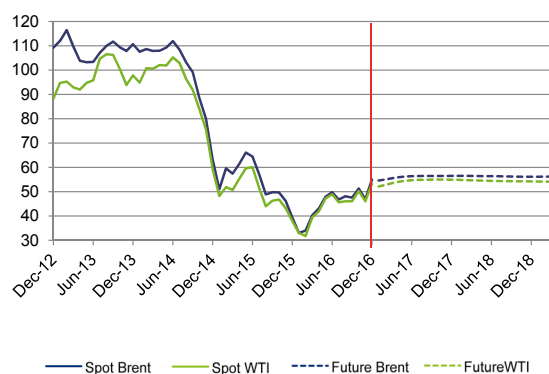


Newsletter Power & Utilities in Europe

Commodities



Crude Oil (\$/bbl)

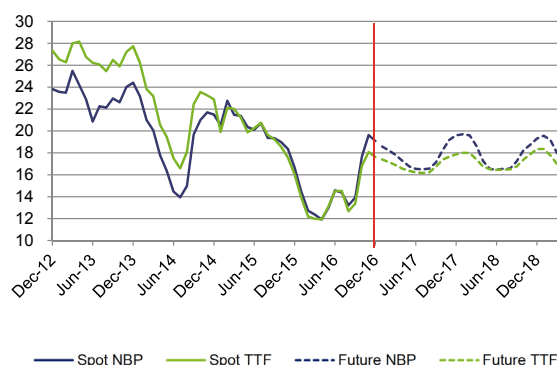


Source Capital IQ

Oil prices have ticked up following the agreement between OPEC and non-OPEC producers to reduce oil output in late November. A return to output control may indicate greater stability in future oil prices, although pressure from non-OPEC supply volumes does not make reducing output an easy answer for OPEC.



Gas (€/MWh)

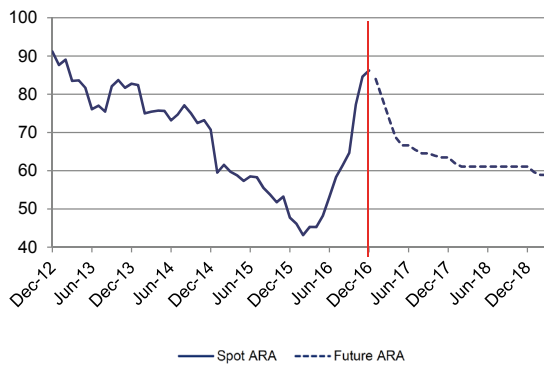


Source Capital IQ

Gas prices have risen sharply through the autumn of 2016 driven by underlying seasonality, an upward move in oil prices feeding through indexation in gas contracts and a cold start to the northern hemisphere winter in some regions. Recent strong alignment between NBP and TTF prices breaks for the 2016/2017 winter and winter periods in the current forward curves, with the NBP winter premium potentially reflecting limited storage capability in GB and recent issues in the availability of Rough.



Coal (\$/metric ton)



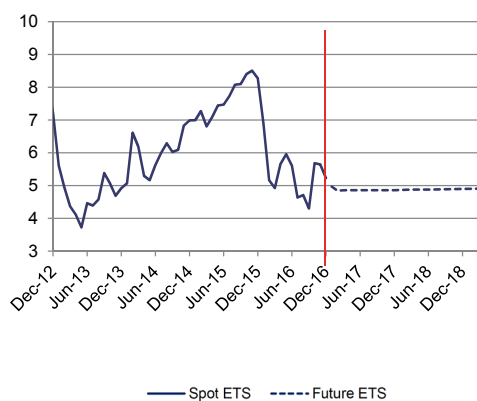
Source Capital IQ

The significant rise in the value of coal through 2016 has been attributed to production capacity closures in China and by major coal producers globally, weather related supply disruption in some regions and a general commodity price uplift as oil and gas prices, the competitor fuels for coal, increase in price.



Carbon

CO₂ (€/ton)



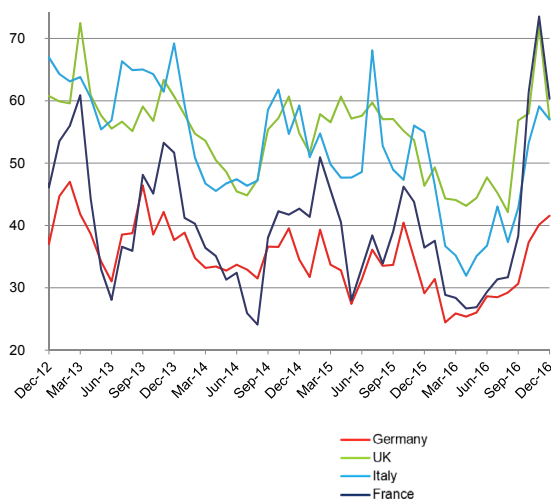
Source Capital IQ

The CO₂ price continues to fluctuate within a narrow and low range, recently 4 E/ton to 6 E/ton. Given the surplus in EU Allowances in the short to medium term, prices reflect market views on when CO₂ constraints will tighten and force real emission reductions, with this being perceived to be some way off currently prices remain depressed.



Baseload Electricity

Baseload Spot Day Ahead (€/MWh)



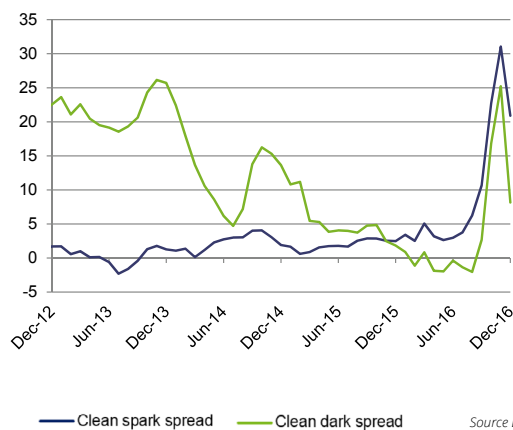
Source Bloomberg

French electricity prices are impacted by the reduction in nuclear output due to plant outage.

In the UK rising coal, prices, rising gas prices and tightening capacity margins have fed through into material price rises. Prices in Germany have remained at levels generally consistent with previous winter periods.



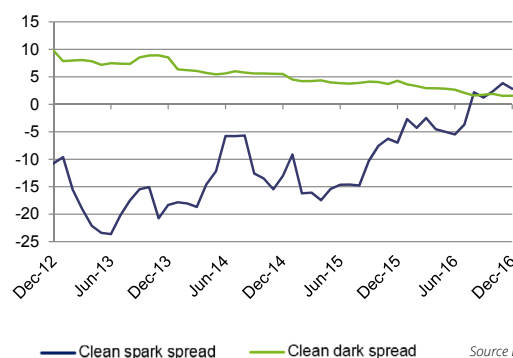
UK clean dark & spark spread (£/MWh)



Clean dark and spark spreads have risen in the UK market as a perceived tightening of the capacity margin has been reflected in the premium over generation costs that generators are able to capture.



German clean dark & spark spread (€/MWh)



German clean dark spreads have continued to drift lower as additional low carbon generation enters the German market and depresses baseload prices. Clean spark spreads have benefitted from the rise in coal prices, making gas-fired generation more competitive versus the significant coal-fired generation fleet in the German market.

Spotlight on Power and Utilities market

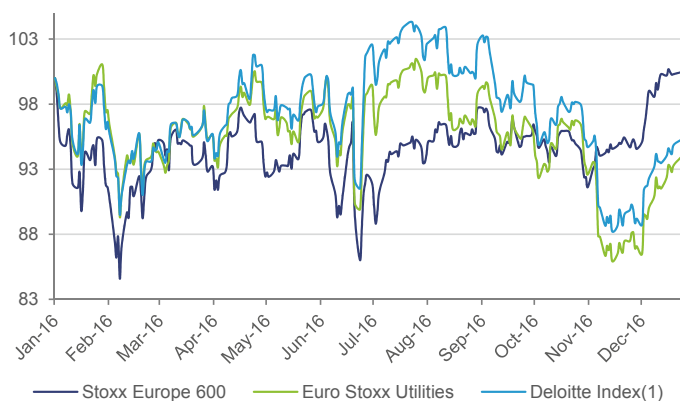
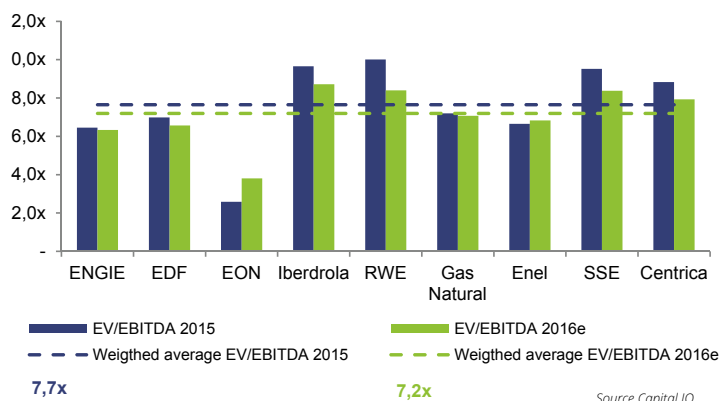
Capital market overview

