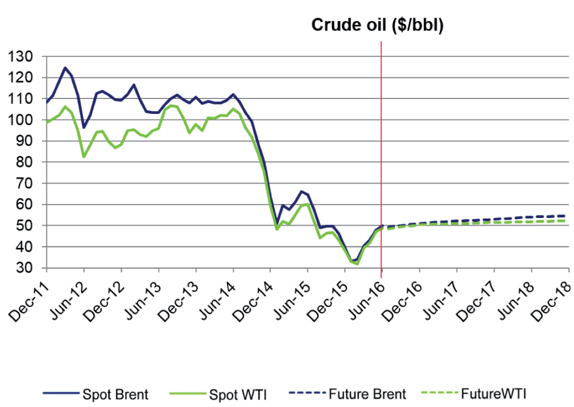
Deloitte.

Power & Utilities
July, 2016

Newsletter
Power & Utilities in Europe

Commodities

Crude Oil ($/bbl)



Source Capital IQ

A flat forward curve does give the market any strong direction.

Crude oil prices have bounced back through 2Q16 to a 2016 high above $51/bbl in June on the backdrop of strong demand and curtailments in supply both from OPEC and Non-OPEC with Canada's wildfires in Alberta in particular. Reduction in US liquids production has largely contributed to narrowing the WTI-Brent spread to zero. The forward is relatively flat as the oil market is in the process of rebalancing with the excess liquidity over demand gradually disappearing. It is worth noting that, in **just over four months, the oil price has almost doubled up** versus a February price level around $ 27/b.

Global oil demand in 2Q16 at 95.5 mb/d was up 1.4 mb/d compared to previous year. For 2016 growth will now be 1.3 mb/d. In 2017, the IEA expects the same rate of growth to be achieved, and global demand to reach 97.4 mb/d. Most of the increase in demand comes from Non-OECD Asia and makes up for the shortfall in OECD countries. The growth rate is slightly above the previous trend, mostly due to relatively low crude oil prices.

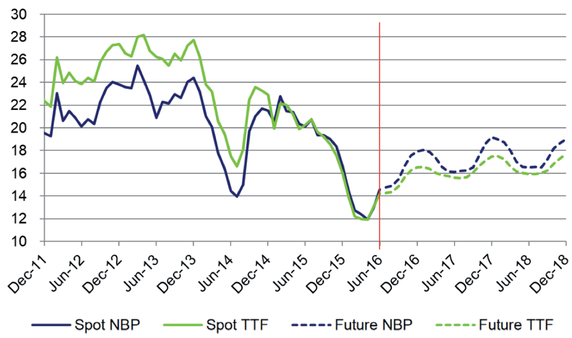
Global supply was 96.5 mb/d at the end of 1Q16, up 1.5 mb/d against the previous year, but went down through 2Q16 to 95.4 mb/d. Outages in OPEC and non-OPEC countries cut global oil supply by nearly 0.8 mb/d in May.

OPEC supply at 32.6 mb/d was affected by continuing outages and sabotage in Nigeria which more than offset the increase in Middle East supply. Iran has clearly emerged as OPEC's fastest source of supply growth this year, rising to 3.56 mb/d a level equivalent to pre-sanction production back in 2011. Iran's gain this year are anticipated to reach 700 kb/d.

Non-OPEC supply at 56.6 mb/d is expected to decline by 0.9 mb/d in 2016, essentially as a result of US shale oil production cuts. Non-OPEC supply growth is expected to go up by a modest 0.2 mb/d in 2017.

Commercial inventories in the OECD increased from March levels by 14.4 mb to stand at 3 065 mb by end-April, a fresh historical high, 222 mb above one year earlier. As the US driving season kicks off, OECD gasoline stocks stand above average levels and the situation is the same in China.

Gas (€/MWh)



Source Capital IQ

The TTF market becoming the EU gas hub for pricing pipeline gas, and the UK's NBP becoming the EU platform for LNG spot pricing.

Global gas prices hit a record low at the beginning of 2Q16 before bouncing back.

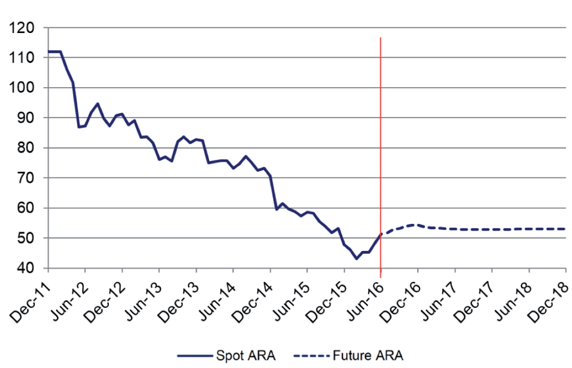
Spot LNG in Asia Pacific dipped to its lowest level since mid-2009, hitting $4.25/MMBtu. In the US, front-month Henry Hub futures trended lower in March, reaching a 17-year low of $1.639/MMBtu as gas production in the US averaged a record 73.3 Bcf/d level of production since 2005.

In Europe, month-ahead gas prices at the **UK NBP have been around the $4/MMBtu mark or 12 €/MWh**. Gas prices went up by some 2 €/MWh over 2Q16 in a context of increased volumes due to gas becoming more competitive in the EU power sector as a result of the Coal Switching Price Index going up. The Dutch month-ahead coal switching price (CSPI) – the theoretical price on the TTF market below which gas becomes more competitive to burn than coal -- rose 8% in May to Eur9.28/MWh, being pushed upward by a modest increase in coal price.

The EU gas market clearly demonstrates today that the incentive of sending out LNG to Asia has disappeared. European LNG reloads over the past year dropped 40%, owing to a sustained fall in the East Asian-European price arbitrage. In the past 12 months, the average JKM (Japan Korea spot market) versus NBP front-month differential was $1.02/MMBtu, compared with $4.17/MMBtu in the year-ago period.

It has to be noted that **volumes on the TTF have increased considerably over the past year, with now TTF outstripping the UK's NBP and showing a preference for the euro-denominated TTF against the trades in sterling on the NBP**. Analysts further mention that the two markets are going through some form of disconnect, with the TTF market becoming the EU gas hub for pricing pipeline gas, and the UK's NBP becoming the EU platform for LNG spot pricing.

Coal ($/metric ton)



Source Capital IQ

Traders on the European market still point out the oversupply from Russian coal trying to find a destination outside of the UK.

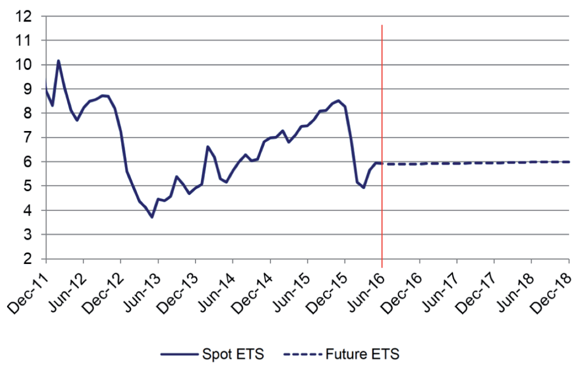
The European-delivered CIF ARA thermal coal market price went up modestly from $ 48/tonne to $ 51/tonne in a very calm market, propped up by the oil price but with fundamentals remaining bearish. **After month of backwardation, the coal market hardly moves to contango** but traders note that it has recently slipped back into backwardation. The increase is also referred to reflect **some short-covering from utility buyer** purchasing cargoes for June. In the Asia-Pacific market, demand remained muted, although rises in domestic coal prices in China drew seaborne offers slightly higher.

Traders on the European market still point out **the oversupply from Russian coal trying to find a destination outside of the UK**. With the UK's Carbon Price Floor, coal is clearly squeezed out of the market, as 6 GW of coal fired power plants are shutting down this year, on top of 15 GW of coal plants who have already been retired over the past 3 years. During 2Q16 there has been periods where no single MWh of coal-fired electricity was generated in the UK.

Combined coal stocks at three delivery terminals in Northwest Europe's Amsterdam-Rotterdam-Antwerp trading hub have also edged 26% lower year-on-year according to data from port sources.

Carbon

CO_2 (€/ton)



Source Capital IQ

At the end of 2Q16, the Spot and Forward EUA price remains flat although a continued evolution of the market structure should exercise an upward pressure on the price

The confirmation by the French energy minister of a carbon price floor at around 30.00 €/tonne CO_2 equivalent to be introduced in France, effective as early as January 2017, had a bullish impact on the French and German wholesale power markets, including the EUA on the ETS.

However, the market sentiment is that the **French proposal is hardly going to create a minimum price for the EU ETS**. Analysts point out that Central and Eastern European countries, who are largely dependent on coal for electricity generation, will make every effort to stop the French proposal raising the EUA price, like Poland did with the proposed Market Stability Reserve prices, fearing a disproportionately large impact on their domestic wholesale power prices. At the end of 2Q16, the Spot and Forward EUA price remains flat although a continued evolution of the market structure should exercise an upward pressure on the price :

(i) A **continued reduction in May of the surplus of allowances**, who shrink by 300 mt/CO_2 to 1.78 billion mt, as part of the "backloading" provisions. Without backloading, the surplus would have been almost 40% higher at the end of 2015, according to a recent EC statement.

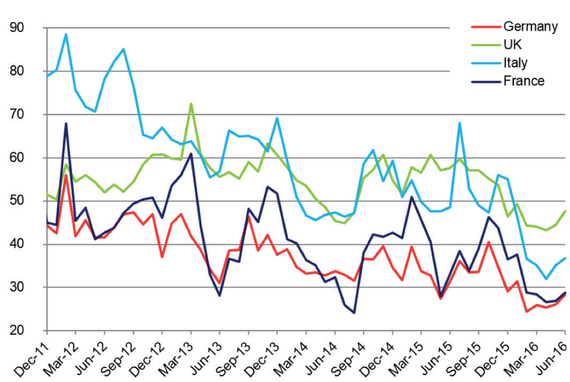
(ii) 200 million **fewer international emissions credits** were exchanged for EU carbon allowances in 2015 compared with the previous year, reflecting the 2014 deadline to exchange credits from the first commitment period of the Kyoto Protocol.

The EU utilities have also increased their generation output in 2015 as the EU economy expands, which would in itself imply stronger demand for EUAs. But, in actual fact, the increase in generation is mostly coming from the renewables energy in 2015. This leads to a reduced emissions-intensity of electricity generation and cuts demand for EUAs in the power sector further.

The EU carbon market is not expected to change substantially before the long-awaited revision of the EU ETS Directive which the parliament and the EU Council are due to discuss by end-2016 and agree on early 2017.

