels, but not to the extent that a company would choose coal over other fuels based purely on the benefits provided by this new technology.

Supercritical technology, although no more expensive than traditional techniques, does not reduce CO2 emissions to anywhere near the levels of other fuels. IGCC's effectiveness in this area comes at a cost. Although this new technology will make coal more appealing in an age of global warming, the cost of reducing CO2 will remain greater for coal than other fuels such as gas, nuclear, or hydro. This is due to the simple fact that burning coal produces more CO2 than other fuels. Nevertheless, this new technology can create meaningful CO2 reduction and help coal-fired utilities adhere to their environmental allowances. ■

EUROPEAN NUCLEAR POWER SHOWS SIGNS OF SURGING BACK, BUT IT'S NO RENAISSANCE

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Nuclear power has been a strong contributor in the recent boost in profitability of some of Europe's largest electricity utilities, such as E.ON AG (AA-/Negative/A-1+), RWE AG (A+/Negative/A-1), and Vattenfall AB (A-/Positive/A-2). At the same time, political acceptance of nuclear power in Europe appears to be increasing in some countries on the back of concerns over high energy prices, the large costs and difficulties in cutting carbon dioxide (CO2) emissions, and the increasing dependence on gas imports to the region.

Despite these positive trends for atomic energy, Standard & Poor's Ratings Services considers it too early to speak about a nuclear renaissance. The large capital investments and long construction lead-times, together with the inherent political and operational risks of nuclear generation is restricting commercial interest in new nuclear generation. Today's deregulated and rapidly changing market environment is also very different from the protected and government-supported environment that prevailed when European nuclear investment was at its peak 25 years ago. We believe that significant investment in new nuclear generation in Europe would require fossil fuel prices, CO2 emissions reduction requirements, and market concentration to increase even further. Moreover, politicians would need to create more stable planning and operating conditions.

Until then, Standard & Poor's expects that investments in new nuclear capacity will remain limited in most EU markets in the medium term, with the exception of France and Finland where new reactors are now being built. Instead, most investments in nuclear generation are likely to be directed at extending the lifetime and incrementally increasing the capacity of plants, which is considerably less costly and involves significantly fewer risks.

European Nuclear Generators Thriving On Current Surge In Power Prices

The current high price environment in the European power market, with base-load prices in Continental Europe at well above 35 ($42.4) per mega-watt-hour (MWh), is highly beneficial for nuclear operators, including Electricité de France (EDF; AA-/Negative/A-1+), Electrabel (part of Suez S.A. A-/Stable/A-2), E.ON, RWE, and Vattenfall. One of the principal drivers of higher power prices has been the increase in gas and CO2 emissions allowance input costs, costs which are not borne by nuclear power. Consequently, nuclear generation operating margins have increased substantially as power prices have risen, with typical variable nuclear generation costs remaining at about 10/MWh. The tripling of nuclear fuel prices seen in recent years as a result of a tighter supply balance has had only a marginal affect, as it is still constitutes a cost of only about 5- 6 per MWh produced.

Improved generation profitability has been one of a number of contributors to the generally stronger financial performance of European vertically integrated utilities in recent years, and nuclear generation has certainly contributed to this. This is illustrated by the case of Sweden-based Vattenfall. In 2001, when the Nordic wholesale electricity prices were about 23/MWh on average, Vattenfall's 37 TWh of Swedish nuclear generation (excluding minority stakes) contributed about 210 million, to EBITDA (calculated on average wholesale prices and operating costs excluding depreciation of about 4/MWh), or 10% to the total. At the 2004 price level of 28/MWh, with 41 TWh of generation volume, the 2004 EBITDA contribution was about 560 million, an increase of 165% and more than 15% of the total, which had grown significantly through acquisitions.

A More Positive Attitude To Nuclear Power In Europe?

In addition to the current favorable market conditions, the political attitude to nuclear generation appears to becoming more open to a debate about whether nuclear power can and should have a long-term role to play in national energy policies in countries such as Germany and the U.K. where nuclear generation has not been politically popular for some years. This change of attitude is the result of three factors. First, European power prices have increased on the back of high oil- and gas prices, and nuclear fuel costs are largely insensitive to this phenomenon. Second, nuclear generation does not emit CO2, and would therefore help countries hit greenhouse gas emission reduction targets and meet climate change commitments without incurring high costs for cutting emissions. Finally, nuclear power may have a role to play in reducing security-of-supply risk by reducing the EU's future dependence on oil and gas imports.

Ultimately, politicians are concerned over the negative impact of high energy prices on the international competitiveness of European industry, as well as over Europe's growing dependence on energy imports resulting from a rebalancing toward increased gas generation. Nuclear power is, however, a highly sensitive topic, and reaching

the required broader social consensus in favor of it could still be challenging in certain countries. Political support for nuclear power has remained strong in France, Finland, and several Eastern European countries. Germany, the U.K., Sweden, and Belgium have been less favorably disposed toward nuclear generation since the 1980s, and currently plan to fully phase out nuclear generation. This process has already started in Germany and Sweden, and may accelerate over the coming decade if current policies are maintained.

There is now, however, a renewed debate about the long-term role of nuclear generation in EU member countries. This could potentially result in the lifetime of existing plants being extended, for example, in Germany, Sweden, the Netherlands, and the U.K. In countries such as Italy, the Netherlands, Poland, and the U.K., politicians have even begun discussing the potential for investing in new nuclear generation.

A key factor for the European power sector in this respect is the future development of German energy policy. Uncertainty remains, however, after the German parliamentary elections in September 2005. The right-of-centre CDU/CSU and FPD parties, which had hoped to oust the current Social Democratic and Environmentalist coalition government, had indicated a willingness to abolish the so-called nuclear consensus agreement. This caps the average lifetime of nuclear plants at 32 years and affects some 20,000 MW of nuclear capacity, which, under the agreement, is required to be decommissioned in the period 2008-2020. The abolition of this agreement would be favorable for nuclear operators E.ON, RWE, EnBW Energie Baden-Wuerttemberg AG (A-/Stable/A-2), and Vattenfall in Germany. It would allow these companies to generate positive cash flow from the affected plants for longer, and would delay replacement capital expenditure and the financing of significant nuclear asset retirement obligations. It would also reduce the competitiveness of other types of generation, including gas, hard coal, and renewable generation across Central Europe.

The CDU/CSU and FPD parties did not, however, win enough seats to form a government, and it now appears likely that there may be a coalition between the CDU/CSU and SDP parties. While there is, of course, uncertainty over how things will develop in the next German government, the new coalition is not likely to include the Green Party, which is not in favor of nuclear power, and German nuclear policy may therefore soften. In any case, it is very likely that any pro-nuclear "concessions" will be balanced by requirements on the utilities in other areas, such as increased R&D efforts, competitive behavior, or taxation issues. In light of significant price increases and the country's lackluster economy, the general political environment is somewhat sensitive to the large utilities.

A potential shift in nuclear policy in Sweden would similarly have a positive effect for the operators of nuclear generation in Sweden, that is Vattenfall, Fortum Oyj (A-/Stable/A-2), and E.ON Sverige AB (A/Stable/A-1). Such a change in policy would have less of an effect than in Germany, however, given that plant lifetimes in Sweden are assumed to be 40 years. Such a shift is unlikely by the current Social Democratic government, which rules with the support of the Left and Green parties, but could potentially occur if a Centre-Right coalition government were elected in the 2006 elections.