	Deloitte Index ⁽¹⁾	Enel	Iberdrola	Engie	EDF	Gas Natural	SSE	Centrica	E.ON	RWE
Market cap. ratios										
Currency		EUR	EUR	EUR	EUR	EUR	GBP	GBP	EUR	EUR
Market cap. (Dec. 16)		40 628	37 351	28 725	21 333	17 099	15 149	12 138	12 627	7 034
3m stock price performance	-4%	7%	4%	-11%	-11%	-1%	-2%	2%	7%	-23%
YoY stock price performance	-5%	11%	-3%	-23%	-24%	-3%	3%	10%	-21%	7%
Market multiples										
EV/EBITDA 2015	7,6x	6,7x	9,7x	6,5x	7,0x	7,2x	9,5x	8,8x	2,6x	10,0x
EV/EBITDA 2016	7,2x	6,8x	8,7x	6,3x	6,6x	7,1x	8,4x	7,9x	3,8x	8,4x
P/E 2015	12,0x	18,5x	15,3x	n.m.	18,0x	11,4x	25,9x	n.m.	n.m.	n.m.
P/E 2016	12,7x	12,6x	14,5x	11,7x	6,9x	12,7x	12,5x	14,2x	14,8x	10,9x
Price/book value 2015	1,4x	1,2x	1,0x	0,7x	0,6x	1,2x	3,1x	n.m.	n.m.	1,4x
Profitability ratios										
ROE forward 12m	15%	10%	7%	6%	9%	9%	23%	73% ⁽²⁾	5%	10%
ROCE forward 12m	13%	9%	5%	6%	6%	7%	13%	17%	77% ⁽³⁾	14%
EBITDA margin 2015	20%	21%	22%	15%	20%	19%	8%	8%	6%	10%
EBITDA margin 2016	21%	20%	24%	16%	23%	20%	8%	9%	13%	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%	7%

(1) Deloitte Index is composed of Engie, EDF, E.ON, 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

(3) Ratio linked to classification of Uniper as held for sale and regards as cash in the ratio



Key messages from brokers and analysts

"For the first time in 4 years, we are positive on central European generation"
(Crédit Suisse – December 12, 2016)

"Power prices in Europe over-inflated by a combination of short-term factors"
(HSBC – November 14, 2016)

"EU Carbon price too low for German targets – additional measures on coal are likely"
(UBS – November 25, 2016)

"UK – Another disappointing capacity auction results"
(Deutsche Bank - December 9, 2016)

"Renewables competitiveness – offshore cost falling fast but auction prices not perfect indicators"
(UBS – November 21, 2016)

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

M&A Trends

Transactions involving Power & Utilities companies

Tenaga Nasional Bhd, Main Malaysian energy provider, and **EFG Hermes**, an investment bank, entered into a definitive **agreement with TerraForm Power to acquire its 365 MW solar energy portfolio** in the United Kingdom with an enterprise value of c. **£470m**. (*Reuters – January 6, 2017*)

Engie signed an **agreement with Enea**, a state-owned Polish utility company **to sell Engie Energie Polska for c. €250m**, the owner of the Polaniec Power plant in Poland consisting of 7 coal units and 1 biomass unit representing a total capacity of 1.9GW. (*GlobalData – December 26, 2016*)

Endesa has bought from **Enel** its systems and telecommunication business for **€246m**. The acquisition is part of Endesa ongoing strategic plan to focus on the digitalization of the company's network and processes. (*Spanish Collection – December 21, 2016*)

Eneco, Dutch renewable energy operators, and **Mitsubishi** will co-fund the **370 MW Norther offshore wind power project in Belgium with a 50% stake**, the remaining 50% should be owned by Nethys, local telecommunication services providers. **The project is £1.3bn worth**. (*CTBR - December 15, 2016*)

Enel acquired for **€640m** through a tender process 95% of **CELG**, an energy distribution company that operates in the Brazilian state of Goiás. (*Spanish Collection - December 2, 2016*)

Swiss utility **BKW** has acquired Swiss power producer **Alpiq's 30.3% interest in grid operator Swissgrid** in a deal worth **€137m**. (*GlobalData - November 11, 2016*)

Fenosa sold its **20% stake in Chile's liquefied natural gas (LNG) regasification plan GNL Quintero** to sector player **Enagas** for **€176m**. (*Spanish Collection - November 9, 2016*)

Transaction involving equity funds

National Grid entered in a **bidding agreement to sell 61% of its interest in its UK gas distribution business to a consortium of long-term infrastructure investors** in a deal valuing the unit at c. **£13.8bn** that should return **£3.6bn** in cash to National Grid. (*DowJones – December 8, 2016*)

Macquarie Group, the equity fund, has agreed to acquire a **50% stake in the 573MW Race Bank offshore wind farm in the UK in a £1.9bn deal**. (*The Telegraph – December 22, 2016*)

Spanish lender **Unicaja Banco** has sold **0.5% of Iberdrola share capital for €192m** to qualified investors through an accelerated bookbuild. (*GlobalData – December 16, 2016*)

Dutch utility group **Delta** has agreed to sell its retail energy and cable telecom activities to **EQT Infrastructure**, a private equity fund, for **€488m**. (*Telecompaper – December 6, 2016*)

The shareholders of Greece's national power utility **PPC** have approved the **sale of a 24% stake** in PPC's fully owned power transmission network subsidiary **ADMIE to China's State Grid International Development for €320m bid** (*Reuters - November 28, 2016*)

Alliance SE agreed to **acquire from E.on for €270m a 30% share in E.on Distributie Romania**, a Romanian electricity (80,000 km grid) and gas distribution (20,000 km grid) network operator in a move aimed at supporting the German Issuer's widening of its infrastructure assets portfolio. (*GlobalData - November 28, 2016*)

3i Infrastructure, a private equity fund, has agreed to acquire 100% of **Infinis**, a UK firm engaged in the generation renewable power from landfill gas and wind, for **£185m**. (*MarketLine - November 2, 2016*)

The **Abu Dhabi Investment Authority (ADIA)** will acquire a **16.7% stake in Scotia Gas Networks (SGN)**, a UK firm operating two networks which distributes gas, from **SSE** in a deal worth **£621m**. (*MarketLine - October 18, 2016*)

European Power and Utilities companies wrap-up

In the two last quarters of 2016 the adverse impact of **low commodities prices** are balanced by positive impacts an **increased volatility in power prices** linked to french nuclear power plant outages and **temperatures colder than in the past**.

European Power Utilities are currently in a phase of **assets disposals** in order to **focus on strategic business** but also to respect **cash discipline commitments**.

European Power Utilities having a **large footprint in Renewables** are now the **blueship of investors** while European Power Utilities involved in **nuclear are pledged with uncertainties** regarding investment trajectory (EDF) of phase-out (Uniper (E.on) and RWE).

Most of European Power Utilities confirmed their 2016 guidance.



Q3 2016 Highlights

- **Q3 sales of €52bn, down by 3.1% :**
 - Adverse effect of **electricity price drop** in France and the UK.
 - Favourable impact in France of the **2014 tariff adjustment**: +€1,0bn.
 - **France nuclear output penalized** (9.2TWh at 9M 2016 below 2015) by additional controls, in particular on steam generators.
- **Global spot prices decrease in Europe.**
- **Slight organic decrease at EBITDA level (-2%):**
 - Adverse price impact on merchant activities partially compensated by nuclear volumes in Belgium, commissioning of new assets and impact of the Lean 2018 performance plan.
- **Strong organic growth of current operating income (+7%):**
 - The reduction of depreciation and amortization charges and the reclassification as held for sale of the merchant power generation assets in the US enabled to more than compensate the organic decrease of EBITDA.
- **Solid operational cash flow generation of €6.8bn** for the first 9 months down 0.6bn vs last year due to year on year changes in working capital requirement (€-0.2bn), albeit strongly improving compared to June 30, 2016.
- **Group transformation plan well on track.**

Key events in the period

- Issuance of **€5.4bn senior bonds**.
- Strong activity in M&A:
 - Negotiations to **sell EDF Polska's assets**.
 - **Sell of Demasz**, an integrated Hungarian power company, to Hungary's state-owned utilities company ENKSZ.
 - Binding agreement to **sell 49.9% of RTE (French electricity TSO) to CDC and CNP Assurance** (Equity value of €8.4bn).
 - **Sale of 300,000 m² of real estate** and business assets in France to Tikehau.
 - Agreement to purchase a **controlling stake in Areva NP** FOR €2.5bn with a finalisation contemplated in 2017.
- **Disposal of CSPE (receivable linked to the compensation of the additional costs related to electricity public service)** in an amount of €1.5bn allowing a decrease in net debt by €0.6bn.
- Start-up on January 1st, 2017 of commercial operations at the **Dunkirk regasification terminal**.
- Implementation of the **strategy towards energy transition**.
- Agreement to **renegotiate long-term gas supply contracts with Gazprom and Statoil**.
- **Several projects won in solar** (India and Mexico) or under construction (SouthAfrica).
- **Decision to close Hazelwood** power station in Australia at the end of March 2017.
- Inauguration of Jirau in Brazil, the Group's largest hydropower.
- **Sale of the Polaniec** power plant to Enea.

FY 2016 Outlook

- **EBITDA guidance for FY 2016 adjusted to €16.0bn-€16.3bn** as consequence of drop in French nuclear output and 2014 tariff adjustment.
- **FY 2016 guidance confirmed** on net recurring income group share (at the low end of the range), on net debt/EBITDA ratio and on dividend.



Q3 2016 Highlights

- Sales in the first quarter went down by 12% compared to last year principally due to lower volumes and lower prices.
- EBITDA and underlying net income dominated by Gazprom agreement decreased by 13% and 8% year on year.
- Net debt increased by €2.3bn to €24bn.
- Sales in the third quarter went down by 5% due to declining volumes and prices in the gas business, and falling sales to residential and commercial customers in the electricity business in addition to FX losses.
- The nine months EBITDA is decreasing by 13% reaching €3.8bn due to expenses for maintaining network infrastructure and unusually weak performance in the trading business.
- The net income decreases from €1.9bn in Q3 2015 to €11m in Q3 2016 due to the €1.5bn RWE Dea discontinued operation income recorded in 2015.
- Net debt increased by €1.9bn amounting to €27.4bn.

Key events in the period

- The Federal Constitutional ruled that compensation should be awarded for the early nuclear phase-out.
- E.ON included in the Dow Jones Sustainability Indices World and Europe.
- Long term partnership with the Belgian company Promat to operate a high efficient cogeneration plant.
- Significant investment in wind in the US:
 - Wind farm construction (Texas: 228MW and Illinois: 278MW).
 - 100 MW Power Purchase Agreement with major Customers.
 - Agreement on Plant Services on nearly 1.000 MW of Third Party Wind Farms.
- Effective separation of RWE AG and innogy SE.
- innogy to acquire the German solar power and battery specialist BELECTRIC Solar & Battery : The purchase price is in the high double-digit million euro range, with the transaction due to be completed in early 2017.
- innogy IPO allowing €2.6bn in proceeds for RWE AG.

