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POWERING INVESTMENTS: CHALLENGES FOR THE LIBERALISED ELECTRICITY SECTOR

FULL REPORT

A EURELECTRIC report, DECEMBER 2012

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In line with its mission, EURELECTRIC seeks to contribute to the competitiveness of the electricity industry, to provide effective representation for the industry in public affairs, and to promote the role of electricity both in the advancement of society and in helping provide solutions to the challenges of sustainable development.

EURELECTRIC's formal opinions, policy positions and reports are formulated in Working Groups, composed of experts from the electricity industry, supervised by five Committees. This "structure of expertise" ensures that EURELECTRIC's published documents are based on high-quality input with up-to-date information.

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Powering Investments: Challenges for the Liberalised Electricity Sector

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Foreword

How much power generation capacity do we need to keep the lights on? Normally, the market would deliver an answer to this question. Yet this mechanism is not working as smoothly as it should. Unexpected changes have taken place: the recession has hit European economies, and electricity demand has dropped. Existing power plants are experiencing a profitability challenge: subsidised renewables generation is displacing conventional generation and reducing the peak prices conventional plants need to repay their investments – yet at the same time the conventional park remains crucial to deliver the flexibility needed for keeping the lights on. Not only that: running a plant today might even imply losing money through the new phenomenon of negative prices – truly an upside-down world.

Yet despite today's troubling economic climate, most scenarios, including the European Commission's Energy Roadmap 2050, suggest that electricity demand will grow in the medium to long term. This trend will be driven by the electrification of transport, but also of the heating and cooling sector. In this context, a secure electricity supply can only be maintained if an appropriate generation level exists and if reserve capacities and flexibility are available to balance the increasing share of intermittent renewables in the electricity system.

The European electricity industry takes the investment challenge very seriously. EURELECTRIC supports the expansion of renewables as a promising set of low-carbon technologies that will help Europe achieve its decarbonisation objective by 2050. Yet their development, as much as that of all other technologies, must be cost-efficient, market-based, and European rather than national. A system approach to their expansion must ensure that generation capacity is added based on demand and market signals, not subsidies.

During the Great Depression of the 1930s, brilliant minds like Roosevelt or Keynes thought in long-term perspectives and opportunities. The electrification of the US countryside, to cite just one example, took place in those dark days. New values were created for the next generations, through power generation and infrastructure, innovation and vision.

Today, our choice is the same again: in times of crisis it is decisive to work towards a vision and added value for the next generations. Investing in the power system is the basis for the advancement of society – let us start from here. An intelligent innovation policy, the constructive cooperation between governments and the private sector, in short an enabling investment climate will help the European power sector promote the well-being of European citizens, and Europe's competitiveness in the world.

Fulvio Conti, President of EURELECTRIC, CEO ENEL

Introduction

The EURELECTRIC Investment Action Plan assessed the main obstacles to investment in the liberalised power sector. Investments in regulated parts of the electricity value chain – distribution networks and transmission – were deliberately kept out of the report's scope: they are not subject to the same constraints and face different challenges today.[1] Nevertheless reference is made to the full electricity value chain where needed – e.g. the impact of more transmission, smarter distribution grids, storage or energy efficiency on generation adequacy – since a fragmented view on the power system can lead to erroneous conclusions.

Two meetings of a high-level EURELECTRIC Task Force took place in April and July 2012, gathering representatives from the electricity industry, banking sector, consultancies, think tanks and academia. They addressed generation adequacy, investments or investment obstacles by technology, taxes and regional differences in investment trends, as well as the regulatory framework. A broader exchange of views took place at an internal workshop in September when participants from the industry at large were involved. A survey on the investment climate, commissioned by EURELECTRIC and discussed at the workshop, clearly stressed that the current regulatory uncertainty and policy contradictions were the most important obstacles to investments, as seen by the industry.

Investors have other opportunities beyond the electricity sector, and as a banker highlighted during the workshop, many would rather avoid Europe currently and go elsewhere. This perception applies as much to the so-called 'new' investors as to the existing ones. EURELECTRIC members believe that it is time to put Europe more sharply in focus: it is the European energy transition that they want to invest in. This report is targeted to the EU institutions, but also to national politicians and regulators: policymaking has to be optimal to support the transition to the low carbon energy system – which, ultimately, can be delivered only by the private sector.

This report captures in more detail the views presented by members of our high-level task force. The report consists of five parts. Part I covers investment challenges, including a discussion about generation adequacy and perceived risks; Part II discusses regional differences in the investment climate across Europe; Part III presents increasing risks and taxes; Part IV looks at the situation for different generation technologies; and Part V focuses on elements of the solution, including primacy for the ETS within the policy measures, as well as a stronger focus on innovation and the deployment of innovative solutions. The contributions reflect the views of the individual authors, unless otherwise stated. A summary of findings and recommendations, reflecting the views of EURELECTRIC's membership, has been published separately.

David Porter, Chairman of EURELECTRIC's Energy Policy and Generation Committee

[1] Investment conditions for distribution grid companies have been addressed in other EURELECTRIC publications such as the *Regulation for Smart Grids* report.

Part I – Power Generation Investments Challenged

GENERATION ADEQUACY AND THE INVESTMENT CONUNDRUM: DO WE ACTUALLY NEED MORE CAPACITY? - GIUSEPPE LORUBIO, EURELECTRIC

Investment in the power sector is a long-term business. An appropriate forecast of demand and supply is crucial to deliver this investment in time, not least considering the long lead times for new build, public acceptance, authorisations, etc. Where do we stand on this?

The European Commission has estimated that the power generation sector alone needs hundreds of billions of euros to close a capacity gap of almost 350 GW by 2020[2]. This impressive figure takes into account *inter alia* the ageing of the current power plant fleet, the requirements imposed by the EU renewables policy and the phase-outs due to the Large Combustion Plant and Industrial Emissions Directives. On these grounds, one could wonder why the current investment climate in power generation is as unfavourable as some describe: shouldn't the need for additional capacity going forward logically incentivise investments? However, questions like "Does the system need more capacity?" or "Is current capacity able to keep up with electricity demand?" have no straightforward answer; any serious answers must take a number of broader considerations into account.

A common means of estimating how much generation capacity is needed is the **concept of generation adequacy**. Generation adequacy is defined as "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements"[3]. Obviously, therefore, the timescales involved vary. The Council of European Energy Regulators (CEER), for instance, has opted for a broad definition stating that "all timeframes must be considered from several years ahead (investments in new generation capacity) to close to real-time (e.g. sufficient margin over peak load)."[4] However, EURELECTRIC believes that generation adequacy should refer to the ability of the power system to cope with changes in the balance between supply and demand in the medium to long-term, i.e. ensuring that enough capacity is available to keep the lights on. In our view, the operational reliability of the system in the shorter term does not qualify as generation adequacy, but rather as system reliability.

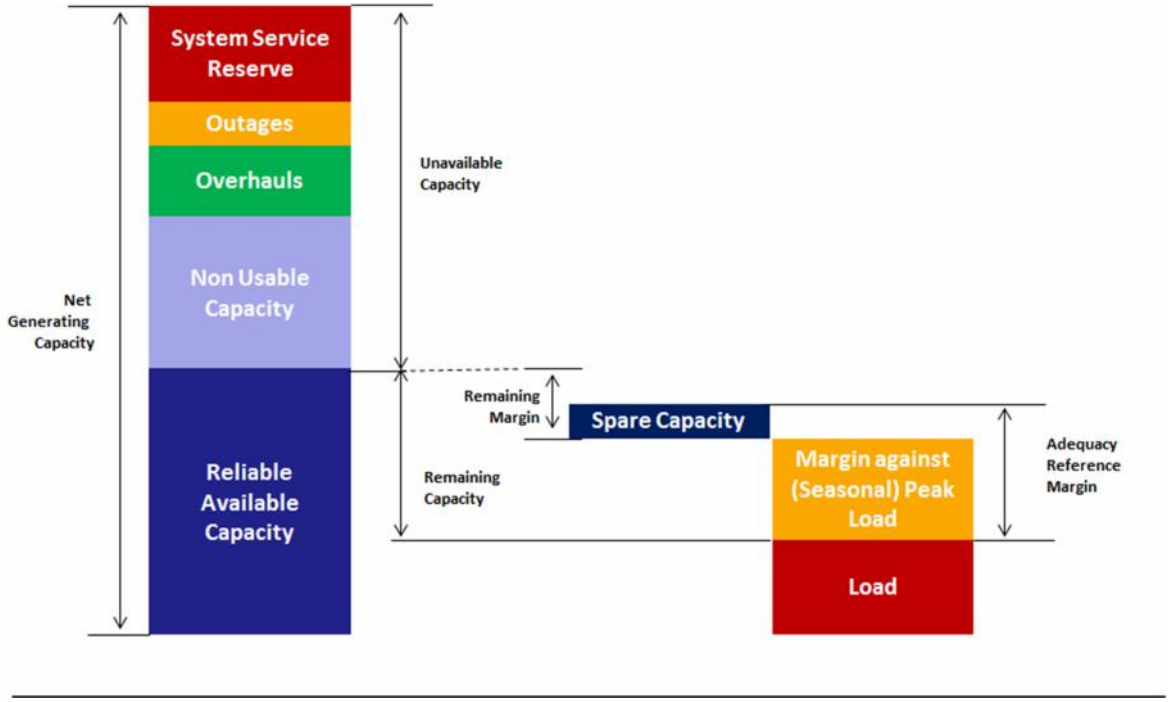
The European Network of Transmission System Operators for Electricity (ENTSO-E) has devised a methodology, depicted in Figure 1, to evaluate generation adequacy. The adequacy reference margin (ARM) – the indicator used to assess generation adequacy in most situations – is derived from the reliable available capacity (RAC), i.e. the share of the net generating capacity deemed to be always available to generate electricity. The ARM is made up of two components: the margin against (seasonal) peak load and spare capacity, with the former including the capacity needed on top of reference load and below the seasonal peak load, and the latter including capacity reserved for unforeseen extreme conditions.

2 Data in Europe Commission, Energy Roadmap 2050 (COM/2011/0885/Final)

3 Source: US regulator NERC, FAQs, definitions, http://www.nerc.com/page.php?cid=1%7C7%7C114

4 CEER, Generation Adequacy Treatment in Electricity: A CEER Call for Evidence, 10 December 2009

Figure 1: Generation adequacy analysis



Source: ENTSO-E

Applying this methodology ENTSO-E has published a System Outlook and Adequacy Forecast (SO&AF) report[5] that serves as basis for its Ten Year Network Development Plan and evaluates generation adequacy across Europe until 2020-25 – depending on the scenario taken into account. The scenarios give the following picture on the development of demand and power generation capacity in Europe:

- Load and consumption are expected to increase in all scenarios;
- Electricity demand goes up by 0.75% per year till 2020 (aggregated European data) in the EU 2020 scenario;
- Net generating capacity (NGC) steadily increases in all scenarios, with renewables taking the lion's share of this growth. Indeed, the NGC of renewables almost doubles from 2012 to 2020, from 300 GW to 550 GW (EU Scenario 2020).

Based on this analysis, the report concludes that generation adequacy is ensured in most situations and in all scenarios but one for a limited number of years. Adequacy in Scenario A is ensured until January 2016, after which new generating capacity would be required to deal with unexpected load variations.

However, relying on a purely mathematical, static approach to assess generation adequacy could be ill-considered. First and foremost, the profitability of (some categories of) conventional generating assets, in particular fossil-fuelled plants but also hydro plants, is seriously constrained by overcapacity and by strong penetration of subsidised renewables, which is becoming a common feature of many electricity markets. In some cases the situation is aggravated further because renewables – above all solar photovoltaic (PV) – cut across peak hours in which generators such as combined cycle gas turbines (CCGTs) and pumped hydro schemes used to provide electricity. Under such conditions, conventional generators struggle to recover their fixed

[5] ENTSO-E, System Adequacy Outlook and Forecast, June 2012

costs – the well-known 'missing money' problem. If companies decide to withdraw unprofitable plants before the originally planned decommissioning date, capacity margins could be reduced.

Furthermore, the current double-dip recession in Europe has reduced electricity demand, with corresponding knock-on effects for investment plans and the need to build new capacity and/or upgrade older assets. As the GDP of some of the EU's major economies continues to shrink, electricity consumption shrinks as well. What makes things problematic is that estimates up to 2020 or 2025 appear to be unreliable and forecasting electricity demand is riddled with uncertainty as to how and when recovery will eventually happen. Expected increases in energy efficiency will also depress electricity demand going forward, above all if energy saving obligations are implemented.

In conclusion, although commonly used generation adequacy indicators portray a comfortable situation, generation adequacy could be jeopardised in some circumstances as loss-making generators close unprofitable plants.

Whether investments in power generation projects are ultimately realised depends not only on factors like underlying commodity prices, emission allowance prices, discount rates, or cost of capital, but to a large extent on an enabling political and regulatory framework. After a first phase of investments driven by market liberalisation, the stimulus for investment – and often the obstacle to it – has recently come primarily from legislation and regulation.

Overall, EURELECTRIC believes that there is an urgent need to fix the above-mentioned generation adequacy issues in some regions. Connecting oversupplied to insufficiently supplied regions would be in tune with the single market, illustrating also the inter-linkages between transmission and generation investments. Considering the huge delays in setting up new interconnections however, there is a more immediate need to maintain the system in balance. The best solution to driving investment in generation, as stressed by EURELECTRIC several times, is the elimination of current market distortions.[6]

[6] EURELECTRIC, Renewables Integration and Market Design: are Capacity Remuneration Mechanisms needed to ensure generation adequacy?, May 2011

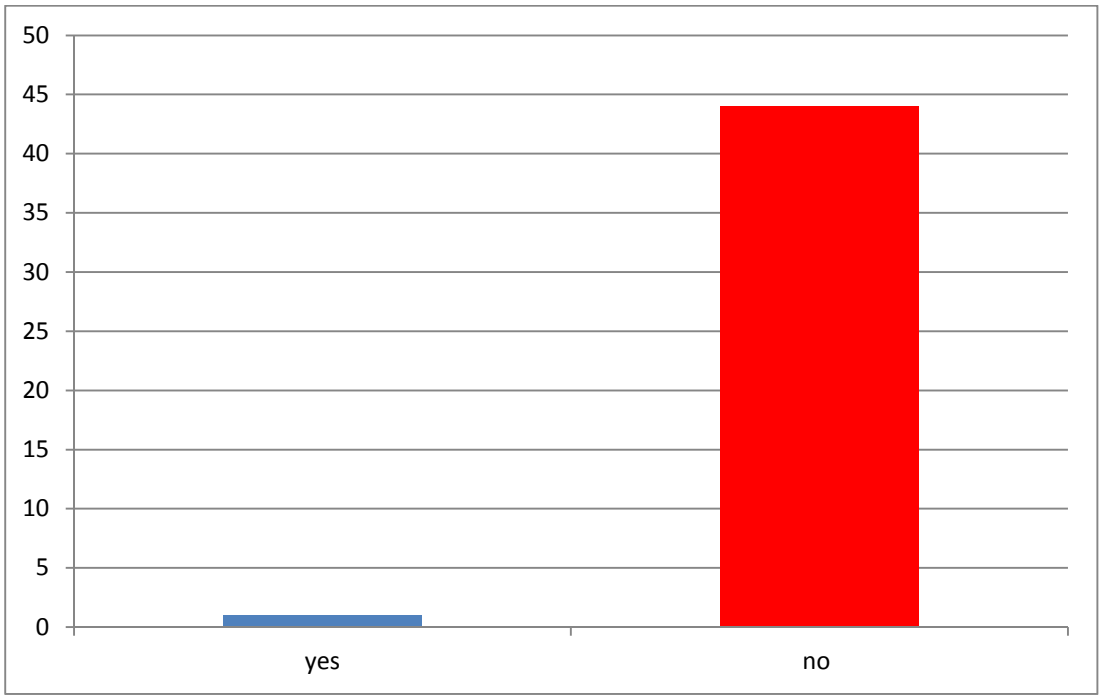
KEY FINDINGS OF EURELECTRIC'S INVESTMENT SURVEY - PIERRE SCHLOSSER, EURELECTRIC

In the context of its Investment Action Plan, EURELECTRIC conducted a qualitative survey on the investment climate among its membership. The answers provided gave strategic and high-level financial insight on the current investment climate, as experienced by business leaders. Three questions and the respective responses are summarised below. The full questionnaire can be found in the annex to this report.