Large-Scale European Nuclear Investments Remain On The Back-Burner

Most European nuclear plants were built in the 1970s and 1980s, partly in response to the oil crisis and the concern over countries' dependency on volatile fuel imports in the overall energy mix. The European Commission estimates that without any lifetime extensions, 50 to 60 of the 155 nuclear reactors operating in the EU will be decommissioned by 2025. This is equivalent to some 40 gigawatts of capacity, 40% of current European nuclear capacity, and some 10% of total European generation capacity. Some Eastern European countries have agreed to phase out Soviet-era nuclear reactors, considered to be hazardous, as part of their accession to the EU (this includes Lithuania's Ignalina and Slovakia's Buhomice plants).

Although a new generation 1,600 MW nuclear reactor that is supposedly safer and more efficient is being constructed in Finland, and one similar reactor is at the advanced planning stage in France, investments in new nuclear generation in Western Europe remain limited. For the time being, Standard & Poor's expects most investments to be directed toward lifetime extension and capacity upgrading, subject to government approval. For example, Vattenfall plans to spend Swedish krona 24 billion (2.5 billion) on maintenance and upgrading investments in its Swedish nuclear plants over 2004-2014 (about 20% of the group's total planned capital expenditures). This could increase its Swedish nuclear generation by some 9 TWh, but the final regulatory approval for the planned capacity increases rests with the Swedish government. In the U.K., British Energy Holdings PLC (BB+/Stable/--) has initiated a life-

time extension of its Dungeness plant. Similar projects are underway in Eastern Europe, including in the Czech Republic (the Dukovany plant owned by CEZ a.s. BBB+/Positive/--), and in Hungary (the Pak's plant owned by Magyar Villamos Mûvek Rt. (not rated)).

Significant Hurdles Remain For Large-Scale Nuclear Investment

Although there is growing interest in maintaining the nuclear option in Europe, it is too early to speak about a nuclear renaissance. With very few exceptions, the current generation of European power plants were all commissioned in tightly regulated markets in which the regulation provided both protection from competitive threats and mitigation of operating and financial risk, both in terms of recovering costs and mitigating operating risks. This provided a high degree of visibility about the return on the nuclear investment. There was also strong government involvement, via government-owned companies or a very clear link to overall, centrally planned energy policies.

Following the liberalization of many European power markets, this visibility has reduced markedly. The development of new nuclear generation in the deregulated European market environment would be a high-risk venture given the long construction times, the inherently large size, high capital costs, and the lack of revenue predictability. This is made more difficult by the cash flow profile of nuclear plants, which requires significant up-front investment and a long lead-time before the plant is completed and begins to generate positive cash flow. Changing power prices, fuel price economics, supply and demand patterns, and interest rates can rapidly negatively impact the economics of and ultimate return on investment of a new nuclear plant, just like any other investment. In this respect, the large investment and long lead-time required in new nuclear generation compares poorly with the smaller and faster incremental investments required of and the lower political and operational risk in gas-fired generation capacity. Furthermore, the planning approval process is likely to be more sensitive and cumbersome today than in the 1970s and 1980s, when most reactors were constructed, and this increases the investment risk. Government-owned companies that used to take part in nuclear projects have been privatized in a number of cases, and energy policy is executed on market-based factors rather than through central planning.

Above all, public acceptance and political support for nuclear generation will always remain vulnerable to changes in the perception of nuclear safety, and this would represent a significant risk for any operator intent on building a new nuclear plant. A Chernobyl-like accident or terrorist incidents could rapidly alter the public's acceptance of nuclear power, resulting in a change in operating environment for nuclear generators. This could potentially have a devastating impact on the return on such a capital-intensive, long-lived asset.

Furthermore, greater clarity on long-term climate change policies, together with a solution to issues such as how to accommodate the final storage of nuclear waste and a far-reaching social consensus, are likely to be required before potential large-scale capacity additions can happen.

Some Eastern European governments (including those of Slovakia and Bulgaria) are actively promoting new nuclear capacity. However, such investment projects could involve even higher risk given the less mature and stable political and market environments in these countries, and it is far from certain that external funding will be available. Government involvement in new nuclear projects could be problematic, since EU state-aid rules could make it difficult to establish the indirect or direct state support mechanisms, such as financial guarantees or special regulatory features. There could, however, potentially be interest in such projects from major Western utilities that want to maintain or develop their nuclear expertise while not having the possibility or interest to do this in their core markets.

The capital intensity and high risk of nuclear operations will ensure that the ownership of European nuclear assets will remain highly concentrated. In countries with a dominant power company, all nuclear assets are owned by a single company, as is the case with EDF in France, Electrabel in Belgium, and CEZ in the Czech Republic. In countries with a more fragmented generation market structure, such as Germany, Finland, Spain, and Sweden, nuclear assets tend to be owned by the largest utilities.

Nuclear generation plants have often been constructed by ownership consortiums of generation companies and, in the case of Finnish operator Teollisuuden Voima Oy (TVO; BBB/Stable/A-2), by industrial companies in order to exploit economies of scale and reduce risks for the individual company. This is the case in about one-half of the plants in Germany, Sweden, Spain, and Finland. Finnish nuclear operator TVO, which is owned jointly by a large number domestic industrial companies, municipal utilities and the incumbent electric utility Fortum, is probably the most prevalent example of this. While major industrial

users of power could see investment in nuclear generation as a way to secure long-term stable power supplies in today's volatile and fuel price sensitive markets, Standard & Poor's believes that the Finnish mixed-ownership model will be difficult to replicate elsewhere. It is far from certain that the major utilities would be interested in allowing direct ownership and influence in nuclear reactor projects by industrial end-customers. Moreover, it would be very difficult for industrial companies to gain sufficient technical nuclear competence to be granted a nuclear plant concession on their own.

As the risk of nuclear generation has increased in the now deregulated market environment, more joint-ventures involving major utilities would be expected for new nuclear power projects. For instance EDF is seeking to attract partners for its new EPR nuclear generation plant in Flamanville (Normandy), and has already reached agreement with Enel. ■

U.K. WIND POWER FRAMEWORK IS IMPROVING BUT CLOUDS REMAIN ON THE HORIZON

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Significant developments have taken place in the U.K. wind power sector in the first half of 2005, but their impact on credit quality has been mixed. Nevertheless, the extension of the Renewables Obligation (RO) to 2015 and the capital allowance by OFGEM for the national grid to undertake grid improvements are all positive changes.

Despite political interest in renewable energy in general, and wind power in particular, the obstacles to turning interest into financially viable schemes in the U.K. remain considerable. Although wind is becoming increasingly price competitive, support from tax subsidies, renewable certificates, or subsidized prices remain important contributors to the current Europe-wide growth in wind generation. Over the last five years, the provision of such financial supports has largely been driven by governments' commitments to reducing emissions of greenhouse gases to levels agreed under the Kyoto protocols.

To date, Standard & Poor's has rated two wind projects: FPL Energy American Wind LLC (senior secured debt BBB-/Stable) in the U.S. and Max Two Ltd., in the Breeze One transaction in Germany (senior secured debt BBB-/Stable). The ratings on these transactions followed significant research by Standard & Poor's to establish whether wind projects could reach investment-grade credit quality. The variability of, and the projects' lack of control over, the main energy source, wind, is and will remain the key obstacle to achieving investment-grade ratings, despite supportive regulatory regimes. No projects have yet been rated in the U.K., but Standard & Poor's Ratings Services believes that in the right environment U.K. projects could progress toward achieving investment-grade credit quality

Despite record growth in U.K. onshore wind power installation in 2004, the sector still faces uncertainty regarding planning requirements, infrastructure, and grid access costs. Meeting the government's targets will depend on offshore schemes going ahead as planned. Concerns about possible planning delays, opposition from military and civil aviation authorities about radar interference, and the cost and availability of grid connections--all of which could undermine the economics of offshore schemes--also need to be addressed.

