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Can the European gas market absorb additional gas volumes? How? How much? Where?

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ABSTRACT

In the next years, holders of free LNG volumes or liquefaction capacity, mainly in Australia and the U.S., need to find sales markets for additional quantities of 71 mtpa to 79 mtpa in order to amortize their investments or to fulfill their contractual obligations.

The European electricity sector is a possible candidate to absorb additional volumes. Compared to other consumption sectors, it is the only one which can accommodate additional volumes in the short-term. To gain share in the power market, gas would have to replace production from coal-fired plants.

Based on a macro perspective analysis using publically available statistics, we estimate that, in 2014, a total of 295 TWh_{el} of coal-based electricity production from the UK, Italy, Germany, the Netherlands, Spain and Belgium could have been substituted. In the years from 2010 to 2014, electricity output from gas-fired plants decreased substantially in Europe. Our assessment shows that the spare installed capacity of gas power plants in the six analyzed countries could have realized about 214 TWh_{el} to 284 TWh_{el} of the substitution potential from coal which corresponds to around 27 mtpa to 36 mtpa of gas input.

In a micro perspective analysis, we assess under which gas price scenario a representative German CCGT plant would have increased its production. For this, we use a clean spark spread model assuming a hub-based gas procurement and electricity sale strategy of a specific power plant set-up. The results show that a reduction of the 2015 average Day Ahead gas price between -30% to -50% could have – all other things being equal – reestablished a capacity factor formerly seen between 2009 and 2011, when the capacity factor of CCGT plants was close to their usually planned capacity utilization.[1]

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[1] For example, the capacity factor of the German state-of-the-art CCGT plant Irsching 5 was about 46% in 2010 which is also the lower end of the plant's projected capacity utilization. See "Von erneuerbaren Energien überrascht", in Mittelbayerische Zeitung, 05 February 2013, and „Irsching 5: Zeil will Betrieb anordnen", in Zeitung für kommunale Wirtschaft, 13 March 2013.

1 INTRODUCTION – WHERE TO SELL THE EXCESS GAS

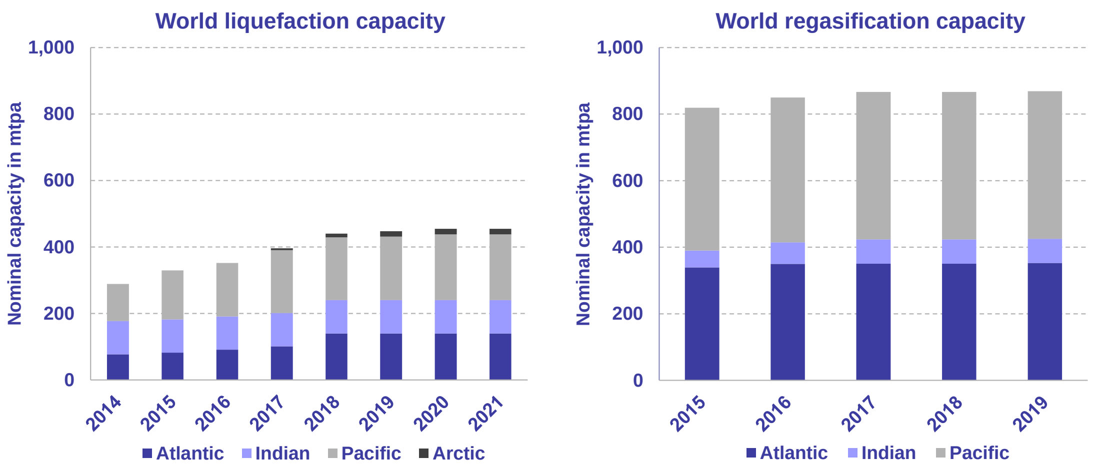
At the moment, the energy industry is discussing the occurrence of a significant worldwide oversupply of natural gas. It is expected that the oversupply of gas will be the dominant situation also for the years to come and will be a key market driver for gas industry players.