FY 2016 Outlook

2016 guidance confirmed.

2016 guidance confirmed.



Q3 2016 Highlights

- Sales decreased by 7% year on year driven by electricity demand in respect with mild winter weather and adverse FX effects.
- Q3 2016 EBITDA increased by 4.2% including FX impact:
 - Negative FX impact (mainly due to GBP depreciation) and weaker UK performance in renewables.
 - Totally compensated by positive impact from UIL contribution and lower prices in Spain in renewables.
- Recurring net profit grows by 17% to €1.9bn
- Net sales decline by 14.6%
- EBITDA totalled €3,640m, a 6.8% decrease compared to Q3 2015 due to:
 - Adverse impacts of changes in commodity prices in gas supply business (particularly in international LNG).
 - Cessation of the liquefied petroleum gas business in Chile.
- Gas investments increase (+ €200m vs Q3 2015) while investments in electricity distribution in Spain grow by 17%.

Key events in the period

- Capital increase through the issuance of 122 million new shares, to bring the number of shares at 6,362 million.
- €0.7bn green bond issuance with a 9 years maturity and a 0.375% annual coupon.
- Loan draw of €600 million granted by the EIB to finance investments in the gas distribution business in Spain.
- Sale of the 42.5% stake in Planta regasificación de Sagunto (Spain) and the 20% stake in GNL Quinteo (Chile) to Enagas.

FY 2016 Outlook

2016 guidance confirmed.

2016 guidance confirmed.



Q3 2016 Highlights

- **Q3 2016 sales decrease by 8.1% compared to last year attributable to a reduction of electricity sales in the mature markets, a decline in trading activities and negative FX effects.**
- **EBITDA is stable at €11.9bn as a result of a balance between:**
 - Adverse effects from FX, decline of trading, generation and renewable energies.
 - Positive effects from operational efficiency and growth, EBITDA contributions of Latam, Iberia and Italy with renewable margins increase as consequence of gas price review in Italy.
- **UK Home** energy accounts broadly flat since the half year with new tariffs launch and CMA remedies implementation.
- **UK Business** continuing to deliver strong working capital inflows.
- Stronger second half performance in **North America energy supply** and services as expected, following a first half impacted by warm weather.
- **ENER-G Cogen integration** proceeding to plan and Neas acquisition completed. Both acquisitions add core capabilities to the Group.
- **Strong energy marketing and trading performance** benefiting from power price volatility and the optimisation of flexible gas contracts.
- **Group net debt is expected to be lower at the end of 2016 than at 30 June 2016**, reflecting a strong cash focus and capital discipline.

Key events in the period

- **Disposal of 50% of Slovenské elektrárne to EPH.**
- Announcement of **significant investment in renewables**:
 - \$120 mn in the construction of the wind farm through its subsidiary Enel Green Power México.
 - \$30 million in the exploration of geothermal resources in Indonesia.
- **Enel Green Power International sells Enel Green Power España to Endesa Generación.**
- **Sale of Marcinelle Energie**, a 400MW CCGT in Belgium, to Direct Energie.
- **Disposal of 400 MW CCGT in Belgium.**
- **Acquisition of CELG, an energy distribution company that operates in the Brazilian state of Goiás for approx. 640m.**
- **Presentation of the 2017-2019 strategic plan focused on digitalization and customers.**
- **Windfarm project in Missouri (300MW) representing a €500m investment.**
- **Strategic alliance with Tokyo Gas in LNG activities.**
- **Divestment of Trinidad and Tobago E&P portfolio announced**; Canada E&P and Lincs wind farm disposal processes are ongoing and expected to complete in 2017.
- **British Gas Business agrees to pay £4.5 million over failure to deliver advanced meters to some larger businesses by April 2014.**
- **The company has been awarded capacity market agreements starting in October 2020 for three projects:**
 - A 49MW battery storage facility at Roosecote in Cumbria.
 - Two 50MW fast response distributed generation gas-fired plants at Brigg in North East Lincolnshire and Peterborough in Cambridgeshire.
 - A 370MW combined cycle gas turbine at King's Lynn in Norfolk.
- **Contract with JERA to purchase up to 6 cargoes per annum at the Isle of Grain Terminal in the UK.**
- **First gas produced from the Cygnus field in the UK North Sea on 13 December.**

FY 2016 Outlook

2016 guidance confirmed.

2016 guidance confirmed.

Topics

1 - Support for renewable electricity: forever and ever?

Sources: ENTSO-E, Statistical factsheet 2015 – IRENA, Renewable energy auctions, 2017 – Jenkins, 2015 – Sivaram and Khan, 2016 – Green and Léautier, 2016

While recent cases have shown that green electricity could now already compete with conventional generation in some places (in Abu Dhabi, a new tender for solar PV in 2016 resulted in a new lowest equivalent price of 24 \$/MWh), the global achievement of objectives in terms of deployment and competitiveness of renewable energy sources (RES) is still dependent on the support from energy and climate policies. In most countries, new RES capacities investments are enabled through a series of subsidies and support schemes (feed-in tariffs, feed-in premiums, green certificates) whose aim is to complement liberalized (but imperfect) energy markets. By themselves, in most places **the markets are still unable to integrate RES on a major scale due to the existence of market failures** (authorization for RES to sell services on several energy markets, too low carbon price, etc.). Moreover in most places, subsidies are still required. They are justified from an economic point of view because they push the development of RES capacities which have a value in terms of social welfare, but could not develop otherwise.

Generally speaking, **RES support schemes generate a positive value for the social welfare through the continuous decrease in the cost of RES generation they enable**. Thanks to the subsidies, new capacities are installed and generate substantial learning effects in terms of efficiency and innovation. In the long-term, the resulting decrease in technology cost is expected to bring RES to competitiveness in many regions like Europe and North America. This should benefit the whole energy system, and the expected energy cost savings compared with the “status-quo” situation (of conventional generation only) are enough to justify the scale of the current subsidies.

RES deployment has multiple impacts on energy markets

Thanks to support schemes in place, RES electricity generation has soared over the past

decade. Installed capacity in Europe reached 410 GW in 2015, with a penetration in electricity generated of 32%¹. Meanwhile, **the cost of RES generation has decreased faster than expected, with the newest auctions for wind or solar nearing or falling under the EUR 30/MWh threshold in most favorable locations**. In Europe, where energy markets are highly dependent on existing conventional generation and where conditions for a full reliance on RES sources are not met yet (issues of peak demand, flexibility requirement, climate...), the threshold of EUR 80/MWh has finally been crossed².

The support schemes, however successful, have unfortunately led to market and competition distortions. In the European Union, feed-in tariffs have long been considered as the most efficient way to incentivize RES deployment, but this has led to issues as those schemes isolate RES producers from market risks. As producers receive the same compensation whatever the actual energy price, they are not responsive to market signals and their decisions often bring private gains but losses for the system as a whole. For instance, feed-in tariffs are often associated with priority of injection, which completes the RES-E generation purchase agreement and ensures that their electricity will be sold in priority on the market. This isolates the RES-E generators from the demand risk, as they are guaranteed to get paid for the electricity they produce at almost every demand level, independently of the marginal price on the market. This can lead to severe distortions, such as increased frequency of negative prices: in Germany for example, 126 hours of negative prices were observed in 2015 on the spot market, with a peak at -80€/MWh.

Another impact of RES penetration on the energy market is the so-called merit-order effect, which is characterized by a continuous decrease in the average energy price caused by new RES deployment. This effect is particularly visible in liberalized and

The markets are still unable to integrate RES on a major scale due to the existence of market failures.

The cost of RES generation has decreased faster than expected, with the newest auctions for wind or solar nearing or falling under the EUR 30/MWh threshold in most favorable locations.

The support schemes, however successful, have unfortunately led to market and competition distortions.

1. ENTSO-E Statistical Factsheet 2015 - https://www.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs2015_web.pdf

2. IRENA, 2017. Renewable energy auctions. http://www.irena.org/DocumentDownloads/Publications/IRENA_REAuctions_summary_2017.pdf

already mature energy markets where the share of installed conventional generation is high.

The merit order effect can be described as follows: in the wholesale market, producers bid the electricity they generate according to their variable cost (a proxy of the marginal cost). The capacities with the lowest variable cost are the first selected to meet demand, and the variable cost of the last selected unit sets the corresponding wholesale price. The base-load capacities (e.g., nuclear plants) have low variable costs and are ensured to produce nearly all the year, while peak capacities (oil), with the highest variable costs, only generate when demand is high. When the penetration of RES (which has the lowest variable cost, at almost zero) remains low enough, the last unit of energy called at each hour remains the same as in the situation with no RES, and thus the energy price at each hour does not change. Conversely, **the energy price gets lower the more RES penetration increases**: as the share of renewables grows, they replace conventional technologies as the marginal sources at base-load. **Meanwhile, the former marginal technologies at base-load now become marginal at semi-load, etc.** Overall, there is a shift in the merit order and the most expensive technologies are activated less often. This results in a decrease of the average energy price.

The present deployment of RES is a risk for renewables' own future

Due to the merit-order effect, the increase in RES penetration in energy markets leads to lower market prices. Yet, the level of subsidy for renewable is determined by the difference between this market price and the total RES cost (or LCOE, levelized cost of energy). **All other things being equal, the merit-order effect could lead to the need to increase the support level.**

In reality, RES continuous deployment has of course induced a sharp decrease in technology cost and a significant progress along the learning curve. **In a perfect situation, the decrease in RES cost is sufficient to over-compensate the merit-order effect**, then leading to a progressive decrease in RES support, and enabling the direct integration of new technologies in the energy market in the near future. In very favorable situations (e.g., sunny or very windy countries), the LCOE of renewable electricity generation is already low enough for RES to compete on an equal basis.