QUESTION 1/ The European Commission has estimated that 1 trillion euros will be invested in the European sector (gas and electricity) by 2020; the IEA has estimated that 1.9 trillion dollars will have to be invested in the European electricity sector by 2035.

Asked whether they considered the above figures realistic, 44 out of the 45 participants surveyed by EURELECTRIC clearly said these investment volumes would not occur (Figure 2).

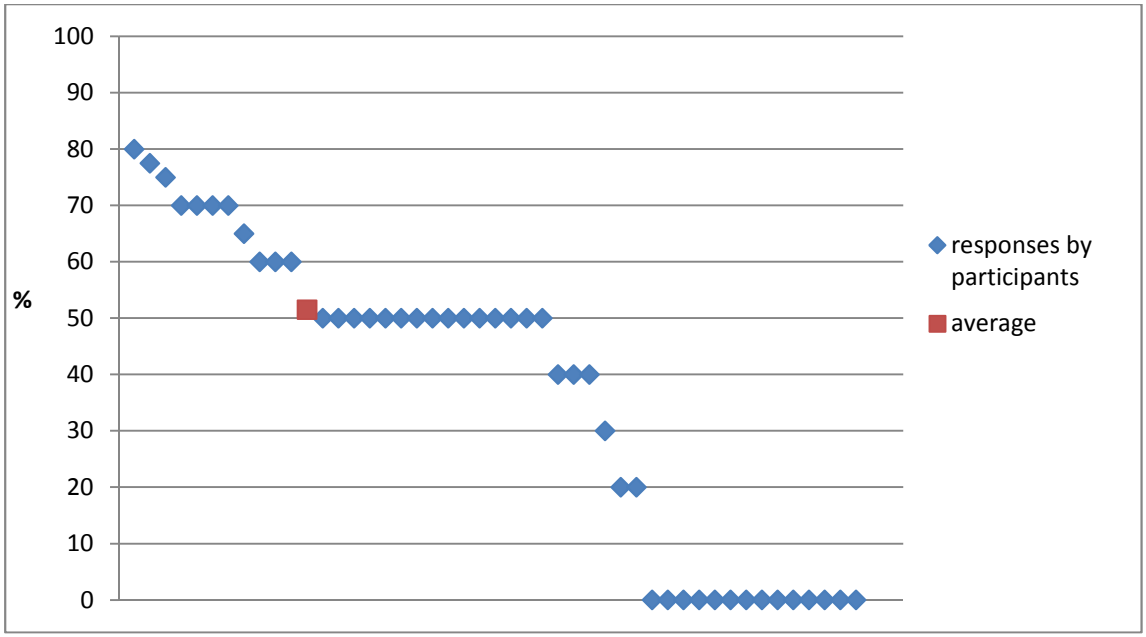
Figure 2: Likelihood of forecasted €1 trillion investment to become reality according to EURELECTRIC members



QUESTION 2/ What percentage of these investments will materialise in reality?

Instead, survey participants expected only about half – 51.5% – of these investments to take place, with responses varying from 20 to 80% (Figure 3).

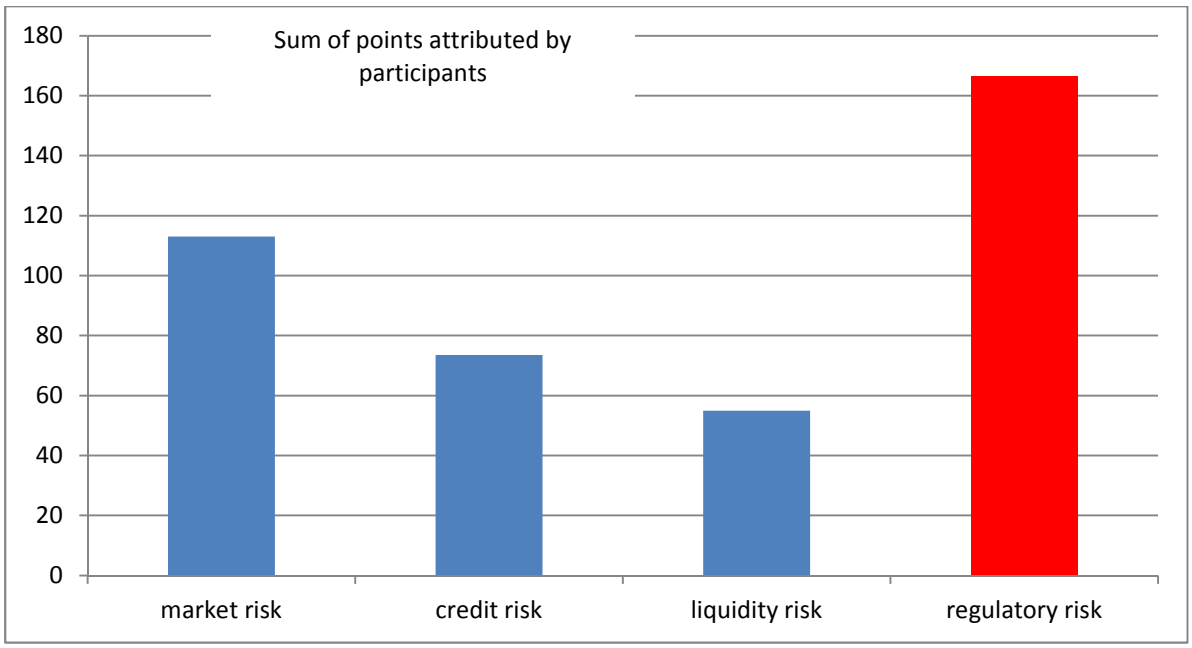
Figure 3: Expected share of the forecasted €1 trillion investment to become reality, according to EURELECTRIC members



QUESTION 3/ Which risk do you rank highest when making your investment decisions?

Participants were offered a choice of risks and asked to rate each risk by attributing them points from 1 to 4, four denoting the highest risk. The highest risk as ranked by the 45 survey participants was regulatory risk, followed by market, credit and liquidity risks. This confirms EURELECTRIC's message that, despite being used to the manifold risks inherent in the sector's long investment cycles, investors today face risks that often exceed acceptable limits. Risks must generally remain proportionate, and regulatory risks cannot be hedged.

Figure 4: Assessment of different types of risk



Part II – A Diverging Investment Climate Across Europe

COMMON ELECTRICITY MARKET IMPROVING THE INVESTMENT CLIMATE - ULRICH BANG, DANISH ENERGY ASSOCIATION

The investment climate has at large been more advantageous in the Nordic region than in many other regions in Europe, and investments in power generation have been realised. The development of the common electricity market, which started in the 1990s, has led to a wholesale market that functions well and provides a sound business environment for the electricity industry. There are several examples of continuous political commitments that have provided a stable regulatory framework for investors.

On an overall level, the Nordic countries benefit from a pluralistic and consensus-seeking political tradition. Energy policy in the Nordic countries, i.e. Sweden, Finland, Norway and Denmark, is generally characterized by broad political settlements and thus a large degree of continuity, regardless of changes in government.[7]

The continuity has manifested itself in a **sustained commitment by Nordic countries to the use of certain energy sources**. Examples are the renewable energy deployment in Denmark and the continued investment and re-investment in nuclear and increasing use of biomass in Finland. Long-term regulatory stability without major stop-and-go discussions has provided security for investments in these technologies. In Denmark, all main political parties have been committed to renewables; hence the discussion has focused on the timing of the investments rather than a discussion of, for instance, whether to go for nuclear or not. Finland has created a comprehensive legislative framework that provides a basis for parliament decisions on new nuclear projects and final disposal of nuclear waste.

Governmental support schemes for renewable energy in the Nordic countries have been flexible and aimed at making **renewable electricity function on market terms**. The paradigmatic way of supporting technologies has been to let every power plant participate in the wholesale market and feed in accordingly, relative to their marginal cost of production. In other words, priority dispatch has not been applied and producers of renewable electricity have the same market responsibilities as other power producers. The merit order of power generation has ensured the uptake of renewable electricity in the market.

The support systems as such vary between countries. Sweden, with its electricity certificate scheme, has been relying on a technology-neutral approach for a decade now, whereas Denmark and Finland have selected technology specific feed-in tariffs to promote renewable electricity.

In 2011, Norway and Sweden joined together in their efforts to increase renewable electricity cost-efficiently, and the Norwegian-Swedish electricity certificate scheme became the first multi-country joint support scheme. The scheme is an example of the Nordic region being a forerunner in exploring new ways to ensure a well-functioning electricity market. The majority of stakeholders, from political parties to power companies, are very satisfied with the quota system, which delivers a cost-effective outcome.

Because politicians determine the tariff levels, or the formulas that are used to determine the tariff levels, the Danish and Finnish schemes do not foster **competition between different**

[7] One important exception to this is the position of nuclear in Sweden.

renewable electricity technologies in a similar manner as the Swedish electricity certificate scheme.

COOPERATION ENSURING THE INTEGRATION OF THE ELECTRICITY MARKET

Energy investors in the Nordic countries have benefited from **a common spot market and dispatch system** and an **extensive transmission network** across the Nordpool area. Although end-user power prices are still regulated in Denmark, Nordic policymakers and authorities have generally had a strong faith that a deregulated, integrated power market will deliver cost-efficiently, and have acted accordingly.

The Nordic wholesale electricity market, with a turnover of around 400 TWh, has been fully integrated since 2000 when Denmark joined Nordpool. In 2011, 73% of power consumption[8] in Nordic countries was bought on elspot, the Nordpool day-ahead market. All price areas in Nordic countries had the same wholesale power price 42% of time in 2011 and 19% of the time in 2010. The market share for the biggest player on NordPool Spot is less than 20%, so no-one has a dominant position.

Although more network investments are needed and are in the pipeline, Sweden, Norway, Finland and the eastern part of Denmark are well interconnected in a common, phase synchronised electricity grid, ensuring high transmission capacity. The Nordic countries have long cooperated in coordinating their power production according to demand (price) in the NordEl dispatch system, paving the way for the current NordPool elspot market.

The four Nordic **TSOs have cooperated** rather effectively to integrate the Nordic area and have been committed to linking the Nordic market to the continent with strong interconnectors. The transmission grids are managed, strengthened and extended based on societal cost-benefit analysis whereby the business case of a given interconnector depends on the consumer surplus, the producer surplus and the congestion rent of a given project. This ensures that the interconnectors needed the most by the market are built instead of only prioritising the projects with the highest congestion rent.

While network investments may have been carried out more successfully than in other parts of Europe, there have been significant delays in important projects. For example, the construction of the Swedish Southern link has been delayed with several years and delays are expected also in the construction of the South West link. They are supposed to reduce significantly the congestions in the Nordic market. In addition, the weaknesses in the southern part of the Norwegian transmission grid are a considerable challenge for increasing the cross border capacity.

The division of the Nordic market into price zones has made transmission restrictions and necessary areas of grid enforcement visible. Denmark and Norway have been divided into several price areas for a long time, whereas Sweden was divided into 4 prices areas in 2011. The benefits of price areas are clear in terms of creating transparency of grid congestion, but price areas have to be established in a way that enables an efficient electricity market and competition between market players.

There are examples of **innovative financing** of new power generation in the Nordic countries. In Denmark utilities have been instrumental in attracting institutional investors to co-finance new offshore wind parks. Especially DONG Energy has been leading this approach by investing in offshore wind parks and selling up to 49% of the park to institutional investors once the park has

[8] Nordpool Spot Annual report 2011

been commissioned. DONG Energy continues in these cases to operate the installations. This approach has been valuable in a time where the balance sheets of utilities are under pressure.

SUDDEN REGULATORY INTERVENTIONS INCREASING

The past may have been characterised by stable investment climate, but it is not equally certain that the future will hold the same for the Nordic power producers. In June 2012 an overwhelming 96% of respondents[9] from the Finnish energy sector estimated in a survey that political risk has grown during recent years. More than half of them indicated that political risk has grown significantly. The discussion on windfall taxes for nuclear and hydropower persists and drastic sudden increases in taxes on gas used in heat production were introduced a couple of years ago.

Similar enthusiasm by politicians to **introduce new taxes and increase the existing taxes** on energy production and electricity consumption has been experienced in other Nordic countries. In Norway, municipalities may decide to levy a property tax on hydropower plant (e.g. a rate of 0.7% based upon a calculated market value). The calculated market value may vary between a fixed minimum and maximum value. The maximum value has been raised by 5% from 2012 and by another 11% from 2013. This change is expected to increase the total property tax for hydropower plants by €15 million in 2012 and €40 million in 2013. Also in Sweden a large increase in the property tax for hydropower has been enforced. Furthermore, the implementation of the Water Framework Directive creates a risk of reduced hydropower production.

In Sweden, nuclear power has been an issue of popular controversy and **political stop-and-go discussion** for decades. This continuing uncertainty about the future of nuclear in Sweden resulted in having to carry out large investments in refurbishment and increased safety measures over a short period of time, leading to very low availability for the Swedish nuclear plants and holding back other investments in the sector. This is an example of how risks of a changing regulatory framework create sub-optimal outcomes.

Regulation preventing the simultaneous ownership of transmission systems and production capacities – part of the so-called unbundling process – creates unintended problems when institutional investors in the energy sector (e.g. pension funds) are kept from investing in transmission capacity due to financial engagement in generation. The **unbundling provisions** are seen as a regulatory risk, because it is not clear how they limit the institutional investors' simultaneous involvement in transmission and power generation; guidelines from the European Commission on the interpretation could make it easier for the energy sector to attract institutional investors.

NEXT STEPS TO IMPROVE THE INVESTMENT CLIMATE

At EU level, the unknown future of the European Emissions Trading System (ETS) and whether there will be binding goals for renewables in the European post-2020 energy mix is a specific case of the general problem of regulatory risks. This is not unique to the Nordic countries and must be dealt with on a broader European scale – preferably without delay as uncertainty surrounding the future of the ETS is definitely an obstacle to investments.

The electricity system all over Europe, including in the Nordic region, is facing the need for investment in new generation capacity as old plants are decommissioned. In this respect there is a call for political leadership in the EU to strengthen the **ETS to be the key instrument** in delivering investments today and beyond to decarbonise the power sector, as outlined in

[9] Aula Research Oy, 2012
http://energia.fi/sites/default/files/images/poliittinen_riski_suomessa_energiateollisuus_ry_200612_0.pdf

EURELECTRIC's CEO declaration from 2009. Also, further European integration – transmission capacity and market coupling and better coordination of national policy measures – is needed to further strengthen the business case, especially for renewables.

Furthermore, there is a need for less ad-hoc political interventions that are not in line with overall policy targets and for **greater regulatory stability** to ensure the needed long-term investments in production and transmission capacity in particular, as well as the deployment of smart grids, all of which will help to reduce CO_2 emissions.

OVERCAPACITY AND ECONOMIC CRISIS: A TALE OF TWO COUNTRIES FROM SOUTHERN EUROPE - STEFANO DA EMPOLI, I-COM

Although Spain and Italy are characterized by a different energy mix and other structural divergences, they share a similar turn in recent generation developments and future scenarios.

Following market opening in the late 1990s, both countries invested heavily in new capacity and repowering of existing capacity. While most investments focused on CCGT plants, Spain also experienced strong growth in wind power capacity.

In the first half of the past decade, high consumption growth, especially in Spain, was the main driver of a very significant capacity expansion. Between 2000 and 2008, total installed electricity capacity increased by 84% in Spain and 30% in Italy (against the EU average of 24%). At the time, that trend was consistent with past demand growth and most sensible future scenarios.

However, reality took a very different turn. Starting from 2008, the economic crisis has affected Italy and Spain more than most countries in Europe. Electricity consumption has not even regained its pre-crisis level. In 2011, consumption in Spain was 5.9% lower than in 2008. In the same period, it decreased by 1,4% in Italy.

LARGE INVESTMENTS FOLLOWED BY DECREASING DEMAND

Even if at that point several investment projects in generation were abandoned, several factors continued to drive up capacity in both countries. In particular, renewables growth played a leading role. Between 2005 and 2011, Italy installed 5 GW of wind power capacity and 12.8 GW of photovoltaic capacity – 9.3 GW of photovoltaic capacity in 2011 alone, by far the highest figure in the world that year. The proportion between the two renewable sources was different in Spain – 4.9 GW of photovoltaic capacity and 9 GW of wind in the same period – but the overall sum was quite similar. After Germany, Italy and Spain are today the leading countries in Europe in terms of installed photovoltaic and wind capacity.

