

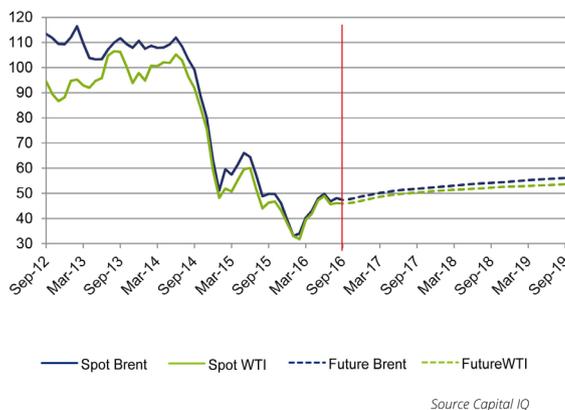


## Newsletter Power & Utilities in Europe

### Commodities



#### Crude Oil (\$/bbl)



With the price of oil at current levels, supply should contract and demand should grow strongly. However, the opposite seems to be happening.

**Global oil demand at 96.99 mbbbls/d has gone up by just under 1.3 mbbbl/d year-on-year during 3Q16.** With the price of oil at current levels, supply should contract and demand should grow strongly. However, the opposite seems to be happening. Demand growth is slowing and supply is rising, whilst stocks of oil in OECD countries are swelling to record levels. European oil demand shows dramatic contractions, particularly in Italy, France, Austria and the Nordics. A significant deceleration in non-OECD deliveries has also been seen in particular in China with an oil demand showing a complete absence of year-on-year growth for the first time since the end of the Great Recession of 2008.

**The outlook for demand is almost flat with oil demand staying at 97 mbbbls/d until the end of 2016.** The IEA outlook for 2017 confirms a global increase of just 1.2 mbbbls/d, or 0.2 mbbbls/d lower than previously anticipated.

**World oil supplies fell by 0.3 mb/d in August, dragged lower by non-OPEC.** At 96.9 mb/d, global oil output was 0.3 mb/d below a year ago. Near-record OPEC supply almost offset a steep non-OPEC decline of around 0.3mb/d in August to 56.4 mb/d. The US accounted for most of the loss. According to the IEA mid-term oil report, Non-OPEC supply is expected to return to growth in 2017 (+380 kb/d) following an anticipated 840 kb/d decline this year.

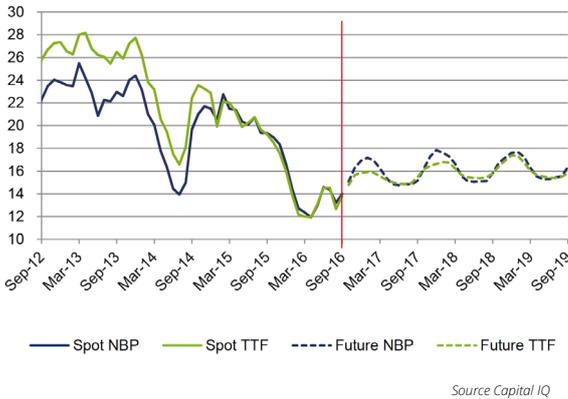
**OPEC crude production edged up to 33.47 mb/d in August - testing record rates as Middle East producers opened the taps.** Kuwait and the UAE hit their highest output ever and Iraq lifted supplies. Output from Saudi Arabia held near a record, while Iran reached a post-sanctions high. Overall OPEC supply stood 930 kb/d above a year ago.

**OECD total inventories grew by 32.5 mb in July to a fresh record** of 3 111 mb which remained steady through the summer in spite of peak refinery runs over the holiday season.

On a yearly average, global demand for 2016 will reach 96.1 mbbbl/d, 1.5 mbbbl/d over the average level in 2015. Demand in 2017 is anticipated to increase by 1.2 mbbbls/d to 97.3 mbbbls/d. **Supply in Q3 2016 reach 96.9 mbbbls/d or an 800 kbbls/d excess supply.** The latest cut in OPEC production (by an announced figure that could go up to 700 kbbls/d) decided on September 28th will only gradually rebalance the market, if at all, as supply will continue to outpace demand.



Gas (€/MWh)



European gas has now fallen low enough to make the most efficient gas plants competitive with the least efficient coal plants.

UK and European spot gas references dipped to the 12 €/MWh threshold in March. After a modest rebound, they dropped down again to 12 €/MWh during the summer.

The explanation behind this further fall in gas prices is to be found in a **weaker crude pricing against the backdrop of a long system and soft commodity prices.**

With a gas price level of 12 €/MWh, the marginal cost of gas-fired electricity generation is now equivalent to just over 30 €/MWh in Germany, still not low enough to be in the money but getting closer to the marginal cost of coal-fired electricity of around 24 €/MWh. **For the first time in four years, gas is now approaching the Coal Switching Price floor on the continent and competing with coal for power generation.** The current Coal Switching Price Index on the Dutch TTF platform is calculated at around 11 €/MWh end of August, its lowest level since late 2009. The CSPI is the gas price that would make the running costs of a hypothetical generator the same using either coal- or gas-fired plants.

In actual fact, as gas analysts point out, **European gas has now fallen low enough to make the most efficient gas plants competitive with the least efficient coal plants.** The effect is stronger in the UK with the carbon tax at £18.1/tonne.

**However traders are pointing to a sentiment of tight market rather stronger fundamentals, and European gas demand remains bearish in general.**

**In this context, Gazprom, as many gas companies, could also delay or postpone new projects such as Nord Stream 2 and the recently signed agreement to build the Turkish Stream project still faces a bearish gas demand.**



Coal (\$/metric ton)



The fundamentals of the European coal market are unchanged, amidst stable, depressed demand and weak crude oil prices.

**Unexpectedly, the Spot ARA price level and the one year forwards have risen well above the \$60 /t level, from a “spot” low which touched the \$36/t threshold earlier in 2016.** Since the beginning of April, Europe-delivered CIF ARA, both thermal coal spot and year-ahead futures, have risen around 40%.

International seaborne thermal coal trade has been driven upwards by increased activity by Chinese buyers, seeking to secure volumes ahead of government action to cut domestic production and reduce surplus capacity with a view to rebalancing of a previously oversupplied market.

However, as is the case for gas (see comment above), the European ARA coal prices may have gone up on the back of fundamentals in China **but the fundamentals of the European coal market are unchanged, amidst stable, depressed demand and weak crude oil prices.** Only 39 trades totalling around 2 million metric tonnes for physical delivery into ARA have taken place over June and July according to Platts records, while port stocks had largely remained static around 3 million mt (an all-time high) through the period.

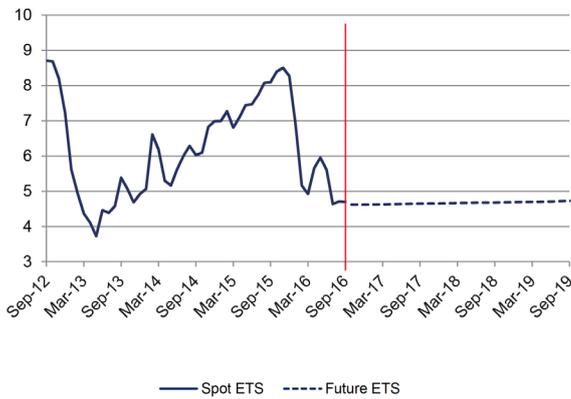
Coal use for UK power production was down by 71% year-on-year in the second quarter of 2016, a record low in 21 years, on dwindling coal-fired profit margins and shrinking available coal generating capacity, the UK Department of Business, Energy and Industrial Strategy said. Another 5 GW of UK coal-fired power capacity was taken off the wholesale market at the end of the first semester due to challenging market conditions and higher carbon costs.

**The drop in coal for power burn resulted in lower electricity supplied by major coal-fired power producers in the UK, with renewables and gas sources replacing the lost coal capacity. Analysts point out that Western coal markets will face greater attrition and consolidation in 2017 as industrial and utility demand softens and term contracts are not renewed.**



**Carbon**

CO<sub>2</sub> (€/ton)



Source Capital IQ

The underlying energy and carbon markets are stable to bearish as market participants are looking for signs of meaningful market reforms.

Although several nuclear plants remain offline in Germany and France - which may prompt increased fossil fuel burn to replace the reactors' output, hiking demand for EUAs -, EU carbon prices have come under pressure in recent months from falling coal-fired operations and rising gas-fired hours, denting demand for EUAs. The latest EU trade suggest that EUA prices are to drop even below the 4 €/mt watermark reaching their three-year low by October.

The underlying energy and carbon markets are stable to bearish as market participants are **looking for signs of meaningful market reforms**, which are increasingly needed to meet the EU objectives 2030:

**1. 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. Decisions are expected on the Phase 4 of the ETS, starting in 2021, in particular. They include raising the annual reduction rate for the cap on ETS allowances to 2.2% from 1.74% to cut ETS sector emissions by 43% compared with 2005 levels by 2030. The 2013 cap for emissions from fixed installations was set at 2 billion allowances per annum. This means that each year from 2021 the number of allowances released to the market would be reduced by about 48 million allowances yearly, instead of 38 million today. The Slovakian Presidency of the EU on Thursday said it is pushing EU governments to agree on proposed post-2020 EU ETS reforms before the end of its presidency in December.

**2. The Market Stability Reserve, which was set up with a view to backloading excess carbon credits and is expected to be built as of 2018, is still strongly rejected by Poland.**

3. The European Commission is also reported to be making a proposal to raise the EU energy efficiency target for 2030 to 30% from the current 27%. **Any new energy saving measures or any move to hike energy efficiency would lead to a reduction of EUA demand and be a clear bearish signal for EUA prices.**

4. The EU Parliament's **Environment Committee (ENVI) is pressing ahead for the parliament to consent to the EU's ratification of the Paris Agreement** on climate change, and to upgrade its emission reduction pledges to close the gap between individual countries' agreed targets and the Paris goals.

Against this backdrop, Poland, who vetoed last year the 2012 Doha Amendment which extends the Kyoto Protocol until 2020, is linking its support for EU ratification of the Paris Agreement to ongoing free allocation of EUAs to finance new coal-fired power plants.

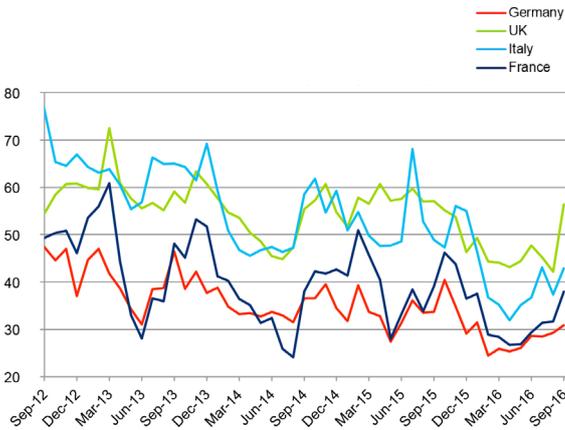
Poland is due to build 5.8 GW of new coal and lignite plants. Poland requests more AAUs (the equivalent of EUAs for Governments) to be issued for the second period of the Kyoto Protocol (2013-20) as well as transferring unused AAUs from the first period (2008-12). Unanimity amongst EU Member States is needed to ratify the Paris Agreement.

**More AAUs being issued, together with more free allocations of EUAs, will come as a clear bearish influence on EUA prices, and make recalibrating the EU ETS emission cap even more challenging.**



## Baseload Electricity

Baseload Spot Day Ahead (€/MWh)



Source Bloomberg

The higher renewables output together with increased gas burn amid falling gas prices helped to offset lower nuclear generation in Germany and France.

Although European and UK Day-Ahead Baseload electricity prices went up through 3Q 2016, all of them are still below any September level in the previous years. French prices picked up to the level of 38 €/MWh reflecting the short term marginal cost of gas-fired generation in a context of lower gas prices which have reached 12 €/MWh (see Gas section above). This price level for French electricity is 3% lower than last year's level, but 40% lower than in September 2013.

Electricity price movements in Europe have been impacted by:

1. **A reduced supply of nuclear electricity due to outages in France**, where nine of the 18 reactors were under scheduled outages resulting in complete unavailability for several days up to one full month of August;
2. **A reduced capacity on the France/UK interconnector** expected to be as much as 50% to 1 GW as of September, pushing UK base-load power prices up;

But also:

3. Continued increase in renewable generation and capacity expansion in Germany, France, the UK and Italy.

In practice, **the higher renewables output together with increased gas burn amid falling gas prices helped to offset lower nuclear generation in Germany and France** down by over 21 TWh so far this year with French August nuclear output plunging by 5 TWh alone.

German baseload day-ahead prices were assessed at 31.00 €/MWh in early September amid bearish global markets and a rise in wind power output. On the "bull side", prices have been lifted by heat-driven demand gains, plant outages and rebounding coal prices which decoupled from bearish gas and for the first time on the continent prompted some coal-to-gas switching. With the German clean-dark spread for the oldest coal-fired power plants dropping below the German clean spark spread for the most modern gas plants on a few occasions in August, some of RWE's and Trianel's CCGT **gas plants have been running baseload for the first time since early 2010**.