Standard & Poor's considers grid upgrades to be critical for delivering the government's 2010 renewable energy targets. The energy regulator, OFGEM, gave the national grid a capital expenditure allowance to upgrade the grid for wind power. This is positive, but, together with technology and planning risks, this expenditure requires close monitoring and contingency planning.

Various third-party reports, such as the national Audit Office's (NAO) review, based on research by Oxera, an independent economics consultancy research, suggest that the U.K. is reasonably to well on track to meet the targets for 2010 and 2015. A successful solution to the constraining factors and ongoing, clear, and public support for the sector from the U.K. government, however, are vital to the success of the plans. The review of the industry by the Department of Trade and Industry (DTI) in 2005 will give a clear indication about its long-term support for the sector. In addition to the importance of the government review, the distinctive risks of large offshore wind farms, on which much of the U.K.'s wind power growth depends, must be addressed.

Wind Abundance, But A Shortage Of Installed Capacity

Wind energy is widely recognized as an abundant energy resource indigenous to the U.K. The U.K. is by far Europe's windiest country, with more than 40% of the continent's total resources. To date, 96 wind energy projects totaling 785 MW have been commissioned in the U.K., a figure that should increase rapidly over the next few years.

The RO mechanism, which came into force in April 2002, requires all electricity suppliers to source 10% of their supply from renewable energy sources by 2010. In December 2004, this target was increased to 15% of electricity supply by 2015, and 20% by 2020. These extensions were of significant benefit to wind projects entering into long-term contracts and therefore provided a strong support for the long-term viability of the industry. Wind energy's key role in delivering the U.K.'s renewables policy means that the sector is expected to supply three-quarters of the targeted 10% of U.K. energy generation from renewable sources by 2010, equivalent to about 8,000 MW of capacity. Onshore and offshore developments are expected to share this supply about equally.

Onshore, this equates to a further 2,000 new turbines, assuming an average size of 1.8 MW, in addition to the 1,150 turbines already installed. Fewer will be needed offshore, about 1,500 turbines, because larger, more powerful machines can be used. The most recent offshore turbine installation in the U.K. was of 3 MW, and larger machines are being trialed. Fewer turbines than forecast may eventually be needed given the continual advances in wind turbine technology.

The fundamental concern about the RO is that any investment made under it is exposed to numerous reviews and potential changes, which may take place at any time between the moment that investment is made and the point at which invested capital is fully repaid from project cash flows. Nevertheless, projects in operation or under construction are expected not to encounter regimes or operating issues that are worse than at the time they started building the capacity.

The high level of growth required in wind power appears to have considerable industry support, but several factors may prevent the targets being met. These include: the contribution of cofiring (simultaneous combustion of a supplementary fuel with a base fuel, e.g. coal with wood, or gas with agribusiness wastes) generation to reducing emission targets; the EU's report on a potential harmonized renewables system in 2005; the U.K.'s scheduled RO review in 2005-2006; grandfathering in case the rules change; and levels of consumer concern about environmental issues. The recent publication of the NAO report on renewable energy has also indicated that meeting the U.K. renewables target is dependent on maintaining good progress in overcoming planning issues and reinforcing the grid.

Wind Power Growth

Charts 1 and 2 show that in 2004 a record 191 MW of wind capacity was built onshore, and a further 60 MW offshore. A record 700 MW received planning consent, representing an approval rate of more than 80%. With more than 500 MW already under construction, 2005 promises to be even more successful. It is expected that projects totaling more than 7,000 MW will be applying for permits in the next one or two years. The industry installed slightly more than 100 MW in 2003 and during the past decade has installed an average of just 50 MW a year. In the European context, the levels of new built in 2004 remain very low compared with leading countries such as Germany and Spain.

Improvement on the U.K.'s slow growth to date would require, among other things, an improved planning permission system able to deliver timely, robust decisions that address all the issues, and a long-term, benign regulatory framework. A recent study by the British Wind Energy Association shows that the average time for achieving final planning consent for a wind farm application is 14-30 months. In order to achieve the 2010 target, an additional 2,168 MW of onshore wind is needed. The majority of planning consents must be in place by 2007 to deliver the projects on time.

The pace of deployment is increasing, however. Another 18 developments providing a further 617 MW are likely to be completed in 2006. Work has yet to start on a further 68 schemes totaling 2,000 MW, half of them offshore, which have received planning permission. Another 96 schemes, mostly onshore, totaling 5,000 MW, equivalent to 5% of the country's electricity needs, have been submitted for planning approval.

Chart 1
U.K. Wind Capacity Built In 2004

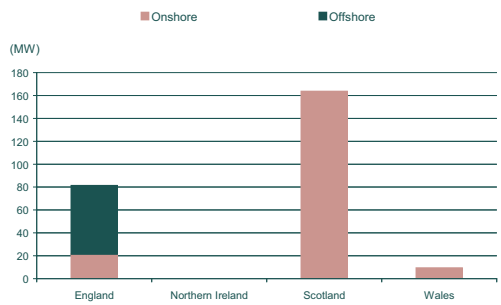
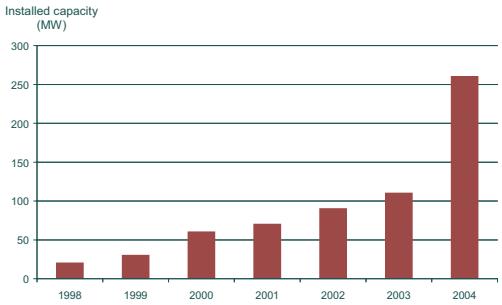


Chart 2
U.K. Installed Wind Capacity Growth



Will Wind Power Be Price Competitive?

For wind power to continue its growth in circumstances where it remains more expensive than other energy sources, public and government support is crucial. A report by the Royal Academy of Engineering, "The Costs of Generating Electricity", portrays wind power as very expensive, and nuclear as getting cheaper as new technology emerges. It claims that the U.K.'s cheapest electricity will come from gas turbines and nuclear stations, and cost just 2.3p per kilowatt-hour (kWh), compared with 3.7p/kWh for onshore wind and 5.5p/kWh for offshore wind. The study did not, however, cover transmission

costs for individual technologies or storage costs for gas to ensure security of supply because: "the market currently absorbs these through system operating costs or the cost of gas."

The DTI, however, expects investment in the sector to lead to unit cost reductions for most technologies in the future, which should make renewable energy more cost effective as a means of reducing carbon dioxide emissions. In the recent Renewables Innovation Review, the DTI established estimates of average unit costs for each main technology, and will revisit some of these estimates as part of the 2005 RO review. The outcome of this review will be key to shaping future government support for the sector.

Outside these various reviews and reports, the competitiveness of wind energy is improving. This is due to various factors: increased turbine size, reduced costs per kilowatt-hour, and increasing costs of gas and coal. Prices bid into the Non-Fossil Fuel Obligation (NFFO)--which offered 15-year contracts--are a good guide to changes in wind power economics. Taking the minimum bids, prices (1998 levels) fell to 2.40p/kWh in 2004 from 4.56p/in 1994. The introduction of the RO has masked the underlying trends because as a shortage of all renewables, plus future renewable obligation uncertainties, has driven prices up. The present installed cost for onshore wind in the U.K. is about £650 per kilowatt (kW), and for offshore about £1,000/kW. For offshore wind, this includes about £100/kW for the farm-to-shore connection and £150/kW for interturbine cabling.