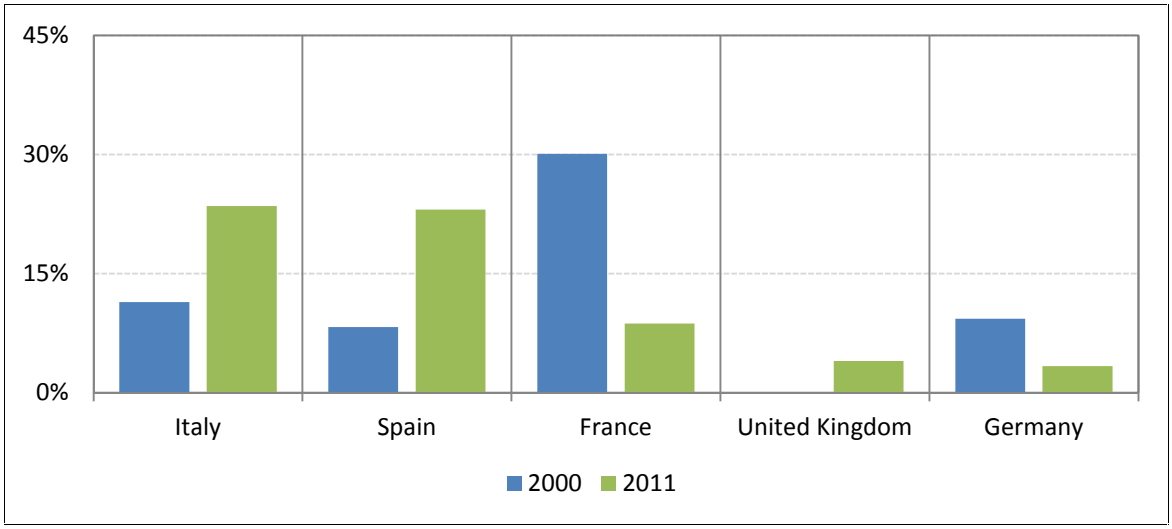
Weak demand and an impressive expansion of generating capacity, driven first by CCGT and then by RES, have significantly increased the reserve margin, expressed as the percentage of installed capacity in excess of peak demand.

As a result, Italy and Spain had the largest reserve margin (without considering import capacity) among largest European economies in 2011. Italy's reserve margin was 23.5% and Spain's 23% respectively, against 8.7% for France, 4% for the UK and 3.3% for Germany (see Figure 5).

This is all the more remarkable as, only a decade earlier, Italy and Spain had been in a very different situation. Italy reached a low point in 2002 with a reserve margin of 6.3%. In 2003 it was even forced to implement a plan of limited rationing, due to very hot weather that caused high demand and the closure of many plants in Italy and across Europe, affecting imports. Spain was also in a dire situation, with a reserve margin of 8.3% in 2000.

Given the current situation, the outlook for investments in the generation sector in the next years seems rather negative in both countries.

Figure 5: Reserve margin (%) in selected European countries



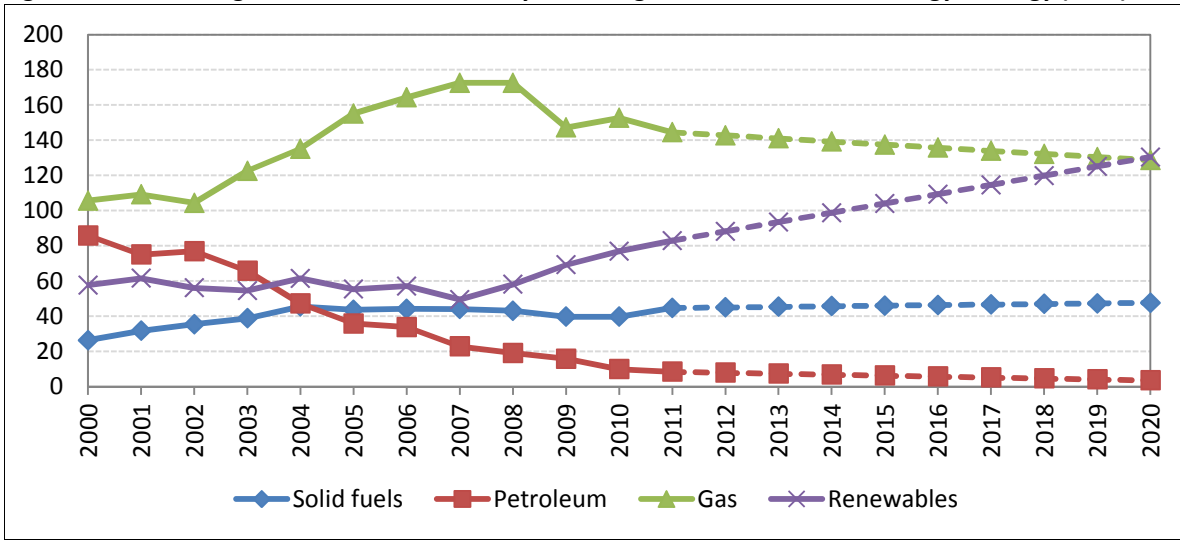
Note: UK figure for 2000 is not available, Source: ENTSO-E, I-Com

In 2010, Spain's National Renewable Energy Action Plan envisioned a bright future for both RES and natural gas. According to the reference scenario, their production was predicted to grow by 85% and 52% respectively between 2010 and 2020. In the energy efficiency scenario, growth for gas would have been lower but still high (+30%), with a stable increase in RES generation. Nuclear and coal penetration was envisioned stable in both scenarios.

However, the Spanish Renewable Energy Action Plan was based on macroeconomic scenarios that have in the meantime turned out be completely unrealistic. GDP growth was estimated to grow yearly in the range 2.2%-2.5% between 2011 and 2020. But as of October 2012 the IMF expects an annual increase of only 0.5% between 2011 and 2017.

The Italian economy is expected to expand even less, on average 0.3% between 2011 and 2017 according to the same IMF estimates. The draft version of the Italian National Energy Strategy, which came out in October 2012, foresees a growth of RES generation (+51% during the period 2011-2020) with a significant decrease of gas (-9.76% compared to 2011 and an impressive -24.6% compared to 2008). In 2020, renewable electricity is forecast to overtake gas as the most significant generation source. It should be noted that even the Italian National Energy Strategy takes a different view of macroeconomic conditions, assuming an annual growth rate of 1.1% during the current decade.

Figure 6: Power generation scenario in Italy according to the new National Energy Strategy (TWh)



Source: Terna, Italian National Energy Strategy (Official Draft, October 2012)

QUIET TIMES EXPECTED REGARDING INVESTMENTS

In a dismal and perhaps even worsening macroeconomic scenario for both Spain and Italy, the future outlook is quite different for renewable electricity and gas-fired generation. Although both countries are already very close to reaching their respective targets for RES-E, according to their national plans, it is likely that additional RES capacity will continue to be deployed in the next years, although at a decreased rate.

At the same time, investments in gas generation or in other sources would be virtually impossible to sustain under the current situation of overcapacity and anaemic electricity demand. Indeed, especially in Italy, gas plants already in place would operate for a significantly lower number of hours than expected by investors and in some cases generation companies, mostly reliant on CCGT, may suffer from sizeable losses.

Part III – Risks and Taxes on the Rise

PROVIDING FUNDING FOR THE POWER SECTOR – A RISKY EXERCISE? - VITTORIO D'ECCLESIIS, ENI SPA & RUI EUSTÁQUIO EDP

The debate on the investment needs in the power sector has very often focused on the adequateness of expected return. The issue of consistent levels of remuneration has been extensively discussed, in view of attracting capital from markets in an environment that is becoming much more competitive. In raising funds from capital markets, the power sector currently faces competition not only from other industrial sectors, but also from the banking sector itself, which must comply with new capital requirements, and from governments that must finance their public debt.

But the analysis of an adequate return threshold cannot be performed without considering the corresponding risk profile that – in a world of constrained capital resources – might jeopardise the overall financial feasibility of the planned investments.

The utility sector has been traditionally considered by investors as a defensive sector due to the lower level of risk compared to other industrial sectors. As a consequence investing in utilities was considered as a means of reducing the total volatility of an equity portfolio. Due to the relatively low level of risk and the perceived stability of the utility sector, utilities' shares were expected to overperform the average market during periods of downside, losing on average less than the market, and to underperform the market in periods of upside, gaining on average less than the market.

This market evaluation of the utility sector was related to several key perceived strengths:

- Low but stable – and substantially non-cyclical – demand growth;
- Financial robustness, supported by stable cash-flows from regulated or "quasi-regulated" business (such as renewable and retail to residential sector);
- implicit public back-up, with states often the owner of a stake-holding and/or golden share.

Any analysis of financial feasibility and high rates for investments in the power sector cannot overlook the evolution of risk drivers and the effects of said evolution on the sector's risk profile. An essential part of the viability evaluation is actually to verify on an on-going basis the sustainability of the risk/reward balance for the sector.

INCREASING AND NEW RISKS IN THE POWER SECTOR

EURELECTRIC has been analysing key emerging risks for the power sector, focusing in particular on market risk, credit risk, liquidity risk, sovereign risk and regulatory risk.

As far as **market risk** is concerned, the old picture of the relatively defensive cash flow structure, based on a significant chunk of regulated and "quasi-regulated" business, has significantly changed since liberalisation.

On the one hand the margins associated with the power sector are increasingly being evaluated against volatile wholesale market prices rather than stable final retail prices. Over the last decade energy commodities have become an asset class in itself for financial investments, as capital markets looked for alternative ways to achieve attractive returns and diversification. This financial demand for commodities eventually created a growing correlation between energy

markets and other financial asset classes (interest rates, foreign exchanges, equities) and, especially during the latest financial crises, resulted in high market volatility.

On the other hand the attractiveness of "quasi-regulated business" has been heavily affected by the **regulatory risk** in itself, which is now perceived as one of the main drivers, if not the most significant one, in the utility sector's risk map. Investors today are ever more prudent about the reliability of cash flows coming e.g. from renewables, due to regulatory risk that might impact both the volatility of emission markets and the revision of incentives or fiscal regimes.

The **credit and liquidity risk** profile of the power sector has been evolving accordingly, with a perceived increase of both its components, i.e. counterparty creditworthiness and exposure. In terms of counterparty creditworthiness the risk profile has deteriorated across the board, with industrial customers, financial institutions and governments all generally downgraded, triggering higher credit cost for the sector. In terms of exposure, beyond the traditional risk of unpaid customer bills, the rapid development of forward/future markets has progressively exposed the power sector to replacement risk, i.e. the positive market value of physical and financial forward/future contracts in case of defaulting counterparty. This phenomenon is increasingly translating into a liquidity risk for utilities, as the regulatory and business environment pushes to mitigate credit risk directly through daily cash settlement of outstanding credits. Liquidity risk is becoming a more stringent constraint for utilities, since the reduced access to capital markets is obliging them to set up additional cash buffers and credit lines to support the higher liquidity ratios requested by rating agencies and financial institutions.

THE MOST RECENT EMERGING RISK: SOVEREIGN RISK

Adding to this framework, **sovereign risk** represents a very recent and fast growing emerging risk for the sector. Public stockholding in many larger utilities, once considered a strength, has now become a threat. Ratings directly linked to the sovereign rating will generally move in parallel with a sovereign rating action. So called government-related issuers (GRI), whose ratings incorporate substantial uplift based upon assumptions of possible government intervention in case of default government support, are more likely to be downgraded. In general, a reduction in sovereign creditworthiness can lead to macroeconomic and financial disruption, which may in turn expose companies (even non-GRI companies) to a significant loss of revenue or profitability or to increased funding pressures. In most cases, non-financial corporates will not be rated more than 1-2 notches above the sovereign. The recent downgrading of several EU countries has thus automatically triggered a similar downgrading for utilities. Furthermore sovereign risk often increases the level of perceived regulatory risk for the sector, due to investors' concern that governments are likely to further increase fiscal pressure and reduce tariffs and incentive schemes.

Table 1A and 1B: Evolution of power company ratings in countries under rating downgrade actions

S&P	Dec09	Dec10	Jun11	Dec11	Mar12	Jun12	Sep12
PPC	BBB-	BB+	B-	CCC	CCC	CC	CC
ESB	-	-	BBB+	BBB+	BBB+	BBB+	BBB+
EDP	A-	A-	BBB	BBB	BB+	BB+	BB+
ENEL	A-	A-	A-	A-	BBB+	BBB+	BBB+
Endesa	A-	A-	BBB+	A-	A-	BBB+	BBB+
Iberdrola	A-	A-	A-	A-	A-	BBB+	BBB+
Gas Natural	BBB+	BBB	BBB	BBB	BBB	BBB	BBB

Moody's	Dec09	Dec10	Jun11	Dec11	Mar12	Jun12	Sep12
PPC	-	-	-	-	-	-	-
ESB	-	-	Baa1	Baa3	Baa3	Baa3	Baa3
EDP	A3	A3	Baa1	Baa3	Ba1	Ba1	Ba1
ENEL	A2	A2	A2	A3	A3	Baa1*-	Baa1*-
Endesa	-	-	-	-	-	-	-
Iberdrola	A3	A3	A3	A3	A3	Baa1*-	Baa1*-
Gas Natural	-	Baa2	Baa2	Baa2	Baa2	Baa2*-	Baa2*-

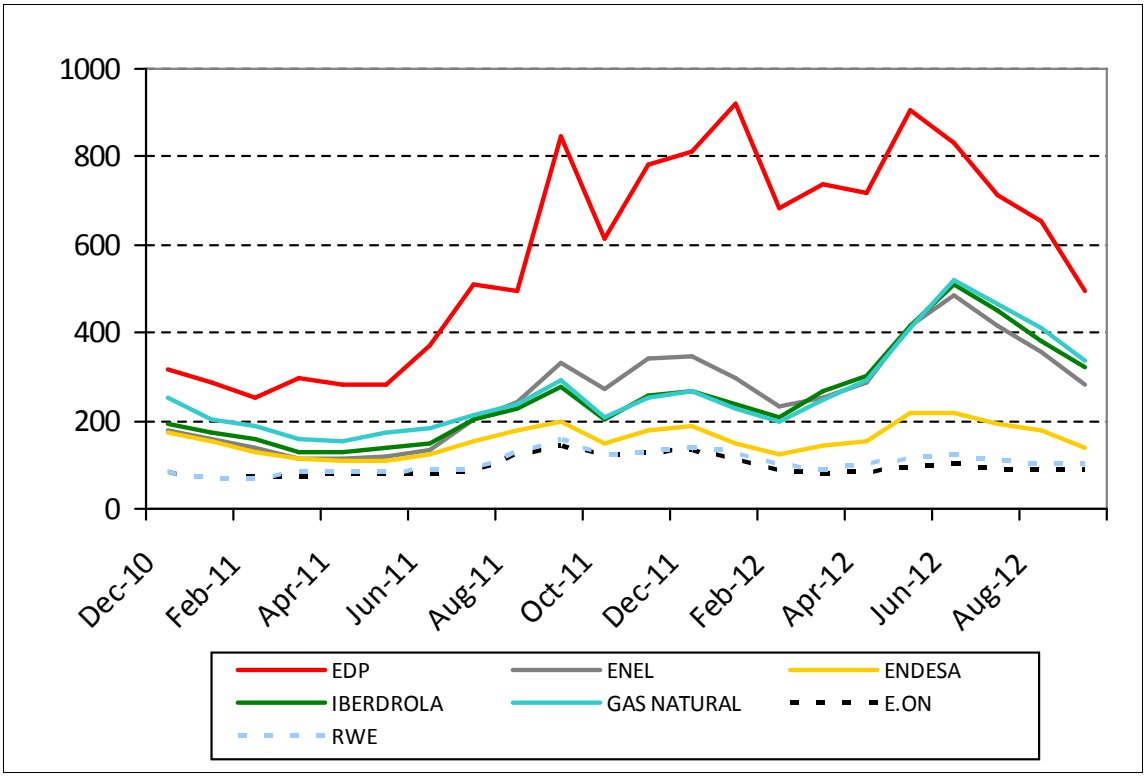
Source: ***Bloomberg***

Thus we observe, after a positive initial impact of financial bailouts in Greece, Ireland and Portugal, a continuous deterioration of credit risk metrics for these countries.

Credit ratings are progressively downgraded, resulting from concerns that austerity measures will not be enough, existing bailout loans might need to be extended, and new countries might start to face similar problems and need a financial bailout, as was recently the case for Spain (S&P rating downgraded from BBB+ to BBB- on 10 October 2012) and Italy.