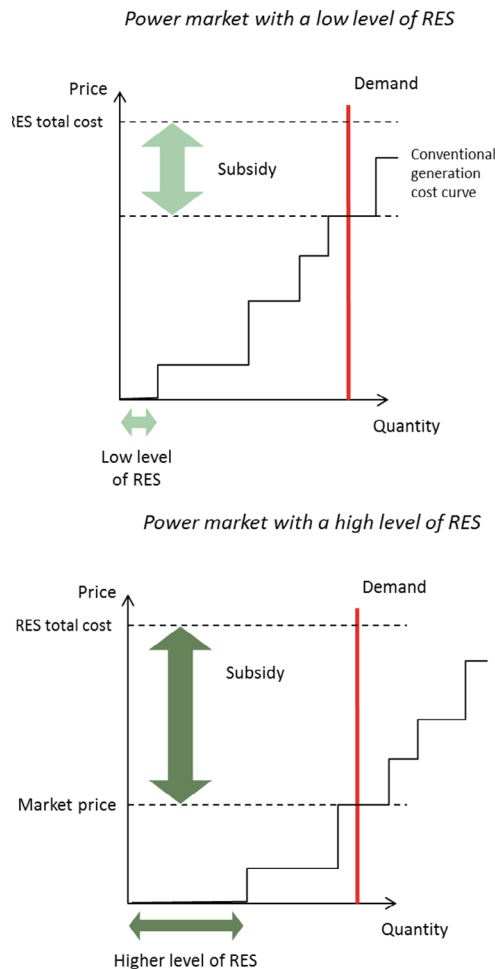


Figure 1 - Impact of the integration of RES on the marginal price and the level of subsidy

The situation is more confused in some liberalized and less favorable energy markets. Empirical studies (Jenkins 2015, Sivaram and Khan 2016) have thus shown that **the decrease in RES costs is sometimes not enough to catch up with the decrease in energy price**. This effect, called value deflation (Green and Léautier 2015), could be summed up as a disappointing race between RES LCOE and the market price. **It is particularly visible in Europe, where the offered bids for new RES are still high** (due, partly, to higher installations and maintenance costs and to poor sun and wind characteristics) **and where the market price conditions are very tight in a context of overcapacity.**

As a result, **unless there is a major drop of RES cost or a stabilization of energy prices (for example due to changes in the energy mix or in the energy market functioning), a paradoxical situation might emerge where**

All other things being equal, the merit-order effect could lead to the need to increase the support level.

The decrease in RES costs is sometimes not enough to catch up with the decrease in energy price.

support to RES never ceases and where RES is never fully integrated into the market.

The value deflation issue must be addressed to prevent an escalation of effects

Energy market designs and the characteristics of RES support schemes should be adjusted to enable further decrease in subsidy and better market integration. **Above all, the key is to avoid the risk of uninterrupted subsidy by pushing now for technological breakthrough.** In particular, this requires highly ambitious support schemes which incentivize disruptive innovation as well as more competition between RES technologies for access to subsidies. RES support could thus be adapted to the level of maturity and technological advancement, with higher subsidies for R&D and demonstration projects, and more commercially oriented schemes (e.g., tax reliefs) for mature technologies. **In any case, it is important to avoid betting only on close-to-maturity technologies, which would result exactly in the feared effect of value deflation.**

As a more open solution to the issue, specific market redesigns could be envisaged to accompany the efforts on RES support. **Policy makers should look at ways to address the decrease in energy prices**, which often goes with an overall situation of overcapacity, as is the case in Europe where plants being replaced by RES do not exit the market quickly enough (Caldecott and McDaniels, 2014). By encouraging early retirement of conventional capacities in excess, the energy price could partly recover, thus mitigating the disconnection between price and RES cost decreases. **To go further, market failures might be addressed regarding the ability of RES to participate to some markets and services, such as reserves and participation to network management.**

As a summary, support schemes for renewable have enabled a successful deployment of these technologies, which has been accompanied by a faster-than-expected decrease in investment cost. But the more RES capacity has been integrated into the energy market, the more distortions and market impacts have become tangible. Energy prices have decreased, along with the marginal value of RES for the system. Further deployment thus implies to maintain subventions as RES generators are still not able to fund their investments by the market alone, and might never be. This *value deflation* phenomenon should be a main concern of energy policy makers, who should thus aim at accelerating the decrease in technology cost and the integration of RES into the market.

Unless there is a major drop of RES cost or a stabilization of energy prices (for example due to changes in the energy mix or in the energy market functioning), a paradoxical situation might emerge where support to RES never ceases and where RES is never fully integrated into the market.

Above all, the key is to avoid the risk of uninterrupted subsidy by pushing now for technological breakthrough.

In any case, it is important to avoid betting only on close-to-maturity technologies, which would result exactly in the feared effect of value deflation.

Policy makers should look at ways to address the decrease in energy prices.

2 - The trial and error process in implementing Capacity Remuneration Mechanisms: First lessons from Belgium and GB

Sources: Department of Energy & Climate Change, New energy infrastructure investment to fuel recovery, 2013 – ENTSO-E, Mid-term Adequacy Forecast 2016 edition, 2015 – RTE, Bilan prévisionnel de l'équilibre offre/demande 2016 – Elia, Etude de l'adéquation et estimation Du besoin De flexibilité Du système Électrique belge Période 2017-2027, 2016

Several countries in Europe have been experiencing risks of electricity shortage. Part of the issue is linked with the inability of power markets to remunerate sufficiently peak capacity (generation and demand response), which then leads to an under-investment phenomenon. This puts at risk the supply of power load and even economy as a whole given its major dependence to electricity. To cope with this problem, several countries have complemented their existing electricity markets with so-called capacity remuneration mechanisms. **Their implementation is complex and has reserved surprises, sometimes to the point of casting doubt on their ability to provide their capacity goals.**

Missing capacity in Europe?

Most European TSOs have performed a risk assessment of their national security of supply in the years to come. These studies assess the risk of load shedding (*i.e.*, curtailment of demand in certain areas to avoid a black-out). In particular, two main used indicators are able to assess the level of capacity adequacy at the national scale. The first one is Energy Not Supplied or Unserved Energy (ENS) due to the demand exceeding the available generating and import capacity. It is expressed in MWh/year. The second is Loss of Load Expectation (LoLE) that refers to the average number of hours (events) within one year for which there is Unserved Energy. Several of these studies indicate a major risk for security of supply in several European countries.

For instance, according to RTE, the French TSO, **the security of supply will be at stake in France as soon as 2017**. The LoLE could rise to almost 7 hours a year (compared to a 3-hour goal) and 2% of the total demand could be unsatisfied during peak hours, **which would have a significant impact in terms of GDP loss**. However, this risk is expected to be reduced after 2020.

Similarly, Belgium had identified in the past a major security of supply risk in 2014 thanks to a preliminary assessment study. Even if the situation over the next few years seems more relaxed, Elia, the Belgium TSO, has identified another likely under-capacity phase after 2023, which could lead to curtailments.

Finally, according to a study made by ENTSO-E, Great Britain could suffer from power shortage in peak load situations during 8 hours in 2020; the situation may improve by 2025 but will remain beyond the 3-hour goal.

Such risk assessment studies are used by policy makers and utilities to justify the need for capacity remuneration mechanisms which should solve the capacity adequacy issue. Taken as a whole, the studies show that the issue goes well beyond the aforementioned countries, once past experiences and projections in the further future are taken into account. As a result, the European energy system is currently characterized by a wave of development of capacity remuneration mechanisms.

Capacity remuneration mechanisms: still in the learning phase?

Many European countries have recently decided to implement new mechanisms to ensure system adequacy in the power system, by having enough generation and demand response capacity to serve the expected highest level of load in a reliable manner. There is no unique solution adopted: for instance, Great Britain has implemented a capacity market whereas Belgium has chosen a strategic reserve mechanism. **The question is now whether they will be effective in providing enough capacity to ensure capacity adequacy.**

The answer is not straightforward whatever the mechanism implemented. It is particularly due to the sheer number of differentiating characteristics and the lack of perspective given the young age of current mechanisms.

Let first consider strategic reserves. This mechanism consists in putting generators outside the market (and compensating them for it) so that they can be available in extreme situations and thus cover extreme power demand. Generators in the strategic reserve are generally close to retirement.

As an illustration, Belgium has implemented a strategic reserve since 2014 and has experienced several events illustrating its limits. A critical situation thus happened during

Capacity Remuneration mechanisms implementation is complex and has reserved surprises, sometimes to the point of casting doubt on their ability to provide their capacity goals.

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the auction for the strategic reserve for winter 2015-2016 (following a similar issue during the previous winter), when the strategic reserve was short of 500-MW capacity because of a too small volume of proposed generation and demand response. **The situation showed that the strategic reserve might not ensure reliability because market players may still be unable to provide enough capacity.** This is especially critical in a context of high uncertainty of the required volume and when strategic reserves are partially filled by annual auctions, as was the case in Belgium. Fortunately, partly thanks to a warm winter, the Belgian issue remained inconsequential and no load disruption was needed to maintain the generation-load balance. It did not prevent however the Belgium system from being assessed at risk at that specific moment. As a reaction, **several short-term emergency measures were incidentally taken to prevent any escalation.** Following these different difficulties, Belgium has been considering the introduction of a capacity market to replace its current strategic reserve.

On the opposite of the Belgium choice of strategic reserve, **Great Britain enforced a capacity mechanism to ensure security of supply.** The principle of such capacity remuneration mechanism is to set up several years ahead auctions for a certain volume of capacity that is assessed as necessary to ensure capacity adequacy. In Great Britain in particular, though, there were several objectives beside pure capacity adequacy. One of the main idea behind the mechanism was thus to "bring on gas and other flexible electricity supply to meet future demand".