Baseload Electricity

Baseload Spot Day Ahead (€/MWh)



Source Capital IQ

Increase in power prices on most EU markets remains modest simply because demand remains sluggish

The recent increase in power prices on most EU markets remains modest simply because **demand remains sluggish**. However, a **few drivers could have pushed prices up further**, including:

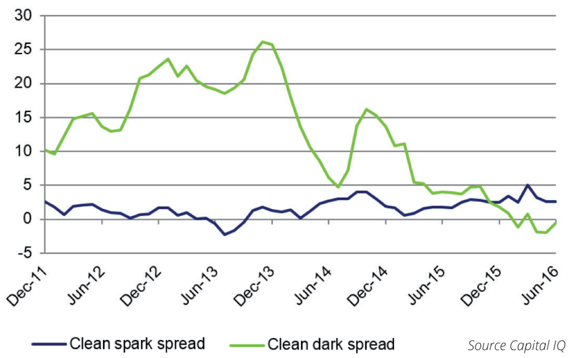
(i) Electricity prices following commodity pricing, including the oil price;

(ii) A price increase in the coal price and in the Coal Switching Price Index, as referred to above;

(iii) Plant outages and low wind power in Germany (wind capacity going down by 2 GW), and solar capacity also down by 2 GW;

(iv) Gas-for-power up over 50% year on year in the UK, against a backdrop of Carbon Price Floor and complete phase out of coal operations.

UK clean dark & spark spread (£/MWh)



Source Capital IQ

The UK clean dark spread, in the context of a 18.08 £/t CO_2 Carbon Price Support and average emissions of 903 kg CO_2/MWh in 2015, **is clearly into the negative territory today.** UK's forward clean dark spreads for Summer 2016 and Summer 2017 have also dropped below zero. As mentioned in our coal section, and in **the Coal in Europe development above, coal power plants over the past two years in the UK have been facing a number of options which were all equally lethal:**

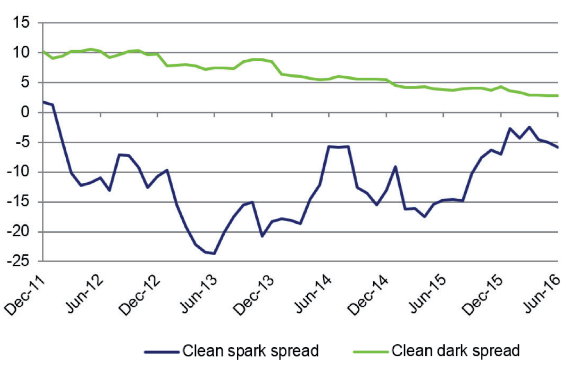
(i) Adapt their plant to the Industrial Emission Directive, it being understood that the UK government considers having all coal plants closed down by 2023, unless they are equipped with CCS technology;
(ii) Operate and generate losses, as a result of the Carbon Price Floor;
(iii) Convert their asset to biomass-fired power plant in order to reap the benefit of the Feed-In Tariff;
(iv) Bid into the capacity mechanism in order to obtain an extra capacity-related remuneration; alternatively
(v) Shut down the plant.

As volumes of gas for power generation in the UK are gradually on the rise, clean spark spreads is very low and going down.

Strangely enough, **as volumes of gas for power generation in the UK are gradually on the rise, clean spark spreads is very low and going down (below £3/MWh)**. This means that running a gas plant in the UK hardly allows you to cover your operation & maintenance costs.

As noted by a few operators, this is a reminder that the **Carbon Price Floor is a doubled-edged sword for gas**; it may make gas more attractive relative to coal, but it also makes competing, low carbon generation technologies more attractive in comparison with any fossil fuel. **The revival of gas for power generation demand is largely predicated on the closure of coal and nuclear plants outstripping the addition of renewables**, given that the demand outlook for electricity is relatively flat.

German clean dark & spark spread (€/MWh)



Source Capital IQ

German clean spark spreads for 50% efficient gas plant are uniformly negative at present, at minus 5.8 €/MWh in June and from ranging from minus €1.11/MWh ($1.21/MWh) day-ahead to minus €8.23/MWh for the year-ahead according to Platts data. Three of the four German gas plants in operation may earn additional revenue from cogeneration (heat and power) operation, but the fourth one which produces power only will generate significant losses.

The German clean dark spread shows a downward trend, indicating that coal burn is gradually becoming less profitable. However, the main factor here is not CO_2 emissions prices, but the steady decline in **German power prices, which are now at 15-year lows**.

The German clean dark spread shows a downward trend, indicating that coal burn is gradually becoming less profitable.

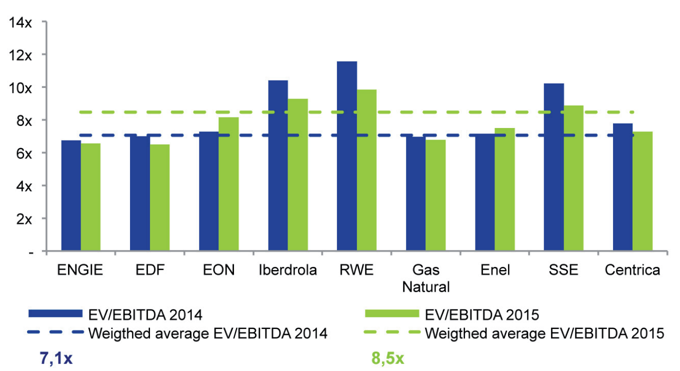
Spotlight on Power and Utilities market

Capital market overview

	Deloitte Index (1)	Enel	Iberdrola	Engie	EDF	Gas Natural	E.ON	SSE	Centrica	RWE
Market cap. ratios										
Currency		EUR	EUR	EUR	EUR	EUR	EUR	GBP	GBP	EUR
Market cap. June 20, 2016)		40 715	37 010	33 291	21 670	17 497	17 102	15 132	11 014	7 701
3m stock price performance	-1%	2%	-2%	3%	8%	-2%	0%	-2%	-11%	4%
YoY stock price performance	-11%	-6%	-6%	-17%	-46%	-14%	-30%	-5%	-24%	-37%
Market multiples										
EV/EBITDA 2015	6.8x	7.1x	10.4x	6.8x	7.0x	7.0x	7.3x	10.2x	7.8x	11.6x
EV/EBITDA 2016	8.7x	7.5x	9.3x	6.6x	6.5x	6.8x	8.1x	8.9x	7.3x	9.8x
P/E 2015	11.8x	18.5x	15.1x	n.m.	18.3x	11.6x	n.m.	25.9x	n.m.	n.m.
P/E 2016	13.2x	13.5x	14.6x	13.1x	7.0x	12.9x	11.8x	12.8x	13.9x	12.5x
Price/book value 2015	1.4x	1.2x	1.0x	0.8x	0.6x	1.2x	1.1x	2.9x	n.m.	1.1x
Profitability ratios										
ROE forward 12m	14%	9%	7%	6%	9%	9%	9%	23%	67%(2)	9%
ROCE forward 12m	8%	9%	4%	5%	5%	8%	9%	11%	18%	9%
EBITDA margin 2015	20%	21%	22%	15%	20%	19%	6%	8%	8%	10%
EBITDA margin 2016	20%	20%	24%	16%	23%	20%	6%	8%	9%	11%
EBIT margin 2015	12%	14%	13%	8%	8%	12%	3%	5%	4%	4%
EBIT margin 2016	12%	12%	13%	9%	11%	12%	3%	6%	5%	6%

(1) Deloitte Index is composed of Engie, EDF, EON, Iberdrola, RWE, Gas Natural, Enel, SSE and Centrica

(2) Ratio linked to the expected level of non recurring income resulting from disposals program by Centrica



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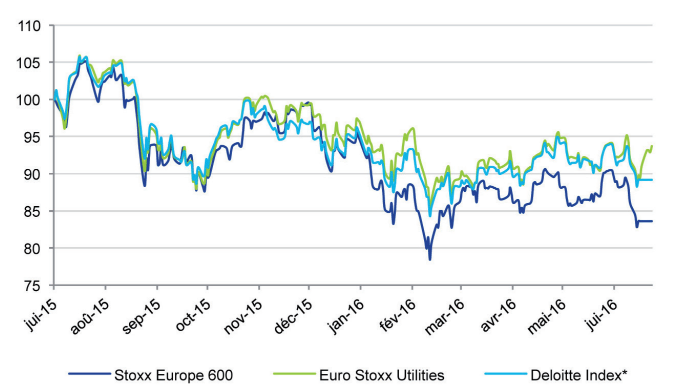


Source Capital IQ

Key messages from brokers and analysts

"After years of sustained growth, a favorable policy backdrop supports further rises in renewable installations"
(HSBC– June 6, 2016)

"Investment to adapt and modernize electricity grid will have to be stepped up"
(HSBC– June 6, 2016)

"What impact could a Carbon Floor Price have on French power prices? - An initial positive for EDF, but further intervention will be needed"
(UBS – May 6, 2016)

"Power prices: a sustainable rally?"
(Morgan Stanley – April 25, 2016)

"The sector's net debt position looks adequate overall … We do not see major risks from upcoming refinancing needs"
(Morgan Stanley – April 19, 2016)

M&A Trends

Transactions involving Power & Utilities companies

Total announced the **acquisition of Lampiris**, the third-largest supplier of natural gas and renewable power to the Belgium residential sector for an amount comprised between **€150m and €200m**. *(Le Monde – June 15, 2016)*

Chinese largest hydropower group **China Three Gorges will acquire German North Sea Windpark Meerwind from Blackstone for €1.6bn**. *(Reuters – June 15, 2016)*

Total is launching a **takeover bid on Saft Group**, a company specialized in **electricity storage solutions**. The total cost should be close to **€860m** based on the €36.5 current offer per share. *(adpnews – June 8, 2016)*

Fortum, a power generation company, agreed to **acquire** from Finnish state and local authorities **for €470m an 81% stake in Ekokem**, a company providing environmental services. *(GlobalData – May 30, 2016)*

Centrica acquired from ENER-G Hodings for £145m ENER-G Cogen, a supplier and operator of combined heat and power plants totaling 1,400 units and over 500MW under contract mainly in the UK. *(Reuters – May 18, 2016)*

EuroSibEnergo, the largest independent power company in Russia, **acquired for $1.1bn from InterRao**, Russian Energy Company, **40% of Irkutskenergo**, Irkutsk city's power generation and distribution company *(Reuters – May 16, 2016)*

A **50% stake in the wind development firm Eolien Maritime France will be bought by Enbridge for $218m** and the remaining stake will be held by EDF Energies Nouvelles. The project cover 3 large-scale offshore wind facilities with a maximum output of 1,428MW. Construction should start in 2017. *(Reuters – May 11, 2016)*

Estonias Eeti Energia agreed to sell 10% of the Estonian 554MW power plant to be commissioned in 2019 and fueled by oil shale. Malaysias YTL Power International now owns a 45% majority stake in this $2.2bn project which is financed up to $1.6bn by Chinese Banks. *(adpnews – May 9, 2016)*

Statoil acquired half of the ownership in the German offshore wind farm Arkona for €1.2bn. E.On is the co-investor in the 1.1MW capacity project. *(Reuters – April 25, 2016)*

Centrica is to buy NEAS, a **Danish company helping wind and solar farm owners to trade their electricity, for £170m**. Neas's customers own 2,500 decentralized energy generation assets across 6 European countries. *(The Daily Telegraph – April 22, 2016)*

Transaction involving equity funds

Vortex, a renewable energy platform managed by the investment bank EFG Hermes, **takes a 49% stake in a 664MW wind power portfolio**, mainly located in Spain and Portugal, from EDP Renovaveis for **€550m**. *(adpnews – June 16, 2016)*

EISER, a private equity fund specialized in infrastructure, agreed to **sell Italian gas pipeline group Societa Gsdotti Italia to the Macquarie group** in deal worth **€550m-€600m**. *(Reuters – June 1, 2016)*

Eurotunnel signed an agreement to **acquire the 49% stake of ElecLink from Star Capital in the 1,000MW interconnection project between France and the UK** which represents a **€500m investment**. After the deal Eurotunnel owns 100% of the project whose commissioning is expected in 2019. (*AFP – May 20, 2016)*

The consortium made of EPH, a Slovakian energy group, and **PPF**, a financial Partner, **acquired the Vattenfall's brown coal mines and power plants** in Saxony and Brandenburg, Germany. The amount of the transaction is not disclosed. The consortium will take over €2.0bn of liabilities and provisions, €3.4bn of fixed assets and €1.7bn of cash *(Reuters – April 18, 2016)*.