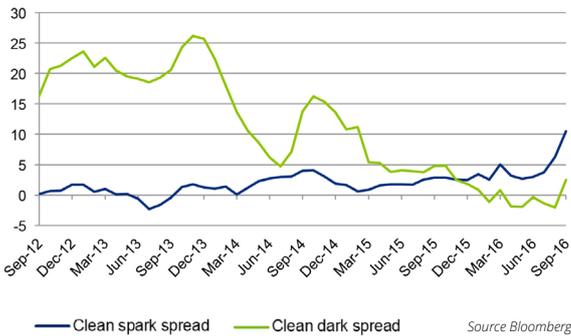
Italy's day-ahead power prices in August dropped 30% on the year on lower than usual temperatures, meaning reduced demand for air conditioning, and plummeting gas prices.

**During the first part of 2016, renewable capacity expansion continued across the EU.** Germany, France, UK, Italy have added 7 GW of wind and solar in H1 2016 with total renewable generation output up 5% in just 6 months at almost 200 TWh across the big four. The electricity generated by wind and solar across these four countries so far this year equates to over 37 billion cubic meters of gas burn (just under 10 % of EU gas demand for a full year) or around 71 million tons of coal based on average efficiencies (around 25% of the overall EU coal demand each year).

Out of the 7 GW of wind and solar capacity increase, Germany added 2.2 GW of new wind capacity of which 1.9 GW was onshore as developers rushed to grab the last available feed-in-tariffs before they are replaced by tenders from 2017. The UK increased its solar capacity by 3.5 GW, now reaching 10.8 GW, according to UK Government figures. France added a combined 1.2 GW of wind and solar with Italy adding a further 0.3 GW.



### UK clean dark & spark spread (£/MWh)



Source Bloomberg

A strong clean spark spread shows clear evidence of the position of gas as a dominant fuel for power generation in the UK.

**The UK clean dark spread** - the theoretical profit realised by a 35% efficient coal plant after paying fuel and carbon costs -, **slips into the negative territory for most of the time in Q3 2016** in the context of a 18.08 £/t CO<sub>2</sub> Carbon Price Support and average emissions of 903 kg CO<sub>2</sub>/MWh for UK coal plants. Although it has picked up modestly in September, the UK clean dark spread is almost 90% down its September 2014 level. UK's forward clean dark spreads suggest that the UK clean dark spread will stay negative through to summer 2017 at least.

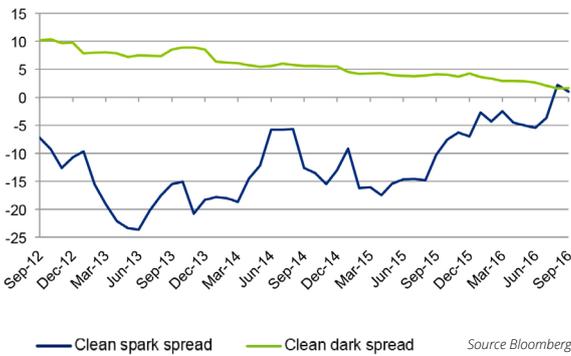
The UK clean spark spread - the theoretical profitability of a 50% efficient HHV gas-fired power plant including emissions - has been multiplied by more than 3 over the quarter and is now above the £10/MWh mark since the introduction of the UK's Carbon Price Support in April 2014.

Year-on-year, **gas load factors have nearly doubled, and coal load factors have halved in the UK. A latest UBS study shows that gas load in the first half of 2016 was 44% relative to 25% in H1 2015, while coal load was 29% relative to 60% in 2015.**

**A strong clean spark spread shows clear evidence of the position of gas as a dominant fuel for power generation in the UK.** This position is strengthened by a weak NBP curve which boosts gas-burn profitability amid constrained coal availability. With a current 10 GW available capacity, coal now accounts for less than half of the gas-fired capacity at an average of 22 GW.



### German clean dark & spark spread (€/MWh)



Source Bloomberg

The German clean dark spread has now gone down by almost 50% compared to last year and 80% over the past four years.

The TTF gas price fell to its lowest level since late 2009 on the back of solid supply allied to next to no injections into gas storage facilities, in addition to the euro strengthening against the pound. At the same time, in a context of low fossil fuel prices and abundant renewable generation, German spot power prices dropped to as low as €19/MWh over the summer.

As a consequence, **the German clean spark spread** — a measure of profitability for a 50% efficient gas plant after taking into account fuel and carbon costs — **jumped into the positive territory (at long last) reaching 2 €/MWh, an almost four-year high, matching the profitability of a coal plant.** This means that, as mentioned above, the European continental gas price is hitting the coal-switching price (CSPI) calculated at €10.60/MWh for the Dutch TTF gas price. The CSPI is the gas price that would make the running costs of a hypothetical generator the same using either coal- or gas-fired plants.

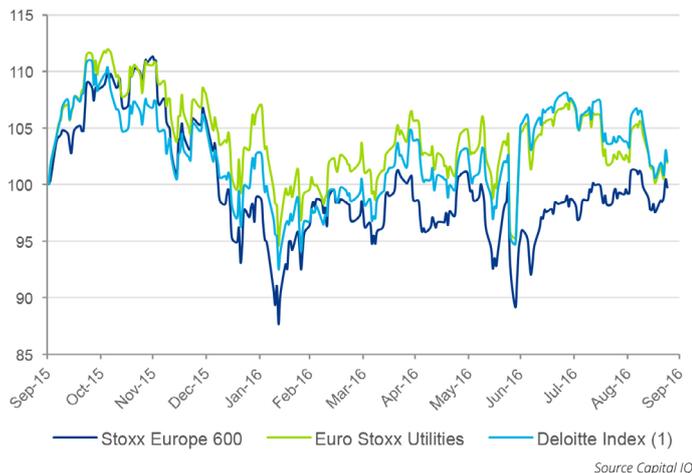
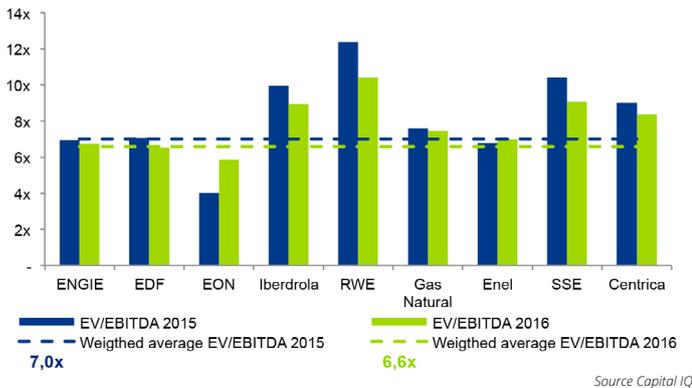
At the same time, the cost of running coal-fired power plants increased on the back of rising fuel prices, with the European benchmark for coal CIF ARA 6,000 kcal/kg hitting a 17-month reaching a high of over \$62/mt (see coal section above). As a consequence, the German clean dark spread – **the profitability of a German 35% efficient coal plant after paying fuel and carbon costs – has now gone down by almost 50% compared to last year and 80% over the past four years.**

# Spotlight on Power and Utilities market

## Capital market overview

	Deloitte Index <sup>(1)</sup>	Enel	Iberdrola	Engie	EDF	Gas Natural	SSE	Centrica	E.ON	RWE
<b>Market cap. ratios</b>										
Currency		EUR	EUR	EUR	EUR	EUR	GBP	GBP	EUR	EUR
Market cap. (Sept. 2016)		40 477	37 490	33 575	22 417	18 334	15 565	12 538	13 614	9 146
3m stock price performance	-3%	0%	-1%	-5%	-4%	3%	-1%	0%	-32%	4%
<b>YoY stock price performance</b>	<b>2%</b>	2%	2%	-1%	<b>-30%</b>	3%	5%	3%	-16%	<b>56%</b>
<b>Market multiples</b>										
EV/EBITDA 2015	6,6x	6,8x	10,0x	6,9x	7,1x	7,6x	10,4x	9,0x	4,0x	12,4x
EV/EBITDA 2016	6,3x	7,0x	9,0x	6,7x	6,5x	7,5x	9,1x	8,4x	5,9x	10,4x
P/E 2015	12,2x	18,4x	15,3x	n.m.	18,9x	12,2x	26,6x	n.m.	n.m.	n.m.
P/E 2016	13,8x	12,8x	14,6x	13,2x	6,9x	13,7x	13,0x	15,4x	16,9x	14,5x
<b>Price/book value 2015</b>	<b>1,5x</b>	1,2x	1,0x	0,8x	<b>0,6x</b>	1,3x	<b>3,0x</b>	n.m.	1,4x	1,5x
<b>Profitability ratios</b>										
ROE forward 12m	14%	10%	7%	6%	9%	9%	23%	69% <sup>(2)</sup>	5%	9%
ROCE forward 12m	8%	8%	5%	6%	6%	7%	11%	17%	13%	9%
EBITDA margin 2015	20%	21%	22%	15%	20%	19%	8%	8%	6%	10%
EBITDA margin 2016	21%	20%	24%	16%	23%	20%	8%	9%	12%	12%
EBIT margin 2015	12%	14%	13%	8%	8%	12%	5%	4%	3%	4%
EBIT margin 2016	13%	12%	14%	9%	11%	12%	6%	5%	8%	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



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

### Key messages from brokers and analysts

“Regulated and renewables are the main growth areas for most companies”  
 (Morgan Stanley - September 19, 2016)

“Renewable competitiveness monitor – Focus on offshore wind”  
 (UBS, August 22, 2016)

“UK green policy at an inflection point”  
 (JP Morgan, September 15, 2016)

“More pain ahead for UK coal”  
 (UBS, July 15, 2016)

“The lack of effective government in Spain is sustaining a “quiet period” in terms of regulation noise”  
 (HSBC – September 23, 2016)

## M&A Trends

### Transactions involving Power & Utilities companies

**EPH**, a Slovakian energy Group, **acquired from Enel for €375m 50% in Slovak Power Holding**. The company owns 66% in Slovenske elektrarne that owns and operate nuclear, coal and hydro power plants with a revenue of €2.3bn. (*GlobalData – August 1, 2016*)

Chinese largest hydropower group **China Three Gorges Corporation acquired BCP Meerwind Luxembourg**, a 288MW offshore wind power plant, **from Blackstone for \$730.6m**. (*GlobalData – August 23, 2016*)

**Innogy**, company hosting RWE's renewables assets, announced **to take over Belectric Solar & Battery Holding GmbH, a local solar and battery specialist**, in the high double digit million euro range, to expand its position on utility-scale photovoltaic power plants and battery storage technologies. (*SeeNews– August 30, 2016*)

**Fortum** acquired **Ekokem, a Finnish company providing environmental management services, for a total amount estimated at €700m (81% from Finnish authorities for €470m and the remaining through by public tender**. (*GlobalData – September 1, 2016*)

**Korea Electric Power Plants acquired stake in NuGeneration from Toshiba and Engie**. NuGeneration is engaged in construction and development of the Moorside nuclear power project situated in England. The total installed capacity of the power plant is 3,800 MW with a £10bn expected cost. (*GlobalData – September 14, 2016*)

French Nuclear group **Areva announced** to withdraw from wind power business by **selling its stake in Adwen JV to Gamesa**. In June 2016 Siemens took over a majority shareholding in Gamesa for over €1 billion. (German Collection – September 16, 2016)

Spanish gas distribution company **Enagas bought a 20% stake in Chile's liquefied natural gas (LNG) regasification plant GNL Quintero from Endesa Chile for \$197m**. (*Spanish Collection – September 16, 2016*)

**SunPower Corporation acquired for \$170m AU Optronics Corp's share of Melaka**, a Malaysian solar cells manufacturers. (*Accesswire – September 21, 2016*)

Irish-owned wind independent service provider **Optinergy**, part of Galetech Energy Developments Group Ltd, acquired the wind energy-focused **O&M division of LotusWorks**, as part of a **€650m group pipeline investment**. (*SeeNews – July 25, 2016*)

### Transaction involving equity funds

**The Balfour Beatty Equitix Consortium**, an investment company, has agreed **to acquire from E.ON SE for £162.9m the company that should connect the 229MW Humber Gateway offshore plant**. (*GlobalData – September 8, 2016*)

**InfraRed Capital Partners**, an investment company, **acquires Afton** a 50MW wind farm in Scotland, E.ON Climate & Renewables for **\$101.7m**. (*GlobalData – September 21, 2016*)

# European Power and Utilities companies wrap-up

The HY16 performances are negatively impacted by low commodities prices, a broader slowdown in European economy, the warm weather and negative foreign exchange impact. However in this context Renewables and Regulated activities delivered good performances.