RO And Regulatory Risk

Rapid growth in renewable energy generation depends on a policy framework that provides a stable environment for investment, secures returns on investments, and has clear long-term goals. The U.K. government has sought to achieve stability through the RO.

The RO and associated Renewables (Scotland) Obligation came into force in April 2002 as part of the Utilities Act, which replaced the NFFO tendering procedure. Suppliers have to demonstrate compliance with the RO through the presentation of renewables obligations certificates (ROCs), which are issued in proportion to green electricity production. Each ROC represents 1 megawatt-hour (MWh) of renewable electricity from eligible generators. If a supplier does not have enough ROCs, it can purchase them from other suppliers. Alternatively, electricity suppliers are permitted to pay a "buyout" fee rather than acquire the ROCs. That is, if the cost of the ROCs is too high, the electricity supplier may choose to pay this penalty instead of acquiring the certificates. OFGEM is responsible for the administration of the RO and compliance. The obligation is due for a comprehensive review in 2005-2006 regarding how it may be used to support renewables in the long term. Standard & Poor's considers this review to be positive because it will give investors greater confidence about their income streams after 2010.

The fixed level of the RO after 2015-2016 could act as a cap on the expansion of renewable generation. Were generators to meet the obligation level in full, and produce more ROCs than required in any one year, the market price of ROCs would drop significantly, because suppliers would not have to compete for them. The risk would then be that developers hesitate before bringing new projects on stream to protect their revenues from a collapse in ROC prices. In practice, the annual RO levels for the next few years are sufficiently demanding for the risk of a price collapse to be remote.

The RO is complex and its administration continues to evolve. In 2003-2004, onshore wind generation contributed about 16% of ROCs issued.

The RO does not differentiate between different renewable technologies, so the risk is that only the cheapest technologies will be developed unless additional measures are introduced. In the past, the government has supplemented the RO with capital grants for offshore wind power to reflect the fact that offshore wind power is more expensive than onshore. Such grants will not be available for the second round of offshore projects.

The U.K. ROC system provides valuable experience for other countries performing the complicated task of developing tradable green certificate systems. So far, the mechanism has not proved effective at encouraging renewable capacity and the cost of the system per kilowatt-hour is high.

Securing The Buyout Fund

The level of the buyout price and the size of the annual obligation levels are the two main factors that determine the amount of support provided to the renewables industry and the cost of the RO to consumers. Shortfalls in the buyout fund are one of the main risks in the current system. The introduction of measures to secure the buyout fund attempts to mitigate the risk of shortfalls affecting the viability of the renewables industry.

The buyout fund before the changes

All buyout payments made by suppliers for each megawatt-hour of shortfall between the amount of their obligation and the number of ROCs pre-

Table 1: Overview Of Some European Renewable Energy Certification Models

	U.K.	Belgium (Flanders)	Belgium (Wallonia)	Italy	Sweden	Denmark (proposal was abandoned)
Period	Start 2002	Start 2002	Start 2002	Start 2002	Start 2003	Start 2002
Obligation on	Supplier	Supplier	Supplier	Producers and importers	End user	End user
Obligation	3.0% in 2002; 4.3% in 2003; 10.4% in 2010; 15.0% in 2015	1.2% in 2003; 2.0% in 2004 increasing to 6.0% in 2010	3.0% in 2003; increasing to 12.0% in 2010. From Sept 2010, the quota will be multiplied by a factor of 1.01x	2.0% in 2002 increasing annually by 0.35% between 2004 and 2008	7.4% in 2003; 16.9% in 2010	20% by end 2003
Technology bands (baskets) within overall quota	No	No	No	No	No	No
Technologies involved	Small hydro, wind, biomass, solar, geothermal, no waste	All renewables, no solid municipal waste	All renewables and high -quality combined heat and power	All renewables (including large hydro); facilities not older than eight years	Small hydro (less than 1.5 MW), large hydro (in some cases), wind, biomass, geothermal, wave	Small hydro, wind biomass, solar, geothermal, no waste
Whether international trade allowed	No	No	No	Yes, but only in exchange for physical electricity	No	No
Price restrictions (minimum or maximum price)	No, maximum price according to penalty	Maximum price according to penalty, minimum at federal level. Since July 1, 2003, the grid operator has the obligation to buy tradable green certificates (TGCs) issued anywhere in Belgium for the minimum price of: €90 (offshore wind); or €50 (onshore)	Maximum price defined by penalty. Producers of RES-E may exchange their TGC for a subsidy at a fixed price of €65. At federal level, since July 1, 2003, the grid operator TGCs issued anywhere in Belgium for the min price of: €90 (offshore wind);or €50 (onshore)	N/A	Minimum prices: €6 in 2003; €5.5 in 2004; €4.4 in 2005; €3.3 in 2006; €2.2 in 2007; and €0.0 in 2008. Maximum price is defined by penalty	Minimum €0.014/kWh Maximum €0.037/kWh .
Penalty	Buy out price £31.39 in 2004-2005	€75 per certificate (1,000 kWh) in 2003; €100 in 2004; and €125 in 2005	From April 1, 2004, €100 per TGC (1,000 kWh)	N/A	150% of the market piece but with a maximum of a 175 Swedish kroner(Skr) for certificates that should have been surrended in 2004, and Skr240 for 2005	€0.37/kWh
Trading scheme	Stock exchange	Stock exchange	Open trading and direct support	Free or in the power pool	Open	N/A

N/A--Not appliable. kWh--Kilowatt-hour.

sented are placed in a central fund. This money is redistributed to suppliers that have met the obligation in proportion to the number of ROCs presented. Therefore, the real costs for a supplier not complying with the obligation is higher than the buyout price. This is why ROCs trade at higher prices, £40-£50, than the penalty. The buyout price for the period ended March 2005 was £31.39/MWh.

The shortfall in the buyout fund in 2003 followed the financial failure between 2002 and 2004 of three electricity supply companies, TXU U.K. Ltd. in November 2002, Maverick Energy Ltd. in June 2003, and Atlantic Electric and Gas Ltd. in April 2004. These companies defaulted on their payments to the buyout fund. Defaults totaled £23.6 million in 2002-2003 (nearly 20% of the total due to the fund) and £9.2 million in 2003-2004, and caused a temporary loss of confidence in the renewables market.

OFGEM figures show that electricity companies missed the target for renewable electricity by 40%

in 2003, the first year of the RO. The production of renewable energy was 5.5 terawatt-hours (TWh), while the obligation was about 9.0 TWh.

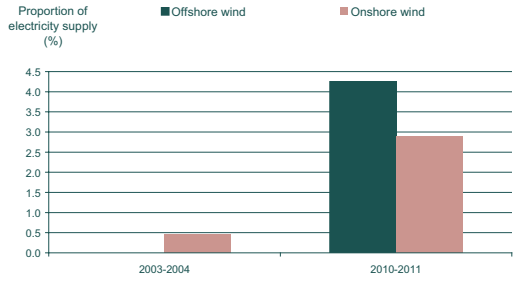
In 2003-2004, eligible renewables accounted for 2.4% of the U.K.'s electricity generation, significantly lower than the obligation level of 4.3%. Chart 3 shows the expected breakdown of generation levels by renewable technology. The buyout fund almost doubled between 2002-2003 and 2003-2004, in part due to the lower percentage of ROCs produced in relation to the obligation compared with the earlier years and the fall in the amount of buyout payments not made as a result of suppliers in administration. This figure fell to about £9 million from about £24 million in 2002-2003.

The changes

The Renewables Obligation Order 2005 contains two measures intended to mitigate shortfalls in the buyout fund. These are surcharges on late payments and mutualization.