Following sovereign rating downgrades, power companies in these countries faced significant rating downgrades. As shown in the tables above, companies that were usually in the A rating zone were pushed down by sovereign downgrades. Not a single power company in those countries now has an A rating – and EDP and PPC have even been pushed out of the investment grade region.

Figure 7: 5-year Credit Default Swaps (CDS) – evolution (in basis points)

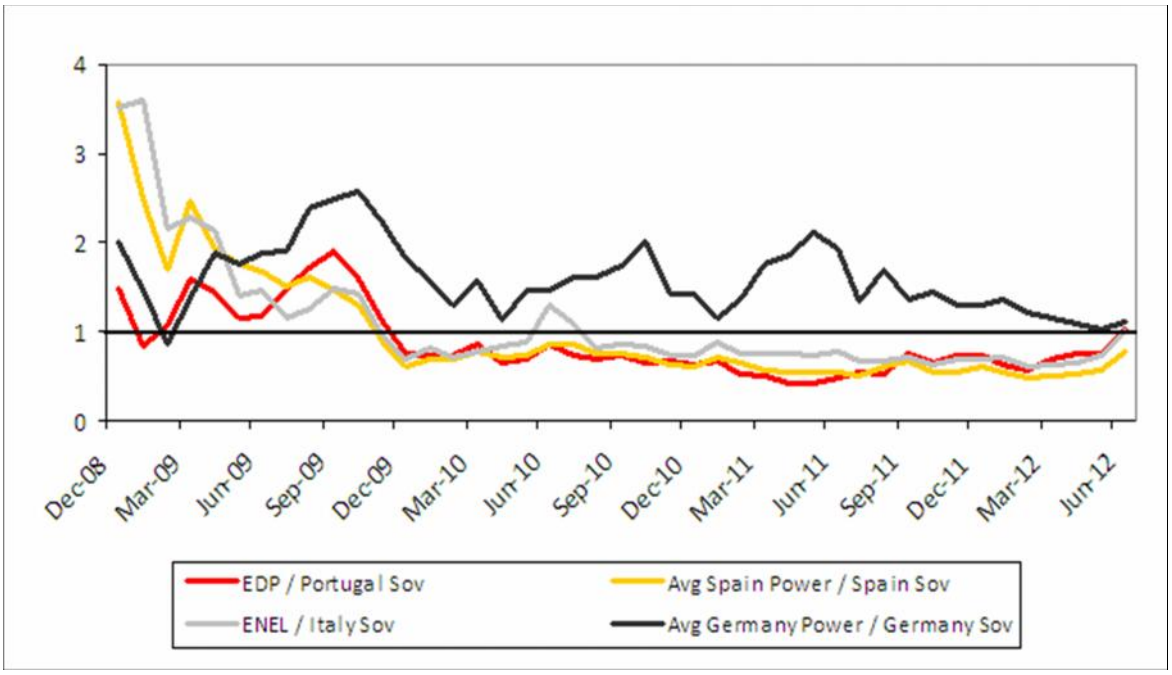


Source: ***Bloomberg***

Credit default swaps (CDS) follow the trend observed by credit ratings, with an increase indicating that investors perceive a growing default risk for these countries/companies.

Figure 7 shows a continuous increase in CDS until May 2012, reflecting all the uncertainty concerning the lack of integrated European efforts to end the crisis and stop contagion to other countries, namely Spain and Italy. In June 2012, markets reacted very positively to election results in Greece, the bailout of Spanish banks and the proposal for the European Stability Mechanism (ESM) with the subsequent bond-buying programme in the secondary market of the European Central Bank (ECB) – and the evolution of CDS shows that tendency. Nevertheless, in September markets refocused on Spain, and amid strong expectations of a Spanish economic and financial bailout, the rating for Spain was downgraded and power companies in Spain followed.

Figure 8: Corporate CDS versus sovereign CDS



Note: ***Average for Spain includes Endesa, Iberdrola and Gas Natural; Average for Germany includes RWE and EON.***

Portuguese, Spanish and Italian power companies had lower CDS than the respective sovereign in the last two years, reflecting investors' perception that these corporates posed lower risk. This situation was not verified before 2010 in the peripheral countries, but it is still observable in Germany for example.

CONCLUSIONS

The emergence of the described new risks in the utility landscape is occurring in a context of reduced expected profitability. Most mid- and long-term projections by financial institutions and public think tanks expect lower demand growth and shrinking production spreads. **The need to rebalance the risk/reward profile for the utility sector must therefore be accurately taken into account** when companies and investors consider the financial sustainability of capital-intensive investment plans. Ultimately, capital markets will only consider the utility sector attractive if new emerging risk drivers are either properly managed and mitigated or adequately remunerated in the expected profits.

NEW TAXES HINDERING INVESTMENTS - CHARLOTTE RENAUD, EURELECTRIC

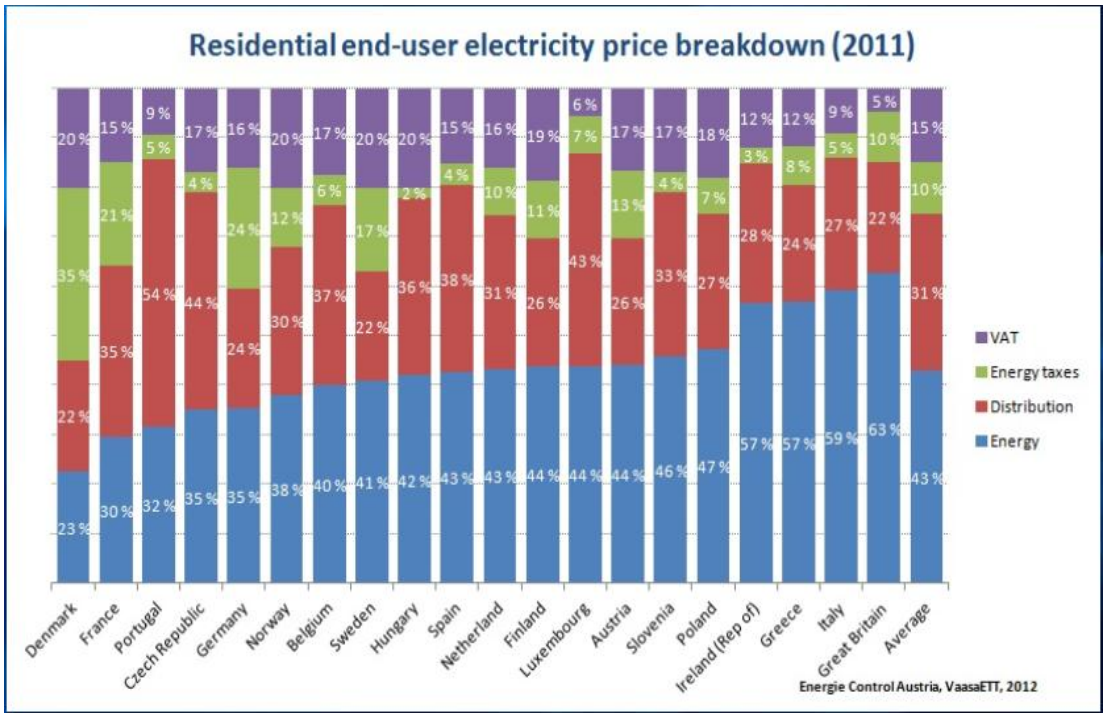
For many years, EURELECTRIC has been monitoring taxation developments in the European electricity sector, focusing in particular on the taxes and levies introduced on the production, transport and sale of electricity.

The tax burden on the electricity sector has continuously increased in recent years. Moreover, it is becoming ever more diversified. With market integration as one of our cornerstones, EURELECTRIC fears that those developments might create undue market distortions, thereby leading to severe impediments in the development of electricity markets.

The above-mentioned taxation developments also make it difficult for electricity companies to make their business case and thus hamper investments in existing and new power plants. Indeed, with a modest cash flow generation capacity, and being forced to reduce their debt level to maintain their rating, many companies might be forced to run divestment programmes and to decommission some existing power plants to reduce their debt/equity ratio.

Supporters of these taxes often claim that they are more than justified since electricity prices are considered high in many countries and the perception is that profits are high. But high prices for customers do not necessarily equal high profits for companies. Many consumers are not aware that the energy component often accounts for less than half of the total bill, as can be seen (in blue) in Figure 9 below. In fact, the average share of the energy component in the bill is 43%. The tax components have been increasing constantly since the 1990s, while the electricity (commodity) price itself has remained rather stable.

Figure 9: Breakdown of residential end-user electricity price



Source: Energie Control Austria, VaasaETT, 2012

Recent years have seen a sudden introduction of various new taxes and tax reforms that have significantly changed the business cases of many companies. The following examples from across Europe give a good picture of the most recent electricity-related taxation trends.

TAX DEVELOPMENTS IN THE POWER SECTOR

Nuclear power generation continued to be heavily taxed. In Belgium, a tax has been introduced on profits derived from nuclear production. The tax is split among nuclear producers on the basis of their respective production share in the last calendar year. At the end of 2011, the Belgian government announced that the annual amount of this tax would increase from €250 to €550 million as of 1 January 2012. In Sweden, nuclear power is also taxed based on the thermal production capacity of the nuclear reactor (e.g. the rate is 1,200€/MW of the permitted thermal capacity and calendar monthMeanwhile, in Germany, there are doubts about the constitutionality of the nuclear fuel rod tax introduced in 2011 and expected to last until 2016.

Emissions trading is used to reduce the CO_2 emissions in the power sector and it is questionable whether overlapping measures bring any additional benefits in this regard. Nevertheless fossil fuel fired power generation has continued to be heavily taxed by some member states. In Belgium, electricity companies have to pay a tax of 11.6526€/t of coal and a federal levy of 0.6484€/MWh of natural gas used for power generation. In Finland, fuels for power generation are not taxed, but the business case of combined heat and power plants is being weakened by increasing the tax on gas used for heat production from 2.1 €/MWh to 13.7 €/MWh between 2010 and 2015 and the introduction of a new tax for peat.

Fiscal measures on renewable energy sources have also increased in some member states. In Sweden, the real estate tax on hydropower plants increased from 0.5% to 2.8% between 2006 and 2011. In Slovenia as well, the concession fees for commercial exploitation of water for power generation still represent a huge part of company expenses (e.g. at least 10% of the sales value of electricity generated). In Norway, municipalities may decide to levy a property tax for hydropower plant (e.g. a rate of 0.7% based upon a calculated market value). The calculated market value may vary between a fixed minimum and maximum value. The maximum value has been raised by 5% from 2012 and by another 11% from 2013. This change is expected to increase the total property tax for hydropower plants by € 15 million in 2012 and € 40 million in 2013.

In France, the Finance Bill for 2012 set up an annual outstanding tax to finance CO_2 allowances granted by the State to new industrial plants entering into the EU Emissions Trading Scheme (EU ETS) in 2011.This tax applies to “incumbent” emitters which have received CO_2 allowances covering more than 60,000 tonnes of the CO_2 national - allocation plan for the 2008-2012 trading period. It is levied at a rate of 0.052% of the company's FY 2011 turnover. Tax cannot exceed the number of CO_2 allowances received by the taxpayer from 1 January 2008 to 31 December 2012, multiplied by €6.18.

The so-called “Robin Hood” tax regime, which taxes company profits, remains intact in Hungary until end 2012, while the application scope and rate of this tax has increased in Italy (from 6.5% to 10.5% for 2011, 2012 and 2013). In Hungary, an additional tax on energy suppliers was introduced for three years from 2010 and is imposed on retail, telecommunications activities and energy suppliers. The tax base is net sales revenues, with a rate between 0.3 % and 1.05%.

CONCLUSIONS

As a side-effect of the public debt crisis, governments have intensified their efforts to search for new sources to fund public debts, increasing regulatory risk for the European electricity industry at large. The increasing taxation weakens companies' ability to make new investments. Moreover the introduction of new taxes that decrease the profitability of earlier investments makes investors fear similar measures in the future.

The growing and increasingly diversified taxation of the electricity sector is likely to result in undue market distortions. It is of key importance to develop measures aimed at improving tax harmonisation in the European electricity sector in order to ensure a level playing field across Europe.

A BANKER'S PERSPECTIVE: EVOLVING ATTRACTIVENESS OF THE POWER SECTOR - ALLAN BAKER, SOCIÉTÉ GÉNÉRALE

Power project finance in Europe has traditionally focused on markets where the liberalisation process has created a regulatory framework that supported the development of generation capacity by independent developers. Developers were also able to enter into long-term power purchase agreements (PPAs) with incumbent vertically integrated utilities or other market counterparties to pass the commodity risk to entities better equipped to manage this risk. Although the utility companies themselves have also invested heavily in generation capacity, they have almost always chosen to finance on balance sheet rather than incur the costs and perceived constraints of project finance.

This model has proved to be successful in many parts of Europe including the UK, the Netherlands, Spain, Portugal, Italy and some Central European countries, and has made a material contribution to opening these markets to competition in the generation sector. However, recent events have led to some fundamental changes in the European power landscape and have also called into question the role of both independent developers and project finance in European generation markets in the future. These include:

- Prolonged global economic recession and banking crisis;
- Fukushima and the decisions taken in respect of nuclear capacity in the aftermath;
- High levels of investment in the renewable energy sector in response to green energy policy drivers;
- Perceived increase in regulatory/policy risk, with a number of countries embarking on reviews of their energy markets; and
- Need for significant replacement of ageing, and therefore less efficient, generation and other infrastructure in many countries of Europe.

From the perspective of a financial institution, there has been a feeling that the fundamentals of liberalised European power markets were largely predictable and could be modelled to understand the long-term economics of power projects being financed. This was to a certain extent true, particularly for "island markets" such as the UK with limited interconnection, but the increased complexity introduced by the above factors among other things is now challenging this perception.

RENEWABLE ELECTRICITY CHANGES THE MARKET DYNAMICS

To a certain extent, all the above issues are interrelated. But the most fundamental and destabilising change in the market has been the introduction of substantial amounts of renewable capacity, based on various forms of incentive schemes. In effect, this capacity could be considered "must run" capacity with near zero marginal cost – so despite being intermittent, it displaces thermal capacity when operating. Given the environmental objectives of this investment, one would assume that the capacity being displaced would be older coal plant with high carbon intensity. However, relative fuel economics, low EU ETS certificate prices and other factors have had led to the displacement of gas capacity, rather than coal, in many markets. This is a paradoxical situation, but one which is expected to continue for some time. Going forward, it is evident that significant amounts of older coal capacity will be retired in view of the imminent deadline of the Large Combustion Plants Directive and the Industrial Emissions Directive. The same applies to substantial nuclear capacity, either due to age or as a result of political decisions.

Does this mean therefore that there will be a boom in investment in new nuclear and cleaner CCGT capacity to fill the gap and balance the boom in intermittent renewable capacity? The

answer is not clear in the medium term as much depends on the level of renewable development materialising and also on policy decisions and market reviews aimed and apparently rebalancing the playing field for all generators. Fundamental market/policy reviews underway in the UK, Spain and elsewhere currently make it very difficult for financial institutions to evaluate which technologies in which countries will be "economic" and over what timeframe. This in turn makes it very difficult for us to commit finance in the power sector over the 15 year plus time horizon necessary for this kind of utility investment, unless we have a PPA with a strong counterparty such as a vertically integrated utility, capable of underwriting this market uncertainty risk. However, as indicated below, this type of arrangement is not generally available in Europe at the moment for a number of reasons.

SOFT DEMAND SIDE OF THE EQUATION IS COMPLICATING THE PICTURE

The final complicating factor is on the demand side where outlook is impacted by the prolonged economic recession and increasingly by energy efficiency, which could become more significant, following the recently issued Energy Efficiency Directive ("EED") in electricity usage, amongst other things. These have led to a decline in energy demand in many countries of the region. Taking the UK domestic appliance power consumption as a proxy for consumer driven demand for electricity over the whole of Europe, it is evident that energy efficiency savings have offset the increased demand for the period 2000 to 2010 to a certain extent. Progress on the EED energy savings targets will be reviewed in 2014 and should they be insufficient, is likely to lead to mandatory national energy efficiency targets. As such, the overall soft demand is considered to continue for the short to medium term, thus complicating the investment decision for generation capacity.