In a world of low commodity prices and a broader slowdown in the European economy, the HY16 performances are mainly driven by the warm weather and negative foreign exchange impact. These effects have been partially offset by good performances in Renewables and Regulated activities.

In this context companies are still focusing on their more visible business to grow (Renewable and Regulated activities) and on performance programs.

The focus on Renewable and Regulated activities is namely becoming a reality with the finalization of the spin-off between E.ON and Uniper and the IPO of Innogy by RWE.

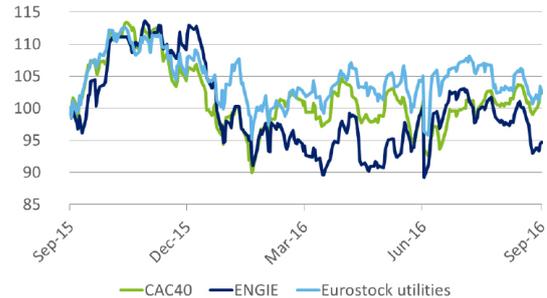
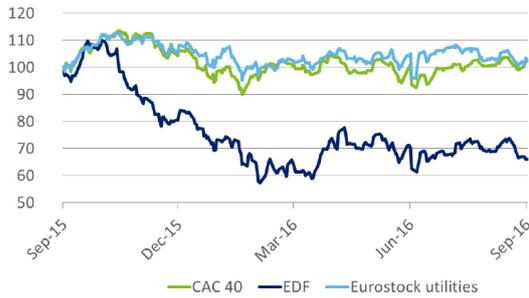
The major announcements of the quarter are probably coming from EDF with the green light on the construction of 2 nuclear EPR reactors in the UK, the decision to extend the depreciation period from 40 to 50 years of 33 reactors out of 58 in operation, and the agreement with the French Government to close Fessenheim nuclear power plant.

FY16 outlooks are confirmed for all Utilities and upgraded for Enel and Centrica.





Share Price Perf. Sep. 2015 Sep. 2016



Key Reported Financials

In billion of €	H1 2016	H1 2015	Var.
Sales	36.7	38.9	-6%
<b>EBITDA</b>	<b>8.9</b>	<b>9.1</b>	<b>-2%</b>
Operating Income	4.5	4.5	-
<b>Recurring net income Gr</b>	<b>3.0</b>	<b>2.9</b>	<b>3%</b>
<b>Net Income Gr Share</b>	<b>2.1</b>	<b>2.5</b>	<b>-16%</b>
Operating CF	6.2	6.1	2%
Net Capex	-6.9	-6.5	6%
Net debt	-36.2	-37.4*	-3%

\* as of Dec. 31, 2015

In billion of €	H1 2016	H1 2015	Var.
Sales	33.5	38.5	-13%
<b>EBITDA</b>	<b>5.7</b>	<b>6.1</b>	<b>-8%</b>
Operating Income	3.5	3.6	-3%
<b>Recurring net income Gr</b>	<b>1.5</b>	<b>1.6</b>	<b>-6%</b>
<b>Net Income Gr Share</b>	<b>1.2</b>	<b>1.1</b>	<b>9%</b>
Operating CF	4.5	6.0	-25%
Net Capex	-3.1	-2.9	7%
Net debt	-26.0	-27.7*	-6%

\* as of Dec. 31, 2015

H1 2016 Highlights

- Ebitda amounted to €8.9bn, -2% vs H1 2015, due to:
  - low power prices combined with end of regulated tariffs to industrial customers in France,
  - very good performance in renewables (6TWH generated in H1-2016)
  - challenging market conditions in the UK partially offset by good nuclear output
- Operating income benefits from extension of the depreciation period from 40 to 50 years of the 900MW nuclear fleet (33 reactors out of 58 in operation) partially offset by non recurring income recorded in 2015.
- Preliminary agreement with the French Government on Fessenheim nuclear power plant for a closure in 2018 associated to a €400m indemnity.
- MoU signed with Areva formalising the progress of discussions on their projected partnership with namely the contemplated acquisition by EDF of an exclusive control of AREVA nuclear reactor business (equity value of €2.5bn)
- Green light from both the EDF Board of Directors and UK Government on Hinkley Point C project (2 nuclear EPR reactors)
- Exclusive negotiations with Caisse des Dépôts and CNP Assurances for a partial disposal of RTE, the French electricity TSO (Equity value of €8.4bn)

- Ebitda reached €5.7bn, -8% vs H1 2015, due to:
  - Unfavourable exchange rate effect and negative prices impacts for gas and LNG midstream activities and in a lesser extent for E&P and power generation.
  - These items are partially offset by (i) the positive impact of the restart of Doel 3, Tihange 2 and Doel 2 nuclear power plants in Belgium, (ii) the initial effects of the Lean 2018 performance program and (iii) commissioning of new assets.
- The operating income is positively impacted by the the reduction of depreciation and amortization charge as result of impairments and reclassification of assets as held for sale recorded in 2015.
- Significant developments in low CO2 power generation:
  - 500MW low CO2 capacity commissioned
  - 400 MW of solar tenders won
  - Acquisition of Maia Eolis reinforcing leadership position of Engie in Wind
- Increased visibility on French regulated transmission and distribution networks:
  - New 4 years framework for distribution
  - Ongoing public consultation for transmission and LNG terminals
- Transformation plan well on track

FY 2016 Outlook

2016 guidance confirmed and 2018 ambitions maintained

2016 guidance confirmed



Share Price Perf. Sep. 2015 Sep. 2016



Key Reported Financials

In billion of €	H1 2016	H1 2015	Var.
Sales	20.3	22.8	-11%
<b>EBITDA</b>	<b>2.9</b>	<b>3.3</b>	<b>-12%</b>
Operating Income	2.0	2.1	-5%
<b>Recurring net income Gr</b>	<b>0.6</b>	<b>0.8</b>	<b>-25%</b>
<b>Net Income Gr Share</b>	<b>-3.0</b>	<b>1.1</b>	<b>-373%</b>
Operating CF	0.7	3.2	-78%
Net Capex	-1.3	-1.1	18%
Net debt	-25.5	-27.7*	-8%

\* as of Dec. 31, 2015

In billion of €	H1 2016	H1 2015	Var.
Sales	23.9	24.8	-4%
<b>EBITDA</b>	<b>3.0</b>	<b>3.2</b>	<b>-6%</b>
Operating Income	1.9	2.0	-5%
<b>Recurring net income Gr</b>	<b>0.6</b>	<b>0.5</b>	<b>-20%</b>
<b>Net Income Gr Share</b>	<b>0.5</b>	<b>1.7</b>	<b>-71%</b>
Operating CF	-1.0	0.7	-243%
Net Capex	-0.8	-1.2	-33%
Net debt	-28.3	-25.1*	13%

\* as of Dec. 31, 2015

H1 2016 Highlights

- **Ebitda amounted to €2.9bn, -12% vs H1 2015.** In April 2016 Management Board of E.ON announced to move from EBITDA to operating income (EBIT) to comment its performance meaning that no analyses on EBITDA is provided by E.ON.
- Operating income decreased by €0.1bn due to a **deterioration in German Nuclear Power plants** managed by Preussen Elektra **partially balanced by a positive variation on core business** (good performance in renewables and Customers solutions partially offset by a drop in Energy networks).
- Following the approval of the spin-off by the Annual Shareholders meeting, E.ON announced its intention to enter in an **agreement with Uniper to allow the deconsolidation of Uniper Group no later than first half of 2017**. In this respect E.ON classified **Uniper as discontinued operation and assets held for sale**. Before the reclassification a €2.9bn impairment charge was recognized namely on European generation (€1.8bn) and Global commodities (€1.1bn).
- **Regulatory update in Germany for energy networks** with an updated incentive regulation and the change of allowed returned on equity.
- **Significant developments in windfarm power plants:**
  - The 200MW Colbek's Corner windfarm in Texas is fully operational since May 2016.
  - Other windfarm projects are on track (Twin Forks 278MW in 2017, Rampion 400 MW in 2018, Arkona 385MW in 2019)
- Ebitda reached €3.0bn, -6% vs H1 2015 in a context marked by a continuous economic **upturn and higher energy consumption in RWE's key market but offset by a weather warmer** than in 2015 and lower wholesale and retail gas prices.
- Operating income decreased by €0.1bn due to **significantly lower earnings from energy trading** but partially offset by a positive impact of cost reductions in conventional power generation.
- The financial loss worsed by €0.3bn due to losses from the sale of securities compared to profits in 2015.
- **In 2015 the sale of RWE Dea contributed to the net income with a €1.5bn profit.**
- **IPO of Innogy**, RWE's subsidiary hosting business in Renewables, Grid and Supply, with a market capitalization of close to €20bn (€8bn for RWE). RWE still owns 75% of Innogy share capital after 10% offer through newly issued shares and 15% sold through a private placement.
- **No consensus found yet between German government and utilities about financing nuclear exit**
- **Agreement with Gazprom on long-term gas procurement contract**
- Rating downgrade to Baa3 / BBB-

FY 2016 Outlook

2016 guidance confirmed

2016 guidance confirmed



Share Price Perf. Sep. 2015 Sep. 2016



Key Reported Financials

In billion of €	H1 2016	H1 2015	Var.
Sales	34.2	37.6	-9%
<b>EBITDA</b>	<b>8.1</b>	<b>8.0</b>	<b>1%</b>
Operating Income	5.2	5.1	2%
<b>Recurring net income Gr</b>	<b>1.7</b>	<b>1.6</b>	<b>6%</b>
<b>Net Income Gr Share</b>	<b>1.8</b>	<b>1.8</b>	-
Operating CF	4.2	3.0	40%
Net Capex	-3.5	-2.8	25%
Net debt	-38.1	-37.5*	2%

In billion of €**	H1 2016	H1 2015	Var.
Sales	15.8	18.3	-14%
<b>EBITDA</b>	<b>na</b>	<b>na</b>	
Operating Income	2.1	1.6	31%
<b>Recurring net income Gr</b>	<b>0.6</b>	<b>0.7</b>	<b>-14%</b>
<b>Net Income Gr Share</b>	<b>1.4</b>	<b>1.2</b>	<b>17%</b>
Operating CF	1.7	1.4	21%
Net Capex	-0.5	-0.5	-
Net debt	-4.5	-5.8*	-22%

\* as of Dec. 31, 2015

\*\*assuming a fixed exchange rate of 1.18 into euros

H1 2016 Highlights

- Ebitda improved to €8.1bn, +1% vs H1 2015 in a context of sales decrease due to a decline in both electricity sale and electricity trading. This performance is attributable to:
  - **better than expected operating performance of generation in Italy and Spain,**
  - the performance posted in **Latin America with a 40% growth** despite local economic slowdown.
- Enel reported since the beginning of the year the acquisition of c.400,000 new customers
- **Metroweb integration with Enel Open Fiber** for the integration of Broadband in Italy
- **Latam reorganization** (breakup of Enersis split into two listed company with Enersis Chile (power generation and distribution in Chile) and Enersis Americas (activities in Colombia, Brazil, Peru and Argentina)) still under progress
- Activities reorganisation with Endesa unit buying 60% of Enel Green Power Espana for €1.21bn
- **Significant investments** in Solar plant from Enel Green Power for \$410m
- Sale of 50% in Slovak Power Holding to EPH for \$406m
- Operating income amounts to €2.1bn and includes **a €1.1bn profit related to energy trades remeasurement (€0.5bn in H1 2015)**. Excluding energy trades remeasurement operating income is down by €0.1bn at €1.0bn.
- The **decrease in recurring operating income** is primarily reflecting extreme **warm weather in North America and the impact of low commodity prices on E&P and Central power generation**, partially offset by cost efficiency.
- **Strong progress on cost saving** targets with efficiency of €0.2bn delivered in H1 2016
- **UK Home energy account losses** of 3% in H1 2016 due to long-term roll-offs and increased competitive intensity as consequence of CMA pressure.
- Centrica is extending its capacities in generation distribution and asset management thanks to **ENER-G Cogen and Neas Energy acquisitions**, and is launching new innovative services to market.
- **GLID wind-farm sale completed and Canada E&P disposal process commenced**
- Moody's rating confirmed at Baa1, stable outlook
- Brexit vote creates uncertainty but limited immediate impact

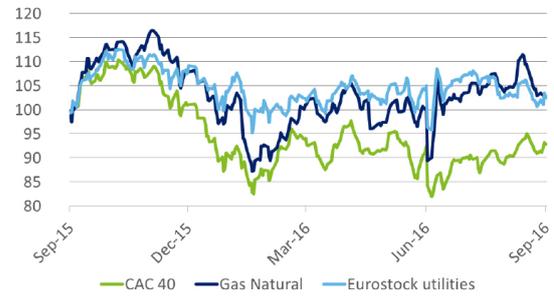
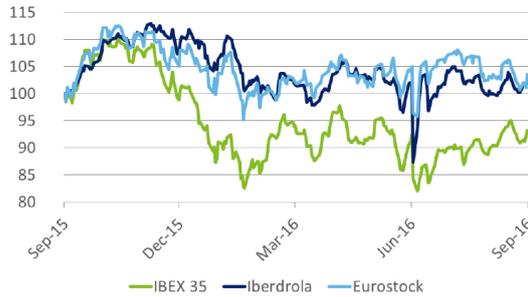
FY 2016 Outlook

