Argus White Paper:

European thermal coal winter outlook 2019-20

Growth in European thermal coal demand this winter is contingent on colder-than-average weather driving power generation higher along with weaker output from nuclear and renewables, with a downturn in overall demand likely in normal conditions. Risks to prices and demand are further skewed to the downside by high stocks and the potential for persistent oversupply of competing generation fuel natural gas.

European winter demand for thermal coal will fall in 2019-20 from the previous winter unless the region faces above-average power demand and unseasonably low renewable and nuclear output compared with the three-year average.

The biggest year-on-year declines are likely to come early in the season as a result of stronger competition from natural gas for power generation through October and November. Forward prices point to a recovery in coal's share of overall generation from fossil fuels from December, but the potential for strong natural gas supply throughout the winter presents a significant downside risk to this outlook.

High coal inventories at northwest European ports and power plants following record-low summer consumption and a persistent contango in forward prices means the continent is well stocked to cope with short-term spikes in demand, and less able to absorb surplus supply from the seaborne market. Europe's more limited capacity for imports should stem upside potential for prices and is likely to trigger a supply adjustment in the Atlantic basin, with US and Colombian exports to bear the brunt of any downturn in demand.

4Q fuel switching to weigh on winter coal burn

There is scope for a year-on-year increase in total generation from fossil fuels in key markets in western Europe under a base scenario, following a particularly mild winter in 2018-19 and above-average renewable load factors.

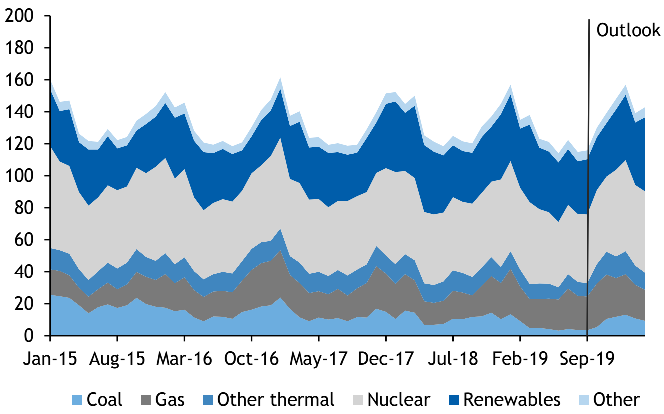
But overall coal demand would still decline as a result of strong competition from natural gas early in the season and steep drops in coal-fired power generation during the fourth quarter. So year-on-year growth in coal-fired power generation depends on power demand rising above the seasonal average alongside nuclear and renewable load factors remaining low during the peak heating months.

Fossil fuel-fired generation in Germany, Spain, the UK and France slipped by 11pc on the year, or 32.5TWh, to 260.8TWh in winter 2018-19, driven by a 24.7TWh drop in overall power demand and compounded by a 6.2TWh rise in renewable output. Under a base scenario this winter — which assumes that total power generation, output from nuclear plants and load factors for wind and solar capacity all track the three-year average, total generation from fossil fuels would rise by around 21.7TWh to 282.5TWh.

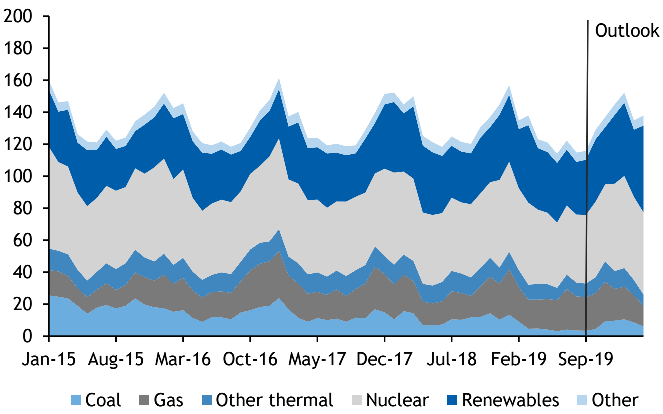
In a high-demand scenario — where power generation in each winter month is in line with the highest output recorded for that month over the past three winters and nuclear output and wind and solar load factors track the lowest seen over the same period — fossil fuel-fired generation would climb by 82.7TWh on the year in October-March. But generation from fossil fuels could drop by 32.8TWh in a low-demand scenario — where overall power generation tracks the lowest output seen in each month in the past three winters and nuclear output and renewable load factors match the three-year highs.

Winter coal-fired generation only rises in the high-demand scenario, as significant coal-to-gas fuel switching early in the fourth quarter is likely to offset potential growth later in the season under the base and low-demand scenarios.