Aquitix, an investment firm, **acquired 25% of Atlantis Resources**, a subsidiary of Tidal Power Generation Company, hosting **5 power plants in Scotland** with a 650MW installed capacity for £100m. *(GlobalData – April 5, 2016)*

European Power and Utilities companies wrap-up

Financial results of Power and utilities companies are still under pressure during the first quarter due to continuous **electricity and commodities low prices, and low volumes** attributable to winter's mild-weather.

The biggest announcement arose from the **German Nuclear Commission (KFK) that released its suggestions to address the nuclear provision issue in Germany**:

- **Decommission liabilities should stay with the Companies** but should be done using the immediate dismantling method, not safe enclosure.
- The nuclear waste storage should be financed by companies but they would pay **a 35% risk premium on the top of face-value provision**. It means that companies would be liable of €23.3bn for storage costs incl. a €6.1bn premium. Once the premium is paid the **nuclear waste liability would be fully transferred to the German State.**

Concerns emerged from these suggestions especially on their **consequences on liquidity and equity value of German operators... It also increase focus on the subject of nuclear liabilities across Europe including comparison among companies.**

Most of European Power Utilities **confirm their FY2016 guidance**.

	EDF	ENGIE
Q1 2016 Highlights	• First quarter sales of €21.4bn, down by 6.0% in an unfavourable environment in Europe: - Lower nuclear outuput in France (-2.1TWh ie -1.8%) due to reduced available units. - Wholesale power price at historically low level and end of regulated tariff for industrial customers. - Good operational performance of the nuclear fleet in the UK offset by a decrease in the average number of residential customers.	• Organic growth at EBITDA and current operating income level: • Thanks to : - Restart of nuclear power plant in Belgium. - The commissioning of new assets. - The first impacts of the Lean 2018 performance program. - Adverse context marked by the price decrease on energy markets for merchant activities. • Solid generation of operating cash flow impacted by margin call and temporary WCR elements to the extend €1.5bn • Net debt further reduced by €0.7bn • Group transformation well on track
Key events in the period	• Developments in renewable energy and low carbon energies in the United States, Egypt and India. • Project to acquire Studsvik's decommissioning and waste management activities in Sweden and in the UK. • Strategic partnership with Enbridge for the first three offshore windfarms on the French coast.	• Implementation of the strategy towards energy transition: - 4 projects won in solar (278MW in aggregate). - Acquisition of Maïa Eolis in Wind. - Contract signed to supply LNG to AES power plant in Panama. - Agreement on the gas price revision with Gazprom. - Closing of OpTerra acquisition in the US.
FY 2016 Outlook	• FY 2016 targets confirmed. • Ambition of a positive cash flow after dividend in 2018 maintained. • Action plan presented on April 22, 2016 to support the the CAP 2030 Group's strategy: - Asset disposal plan of approx. €10bn by 2020. - A project to increase capital of approx. €4bn. - Reduction in opex of at least €1bn by 2019 vs 2015. - Net investments (excluding Linky and new developments) optimised by €2bn in 2018 compared to 2015, and reaching €10.5bn in 2018.	• FY 2016 targets confirmed.

	e·on	RWE
Q1 2016 Highlights	• Sales in the first quarter went down by 12% compared to last year principally due to lower volumes and lower prices. • EBITDA and underlying net income dominated by Gazprom agreement declined by 9% year on year. • Net debt reduced by €1bn to €27bn.	• Sales in the first quarter went down by 6% due to customers losses in the UK and a negative FX on GBP. • EBITDA is improving by 5% reaching €2.3bn due to positive effect of energy trading with an above-range contribution to earnings. • The net income fell from €2.3bn in Q1 2015 to €1.0bn in Q1 2016 due to the €1.5bn RWE Dea discountinued operation income recorded in 2015. • Net debt increased by €2.8bn amounting to €27.9bn.
Key events in the period	• Shareholders resolve to spin off Uniper (Conventional energy business) with a full effect and listing expected on H2 2016. • Announcemnt that the plan of the German nuclear commission (KFK) to finance the phase out of nuclear power generation in Germany are not acceptable since it includes a huge risk premium and overburden the concerned energy companies' economic capabilities. • Agreement with Gazprom on price adjustments to long-term gas supply contracts resulting in a non-recurring positive EBITDA effect of about €380 million in the first quarter of 2016. The release of the remaining provisions, made in several years, will result in cash outflow of € 800 million, probably in the second quarter. • Commissioning of two significant offshore wind farms and unit 3 at Maasvlakte power station.	• Announcement of further additional measures to increase earnings increasing the efficiency program by €0.5bn to €2.5bn with a full effect starting 2018. • Suspension of the dividend on common shares. • Agreement with TIGAZ, the Hungarian gas utility to acquire its industrial and corporate customers. • Sell of the 18.4% stake in Enovos, the Luxembourg based utility. • Announcement that the plans of commission for examination of the financing of the nuclear phase out (KFK) nevertheless overburden energy companies' economic capabilities including RWE. • Rating downgrade to Baa3 (Moody's) / BBB- (S&P).
FY 2016 Outlook	• FY 2016 targets confirmed.	• FY 2016 targets confirmed.

	Enel	Centrica
Q1 2016 Highlights	• Q1 2016 sales decrease by 11% compared to last year attributable to a reduction of electricity sales in the mature markets, a decline in trading activities and negative FX effects. • EBITDA is stable at €4.0bn as a result of a balance between: - Adverse effects from FX, decline of trading, generation and renewable margins as consequence of drop in electricity prices. - Positive effects from operational efficiency, additional renewable capacities, improvement in performance in mature end-user markets and generation margin in Chile.	• UK Home energy supply down by 1.5% in Q1 as a result of significant long term contracts roll-off. • Return to profitability in UK Business, with continued progress on cash collection. • Solid delivery in North America energy supply and services against the backdrop of an exceptionally warm winter. • Good operational performance in E&P and Central Power Generation in low commodity price environment. • Net debt reduction to £4.4 billion in the first quarter, benefiting from strong working capital management and seasonal phasing of cash flows.
Key events in the period	• Full integration of Enel Green Power following its delisting. • Announcement of significant investment in renewables: - $1bn in three solar projects in Mexico to be completed in 2018. - Solar and wind projects in the US and Brazil representing a $1.1 in aggregate to be completed in 2017. • As part of Enel Open Fiber (EOF) development ENEL announced exclusive rights to negociate a business integration between EOF and Metroweb.	• Connected boiler offering, 'Boiler IQ', launched in March; continued strong customer demand. • Killingholme power station now closed as previously announced. • Centrica acquires CHP business to enhance distributed energy offering and Neas a leader in energy management. • In March, the CMA announced the Provisional Decision on Remedies in relation to its investigation into the UK energy market. Centrica has now submitted its formal response ahead of the Final Report due in June.
FY 2016 Outlook	• FY 2016 targets confirmed.	• FY 2016 targets confirmed.

	Iberdrola	gasNatural
Q1 2016 Highlights	• Sales decreased by 7% year on year driven by electricity demand in respect with mild winter weather and adverse FX effects. • Q1 2016 EBITDA decreased by 6% as affected by atypical effects: - Adverse FX effects and one-off items (UK customers compensation in 2016 and provision reversals in 2015). - Partially offset by positive impact from UIL contribution (€107m), and gas demand increase in the US and good performance in renewable. • Excluding FX and one-off items (totaling €-237m) the EBITDA should have remained stable.	• EBITDA totalled €1,216m, a 10% derease compared to Q1 2015 due to: - Unfavourable commodity prices. - Adverse FX effects on Brazilian real and Colombian peso. - Number of regulatory adjustments. • Strong performance of regulated activities. • Adjusted of FX and regulatory adjustments the EBIDTA should have decreased by 3%. • LatAm continues to be a growth plateform despite depreciation of local currencies.
Key events in the period	• Rating upgrade to BBB+ by S&P and to positive outlook by Moody's. • Capital reduction of 2.46% to maintain the number of shares at 6,240 million. • €1.0bn Green bond issuance with a 10 years maturity and a 1.12% annual coupon. • Disinvestment in Italy for €194m.	• Issue of €600m notes maturing in 2026 with a 1.25% annual coupon. • Approval by the Board of Directors of a dividend policy for 2017-2018 that entails a pay-out of 70% and at least 1€ per share.
FY 2016 Outlook	• FY 2016 targets confirmed.	• Expectation for an improved performance in H2-2016 compared to a challenging H1-2016.

Topics

1 – Demand Response: untapped and underutilized

In a decarbonised power system, a high level of renewable energy sources causes new operational requirements for electricity system operators: wind and solar for instance do not contribute to meeting demand when there is no wind or sun, but can potentially lead to over-generation when they are abundant. Their variations need to be managed. Furthermore, the system needs to ensure adequacy, i.e. security of supply, when the electricity generation sources do not have the technical ability to produce baseload power. **The most efficient way of addressing this variability is referred to as Demand Response.** Demand response decreases demand when the system is tight, and incentivises the timing of power consumption to when supply from low-carbon resources is abundant.

According to the IEA, demand response potential amounts to around 15% of peak demand and is expected to reach or exceed 150 GW by 2050 in the European Union, equivalent to 12% of the EU installed capacity by then.

Demand response can be in the form of:

(i) **flexibility mechanisms** whereby large manufacturing sites adjust production processes to electricity prices ;
(ii) **automated solutions** to manage air conditioning or lighting systems for services industries or SMEs;
(iii) **smart appliances offering consumers energy savings** for residential users; or
(iv) **electric vehicles**, in the transport industry.

Demand response is used to increase the flexibility of the load according to different market situations, in particular by:

(i) **reducing peak consumption** during tight system conditions so as to release pressure on generation and grid capacity, eventually reducing the need for investment in peak generation assets (peak shaving);
(ii) **increasing or shifting consumption to hours of ample generation** of wind and solar power (the network is under over load);
(iii) **reducing carbon emissions** by moving demand away from times when carbon intensive generation devices (coal or gas) have to be dispatched, to periods of time when less carbon intensive capacity is available;
(iv) **reducing the steep ramping needs at peak time** in order to reduce constraint on generation or transmission assets when electricity supply needs to increase quickly.

Demand response technologies include building management solutions, such as on-site generation, water heating, digitally controlled thermostats, automated lighting systems, or storage devices like batteries...

The only demand responsive storage and generating technology today is pumped-storage hydropower, with an installed capacity of 140 GW worldwide connected to the grid in 2014.

What is the most efficient regulatory package to incentivise investment in demand response today, and to remunerate adequately (i) electricity that has not been produced or supplied, and (ii) electricity that has not been used?