Chart 3

Eligible Generation Under The Renewables Obligation, Actual And Estimated



Source: Oxera and OFGEM

The surcharges provide a further deterrent to suppliers making late payments to the buyout fund. By attaching surcharges that increase every day for which the payment is overdue, the government expects suppliers to continue treating their obligation to make the due payments to the buyout fund as a priority.

Standard & Poor's notes that the rate must be sufficient to make the existence of surcharges an incentive for suppliers to make their payments on time, without being an undue burden on business and consumers. The government has proposed 5% over the Bank of England base rate, chargeable daily. The surcharge would apply from the day after payments should have been made.

The mutualization process means that where a supplier has failed to comply with its RO and there is a shortfall in the expected buyout fund, each supplier--excluding any that have failed to discharge any of their RO for the period in question--is required to contribute a sum to make up the shortfall. These sums will make up the mutualization fund. The mutualization process will be triggered when there is a shortfall in the buyout fund of at least £1 million per 1% of the RO. This will mean that in 2005-2006 the level of the trigger will be £5.5 million.

Offshore Wind

The wind energy resource at sea is extremely large, and the U.K. has more than 33% of the total European potential. It is equivalent to three times the U.K.'s annual electricity consumption. The tapping of this potential through offshore wind farms is essential to meeting the government's commitment to producing 10% of national energy needs from renewable resources by 2010. Offshore development is therefore set to increase steadily from the 60 MW already installed, with a substantial proportion of total European offshore wind resources in U.K. waters.

Lack of experience represents a risk

There is relatively little direct industry experience of operating offshore. The sector therefore requires further development, demonstration, and assessment before becoming a proven and commercial technology. The success of onshore wind provides some confidence, although uncertainty remains regarding the potential for a substantial reduction in costs.

Standard & Poor's believes that the risks and costs for early developers are high because generating plant will be partly experimental in nature, with improved designs and cost reductions evolving as experience develops. The U.K. is considered the best market for wind in the world, however, due to its favorable combination of wind resource, strong offshore regime, and the recent extension of the RO to 15% by 2015.

Current projects

More than 1,000 MW of projects have been allocated seabed leases under the first round of U.K. offshore development, and two have already been built: North Hoyle (60 MW) and Scroby Sands (60 MW). This year should see construction completed at the much bigger Kentish Flats development off the Thames Estuary and good progress made at Barrow, off the coast of Cumbria. Each of these will have thirty 3 MW Vestas turbines installed.

New offshore regulatory regime

The U.K. government has announced that it will

introduce a new regulatory regime for offshore transmission and offshore distribution. The Energy Act 2004 contains provisions to allow the relevant secretary of state to modify the licensing regime for the purposes connected with offshore transmission and offshore distribution. The development of offshore wind generation is likely to have implications for transmission system investment, although the extent and timing of the demand for additional investment is not yet clear. OFGEM and the DTI are working on these issues and will hold consultation on these matters later in 2005.

Technological issues

The present technology is limited by the depth at which foundations can be placed, and the cost of grid connection is a vital consideration. As a result, all the proposed first round of wind farm sites are in water no deeper than 20 meters and no further than 12 kilometers offshore. Furthermore, the nature and scale of the activity and the statutory consents required place great emphasis on environmental considerations during planning, construction, and operation phases.

One of the attractions of offshore wind power is that wind speeds are generally higher offshore than on land. Standard & Poor's also understands that offshore wind turbulence is lower. This means that turbines are subject to fewer stresses from the wind, although this tends to be offset by the higher wind speeds and the need to design the structures to take account of wave loads and wind/wave interaction.

High construction and operational costs

Although the technology is improving, the cost of offshore wind is higher than expected. The current generation of offshore wind turbines are not specifically designed for offshore use. The need for more expensive foundations and the need to "marinize" the wind turbines to protect them from the corrosive influence of salt spray push up the costs of offshore wind energy relative to onshore. For example, marinizing the turbines usually adds about 1%-2% to the cost. There is as yet no model for mitigating the construction risk. The cost of the cable connection may also be more expensive than for onshore developments, although this is not always the case. The cost of grid connection at remote upland sites may be more expensive if grid reinforcement is required.

Operation and maintenance costs may be increased and there may be a risk of lower availability because it might be difficult to reach the turbines during bad weather. There are also development expenses such as securing consent, environmental impact assessment, and geological studies.

Round 2

In December 2003, the final results of bidding for the second round of offshore wind farms were announced. The right to develop 15 sites totaling 5.4 gigawatts (GW)-7.2 GW was awarded to 10 companies or consortia. If all the plants are built, the DTI forecasts that Round 2 offshore wind farms could power one in six U.K. homes by 2010. This is, however, dependent on the sector overcoming a number of difficulties. There is little worldwide experience of building and operating offshore wind farms and, until recently, virtually none in the U.K.

Round 2 sites are larger than Round 1 sites and will use more powerful machines, at greater distances from shore. Each Round 1 site was awarded permission for a maximum of 30 turbines, but there is no limit for Round 2, and some very large schemes have been awarded sites: two have capacity of 1 GW or more, as much as nuclear power stations. The first of these turbines will not be built until 2007 at the earliest, with most construction planned for 2008-2010.

Some of the Round 2 sites are more than 12 nautical miles out to sea, and therefore outside the U.K.'s territorial waters. In order to have the legal powers to license and grant consent to wind projects outside its waters, the government has legislated to create Renewable Energy Zones into which it can extend the Section 36 consenting regime. This power is contained in the Energy Act, which gained Royal Assent in July 2004.

Nearly all the Round 1 projects have benefited from capital grants provided by the U.K. government, which made an important contribution to their costs. These grants will not be available for the second round. Round 2 offshore wind projects will require substantial debt financing and therefore an appropriate financial framework will be important for encouraging investment.

Wind On The Radar

The Ministry of Defence (MoD) has a policy to register its concerns regarding proposed wind farms at the preplanning stage. Its concerns stem from proposed wind turbines that: are within 74 kilometers and the line of sight of its air defense radar sites; are within 66 kilometers and the line of sight of its air traffic radars; compromise seismic monitoring; or interfere with aerodrome safety. This policy has meant that in 1996-2003 the MoD registered concerns about almost one-half of all preplanning proposals for proposed onshore wind farms, although it formally objected to very few planning applications.

The Maritime & Coastguard Agency and NPower Renewables Ltd., a U.K. renewable ener-

gy generator, however, published the results of trials undertaken in 2004 to assess the impact of offshore wind farms on marine radar, communications, and positioning systems. The trials took place at the U.K.'s first major offshore wind farm at North Hoyle, off the coast of North Wales, which covers an area of 6 square kilometers and comprises 30 turbines, each with an approximate maximum height of 110 meters above mean sea level and rotors of 78 meters diameter.

The report concludes that offshore wind farms have minimal impact on communications systems (VHF radios and even mobile phones where there is coverage), ships' automatic identification systems, or the reception of Global Positioning System data. In addition, there were few problems with magnetic compasses other than those that could be reasonably expected (i.e. close to the metal structures). It also concludes that although the wind farm may be clearly and readily identified at distance by radar, spurious radar returns may be generated in closer proximity to the turbines. Similar effects can occur with land-based marine radars and the report suggested that mitigation measures may be needed. ■

NEW TARIFF REGIME BRIGHTENS HORIZON FOR WIND POWER IN SPAIN

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Spain's new regulation for renewable energies, passed in March 2004, has introduced a clearer methodology for the remuneration of such energies, thereby addressing one of Standard & Poor's Ratings Services concerns with respect to the previous regulation (Royal Decree-RD 2818/1998). The new methodology provides for tariff revisions, but only for wind parks coming on stream after such revisions have occurred; wind parks already in operation will not be affected. The clear adjustment mechanism for tariffs established by the new regulation--RD436/20040 (RD)--and the reduced uncertainty regarding future tariff revisions for existing projects are favorable factors from a rating perspective.