The gas oversupply is mainly triggered by two opposing developments:

- first, the weakened economy in Asia and the resulting gas offtake which has fallen behind expectations especially in China, and
- second, even though that gas markets are dominated by low gas and oil prices, additional gas reserves will come on stream in the following years due to major LNG infrastructure projects being build and commissioned mainly in the US and Australia. Figure 1-1 shows that, from 2016 to 2019, world liquefaction capacities are about to increase by 27% and the regasification capacities remain on a high level.

Due to the already taken final investment decisions and the cash-flow expectation of the project finance partners, the high utilization rate of the existing liquefaction capacities will also have to apply to the new infrastructure which means that additional LNG volumes in the magnitude of 71 mtpa to 79 mtpa will have to be sold. The resulting question is where the additional LNG volumes can be marketed.

Figure 1-1: Development of world liquefaction and regasification capacity (operational and under construction)



Source: GIIGNL, IGU, TEAM CONSULT analysis

Although the supply situation of pipeline gas is stable and sufficient for the time being, European markets may be the “last resort” for additional LNG volumes.

First, on the supply side, it is expected that the European indigenous gas production will decrease in the near future. Thus, Europe will have to fill a production gap and might use LNG to do so.

Second, on the demand side, there are the market segments that might be able to absorb additional volumes. Since the heating sector has a price-inelastic and rather stable demand, the segment will not absorb significant additional volumes in the short-term. However, operators of gas power plants with access to trading markets for gas and electricity are able to respond quickly to changing market prices. A decrease in gas price at the gas exchange will translate directly into lower marginal costs for the electricity to be marketed at the power exchange. Thus, the European electricity sector may be suitable to absorb extra gas volumes especially in the context of low plant utilization rates which are observed at the moment. In theory, the power markets can absorb as much additional electricity from natural gas as gas power plants are able to substitute generating capacities using other fuels.

Although any other fuel is a competitor to gas on a marginal cost base, hard coal[2] may be considered as the direct competitor in the merit order of European power markets. This is because renewable energies retain a feed-in priority and often have marginal costs close to zero. The residual load is then first supplied by lignite and nuclear plants which operate with relatively low marginal costs. Any additional load to be supplied – normally mid or peak load – will be provided by hard coal and gas power plants with higher marginal costs depending on their technical and economic parameters.

Based on these considerations, we analyze,

- in a macro perspective analysis, how much electricity from hard coal can be replaced by gas-fired power plants in the six largest markets for electricity from gas-fired plants (UK, Italy, Germany, the Netherlands, Spain and Belgium[3]). We look at official statistics regarding European power production from gas and hard coal as published by Eurostat. Based on these figures, we estimate the potential for substitution of electricity from hard coal.

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2 In this article, we use the terms coal or hard coal for sub-bituminous coal and explicitly exclude lignite from our analyses. The term gas is used for natural gas.

3 Based on this delimitation, large electricity markets such as France are not assessed in this article.

- in a micro perspective analysis, under which gas price scenarios gas could potentially substitute coal and reestablish capacity factors observed in previous years. We exemplarily calculate different gas price scenarios under which a specific gas-fired power plant set-up would have (ceteris paribus) reached such capacity factors in the German power market in 2015.

2 MACRO PERSPECTIVE ANALYSIS – SUBSTITUTION POTENTIAL FOR ELECTRICITY FROM COAL

Theoretical potential for substitution of coal-based electricity production by gas power plants

A fuel switch in power production is limited from the coal and from the gas side. On the coal side, there is only a certain amount of electricity from coal that can be replaced. The substitution potential is further limited due to production from combined heat and power (CHP) plants which must produce heat. On the gas side, to realize the substitution potential, there must be unused power generation capacity available.