There are three different regulatory and economic approaches to demand response:

(i) Demand response is considered to be a price response, **where the consumer adjusts his consumption to prices**, in which case the consumer is incentivised to reduce his load or shift his consumption at a later time: this system requires "**Dynamic Pricing**" where consumers are aware of the electricity market price in real-time, or
(ii) **Demand response is treated as generation resource**, where an individual's consumption is estimated ("imputed demand response") on a baseline and the demand response calculated on that basis participates in markets as a source of generation. **The consumer is then paid for capacity and/or energy** as the case may be.
(iii) Demand response is considered as Ancillary services procurement and **the consumer (often a retailer) is paid for services** under a contract identical to System frequency control, Spinning reserve or Non-Spinning reserve procurement.

The first type of compensation for demand response has been in effect since the 1960s in France who has been a front-runner in the implementation of time-of-use and dynamic electricity tariffs. Since the 1960s, EdF, the

Demand response potential amounts to around 15% of peak demand and is expected to reach or exceed 150 GW by 2050 in the European Union.

What is the most efficient regulatory package to incentivise investment in demand response today, and to remunerate adequately (i) electricity that has not been produced or supplied, and (ii) electricity that has not been used?

Demand response can also be a product on the ancillary services market.

French utility, proposes differentiated electricity tariffs (day/night and seasonal), known as EJP (*effacement jour de pointe*) tariffs. These are identical to what Critical Peak Prices are today on the US market, and are based on the ability of customers to shift load. The French demand response capacity went up to 6 GW in 2000, today declining to 3 GW. With the liberalisation of the electricity markets, demand response can participate in capacity, energy and balancing markets pursuant to a 2012 provision known as NEBEF (*notifications d'échange de blocs d'effacement*) and earn a remuneration of load shifting as contracted by aggregators having with the French TSO as counterparty.

The second type of regulatory package regarding demand response is in force in New York where demand response is eligible as an emergency resource when generation shortages put grid reliability at risk. In this case, large consumers voluntarily commit to reduce their power consumption and receive compensation from NYISO (New York Independent System Operator). Demand response is eligible in the Day-ahead DR Program, where the load reduction is considered a "negawatt" and the remuneration is fixed by the market clearing price (Energy price reflective of the Locational Marginal Price, see above).

Finally, demand response can also be a product on the ancillary services market, when a consumer can bid its load curtailment capacity into the real-time market and provide additional resources into operating reserves and regulation services. In this case, the scheduled offers are paid the market clearing price for capacity in the Capacity market.

On the US PJM market, capacity markets represent around 20-30% of generators' revenues. The capacity does not have to actually produce electricity, but only to be available in case of need.

Demand Response is a game changer to the extent that it solves adequacy issues, allowing the market to better balance supply and demand in highly variable decarbonised systems. It also allows to adjust to decentralised systems and optimise grid usage depending on wholesale prices, network charges and storage costs.

Save for some national initiatives as above, there are, however, very few policies or incentives in support of Demand Response mechanisms in the world. The main obstacle to incentivising Demand Response seems to be the low energy prices, or low prices for capacity, which have been achieved on the wholesale markets in particular in the EU. In a context of (i) low energy prices and (ii) significant over-capacities, Demand Response providers can only generate little earnings today, as the value attached to releasing energy or capacity is low. However, in a system when baseload generation devices are gradually phased out, the value of Demand Response should increase significantly in the near future.

The main obstacle to incentivising Demand Response seems to be the low energy prices, or low prices for capacity.

2 – Are energy markets capable of delivering low-carbon investment?

The view from the IEA on redesigning electricity markets: Re-Powering Electricity Market (April 2016)

Competitive electricity markets are being challenged by the transition policies to a low-carbon economy. At first glance, developing a low-carbon economy conflicts with market mechanisms: (i) the response to climate change does not fit well with markets and cannot be limited to a market-driven carbon price, and (ii) policies in support of technology-specific objectives are creating distortions which ultimately result in the abandonment of competitive markets.

For the first time, the IEA deliver their recommendations on electricity market design and necessary reforms with a view to combining low-carbon power system and an efficient electricity market framework.

Markets have not delivered

The EU Emissions Trading System (EU ETS) has failed (i) to deliver a carbon price that is reflective of the climate liability, and (ii) to produce a price signal that gives adequate long-term visibility for either operations or investment. But (iii) it still has added a new level of uncertainty and regulatory risks for investors.

The EU Emissions Trading System (EU ETS) has failed (i) to deliver a carbon price that is reflective of the climate liability.

As far as electricity markets are concerned, the first issue is that current market prices for power are too low to attract any investment in low-carbon technologies, both in the United States, with prices in the range of 30-40 USD/MWh, or in Europe with a price range around 30-50 EUR/MWh. In addition to the above, the introduction of zero marginal cost technologies are likely to keep prices low in the coming years.

This leads to the second issue with combining market mechanisms and low-carbon generation: power markets set prices based on short-term marginal costs. Marginal cost pricing leads to prices which do not reflect the full generation cost and therefore make the recovery of the high upfront fixed investment costs of renewables and CCS almost impossible.

But Regulation has not been delivered either…

The transition to a low-carbon economy in the EU is supported by a host of different targets (carbon emissions, renewables, energy efficiency, interconnection capacity) with different objectives across EU Member States – instead of a basic supply & demand analysis – which are aimed at insulating investors from market risk and price signals, and are hardly conducive to a single energy market. Two clear examples: (i) renewable capacities have been developed irrespective of any retirement schedule of existing generation capacities; (ii) renewable energy producers are still being paid the Feed-In Tariff for their output, even when the electricity price is negative on the wholesale electricity market.

The real issue is not about market versus subsidies, but about two different public policy designs:

(i) In the United States, renewables are deployed with subsidies that take the form of tax credits, reducing fiscal revenues, and leaving the plant owners exposed to some market risk.

(ii) In the EU, the cost of renewable policies is entirely paid by electricity consumers at retail level, although all consumers are not contributing to this cost as a number of intensive-users exempt from paying the surcharge. As a consequence, retail prices go up and are borne by small to mid-size European electricity consumers only, whilst the fiscal revenues are unchanged or increased.

According to the IEA, the EU electricity market should move to a US-style organisation and market pricing system.

(i) Markets have to be designed at local level to integrate distributed resources

On the PJM market in the US (150 GW across more than 14 states), an independent system operator (ISO) - or a regional transmission organisation (RTO) - acts as a central entity that dispatches power plants on the basis of bids, taking into account the technical possibilities of the transmission infrastructure. PJM calculates locational marginal prices (LMPs) based on the bid of the last unit needed to meet demand, and these constitute the uniform remuneration of all the power plants that cleared in the market. In actual fact, the US Locational Marginal Prices system is a highly complex system, with 12 nodal points, 12 local prices, i.e. what the IEA refers to as a market with high geographical resolution. The merit of LMP pricing is (i) to reflect real, physical marginal costs at clearly defined locations, and (ii) price network congestion.

In Europe, market coupling has been used as a method for integrating nationally organised electricity markets under different market platforms (also called power exchanges), while taking into account cross-border transmission capacity and facilitating cross-border trade. However, it creates what the IEA calls a low geographical resolution system as Europe prices are uniform for large zones (in actual fact EU countries), and do not necessarily reflect the actual marginal cost of the system or the price actually paid by consumers. According to the IEA, electricity pricing with a higher geographical resolution has to be developed in the Day-Ahead market in the EU, especially in view of integrating variable, distributed renewable power sources like wind and solar into the market framework.

(ii) EU electricity market should also move to a higher temporal resolution

Short-term markets must be upgraded so that Intraday and real-time markets could be more reflective of the real, physical marginal cost of generating electricity at a given point in time, in line with the time of use (ToU) pricing as is effective in California: when there is too much wind or sun, the market should discourage production from one or the other. Uniform prices (like the EPEX spot price) should be used however for balancing.

(iii) Three different market structures

According to the IEA, three building blocks are necessary for a proper functioning power market:

1. A short-term market (Day-Ahead, Intraday,

According to the IEA, the EU electricity market should move to a US-style organisation and market pricing system.

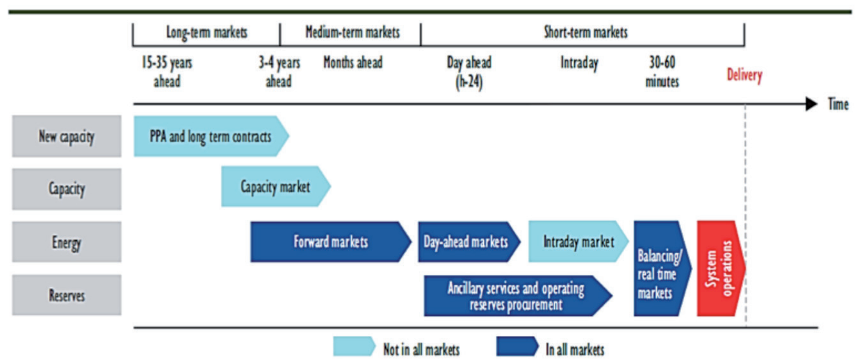
Re-introducing long term contracts with long term pricing formulae is badly needed. This could easily conflict with EU regulations on long term undertakings.

Balancing) with a **locational dimension (nodal pricing)**, where the price will reflect the short-term marginal price of the marginal unit at the specific location where the power is generated or consumed (US LMP).

2. **A Medium-term market (one month in advance to three years)** to be a formal, organised market with forward standard products traded bilaterally over the counter, as is the case for roughly 90% of European electricity traded today by generators, traders or retailers.
3. **A Long-term investment market (3 to 30 years)** to allow investors to take decisions on long-lived assets that will operate well beyond the three years of most forward markets. This is necessary to reflect the evolution of demand growth, the evolution of the capacity mix and fuel prices, and all the other fundamentals of electricity prices, including technology breakthrough. This long term market can be in the form of (i) a **market for capacity, and (ii) long term contracts for the off-take of electricity at a predefined price**, including power purchase agreements or feed-in tariffs. Such agreements can be bilateral contracts between a utility and an independent power producer, or the result of auctions.

The International Energy Agency report sends the strong message that **the nature of electricity calls for different types of markets and different pricing mechanisms in the short, medium and long term.** The AIE report further indicates that **re-introducing long term contracts with long term pricing formulae is badly needed**. This could easily conflict with EU regulations on long term undertakings.

The different building blocks of a properly functioning power market (IEA, Re-powering Markets, 2016).



3 - Obituary: Coal in Europe

Sources: Euracoal 2015; IEA Coal Medium-Term Market Report 2015, Market Analysis and Forecasts to 2020; IFRI report January 2016

Coal accounts for 88% of the remaining proven fossil fuel reserves in the EU today. The EU is the fourth largest coal consumer in the world. In 2014, the EU consumed 711 Mt of coal and lignite (equivalent to 18% of the energy mix) of which 406 Mt were domestically extracted and 205 Mt imported mainly from Russia and Colombia. In countries like Poland, Bulgaria, Greece, Estonia or the Czech Republic, coal accounts for more than 50% of total power generation and is a vital contribution to the security of energy supply. In 2014, Germany maintained its position as the largest coal consumer within the European Union and fourth-largest coal consumer in the world. Two EU Member States together represent more than 50% of the EU coal demand, including Germany (236 Mt/year) and Poland (137 Mt/y). In 2012, the coal industry provided some 240,000 jobs in the EU-28.