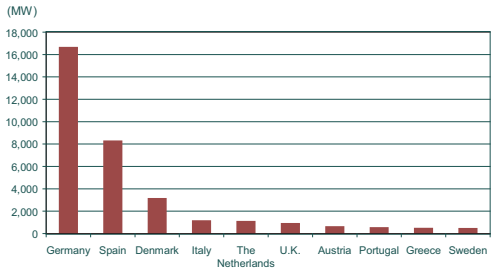
On the other hand, Spanish wind farm projects remain exposed to the price of electricity, irrespective of the type of tariff system they have chosen. In addition, wind farm projects are now exposed to the potential risk of forecasting electricity production to be fed into the system and could be subject to penalties for deviating from programmed production. Lastly, while the white paper for the electricity sector, expected to be published in 2005, is unlikely to directly introduce any changes to wind power regulation, we will monitor the outcome, as it could affect the methodology for calculating the electricity tariff over the medium term.

Standard & Poor's sees the new RD as a step forward in achieving a clear and transparent tariff methodology, which is a key credit factor in order for wind projects to attain investment-grade ratings, contributing to cash flow predictability. Our approach to rating wind power projects broadly follows our project finance methodology (see our March 19, 2001, report "Debt Rating Criteria For Energy, Industrial, And Infrastructure Project Finance," available on Ratings Direct); however, there are major credit concerns specific to wind power projects, such as wind resources, technology, and the regulatory framework. These concerns are addressed in our Nov. 11, 2003, report "Are European Wind Power Projects On Their Way To Investment Grade?" (also available on Ratings Direct). In analyzing wind power projects, we take into account a number of scenarios, focused on turbine availability, maintenance costs, penalties for deviating from programmed production, electricity prices, and wind forecasts; the wind forecast stress scenario includes a "P90" probability.

A Surge In Investments In 2004

Investment in wind power farms continued to grow rapidly in Spain during 2004. Installed capacity increased by a record 33%, reaching 8,263 MW (see Chart 1) and propelling Spain to the No. 2 position worldwide, behind Germany

Chart 1
European Wind Power Installed Capacity In 2004

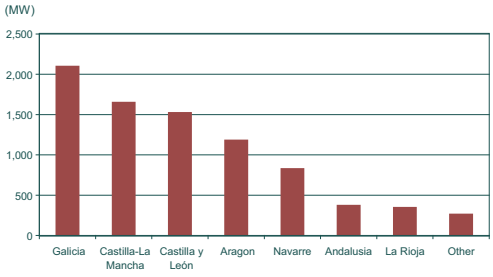


Source: EWEA.

(16,629 MW) and ahead of the U.S. (in third place with 6,740 MW).

The highest growth in installed capacity in Spain in 2004 was in the Autonomous Communities (regions) of Castilla–La Mancha (an increase of 731 MW) and Castilla y León (an increase of 577 MW). Chart 2 below shows

Chart 2
Installed Capacity In Spain In 2004



Source: AEE.

installed capacity of wind farms in Spain by autonomous community.

The 2005 year started with a record for wind power in Spain, with this renewable energy having covered up to 13% of total energy consumed on the coldest days of winter (e.g., 820,000 MW of total energy was consumed on Jan. 24, 2005, compared with wind power production of 105,000 MW). As growth in electricity demand in

Spain has exceeded forecasts, the current target of 13,000 MW of installed power capacity by 2011 could be raised, to 20,000 MW. That said, tariff revisions under the new RD--with the first one to take place in 2006--and the possible lack of good wind sites may make this target challenging.

New Regulation Is Largely Favorable

The new regulation introduces a clear and transparent mechanism for tariff adjustment, which the previous regulation (RD2818/1998) lacked (see our Nov. 11, 2003, report "Wind Power Picking Up Force In Spain, But Remuneration Is A Concern," available on RatingsDirect). The 2004 RD gives wind power producers two remuneration options: 1) sell their production to the distributor at a regulated ("feed-in") tariff, or 2) sell their production directly to the market at the market price plus an incentive and premium, as well as a capacity payment. Wind power producers can choose annually between each alternative--a positive feature that already existed in RD2818/1998. Thus, if pool prices are low one year and are expected to follow a downward trend, a wind power producer can "protect" its cash flow by changing to the regulated regime.

Wind power producers that choose the regulated tariff will receive a percent of the average reference tariff (ART) defined in RD 1432/2002. (In short, the ART is derived by dividing the total costs of the Spanish electricity system by the expected electricity demand for the same period). According to RD1432/2002, the annual increase in the ART should not exceed 1.4% (with a 2% cap in certain cases.) A positive feature from a credit perspective is that the feed-in tariff mechanism is defined for the life of the project. The new RD establishes that the feed-in tariff will be:

- 90% of the ART during the first five years of operation,
- 85% of the ART during the subsequent 10 years, and
- 80% of the ART thereafter.

If the wind power producer chooses to sell its production in the electricity market, it will receive:

- The pool price,
- Plus a premium: 40% of the ART,
- Plus an incentive: 10% of the ART,
- Plus a capacity payment.

Those wind farms that started operations under RD 2818/1998 may, if they choose, remain subject to the methodology set out in this decree until 2007. At that time, however, they will have to choose one of the two remuneration options proposed by the new RD.

A couple of less favorable features

While beneficial overall, the new regulation has a couple of drawbacks:

Indirect exposure to electricity prices.

The ART is indirectly exposed to electricity price volatility. This risk is somewhat mitigated, however, by the provisions of RD1432/2002, the continued increase in demand for electricity in Spain, and the tariff deficit expected for 2005. Downside price fluctuations in the near-to-medium term therefore seem unlikely.

Risk of deviations from programmed electricity production.

The new regulation requires wind farms, as of Jan. 1, 2006, to provide the distributor with a program of expected energy production. Deviations of more than 20% from this program are subject to penalties of 10% of the amount resulting from application of the ART to the sum of monthly deviations that exceed the allowance. This requirement creates some uncertainty in the short term, as the programming technology must first be learned and applied by wind power producers. While the allowance seems reasonable, it will only be possible to assess the real impact on projects' revenues once the system has been applied. When running sensitivity analyses, Standard & Poor's will have to be satisfied with the technology used for programming production and the company's experience in forecasting wind production. ■

FRENCH WIND POWER GAINING MOMENTUM BUT NOT YET A BREEZE

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The strong increase in installed capacity since 2002 suggests that the use of wind power in France is gaining momentum. In reality, however, wind power is only marginally contributing to the country's renewable power installation targets. At year-end 2004, only 386MW of wind power capacity had been installed. Although the government is considering changes to current legislation to spur growth, considerable challenges remain to be surmounted if it is to achieve its 2,000MW installed-capacity target by year-end 2006. These challenges relate in particular to:

- France's strong focus on nuclear power;
- Regulations on tariffs and the size of wind parks;
- Grid access; and
- The procedures operators are required to go through to sign a power purchase agreement (PPA).

In this report, we look at the growth of wind power in France and examine its competitors within the energy sector. We consider the potential for wind power and assess what is holding it back from more rapid growth, including a detailed analysis of the complex regulatory issues facing the sector. Finally, we examine a number of obstacles to wind farms gaining an investment grade rating with which to access the capital markets, as well as some features that bode well for such ratings.