Upgrade of 2016 net income guidance by 3% at €3.2bn

2016 Full-year cash flow and financial targets underpinned



Share Price Perf. Sep. 2015 Sep. 2016



Key Reported Financials

In billion of €	H1 2016	H1 2015	Var.
Sales	14.9	16.1	-7%
<b>EBITDA</b>	<b>3.9</b>	<b>3.8</b>	<b>3%</b>
Operating Income	2.3	2.2	5%
<b>Recurring net income Gr</b>	<b>1.4</b>	<b>1.3</b>	<b>8%</b>
<b>Net Income Gr Share</b>	<b>1.5</b>	<b>1.5</b>	-
Operating CF	3.2	3.0	7%
Net Capex	-1.9	-1.3	46%
Net debt	-28.0	-28.1*	-

\* as of Dec. 31, 2015

In billion of €	H1 2016	H1 2015	Var.
Sales	11.4	13.4	-15%
<b>EBITDA</b>	<b>2.5</b>	<b>2.7</b>	<b>7%</b>
Operating Income	1.4	1.6	-13%
<b>Recurring net income Gr</b>	<b>na</b>	<b>na</b>	
<b>Net Income Gr Share</b>	<b>0.6</b>	<b>0.7</b>	<b>-14%</b>
Operating CF	1.8	1.6	13%
Net Capex	-0.6	-0.7	-14%
Net debt	-15.8	-15.6*	1%

\* as of Dec. 31, 2015

H1 2016 Highlights

- Ebitda grow to €3.9bn, +3% vs H1 2015, thanks to:
  - **improvement of Network business performance in Spain and US** surmounting negative FX impact
  - **Higher output from Renewables in Spain and US**, partially offset by lower output in the UK
  - **Lower tariff in Mexico** for regulated generation
  - Higher output and retail activity on liberalised generation and supply in Spain
- The **regulated business EBITDA is improving** by €0.1bn thanks to US networks on partially offset by lower performance on Mexican generation and renewables
- Good progress in the development of Transmission and Distribution Networks and 5,000 MW of windfarm and regulated generation
- The integration of UIL in Avangrid contributed to Ebitda for \$0.2bn and investment plan is on track**
- Sale of wind assets portfolio in Italy representing 0.5GW of combined installed capacity

- Net sales totalled €11.4bn in H1 2016, a **15% decline compared to 2015** broadly due to:
  - The consequence of **disposal of the liquefied petroleum gas business in Chile** (Gasco) in 2015. Excluding this operation the decline would have been 6%;
  - The **decline in commodity prices**
  - The **negative FX impact** especially linked to depreciation of Colombian peso and Brazilian real.
- Ebitda reached €2.5bn, -7% vs H1 2015, due to the above item and negative FX impact in particular which accounts for €0.1bn.
- The contribution in Ebitda from operations in Spain increased by 2%, while the contribution from international activities dropped by 15%.**
- Sale of the 20% stake in GNL Quinteros (Chile) to Enagas for €0.2bn**
- Issue of (i) a €0.6bn EMTN notes maturing in 2026 with a 1.25% annual coupon and (ii) a €0.3bn bond maturing in 2021 with a 0.515% annual coupon through a private placement

FY 2016 Outlook

2016 guidance confirmed

2016 guidance confirmed

# Topics

## 1 - Gas in Europe: where are we today?

Sources: IEA, WEO 2015 - IEA, Gas Medium-Term Market Report 2016 - BP Statistical Review 2016 - Oxford Institute for Energy Studies Forum, August 2016

Gas consumption in the European Union has grown steadily from 1965 to 2005, when it reached its peak at 500 Bcm per annum. It kept stable at this maximum level during 5 years, and began decreasing in 2011. Between 2010 and 2014, EU gas consumption has experienced a sharp decline of 23% to 385 Bcm/y, slipping below the 400 Bcm/y threshold, a level not observed since 1995. This is due to structural shifts to the European economy, changing consumption patterns and significant progress on energy efficiency. Gas consumption has stabilized at 402 Bcm in 2015.

**The outlook on EU gas consumption is that gas demand will stay flat, or even drop slightly again, until 2020 at which point it starts increasing.**

In parallel, the EU gas production is due to decline by more than 40% over the next two decades. According to BP Statistical database, the EU's net imports of natural gas are expected to rise by 41% over the 2015 – 2035 period, with increases in both LNG and Russian pipeline imports. Russian pipeline's share of EU gas consumption is likely to hold steady around 30%, while the share of LNG rises from 7% in 2014 to 28% by 2035.

**Gas demand in the EU: falling but expected to recover**

Gas use across the EU has declined in almost all countries between 2010 and 2015 except for Bulgaria (+12.3%) and Poland (+8%), to include Norway as well (+17%) although this country is no EU member state. Demand in Scandinavia decreased the most (-36% for Denmark, -46% for Finland and -43% for Sweden) where energy efficiency policies have been strong. Next were Hungary (-29%), the UK (-28%) and the Netherlands (-27%).

**Gas consumption is highly concentrated in the EU.** In 2015, 75% of total consumption is accounted for by only six countries: Germany, the UK, Italy, France, the Netherlands and Spain. Germany, the UK and Italy alone represent 50% of total EU demand. According to the IEA, gas demand across OECD Europe has dropped in all sectors, and most notably in power and residential. **Between 2010 and 2015, residential demand decreased by**

**11%, from 223 Bcm to 199 Bcm/y; and by 30% in the sole power sector, from 201 Bcm to 140 Bcm/y or a contraction equivalent of the loss of the total gas consumption of Germany,** the sixth largest gas user in the world. As far as power generation is concerned, the main drivers were a declining electricity consumption due to increased energy efficiency and changing consumption patterns in combination with a significant increase in renewable generation. In addition, gas lost even more ground from 2011 onwards as coal plants became more competitive than gas plants in the context of falling coal prices and low carbon prices. In the residential sector, energy efficiency programmes in Germany and the UK have been particularly impactful on gas demand as well.

Looking ahead, gas demand in the EU however is expected to increase in the years to come. According to the IEA, consumption in Europe should increase by a modest 2.5 %, or 10 Bcm between 2015 and 2021. Looking further ahead, **the European Network of Transmission System Operators for Gas (ENTSOG) expects a 13% to 35% increase in EU gas demand to 2030**, with the demand breakdown between countries remaining stable. The increase in gas use is expected to be driven by power generation. Gas-fired power generation should increase by 3% in OECD Europe between 2013 and 2020, according to the IEA. Meanwhile, renewables capacity expansion, whilst supported by the EU commitment to reach 20% renewable energy in the overall energy supply by 2020, will continue. Gas-fired power generation is expected to gain some market share at the expense of the coal and nuclear plants which are earmarked for retirement. The limits imposed by the EU Industrial Emission Directive, together with other EU policies should result in coal plants retirements of over 30 GW from 2015 to 2021, and up to 70 GW between 2014 and 2030 in Europe<sup>1</sup>. Nuclear capacity should also decline by 7 GW between 2014 and 2021<sup>1</sup>, driven by retirements in Germany, and by 17 GW in total in the EU between 2014 and 2030. The capacity of gas to capture the coal and nuclear market shares will very much depend on the

The outlook on EU gas consumption is that gas demand will stay flat, or even drop slightly again, until 2020 at which point it starts increasing.

The European Network of Transmission System Operators for Gas (ENTSOG) expects a 13% to 35% increase in EU gas demand to 2030.

1. IEA, 2015

competitiveness of the gas price (i.e. the Coal Switching price) and the level of the carbon price. Except in the UK, where the existence of a carbon price floors has allowed gas fired plants to be competitive against coal in 2015, gas prices are only just reaching the Coal Switching Price of 11 €/MWh on continental Europe (see Commodity Prices above), with a Carbon Switch Price which was calculated at 18 €/tonne in Germany during the summer.

Outside the power sector, the IEA projects EU gas consumption to remain relatively flat. Small increases in the industrial sector should offset small declines for residential and commercial.

### **EU gas production in the EU should keep decreasing**

Since 1970<sup>2</sup> the supply of gas in the EU has never experienced as fast a decrease as these last years, mirroring falling oil and gas prices combined to a slowing demand. The EU gas production fell by 32%, from 176 Bcm in 2010 to 120 Bcm/y in 2015<sup>3</sup>. The fastest declines came from Denmark (-44%), the Netherlands (-39%), Germany (-32%) and the UK (-31%), whereas only very few countries experienced growth: Romania (+8%), and Poland's remained stable. Norway's production grew by 9%, from 107 Bcm in 2010 to 117 Bcm/y in 2015 in a bid to keep its European continental market share. Supply in the EU is dominated by the UK and Netherlands, which together account for almost 70% of production in 2015. Including Norway into EU domestic gas production perimeter, Norway accounts for 49% of total domestic supply in 2015.

### **The mature fields of Norway, the UK and the Netherlands together account for 84% of the production.**

The production in the Netherlands comes almost only from one big field (Groningen) and several onshore small fields which have been propped up by Dutch policies over the years. Last years' decrease results from the government's decision to cap Groningen production, in response to an increased seismic activity in the region linked to gas production. In 2015, the Groningen field production was capped at 27 Bcm/y, or half of its 2013 level. According to the IEA, production should keep declining (-10 Bcm/y between 2015 and 2021) with the cap on Groningen continuing and the small fields production also decreasing. Norway's production recovered in 2015 after a decline in 2013 and 2014, but is expected to decrease again by 10 Bcm between 2015-2021, with low oil and gas

prices causing a slowdown in the exploration & production investments (down by 25% since 2013 according to the Norwegian Petroleum Directorate). Low prices also hit hard the UK production which is anticipated to lose 10 Bcm between 2015 and 2021. **Companies are fighting to survive and maintain exploration.** Despite tax concessions in the UK and the Netherlands, including major tax reductions introduced by the UK government in 2015 and in 2016 budget, production in the North Sea should continue to decrease and result in an increase in decommissioning of platforms and infrastructure. **The TYNDP 2015 of the ENTSOG has a point therefore in highlighting the fact that the EU will be an increasingly net importer of gas on the long run.**

### **The latest development of EU gas infrastructure**

In 2015, imported gas represented 88% of total EU gas demand<sup>4</sup> and most of it was pipe gas. The main source of OECD Europe gas imports was Russia with 158 bcm of natural gas or 33% of the total EU demand, coming via the Brotherhood and the Yamal pipe system, as well as the Nord Stream 1 pipeline today. The major challenge over that years has been to diversify sources outside of Russia and increase interconnectivity inside Europe. Major recent pipelines additions have been keen to avoid the thorny issue with transit countries, including

- (i) Nord Stream, that began operations in 2012 and allows Russia to bypass the Ukraine and deliver gas directly to Germany, and
- (ii) Medgaz, a pipeline with a 8 Bcm capacity which runs from Algeria to Spain bypassing Morocco and began operations in 2011.

**Further options to diversify supply via pipelines include the Galsi pipeline (connecting Algeria straight to Sardinia) or the Turkish Stream from Russia to Turkey and onwards into the EU, but none are to be operational before beyond 2025.** The Turkish Stream project, announced by Russia as an alternative to the long promoted and eventually scrapped South Stream project, was initially planned with four lines, three of which would serve to replace transit through Ukraine. The gas was supposed to be delivered at the Turkish-Greek border and the EU should be responsible for building connecting pipelines on its territory.

Outside the power sector, the IEA projects EU gas consumption to remain relatively flat. Small increases in the industrial sector should offset small declines for residential and commercial.

The TYNDP 2015 of the ENTSOG has a point therefore in highlighting the fact that the EU will be an increasingly net importer of gas on the long run.

2. Statistical period observed by the BP Statistical Review 2016

3. BP Statistical review 2016

4. Oxford Energy Forum, 2016

Gazprom recently announced that gas should actually continue to transit through Europe and that the capacity of the project would be reduced from 63 Bcm/ year to 31 Bcm/ year. Following recent tensions between Russia and Turkey, including the shooting down of a Russian military aircraft by the Turkish army, experts think that the project could even be abandoned.

**In addition to these new pipelines, increased interconnectivity in Europe came from introducing reverse flows capabilities on existing lines.** For example, the establishment of reverse flows on the Brotherhood pipeline (connecting Russia to central Europe) allows for gas flows from Western to Eastern European countries, including sales of Russian imported gas to the Ukraine by EU gas operators. Storage capacities have also developed (from 118 bcm in 2010 to 137 bcm in 2015 in OECD Europe) with a view to increasing energy security.