Abundant and available, coal is also a highly competitive energy source with international coal prices as low as 5 to 6 €/MWh in Europe. As mentioned by the EU coal industry association, Euracoal, if coal was not the EU electricity price setter today, the European electricity system would be faced with much higher energy prices for both industrial and residential consumers.

However, large scale coal use, with some 0.9 tonne of CO_2 emission per MWh of coal-fired electricity produced, clearly conflicts with the achievement of the low-carbon energy and climate objectives of the EU policies, including 2020 objectives and 2050 Roadmap. Over the past 10 years, the introduction of new environmental regulations together with the implementation of the EU climate policies have resulted in squeezing coal out of the market and coal plant closure.

If coal was not the EU electricity price setter today, the European electricity system would be faced with much higher energy prices for both industrial and residential consumers.

Coal demand in Europe

Today, EU coal consumption is 14% below the levels of 2007. In the European Union, the outlook for coal power generation is to decline on average over 1.5% per year through 2020.

In 2014, according to the IEA database, coal use has a 17% share in the EU energy mix but a 28% in the electricity production mix of the European Union. The EU coal-fired capacity, at 185 GW in 2014, is expected to drop to 77 GW only in 2040 under the New Policies Scenario of the IEA. Coal-fired electricity generation in the EU, around 900 TWh in 2014, is hardly to exceed 200 TWh by 2040 or 6% of the production mix by then. In the WEO 450 Scenario, the net retirement of coal capacity in OECD Europe is 140 GW by 2040, or 75% of the 2014 installed capacity.

Over the past two years, the most significant contributors to the decline in coal-fired power generation have been witnessed in the UK with a 34 TWh decrease (about 25% drop), and in France (a 50% drop with 12 TWh decline), although the coal-fired power generation increased in a few EU Member States as a result of new coal plant commissioning as developed below.

EU Regulatory Package

The European coal industry has been under mounting pressure from environmental legislation, be it at national and international levels.

At EU level, coal use is directly affected by:

(i) The 2030 Ojectives, agreed to by the EU Member States leaders in October 2014;

(ii) The EU ETS;

(iii) Any additional domestic carbon tax, whether in the form of a carbon price floor as is the case in the UK, or as a new tax on carbon emissions as France is proposing for an amount of 30€/t tax on CO_2 in addition to the EU ETS system;

(iv) The EU wide Directives on industrial emissions and pollution, including:

- The Large Combustion Plant Directive (LCPD, 2001/80/EC), a European Union directive which required member states of the European Union to limit by law flue gas emissions from combustion plant having thermal capacity of 50 MW or greater. The directive applied to most industrial installations, in particular fossil-fuel power stations which were given the option, either to comply with the emissions limits, or 'opt out', i.e. agree to a maximum of 20,000 hours of further operation and then close completely by the end of 2015. **Across Europe, 205 plants have opted out, with 15 GW of coal capacity closing up in 2013 and 2014 mostly in the UK and in France.** The Large Combustion Plant Directive was superseded by the Industrial Emissions Directive on 1 January 2016.
- The Industrial Emission Directive (IED), effective January 2016, consolidates the requirements of the Large Combustion Plant Directive (LCPD), Waste Incineration Directive (WID) and Integrated Pollution Prevention and Control (IPPC) Directive which limit emissions of SO2, NOx and particulates. Under the IED, around 50,000 industrial installations in the EU are required to operate in accordance with a permit to be granted by the public authorities in the Member States and conditional upon the Best Available Techniques (which includes Carbon Capture and Storage as far as coal generation is concerned).
  - Under the IED, existing coal plants in excess of 300 MW capacity must limit their SOx and NOx emissions at 200 mgNm3 and particulates emissions at 20 mg/Nm3. **This means that some 50 to 55 GW of coal capacities will have to shut down before 2020/2023, equivalent to one-third of the EU coal-fired capacity at the end of 2014.**
  - For new coal-fired power plants to be compliant with IED over a 500 MW capacity, SOx and NOx emissions are capped at 150 mg/Nm3 (**equivalent to a further 25% reduction compared to LCPD provisions**) and particulates are limited 10 mg/Nm3 (or a **50% reduction versus LCPD**). This further means that **no coal plant may be built in the EU unless it is equipped with CCS technology.**

In addition to the above, the 2015 Sector Understanding on Export Credits for Coal-Fired electricity generation projects (CFSU) of the OECD has been agreed by the Participants to the Arrangement on Officially Supported Export Credits and will be effective as of 1 January 2017. **The agreement removes export credit support for large super and sub-critical coal-fired power plants, making multilateral funding options only available**

The European coal industry has been under mounting pressure from environmental legislation, be it at national and international levels.

Some 50 to 55 GW of coal capacities will have to shut down before 2020/2023, equivalent to one-third of the EU coal-fired capacity at the end of 2014.

In addition to regulatory constraints, utilities, banks and investors have come under considerable pressure from stakeholders either to stop supporting coal investments or divest coal altogether.

to the ultra-super critical technology or CCS equipment. This measure is likely to restrict the development of new coal capacities in those emerging economies with a constrained access to financial markets.

Finally, in addition to regulatory constraints, utilities, banks and investors have come under considerable pressure from stakeholders either to stop supporting coal investments or divest coal altogether.

How are EU Member States to meet their 2030 objectives (essentially by phasing out coal) and ensure system adequacy at the same time? EU Member States seem to be highly divided over the question, with Central and Eastern European States currently building three times as much new coal capacities as Western Europe does: in 2015, over 6 GW of coal plant capacity (not all of it being compliant with the above regulations) was under construction in Poland, Bosnia, the Czech Republic and Serbia, compared with 2.2 GW in the Netherlands and Germany.

(i) Germany: nuclear phase out, coal capacity retirements but also new built; lignite in capacity reserve in lieu of capacity market

Coal accounts for a 25% share in the German energy mix and a 43% share in the electricity mix whilst the renewables hold a 25% market share in 2014.

Under the Energiewende and Climate Plan objectives (BMUB, 2014) which adds to the requirements under the EU objectives, Germany is committed to

- reducing its GHG emissions by 40% in 2020 and 80% by 2050 versus 1990 levels
- phasing out its nuclear park by 2022
- a renewable contribution of 35% to electricity production in 2020 and 60% by 2050.

Pursuant to LCPD, then IED, plant closures in Germany will include 7 GW from the oldest lignite-fired capacities (to include the 2.7 GW transferred to capacity reserve referred to below) from now until 2025, at which point coal-fired and lignite-fired capacities will still be 40 GW (as opposed to 47 GW today) and 20 to 34 GW by 2035.

German power producers have already cancelled over 22 GW of coal-fired new- built projects between 2007 and 2013. Germany is still constructing new coal-fired power plants which have been decided prior to the global financial crisis in 2008, representing a total capacity of 8.4 GW with an overall efficiency of 46% for coal and 43% for lignite entailing a 30% CO_2 emission reduction per each MWh produced.

Pursuant to a new set of objectives in order to put the country on a pathway consistent with meeting the EU and national objectives, the German Government imposed an extra 22 Mt/y emissions reduction on electricity generators which was meant to be achieved through a carbon tax but which was ultimately met by transferring a 2.7 GW lignite-fired capacity (eight lignite units to be compensated to their owners – including RWE and MIBRAG - for €1.6bn in total and for a duration of four years, after which they would have to close down) to a strategy reserve in order to address peak. **The German Government has just obtained EU clearance on such a transfer which was initially challenged as illegal state aid but eventually accepted by the European Commission on the ground that the lignite reserve capacity will not distort the market as it will not produce and is to be decommissioned after four years at the expense of its owners.**

By 2018, Germany could end up with a coal capacity of 48.4 GW, slightly above 2014 level.

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(ii) UK: full coal retirement by 2023

The UK is committed to reducing its emissions by 80% by 2050.

As of 2015, 10 GW of coal-fired capacity has been shut down pursuant to LCPD, having utilised their 20 000 hours allowed under the "opt-out" derogation. In 2016, an extra three coal plants representing 6.4 GW are due to close down in accordance with IED. The remaining 9 coal plants representing 15 GW of British coal-fired capacities will have to be shut down further to the IED until 2023.

The UK coal use has gone down by 20% in 2014 at 49 Mt/y. Coal accounts for 30% of the electricity production mix (in addition to 30% gas, 19% renewable energies, 19% nuclear).

The introduction of a Carbon Price Floor (CPF) of 4.94 £/tCO_2 in 2013 which increased to 9.55 £/tCO_2 as of March 2014, then 18.08 £/t CO_2 from April 2015 until the end of the decade has resulted in most coal plants – which have emitted 903 kg CO_2 /MWh in 2015 - to become largely unprofitable and stop producing today.

Coal plants who failed to win contracts in the last capacity market auctions for 2019/20 delivery are part of the closure programme.

Coal plants who failed to win contracts in the last capacity market auctions for 2019/20 delivery are part of the closure programme. And the three 443 MW units of SSE at Fiddler's Ferry which had been successful in the first T-4 capacity market auction of December 2014, for delivery in 2018/2019, have also closed ahead of delivery with a penalty fee to be due of around £33 million: market operators point out that it makes more sense for SSE to contemplate making a substantial payment in lieu of the capacity agreement relating to Fiddler's Ferry in 2018/19 demonstrates just how economically challenged coal-fired power generation has become in the UK.

We could note that some generation plants having a capacity contract for 2018/2019 and 2019/2020 intend to reduce their investment in clean-up technology that will limit ongoing operation.

This also explains that **many UK generators are actively pursuing biomass conversions of their coal fleet, encouraged both by green tariffs and the carbon price support mechanism.**

(iii) The Netherlands: coal projects but Parliament considers coal exit

In 2014, the Netherlands generated around 52% of their electricity from gas, 28% from coal, 11% from wind and biomass, and just below 5% from nuclear. The total installed coal capacity is to be reduced from 3 910 MW in 2014 to 3 500 MW in 2016. However, three coal-fired power plants – ENGIE Rotterdam (800 MW), Uniper Maasvlakte MPP Rotterdam (1 100 MW) and RWE Essent Eemshaven (1 600 MW) – started operations in 2015, assuring electricity supply and grid stability. In the power sector, the Netherlands has had a progressive policy on coal and the government has supported CCS demonstration projects. As a result, three large ultra - supercritical coal - fired power plants have been built (Eemsmond near Groningen, RWE / ESSENT's 1 600 MW coal - and biomass – fired Eemshaven power plant). A planned CCS project at Eemshaven was submitted, through the Dutch authorities, for EU funding from the New Entrants´ Reserve 300 under the EU Emissions Trading Scheme. Trials of CO_2 storage in North Sea oil and gas fields will be undertaken as part of the ROAD project (Rotterdam Opslag en Afvang Demonstratieproject) whilst the CINTRA consortium has proposed a CO_2 hub with ship transport of CO_2 to offshore operations for enhanced oil recovery. However, in June 2015, the Hague District Court ordered the Dutch government to take more action to reduce greenhouse gas emissions. **As a consequence of this court ruling, the Dutch parliament in November 2015 voted a decision to contemplate the phasing out all coal power plants by 2030.**

The Dutch parliament in November 2015 voted a decision to contemplate the phasing out all coal power plants by 2030.