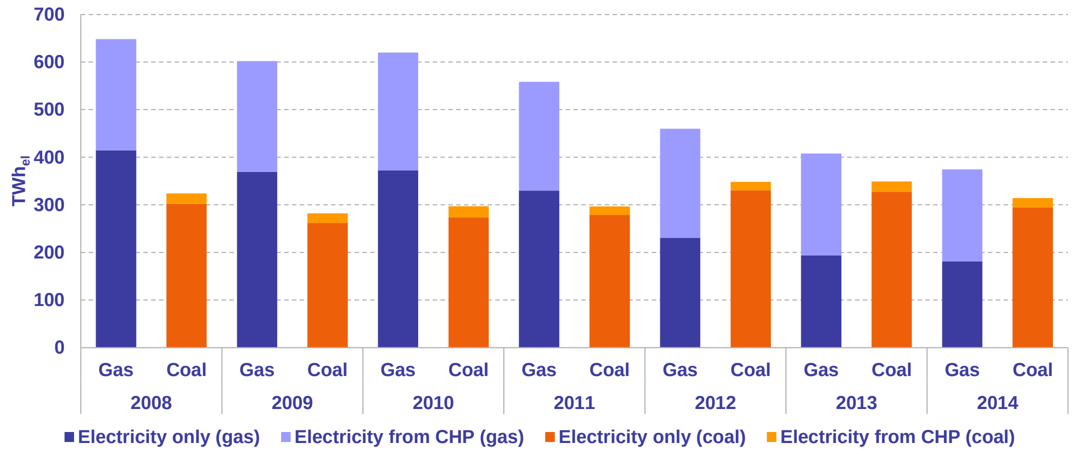
The lower of the two figures – unused gas capacity available and substitutable coal-fired electricity production – sets a maximum limit to the amount of electricity that can be fuel-switched from coal-fired to gas-fired production.

Assessing the six largest markets of gas-based electricity production

On the gas side, the UK, Italy, Germany, the Netherlands, Spain and Belgium accounted for a stable share of 79% to 82% in EU-28 gas-fired electricity production in the period from 2008 to 2014. From the combined development of power generation from industrial and public gas plants of the six countries, as shown in figure 2-1, we see that:

- Decreasing combined output: in the six countries, the production of electricity from gas has substantially decreased. The maximum combined output of 648 TWh_{el} was realized in 2008 and it shrank by about 42% to 375 TWh_{el} in 2014. Only the UK market managed to slightly recover from a minimum of 96 TWh_{el} in 2013 to 101 TWh_{el} in 2014.
- Increasing share of CHP production: in the period from 2008 to 2014, the relative share of electricity from CHP production shows an increasing trend. In 2008, it was 36% and it rose to about 52% in 2013 and 2014. However, the absolute power production from co-generation plants declined and reached its lowest of 193 TWh_{el} in 2014. Thus, the increasing share of CHP production solely results from the more pronounced fall of production from electricity-only plants.

Figure 2-1: Development of electricity production from gas and coal in six European countries (combined)



Source: Eurostat, TEAM CONSULT analysis

On the coal side, UK, Italy, Germany, the Netherlands, Spain and Belgium also hold the lions share in EU-28 coal-fired electricity production which varies between 63% (2009) and 70% (2014). This indicates that the six countries are the right markets to address for the substitution of power from coal. From figure 2-1, we further note:

- By contrast to power production from gas, the combined power production from coal plants has increased by 25% from 282 TWh_{el} in 2009 to 352 TWh_{el} in 2013. It fell again to 314 TWh_{el} (electricity only: 295 TWh_{el}) in 2014[4]. Only in the Netherlands and in Spain, a slightly increasing power output from coal is observable compared to 2013.
- Stable, low share of CHP production: the share of electricity production from CHP plants varies between 5% (2012) and 8% (2010). In absolute terms, the share corresponds to 18 TWh_{el} and 23 TWh_{el}.