LNG imports appears as the main competition for Russian gas in the coming years. As per IEA figures, LNG import capacity in OECD Europe reached 203 bcm in 2014, a 12% increase of since 2010. Terminals are well spread in Europe and vary in size, from less than 1 Bcm in Norway or Sweden to almost 20 Bcm in the UK. In 2014, the total LNG regasification capacity in OECD Europe represented about 45% of the region's consumption. Spain alone represents 29% of the EU regasification capacity. Together, the UK, France, the Netherlands and Belgium account for 47% of the total EU capacity. The fastest increases in capacity between 2010 and 2015 occurred in France and the Netherlands, the UK, Poland and Lithuania. **However and despite the long-standing effort of the EU to diversify gas supply, the utilisation rate of EU regasification terminals has been low over the past years;** it was just above 20% in 2014 and kept decreasing in 2015. As LNG is part of a global market, flows are directed to markets offering higher prices, Asia in particular. But with supplies of LNG increasing and the European-Asian differential price collapsing, the incentive for EU operators to reload and reroute EU LNG to Asia has disappeared.

Further afield, pipeline projects around the Caspian basin, referred to as through the Southern Gas Corridor project, are considered as an important source of future gas supply to the EU. The whole project consists of a series of pipelines – including the Trans-Anatolian pipeline (TANAP) and Trans-Adriatic pipeline (TAP) which will transport gas from Azerbaijan to European markets. The first gas is expected to reach Turkey in 2018, with supply to Europe expected by 2020. Once this connection becomes fully operational, it will enable the EU to import natural gas from Azerbaijan, Turkmenistan and possibly Iran. The EU has been lobbying for the Trans-Caspian gas pipeline project as a part of the TANAP project with a view to connecting Azerbaijan, Georgia, Turkmenistan, Turkey and the EU. However, in addition to technical risks such as gas reserves and construction risks, the legal status of the Caspian Sea and environmental concerns have been flagged by both Moscow and Tehran as major obstacles.

**The Ten-Year Network Development Plan 2015 (TYNDP) of the European Network of the Transmission System Operators of Gas (ENTSO-G) contemplates 259 infrastructure development projects (Projects of Common Interest) to ensure the security of gas supply to the EU over a two-decade period, 2015 to 2035.** The European gas supply is still considered a security concern that requires promotion of new pipelines and terminals. However, gas companies across Europe are holding plenty of unused capacities today. Gas transportation, interconnection or storage facilities are largely idle. One would think that the gas infrastructure projects above will find it difficult to attract investors' and lenders' interest, at least in the current EU market context.

Despite the long-standing effort of the EU to diversify gas supply, the utilisation rate of EU regasification terminals has been low over the past years.

The European gas supply is still considered a security concern that requires promotion of new pipelines and terminals. However, gas companies across Europe are holding plenty of unused capacities today.

## 2 - Is Solar PV the next electricity revolution in the US?

Sources: IEA – NEA, *Projected Costs of Generating Electricity, 2015 Edition* - NREL, *Photovoltaic System Pricing Trends, 2016* - IRENA report, 2015 - UBS Research Study, *Pan European Utilities, Renewables competitiveness monitor, August 2016* - Mirova, *When renewable energy met sustainable growth, July 2016*

### **Solar accounts for 1.1% in the electrical capacity in the US, or 13 GW which is about half of the current solar capacity of Germany.**

It represents 0.3% of electrical generation (15 TWh) in 2013. However, US solar PV is expected to represent 8.9% in electrical capacity (120 GW) and 4.2% in electrical generation (209 TWh) in 2040.

Solar installation costs are divided almost evenly between hardware costs (PV module production and balance of system –BOS- costs, i.e. additions of components to modules) and soft costs (permitting, labour, site preparation, grid connection, financing, and installation fees). In 2015, hardware costs (45% to 66% of total costs) are taken in a 1.2 to 1.4 \$/W range, while soft costs (34% to 55% of total) vary between 0.6 and 1.7 \$/W depending on the scale of the system. Until now, the greatest opportunity for costs reductions has lied in hardware costs, especially module production. Module production is a multi-step process that generally mobilizes different types of players. It requires the production of ultrapure silicon that will then be treated to become cells, and cells will be fused together into modules. As cell manufacturing is highly capital intensive (\$1-2 million / MW of plant capacity<sup>5</sup>), the majority of players are located in China. They are able to offer lower costs but their frail regulation and low transparency compared to other players is often pointed at as a risk factor. Module and panel production is less capital intensive and assumed by smaller players close to the end markets, mostly Europe and the US. Eventually, installation represents low capital costs but high labour costs, resulting in an often regional and fragmented market.

### **The fast development of PV manufacturing capacity in China, largely resulting from the EU support policies to solar combined with the decrease of polysilicon prices and scale effects, has caused the global price for PV modules to decline by 75% between 2007 and 2015<sup>6</sup>.**

As the technology matures, decreases are slowing, emphasizing the need to increase efficiency and reduce Balance-Of-System costs and soft costs, which, for utility-scale PV plants, could fall by between 55% and 74% between

2015 and 2025 according to the International Renewable Energy Agency. A September 2016 study from UBS demonstrates that the overall investment cost for solar PV has been divided by a factor 3 between 2010 and now.

### **According to the IEA, the Levelized Cost Of Electricity (LCOE) for solar PV is comprised in a 53-300 \$/MWh range depending on country, size of the system and cost of capital. Recent solar auctions have been reported to have reached a level as low as 30 \$/MWh in Latin America.**

**Solar prices in the US have decreased extremely rapidly over the past years.** With the US solar LCOE sitting between 50 and 85 \$/MWh (under a 7% WACC assumption), the US solar electricity seems to be way more competitive than Europe's. European solar LCOE, according to the latest study from UBS (*UBS Global Research, Pan European Utilities, Renewables Competitiveness Monitor, 22 August 2016*), are between 84 and 112 \$/MWh. It would seem that the large difference between US and EU solar prices is accounted for by the Operation & Maintenance costs which in the US are 75% to 80% below the levels published in Italy, Spain, France or Germany.

On a global scale, solar broadly remains more expensive than gas (60-140 \$/MWh), onshore wind (32-220 \$/MWh) and nuclear (25-140 \$/MWh) but slightly below offshore wind (102-330 \$/MWh).

### **The US solar regulatory package: a mix of tax cuts and PPAs which proved more efficient than the EU Feed-In Tariffs?**

US policy incentives behind renewables are essentially through tax. US fiscal incentives to prop up the development of solar include:

- the Investment Tax Credit (ITC), a one-time credit of 30% of installed costs applied to solar projects, and
- the Modified Accelerated Cost Recovery System (MACRS), an accelerated depreciation scheme which is eligible to companies of all size, but in fact largely used by utilities.
- Power-Purchase Agreement (PPA) are financial agreements where a developer arranges for the design, permitting, financing and

Solar accounts for 1.1% in the electrical capacity in the US, or 13 GW which is about half of the current solar capacity of Germany.

The US solar regulatory package: a mix of tax cuts and PPAs which proved more efficient than the EU Feed-In Tariffs?

5. Mirova, 2016

6. NREL, *Photovoltaic System Pricing Trends*, in IEA 2016

installation of a solar energy system on a customer's property at little to no cost. The developer sells the power generated to the host customer at a fixed rate.

**At State level, Renewable Portfolio Standards (RPS) can support solar development by imposing a fixed portion of electricity from renewables.** RPS have been the basis of the development of a green power market. Producers sell Renewables Energy Certificates (REC) either to players that do not comply with RPS obligation, or wish to buy them as a financial investment. The sale of REC forms an additional revenue to the sale of power for solar PV producers. **The main difference with the European Feed-In Tariffs is that REC prices fluctuate depending on liquidity and market conditions.**

Solar PV are either installed on residential and commercial buildings, or ground mounted installations. In the first case, they can be owned by the electricity consumer himself, or by a third party company that leases the spaces and sell the resulting power to the consumer at a lower rate than the local utility. In the second case, installations have an installed capacity in excess of 1 MW. They are, owned and operated by a utility or an independent power producer (IPP) who is responsible for selling power into the grid and manages its exposure to RECs and the green markets. Under a third configuration, a company (or a government) may wish to develop and use a solar system, either onsite or offsite, at minimal upfront costs, without having to secure the financing of it. **A developer then will act as an IPP, and draw on the fiscal incentives and PPA guarantees to secure the financing and profitability, and sell the electricity and RECs back to the company, potentially at a premium over the market price.**

This is the case for the Apple deal with First Solar: under a 25-year PPA announced in 2015, First Solar will build and operate the plant and Apple will buy the power.

One may wonder if the solar cost decrease that has been seen in the US is accounted for by more competitive systems (continued costs reductions beyond hardware costs, development of storage systems ...) or a more appropriate support mechanism: tax incentives in the US have had the effect of benefiting the developer and reducing fiscal revenues for the State, whilst the European Feed-In Tariff have guaranteed revenues to the developers whilst ensuring solid tax returns to the states.

Today the US has a solar industry that is booming. **As a US developer recently put it: "While it took us 40 years to hit 1 million U.S. solar installations, we're expected to hit 2 million within the next two years".**

The main difference with the European Feed-In Tariffs is that REC prices fluctuate depending on liquidity and market conditions.

As a US developer recently put it: "While it took us 40 years to hit 1 million U.S. solar installations, we're expected to hit 2 million within the next two years".

### 3 - Disclosure by financial and non-financial companies of climate-related information for French companies

In 2015, the COP21 and the Paris agreement emphasised the significant role of companies in fighting climate change and the importance of adequate monitoring and reporting of greenhouse gas (GHG) emissions. In 2015 as well, the French Law for the Energy Transition and Green Growth took an important step in this direction; it can even be considered as a world premiere for some of its requirements on disclosure of information by companies and investors on climate risks. As such, this law and how it is to be implemented are worth having a close look, even for non-French companies.

The scope of the French Law for the Energy Transition (adopted in August 2016) is very wide, from nuclear production to plastic bags. Its article 173 deals with disclosure by financial and non-financial companies of climate-related information, including how they are exposed to climate change, the risks companies face because of climate change, their carbon footprint, and their contribution to the energy and ecological transition. The main requirements are the following:

1. All French listed companies are required to publish greenhouse gas (GHG) emissions generated directly and indirectly by their activities (scope 1 and 2 emissions, as before, and, in addition, Scope 3 emissions);
2. Non-financial companies will have to disclose the financial risks posed by climate-related impacts and their associated low-carbon strategies;
3. Financial institutions will have to disclose how they take into account environmental, social and corporate governance (ESG) criteria (including criteria related to climate), how they are exposed to climate risks through their investments and how they use their voting rights to contribute to the energy and ecological transition.

#### 1) French listed companies shall publish information on the emissions of greenhouse gases generated by the company's activities, including those generated by the use of goods and services it produces, whenever they are "significant".

So, in addition to direct GHG emissions (that have to be reported in annual reports since 2012, and article 225 of the French law "Grenelle 2"), significant indirect GHG emissions have thus to be quantified and disclosed as well. These emissions can be related to the use of goods and services produced and sold

by the company ("downstream" emissions). The word "including" puts forward that it is not exclusive: "upstream" emissions (emissions due to non-energy goods and services bought by the company) shall be disclosed as well, if they are considered as "significant". In other words, reporting on GHG emissions is no longer limited to Scope 1 (direct emissions) and to Scope 2 (emissions related to energy consumption); **it has to include also Scope 3 emissions (indirect emissions) when they are considered as significant.** The relative importance of Scope 3 emissions varies greatly depending on the activity of companies; in some cases, they can be up to 100 times higher than Scope 1 and Scope 2 emissions. For instance, when building a solar farm, most GHG emissions come from the production of wafers (Scope 3, upstream); for a company producing and distributing fossil fuels, most GHG emissions come from the combustion of products sold (Scope 3, downstream).

#### 2) Non-financial companies will have to disclose:

- the **financial risks** posed by climate-related impacts, and
- the **low-carbon strategies** they implement throughout all their activities to reduce these risks.

The financial risks posed by climate-related impacts are poorly addressed by the Law, as it describes neither what they should include nor how to assess and report them.

#### 3) Institutional investors and asset managers

(insurance companies, mutual funds, public institutions (such as Caisse des Dépôts), public and private pension funds, etc.) have to include in their annual report, and communicate to their clients and beneficiaries, information on their climate-associated strategies and climate-related risks. Said information shall include at least the following topics:

- How their investment decision-making process takes into account environmental, social and corporate governance (ESG) criteria and criteria related to energy and ecological transition;
- How their climate change strategy has an influence on their voting rights associated with their investments;
- How they are exposed to climate risks through their investments (inter alia, they shall disclose the GHG emissions associated with their investments);
- Their contribution to the national climate strategy and to the targets of the national energy and ecological transition.

In 2015 as well, the French Law for the Energy Transition and Green Growth took an important step in this direction; it can even be considered as a world premiere for some of its requirements on disclosure of information by companies and investors on climate risks.