Base scenario TWh



Low fossil fuel demand scenario TWh

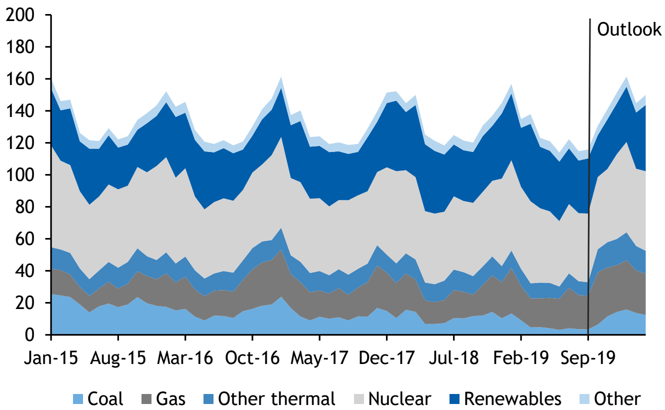


A surge in LNG imports to Europe and a 34pc drop in natural gas storage injections owing to unusually high post-winter stocks at the start of April weighed on gas prices and provoked significant coal-to-gas fuel switching this summer. Coal-fired generation across Germany, Spain, the UK and France accounted for only 11.6pc of total summer output from fossil fuels after German month-ahead clean dark spreads for 40pc-efficient coal-fired plants averaged €6.25/MWh below clean spark spreads for 55pc-efficient gas-fired plants.

Coal accounted for just under a quarter of total generation from fossil fuels in April-September 2018, when clean dark spreads were €3.86/MWh higher on average than clean spark spreads. The drop in share over the most recent summer resulted in a 30.3TWh drop in coal-fired generation, equivalent to around 11.4mn t of 5,700 kcal/kg coal burn in 40pc efficient plants.

With gas stocks in northwest Europe now close to capacity and 10pc higher compared with mid-October 2018, gas prices have remained under pressure and highly competitive with coal for thermal generation early this winter. The month-ahead clean dark spread for base-load output in October was €8.64/MWh lower than the clean spark spread during September, and the equivalent differential between November coal and gas margins averaged minus €2.29/MWh in the first half of October.

High fossil fuel demand scenario TWh



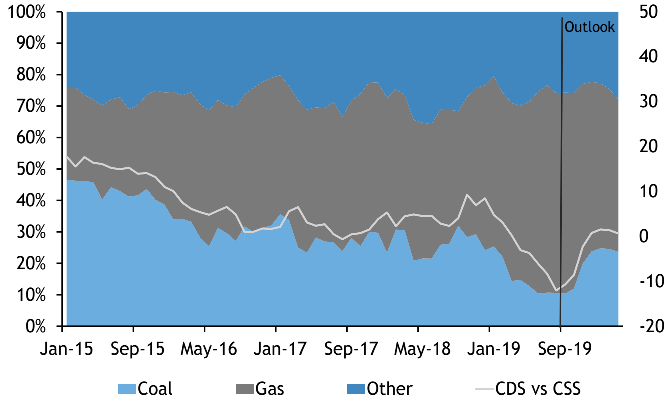
Based on the historical correlation between coal and gas' share of the fossil fuel generation mix and the differential between clean dark and clean spark spreads, coal may account for only 12pc and 20pc, respectively, of fossil fuel generation in October and November this winter, which would be down from 28pc and 29pc last year. Gas-fired generation in contrast would climb to a 62pc and 57pc respective share in October and November, compared with 45pc and 47pc last winter, assuming an unchanged share for other thermal output.

This would cut aggregate October-November coal-fired generation by 10.6TWh and 12.7TWh, respectively, in the base and low-demand scenarios, while output in the event of high-demand would still fall by 8.5TWh. This would result in winter coal demand falling by between 3.2mn t and 4.8mn t from a year earlier after the first two months of the season.

Total generation from fossil fuels across Germany, Spain, the UK and France was down by 2.1TWh on the year in the first half of October at 15.5TWh, amid unseasonably mild and windy conditions, with coal-fired generation accounting for less than 11pc, or 1.7TWh, of the total and gas 65pc. Daily mean temperatures in Munich were slightly higher than the long-term average over 1-14 October, while wind load factors were higher on the year in every market except Spain.

Forward prices currently suggest that gas will compete less strongly for thermal generation from December, which could pave the way for stronger power-sector coal consumption. Clean dark spreads for base-load generation in December, January and February held average advantages of €0.77/MWh, €1.53/MWh and €1.38/MWh, respectively, over clean spark spreads during the first half of October, which could help to lift coal's share of fossil fuel generation to around 24-25pc if those margins remain intact closer to delivery. This

Fossil fuel output shares vs CDS premium €/MWh



would be broadly in line or slightly higher than coal's share in December-February last winter.

In the high-demand scenario, a 24pc share of fossil fuel generation could lift aggregate coal-fired power generation by as much as 11TWh over the three peak-demand winter months. But growth is more modest at 2.8TWh in the base scenario and output could fall by nearly 4TWh in the event of mild weather and strong nuclear and renewable generation.

The base-load clean dark spread for March 2020 has held a slender €0.65/MWh premium to equivalent clean spark spreads at around €3/MWh in recent weeks. If sustained into delivery, this would mark an improvement in coal-fired generation economics compared with last winter, when the month-ahead clean dark spread for March 2019 was €0.27/MWh higher than the clean spark spread at an average of €0.31/MWh.