Whilst replacement rather than demand growth has been a major factor in investment decisions for Europe, the decline in demand for generation has further increased the reserve margins on many systems and has been further exacerbated in the short term by commissioning of capacity already underway before the worst of the recession hit. If the markets function properly, low margins on capacity will eventually force the closure of the least economic capacity which will, together with forced closures for environmental and policy reasons, rebalance the market as has been seen in previous over-build situations (in the UK and US for example). However, the argument for this is less compelling for the financial community at the moment as we see various "interventions" in markets that potentially change the fundamentals, including:

- Continued development of significant renewable capacity on a subsidised basis, but also the potential restructuring of renewable incentive schemes in much of Europe;
- Potential for the introduction in some markets of carbon capture & storage (CCS) capacity, presumably on a similarly subsidised basis;
- Potential for the wider introduction of capacity payment mechanisms in individual member states to encourage the availability of reserve thermal capacity to balance renewable intermittency with the added uncertainty of related policy at EU level;
- The legally binding demand reduction targets of the new EU Energy Efficiency Directive agreed in September 2012 as discussed above; and
- The potential reform of the EU ETS to create a more significant penalty for CO_2 emissions (the UK having already introduced a carbon floor price mechanism).

POLICIES IN PROGRESS TROUBLING FINANCIERS

Financial institutions can analyse and price risk if they are able to understand the risk. The issue now being faced is that many of the above factors are "work in progress" with, to a certain extent, uncertain outcomes. There is therefore a real risk that financial institutions will sit on their hands and wait for these issues to wash through before assessing whether the European power

markets are bankable. Due to the reliance on debt financing, this will inevitably mean that the development of independent generating capacity will also be stymied. Is this significant for Europe's immediate energy security? Possibly not at the moment, but with the scale of upgrade and replacement investment required across Europe in the coming 10-15 years, debt of some form will be a crucial component of the ability of the sector to deliver the investment required, as even the largest utilities are facing pressure on their balance sheets (and ratings), with a number already considering asset sales to finance their investment needs. Without regulatory and policy clarity in the sector, utilities, rating agencies and the financial community will take a very cautious view across the sector, and for financial institutions that can translate into very selective lending or actively avoiding the sector altogether.

Finally, it has to be recognised that the global financial crisis has impacted on the balance sheets of the financial institutions that have traditionally financed the European utilities business on both a project and corporate finance basis. This has manifested itself in a reduction of liquidity for the sector as institutions have either refocused their operations or withdrawn from the market completely. More significantly, this has led to a change in the risk appetite of institutions as financing regulatory changes such as Basle III change the way these institutions look at their own capital structure and balance sheet usage.

WHERE WILL THE INVESTMENTS GO?

As with all sectors requiring investment, the European power market has to compete on a global basis to attract capital to invest in projects. Having said all this, financial institutions are flexible, innovative and able to adapt to regulatory change as has been demonstrated through many years of change in the sector. An example of this is the recent financing of an 800MW CCGT new build in the UK which was financed on a non recourse basis despite low spark spreads. The Sponsors in that project were able to take more robust projections on future spark spreads however few such projects are reaching financial close given the regulatory uncertainty inherent in such projects impacting new generation capacity. In the end, those most active in the sector – whether utilities, developers or financial institutions – realise that there will inevitably be a need for changes in market structures and regulation to adapt to changing circumstances. The real problem for financial institutions is not necessarily the change itself but the uncertainty surrounding the implementation of change. There is no doubt that in the current European power markets there is a period of unprecedented and fundamental change underway. The risk is that this will lead to (and in fact we are probably already seeing) an extended period of hiatus whilst the "new" market structures are implemented and settle down before financial institutions are willing to commit significant capital to the sector. In the interim, many international financial institutions have the ability to quickly switch their focus to other, more attractive markets. Drawing back the interest of these institutions may not be as easy if there is a prolonged period of instability. Confidence takes a long time to build in financial institutions but is easily shattered.

Part IV – Investment Prospects by Technology

MAINTAINING SYSTEM STABILITY IN AN EVOLVING GENERATION PORTFOLIO - FRANZ BAUER, VGB POWERTECH

The European electricity sector is facing a major challenge in meeting political targets on the one hand and the requirements for secure and affordable supply on the other. The EU's 20-20-20 targets, enhanced by the different support schemes for renewables (RES) in Europe, have resulted in a tremendous increase of RES capacity in Europe. Incentives to increase the share of renewable electricity include mainly taxes, feed-in tariffs or others measures in combination with priority dispatch.

A RADICALLY CHANGED ROLE FOR CONVENTIONAL POWER PLANTS

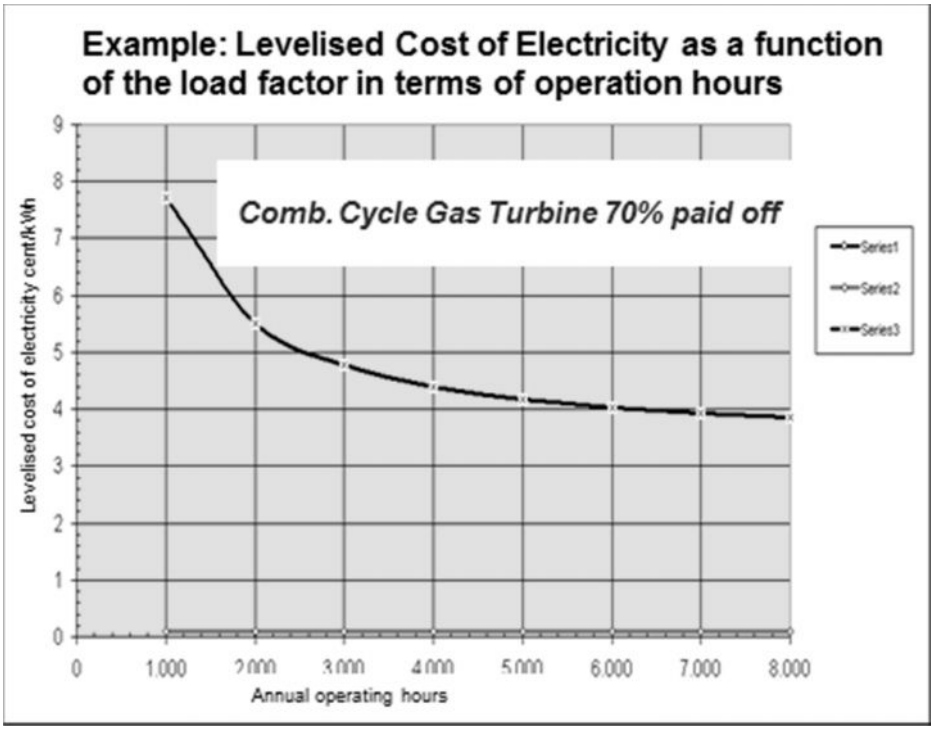
The supply pattern has also changed drastically, with an increasing share of variable RES generation, which is determined by the weather conditions rather than customer demand. As a result, the system has to be balanced by the residual conventional power plants with their planning capability at any time. The generation pattern of those residual power plants is closely linked to that of RES – and is characterised by high requirements for a very flexible operating mode following the ups and downs of the RES pattern.

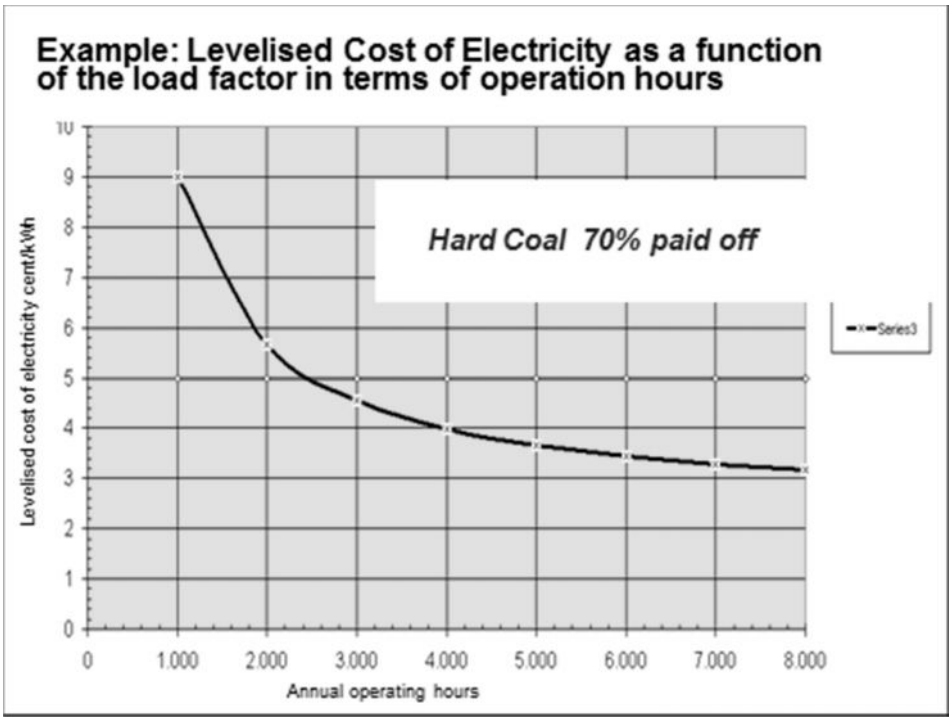
DECREASING PROFITS AS A CONSEQUENCE

The new role of conventional generation is radically affecting its profits. In a liberalised market the price is determined by the marginal power plant selected at the power exchange. The order in which power plants come online is described by the so-called merit order, which depends on the marginal costs of different forms of power generation. The priority dispatch of RES lowers the overall price level because the dominance of the cheapest generation part of the conventional fleet shifts the curve to the lower side. Shifting the merit order towards lower cost forces conventional generators to a tremendous pressure on costs. In addition, the priority dispatch of RES leads to a reduction of their operating hours, making it challenging or even impossible to generate electricity without losses.

The general cost structure of power generation is such that reducing the operating hours drastically increases the cost (Figure 10). VGB regularly investigates the capital expenditures (Capex) and operational expenditures (Opex) of power generation. The results show that the costs are no longer covered by the markets. Even depreciated plants in terms of Capex are no longer commercially viable.

Figure 10: Cost structure of power generation





Source: VGB Powertech

TASK OF THE CONVENTIONAL FLEET

This flexible operation mode leads to a much higher wear impact on the plant components, reducing their life time and increasing the maintenance cost as well as eventually the overall unavailability of the power plants. Statistics for availability and unavailability – distinguished by

planned and forced outages – clearly indicate an increase of planned outages, i.e. major maintenance interventions due to repair and upgrading measures, and forced outages, i.e. components approaching the end of their life time and higher damage rates due to frequent load-following operation.

This has a major impact on the generation fleet as a whole because Europe has an ageing fleet: about 70% of conventional power plants are older than 30 years. There is a growing need to replace old units.

INCENTIVES FOR INVESTMENTS MISSING

In this context the role of the regulatory framework is highly relevant. The framework is set by support schemes for RES on the one hand and the EU Emissions Trading Scheme on the other. The two simultaneous approaches overlap and contradict one another: the high RES percentage in generation decreases the demand for CO_2 allowances and creates a surplus of CO_2 allowances. Low prices for CO_2 allowances are undermining the original intention of creating incentives for innovation and investments in new low-carbon power plants.

The conclusions are relative simple: there are no incentives to invest in residual conventional power plants although such investments are needed in order to modernise the ageing power generation fleet and meet the new emission limits. The interference between the EU ETS and RES support schemes is to blame – an indication of the urgent need to harmonise the regulatory framework. Beyond this very important issue the technological challenge is one of the top priorities: without innovation – in RES and conventional power plants – future power supply will neither be secure nor affordable, nor will the environmental targets be met.

THE ECONOMIC CRISIS CHALLENGING RES DEVELOPMENT IN EUROPE - PIERRE SCHLOSSER & NIINA HONKASALO, EURELECTRIC

Europe has experienced a strong growth of renewables over the last decade. This development has added a new set of technologies to the existing power generation portfolio and has thus contributed to diversification, security of supply, and the shift towards a greener, low-carbon economy. Renewable energies form indeed a group of more than ten different technologies, with different levels of maturity and deployment.

Renewable electricity has long played a particularly important role in some EU countries that can be considered forerunners. The development of RES in Europe started mainly with wind power in a limited number of countries, before enlarging especially to PV and biomass, as well as other renewable technologies across Europe – indeed pushed by the EU legislation since 2007 and 2009. In recent years European governments have spent increasing amounts of money to incentivise investments in renewable power generation and meet the renewable energy targets set by the European Renewable Energy Directive[10].

Yet as the economic crisis persists, public acceptance for the most expensive RES technologies is becoming more fragile. Learning curves for PV in particular, but also wind, due to large-scale deployment have in a way overtaken the support schemes – ensuring high profits for investors, but a huge burden for retail customers. In many countries there is therefore a need to reform support schemes for the sake of cost-efficiency, while ensuring that no retroactive changes take place and that RES development continues. There is no question about the 'what' of RES development, but of the how, and of the level playing field with other technologies.

The country and technology overview below provides an overview of current challenges and recent geographical and technological trends related to expanding RES capacity in Europe.

SUPPORT SCHEMES UNDER REVISION

In **Spain**, a freeze on all types of RES support subsidies was adopted in February 2012. New plants will not be admitted for support until 2017. This decision aimed at curbing the country's € 24 bn "tariff deficit", an enormous liability that constitutes the legacy of Spanish RES policy, in which poorly designed and overly generous support schemes led to unsustainable bubbles. The move is seen by some RES investors as a necessary step to put RES development onto a more sustainable track and avoid over-compensation and burst-and-bust cycles like those that took place for PV and CSP.

Italy held the record for newly installed PV capacity in 2011 and has experienced a tremendous expansion of capacity (around 9 GW). But the government has now become keen to recalibrate RES support schemes to avoid overheating and to reduce support in line with cost developments, without however crippling a growing industry. In July 2012, the government thus signed decrees on new RES support schemes which – further to a transition period – will cap the amount of spending granted annually to RES technologies at 500 million euros (200 million for PV).

Germany saw its support for PV slashed in spring 2012 by 20-30% (depending on the size of the installation). Moreover, policymakers ensured that a limit to its annual development was set to 2,500-3,500 MW, and the overall installed PV capacity eligible for policy support was capped at 52 GW. Support designs and notably the market exposure conditions for wind onshore capacities were revised and some concerns were expressed concerning the existing type of support

[10] EU Directive 2009/28/EC

schemes (feed-in tariffs and premiums), with some voices advocating a move towards a renewable obligation scheme[11].

In **France,** the development of onshore wind is continuing while the growth of PV has been more limited, mainly due to a moratorium on new support schemes implemented in 2010. Support for PV has now been reduced and a tendering process has been introduced for installations larger than 100 kW. The policy focus seems to have shifted towards offshore wind and, beyond renewables, to energy efficiency. A new energy concept will be coined over the next months, further to a change of policy direction promoted by the newly elected French President François Hollande, who is keen to reduce the share of nuclear power in the French electricity mix to 50% by 2025.

In the **UK**, the government has introduced, throughout 2012, an array of revisions to policy support for all RES technologies. This included far-reaching changes to PV support such as: a reduction of the generation tariff for new PV installations from 1 August 2012, a reduction in the tariff lifetime for new PV installations from the current 25 years to 20 years as of 1 August 2012, and the introduction of a digressive mechanism that will reduce generation tariffs on a quarterly basis, based on PV deployment. The government is now clearly prioritising offshore wind as a key technology to support in the coming years and is promoting it generously as a result.

Finland adopted in 2011 a premium feed-in tariff system as the main measure to support renewable electricity. The feed-in tariff had the effect of raising interest in broad expansion of wind power among Finnish producers for the first time. However whether Finland reaches its renewables targets largely depends on how well it manages to further increase the already high share of wood-based fuels. Since 2011, the scope of the support for renewable electricity has already been slightly diminished and reducing the premium for wood chips is under discussion. At the same time, the parliament is debating a proposal to introduce a higher tariff for co-firing of biomass. New measures to bring more energy wood to the market are late, and the overall regulatory framework for biomass energy has lately been in constant change although political will for its promotion exists.

Sweden has so far proven to take a more constant approach to renewable electricity support. For almost ten years the country has been using an electricity certificate system to increase the share of renewable electricity. Long-term targets contribute to the reliability of the system: in Sweden the annual share of renewable electricity to be sold has been set until 2035 [12].

Norway joined the electricity certificate system in 2012. This joint certificate scheme between Sweden and Norway is a positive development as it constitutes the first use of the cooperation mechanisms foreseen by the RES Directive; moreover, it could be potentially expanded to other member states. Given the current gloomy economic context, it is disappointing that member states do not express interest in using the cooperation mechanisms to reduce the cost of complying with their targets – especially for member states with higher GDP (and therefore higher targets) but relatively low RES potential, and therefore expensive national RES resources.