The financial risks posed by climate-related impacts are poorly addressed by the Law, as it describes neither what they should include nor how to assess and report them.

In addition to the law, the implementation decree provides a more precise list of required information from institutional investors and asset managers and the way to present it:

- How they communicate their climate strategies to their beneficiaries and clients;
- Adhesion to an initiative, association, organism or label related to ESG information, if any;
- Among the environmental risks they disclose, they have to make a distinction between physical risks (exposure to physical consequences directly caused by climate change) and transition risks (exposure to evolutions caused by the transition to a low-carbon economy);
- Their methodologies to analyse these risks; in particular precisions can be given on how these methodologies take into account the following elements:
  - Consequences of climate change and of extreme weather events;
  - Evolution of availability and price of natural resources;
  - Coherence between investments and a low-carbon strategy (inter alia for investments in companies dealing with fossil fuels);
  - Data on GHG emissions: past and future, direct and indirect emissions from emitters within their investment portfolio;
  - Any elements that enable a better understanding of their exposure to climate risks.

**All these requirements apply from the fiscal year ending on December 31, 2016.** A first evaluation of these requirements will have to take place after 2 years.

On the whole, these new requirements have been welcomed by most stakeholders. However **a few limitations have been put forward:**

- **The deadlines are very tight:** regarding indirect GHG emissions, the implementation decree was published in August 2016 and applies from the fiscal year ending on December 31, 2016.
- **The Directive on disclosure of non-financial information (Directive 2013/34/EU) is about to be transposed into French law** (the transposition by Member States has to be realised by 6 December 2016), which may modify further obligations regarding reporting on non-financial information. It may have been more efficient to wait for the outcome of this transposition before modifying these reporting requirements.
- **Another key discussion point is about the readiness of required methodologies to implement these disclosure requirements.**

Actually, French government purposely published a text without imposing strict and detailed methodologies (for instance, propositions to introduce specific requirements for specific sectors were discarded). They opted for a flexible approach (comply or explain), to allow companies and investors to set up the most relevant reporting methodologies themselves, on a voluntary basis.

**The current challenge is now to decide how to implement these requirements in practice, starting from reporting year 2016:**

- **Quantifying Scope 3 emissions can be realised with robust existing methodologies** (e.g. GHG Protocol). **But the challenge lies more in data collection.** It requires to gather information that is not within the direct scope of activity of the company; collecting upstream and downstream data may require deep interaction between a company and its stakeholders involved in the same value chain (both providers and clients).
- **Practical methodologies are not clearly defined yet to:**
  - assess and report climate-related risks for financial and non-financial companies,
  - analyse the coherence between investment policies and low-carbon national strategies,
  - quantify GHG emissions associated with a given investment portfolio.

In this context, international efforts to define guidance and best practices are highly welcome. **One of the most advanced initiative in this direction has been undertaken by the Financial Stability Board (FSB). In December 2015, it launched the industry-led Task Force on Climate-related Financial Disclosures (TCFD), after a request from the G20 in April 2015.** This task force aims at promoting more effective climate-related disclosures and at developing a set of recommendations for voluntary, consistent climate-related financial risk disclosures for use by companies in providing information to investors, lenders, insurers, and other stakeholders; these recommendations will apply both to financial and non-financial firms. The TCFD considers three categories of risks related to climate change: **physical, liability and transition risks.** It delivered a first report in March 2016, describing the fundamental disclosure principles. A final report to be published by mid-December 2016 will set out specific recommendations and guidelines for voluntary disclosure by identifying leading practices to improve consistency, accessibility, clarity, and usefulness of climate-related financial reporting.

All these requirements apply from the fiscal year ending on December 31, 2016. A first evaluation of these requirements will have to take place after 2 years.

The current challenge is now to decide how to implement these requirements in practice, starting from reporting year 2016.

In particular, the TCFD is likely to propose **disclosure in four different dimensions:**

- **governance:** vision of the Board on the risks and opportunities related to climate; role of the company's management regarding the assessment and the management of these risks and opportunities;
- **strategy:** risks and opportunities identified in the short, medium and long terms; potential impact on the company's business and strategy; impact of a "two degrees" scenario on the company's business model, strategy and financial plan;
- **risk management:** process used to identify and assess climate-related risks; processes to manage these risks; how these processes are integrated into the overall risk management strategy;
- **metrics and targets:** metrics used to measure and monitor these risks and opportunities; reporting on Scope 1 and Scope 2 emissions and, if relevant, Scope 3 emissions; goals and targets used in relation to climate change.

The TCFD is also considering proposing that companies use (and disclose) **scenario analyses for forward-looking assessment of risks and opportunities**. It would enable companies to evaluate the potential impacts of different climate scenarios on their risks and financial returns and the effect of such scenarios on their financial and strategic positions.

**Monitoring and disclosing GHG emissions throughout their value chain and climate-related risks is a key element of companies and investors' involvement in any climate change mitigation global strategy. The law for the energy transition puts France at the forefront of this trend; it increases also the demand for robust methodologies and widely acknowledged standards. The development of new guidelines and recommendations is rather urgent and is currently underway, which can be witnessed for instance with TCFD's initiative.**

Monitoring and disclosing GHG emissions throughout their value chain and climate-related risks is a key element of companies and investors' involvement in any climate change mitigation global strategy.

## 4 – Carbon taxes

Sources: Gerard Mestrallet Report to the French Minister of Energy & Environment, Carbon Pricing Proposal (in French only) July 2016 - Mirova, Investing in a low carbon economy, Special Issue COP 21 - EPE, I4CE, Institute for Climate Economics, Prix interne du Carbone (in French only), September 2016 - World Bank report 2015

**Although carbon pricing is no new topic, it becomes a hot topic when regulators and lawmakers start wondering which policy instrument between carbon tax and carbon trade in the context of fighting climate change is most efficient.** Carbon pricing aims at giving an economic value to a tonne of Green House Gas (GHG) emissions to both make polluters pay and encourage emission reduction strategies and investments. As of now, carbon pricing remains a national consideration, as no global mandatory system exists.

Two main carbon pricing mechanisms are used to support investment in emissions reductions and/or penalise emissions:

- (i) A financial disincentive, generally **a tax**, applied to a company or end-user for every tonne of GHG released. No cap is set on the volume that will depend on how much emitters are willing to pay. Examples include the UK Carbon Price Floor, or the announced French Tax on Carbon for 30 €/tonne.
- (ii) Alternatively under the so called **"cap-and-trade"** systems like the European Emission Trading Scheme (ETS), an emission cap is

set for each year (normally decreasing every year) with a number of quotas to reflect the emission cap; and market participants need to buy emission quotas relative to their physical emissions. Quotas are traded on a carbon market. Their price is determined daily and meant to reflect the short term marginal cost of carbon abatement at any point in time.

**In other words, a cap-and-trade system sets a cap on volumes of carbon and lets the market adjust the price. A carbon tax does exactly the opposite: it gives a price to each tonne of carbon and lets the market adjust the volumes.**

About 40 national jurisdictions and over 20 cities, states, and regions, accounting for about 7 GtCO<sub>2</sub>-equivalent ("tCO<sub>2</sub>-eq"), or 12% of 2015 global emissions, are covered by **carbon pricing mechanisms<sup>8</sup> including 15 ETs and 16 carbon taxes<sup>9</sup>.**

Carbon pricing is no new topic, but it becomes a hot topic when wondering about the most efficient policy instrument between carbon tax and carbon trade.

8. World Bank Group, 2015

9. I4CE, 2016

The EU ETS is the largest internal system with 2 GtCO<sub>2</sub>-eq of emissions covered but due to an excess liquidity of EUAs (EU quotas) and free allowances, the carbon price is relatively low today with 5.5 €/tCO<sub>2</sub>-eq compared to a 1-130 \$/tCO<sub>2</sub>-eq global range. A structural reform is under way at European Commission level in 2015 to reduce allowances and enable cost-effective emission reductions in the decade to come. China and the United States are the countries with the largest volume of physical emissions (respectively 8 Gt CO<sub>2</sub>-eq for China and just under 6 Gt CO<sub>2</sub>-eq for the US). They are also the countries with the smallest share of emissions covered by carbon pricing instruments (1 GtCO<sub>2</sub>-eq for China or 12% and 0.5 GtCO<sub>2</sub>-eq for the US or 8%) amongst comparable economies. China currently has seven pilot ETSs, which together form the largest national carbon pricing initiative in terms of volume (price ranging from 1 to 6 €/tCO<sub>2</sub>-eq) and should move to a national ETS. In North America, California and Québec's cap-and-trade programs expanded their GHG emissions coverage from about 35% to 85% by including transport fuel. Ontario announced its intention to implement an ETS linked to California and Québec's programs. Other countries in Asia Pacific and North America also have or intend to have EU-style ETS mechanisms soon.

#### How do Carbon taxes work?

One of the main carbon pricing mechanisms used across the world, the carbon tax is an additional cost added to the sale price of a good depending on the quantity of GHGs emitted during its production and/or use. It is set at country or state level. Carbon tax offers visibility on carbon pricing, as the price of carbon is known to all time, therefore allowing investors to make investment decisions in low carbon technology. However a carbon tax does not ensure a level of emissions reductions. **The tax is sector-specific and can target upstream producers, downstream companies, or end-users. A carbon tax is generally the easiest pricing mechanism to implement and operate, as it only requires to monitor and report emissions.** The choice between carbon pricing mechanisms is usually reflective of a particular context. For example, the EU never had authority to impose a tax across EU member states but could create an ETS market, whereas South Africa opted for a tax as an EU-type ETS system would not have been efficient given the concentration of the energy sector around the coal industry only. However, a carbon tax system can be the first step to an ETS; it may co-exist with it or complete it by not targeting the same sectors or players. The carbon taxes in France,

Ireland, Portugal and Sweden, for instance, are applicable to selected, non-EU ETS sectors. In France, the tax only applies to energy products not covered by the EU ETS while Sweden allows carbon tax exemptions for installations under the EU ETS, with the most recent increase in exemption starting from 2014 for district heating plants participating in the EU ETS. Revenues raised by carbon taxes can be used in various ways (energy and climate related programs, redistribution, tax reductions etc).

#### Carbon Taxes across the world

As of today, carbon taxes are to be found mostly in Europe, but also in a few other places including Shanghai, Japan, Mexico or British Columbia, Canada. Sectors with a high dependence on fossil fuels and a high share of global CO<sub>2</sub> emissions are particularly targeted: transport, power production, or industries such as paper, chemicals, construction. Among EU countries, some countries use carbon taxes in addition to the ETS whereas other exclude industries already covered by it.

The level of carbon taxes varies widely across the world, from 1 \$ to 130\$/tCO<sub>2</sub>-eq in Sweden with sometimes differentiated taxes in a same country. Nordic European countries show the highest tax level (57-58 €/tCO<sub>2</sub>-eq in Finland applicable to heat and electricity production as well as transportation and heating fuels, 30 to 134 €/tCO<sub>2</sub>-eq in Norway on oil industries, 96 €/tCO<sub>2</sub>-eq in Sweden on natural gas, gasoline, coal, light and heavy fuel oil, liquefied petroleum gas (LPG), and home heating oil. The latest carbon taxes include the UK Carbon Floor Price of 18£/tCO<sub>2</sub>-eq, or France's announced *Taxe Carbone* of 30€/tCO<sub>2</sub>-eq.

According to the IEA, these price levels are not high enough yet to achieve the volume reductions consistent with energy transition scenarios as the 450 ppm Scenario of the IEA (in line with capping the temperature increase to 2 degrees by the end of the century) is based on an underlying assumption of carbon price reaching 100 to 140 \$/tCO<sub>2</sub>-eq between 2030 and 2040.

**Currently, 85% of emissions covered by both Cap-and-Trade and Tax mechanisms in the world are priced under 10\$ tCO<sub>2</sub>.**

A carbon tax is generally the easiest pricing mechanism to implement and operate, as it only requires to monitor and report emissions.

Carbon price levels are not high enough yet to achieve the energy transition scenarios of the IEA in line with capping the temperature increase to 2 degrees by the end of the century.

### **Carbon taxes: a climate risk management tool for companies and countries**

Putting a price on carbon is increasingly perceived as a way to measure, monitor and manage the climate risk. Climate change involves risks of many kinds: physical risks, with global warming and its consequences (drought, climatic catastrophes, ecosystems change etc), regulatory risks, financial risks including physical and financial assets whose value is impaired in consideration of their damage to the environment, stranded assets, as well as legal and regulatory risks (e.g. coal plants in the US and the EU which are now earmarked for early closure). Governments often focus on physical risks and try to mitigate them with regulation, tax and policies, while companies try to anticipate the financial, legal and regulatory risks. According to Mark Carney, Governor of the Bank of England and President of G20 FSB, the financial industry (institutional investors and insurers especially) natural catastrophes, assets devaluation resulting in loss of value, to include legal claim from investors is a risk which is today completely undervalued. For countries as well as companies, pricing carbon is a way to identify, measure and anticipate risks in their long term investment decisions.