(iv) Poland: coal to remain the strategy energy (imported) source until 2050

Power demand is projected to grow by 2.5% on average over the outlook period as a result of the strong economic growth.

With a coal-fired capacity of 30 GW, coal accounts for 55% of the energy mix in Poland, and 85% of the electricity generation mix and 75% of the district heating in Poland. The conservative Law and Justice (PiS) government takes the view that coal is a matter of strategic independence for Poland and wants it to be the main source of energy of the country, although it imports 50% of its coal needs. Under the central scenario ("balanced scenario") Poland 2050, coal and lignite will still account for 60% of the electricity generation by 2050 in the country, the balance being supplied by a mix of nuclear (2x3 GW to be commissioned before 2035), gas and renewables. This decision incidentally conflicts with European Council decision 2010/787/UE, 10th December 2010, which imposes mine closure for mines running deficits: a situation in which Polish mines operators (namely two coal companies, Kompania Węglowa and Katowicki Holding Węglowyare) are finding themselves with the current coal price slump.

Poland faces a second challenge with its ageing fleet of power plants: 45% of Polish coal plants are more than 30 years-old and 77% are more than 20 years-old. Pursuant to IED, Poland will need to shut down a capacity of 6 600 MW by 2020 (and an additional 10 000 MW by 2028).

However, **four investment projects in coal-fired generation with a total capacity of 4.2 GW, of which Ultra-Supercritical and Supercritical coal power plants,** are expected to come online between 2017 and 2019. With the start of operations at these projects, older units at the same locations will be shut down. Consequently the efficiency of the Polish thermal power plant fleet will increase from approximately 34% currently to 36% by 2020. As a result, coal consumption in the Polish power sector is forecast to grow from 47 Mtce in 2014 to 51 Mtce in 2020. **On the long run, Poland is determined to keep coal well above 50% of its energy mix, even if this generates conflicts with the EU.**

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(v) Spain: support to the national coal

industry

Spain consumed in excess of 11 Mt of coal in 2014. The Spanish electricity capacity mix at the end of 2014 includes 18% hydro, 8% nuclear, 11% coal, 25% gas, around 7% solar and 23% wind.
Spain supports its coal industry through the provisions of Royal Decrees 134 / 2010 and 1221 / 2010 which took effect in 2011 and helped to maintain demand for indigenous hard coal via an off – take obligation on utility companies of up to 23.4 TWh per year (around 8% of the total domestic electricity demand) from the coal units still burning local coal. Most plants are now fully compliant with the IED. As far as reducing carbon dioxide (CO_2) emissions is concerned, it is foreseen that all Spanish power plants will be CO_2 capture - ready by 2020 pursuant to the European Energy Programme for Recovery, and this should allow the continued use of indigenous coal at reasonable prices at least until 2050. **For decades now, like Poland, Spain has had the long-standing strategy to support its coal industry, including coal mining, given its national importance.**

(vi) France has already phased out coal; Italy, Turkey to build new coal plants

Between 2013 and 2015, **all coal-fired power plants, owned by EdF or E.On, have shut down in accordance with LCPD in France**, save for E.On's 230 MW conversion to biomass in Provence and EdF's 595 MW unit 5 on coal in Le Havre (to be a CCS pilot plant). **Italy** is also considering a number of high efficiency coal plants as well as CCS demonstration project or coal gasification units. In 2015, the **Turkish government** approved the construction of three new coal-fired power plants, increasing the 12 GW national coal capacity by 2 480 MW and thermal coal imports by 6.2 Mt/year. None of the proposed projects seem to be in line with IED.

For quite a number of EU Member States, the domestic coal industry is a sensitive sector which EU climate policies will find it hard to scale down. However, the boldest moves towards phasing out coal completely have taken place in the UK and France so far. Poland and Spain are probably those who will support coal the most.

Coal still remains the large carbon "stock" of emissions to be reduced in the EU. The European Union will probably not avoid the daunting task of scheming a European plan for limiting coal and finding a substitute.

For decades now, like Poland, Spain has had the long-standing strategy to support its coal industry, including coal mining, given its national importance.

The European Union will probably not avoid the daunting task of scheming a European plan for limiting coal and finding a substitute.

4 – A gas pricing revolution has taken place in the EU (2005 – 2015) but the Golden Age of Gas may still have to wait

(*) Medium Term Gas Market Report

(**) BP Statistical Review 2016

(***) International Gas Union, Wholesale Gas Price Survey, 2016 Edition

The long heralded Golden Age of Gas (IEA Report, 2011) does not seem to be in sight yet in Europe, despite of a slight uptick in recent gas demand. On the medium to long run, the current demand projections from most experts for 2025 onwards drop versus previous estimates.

Under its most recent publication (*), the IEA forecasts European gas demand at 496 Bcm in 2020, below the level of demand in 2015, then rising marginally year-on-year to 523 Bcm in 2025. Other than gas volumes for the power generation, the IEA sees European gas demand from the industrial, buildings and other sectors all declining. Growth in **global gas consumption will weaken** to an average annual growth of 1.5 per cent between 2015 and 2021. This compares with an annual rate of 2.5 per cent over the prior six years. The **main driver for gas demand** appears to be in the developing world, particularly in Asia where around **800 million mt of coal consumption in China and India, equivalent to a fresh gas demand of 500 bcm/y approximately**, will be impossible to be replaced with wind and solar power as part of the decarbonisation policies.

On the supply side, the major capacity additions will come from the new LNG liquefaction trains coming on line over the next five years, mostly in the US and Australia, which are expected to increase the global gas liquefaction capacity by some 150 bcm/y between 2015 and 2019, or the equivalent of Gazprom's yearly exports which will increase the existing excess liquidity on the European or Asian markets.

The consequence is that markets operators are preparing for a likely price war.
In Asia, gas prices, assessed by Platts, have declined another 35 % since the start of 2016 to $4.40/MMBtu. This figure compares to about

The consequence is that markets operators are preparing for a likely price war.

$11/MMBtu about a year ago. In the US, the gas benchmark has plunged below $2/MMBtu and the front-month Henry Hub futures has reached a 17-year low of $1.6/MMBtu early April. In Europe, spot gas trades around 14.5 €/MWh on the TTF market by mid-June 2016, which is equivalent to $4.7/MMBtu.

According to the latest International Gas Union (IGU) report, May 2016 ***, 64% of European gas (up to 92% in Northwest Europe) at the end of 2015 was hub-price as opposed to 15% in 2005. These volumes represented about 315 Bcm, with 73 Bcm mainly from UK and Dutch production, 224 Bcm from pipeline imports, mainly into Northwest Europe and Italy, while LNG imports accounted for 19 Bcm, half of it flowing to the UK, the other half being largely spot cargoes. More than 40% of LNG imports into Europe are now under hub-indexed contracts. In comparison, 31% of worldwide LNG imports are hub-indexed.

Conversely, oil-price indexation in Europe slipped to 30% from 78% in the same period. Oil-indexed volumes totaled 146 Bcm, with 114 Bcm gas pipeline and 28 Bcm of LNG imports into Spain, France, Italy, Turkey, Portugal and Greece. The remaining oil-indexed volume (4 Bcm) came from domestic output. Another 8 bcm/y were accounted for as pipeline imports into Turkey via bilateral contracts.

With the EU gas market becoming predominantly hub-priced and a price war looming, traditional gas sellers are reviewing their strategy.

In a recent statement, Statoil made it clear that they were no outright price taker and they were not defending their European market share at any price. However, Statoil production hit 115 Bcm in 2015, an all-time high; and in 2016, they raised the production permit from its swing Troll field for Gas Year 2016 to 33 Bcm from 30 Bcm, spurring talk it was aiming to ward off US LNG by producing at maximum levels. Norway says they could maintain current production levels until at least 2035.

At the same time, the first US LNG shipments are due this year, starting supply in Portugal. According to Sempra LNG of the US, even at 100% capacity operation for the new LNG trains, there will be a supply gap by 2025 and consequently there are plenty of places for US LNG to go and to compete with existing suppliers, in particular of Asia's and Europe's. The same source quotes US LNG could land in Europe as competitive as $3.40/MMBtu, equivalent to 10 €/MWh against spot price of 14.5 €/MWh currently. The above figure would have to cover the tolling fee payable to the liquefaction plant in the US and the cost of shipping LNG to the European beach, therefore leaving very little, if not a negative amount, to the US fracker.

Just as Saudi Arabia for the global oil market, Gazprom, with its large resource base, well-developed transport infrastructure and low production costs, together with a huge portfolio of long-term supply contracts, is the main holder of spare capacity in the global and European gas market in particular. Gazprom believes it can stay competitive with a production cost around $0.40/MMBtu, rising to $0.80/MMBtu when Mineral Extraction Tax is added. Nonetheless, even if Gazprom retains its market share, it looks likely to do so only at the cost of much lower revenues. Gazprom is already receiving less for its gas exports to Europe because of the fall in the oil price since summer 2014. In its 2016 budget, it assumes an average gas price of $199/1,000 cu m, compared with $243/1,000 cu m in 2014, but based on a $50/b average oil price. At a $35/b average, Gazprom sees its average gas price at $169/1,000 cu m, equivalent to 15 €/MWh or $ 5/MMBtu.

In actual fact, both Norway and Russia are prepared to make the most of their already developed export infrastructure to Europe, which puts them in a position to export gas to the EU at a cost reflecting the short term marginal cost of shipping. The cost to Gazprom of delivering its gas to Germany is $3.5 /MMBtu compared with an estimated $4.3 /MMBtu which Gazprom estimate is the break-even for US LNG supplies despite US gas prices trading near 16-year lows. Gazprom's strategy is quite clear: first, to price cargoes of US LNG out of the European market in the short term; second, to disincentivise new investments in LNG projects in the longer term.

A fully-fledged price war in the European gas market could have a large-scale effect across other regions and commodities — from Australian LNG to Colombian coal — as well as threatening the viability of the nascent US LNG industry.

With the EU gas market becoming predominantly hub-priced and a price war looming, traditional gas sellers are reviewing their strategy.

A fully-fledged price war in the European gas market could have a large-scale effect across other regions and commodities — from Australian LNG to Colombian coal — as well as threatening the viability of the nascent US LNG industry.

Policy and Regulation Radar

This section summarizes the key changes respectively in the EU or in the country regulation that may significantly affect the power and utilities companies.

What is changing in the EU regulation?