Three rounds of auctions have so far been organized and have proven successful with regard to the capacity adequacy objective: all required demand for capacity was thus met¹. Nevertheless, **the analysis of outcomes of these auctions shows some serious concerns about the efficiency of the mechanism and its eventual success.**

Indeed, following the first capacity auction (for winter 2018/2019), two awarded plants announced they might eventually not be able to generate during the corresponding winter because of financial constraints. Of course, penalties are enforced in the capacity mechanism to prevent such events from happening, by incentivizing plants to respect

their capacity contracts. However, it might be more profitable in some cases to pay this fine than to incur additional losses by keeping the plants on. Because of unsustainable losses, Fiddler's Ferry coal plant threatened to close 3 of its 4 units before 2018/2019 and then pay a £33m fine. Similarly, Trafford CCGT, the only new build plant awarded for a 15-year contract, fails to find investors and decide to give up its agreement.

These two decisions, if confirmed, might very well lead to a 3-GW capacity shortage for winter 2018/2019, thus jeopardizing security of supply even though the capacity market was successful and the required demand met. Hopefully, this gap should be solved thanks to an additional auction, which will take place one year before the 2018/2019 winter. However, this situation will surely put pressure on this auction and the final outcomes might be more expensive.

In any case, **these two examples highlight the risks of capacity shortage if the design of the capacity market (and particularly enforced penalties) is not incentivizing enough.** To avoid such cases in future auctions, the government introduced tougher penalties.

Beside the risk of an eventual capacity shortage, previous outcomes from the UK capacity market emphasize that **this new mechanism does not attract enough investments, in particular in gas-fired plants.** This point was one of the initial goal of the British government when introducing the capacity market, but so far most of awarded new investments consist of small-scale diesel generators which, thanks to several specific benefits, have a competitive advantage over CCGT plants. Only two new CCGT were successful in previous auctions, one of which failed afterwards to find investors.

The government reacted by modifying the current design to attract more CCGT investments. The demand target level is to be increased for the 2021/2022 auction by at least 3 GW. By buying more capacity four years ahead, it is more likely (but not guaranteed) that new gas capacity will clear the market. Similarly, the potential unfair competitive advantage of small embedded diesel generation is currently under review (in particular regarding its emission levels).

The situation showed that the strategic reserve might not ensure reliability because market players may still be unable to provide enough capacity.

This new mechanism does not attract enough investments, in particular in gas-fired plants.

1. The capacity price was £19.40 per kW for the first year, £18 per kW for the second and £22.5 per kW in the last auction.

This second issue with the British capacity mechanism also highlights to what extent these complex additional market mechanisms could fail to reach the expected goals and how continuous redesign may be necessary. Taking all capacity remuneration mechanisms into consideration, **one should however not condemn too harshly their ability to cope with policy objectives.** As was the case in Belgium and Great Britain, **a first phase of trial and error is likely to characterize most mechanisms before a more efficient calibration is found and their interaction with the energy market is refined.**

Moreover, beyond these possible inefficiencies of national capacity remuneration mechanisms during their first years of implementation, **there is also a major risk of inefficiencies at the European level resulting from the non-harmonization of these mechanisms.** Having different national capacity remuneration mechanism, whose designs can significantly differ from one country to another, could jeopardize the drive to have an internal common power market in Europe.

There is also a major risk of inefficiencies at the European level resulting from the non-harmonization of capacity remuneration mechanisms

3 - Financial distress of European Gas and Power TSOs?

Sources: ACER, ACER market monitoring report 2014 – European Commission, Consumer bills and costs in Europe 2014

Upgrading and expanding the European energy transmission networks is crucial to enable the objectives linked with the three pillars of European energy policy (integration into regional markets, integration of renewables and security of supply). It is necessary for the development of renewable generation in the electricity sector, as such generation is often located far from consumption centers (like cities). It is also needed in order to complete the gas and electricity internal markets so that physical trading constraints are removed and security of supply is maintained.

Deloitte Economic Consulting France (formerly Microeconomix) and BearingPoint conducted in 2015 a study for DG Energy of the European Commission on the investment conditions for electricity and gas Transmission System Operators (TSOs) in the EU. **The financing conditions and the financial impact of planned investments were assessed for 39 electricity and gas TSOs in 14 EU Member States, accounting for 82% of total EU GDP.** Those TSOs cumulate a total Regulated Asset Base (RAB) of € 66.7 billion in electricity transmission and € 45.6 billion in gas transmission. In regulatory terms, the RAB of a TSO comprises all assets that are recognized by the national regulator as part of the national transmission network, and at least partly financed through the transmission tariffs and hence the end-users. The RAB is broadly assimilated to the accounting value of those assets, and **tends to rise when the level of new investments (renewal, expansion) is high. On the contrary, aging networks show diminishing RABs.**

A multi-billion wave of transmission network investment expected over the next ten years

Based on their comprehensive national development plans available in 2015, **the 39 TSOs studied will invest some € 65 billion in electricity transmission assets** (excluding offshore projects, but driven by grid renewal, RES integration and risks for security of supply) **and € 20 billion at most in gas transmission** (related to new cross-border pipelines and LNG terminals, with potentially competing PCI projects) **between 2015 and 2024, with an investment peak around 2016.**

The amount of annual network investment for the electricity TSOs in the panel is expected to increase by 28% by 2020 compared to the average figure for the 2010-2014 period (i.e. from € 5.9 billion annually on average to € 7.6 billion). By contrast, in the gas sector, the total amount of network investment in the years to come (around € 2.6 billion annually including potentially competing PCI projects) will decrease by 13% compared to the last five years.

Hence, **the electricity sector is a particular concern with regard to the ability to carry out investment programs** over the next ten years. 79% of studied electricity TSOs (94% of the 2014 cumulated RAB) will increase their RAB to respond to the three pillars of the European energy policy. This applies to both “mature” TSOs (those who already have a highly meshed power grid and a good level of interconnections) and “recent” TSOs (mostly in recent Member States).

Upgrading and expanding the European energy transmission networks is crucial.

The financing conditions and the financial impact of planned investments were assessed for 39 electricity and gas TSOs in 14 EU Member States, accounting for 82% of total EU GDP.

The electricity sector is a particular concern with regard to the ability to carry out investment programs.

To assess the impact of planned investments on the TSOs' financial situation, the study simulated the comprehensive national development plans and current regulatory parameters of TSOs over ten years. The financial situations were modelled by looking at the evolution of financial ratios usually used to evaluate TSOs' credit ratings (e.g., net debt/RAB rating), and by assessing the risk that those simulated credit ratings would improve or worsen.

TSOs are generally resilient to their investment program

More than half of TSOs appear as financially resilient to their investment plans in the next ten years. Nevertheless, the results show that **2 gas TSOs (9% of 2015-2024 gas transmission investments in the studied panel) and 4 electricity TSOs (41% of 2015-2024 electricity transmission investments) will end up or remain in deteriorated financial conditions** due to RAB increase, with their investment grade being the last before non-investment. The debt level will go or remain higher than 60% over the studied period, possibly requiring an adaptation of the financial behavior of TSOs' shareholders. In most cases, **equity injection is possible when the investment trends are durable, while an optimization of the payout ratio can only be considered as a last resort option.**

In a more extreme situation, eight TSOs will end up with a debt-to-RAB ratio over 80% (all but one of them increasing their RAB¹): two gas TSOs (1% of total gas investment) and six electricity TSOs (27% of electricity investment), which would normally lead to financing constraints.

Considering the expected evolutions of the financial situation until 2024, some network investments could therefore appear at risk from a financial point of view. **The financing challenge would be particularly pronounced in the electricity transmission sector where 68% of the overall amount of investment (in the study's scope) could be jeopardized for financial reason.** Considering that those investments are mainly driven by the integration of renewable energy sources, the success of energy transmission could then be at stake, with heightened risks in terms of congestion and security of supply.

Yet, the confrontation of these financing risks with the reality shows a different situation. Accordingly, achieving the planned transmission investments will require some significant increase of the debt level for European TSOs, which could possibly decrease their capacity to secure funds. **However, the energy infrastructure sector benefits from a very favorable perception by investors and financing markets.** The sector is stable and regulated; it offers long-term maturities and foreseeable cash-flows which explain their attractiveness in a context of economic turmoil. Furthermore, given the very low interest rates observed elsewhere, a decrease in regulated WACC would not endanger the financing attractiveness of European TSOs.

The macroeconomic impact on transmission tariffs' increase will be reasonable

With the energy demand trend being quite flat, the wave of investments to come is expected to result in a clear increase in transmission tariffs. Based on the study's modelling assumptions, the annual tariff increase for residential consumers should for example be **0.8% in the gas sector (ranging from -4 % to +4 %) and 2.2% in the electricity sector (ranging from -3 % to + 5 %) in nominal terms.** This highlights the higher stress for the electricity sector.

Tariff increase is particularly unavoidable for financially stressed TSOs which face strong investment objectives. Investing TSOs with a difficult indebtedness outlook would otherwise be the first affected financially. This also points **to a necessary complementarity between debt and tariff increases to meet investment programmes.**

At a broader level, due to the low impact of transmission tariff on the energy bill (6.5% on average in gas and 6.1% on average in electricity, based on official ACER and EC figures and internal assumptions when needed) and thus on the average household expenditure baskets (<0.2% on average, based on EC figures), **the final impact of transmission tariff increases and investment plans on the end-user should remain limited.**

The financing challenge would be particularly pronounced in the electricity transmission sector where 68% of the overall amount of investment (in the study's scope) could be jeopardized for financial reason.

Tariff increase is particularly unavoidable for financially stressed TSOs which face strong investment objectives.

1. One TSO was initially in a non-investment grade and will not improve its financial situation enough, despite the decrease in its RAB and investment programme.

Assuming that the other components of the energy bill do not increase more than inflation, **transmission tariff variation would lead to a mean 0.05% annual increase in the gas bill, and a mean 0.14% increase in the electricity bill between 2015 and 2024.**

Those tariff increases may also ultimately lead to a reduction or smaller increase in the other energy bill components, as **investments are generally selected based on their cost-benefit analysis and on their ability to increase the social welfare** (by lowering congestion costs, increasing security of supply, cheapening RES integration). ENTSO-E in its last TYNDP (draft 2016) for example indicates that the electricity investment package² should lead to average 1-to-2 €/MWh increases in the transmission price but to 1.5-to-5 €/MWh drops of the electricity price³.