Still A Marginal Power Sub-Sector, Despite Momentum Since 2002

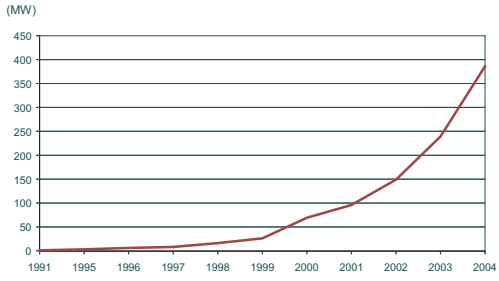
Favorable feed-in tariffs have supported recent momentum

Installed wind power capacity in France grew to 386MW at year-end 2004, from 149MW in 2002, thereby achieving an impressive 61% rise in each of 2003 and 2004 (see Chart 1). If we put this in context, France is only ranked eleventh in the European Union (EU-25) in terms of installed capacity, and lags far behind the three European leaders: Germany (more than 16,000MW), Spain 8,260MW, and Denmark (3,100MW).

Growth of installed capacity in France in 2004 was most likely attributable to the increased interest from and experience of project developers, and to the regulatory regime that has been in place since June 2001. This regime requires Electricité de France (EDF; AA-/Negative/A-1+) to buy the power generated by those wind farms with a capacity of up to 12MW at an agreed feed-in tariff under a 15-year PPA.

As in other European countries, the feed-in tariff from which wind farms benefit is higher than existing market prices for power. Nevertheless, the higher tariffs may only be applicable in the first five years of operation. If a wind farm is highly successful, prices over the subsequent 10 years will be lower (see Feed-in Tariff subsection).

Chart 1
Acceleration of French Wind Power Installed Capacity



Source: Ministries of the Economy, Finance, and Industry

Wind power is increasingly less expensive…

Wind power is more attractive, in terms of cost, compared with 20 years ago: production costs are now about one-fifth of the 1985 level; in the past five years alone they have fallen by an estimated 20%. Although wind energy feed-in tariffs are relatively competitive compared with those of other renewable energies, wind energy costs (€0.056/kWh in 2003) cannot compete with those of nuclear energy or combined-cycle gas turbines (CCGTs), which are considered to present benchmark figures and cost on average €0.027/kWh and €0.035/kWh, respectively, in 2003.

…and likely to be more competitive in the long run

According to the Syndicat des Energies Renouvelables (the French renewables association), by 2015, wind power with expected average tariffs of €0.040-€0.041/kWh for PPAs is likely

to be in more of a position to compete with power generated by CCGTs, whose costs may be negatively affected by higher gas prices. Accordingly, wind power feed-in tariffs are likely to fall by 35% over the next ten years (on a constant price basis); this seems achievable, given ongoing technology improvements. From a ratings perspective, lower feed-in tariffs would have to be mitigated by supportive legal backgrounds, strong PPAs, and robust financial structures, in order for Standard & Poor's to assign investment grade ratings to French wind projects.

Continuing focus on nuclear energy

Electricity production from wind power in France doubled between 2002 and 2004, but only represented 0.1% of total gross electricity production in 2004. Since the early 1970--in order to mitigate high oil prices--and affirmed since then, there has been a strong political focus on nuclear power in France: Nuclear plants generated 78% of total French gross electricity production in 2004. We expect nuclear power to remain at the core of French energy policy and to continue to represent the main source of electricity in France, as illustrated by two recent government decisions. The first of these saw the lifespan of EDF's French plants extended to 40 years from 30 years. The second involved the granting of government approval to the next generation of nuclear plants. In contrast, Germany has started decommissioning its nuclear plants and continues to place strong emphasis on renewable energies in general, and wind power in particular.

French Wind Power Has Strong Potential, But Ambitious Targets

Under the terms of the Kyoto Protocol to the United Nations Framework on Climate Change (Kyoto Agreement), the French government is required to achieve a share of renewable energy to total energy production of 21%, against 13% at year-end 2004. To reach this target, the government is increasingly trying to support the development of wind power. The wind power regulation approved in 2001 was an important step towards achieving this goal.

France lags its European neighbors in renewables production

Although the use of wind power in France lags behind that of other European countries, in the EU as a whole, France is a large producer of renewable energies in actual terms. Some 6.7% of the country's total primary energy consumption at year-end 2004 was generated by renewable energies, compared with an EU average of 5.8% (Source: Observatoire de l'Energie, Ministry of Economy, 2005). This is, to some extent, attributable to wood energy, hydrotechnology, and biogas, among others, which have to date benefited from France's large hydro-capacity, and expansive forests and agricultural land. These renewable energies now have limited additional room for growth. Of France's renewable technologies, wind power presents the best long-term growth potential: Solar power is expensive and makes limited sense (except in southern and overseas France); meanwhile, biomass arrangements are tough to envisage on a wide scale, and most of the economical hydrotechnology sources available in France have already been tapped.

Government unlikely to meet its target by 2007

A government decree in March 2003 set a minimum objective of 2,000MW of installed wind-power capacity at year-end 2006. In order to meet this target, the government has invited tenders for a 1,000MW installed capacity onshore wind-power station and a 500MW installed capacity offshore wind-power station to be in place by Jan. 1, 2007. At the end of May 2005, however, the government had still not made public the outcome of these tenders. Accordingly, it seems unlikely that the 2,000MW target, which would represent 128% growth over the preceding two-year period, will be achieved.

But momentum continues

Wind power still represents the majority of new applications for power from renewables in France. According to EDF, 95% out of 3,820MW of applications for grid connection at year-end 2004 were wind power projects. This suggests strong interest from developers, but may result in potential delays for some wind projects, which will be connected to the grid based on their rank in the connection waiting list. The number of applications implies that a considerable number

of projects have overcome potential constraints, such as obtaining building permits, environmental studies and public investigations, and operating authorization (See Table 1). Increased interest from utilities that are committing their balance sheets to developing wind power could provide further support to the concept.

Wind power also presents a suitable access point for foreign companies to the French electricity market, which remains dominated by the national incumbent and where opportunities for acquiring independent producers are limited. For example, in early June 2005, Spain-based utility Iberdrola S.A. (A+/Stable/A-1) announced that it was purchasing building rights for four wind farm projects in France from German company P&T Technology.

Over the longer term, in contrast to its neighbors, the ability of the French grid to cope with an increase in wind power further to managing the supply/demand balance is unlikely to be an issue. Although peak demand has been successfully covered by wind-power generation in Denmark, for example, any ongoing problems are more likely to be due the relative unreliability of the wind source. In the same vein, this will oblige EDF to install open-cycle gas turbines and run them during seasonal peaks.

Given that the wind-power sector in France is still in its infancy, and provided developers can achieve some larger scale projects that benefit from the supportive regulation, the sector has yet to benefit from the technological developments in wind power over the past decade. Increased turbine size has reduced costs and, although nuclear power is still cheaper, developers are likely to be able to offer more competitive projects that could support growth.

Complex, Multi-Step, Regulatory Framework May Undermine Growth

To promote the development of renewable energy in France, the current Electricity Law requires EDF and the other distributors, if so requested by a producer, to purchase wind farm-generated electricity. This purchase obligation currently only applies to those wind farms with a generating capacity not exceeding 12MW. This is clearly a limiting factor for growth, as larger wind parks are likely to benefit from lower costs and, accordingly, to present a more attractive investment opportunity to developers.

The terms and conditions applicable to the purchase obligation are set out in a decree issued in May 2001 (N°2001-410) and by the prices fixed under the legal order dated 8 June 2001.