The signature of the Paris Agreement

Key features	Insights
The **COP21 UN Climate Change Conference**, which took place last December in Paris, reached a **global agreement to tackle climate change**. This agreement set out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C. On 22th April 2016, the **European Union has signed the Paris Agreement** in New York. The agreement will be open for signature for one year.	In order to translate the Paris Agreement into policies, the EU has been **meeting with other countries** around the globe during the last months: - **EU - India Summit**: On 30th March, the EU and India decided to step up their cooperation to fight climate change and adopted the **Joint Declaration on a Clean Energy and Climate Partnership**. It is key for the implementation of the Paris Agreement. The Joint Declaration intends to reinforce energy cooperation, mainly on renewable energy sources, promote clean energy generation and increased energy efficiency. - **G7 Energy ministerial meeting**: The G7 is definitely committed to working together on the transition towards a more competitive, secure and sustainable energy system, and this will require significant investments. **The G7 considers that the Paris Agreement gives us the right framework to boost these investments**. In this context the G7 calls attention to the **energy security** especially on gas supply with a focus on LNG, cyber security especially for energy networks, electricity security namely on regulatory frameworks to boost competition. It also calls for **energy sustainability** with a strong support to innovation and deployment of energies technologies, energy efficiency and nuclear energy and safety. - **EU - US Energy Council:** Following the adoption of the Paris Agreement, the Energy Council also constitutes a platform for transatlantic dialogue on how to accelerate the clean energy transition. On 4th May, the EU-US Energy Council focused the discussion on **energy security challenges**, the importance of fully integrating the **EU's internal market**, the **Nord Stream 2 pipeline** and the importance of increased **co-operation to ensure** that the **commitments made at COP 21** are fulfilled.
	Next steps
	The Paris Agreement will enter into force once it has been ratified by at least 55 parties, representing at least 55 per cent of global greenhouse gas emissions.

Link: ***Paris Agreement signing ceremony in New York***
Link: ***EU – India Summit***
Link: ***G7 Energy ministerial meeting***
Link ***EU-US Energy Council***

North Seas countries: Agreement on energy cooperation

Key features	Insights
On 6th June 2016, the **North Seas region countries** (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden) have signed an **agreement** to further strengthen their **energy cooperation**. The aim is to create good conditions for the **development of offshore wind energy** in order to ensure a sustainable, secure and affordable energy supply in the North Seas countries. This agreement will also facilitate the **building of missing electricity links**, allow **more trading** of energy and **further integration of energy markets**.	The agreement includes a **work programme from 2016 to 2019**. Energy cooperation between the countries will focus on **four main areas**: - **Maritime spatial planning**: Participating countries will work on optimising the use of limited space in this intensively used sea. This will include data sharing, finding common approaches to environmental impacts, and the coordination of permitting procedures. - **Offshore grids and other offshore infrastructure**: The electricity grid has to be developed so that it is able to accommodate large scale offshore wind energy. Markets should be well connected to allow electricity to flow. Participating countries will work on improving coordination of grid planning and development exploring potential synergies with the offshore oil and gas sectors. - **Support framework and finance for offshore wind projects**: In future, participating countries will share information about their individual offshore infrastructure needs. This will help plan the investments as well as align support schemes and mobilise investment capital for joint projects. - **Standards, technical rules and regulations**: Participating countries will work towards mutual recognition of national standards. The aim is to identify best practices and ways to harmonise technical rules and standards across the region. The cooperation also aims to reduce costs throughout the lifecycle of generation facilities. **Next steps** The initiative remains open to the participation of all countries with an interest in the North Seas.

Link: ***North Seas Countries agree on closer energy cooperation***

European Energy Council: IGAs and Security of gas supply

Key features	Insights
In line with the Energy Union Strategy, on 6th June 2016 the Energy Council: - Agreed on the proposal for a decision on establishing an **information exchange mechanism** with regard to **intergovernmental agreements (IGAs) and non-binding instruments** between member states and third countries in the field of energy. - Discussed the **proposal for a revised regulation** concerning measures to safeguard the **security of gas supply**, published in February 2016. Both are two major steps for strengthening the EU´s energy security which is one of the building blocks of the Energy Union Strategy.	- **Intergovernmental agreements (IGAs)**: The aim of the proposed decision is to enhance the transparency and consistency of the EU's external energy relations and to strengthen its negotiating stance vis-à-vis third countries. It will also contribute to the proper functioning of the internal energy market. The compromise reached was based on the following elements: • Commission will conduct an assessment of gas-related IGAs before they are signed. • Member states may request the previous assessment for other non-gas related IGAs. • Member states shall keep the Commission informed both before the start and during the negotiations of all IGAs. • All non-gas related IGAs shall be notified to the Commission "upon ratification". • Non-binding instruments will not have to be notified. • Commission will develop model clauses and guidance. - **Security of gas supply**: The main purpose of the proposal is to minimize the impact of a potential gas disruption by improving cooperation between member states and by building on the achievements of the internal energy market. It also aims to increase trust and solidarity at the regional and EU level. The main changes proposed are the following: • Enhanced regional cooperation and coordination. • New solidarity principle. • Mandatory regional preventive action plans and emergency plans, as well as regional risk assessments, to be prepared jointly. • Stricter obligations to ensure that the necessary infrastructure is available.
	Next steps
	The agreement with regard to IGAs will allow the Council to start negotiations with the European Parliament with a view to the final adoption of the proposal. The Gas Coordination Group will be convened in order to clarify technical issues regarding the proposed regulation concerning security of gas supply.

Link: ***European Energy Council***

Country reporting on changes in the Policy and Regulation framework

Germany			
Topic	**Key features**	**Insights**	**Next Steps**
Draft of the Electricity Market Act (Strom-marktgesetz) and the Capacity Reserve Ordinance	**Key aspects** of the regulation: • New power market design with focus on system stability, renewables integration, guarantee of unregulated wholesale prices as well as conventional power plant regulation • Guarantee of no regulatory intervention in power wholesale prices • Introduction of a power plant capacity reserve as well as further development of power plant network reserve • Partial phase-out of lignite power plants **Changes introduced** by the new regulation: • Guarantee of non-regulated wholesale prices in order to allow price signals to influence energy consumption • Introduction of a power plant capacity reserve to ensure a sufficient supply when price signals on the market do not meet supply or demand • Further reduction of control energy by strengthening of balancing group commitments • Development of demand-response management • Further development and amendments to the power plant network reserve, which consists of system relevant power plants that filed an approval for decommissioning • Entitlement to TSOs to build and operate new power plants for system stability • Set up of a national information platform which gathers electricity market data to promote efficient generation, consumption and trading decisions • Abolishment of incentives for power plants; in particular avoided grid charges, which were to be paid for power plants feeding into lower voltage grids, will not be paid to new installations (as of 2021) • Removal of lignite-fired power plants with a total capacity of 2.7 GW from the market and closing them down as of 2016 • Recharging points for electric vehicles are implemented in the system of the Energy Industry Act The Electricity Market Act is an umbrella act. It amends various acts and ordinances, including the Energy Industry Act, the Renewable Energy Sources Act and the Reserve Power Plant Ordinance.	The Electricity Market Act is an opportunity for Power and Utilities companies and creates new business opportunities like: • The optimal reaction to price signals may enable to generate, consume and trade more efficiently • New source of income for Power Companies by taking part in capacity reserve • Implementation of recharging points into the Energy Industry Act reduces legal risks for Utilities companies and automotive companies Possible threats are: • Uncertainty about economic and market effects of capacity and network reserve as well as further means to reduce control energy • The decommissioning of lignite-fired power plants constitutes a threat for the lignite power industry	On June 23rd, 2016 the German Bundestag adopted the Electricity Market Act. In the next step the German Bundesrat can decide on an appeal against the Act. If not, the Act can come into force. More information on the web page of the Federal Ministry of Economic Affairs and Energy (BMWi): ***http://www.bmwi.de/EN/Topics/Energy/Electricity-Market-of-the-Future/electricity-market-2-0.html***

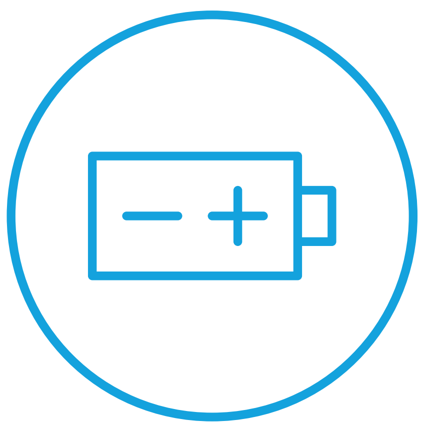
Country reporting on changes in the Policy and Regulation framework

Germany			
Topic	**Key features**	**Insights**	**Next Steps**
Draft of the Renewable Energy Sources Act 2016 (EEG 2016)	Key aspects of the regulation: • Abolition of legally specified premium for new offshore and onshore wind parks and photovoltaic installations with a capacity of more than 750 kW and for new biomass installations with a capacity of more than 150 kW; as of 2017 the premium will be determined by auctions • The tender procedures cover over 80 per cent of the renewable energy generated in new installations in Germany	Possible threats are: • Tender procedures require high bureaucratic efforts for market participants and constitute an economic risk. For small market participants this may be a barrier to participate in procedures.	The parliamentary process has begun on June 21st, 2016. The first of three consultations in the German Bundestag took place on June 24th, 2016. Coming into force is planned for Summer 2016. The Approval of the European Commission is expected in autumn 2016. More information in the key points by the Federal Ministry of Economic Affairs and Energy (BMWi): ***http://www.bmwi.de/English/Redaktion/Pdf/eckpunktepapier-eeg-2016,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf***
Cross-border Renewable Energy Ordinance (GEEV)	Key aspects of the regulation: • 5 % of the tendered generation capacity within the scope of the EEG-auctions will be opened for participants in other EU members states • Precondition is an international cooperation agreement between Germany and the respective other EU member state stipulating the reciprocal cross-border opening of the national promotion schemes	Possible opportunities are • Foreign Power companies are able to engage in the expansion of Renewable Energy in Germany	Adoption by the German Federal Government took place on June 1st, 2016. Coming into force can be expected within the next days/weeks.
Critical Infrastructures Ordinance (BSI-KritisV)	Key aspects of the regulation: • Determination of Critical Infrastructures in the energy sector (inter alia) • Operators of Critical Infrastructures are obliged to implement specific IT-security systems until May 2018 and have to fulfil reporting obligations concerning any disruption of their installation according to the IT-Security Act and Energy Industry Act (BSI-G, EnWG)	Possible threats are: • IT-security systems may cause high costs, which are not in every case accepted in network tariff regulation • Reporting obligations require implementation of new internal processes	Applicable since May 3rd, 2016

United Kingdom			
Topic	**Key features**	**Insights**	**Next Steps**
Capacity Market	• The UK's Department of Energy and Climate Change (DECC) undertook a **consultation** in early 2016 to **reform the Capacity Market** to ensure that it remains fit for purpose. • The consultation has concluded and the key outcomes are: - holding of an **'early' auction for capacity delivery in 2017/18**; - **tighter delivery incentives** to ensure that agreed capacity is being delivered; and - buying **more capacity earlier**.	• It appears that there will be **higher capacity demand** compared to previous auctions, coupled with **tighter rules around project delivery** for successful market participants. • This will affect the demand-supply fundamentals and may lead to a significantly **different outcome** in the next auction compared to the previous ones, particularly with respect to the **clearing auction prices**. • This will also be affected by the ongoing assessment of embedded benefits for **distribution-connected generation** and **emissions regulations for small-scale diesel generators**, as it will have implications for **their participation in the capacity market.** • Clients would benefit from understanding in greater detail the implications of the changes discussed above for bidding strategies and its impact on pricing levels.	The changes will be implemented this year to enable the holding of **auctions** towards the **end of this year** and **early next year.**
Fracking tests' approval	• There has been significant debate around the environmental consequences of fracking since 2011 when fracking tests were linked to the probable cause of minor earthquakes. • However, very recently, the **UK's first fracking tests in five years received approval.** The North Yorkshire council approved fracking tests by Third Energy.	• While the tests have been approved at a particular site, there is **significant uncertainty** related to the evolution and development of the **shale gas sector** as a whole. • Prior to the approval of the recent application by Third Energy, a **few applications for fracking** in Lancashire were been **rejected** by councillors and are in the appeals process.	It remains to be seen whether and how quickly this sector evolves.
Nuclear investment	• The final investment decision on the **Hinkley Point C nuclear power plant** in the UK has been **delayed** a few times by EdF. It is not clear when the decision will be made.	• The Hinkley Point C power station is **expected to be a large contributor** to the power generation mix in the future. • The delays in making the final investment decision may have implications related to the timing of project delivery. This would have **implications** on how the **generation mix** evolves in the future and its impact on **market fundamentals and pricing.**	It has been suggested that the decision will be made within **this year.**