Other barriers to investments are as important as TSOs' financial situation

Rather than the impact of investments on TSO financial situation, interviews and surveys with gas and electricity TSOs, NRAs and investors showed that the attractiveness of energy infrastructure investments above all depends on other barriers.

The regulatory framework is perceived as the main barrier to TSO investment attractiveness. Investors and TSOs, when looking to finance network investment, appear to look at five criteria with regard to regulation:

- **Recoverability of costs:** the ability of TSOs to recover their (investment) costs is a main driver of their financing investment. This ability is mostly affected by the level of the weighted average cost of capital (WACC) that rewards TSOs for their investments. A WACC premium can also be added to the nominal value of the WACC for some specific and risky investments. Lastly, as incentive regulation is generally applied for TSO cost reduction or quality of service, recoverability can be compromised depending of the strength of applied incentives.
- **Flexibility in the face of uncertainties linked to the investment plan:** the schedule for planned investments is not necessarily followed; incremental investments can also be needed within the regulatory period. The regulated remuneration of TSOs should thus remain flexible to accommodate these

uncertainties and unexpected variations in investment costs, for instance by reducing the time-lag for inclusion of unexpected investments in the RAB, or by remunerating work-in progress.

- **Stability within the regulatory period and between regulatory period:** the financial market is very sensitive to stability characteristics, such as the duration of the regulatory period (the shorter it is the higher the risk of regulatory change between regulatory periods), the track record of unexpected change of rules by the regulator during regulatory periods and the transparency of regulation (since it is more difficult to change rules when they are publicly known). The investors are also particularly sensitive to the recognition by the regulator of assets recognized in previous regulatory periods. The risk of stranded assets that would be impaired by the regulator thus remains high in the transmission sector and in particular for gas transmission assets.
- **Authority and autonomy of the regulator:** this criterion gives an indication to investors about the robustness of its decision. Investors are particularly interested in details on the scope of the NRA⁴'s responsibilities (what can it decide?), their insulation from the political sphere (would it allow a needed tariff increase?) and their competencies with regard to decision making (is it able to grasp the issues faced by TSOs?).
- **Legal openness or restriction on TSOs assets investment:** the environment will be more investor-friendly if there are less legal restrictions to invest in TSOs, through TSO shareholding or holding stakes in SPVs (Special Purpose Vehicle) related to transmission assets.

TSO financial attractiveness should therefore be a priority of regulatory actions and improvements. Regulators should in any case ensure that planned investments that have the most value for the system in the long term can be financed and carried out without putting TSO's financial situation at risk, and at the least cost for the end-user.

Transmission tariff variation would lead to a mean 0.05% annual increase in the gas bill, and a mean 0.14% increase in the electricity bill between 2015 and 2024.

2. 150 B€ in EU-28 of transmission and storage investments before 2050 – Source: TYNDP 2016.

3. Those forecasts were updated in the draft 2016 TYNDP. ENTSO-E now expects a 1-to-2 €/MWh increase in transmission price due to investments against a 1.5-to-5 €/MWh potential reduction in wholesale prices.

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?

Package of legislative proposals: « Clean Energy for all Europeans »

Key features	Insights
<p>On 30th November 2016, the European Commission presented a package of measures in order to strength the clean energy transition and the achievement of the European target to cut at least by 40% its greenhouse gas emission for 2030.</p> <p>These measures would modify the existing directives on Renewable Energy, Energy efficiency, Energy Performance of Buildings.</p> <p>On Renewable energy the revised Directive will set a regulatory framework that leads to investor certainty and allows a level playing field for all technologies without jeopardising our climate and energy targets.</p> <p>On Energy efficiency: The revised Directive will set the framework for improving energy efficiency in general and in buildings. It aligns energy efficiency targets with the EU 2030 climate and energy framework.</p> <p>The measure should also impact the electricity market Design to enable a clean energy transition to take place, at the best value for consumers. It should also impact Governance rules for the Energy Union: with a robust Energy Union Governance to ensure that the Energy Union Strategy objectives across all five dimensions, and in particular the 2030 energy and climate targets, are met.</p>	<p>The expected change on the Renewable Energy Directive are:</p> <p>Creating a framework for further deployment of renewables in the Electricity Sector by:</p> <ul style="list-style-type: none"> • Including general principles for designing support schemes. • Simplifying administrative procedures to accept new projects. <p>Mainstreaming renewables in the Heating and Cooling Sector by:</p> <ul style="list-style-type: none"> • Sustaining the increase the share of renewables in heating and cooling supply to increase its share by 1% per year until 2030. • Opening access rights to local district heating and cooling systems for producers of renewables, under certain conditions. <p>Decarbonising and diversifying the Transport Sector with:</p> <ul style="list-style-type: none"> • A progressive obligation on European transport fuel suppliers to increase share of renewable and low-carbon fuels from 1.5% in 2021 to 6.8 % in 2030, with at least 3.6% of advanced biofuels. • A progressive cap on the share of food-based biofuels on the EU renewable energy target (7% in 2021 to 3.8% in 2030). • National databases to ensure traceability of the fuels. <p>Empowering and informing consumers by:</p> <ul style="list-style-type: none"> • Facilitating renewable electricity self-consumption, and ensuring a remuneration for the electricity feed into the grid. • Recognizing energy communities and facilitates their participation in the market. • Providing information on energy performance and energy sources of district heating and cooling systems. • Improves the quality of information provided to consumers. <p>Strengthening the EU sustainability criteria for bioenergy.</p> <p>Ensuring that EU level binding target is achieved on time and in a cost effective way.</p> <p>The expected change on the Energy Efficiency Directive are:</p> <ul style="list-style-type: none"> • Setting a 30% binding energy efficiency target for 2030 at EU level; • Extending beyond 2020 energy saving obligation on energy suppliers and distributors (1.5% each year from 2021 to 2030); • Improving metering and billing of energy consumption for heating and cooling consumers. <p>The expected change on the Energy Performance of Buildings Directive are:</p> <ul style="list-style-type: none"> • Encouraging the use of ICT technologies, including building automation and charging infrastructure for electric vehicles; • Streamlining or deleting provisions that have not delivered the expected output; • Reinforcing provisions on national long-term building renovation strategies with a view to decarbonising the building stock by mid-century; • In addition, the EC is willing to facilitate private financing for energy efficiency and renewable in buildings.

Package of legislative proposals: « Clean Energy for all Europeans »

Key features	Insights
<p>As part of the modification of the Directives presented previously, the EU should also modify the electricity market Design to enable a clean energy transition to take place, at the best value for consumers.</p>	<p>The objectives of the change on the electricity Market Design should address:</p> <p>Wholesale market:</p> <ul style="list-style-type: none"> • More flexibility on short term markets to the rise in variable renewable generation. • Cancellation of wholesale price caps. • Modification of dispatch rules, creating a level-playing field for larger generation capacities. • Minimizing grid bottlenecks on the borders. • Coordination of operation by TSOs on a regional level. • Better demand participation: remuneration for demand response in line with the flexibility provided. <p>Retail market:</p> <ul style="list-style-type: none"> • Providing consumers with better information about their energy consumption and their costs. • Access in all EU electricity consumers to at least one certified energy comparison tool about the offers. • Facilitating switching conditions. • Every consumer equipped with a smart meter. • Empowering consumers and communities to actively participate in the electricity market and generation. • Allowing consumer to offer demand-response and to receive remuneration, directly or through aggregators. • Removal of retail price regulation while ensuring the protection of vulnerable consumers. • Member States will have to incentivise Distribution System Operators (DSO) to use flexibility services and energy efficiency measures. • A new EU DSO entity will be created. <p>The Market Design Initiative introduces a wider regional and European aspect first into the assessment of capacity needs and seeks to better coordinate national capacity mechanisms.</p>
	<p>Next steps</p>
	<p>All the Energy Union related legislative proposals presented by the Commission in 2015 and 2016 need to be addressed as a priority by the European Parliament and Council.</p>
<p>Link: Clean Energy for All Europeans</p>	

European Energy Council

Key features	Insights
<p>On December 5th, the Commission presented the 'Clean Energy for All Europeans' package to the European Energy Council with a focus on the proposal for a regulation concerning measures to safeguard the security of gas supply. The aim of the regulation is to create a cost-effective EU regional framework that would minimize the impact of a potential gas disruption. Enhanced regional cooperation and coordination are important tools for creating greater solidarity and trust between member states and for strengthening the internal energy market.</p> <p>The EU Ministers highlighted the following objectives:</p> <ul style="list-style-type: none"> • Having coordinated messages. • Implementing the energy diplomacy action plan. • Pursuing diversification of routes and sources. • Increasing cooperation with OPEC. • Focus of the Nord Stream2 project. • Stabilising the Russia-Ukraine relationship. • Protecting European industry against carbon leakage. 	<p>In relation with the security of gas supply, the Council agreed that:</p> <ul style="list-style-type: none"> • Regional cooperation would be based on groups of member states identified on the basis of the main risks for the EU's gas supply. Member states will conduct national risk assessments as well as common risk assessments with other member states, according to the relevant risk. • Exchange of information: long-term contracts which provide 40% or more of annual gas consumption in the member state concerned would be notified to the competent authority. They would be assessed by the competent authority, with regard in particular to their impact on the security of gas supplies in the member state and the region. • Solidarity: Solidarity is a last resort mechanism after all the emergency measures have been exhausted. Solidarity, together with general principles on compensation, should be defined in the text of the regulation, whilst member states should be allowed to take into account their specific national situation and possible different approaches to calculating compensation. <p>In addition, the Council took note the state of play of two important legislative proposals on which the Council has reached general approaches: Decision on intergovernmental agreements (IGAs) and regulation on energy labelling. Negotiations with the European Parliament have started on both proposals.</p>
<p>Next steps</p> <p>The incoming presidency's main priorities for the next six months, will focus on completing legislative work on security of gas supply and energy labelling in connection with the different Energy Directives.</p>	
<p>Link: Energy European Council</p>	