Table 1: French Legal Process For Wind Power

Documents required To install wind power	**Target**	**Issuer**	**Delay**
Building licence	For all installations >12MW prior to the connection procedure	State (préfet)	4 to 9 months (depend ing on public investigation), 8 months in average
Environmental study and public investigation	For installations >2.5 MW	Expert agreed by public and private parties	variable
To produce and deliver wind power			
Operating authorization	For installations >4.5 MW	Minister in charge of energy	4 months
Grid connection convention*	For all commercial installations	RTE (or EDF Distribution)	variable
Certificate and conclusion of an electricity purchase contract with EDF¶	For all commercial installations	Certificate delivered by the DRIRE (State)	variable

*The operator must provide an advance payment of 50% of the costs at the signing. ¶Delivered for installations <12MW. RTE--Réseau de Transport d'Electricité (French power grid, currently a subsidiary of EDF). DRIRE--Direction Régionale de l'Industrie de la Recherche et de l'Environnement.

Grid connection bids

Prior to construction, the wind park developer makes a downpayment to secure a "Proposition Financière et Technique" with EDF, which describes the technical specification of the grid connection, the estimated cost of the work to be undertaken, the timing of the connection, and the developer's position in the connection waiting list. These estimates are then later refined within a

Grid Connection Agreement, which is now only signed during or after construction, and is binding on EDF with regard to costs and times within certain margins. Although Standard & Poor's is not aware of any start-up delays attributable to this procedure, these requirements seem to present developers with uncertainties and upfront costs before construction has even started.

Offtake agreements

Clearly, the ability to enter into a 15-year PPA is a positive factor for developers and thus financiers, as is having EDF as a counterparty. Nevertheless, a peculiarity of the French regime is that the PPA is not signed with the project developer until after it has been constructed and connected to the grid. On submission of a compliance application, the Préfet (the state representative at the department level) is obliged to issue a certificate that states that the project is eligible for an EDF PPA. In most power financings that involve an offtake agreement and are rated by Standard & Poor's, the PPA is signed before or during the early stages of construction. Although the regulations require EDF to sign the PPA subject to the provisions outlined, this lag could lead to delays in the project's ability to generate cash flows and start repaying debt.

Rating issues

In order to assign an investment grade rating to a project, Standard & Poor's needs to be certain--among other criteria--that the signing of the PPA is not going to be delayed, and that a signed document does exist upon the start of operations. We understand, however, that--even without an executed agreement--EDF and the generator are deemed to be operating under the PPA, providing the Préfet's certificate has been delivered and the wind farm has started to deliver power. Furthermore, should a project not be commissioned within three years of the submission of a formal PPA application, the initial five-year period (and its fixed high feed-in tariffs) is shortened correspondingly. In a worse-case scenario, in which insufficient reassurance is given, alternative measures, such as strongly supported contingent equity, will be required.

Land security

An entity's ability to provide security interests to lenders is an important element in trying to achieve an investment grade rating.

The land upon which French wind projects are built is held under construction leases with either private or public landowners. The principle of inalienability means that very little security can be taken on a public sector asset (except in very rare exceptions). Lenders may, however, have ownership rights on the assets via specific long-term leases "Baux Emphytéotiques Administratifs" ("emphyteusis"). Such long-term lease structures may allow public land, and buildings and equipment built on such land, to be temporarily held by the private sector, thereby enabling the granting of security rights.

Lenders' security on the French projects will also be achieved through project finance traditional security package including a share security in each project company, as well as bank account charges and security over the receivables under the PPAs. Specific attention will also have to be paid to the legal structure and security package in the case of offshore projects, which are largely untested.

Table 2: French Tariff Structure

	No. Of Hours	€/MWh	
Band 1	2,000	83.8	This price, plus indexation applies in the last 10 years of the PPA for output less than 2,000 hours
Band 2	2,600	59.5	A price between the band 1 and 2 prices, plus indexation, applies in the last 10 years of the PPA for output between 2,000 and 2,600 hours
Band 3	3,600	30.5	A price between the band 2 and 3 prices, plus indexation, applies in the last 10 years of the PPA for output between 2,600 and 3,600 hours. The band 3 price, plus indexation, applies for output in excess of 3,600 hours

Regulatory Features Require Considerable Thought For Financing

In order to reach the 2010 renewable energy target, millions of euros will have to be invested each

year in France. In those European countries where the use of wind power has increased significantly--like Germany, Spain, and Denmark--supportive regulatory regimes and government policy have been the major drivers of this growth. If France is to follow the same trend, tariff mechanisms will have to be clear and transparent, and free of uncertainties and/or volatility.

Feed-in tariffs

French wind farms producing less than 12MW currently benefit from a fixed-price system that Standard & Poor's in part views positively. The offtake payment under the French PPA is structured to give higher revenues during the initial five years (with a fixed tariff set at the point a constructed project formally applies for a PPA), followed by downward adjustments over the remaining 10 years.

After the first five years of operations, feed-in tariffs include an efficiency factor (negative 3.3% on a constant price basis, given technology enhancements and economies of scale). Tariffs are also based on the wind availability per year (measured as a number of hours, see Table 2). A project's performance during this initial five-year period with high tariffs is therefore crucial to its debt-servicing ability. In essence, the stronger a project's performance during the first five years, the lower the tariff it will receive in the final 10 years. This results in tariffs of €0.0838/kWh for a first five-year period, and then €0.0305/kWh to €0.0838/kWh during the next ten years, depending of the potential of the individual sites.

The French tariff system could have some credit quality implications, as, on this basis, most projects would assume a higher amortization over these initial five years. It is therefore (and in general) important that a relatively high probability is attached to the wind forecasts. While one can catch up on revenues in the remaining ten years through lower tariff deductions than anticipated, if a high amortization is scheduled in the first five years and wind energy production is below expectations, the probability of default increases over these five years. Possible mitigants to this risk are a P90 (90% probability of exceedance level) energy production forecast for base case wind projects, a flexible amortization scheme, and higher debt service reserves.

Changes in French Law affecting wind farm capacity limits

A new energy law is currently being debated within the French parliament, provisions of which propose to amend the existing arrangements in respect of future projects and could jeopardize the development of wind energy. Although current legislation deters the installation of wind farms with a capacity of more than 12MW based on PPAs possible up to 12MW, the Lower House made a complete about-turn by removing this ceiling and propose to replace it with a floor of 20MW above which EDF would be forced to buy wind energy. This would not affect existing wind parks, as they would continue to benefit from the feed-in tariffs regime in place at the time the PPAs were signed. The thinking behind this about-turn was to avoid the construction of a large number of small wind farms spread far and wide, and not always in those places benefiting from the best wind condition--a situation which had previously led to increasing local protests. The new measures could, however, have limited new investments, as they would have lead to EDF only subsidizing major projects.

To address that threat, the Upper House voted in favor of an amendment in which the minimum or maximum threshold concept was abandoned in favor of the introduction of wind development zones--areas where wind turbines must be located--with the automatic obligation for EDF to buy the electricity produced in these zones. The decree is expected in the coming weeks, but the fixing of a threshold to benefit from EDF's purchase obligation is now unlikely, following Lower House approval; rather, cities will remain free to fix--or not--their own floors and ceilings.

Standard & Poor's views this as a reasonable trade-off between economic constraints and the need to avoid uncontrolled development of wind farms, due to the supportive nature of feed-in tariffs. Standard & Poor's does not anticipate that the provisions of any new law will affect the operation or construction of wind farms; rather, any changes would apply to those projects currently being developed. A two-year transition period has been proposed. ■

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