In **Poland** the production of wind electricity and electricity from biomass especially have increased during the last ten years and the annual target for renewable electricity generation has even been exceeded in 2012. The Polish government has been preparing amendments to renewable energy support, including the green certificate system, for two years, and the proposal

[11] RWI Marktwirtschaftliche Energiewende: Ein Wettbewerbsrahmen für die Stromversorgung mit alternativen Technologie, August 2012.

[12] http://www.energimyndigheten.se/Foretag/Elcertifikat/Om-elcertifikatsystemet/

was published in July 2012. The proposal has been criticised as it suggests a ceiling for the price of renewable electricity and cuts the support for biomass[13][14].

Estonia promotes renewable electricity mainly with a premium tariff, but investment support is also provided for certain renewable energy technologies. As a consequence, renewable electricity generation has increased rapidly over the last few years. In 2011 the Estonian authorities concluded that the profit margins for renewable energy producers have been too high, and a decision was recently taken to cut the renewable premiums by 18% in 2013.

The majority of existing RES support schemes in Europe is based on feed-in tariffs/premiums which entail long-term commitments – from 15 to 25 years, but usually 20 years – that aim to guarantee future cash flows for investors and customers alike. This means that regardless of political choices for the support of RES after 2020, European member states will already have made financial commitments until 2032 – or indeed up to 2037. As renewables support leads to such long-term liabilities, it is important to use the money wisely.

EVOLVING PATTERNS OF RES DEVELOPMENT

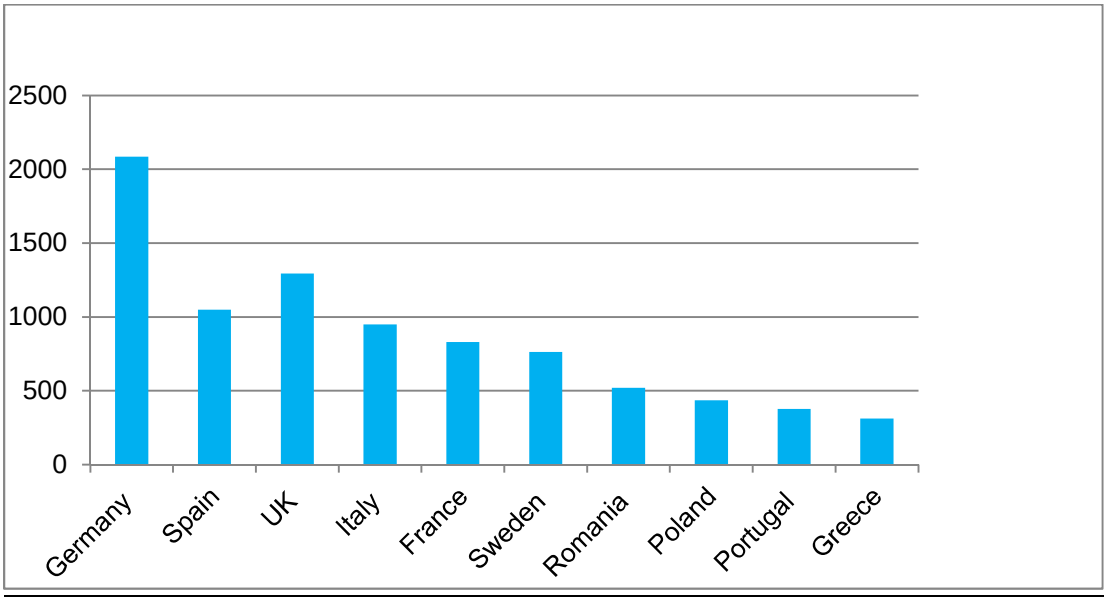
The support schemes have led to a rapid increase in renewable electricity in Europe. The short overview of solar and wind power and electricity produced from bioenergy below gives an impression of recent developments in the deployment of renewable technologies. Although these renewable energy sources were selected as examples, other renewable electricity technologies such as hydropower have of course an instrumental role to play. Moreover, the pattern of RES deployment is changing: the expansion of renewables is becoming both more balanced between different technologies as well as geographically speaking, with more countries than ever investing in RES.

Wind investments in Europe used to be mainly driven by onshore wind in Germany and Spain. Yet the picture is changing. Deployment in Spain has slowed down while the UK (notably thanks to offshore wind) and Italy are catching up.

[13] http://www.psew.pl/en/component/k2/item/624-lawyers-warn-the-new-draft-res-act-features-substantial-shortcomings

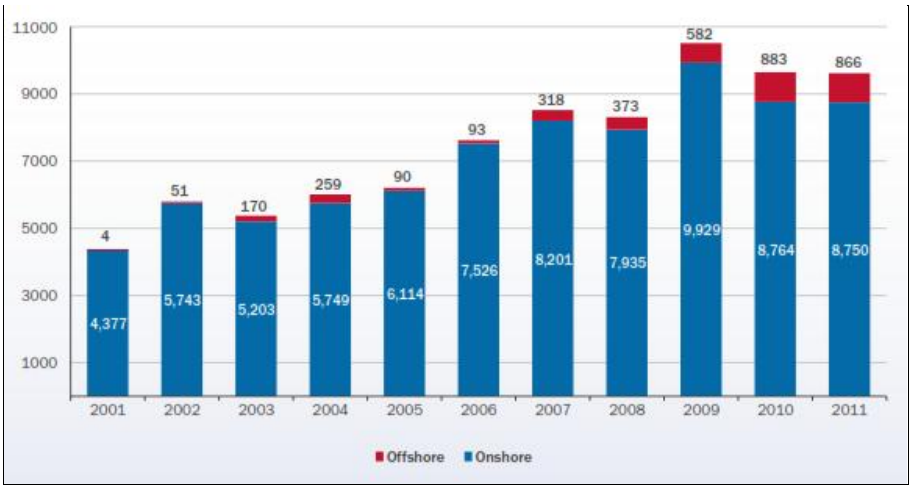
[14] http://www.ft.com/intl/cms/s/2854ffe0-ab0a-11e1-b675-00144feabdc0,Authorised=false.html?_i_location=http%3A%2F%2Fwww.ft.com%2Fcms%2Fs%2F0%2F2854ffe0-ab0a-11e1-b675-00144feabdc0.html&_i_referer=#axzz2AlqrHbDW

Figure 11: Newly connected wind capacity in 2011 (MW)



Source: EWEA

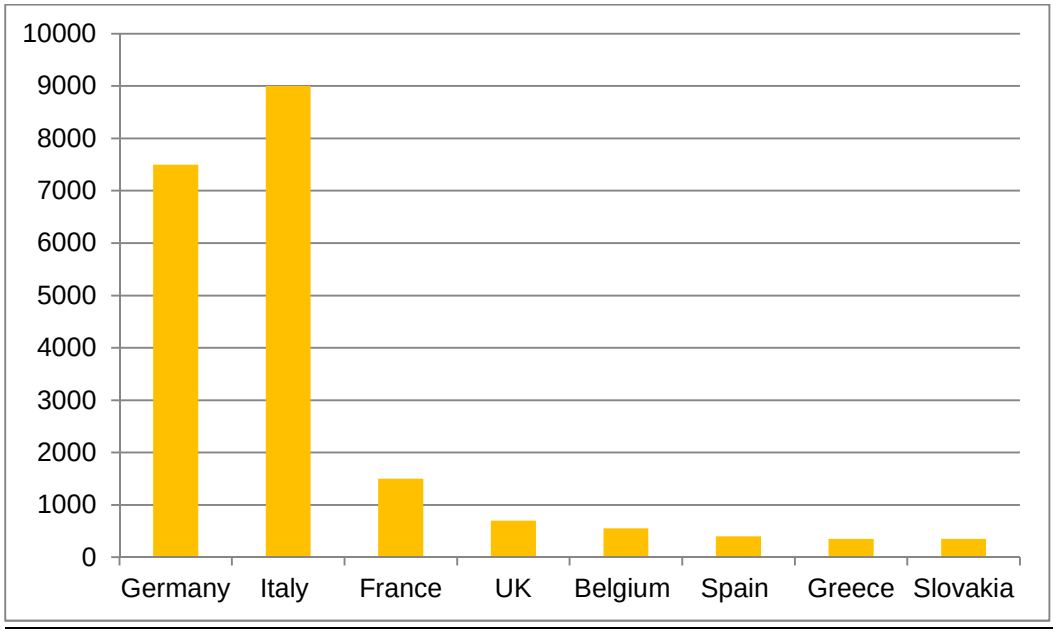
Figure 12: Annual installation of onshore and offshore wind in the EU (GW)



Source : EWEA

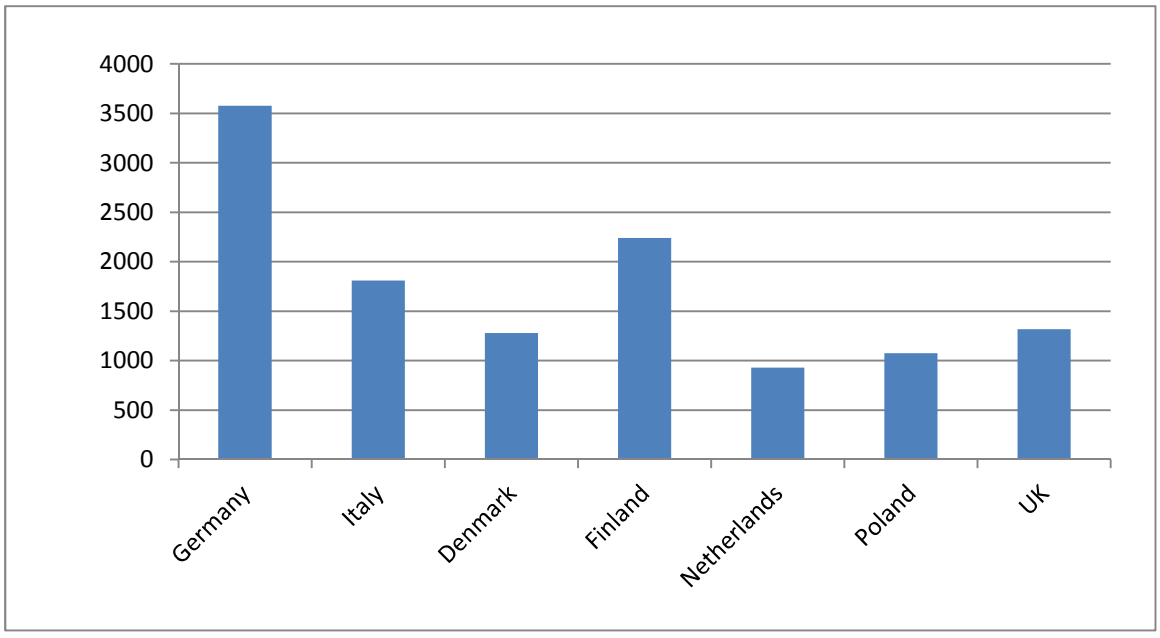
2011 was a turning point for **photovoltaic** in Europe, as Italy overtook Germany in terms of newly (yearly) added PV capacity, adding around 9 GW. Spain saw a sudden drop to only several hundred MWs, while France added around 1.5 GW.

Figure 13: Newly connected PV capacity in 2011 (MW), Source: EPIA



Total electricity production from biomass, biogas and renewable waste in the EU grew by 16.1 TWh from 2009 to 2010. Beyond the electricity sector, the contribution of biomass to renewable energy consumption is naturally considerably larger, with biomass being used mainly for heating and the use of biofuels for transport contributing as well. Within the electricity sector, biomass, biogas and waste are used in both electricity-only and combined heat and power plants.

Figure 14: Increase in power generation from bioenergy from 2009 to 2010 (GWh)



While renewables have spread in Europe, the IEA's 2012 Medium-Term Renewable Energy Market Report[15] shows that renewable deployment is projected to spread on a global scale as well, with increased activity in emerging markets. The forecasts predict that non-OECD countries

[15] Renewable Energy – Medium Term Market Report 2012, Market Trends and Projections to 2017, IEA, 2012

will account for two thirds of overall RES growth in the next five years, with China taking a 40% share. The IEA's regional breakdown of new RES generation additions for the period 2011-2017 sees OECD America gaining 179 TWh (mainly in onshore wind); OECD Asia-Oceania adding 77 TWh (mainly in solar PV); OECD Europe gaining 365 TWh (mainly in onshore wind, followed by hydropower and PV). The non-OECD countries see an increase of 1,220 TWh (mainly in hydropower, followed by onshore wind).

CONCLUSIONS

While the reforms of support schemes have in many cases taken place suddenly and in a manner that led to increased regulatory risks, common trends can be detected. First, member states are striving to get more value for their money and are therefore increasing the cost-efficiency of their support schemes. Overly generous tariffs have been cut in many countries.

Due to the ever more challenging grid integration of renewable electricity, some countries have witnessed a growing interest in more market-based support schemes. The signals that indicate trends towards cost-efficiency and more market-based approaches should be encouraged at European level. While the economic crisis continues, Europe will have to rely on an approach based on cost-efficiency to both reduce emissions and contribute to the competitiveness of the European economies.

This is why RES technologies should take on the same market responsibilities as other power generation technologies: such a step would contribute to both a cost-efficient market integration of renewable electricity and an optimal allocation of resources. RES technologies should carry out their scheduling and operation like any other generation technology, should participate in the wholesale markets and should be subject to equivalent obligations regarding grid connection, balancing, grid charges, etc. In some cases this could require an adjustment of support mechanisms to ensure that new costs imposed on RES generation (such as balancing costs) are correctly considered. The European Commission should take prompt and decisive action to bring RES technologies to equivalent obligations, so that progress can be made well before 2020. It goes without saying that EURELECTRIC, which supports a 'use them all' approach and has no preference for any particular technology provided it respects the market framework and the decarbonisation requirements, does not support subsidies for any technology, and calls for transparency on all support schemes where they exist.

Despite the growing interest of some countries in more market-based approaches, the large majority of support schemes continue to rely on technology-specific support, which contributes to the distortions in the market. With feed-in schemes, governments select the supported technologies by setting specific levels of support for each technology. Certificate systems by contrast provide a uniform level of support for all technologies. This approach provides more flexibility for market players to select the technically and economically optimal renewable electricity technologies.

Power companies and investors alike need stable regulatory frameworks to be able to judge which investments make the most economic sense. European and national policymakers must abandon their current tendency to intervene in a somewhat stop-and-go fashion, disregarding the need for a clear, effective, consistent and supportive framework. Some international experts have already voiced the concern that this could be a make-or-break moment for renewables development in the EU. Indeed, globally, it is expected that more and more deployment of renewable electricity will take place outside of Europe.

In the longer term, it is important to progressively phase out subsidies for RES technologies in Europe once key technologies reach market competitiveness and broad deployment, and to focus

public support on research, development and deployment. Support for RD&D is not only necessary on our path towards sustainable development, it is also critical to avoid creating the type of market distortions that exist today. Policymakers need to take the above issues into account if they want Europe to be able to carry out its energy transition with confidence – as our industry would like to do.

HYDRO INVESTMENTS UNDER STRESS - PEDRO NEVES FERREIRA, EDP

Large hydro has been, since the 1950s and 1960s, a large part of the generation mix in Portugal. It accounted for 95% of total annual output at its peak in 1960, and has since gradually declined in share, currently reaching about 22% of the total annual output in an average hydro year, with about 4,600 MW installed capacity. The volatility of hydropower generation is significant, with output in particularly dry and wet years varying from the average year by up to 50%.

With few exceptions[16], new large hydro projects were stalled in Portugal since the early 1990s. In the mid-90s, a large project was stopped midway through construction, following a decision to avoid flooding of pre-historic engravings. An alternative project was identified but was under dispute at the European Commission level for environmental issues. As a result, construction only began 15 years after the previous project was cancelled.

NEW IMPETUS FOR LARGE-SCALE HYDRO

There are several reasons that make hydro investment compelling both for power producers and society at large. Hydro is a competitive power generation technology, using a clean, indigenous resource and with significant local content. In Portugal, it will be a critical component to comply with the EU's 2020 objectives as well as to provide the needed flexibility to accommodate variable generation, which is set to grow significantly. Additionally, hydro offers a variety of benefits that go beyond the electricity system, such as strategic water reserves, stream and flood regulation, and coherent, inclusive regional development.