Comparing the contrasting developments of gas- and coal-fired electricity generation points out that coal-fired production gained shares in the power market at the costs of gas-fired production. However, the declining output from coal plants in 2014 may be a result of e.g. an increasing generation from renewable sources in the markets. The development indicates that the cake of fossil power production is becoming ever smaller.

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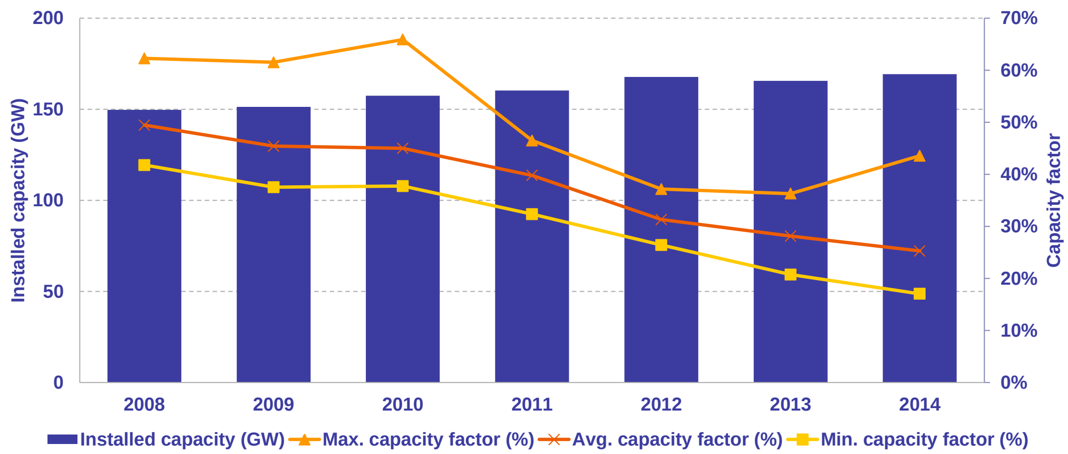
4 This figure can be interpreted as the theoretical substitution potential of coal-based electricity production.

From the perspective of a gas plant operator, the low CHP share of coal plants is good news since, in the short-term, the theoretical substitution potential of coal-fired generation is only diminished by a low share of non-variable CHP production.

Check of available gas capacity

Finally, the question remains whether sufficient free gas capacity is available in order to actually enable a fuel switch from coal to gas. This can be seen from figure 2-2[5].

Figure 2-2: Development of installed gas-fired generation capacity (combined) and capacity factors in six European countries



**Capacity data from Eurelectric is shown. For 2011, values are estimated since figures for this year are not available.*
***For Italy, data from Entso-E is used since Eurelectric makes no statement for this country. Capacity assigned to mixed fuels by Entso-E was distributed pro rata between coal, gas and oil capacity.*
Source: Eurostat, Entso-E, Eurelectric, TEAM CONSULT analysis

The sum of installed gas capacity increased from about 150 GW in 2008 to 169 GW in 2014. In the same period, the average capacity factor fell from 49% to 25% and the minimum and maximum capacity factors show a decrease of comparable magnitude.

We can now assess the additional electricity output which could have been realized by non-operating gas plant capacities in 2014. To draw a more realistic picture, we follow a three-staged approach which is also summarized in Figure 2-3:

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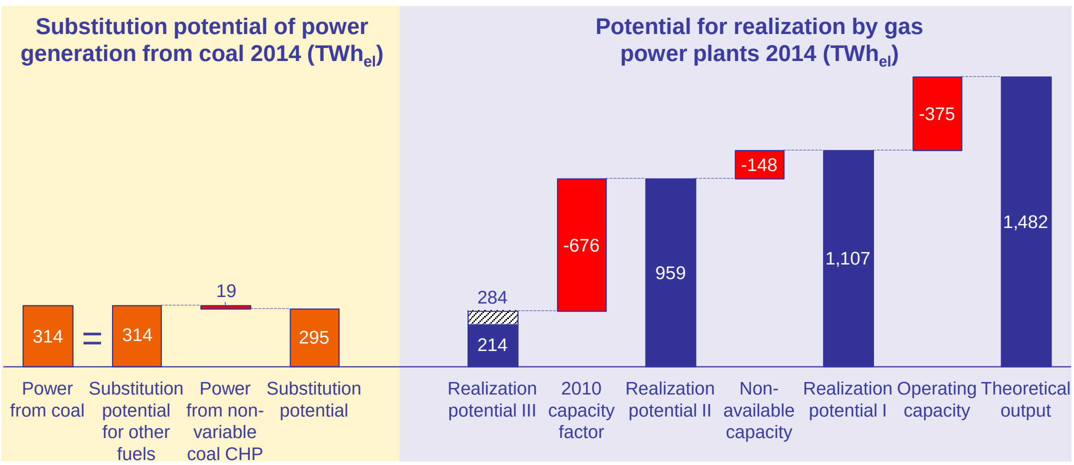
5 Blue columns: combined installed capacity; orange line: maximum capacity factor of six countries which is calculated by putting the annual gas power production of each country in relation to its maximum possible gas power output of a year, based on the installed capacity; yellow line: minimum capacity factor of six countries; red line: average capacity factor across six countries.

- First, the spare gas capacity of the six countries could have produced additional 1,108 TWh_{el}. However, this figure is rather theoretical since it assumes that a capacity factor of 100% can be reached.
- Second, considering that plants may be unavailable e.g. due to unexpected or expected maintenance procedures, the additional output is reduced to 959 TWh_{el} (based on a total plant availability of 90%).
- Third, if we assume the capacity factor reached in each country in 2010 to be a realistic upper level of utilization (i.e. before capacity utilization and power output of gas plants started to fall sharply), the additional electricity output is reduced to 284 TWh_{el}.

Figure 2-3: Substitution potential of electricity from coal vs. realization potential by gas



Source: TEAM CONSULT analysis

Thus, our yearly capacity assessment suggests that up to 96% of the electricity only production from coal-fired power plants in 2014 (which is 295 TWh_{el}) could be substituted by gas power plants. To realize this potential, the availability of cross-border transmission capacity is a prerequisite. Assuming that no transmission capacity between countries is available, leaves an additional output of 214 TWh_{el} (or 73% of coal-based production in non-CHP plants).

We conclude that, on a yearly basis, a more favorable gas price constellation could have forced coal plants out of the money in the power markets and enabled gas plants to substitute major shares of coal-based production.

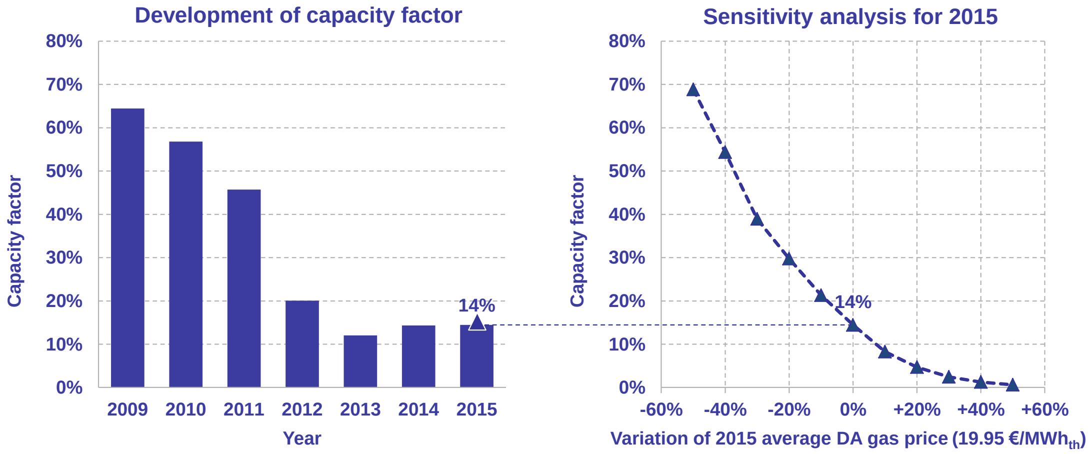
Gas price scenarios which would have enabled e.g. German gas power plants to realize capacity factors of previous years in 2015 are assessed in the micro perspective analysis.