Key consultations from EU

What is discussed?	Insights	Link
<p>"Mid-term evaluation of the Connecting Europe Facility (CEF)"</p>	<p>EU seeks to collect views and suggestions from stakeholders, including citizens, for the purposes of the current mid-term evaluation of the Connecting Europe Facility (CEF) Program. The CEF is a European program aimed at supporting the development of high-performing, sustainable and efficiently interconnected trans-European networks in the field of energy, telecommunications and transport over the period 2014-2020.</p> <p>Closing date: February 27th.</p>	<p>Link to the consultation</p>

Country reporting on changes in the Policy and Regulation framework

Spain			
Topic	Key features	Insights	Next Steps
New calculation methodology for volunteers prices for small consumers (PVPC)	<ul style="list-style-type: none"> The PVPC is the electricity price that the reference retail energy companies apply to small consumers (with a contracted power less than 10 KW) who have been adhered to this tariff. Commercialization costs are one of the components of the PVPC. Now, a new methodology for the calculation of these costs applied to the PVPC has been passed. The new methodology aims to include in the PVPC the commercialization costs of an efficient and well-managed retail energy company. 	<ul style="list-style-type: none"> In order to apply the commercialization costs to the PVPC, new methodology includes a fixed term based on the contracted power and a variable term based on the energy consumed. Before, the calculation only included the power term and it was fixed at 4 €/kW per year. Now, retail energy companies can regularize the amounts billed to consumers adhered to this tariff since 1st April 2014 until now. The expected effect for an average consumer is a little increase of the electricity bill. Following this new methodology, the Spanish government has passed: <ul style="list-style-type: none"> - The value of the fixed term for the years 2014 to 2018 (3.113 €/kW). - The value of the variable term for the years 2014 to 2016 (different values for each year). The value of some components of the variable term for the years 2016 to 2018. 	Retail energy companies can make the regularizations of the amounts billed until 30th September 2017 .
Social tariff cost and protection measures for vulnerable consumers	<ul style="list-style-type: none"> In March 2014, the Spanish government passed a social tariff for vulnerable consumers who met certain social and consumption characteristics. The social tariff supposes a discount of 25% on the PVPC. Companies with simultaneous generation, distribution and retail energy activities (23 companies) have been bearing the costs of the social tariff. Now, a new financing mechanism has been passed. These costs have to be financed by the retail energy companies (more than 250 companies) according to the percentage of customers supplied by each company. 	<ul style="list-style-type: none"> Vulnerable consumers will be divided into categories on the basis of their social characteristics and their purchase power. The base value on which the social tariff is applied may differ according these categories. In addition, the new regulation establishes that retail energy companies couldn't cut off the electricity supply to severe vulnerable consumers attended by social services. Retail energy companies will assume part of these costs together with the Public Administration. Also, the period to cut off the electricity supply in event of non-payment has been extended from two to four months for certain vulnerable consumers. 	A regulatory development for these measures is expected next months .

Country reporting on changes in the Policy and Regulation framework

Spain			
Topic	Key features	Insights	Next Steps
Proposal of Royal Decree for remuneration of new renewable facilities based on an auction	<ul style="list-style-type: none"> Last December, Spanish government launched a public consultation about a proposal of an auction up to 3,000 Mw of renewable power. All renewable technologies could participate in this auction. The objective is to include in the electricity system the most cost efficient project regardless of the technology used. The concept auctioned will be a percentage of reduction on the initial value of the investment fixed by the Spanish government (1,200,000 €/Mw for wind and photovoltaic facilities and 2,000,000 €/Mw for other technologies). This amount will be included in the calculation of the remuneration. After this, the remuneration obtained will be divided by the equivalent hours of functioning fixed by the government (2,800 hours for wind facilities, 2,367 hours for photovoltaic facilities and 5,000 hours for other technologies). The amount obtained is the unit cost overrun for the system. The awarded facilities will be the facilities with the lower unit cost overrun. In addition, new regulation includes the rest of specific retributive parameters for each type of facility. 	<p>Different auctions could be called until reach the maximum limit (3,000 Mw).</p> <p>Each participant will offer a reduction on the initial value of the investment according to their calculations of efficiency and profitability that they expect of each project.</p> <p>The result of the last renewable auction was a reduction of 100% on the initial value of the investment. In order to avoid this situation, the new Royal Decree Proposal includes:</p> <ul style="list-style-type: none"> - That the minimum and maximum values for the percentage of reduction could be fixed by the government. - New requirements of economic guarantees and deadlines. 	<p>The auction is expected in the first quarter of 2017.</p> <p>The projects should be finished before 31st December 2019.</p>

Germany			
Topic	Key features	Insights	Next Steps
Determination on the electricity market communication in the context of the Metering Point Operation Act (MsbG)	<ul style="list-style-type: none"> The Metering Point Operation Act (MsbG) intends a radial communication from the communication unit "smart meter gateway" to all energy market participants. This Act is in force since September 2nd, 2016. According to this Act, metering data have to be provided directly to all market participants and not anymore only to the DSO and from there in a cascade to other market participants.. Now, the new determination recognizes a transition period from October 1st, 2017 to October 1st, 2020. For this period, the preparation and distribution of power values from intelligent measurement systems could still be organized by the distribution network operator. 	<ul style="list-style-type: none"> The transition period allows the market participants to use the previous rules for market communication. 	<p>The determination is in the consultation process. Application of the determination as of summer 2017.</p>

Country reporting on changes in the Policy and Regulation framework

Germany			
Topic	Key features	Insights	Next Steps
Transition from L-Gas ("Low calorific gas") to H-Gas ("High calorific gas"). Amendment of: - Energy Industry Act Gas cooperation agreement	<ul style="list-style-type: none"> Changes introduced by the new regulation: <ul style="list-style-type: none"> Network operator's costs in relation to the transition from L-Gas to H-Gas (e.g. for technical adjustments of consumption units, grid connections) are charged nationwide on every gas supply network. Previously they were only charged to the grids belonging the market area. Network operators are entitled to enter their customer's property to install new network devices. Customers who install new devices which do not have to be adjusted in the course of the transition, can get a compensation from the network operator. Network operators are obliged to inform their customers about the transition 2 years before and about their compensation. According to the aforesaid amendment the gas cooperation agreement had to be changed and now contains details on the compensation for transition costs and their calculation. 	<ul style="list-style-type: none"> Every network user takes the same financial part to finance the transition to H-Gas. The possible threat is that the transition to H-Gas could have high costs. 	Both amendments have come into force on January 1st, 2017.
Amendment of regulations concerning the procedure for awarding concessions for power and gas in the Energy Industry Act	<ul style="list-style-type: none"> Changes introduced by the new regulation: <ul style="list-style-type: none"> According to the amendment the purchase price of a network has to be dependent on the potential income if the concession was awarded to another network operator. The municipality has to inform interested companies on request about the criteria for the selection of a new concession holder. The municipality can demand information from the concession holder concerning the technical and economic condition of the grid. An infringement in the process of awarding concession has to be reprimanded immediately, otherwise the company is excluded with its complaint. 	<ul style="list-style-type: none"> Opportunities for utilities: <ul style="list-style-type: none"> Prevention of litigation proceedings. Protection from excessive purchase prices. Better transparency concerning the condition of the grid. Possible threats are: <ul style="list-style-type: none"> Awarding proceedings have to be monitored closely for not to be excluded with any lawsuit afterwards. 	German Bundestag adopted the amendment on December 1st, 2016. In February 2017 the Bundesrat will decide on the legislative proposal . After this, the provisions can come into force.

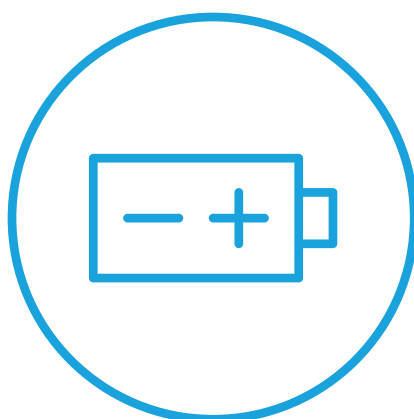
Country reporting on changes in the Policy and Regulation framework

United Kingdom			
Topic	Key features	Insights	Next Steps
Embedded Generation: Modification of TNUoS charging agreement[CMP264 & CMP265]	<ul style="list-style-type: none"> Embedded benefits are transmission cost advantages that small scale distribution connected generation has been able to capture in the GB electricity market. Ofgem (the regulator) considers Transmission Network Utilisation Use of System (TNUoS) demand residual payments to Embedded Generation to be a “major concern” and distortion in the capacity and wholesale market, driving up consumer costs. Hence, Ofgem has sought recommendations by two proposed modifications: <ul style="list-style-type: none"> CMP264 seeks to make changes to the Transport and Tariff Model and billing arrangements. The registration of embedded generators to a Supplier BM Unit can result in a reduction in TNUoS charges payable by the supplier. The embedded generators do not pay generation transmission charges and may receive a significant benefit from the supplier whose TNUoS charges they reduce – “Triad avoidance”. Specifically, Ofgem intends to remove the netting of output from New Embedded Generators when calculating their demand volumes for use in the setting of tariffs for suppliers in the Transport and Tariff model and for actual billing. Ofgem states that this shall eliminate the “Triad avoidance” shared with embedded generators as the supplier would no longer benefit from netting the output from them. CMP265 seeks to change that half hourly (HH) metered demand for TNUoS purposes is charged net of embedded generation (embedded generation is being treated as negative demand for HH TNUoS demand charging purposes). Now, it is proposed that embedded generators that win Capacity Market contracts would not be eligible to receive a credit in respect of the demand residual TNUoS charge. 	<ul style="list-style-type: none"> The new regulation is likely to reduce the competitiveness of smaller distribution system connected generators and improve the competitiveness of large transmission system connected generators. This rebalancing of competitive positions will affect both existing generators and prospective new build developments. Ofgem expects to reduce the cost to consumers with the modification of the current system. 	<p>Ofgem is expected to make a final decision in the first half of 2017.</p> <p>Ofgem expects to enact changes to TNUoS demand residual payments to Embedded Benefits in 2018/19.</p>
Draft Budget Notice for the Second Contracts for Difference (CFD) Allocation Round	<ul style="list-style-type: none"> CFDs ensure generators to receive the difference between a fixed price and a market reference price for the low carbon electricity they produce for the duration of the contract. The Department for Business, Energy and Industrial Strategy (BEIS) intends to allocate £290m in 2011/12 prices for the second Contracts for Difference (CFD) Allocation Round. The budget is set in real terms in an old price base. The budget will be available each financial year for 2021/22 and 2022/23. The Allocation Round intends to support “less established technologies” such as Offshore Wind, Anaerobic Digestion and Geothermal. The budget will be allocated through price guarantees, which are set and vary by technology and fiscal year. A maxima of 150 MW applies to fueled technologies. 	<ul style="list-style-type: none"> The funding guarantee supports the renewable energy industry and should reduce investment risk in the designated technologies 	<p>The auction is to be held in April 2017.</p> <p>A final budget notice is to be issued 10 days in advance.</p>