In 2007, the Portuguese Government decided to give a new impetus to large hydro projects and launched the National Hydro Plan. A list of ten projects was identified and a series of four tenders organised. Participants had to submit a bid, still subject to approval after licensing and environmental procedures, to build and operate the plants under the spot market during the concession period.

Altogether 2.0 GW were awarded in the tendering process, to companies EDP, Iberdrola and Endesa. Additionally, several projects still frozen in licensing procedures were finally advanced, including the one stopped in the mid-90s, and a new law was passed to incentivise repowering of the existing fleet. In total, 4.9 GW of new hydro projects are planned, with 0.4 GW already operating and 1.6 GW under construction.

Yet despite this new impetus, concerns remain. Deteriorating credit conditions, increased regulatory risks linked to the stop-and-go fashion in which policies are often applied, long permitting procedures and low wholesale power prices are delaying construction of several projects, while environmental constraints during the licensing procedures have led to other projects being revised. While credit conditions are tied to the larger issue of the eurozone crisis, providing regulatory stability and longer-term visibility on projects' returns can be addressed by reforming the power market design.

AN INVESTMENT-FRIENDLY FRAMEWORK FOR HYDROPOWER

Hydro, like other CO_2-free power generation technologies (excluding biomass and, to a lesser extent, coal/gas with CCS), has a high share of CAPEX and fixed costs, and a low share of variable OPEX costs. As a consequence, once a plant is operating, generators cannot meaningfully improve its cost-competitiveness, be it in a context of either high or low power prices – it's a sunk cost. The key element for cost-competitiveness is the cost of capital, set ex-ante. Therefore the market

[16] Notably Alqueva, a 240 MW plant with a very large reservoir, an old project built mainly for irrigation purposes

design should increasingly feature a lowering of risk premia through longer-term contracting. Additionally, competitive pressure should focus on the moment when the investment is made. This could for example be achieved through tenders of long-term power purchase agreements. Finally, spot prices will continue to be relevant as short-term optimisation and dispatch signals, even if with progressively lower liquidity.

A correct risk allocation is key: generators can manage construction and operational risk, but not policy risk. Decarbonisation targets lead to significant capital investments, which could turn into stranded investments if, for example, carbon policy is changed. In short, policy risk makes project bankability more difficult: greater visibility is needed as regards the return on investment.

HOW CAN WE INVEST IN NUCLEAR POWER? - MICHEL MATHEU, EDF

Investment in nuclear is at a crossroads. Nuclear is one of the very few low-carbon technologies which can contribute to the necessary decarbonisation of electricity generation and thus of the whole economy. Nevertheless it faces an uncertain investment climate.

Why is this the case? Some reasons are common to nuclear and other low-carbon technologies. Nuclear is capital-intensive. Gas-fired generation can boast much lower capital costs, and even carbon-fired generation is better off in this regard. Even if nuclear is much less capital-intensive per kilowatt-hour generated than offshore wind or photovoltaic, the business plan of a nuclear plant requires such high expenses upfront that it takes decades to reach the break-even point.

This situation is impacted by the fact that a lot of time elapses between the initial investment decision and the commissioning of a plant. Public debate, permitting procedures, and the dialogue with safety authorities impose an even longer preparation period than what is usual for coal-fired generation. A time span of 8 years between decision and commissioning is a minimum and 10 years are not unusual in some countries.

As a result, nuclear investment is strongly impacted by economic and regulatory uncertainties. It clearly remains possible for countries that include nuclear generation in their energy climate strategy to invest in new plants. Even after Fukushima quite a few countries have announced or confirmed very significant investment plans. The most ambitious ones are located outside of Europe: in China, Korea, India or the Gulf states. The question for Europe, where the nuclear option is still open in 16 member states, is: which conditions should be met in order to enable future investments and avoid becoming dependant on equipment and technologies from third countries?

TWO CHALLENGES TO BE TACKLED

First of all, the financial amounts involved are huge. On the one hand a new nuclear plant is worth several billion euros. On the other hand realising heavy maintenance and life time extension investments in existing plants and complying with safety rules agreed upon after Fukushima is extremely costly: for example about 50 billion euros will have to be invested in the French nuclear fleet to these two purposes. Furthermore the required technological expertise is such that only companies with very high scientific and technical skills can compete.

Middle-sized actors have not participated in such a game alone. In the relatively well-off macro-economic situation 10 or 20 years ago large integrated utilities were able to develop the required R&D, to maintain powerful engineering divisions and to raise the necessary funds on a corporate finance basis. In a situation of capital scarcity the required investment costs appear now more difficult to raise.

The second issue is that the regulatory framework, in particular regarding CO2, is far from predictable. Until the beginning of the current economic crisis, a high carbon price after 2020 appeared very likely. In such a context some low-carbon generation like nuclear was significantly more competitive than fossil-fuelled generation. Unfortunately there is not enough certainty today regarding the future regulatory framework and the level of prices delivered by the EU Emissions Trading System. As a result, the business plan of a nuclear plant to be commissioned around 2020 has become highly problematic.

As clearly shown by EURELECTRIC's Power Choices scenarios, which are currently being updated, it is impossible to reach ambitious decarbonisation targets by 2050 at an affordable cost without investing in maintenance and upgrading of existing nuclear plants and building new ones so as to

maintain a nuclear share of above 20%. To this end, a sufficient carbon price and a reliable regulatory framework are needed.

Part V – The Regulatory Framework We Need: Recommendations

COMPLETION OF THE COMMON ELECTRICITY MARKET IS A MUST - HAKAN FEUK, E.ON

Chair of Task Force Market Design for RES of EURELECTRIC

EU electricity markets are experiencing fundamental changes as a result of the EU's policy goals, especially the 2020 renewables (RES) targets. The need to generate a large share of electricity from RES reduces the operating hours and profitability of flexible and back-up generation technologies, such as gas turbines or combined cycle gas turbine plants. However, the latter are necessary to cope with RES intermittency and unpredictability. In some EU markets, their lower levels of expected profitability are significant, raising concerns about future investment decisions and thus generation adequacy.

Academic theory argues that "energy-only" markets would function perfectly if prices were free to rise well above the marginal operating costs during scarcity hours, up to a level determined exclusively by consumers' willingness to pay that price. However, in current electricity markets such "scarcity prices" are reached only at some limited moments, and the revenues generated by price spikes have generally not been enough to cover the fixed costs of "peaking" plants.

If this situation persists, the necessary flexible and back-up generation capacity could eventually be closed and not replaced by new investments. To avoid this, the design and functioning of today's electricity markets must be improved.

To enhance electricity markets' ability to deliver generation adequacy, governments and regulators must first of all allow energy-only markets to function properly. To this end, distortions which hinder the balance of demand and supply must be removed. Such distortions include regulated end-user prices, restrictions on plant operations (such as prevention of plant closures), price caps, and other regulatory or administrative measures which unnecessarily hinder wholesale market outcomes.

At the same time, integration of wholesale markets must remain a top priority for EU and national policymakers. Efforts should thus concentrate on implementing the Target Models of day-ahead market coupling, intra-day and forward markets to fulfil the objective of an EU integrated market by 2014. This process should be accompanied by the strengthening of transmission capacity (both domestic and cross-border) and the establishment of regional balancing markets.

Most importantly, and with a view to enhancing and speeding up the integration of renewables into the EU system, RES generators must be incentivised to progressively enter into the market on a level playing field with all other generators. In particular they should be incentivised to sell their own production into the market as well as to meet scheduling, nomination and balancing requirements as other generators do. In addition, there should be harmonisation towards European-wide market-based support mechanisms: this would expose RES generators to market prices that reflect demand and supply variations and would also allow substantial cost reductions.

Enabling market-based demand to participate in wholesale market spot price formation is fundamental for a well-functioning electricity market, although very difficult to achieve. It would considerably decrease not only peak capacity demand, but also the need for "back-up" plants. Enabling demand response must therefore be a core element of current energy policies.

In markets where all the above improvements have been made and generation adequacy is nevertheless endangered (through reduced investments and early decommissioning), policymakers should consider introducing a capacity remuneration mechanism – ideally at a regional level or at least in coordination with neighbouring markets. In any case, consistency with the process of EU market integration should be ensured.

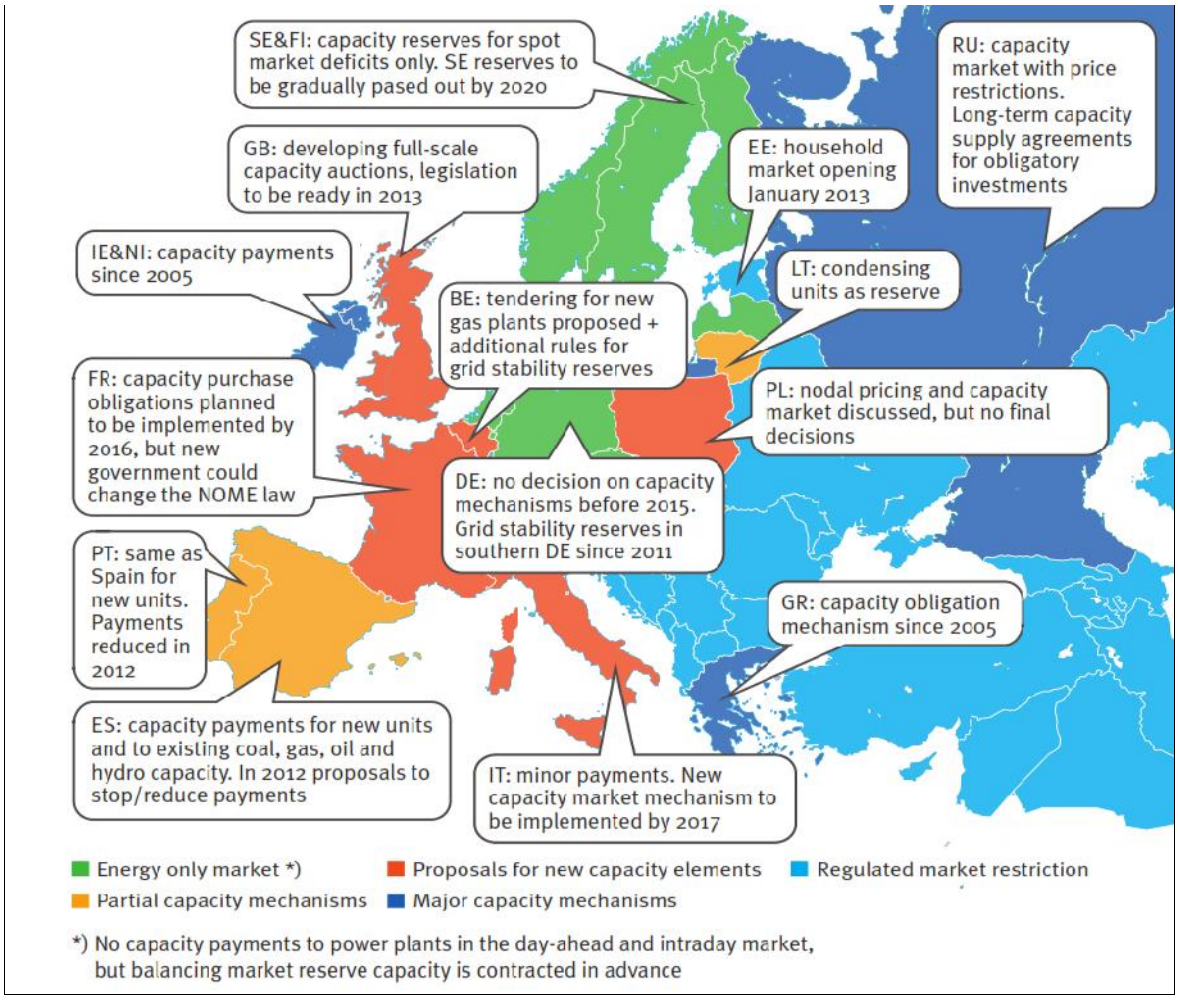
If introduced, capacity remuneration mechanisms should be able to be phased out once the market itself delivers the appropriate investment incentives to ensure the adequacy of the system. In practice, the implemented model, while ensuring sufficient regulatory stability, should produce effects only as long as the underlying problem of generation adequacy requires an additional solution to complement well-functioning wholesale markets. However this must be part of the market design to ensure a predicable regulatory environment.

Finally, while an EU-wide harmonisation of existing or future capacity remuneration mechanisms may be premature and unnecessary at this stage, EURELECTRIC calls on ACER and the European Commission (in cooperation with all relevant EU and national stakeholders) to start working on the development of a set of minimum EU harmonisation requirements. This should ensure the well-functioning of regional markets and compatibility with the aim of reaching an Internal Electricity Market by 2014. In addition, developments in national markets – in particular the implementation of the Target Models – should be closely monitored to ensure this political objective is met.

ONGOING INITIATIVES ON CAPACITY MECHANISMS

Capacity mechanisms are part of the market design in several member states and the introduction is discussed in several other member states, as shown in the overview below.

Figure 15: Overview of capacity remuneration mechanisms across Europe



Source: ***EURELECTRIC***

The implemented/discussed capacity mechanisms are in most cases purely national, but the capacity payments in Portugal/Spain are harmonised and the strategic reserves in Finland/Sweden are harmonised as well. The national capacity mechanisms try to solve different problems. The strategic reserve in Finland/Sweden and the discussed capacity mechanism in France are designed to ensure sufficient capacity at high demand on cold winter days. The upcoming Italian capacity mechanism has a locational element that takes network bottlenecks into account.

Most on-going discussions on the introduction of capacity mechanisms are related to the expected reduction of running hours for conventional generation. But there are also many member states that are not considering the introduction of capacity mechanisms. The European Commission is evaluating the development of capacity mechanisms to make sure that possible national capacity mechanisms do not constitute state aid or hinder the creation of an internal energy market.

USE THE POTENTIAL OF INNOVATION - JOSÉ ARROJO DE LAMO, ENEL

Chair of Task Force Innovation Action Plan of EURELECTRIC

The world is changing fast, with new jobs, markets and products shifting towards emerging economies, while Europe is facing a deep recession. EU challenges include an ageing population and pressure on the welfare systems, and the fact that socioeconomic trends will shift economic growth eastwards. By 2030, 80% of the world population will live in Asia and Africa. A new middle-class population of 3 billion in the Asia-Pacific region will demand huge energy resources, most of which will be off-grid or more decentralised.

The energy sector is facing new challenges as well, which it has begun to tackle. The increase of intermittent renewable energy is one example: in 2010 investments in renewables exceeded investments in fossil fuels for the first time ever, with more than $211 billion. A record 30 GW of solar power was installed in 2011 – 10 times the level installed four years before – raising global installed capacity to 73 GW.

Achieving global low-carbon objectives will require a worldwide effort and an overhaul of the energy system, combining new technologies, energy security and affordability while reinforcing economic competitiveness. Significant investments need to be made in research, development, demonstration and market roll-out of efficient, safe and reliable low-carbon energy technologies and services. New technologies and solutions must compete on cost and reliability against highly optimised energy systems with well-established technologies – and also with non-technological solutions on both the supply and demand sides.

The EU's Energy Roadmap 2050 is a crucial strategic document for the energy sector and confirms the key role of electricity in reaching these challenging goals. But according to the European Commission and the IEA, investments of one trillion euros will be needed in the next 10 years. And unfortunately Europe still does not have the adequate regulatory framework or the minimum market conditions to promote this huge economic effort.

In this context, sustainable technology innovation is a fundamental driver of competitiveness, job creation and long-term economic growth. Especially for the energy sector, innovation can play a catalyst role in Europe, the skills and knowledge set, and creating employment and wealth – while at the same time ensuring decarbonisation as well as competitiveness and security of supply. Furthermore, the European market will continue to be as big as Asia in terms of capex on capacity installed for the huge growth expected in renewables (although the absolute amount of MW installed will be bigger in Asia). Speeding up this development will require a strategic approach, spanning energy supply, demand and use in buildings, services, transport and industrial value chains. It will also require mastering key enabling technologies, in particular ICT solutions and advanced manufacturing, processing and materials.

Unfortunately, in the past years, the EU has been lagging behind USA, Japan, South Korea and China on R&D spending and effectiveness – with the low-tech specialisation of many EU firms being one of the causes of Europe's innovation gap. Despite the huge incentives for the development of technologies like solar photovoltaic, today only one European company is included in the world's top 10 PV producers. Europe is also lagging behind on information and communication technologies (ICT) due to the gap in scientific specialism.