### **The “internal carbon prices” or company carbon taxes**

For a few years now, corporates have been aware that they are facing a significant exposure to the price of carbon in relation to the emissions of their activities. They have also been concerned that the currently depressed level of the ETS quota – at least in Europe – was not reflective of their real carbon risk. Corporates are also aware that the value of their assets or contracts could be significantly impaired depending on the price of carbon, and that a number of their facilities could face, either significant investment in efficiency upgrade or closure, depending on COP 21 decisions or under the 450 ppm Scenario of the IEA for instance.

In absence of a regulated or market-based carbon price, or in addition to it, companies may decide to impose on themselves and use an internal carbon price. Numerous companies have set internal carbon taxes as a way to reduce their emissions, prevent risks and demonstrate their support to the transition to a low carbon economy. According to the Carbon Disclosure Project (CDP), 435 companies across the world have set up and used an internal carbon price in 2014, three times more than the year before. Another 600 companies intend to have one set up over the next 2 years.

Internal carbon pricing can be in two ways: either the company decide to use a theoretical price called “shadow price”, based on the current or anticipated carbon price, which is then used for the purpose of company projections, strategy plans, R&D policy and investments decisions. Or, the company may alternatively apply an internal tax which will increase the costs of operations according to each subsidiary’s or business unit’s emission level. The internal tax will influence the strategy in the same way than the shadow price, but it will also hurt polluting activities financially as it will involve money transfers. The internal proceeds of the tax may be used as the company wishes, from offsetting its carbon footprint to financing internal emissions reduction initiatives or rewarding environmental projects.

### **Companies with high emissions levels, including energy players, will generally use a shadow price whereas less emitting companies, such as service or finance players, elect an internal carbon tax mechanism.**

Veolia, Suez or Total have set shadow prices. Veolia announced its intention to reduce its emissions by 100 MtCO<sub>2</sub>-eq and avoid 50 MtCO<sub>2</sub>-eq by 2020. Integrating a shadow price (up to 31 €/tCO<sub>2</sub>-eq by 2030) is part of this strategy. In order to demonstrate its support to carbon pricing worldwide, Total introduced a carbon shadow price as early as 2008. Once 25 €/tCO<sub>2</sub>-eq, the price has been revised to 30-40 €/tCO<sub>2</sub>-eq in 2016.

Suez, has also decided to use a shadow price for carbon in its investments decisions. Since July 2016, different prices have been introduced in respect of setting up business plans depending on national jurisdictions, e.g. 30 €/tCO<sub>2</sub>-eq in Europe and 50 €/tCO<sub>2</sub>-eq in respect of low carbon business plans. Finally, Société Générale, the French bank, introduced an internal carbon tax in 2011 whereby the banks business units have to pay 10 €/tCO<sub>2</sub>-eq in respect of the carbon emissions of their activity. The money collected is used to finance internal emissions reduction initiatives. La Poste, the French Mail, also decided to compensate its carbon footprint thanks to an internal tax on carbon as of 2012.

A Carbon tax, either at a national, international or company level, is one of the few carbon pricing instruments today. Its role in supporting emissions reductions and investments towards low carbon models is crucial. Its implementation is often easier than the setting up of an EU-style ETS. As a public policy instrument, it can target specific carbon-intensive sectors and it gives price certainty, contrary to the EU-type ETS system.

For a few years now, corporates have been aware that they are facing a significant exposure to the price of carbon in a context of depressed level of the ETS quota not reflective of their real carbon risk.

A Carbon tax, either at a national, international or company level, is one of the few carbon pricing instruments today. Its role in supporting emissions reductions and investments towards low carbon models is crucial.

However, experience today demonstrates that a carbon tax may not be sufficient to contribute the desired emission reduction, unless it is set at a level which governments will probably hesitate to impose on their national industries. In a recent report to the French Government, the former CEO of Engie's is proposing, inter alia, an EU carbon market review leading to the setting up of a carbon price "corridor", with a floor and a cap (25 to 50 €/tCO<sub>2</sub>-eq in 2020, and 50 to 100 €/tCO<sub>2</sub>-eq in 2030), in order to restore investors' confidence and stimulate their investments in low carbon systems.

**More fundamentally, the above internal carbon price initiatives demonstrate that corporates need a long term carbon price assumption as an additional way of "stress-testing" the value of their assets, both with a view to measuring, and protecting against, possible stranded assets in the future.**

The above internal carbon price initiatives demonstrate that corporates need a long term carbon price assumption as an additional way of "stress-testing" the value of their assets.

# 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?

### Informal Energy Council: Energy Union governance, financing and energy prices and costs

Key features	Insights
<p>On 12th July 2016, an <b>informal meeting of EU energy and climate change ministers</b> took place in Bratislava. At this meeting, EU ministers discussed:</p> <ul style="list-style-type: none"> <li>• How to <b>achieve</b> the European Union's <b>climate and energy goals</b>. They focused on <b>sustainable financing</b> of the transition to a low-carbon economy and a <b>new management system</b> for the <b>Energy Union</b>.</li> <li>• The energy prices and costs across Europe and ways to boost competitiveness on energy markets. The meeting aimed to unpick the factors that determine the prices of energy such as market conditions and regulations.</li> <li>• The Commission's plans for an <b>EU Liquefied Natural Gas (LNG) and energy storage strategy</b> which was launched in February this year.</li> </ul>	<p>The main outcomes of the informal meeting of EU energy and climate change ministers were:</p> <ul style="list-style-type: none"> <li>• <b>Energy and climate change policies</b> are closely <b>interlinked</b>. Strengthening the <b>cooperation among Member States</b> in this area is a precondition for effective functioning and reaching Energy Union objectives.</li> <li>• Member States agreed on the need to thoroughly analyse the impact of all newly adopted measures on competitiveness of European enterprises. They emphasized that <b>each state</b> has the right to <b>choose appropriate measures</b> for reaching <b>climate and energy objectives</b> in accordance with the principle of technological neutrality.</li> <li>• The implementation of <b>diversification measures of gas</b> sources via <b>LNG</b> is important for all Member States. It is important to build an intra-European infrastructure that guarantees deliveries of LNG for all EU Member States.</li> </ul>
	<b>Next steps</b>
	<p>Next Energy Council is planned for December 2016.</p>

[Link: Informal Energy Council](#)

### European Commission's proposal: 263 million euros in energy infrastructure

Key features	Insights
<p>On 15th July, EU countries agreed on the European Commission's proposal to <b>invest €263 million</b> in key trans-European <b>energy infrastructure projects</b>.</p> <p>In total, nine projects were selected following a call for proposals under the <b>Connecting Europe Facility (CEF)</b>, an EU funding programme for infrastructure:</p> <ul style="list-style-type: none"> <li>• 5 in the gas sector (€210 million);</li> <li>• 4 in the electricity sector (€53 million).</li> </ul>	<p>The selected projects will <b>increase energy security</b> and help end the isolation of EU countries from EU-wide energy networks.</p> <p>In the gas sector, the allocated grants will cover, among others, the construction of the Balticconnector (EU support €187.5 million), the <b>first bi-directional sub-sea gas pipeline between Estonia and Finland</b>. The Balticconnector:</p> <ul style="list-style-type: none"> <li>• will enhance the security of supply in the Eastern Baltic Sea region;</li> <li>• will provide for the diversification of sources and routes;</li> <li>• will enable competition on the regional gas market.</li> </ul> <p>In the electricity sector, the list will include the construction of a <b>new 140 km electricity line between Dobrudja and Burgas in Bulgaria</b> (EU support €29.9 million). The EU support in Bulgaria:</p> <ul style="list-style-type: none"> <li>• will contribute to reinforce security of electricity supply;</li> <li>• will integrate renewable energy in the electricity market;</li> <li>• will increase future power exchanges, in view of the expected wind power from Greece and photovoltaic energy from South Bulgaria.</li> </ul> <p>The European Commission proposal to select these projects was supported by the CEF Coordination Committee, which consists of representatives from all EU countries.</p>
<b>Next steps</b>	
<p>With a total of €800 million available for grants under CEF Energy in 2016, the second 2016 call for proposals with an indicative budget of €600 million is currently ongoing and will close on 8 November.</p>	

[Link: 263 million euros in energy infrastructure](#)

## European Commission invests in synergies: transport and energy infrastructure

Key features	Insights
<p>On 28<sup>th</sup> September, the European Commission launched the first ever call for proposals under the EU funding programme for infrastructure - the Connecting Europe Facility (CEF) - to <b>support projects fostering synergies between transport and energy infrastructure</b>.</p> <p>The call makes <b>€40 million</b> available to studies supporting <b>smart, sustainable and inclusive growth</b>, in line with the Europe 2020 strategy, as well as enabling the EU to achieve its sustainable development targets through the <b>creation of synergies between transport and energy</b>.</p>	<p>Actions selected under this call will support the deployment of <b>sustainable and efficient transport and energy infrastructure</b> by contributing to achieving the following specific objectives:</p> <ul style="list-style-type: none"> <li>• <b>Transport sector:</b> Ensuring sustainable and efficient transport systems, by supporting a transition to innovative low-carbon and energy-efficient transport technologies and systems, while optimising safety.</li> <li>• <b>Energy sector:</b> <ul style="list-style-type: none"> <li>- Increasing competitiveness by promoting the further integration of the internal energy market and the interoperability of electricity and gas networks across borders;</li> <li>- Supporting projects promoting the interconnection of networks in the Member states;</li> <li>- Removing internal constraints;</li> <li>- Decreasing energy isolation;</li> <li>- Increasing the interconnectivity in electricity and achieving price convergence between the energy markets.</li> </ul> </li> </ul>

### Next steps

Applicants have until 13 December 2016 to submit their proposals. The outcome of the call will be published by April 2017.

[Link: 2016 CEF Synergy call](#)

## Key consultations from EU

What is discussed?	Insights	Link
<p>“Consultation on the Evaluation of Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products”.</p>	<p>EU seeks to collect views and suggestions from stakeholders and citizens for the purposes of the current evaluation of Council Directive 2009/119/EC imposing an obligation on Member States to maintain stocks of crude oil and/or petroleum products.</p> <p>Closing date: November 11th.</p>	<p><a href="#">Link to the consultation</a></p>
<p>“Consultation on the establishment of the annual priority lists for the development of network codes and guidelines for 2017 and beyond”.</p>	<p>EU seeks to consult stakeholders on the priorities for the development of network codes and guidelines for 2017 and beyond. The European Commission has to establish in accordance with Article 6(1) of Regulation (EC) No. 714/2009 (“the Electricity Regulation”) and Article 6(1) of Regulation (EC) No. 715/2009 (“the Gas Regulation”) an annual priority list identifying the areas to be included in the development of network codes.</p> <p>Closing date: October 14th.</p>	<p><a href="#">Link to the consultation</a></p>

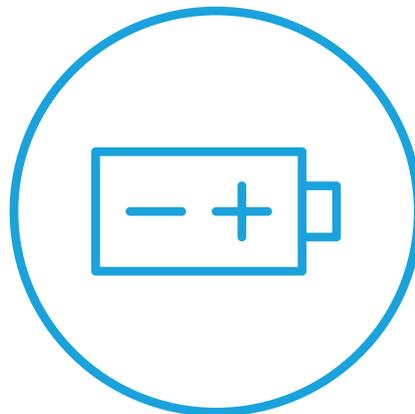
Country reporting on changes in the Policy and Regulation framework

Germany			
Topic	Key features	Insights	Next Steps
Draft of an amendment to the Renewable Energy Sources Act 2017 (EEG 2017) and the Combined Heat and Power Act 2016 (KWKG 2016)	<ul style="list-style-type: none"> <li>In the course of the <b>state aid negotiations</b> between the German Federal Government and the European Commission from August 2016, the <b>German legislator has to adjust</b> several <b>provisions</b> of the (not yet in force) EEG 2017 and KWKG 2016.</li> <li><b>Changes introduced</b> by the new regulation:                             <ul style="list-style-type: none"> <li>- Introduction of <b>tenders</b> for the funding of <b>cogeneration power plants</b> with an installed capacity between <b>1 and 50 MW</b> and of innovative cogeneration systems (e.g. combination with solar thermal energy/thermal pumps);</li> <li>- <b>Discharge of large electricity-consuming enterprises</b> of the <b>KWKG levy</b> (transfer of the EEG's special equalization scheme);</li> <li>- Amendment of the EEG 2017 provisions concerning the grandfathering in the <b>self-supply model</b>: It is stipulated that companies which profit by the grandfathering provisions in the special equalization scheme have to <b>pay 20 % of the EEG levy</b> if they <b>replace the generator</b>. No changes to new power plants.</li> </ul> </li> </ul>	The amendment of the KWKG 2016 may privilege energy intensive companies and can open new saving opportunities.	<p>The first draft was published on September 26th, 2016.</p> <p>The tenders concerning cogeneration power plants will start in Winter 2017/2018.</p>
Ordinance on interruptive loads (AblAV)	The Ordinance regulates the <b>obligation of TSOs</b> to carry out <b>tender procedures</b> concerning <b>interruptive loads</b> .	The ordinance is a <b>new source of income</b> for Power Companies by taking part with interruptive loads.	The ordinance was proclaimed on August 16th, 2016. But it does not come into force before the <b>European Commission's state aid approval</b> . This has not yet happened.