3 MICRO PERSPECTIVE ANALYSIS – GAS PRICE SCENARIOS

In the following, we exemplarily carry out a micro perspective analysis of the German power market. For this, we calculate hourly clean spark spreads of a certain gas power plant set-up[6] which we consider as representative for German combined-cycle gas turbine (CCGT) plants in non-CHP mode. The marginal cost of electricity produced from gas is mainly based on Day Ahead (DA) gas prices at the NetConnect Germany (NCG) hub and prices for carbon emission rights at the European Energy Exchange (EEX). The operator sells the electricity as hourly products for the next day at the EEX Power Exchange.

Given that historical EEX prices are available, we compare the hourly power price with the marginal generation costs of the assumed CCGT plant operator. If a positive spread between price and offer remains, it is accounted as an operating hour. This approach is carried out for every hour of the years from 2009 to 2015. The sum of operating hours of a year is multiplied by an assumed plant availability of 90% and converted into the plant's capacity factor.

Figure 3-1: Development of capacity factor in the German market and sensitivity analysis of capacity factor for 2015 based on variation of average gas price



Source: ICIS Heren, EEX, TEAM CONSULT analysis

[6] Parameter assumptions: efficiency rate (net calorific value): 56.5% (rate of the German CCGT plant in Hamm-Uentrop considering a degradation effect of 1 percentage point), emission factor: 0.202 t CO_2/MWh$_{th}$, variable O&M costs: 1.5 €/MWh$_{el}$, gas transport costs from hub to plant: 0.33 €/MWh$_{th}$.

The results for the years 2009 to 2015 are shown in figure 3-1 (left chart). One can see that the capacity factor of the described plant set-up drastically diminished from 64% in 2009 to 12% in 2013. Such massive drop of capacity factors could actually be observed e.g. in the case of the German plant Irsching 5. The state-of-the-art CCGT plant has a capacity of 860 MW and was commissioned in March 2010. In the same year, a capacity factor of about 46% was achieved which is also the lower end of the plant's projected capacity utilization. However, Irsching 5 was operating less and less in the years after 2010 until the operators temporarily shut-down the plant in 2016.

The capacity factor of our model plant reached its lowest of 12% in 2013 but has recovered only insignificantly since then although the average Day Ahead gas price dropped from 27.17 €/MWh$_{th}$ in 2013 to 19.95 €/MWh$_{th}$ in 2015. The question is which gas price would have triggered capacity factors of previous years in 2015? To address this question, we vary the average Day Ahead gas price of 2015 down to -50% and up to +50% and assume that the resulting price would have applied as procurement price on every day of the same year. All other cost and technical parameters are held fixed although we are aware that market dynamics may lead to e.g. lower costs for carbon emission rights if less coal is burned for power production. The result of the sensitivity analysis can be seen in figure 3-1 (right chart).

Without gas price variation, the capacity factor is 14%. A price reduction of -50% (average gas price of 9.98 €/MWh$_{th}$) would have increased the capacity factor to 69% which is close to the actual capacity factor of 2009. A price reduction of -30% (average gas price of 13.97 €/MWh$_{th}$) would have resulted in a capacity factor of 39% which is close to the actual factor of 2011. If we assume that 2009 to 2011 were years in which operators could run their gas plants in a sufficient number of hours, a reduction of the 2015 average Day Ahead gas price of -50% to -30% would have – all other things being equal – reestablished this situation at least for CCGT plants.