Governments have a crucial role in supporting the whole innovation chain through policies and legal frameworks. In recent years the EU has seen a massive proliferation of action, platforms, communities and R&D infrastructures. Nevertheless, these developments have not generated the expected level of success, perhaps because EU programmes appear largely fragmented,

uncoordinated and bureaucratic. Industry participation, which is also deeply affected by the economic crisis, is therefore in decline.

Europe will again miss its goal of achieving a level of R&D of 3% of GDP. Moreover, projections to 2050 show that the EU-27 share of patents will fall to 20%, although Europe is the world's largest market.

This issue has become a key priority for EURELECTRIC, which is working on an Innovation Action Plan and exchanging views with the Commission and other stakeholders to foster a stronger and more coordinated approach to innovation in Europe. R&D support needs to be available for technologies throughout the entire innovation cycle, including the final stages of development that ensure economic efficiency. Promising technologies require support in overcoming the final hurdles and risks before entering the market, with a very selective approach that allows funding uncompetitive technologies only up to their market effectiveness.

Pool efforts should support extensive programmes beyond the reach of individual countries, such as industrial demonstration and interoperable energy solutions. These demonstration projects will create innovation opportunities for small and large companies, fostering international partnerships and improving their competitiveness. A 'critical mass' is needed to attract interest from other technology leaders, and to re-position Europe as a key technology player in the energy sector.

The following recommendations could be put forward:

- Ensure an appropriate share of R&D funding for energy in the EU, and for the whole innovation value chain: research, development, demonstration, deployment (RD&DD) and market uptake of low-carbon technologies. The focus must be on accelerating their transition to competitiveness. Attribute a strong role to the SET Plan, and team up with industrial stakeholders to make it a success.
- Attribute a particular role to the development of smart grids, smart meters, demand side response, flexible and highly efficient power generation technologies and energy storage.
- Improve coordination with the member states, to stimulate cooperation among them on RD&DD, pooling international efforts to support high-risk, high-cost, long-term programmes (e.g. industrial technology demonstration projects and resource and energy efficiency programmes, especially through public-private initiatives.
- Establish priority areas for public funds, financing and guarantees and ensure EU intellectual property rights protection for supported technologies.
- Establish clear, stable standards and policies to support energy and resource efficiency in sectors that may not be easily responsive to pricing signals as a way to drive implementation and accelerate innovation.

CO_2 – THE KEY DRIVER FOR THE EUROPEAN ENERGIEWENDE - OWEN WILSON, ELECTRICITY ASSOCIATION OF IRELAND

Chair of the Environment and Sustainable Development Policy Committee of EURELECTRIC

The European electricity industry has supported for many years policymakers' desire to reduce the EU's carbon emissions. At a landmark meeting in March 2009, EURELECTRIC welcomed 61 CEOs from 27 European countries, where they signed a declaration which stated: "The power sector, as a significant emitter of greenhouse gases, needs to achieve a carbon-neutral power supply by the middle of this century." The emissions issue is, of course, global and EURELECTRIC has engaged with policymakers and its counterparts around the world to encourage them to address it. No less important, from the point of view of Europe's electricity industry and its customers, is that the subject should be addressed cost-effectively. This requires the integration of legislative and regulatory instruments that deliver multiple policy objectives.

Emission reduction involves the application of very significant resources and investments. Recognising this, EURELECTRIC has argued consistently that cost efficiency should be the primary driver in terms of the sequence in which abatement measures are applied. Based on this perspective we have promoted the concept of emissions trading, as it:

- guarantees delivery of quantitative emission reductions,
- ensures the efficient application of financial and other resources,
- supports the effective functioning of the electricity market and, through its carbon pricing signal,
- promotes investment in low-carbon technologies.

However today, because of overlapping renewable energy and energy efficiency support mechanisms, the price formation signal in the EU ETS has been distorted. As a consequence the objectives of cost-efficient emissions reduction and a market-based investment signal have been undermined. Furthermore, the effective functioning of the underlying electricity market has been placed at risk as the scale and penetration of technology-based subsidies has increased.

The behaviour of the ETS carbon market in response to these events has been taken by some commentators as a sign of failure, rather than an efficient market reaction, and pressure for a political response has grown. EURELECTRIC acknowledges the concerns expressed but considers an effective response should embrace all climate-related instruments (including RES and energy efficiency measures) at least for the period post 2020. Recognising the future scale of investments required and the current weak economic and difficult fiscal climates, EURELECTRIC would contend that a pragmatic approach should be adopted focused on cost efficiency.

On the basis of the above, EURELECTRIC proposes that:

- The EU continues to work towards delivering a comprehensive and equitable global response to climate change,
- The emissions cap trajectory and coupled ETS carbon market should be the key driver of cost-effective carbon abatement within the EU and, as a consequence, the carbon price should be the main driver of overall decarbonisation policies
- However, greater visibility beyond 2020 is required to recover confidence in the market and provide a clear investment signal. This should be delivered ideally through a firm 2030 emissions reduction target,
- As a result of a clear market signal and price and continued cost improvements in low carbon technologies, large-scale technology-specific subsidies should be progressively removed, and that

- The concept of energy efficiency, originally developed in the context of oil shortages, should be re-examined to take account of the carbon content of fuels so as to avoid perverse emission outcomes.

Adopting this approach can ensure emissions target delivery at least cost, supporting EU economic recovery; deliver a clear market-based signal which investors and innovators can evaluate and respond; and support the implementation of a competitive internal electricity market.

Background on Contributors

Fulvio Conti is CEO of ENEL, an Italian based world-wide integrated utility. He has been president of EURELECTRIC since June 2011. He is strongly focused on investments and innovation.

David Porter has been dealing with UK energy policy issues for 25 years and is well-known as a trade association Chief Executive and a commentator on energy issues in the press, radio, TV and at conferences.

In 2010-2012 David Porter led the work to merge three UK associations to create 'Energy UK' and he became its Chief Executive until his retirement in September. He is now involved in part-time work in the energy sector.

He has been a Board member of EURELECTRIC and until December 2012, Chairman of the Energy Policy and Generation Committee. He also chaired the Task Force on Investment.

Giuseppe Lorubio has worked as an advisor within the Energy Policy & Power Generation Unit at EURELECTRIC, the European electricity industry association, since September 2009. He specialises in conventional power generation, low-carbon technologies – including CCS and nuclear –, infrastructure development and scenario analysis and statistics collection.

Before joining EURELECTRIC, Giuseppe Lorubio held positions in both the private sector (at Enel's Brussels office and Italy's Bonatti SpA) and public sector (at the European Commission's DG Transport & Energy as a blue book stagiaire and at the Permanent Representation of Italy to the United Nations in New York). Giuseppe read political science at the Universities of Bologna and Firenze with majors in international relations and European studies, and is currently specialising in regulation of energy utilities at the European University Institute's Florence School of Regulation.

Pierre Schlosser is advisor in the Energy Policy and Generation Unit of EURELECTRIC, the European electricity industry association, where he is in charge of renewable energies and policy.

In the past, Pierre Schlosser has been responsible for several working groups within EURELECTRIC's Network Unit, including the WG Smart Grids/Network of the Future, WG Distribution Regulation and Policy and the WG Distribution Customers & Operation. Besides this, he has also been coordinating the work stream Networks and Demand Side Management within the EURELECTRIC RES Action Plan.

Prior to joining EURELECTRIC in 2008, Pierre Schlosser worked as a *stagiaire* in the European Commission's DG ECFIN. He holds a master's degree in economics (Sciences Po Paris) and a postgraduate master degree in EU economic studies (College of Europe, Bruges).

Ulrich Bang is the Director of International and EU affairs and the coordinator of the Danish Energy Association's (DEA) activities on the European stage. Throughout his career in the DEA Mr Bang has been instrumental in the work for better framework conditions for energy companies in negotiations between the industry and the Danish Government and has since 2010 been in charge of the activities in Brussels. Previously Ulrich Bang has been working for the Danish Energy Agency as a Policy Officer on Energy Efficiency and Climate Change.

Since joining the Danish Energy Association in 2004 he has been working on energy efficiency, renewable energy and energy markets. In 2008-2010 he left the DEA to work as a Sustainable Energy Advisor and CDM Project Developer for CARE International in Ghana. From the base in Ghana he worked on training programmes and development of household energy projects in Ghana, Uganda, Kenya, Tanzania and Sierra Leone besides being engaged in advocacy activities at COP14 and COP15.

Ulrich Bang holds a Master's degree in Socio Economic and Environmental Planning from the University of Roskilde.

Stefano Da Empoli is President of I-Com, the Institute for Competitiveness, a Rome-based think tank founded in 2005 and mainly focused on the energy, telcos&media and pharmaceutical sectors. He is also a lecturer in economics at the University of Rome 3. Previously, from 2002 to 2005, he was director of OPEF, a think tank on energy policy also based in Rome. He has advised several institutions in Italy and elsewhere such as the OECD, the Italian Senate, the Italian Ministry of Environment and a number of energy companies.

Stefano da Empoli has authored several dozens of publications concerning the field of energy regulation. He holds a Master Degree in Economics from the University of Turin and a Master of Arts in Economics from George Mason University (VA).

Vittorio D'Ecclesiis is Vice President of Risk Control and Financial Systems at eni SpA. He has extensive experience in risk management and risk control for energy trading & portfolio management, commodity markets and enterprise risk management, having covered senior roles for trading entities and corporate functions of large utilities and integrated oil & gas companies, such as Vice President of Risk Management, Credit & Middle Office at eni Trading & Shipping, Risk Officer at Edison and Head of Middle Office & Risk Management at Edison Trading.

Vittorio D'Ecclesiis has a Master's degree (cum laude) in Mechanical Engineering and an MBA in Management and Economy of Energetic an d Environmental Enterprises.

Rui Eustáquio started his professional career as a consultant in the Corporate Finance division of Ernst & Young Portugal, being involved in Financial Valuation and M&A projects in different sectors. He joined EDP in 2005 and is currently Senior Manager in the Corporate Risk Management Department.

Rui has a BSc in Economics from Nova School of Business and Economics (Nova SBE) and holds a master's degree in Finance from ISCTE-IUL.

Charlotte Renaud is policy officer for the Management Committee of EURELECTRIC, the European electricity industry association, where she is in charge of economic/financial, legal, and social dialogue dossiers. Besides this, Charlotte is contributing to EURELECTRIC's yearly statistical publication *"Power Statistics & Trends"*. She is also in charge of financial regulation & market integrity dossiers within the Market Unit of EURELECTRIC.

Charlotte Renaud studied at the Institute of Political Sciences of Lille (Sciences Po Lille). She holds a master's degree in political sciences, with a specialisation in European affairs.

Allan Baker Managing Director, Global Head of Power Advisory & Project Finance, has worked at Société Générale for four years and has been involved in the power sector for more than 25 years, initially as an engineer and then in the finance sector. During his career he has advised on and financed projects in Europe, MENA, the US and Asia, and in sectors ranging from green-field renewable energy to the acquisition of large thermal power portfolios. This experience has also encompassed regulated, partially deregulated and merchant power markets. In recent years he has become a leading figure in the CCS area, having been instrumental in bringing the financing perspective to the policy debate based on his experience of advising on two of the world's largest carbon capture and storage (CCS) projects. He has also executed advisory and lending mandates in the solar and off-shore wind sectors.

Allan Baker has a BSc (Hons) in Mechanical Engineering, an MBA, is a Fellow of the Institution of Mechanical Engineers and Chartered Engineer.

Niina Honkasalo is advisor in the Energy Policy and Generation Unit of EURELECTRIC, the European electricity industry association. She has worked previously as an Advisor for Finnish Energy Industries, the sector organisation for the industrial and labour market policy of the energy sector in Finland. She was in charge of policy and legislation issues related to renewable energy policies, taxes, wind power and power generation capacity. Prior to joining Finnish Energy Industries, she worked for the Finnish Ministry of Economy and the Employment, as a coordinator for EU energy affairs and participated in international cooperation.

Niina holds a master's degree in Environmental Engineering and a postgraduate master's degree in Environmental Policy and Management.

Franz Bauer has been working for VGB for roughly 14 years. He has spent his whole career in the power sector and covers the whole generation portfolio. His major focus is on the strategic role of generation within the supply system with its regulatory and market implications.

Pedro Neves Ferreira started his professional career as a consultant with McKinsey & Company, being involved in Corporate Strategy engagements mostly in the energy and telecommunications sectors. He joined EDP in the Strategic Planning Department as Project

Leader, heading this unit as of July 2007. His mission is to support the Board in long-term energy planning decisions and portfolio definition.

Pedro Neves Ferreira holds an MSc in Electrotechnical Engineering from the Technical Institute in Lisbon (IST) and an MBA from INSEAD.

Michel Matheu is currently Head of EU Strategy in the Public Affairs Division of Electricité de France (EDF). Before joining this division he worked for nearly 10 years in the field of economy and regulation of electricity systems, successively as Corporate Strategy Director in charge of regulation, markets and economic studies and as Head of Economy and Public Affairs in the Corporate Renewables Division.

He joined EDF in 2003 after a career in the French Civil Service, where his last job was head of the department in charge of Public Utilities and Environment at the French Planning Office, a state think-tank reporting to the Prime Minister. He has also had experience of research and consulting at the Ecole polytechnique in Paris and of editing journals published by the French Ministry of Industry.

He co-edited with Prof. Claude Henry and Prof. Alain Jeunemaitre the book "Regulation of network utilities. The European experience" (Oxford University Press, 2001).

Hakan Feuk is Vice President Political & Regulatory affairs at E.ON SE. He has been working in the energy sector for more than 20 years and is leading the EURELECTRIC task force on market design for renewables integration.

José Arrojo de Lamo has been working in the electricity sector for the last 23 years and is currently in charge of Innovation at Enel Group. For the last 8 years he has been CIO of Endesa Group.

Previous to his responsibilities at ENDESA he worked 3 years at ABB-Cidespa and 5 years at the National Institute of Industry. He was also Associate Professor at Comillas University, where he has been teaching Electrical Systems for 10 years.

Jose Arrojo represents ENEL and ENDESA at several international institutions and technology platforms. He has been Member of the Board of DS2 (Design of Systems on Silicon) and SADIEL (a Spanish TIC company), Technical Secretariat of Spanish Platform for Intelligent Grids and Chairman of Spanish Platform for Energy Efficiency.

Owen Wilson is Chief Executive of the Electricity Association of Ireland, the representative body for the industry on the island. He was previously employed at ESB where he headed the Group Health, Safety and Environment function. Dr Wilson chairs the Environment and Sustainable Development Policy Committee of EURELECTRIC, the European electricity industry association. He has worked closely with industry, NGOs and officials on a range of national and EU energy, climate and environmental policy issues.

Annex - Survey

The Regulatory Framework needed for investments: Internal workshop investments

1. **The European Commission has estimated that 1 trillion euros will be invested in the European energy sector (gas and electricity) by 2020; the IEA has estimated that 1.9 trillion dollars will have to be invested in the European electricity sector by 2035. Do you believe that…**
    - o Yes, all of these investments will take place.
    - o No, only .....% of these investments will take place

2. **The European power industry is characterised by a diversity of actors (with varying regional, national and international scopes). If your company has an international scope, where do you intend to invest in the next few years?** (*multiple answers possible)*
    - o Europe
    - o Asia
    - o North America
    - o Central and South America
    - o Africa
    - o My company does not intend to invest significantly in the next few years.

3. **Which risk do you rank highest when making your investment decisions?** *(please order them numerically according to the relevance you attribute to them – 1 being the most important)*
    - o Market risk
    - o Credit risk
    - o Liquidity risk
    - o Regulatory risk/political uncertainty

4. **Which power generation technologies will your investments most probably focus on up to 2020?**

5. **According to you, which technology will be most important in bringing the electricity industry towards carbon neutrality?** *(please order them numerically according to the relevance you attribute to them – 1 being the most important)*
    - o Smart Grids
    - o Storage
    - o Carbon Capture and Storage (CCS)
    - o Nuclear
    - o Renewable Energy Sources (RES)
    - o Energy Efficiency

6. **Some analysts (Citigroup, 2011) claim that the European power sector has become "uninvestable". Do you agree?**
    - o Yes, because.....
    - o No, because.....

7. **Who, according to you, will be the major investors in power generation in the next ten years (utilities, hedge funds, private equity funds, pension funds, etc.)?**
    - o Low carbon technologies: ……..
    - o Renewable technologies: …….
    - o Flexible back up technologies: ……

8. **Do you think there is the need to fundamentally adapt the current market design in order to facilitate the transition towards carbon-neutrality?**
    - o Yes, we need .....
    - o No, the current market design is sufficient.

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