France			
Topic	**Key features**	**Insights**	**Next Steps**
New revenue framework for renewable energies	• As part of the Energy transition law three decrees have been passed in order to set a **new framework to sustain the development of renewables energies in France.** • The **major change is the implementation of a supplementary revenue** that supersede the existing purchase obligation for some installations. • The supplementary revenue is **calculated as a premium** paid to the producers in **addition to the revenue earned by selling the energy on the market.** It is determined on the basis of production volumes produced and the difference between (i) a reference tariff, which should be close to the existing guaranteed purchase price, and (ii) a market reference price.	• The new scheme is focused **on medium and large renewables power plants (>500kw)** in order to facilitate their integration on the market but limiting their exposition to prices volatility. • The **purchase obligation should remain applicable for small renewables power plants** (<500kw). • The **administrative process to benefit from the scheme is simplifie**d. The mandatory certification is repealed.	The new scheme is now **in force**
Decree on the organisation of hydro concessions (May)	• On April 27, 2016 a Decree has been passed to organize the hydro concessions in France and especially the condition for their renewal. • Hydro accounts for 11% of the annual electricity production and **61% of production from renewables.** • **Actual hydro concessions were granted without a competitive bidding process that infringe the European regulation on competition.** • Historically concession were awarded for a 75years period and a large portion, around **125 on a total of around 400, should terminate in 2023.** • The decree represents the framework for the upcoming concession renewal process namely by setting: - The **bidding process** and namely **conditions to aggregate small concessions** into a single one. - The **ownership of entities operating the future concession** that should involve local authorities - The **new obligations for concessions operators.**	• The bidding process would be **organized by local authorities** and applying companies should described contemplated measures to: - **Optimize the energy productio**n of the plant. - Ensure an **environmentally sound management of water resources**. - **Remunerate the French State and local authorities.** • The **aggregation of small concessions** located on a same river's portion into a new one with a same deadline is aimed at **optimizing the energy efficiency**. If the end of the concession is extended the new operator would **pay a fee to indemnify the shortened concession.** • **Specific measures are applicable before the end of concessions** currently under operations: - 5 years before expiration of the concession, investments **deemed necessary by local authorities to secure the next exploitation period** would be financed by **French Sate expenses.** - 18 months before actual operator should **present to the French State performances of the plant and measures to secure a smooth transition with a potential new operator.** • The **decision to involve local authoritie**s in the ownership of the entity operating the concession **belongs to the French State**. If positive **local authorities would announced their expected percentage of ownership** and correlatively the **maximum amount they are ready to invest.**	The first concession aggregation and renewal **should take place by the end of 2016.** **However the EU has not yet deliver a green light on this Decree.**

Italy			
Topic	**Key features**	**Insights**	**Next Steps**
Call for tender in order to grant subsidies for the purchase of energy storage systems	• Lombardy Region published a **tender** in order to **subsidize the purchase of energy storage systems** on 6 May. This tender was already defined in deliberation n. 4769 28 January 2016	• The tender offers to public and private entities, having private or professional seat in Lombardia, **€ 2 million** in order to subsidies the purchase of energy storage systems. • The tender sets a c**ap for each subsidy** equal to **€ 5,000** and in any case equal to **50% of the admissible fees** of each intervention admitted to the procedure. • The amount is based on three features, outlined in different quotas A, B and C, respectively concerning the **efficiency** of the storage, the **installation costs** and the **accessory costs**.	



Snapshot on surveys and publications – June 2016

Deloitte

Power & Utilities: Implications of the new leasing standard - May 2016

The International Accounting Standards Board has published IFRS 16 Leases. For lessees, IFRS 16 introduces a single accounting treatment, recognition of a right-of-use asset and a lease liability. For lessors the current finance and operating lease distinction and accounting remains largely unchanged.
Link to the survey

A market approach for valuing wind farm assets - April 2016

Based on a statistical approach the study assigns different values to the individual development stages of a wind farm project. It illustrates and estimates the change in the transaction prices over time and investigated how the value of a wind farm decreases with its age due to the diminishing remaining cash flows of the project.
Link to the survey

A market approach for valuing solar PV farm assets - April 2016

As conservation efforts and alternative energy ramp up, electric utilities can no longer count on customers using more and more power. How to survive? With a new focus on efficiency and cost control, based on technology—particularly Internet of Things applications.
Link to the survey

Agencies or research institutes

International Energy Agency

Technology Collaboration Programmes - 2016

This publication provides an overview of the activities and recent accomplishments of Technology Collaboration Programmes (TCP). TCPs have examined more than 1 900 energy-related topics in the areas of energy efficiency, renewable energy, fossil fuels, fusion power and cross-cutting issues.
Link to the survey

Next Generation Wind and Solar power - 2016

This document focus on contribution that next-generation wind and solar power technology can make to transforming power systems around the globe when combined with advanced, system friendly deployment strategies.
Link to the survey

Global Electric Vehicles Outlook - 2016

This report provides an update on recent Electric Vehicles (EV) developments, providing detailed information on the recent evolution of EV registrations, the number of EVs on the road. It also provides insights to encourage signs that characterized the recent evolution of battery costs and energy density.
Link to the survey

Energy Technology Perspectives - 2016

This paper looks at the technology and policy opportunities available for accelerating the transition to sustainable urban energy systems. Such potential could be the key to successfully driving an energy transition that many still think impossible, provided that local and national actions can be aligned.
Link to the survey

Tracking Clean Energy Progress - 2016

The report highlights the development of key clean energy technologies year on year. This comprehensive overview tracks the evolution of select technologies and sectors against the interim 2025 targets of the International Energy Agency and assess recent trends, Tracking progress and recommended actions.
Link to the survey

European Commission

Selecting Indicators to Measure Energy Poverty – May 2016

Energy poverty is a raising policy issue across the EU. To understand the extent and depth of the problem of affordability of energy services better indicators are needed. The report recommends four key indicators to measure the number of households in energy poverty. These indicators are tested and computed for the Netherlands, Slovakia, Spain and Italy using currently available data.
Link to the survey

Study on regulatory matters concerning the development of the North Sea offshore energy potential – May 2016

The exploitation of wind energy resources from offshore generation in the North and Irish Sea represents an opportunity for the European Union to increase the share of renewable energy generation and, at the same time, support the economic growth and the creation of sustainable jobs.
Link to the survey

Economic analysis of costs and benefits of approaches to enhancing the bargaining power of EU buyers in the wholesale markets of natural gas - April 2016

This study assesses effects and impacts of collective purchasing and other arrangements to improve outcomes for buyers in EU wholesale natural gas markets.
Link to the survey

Study on Energy Efficiency in Enterprises: Energy Audits and Energy Management Systems – April 2016

This document is intended to provide practical guidance to Member States authorities responsible for the transposition and implementation of Article 8 and Annex VI requirements of the EED, including the establishment of transparent and non-discriminatory national minimum criteria for energy audits.
Link to the survey

Identification of future CO_2 infrastructure networks - April 2016

The objectives of the project are to 'collect and to analyse primarily legal information, as well as technical, environmental and economic data linked to carbon dioxide infrastructure, to develop necessary criteria and process for carbon dioxide (CO_2) cross-border infrastructure projects at the EU-level'.
Link to the survey

Eurelectric

Retail pricing for a cost-effective transition to a low-carbon power system – June 2016

Empowered consumers are expected to have a crucial role in the transition towards a decarbonized power system. This reports highlights two main issues. The first problem namely the rising levies and taxes or the so-called "wedge" is known but far from being solved. The second issue - the "mismatch" between the structures of regulated charges in customers' bills and their underlying costs.
Link to the survey

Optimal use of the transmission network : a regional approach – A Eurelectric position paper – June 2016

In Eurelectric 's view, achieving an integrated energy market depends on the ability to maximize the cross-border transmission capacity released to the markets in order to achieve an efficient dispatch of units across Europe.
Link to the survey

Eurelectric statement on the reform of the EU ETS – May 2016

Eurelectric believes that the European power sector's commitment to decarbonize electricity generation, together with the electrification of key sectors, such as heating, cooling and transport, will make a major contribution to help Europe meet its climate change targets.
Link to the survey

2030 Climate & Energy Toolkit - EURELECTRIC's Priorities & Policy Recommendations – May 2016

The Eurelectric 2030 Climate & Energy Toolkit presents the power sector's priorities and key policy recommendations with regard to the different elements of the EU's 2030 Climate & Energy Framework.
Link to the survey

The power sector goes digital - Next generation data management for energy consumers – May 2016

Advances in technologies, telecommunications and data analytics – digitalization- are progressively changing the consumer environment, and together with it, they provide energy players with new opportunities. Digitalisation also poses significant challenges in terms of DSO and retail supply regulation and policy-making.
Link to the survey

Electricity market design: fit for low-carbon transition - April 2016

This paper deals about the upcoming European Commission's new energy market design should ensure that consumers reap the benefit of the linking wholesale and retail markets, ensures that RES are fit for the market and improve the energy market to attract flexible resources and achieve renewable integration.
Link to the survey

Myths and realities of the European electricity retail markets - April 2016

The study urges to provide clarity on the European electricity retail markets in order to facilitate the comparison of suppliers' offers by customers. It is aimed at focusing on the real issue preventing retail market from functioning properly.
Link to the survey

Oxford institute for Energy

Algerian Gas: Troubling Trends, Troubled Policies Adjustment in the Oil Market: Structural, Cyclical or Both? - May 2016

Despite being one of Europe's largest pipeline natural gas suppliers and still very active supplier of liquefied natural gas (LNG) worldwide, Algeria has received limited serious attention as an exporter of gas in recent years. Several developments have taken place which warrant fresh insights on Algeria's natural gas sector trends and the outlook for its export potential.
Link to the survey

Do we have aligned a reliable gas exchange prices in Europe? - April 2016

This paper assesses whether the main European energy exchanges provide a reliable price reference for traded gas. Exchanges are viewed as performing a vital role in the development of a traded commodity market and if gas exchange trading activity exists and offers reliable price signals, we can conclude that these vital functions are provided at a satisfactory level.
Link to the survey

Asian LNG Demand: Key Drivers and Outlook – April 2016

The picture presented in this paper is one of LNG having to shed its mantle of a premium fuel whose import price is linked to that of oil and 're-market' itself as fuel which can contribute to a lower carbon future, by displacing coal in national energy mixes, and equally importantly reducing particulate emissions. This however calls for a radical renaissance in marketing by upstream LNG producers.
Link to the survey

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