On the other hand, a price variation of +50% (average gas price of 29.93 €/MWh$_{th}$) would have resulted in an all-time low capacity factor of 1%. In other words, the highest price increase of our analysis would have meant that the plant is hardly generating at all. Thus, the actual gas price decrease from 2013 to 2015 enabled the operation at least in some few hours but was not sufficient to keep up with the fall in electricity prices that is mainly due to diminishing fuel prices and increasing renewable generation.

A preliminary assessment of the operating hours in 2016 reveals that, in the first half year, a capacity factor of 24% could have been achieved for our model plant. The increase of ten percentage points compared to the whole year 2015 could mark the turning point towards higher capacity utilization of CCGT plants in Germany. However, the increase was realized under an average Day Ahead gas price of 13.18 €/MWh$_{th}$. Our sensitivity analysis would have suggested a much higher capacity factor for such price level in 2015. However, a factor above 24% has not been reached because the remaining economic parameters (electricity and carbon price) have further deteriorated to the detriment of CCGT plants in 2016 compared to 2015.

4 CONCLUSION

Holders of free LNG liquefaction capacity and volumes, mainly in Australia and the USA, need to find sales markets for their spare quantities in order to amortize their investments or to fulfill their contractual obligations.

The European electricity sector is a possible candidate to absorb additional volumes. Compared to other consumption sectors, it is the only one which can accommodate additional volumes in the short-term. To gain share in the power market, production from coal-fired plants would have to be substituted.

The macro perspective analysis demonstrated that the combined theoretical substitution potential of coal-based power of the UK, Italy, Germany, the Netherlands, Spain and Belgium would have been 314 TWh_{el} in 2014. Assuming that electricity production from CHP plants cannot be substituted, the potential is reduced to 295 TWh_{el}. In the years from 2010 to 2014, electricity output from gas-fired plants decreased substantially in Europe. Our assessment showed that the spare installed capacity of gas power plants in the six analyzed countries could have realized about 214 TWh_{el} to 284 TWh_{el} of this potential from coal which corresponds to around 27 mtpa to 36 mtpa of gas input if an average efficiency factor of 50% is assumed.

In the micro perspective analysis, we showed under which gas price scenario a representative German CCGT plant would have increased its production. A variation of the 2015 average Day Ahead gas price between -30% to -50% could have – all other things being equal – reestablished capacity factors which were actually reached between 2009 and 2011. In these years, the capacity factor of CCGT plants was close to capacity utilization that is usually planned when such plants are built.

The question remains if lower gas prices are the only possible trigger of a fuel switch from coal to gas. Political measures (e.g. shortening of carbon emission rights or direct regulatory measures against power production from coal) could also trigger a change in fuel usage without further substantial gas price reductions being necessary.

For further discussions regarding the sales potential of free LNG volumes, it may be worth to analyze:

- how much market share LNG could actually gain in competition with pipeline gas, and

- if such price levels as assessed in the micro analysis would have been viable considering that the short-term marginal costs of supply set the lower bound for gas sales prices. At least in 2009, we could observe that approximately 52 mtpa of LNG were imported to Europe when the average Month Ahead hub price at the British National Balancing Point (NBP) for delivery in the same year was 13 €/MWh_{th}.

Further studies could include scenarios taking account of dynamic developments in the power markets (e.g. German nuclear phase out, increasing renewable production, falling coal prices etc.) and actual merit-order curves. In addition, the substitution potential could be assessed at higher temporal resolutions.

Furthermore, for holders of free LNG volumes, it may be of interest to combine the assessment of sales potentials and prices with the question of necessary steps for a successful market access in the respective European countries.

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Madjid Kübler is the managing director and owner of Team Consult. He has a degree in mathematical economcs and has decades of experience in top management consultancy. Prior to the acquisition of Team Consult, he has worked in senior positions at Accenture and Arthur D. Little. He is continuously engaged in price revisions and arbitration proceedings, both in the role of expert and arbitrator. Madjid regularly appears at conferences as a speaker and presenter.

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