United Kingdom			
Topic	Key features	Insights	Next Steps
Review of embedded benefits	<ul style="list-style-type: none"> <li>Embedded benefits are <b>transmission cost advantages</b> that small scale distribution connected generation has been able to capture in the GB electricity market.</li> <li>Due to concerns that these benefits are <b>distorting competition</b> between <b>types of generation</b> there are now multiple <b>proposals to remove them</b>. Their removal has the support of the regulator, Ofgem.</li> </ul>	<ul style="list-style-type: none"> <li><b>It will take away</b> one of the big <b>drivers for the success of small scale plant</b> in recent <b>capacity mechanism auctions</b>. This could push capacity mechanism <b>clearing prices higher</b> and therefore raise <b>revenues</b> for existing <b>generators</b>.</li> <li>This is likely to be the leading edge of <b>changes to transmission and distribution charging mechanics in the GB market</b> to facilitate efficient connection and operation of storage, smart demand etc.</li> </ul>	<p>Decisions on embedded benefits will happen quickly, potentially <b>before the end of the year</b>.</p> <p>Wider changes to transmission and distribution charging will take materially longer to happen.</p>

France			
Topic	Key features	Insights	Next Steps
Decree on electricity self-consumption	<ul style="list-style-type: none"> <li>The Decree enacts in law the ambition of the Energy transition law to develop electricity self-consumption.</li> <li>Electricity self-consumption relates to electricity produced on-site in order to supply on-site demand.</li> <li>The Decree provides that:                             <ul style="list-style-type: none"> <li>The self-consumption regime is applicable to a single entity but also to a group of producers or individuals;</li> <li>The grid operators are obliged to facilitate the integration of self-consumption;</li> <li>A preferential tariff for using electricity networks would be applied in case of self-consumption since the networks usage is deemed to be lower;</li> <li>A derogation for small installations to facilitate the injection of surplus in electricity networks.</li> </ul> </li> <li><b>The beneficiaries of this scheme would be defined through a tender process.</b></li> </ul>	<ul style="list-style-type: none"> <li>A first tender for has been launched for 40MW aggregated capacity. It is open for installations between 0.1MW and 0.5MW and to all technologies (solar, wind, small hydro ...).</li> <li>The award winners would benefit from a premium in addition to energy consumption or resale. The premium would be indexed on the level of energy self-consumed and the good integration within electricity networks.</li> <li>As part of the scheme the award winner could adopt solutions for electricity storage of demand response management.</li> <li><b>The tender would allow a wide experimentation of new models for electricity production and local consumption especially regarding buildings, small industries and commercial center.</b></li> </ul>	The tender is under process
Approbation of the Multiannual energy program	<ul style="list-style-type: none"> <li>The Energy transition law (ETL) endorsed in 2015 set different ambitious objectives on energy mix (Nuclear below 50% of electricity mix in 2025 and Renewable at 32% of energy consumption in 2025).</li> <li>The Multiannual energy program (MEP) <b>is a strategic view of the energy mix for the next 5 years</b> (exception the first MEP which covers 2016-2018) in order to achieve the long term objectives of the ETL with a top focus to reduce fossil energies consumption.</li> <li><b>The MEP develop two scenarios:</b> one with a high range of renewables capacities development (78GW installed capacities in 2023) and an alternative scenario with a low range (71GW installed capacities in 2023). The renewable installed capacities is 41GW in 2014 and expected to be 52GW in 2018. <b>By comparing 2014 vs the high range the biggest efforts are focused on Wind +17GW and Solar +15GW.</b></li> <li>Should this alternative scenario became a reality then it will call for a drastic change in energy production and consumption trajectories to be in position to reach the ETL objectives.</li> <li><b>The strategic view of the MEP doesn't include specific or practical measures but give a framework for next regulation and related allocation of State funds.</b> Such regulations should focus a specific area (biomass, renewables, energy efficiency ...) and provide practical measures.</li> </ul>	<p>General orientations of the 2016-2018 MEP are:</p> <ul style="list-style-type: none"> <li><b>Energy demand monitoring with:</b> <ul style="list-style-type: none"> <li>The priority to <b>reduce buildings energy consumption</b> through a strong effort on renovation;</li> <li>A financial support to <b>energy efficiency development</b>;</li> <li><b>A monitoring of carbon price with the objective of a €56 per ton price in 2020</b>, namely by proposing a carbon price corridor as part of the EU-ETS reform.</li> </ul> </li> <li><b>How to achieve ETL strong ambition on renewables:</b> <ul style="list-style-type: none"> <li><b>Simplification of administrative process</b> with namely a shortage of tenders periods;</li> <li>Some trial tenders are currently under process before broader tenders for <b>renewable development with namely 1.5GW of solar in 2017 and 2018</b>;</li> <li>Development of cross-funding linked to energy supply from individuals or local authorities.</li> </ul> </li> <li><b>Monitoring</b> of production mix:                             <ul style="list-style-type: none"> <li><b>Strong pressure on coal plants:</b> limited working period before a total exit in 2023;</li> <li><b>Closure of the 2 nuclear reactors of Fessenheim</b>;</li> <li>Development of capacity market and interconnection in order to <b>secure the balance on networks</b>;</li> <li>Optimization of strategic storage of gas and oil;</li> <li>Development of 2GW of energy pumped-storage.</li> </ul> </li> </ul>	The MEP is currently under a consultation process for one month and should be definitively adopted after.

Spain			
Topic	Key features	Insights	Next Steps
Request for information concerning the consumer complaints	<ul style="list-style-type: none"> <li>The CNMC is a public organism that monitors and controls the correct functioning of the energy sector among others.</li> <li>Last August, the CNMC passed a <b>new request for information</b> to the <b>distribution and commercialization</b> companies of <b>gas and electricity</b>, concerning the <b>consumer complaints</b> that these companies receive.</li> <li>The request for information also includes the complaints that commercialization companies send to the distribution companies. This information is requested in order to detect operational incidences.</li> <li>The information reported by the distribution and commercialization companies has to be classified into different <b>types of complaints</b>: incorrect customer service, wrong billings, wrong power cuts, environmental impact of the facilities, quality of the supply, etc.</li> </ul>	<ul style="list-style-type: none"> <li>The CNMC has restricted this request of information to distribution and commercialization companies that exceed a certain threshold of activity, according to their market share. It affects to 34 commercialization companies of electricity, 18 commercialization companies of gas, 35 distribution companies of electricity, and to all the distribution companies of gas (17 companies).</li> <li>Thus the CNMC will have detailed information about <b>complaints presented</b> by consumers and the <b>treatment given</b> to them. Using this information the CNMC will propose appropriate measures to ensure the <b>protection of energy consumers</b>.</li> </ul>	<p>The information submission will be quarterly.</p> <p>The first information submission will include consumer complaints since 1st October 2016.</p>



# Snapshot on surveys and publications – October 2016

## Deloitte

### **Energy efficiency in Europe - The levers to deliver the potential - 2016**

This study aims to identify the main levers for public authorities, private companies and households which could help to better unleash the untapped technical and economic potential of energy efficiency in Europe.

[Link to the survey](#)

### **2016 oil and gas industry survey – 2016**

This report highlights that the oil and gas industry's success is always centred on geology and engineering. Over the last two years, however, above-ground risks have outweighed below-ground risks, primarily affecting oil prices and production.

[Link to the survey](#)

### **Deloitte Resources 2016 Study – 2016**

This annual survey finds both US residential consumers and businesses remain steadfast in their commitment to reducing their energy consumption, even as persistently low energy prices give them less motivation to do so from a financial perspective.

[Link to the survey](#)

### **Deciphering third-party business risk in a period of weak commodity prices - 2016**

This report points out that across the oil and gas industry, many companies are buckling under the steep decline in commodity prices. Forty-two companies filed for bankruptcy in 2015. And with oil prices hovering near 10-year lows, that number could potentially quadruple this year.

[Link to the survey](#)

## Agencies or research institutes

### International Energy Agency

#### **World Energy Outlook 2016 Special Report Energy and Air Pollution – 2016**

This report provides a global outlook for energy and air pollution as well as detailed profiles of key countries and regions. In a Clean Air Scenario, the report proposes a pragmatic and attainable strategy to reconcile the world's energy requirements with its need for cleaner air. Resolving the world's air pollution problem can go hand-in-hand with progress towards other environmental and development goals.

[Link to the survey](#)

#### **Key World Energy Statistics 2016**

It contains data on the supply, transformation and consumption of all major energy sources for the main regions of the world. It gives the interested business person, access to key statistics on more than 130 countries and regions including energy indicators, energy balances, prices and CO2 emissions as well as energy forecasts.

[Link to the survey](#)

#### **CO2 Emissions from Fuel Combustion - 2016**

This report provides comprehensive estimates of CO2 emissions from fuel combustion across the world and across the sectors of the global economy. This 2016 edition includes data from 1971 to 2014 for more than 140 countries and regions worldwide, by sector and by fuel; as well as a number of CO2-related indicators.

[Link to the survey](#)

## European Commission

### **Mid-term evaluation of the Council Directive related to minimum stocks of crude oil – August 2016**

This study has been carried out to assess the functioning and implementation of Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products.

[Link to the survey](#)

### **Energy Efficiency in Enterprises: audit recommendations, costs and savings – August 2016**

Under Article 8 of the Energy Efficiency Directive, Member States must promote the availability to all final customers of high quality energy audits. This report, presents a library of typical cost of energy audits and energy audit recommendations, costs and savings. These represent the most significant energy efficiency opportunities.

[Link to the survey](#)

### **Energy Efficiency in Enterprises: Report on the qualification of energy auditors in all Member States – August 2016**

Under Article 8 of the Energy Efficiency Directive, Member States must promote the availability to all final customers of high quality energy audits. This report describes how Member States put in place accreditation schemes for energy auditors. Best practices are also presented, as well as opportunities for harmonisation of qualification requirements across borders.

[Link to the survey](#)

### **Improving the Sustainability of Fatty Acid Methyl Esters (FAME – Biodiesel) – July 2016**

This study assesses several options to reduce greenhouse gas emissions in the lifecycle of biodiesel fuels based on fatty acid methyl esters (FAME). The options include advanced agricultural techniques, optimum use wastes and co-products and inclusion of other bio-based components in the process.

[Link to the survey](#)

### **EU energy trends and macroeconomic performance – July 2016**

This report highlights the main historical trends in the EU's energy demand and supply, setting them in the context of wider global trends, summarises views on the key drivers of those trends, and discusses the macroeconomic importance of energy.

[Link to the survey](#)

### **Policy-induced energy technological innovation and finance for low-carbon economic growth – July 2016**

This report provides a review and synthesis of current knowledge regarding policy induced energy innovation and technological change and its likely implications for the macro-economy and future low-carbon societies in the European Union.

[Link to the survey](#)

### **Review of current national rules and practices relating to risk preparedness in the area of security of electricity supply – July 2016**

Risk preparedness in the area of security of electricity supply is a raising policy issue across the EU. This study provides an overview of the current legal framework and practices across the EU-28 with regard to security of electricity supply. More specifically, it focuses on how Member States identify, prevent, prepare and respond to security of supply risks and emergency situations.

[Link to the survey](#)

## Eurelectric

### **Launch Event for the TSO-DSO Data Management Report – September 2016**

The report points out that operating the electricity system closer to its limits translates into the need for smarter grids with an efficient exchange of information and data. 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 – remained however overlooked.

[Link to the survey](#)

### **Innovation incentives for DSOs - a must in the new energy market development - A EURELECTRIC position paper – July 2016**

This report provides Distribution Systems Operators (DSOs) that play a key role in implementing innovative ideas to improve the functioning of electricity distribution networks and to develop smart energy systems with the ultimate goal of benefiting customers.

[Link to the survey](#)

## Oxford institute for Energy

### **Not all oil supply shocks are alike either - Disentangling the supply determinant - August 2016**

This report focuses on analysis of oil price shocks using fundamental measures has for years puzzled researchers. Recent theoretical and empirical work has made considerable improvements on how to model the global oil market. Yet, many studies document a decrease in the explanatory ability of the supply side of the market.

[\*Link to the survey\*](#)

### **Flexibility - Enabling Contracts in Electricity Markets - July 2016**

As the share of intermittent renewable energy increases in the energy generation mix, power systems are exposed to greater levels of uncertainty and risks. This reports deals with the growing need for flexibility, along with the fact that it is costly to provide, highlighting the importance of efficient procurement.

[\*Link to the survey\*](#)

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