Country reporting on changes in the Policy and Regulation framework

United Kingdom			
Topic	Key features	Insights	Next Steps
Energy supplier league table	<ul style="list-style-type: none"> The BEIS plans to increase transparency for consumers by publishing a "league table" comparing the average energy bill paid by someone on a standard variable tariff for the larger companies with the contracts available from the 10 cheapest suppliers. The table includes information on the absolute number and share of clients on standard variable tariffs by supplier as well as potential savings when switching to a cheaper supplier. 	<ul style="list-style-type: none"> This regulation aims to reduce the number of standard variable tariff clients for larger energy suppliers and thus is likely to reduce their profits. On the other hand, smaller and cheaper companies are likely to gain from the increased visibility of price differences. 	The league table is already published and can be accessed on the Ofgem website.
Capacity Market: Capacity auctions	<ul style="list-style-type: none"> The BEIS will adapt its approach to capacity auctions in regards to finance obtained under risk finance schemes. These risk finance schemes were essentially concessional finance schemes that provided tax breaks to investment in small companies. In particular, the department proposes to offset capacity payments made to generators that have received financial support via risk financing schemes to increase the competitiveness of projects that have not had support through a risk finance scheme. 	<ul style="list-style-type: none"> The new system is likely to improve the competitiveness of bidders that were unable to obtain funds through a risk finance scheme. This may also increase the clearing price in the auctions due to less capacity being offered that also benefits from concessional finance arrangements. 	The amended regulation came into force on 21 November 2016 and will be applicable for all future capacity market auctions.
Decision on the approach to dealing with supplier insolvency and its consequence for consumers	<ul style="list-style-type: none"> Ofgem has decided to modify its Supplier of Last Resort (SoLR) process with regards to consumer credit balances. If an energy supplier has to file for bankruptcy or is unable to fulfill his contractual obligations, SoLR is determined by a competitive process. Under the new regulation, the process of determining the SoLR will include the acknowledgement of existing consumer credit balances. 	<ul style="list-style-type: none"> The new process will allow supplier to bid along multiple dimensions potentially increasing competition in the SoLR market. The regulation is unlikely to have a profound effect on the overall energy market. 	The decision has been implemented in 2016.

France			
Topic	Key features	Insights	Next Steps
French Capacity market	<ul style="list-style-type: none"> • France set up a capacity market mechanism as part of EU expectation to secure a resilient European electricity system. The system has been approved by European commission on November 8, 2016 and should be in force as of January 1st, 2017. • The mechanism is intended to provide a form of "insurance": operators are rewarded for the contribution of their capacities made to the electric system by being available during period of tight supply. • On the supply side, operators obtain from RTE, the French TSO, a capacity certificate of their ability to deliver a certain electricity volume. • On the demand side, the mechanism designated a scope of entities obliged to purchase such capacity certificates in an amount based on their customer's portfolio consumption in winter period. Distribution operators are also included in the scope of obliged entities in respect with the balancing system. • The capacity market is organized by RTE which performs the balance of capacity certificates. 	<ul style="list-style-type: none"> • Certificates are anonymous, freely transferable and could be utilized solely for a specific period. • The price of certificate is based on the balance between supply and demand. The first auction launched on EPEX Spot in December 2016 resulted in a price of €10 per KW to be delivered in 2017. • Specific rules are applied for the introduction of the mechanism but on a regular basis capacities would be certified 4 years before delivery and the obliged entities would have two year after delivery to purchase certificates. The unbalanced position would be settled using an administrative price of 40€ / MW 	The mechanism would be fully operational in 2017 after a first auction in 2016.



Snapshot on surveys and publications – December 2016

Deloitte

2017 Outlook on Power and Utilities - My Take: Scott Smith – December 2016

This paper assesses the new administration impact in the US power and utilities industry and analyses trends that can help utility companies manage costs.

[Link to the survey](#)

Managing variable and distributed energy resources: A new era for the grid – November 2016

The ongoing electric power industry transformation has ushered in a wave of variable and distributed energy resources on electric grids across the US and globally. Wind and solar installed capacity soared 85 and 1,169 percent, respectively, in the US from 2010 to 2015. And now resources such as battery storage, home energy management systems, and electric vehicles appear poised for strong growth.

[Link to the survey](#)

Alternative thinking – October 2016

Alternative thinking 2016 delves into the game-changers effecting the growth of the renewable energy sector, as well as examining the remaining barriers to growth. The report also explores certain “what if” scenarios that could propel the renewable power sector forward.

[Link to the survey](#)

Agencies or research institutes

International Energy Agency

World Energy Outlook - Executive Summary – November 2016

This outlook offers a comprehensive analysis of what the energy sector might look like, thanks to its energy projections to 2040. It reviews the key opportunities and challenges ahead for renewable energy, the central pillar of the low-carbon energy transition, as well as the critical role for energy efficiency.

[Link to the survey](#)

Global Gas Security Review – November 2016

The document examines the evolving global gas market structures and looks at the market’s ability to respond to potential shocks. It shows that the current situation could lead to a false sense of comfort about gas security, which could evaporate quickly once market conditions change.

[Link to the survey](#)

Energy Efficiency Market Report – October 2016

The IEA Energy Efficiency Market Report tracks the core indicators of energy efficiency. This year, the report takes a new approach and expands the scope of analysis by examining the drivers of energy efficiency programmes in emerging economies, as well as the impact of those policies.

[Link to the survey](#)

20 years of carbon capture and storage – November 2016

This publication reviews progress with CCS technologies and examines their role in achieving below 2°C targets. It considers the implications for climate change if CCS was not a part of the response and examines opportunities to accelerate future deployment of CCS to meet goals of Paris Agreement.

[Link to the survey](#)

CO₂ Emissions From Fuel Combustion Highlights – October 2016

This publication contains a selection of CO₂ emissions data for over 150 countries and regions, including world and regional aggregates, and an analysis of recent trends. Emissions data are based on the IEA World Energy Balances 2016 and on the 2006 IPCC Methodologies for Greenhouse Gas Inventories.

[Link to the survey](#)

European Commission

Integration of electricity balancing markets and regional procurement of balancing reserves – October 2016

The report presents the costs and benefits associated with various models for the cross-zonal exchange of balancing energy and the regional dimensioning and procurement of reserves.

[Link to the survey](#)

Study on evaluating fiscal measures in the national policies and methodologies to implement Article 7 of the Directive on energy efficiency – October 2016

The article 7 of Directive on energy efficiency relates to the National Energy Efficiency Actions plan to be communicated by each Member State. The commission identified a gap between its expectation and plans communicated by Member State. The study clarify expectation from the commission and looks at energy and CO2 taxation measures in more detail for a limited number of Member States.

[Link to the survey](#)

Eurelectric

Options to strengthen the EU ETS – October 2016

With the ambitious Paris agreement and the fact that the Commission proposal does still not put the EU ETS on a linear path to reach the long-term 2050 emission reductions target, the question emerged how to introduce more ambition to the EU ETS. This study picks up this question and analyses several options to strengthen the EU ETS by increasing the ambition in the fourth trading period.

[Link to the survey](#)

Winter Package Solutions – October 2016

EURELECTRIC's Winter Package Solutions brings together the European power sector's key principles and proposals for concrete action with regard to the upcoming set of legislative proposals and other documents that will comprise the forthcoming so-called 'Winter Package'.

[Link to the survey](#)

Toolkit on Decarbonising Heating & Cooling – October 2016

EURELECTRIC's Toolkit on Decarbonizing Heating and Cooling presents the power sector's priorities and key policy recommendations with regard to the different elements to achieve the decarbonization of this key sector of the European economy, and the contribution of the electricity sector towards this goal.

[Link to the survey](#)

Toolkit on Decarbonizing Transport – October 2016

EURELECTRIC's Toolkit on Decarbonizing Transport presents the power sector's priorities and key policy recommendations with regard to the different elements to achieve the decarbonization of this key sector of the European economy, and the contribution of the electricity sector towards this goal.

[Link to the survey](#)

Oxford institute for Energy

European gas grid through the eye of the Tiger – September 2016

The paper compares the evidence for periodic bottlenecks in Europe's gas transmission systems, indicated by price correlation de-linkage – and supporting evidence of apparent physical or contractual flow constraints – with the results obtained by 're-running history' using the EWI TIGER model.

[Link to the survey](#)

Energy subsidy reforms and the impacts on firms: Transmission channels and response measures – October 2016

While the adverse effects of energy price increases are increasingly well understood for households, the existing literature has largely ignored the effect of subsidy reform on firms. This paper argues that this is a gap that must be addressed, in order to design and deliver reforms more effectively, and outlines the most important transmission channels for energy price shocks and the response measures used by firms.

[Link to the survey](#)

Floating Liquefaction (FLNG): Potential for Wider Deployment – November 2016

This paper provides a comprehensive review of the state of play of FLNG, the competing approaches and the advantages and disadvantages compared with conventional onshore liquefaction. It also hints of further potential technology step-out in FLNG once the first wave of projects is successfully commissioned.

[Link to the survey](#)

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