Coal-fired generation would climb on the year under all scenarios in March, if the fuel maintains its current cost advantage over natural gas. But the potential for strong LNG supply and slower gas withdrawals in the intervening months pose considerable downside risk to this outlook.

Total winter power-sector coal demand falls by 3.2TWh in the base scenario or by as much as 15TWh in the event of low demand, which is equivalent to respective falls of 1.2mn t and 5.7mn t in consumption of 5,700 kcal/kg coal by 40pc efficient plants. Colder-than-average weather and low nuclear and renewable output could support a 10.3TWh, or 3.9mn t, year-on-year increase in coal consumption over October-March.

Coal-fired power generation totalled 63.9TWh across Germany, Spain, the UK and France last year — around 45pc of total EU coal-fired output — which is the equivalent of 24mn t of 5,700 kcal/kg coal burn in 40pc efficient plants.

Coal demand in Poland — historically the EU's second-largest coal consumer — will be less susceptible to fuel switching because of the country's limited gas-fired generation capacity. But other western and southern European markets, including Italy and the Netherlands, may follow a similar trend to Germany. Polish coal-fired power generation totalled 42.5TWh last winter — equivalent to 16mn t — and output was down by only 1.6pc from a year earlier this summer, despite weaker gas prices.

Risks skewed to the downside

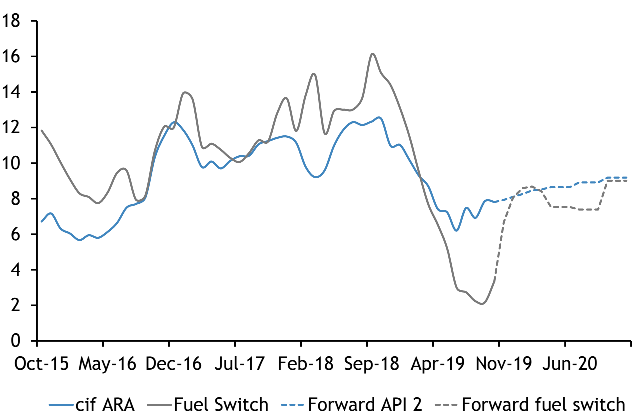
Risks to the winter demand outlook for coal are skewed to the downside as there is potential for sustained natural gas supply to continue to squeeze coal's share of the generation mix this winter, while nuclear output could also increase.

Germany will enter 2020 with lower nuclear power capacity, as the 1.4GW Philippsburg 2 reactor is scheduled to shut at the end of this year — and capacity could be reduced from earlier in December — as part of the German nuclear phase-out to be completed in 2022. In contrast, current schedules in Spain, France and the UK point to a potential increase in availability this winter, which could stabilise total nuclear supply across the four markets as a whole.

But power-sector coal demand this winter is mostly at the mercy of natural gas supply fundamentals. The European gas market has played an important role as a sink for surplus LNG in the Atlantic basin through most of 2019 and will continue to do so this winter, if gas demand in other markets fails to draw supply away from the continent.

European power-sector demand for coal and gas is highly price sensitive, with gas-fired generation climbing and coal burn falling when gas prices are comparatively weak enough to drive fuel switching, as seen this summer. Flexible and price-responsive power-sector demand provides a mechanism — built on Europe's liquid gas markets and abundant LNG import infrastructure — through which a surplus of gas can be cleared, at the expense of coal.

Coal prices vs fuel switch (40% vs 55%) €/MWh



This was the case during the summer, when a surplus of pipeline and LNG supply in excess of what was needed to meet seasonal demand and storage injections spurred a collapse in gas prices, triggering higher power-sector gas demand.

If winter gas supply through storage withdrawals, pipeline imports and LNG receipts tallies with normal seasonal demand, spot gas prices may track at or above coal-to-gas fuel-switching thresholds, in order to stave-off additional power-sector gas demand. This would be likely to sustain coal demand and create upside potential for coal prices, although a significant surplus in excess of normal winter demand would cause gas prices to fall beneath coal-to-gas fuel-switching thresholds and begin to erode coal's share of thermal generation.

In the base scenario, every percentage point shift from coal to gas in the fossil fuel share of total generation would drive a 1.1mn t drop in 5,700 kcal/kg equivalent coal burn across Germany, France, the UK and Spain. Total coal-fired generation in the four countries accounted for 21.5pc of fossil fuel-fired generation last winter, with gas accounting for 44.6pc.

Gas stocks in northwest Europe are at a relatively high level for recent years, and global LNG liquefaction capacity has continued to swell this year, but this does not guarantee an oversupply of winter gas in Europe. A recovery in seasonal heating demand compared with last year, lower gas production in the Netherlands and uncertainty surrounding pipeline imports from Russia all have the potential to counter the build-up of a winter surplus, while a recovery in northeast Asian gas demand could stem LNG availability in the Atlantic basin.

Gas production in the Netherlands is expected to fall by around a third to 11.8bn m³ in the 2019-20 gas year ending September as a result of government-enforced cuts, with more pipeline and LNG imports likely to be needed to offset the decline.

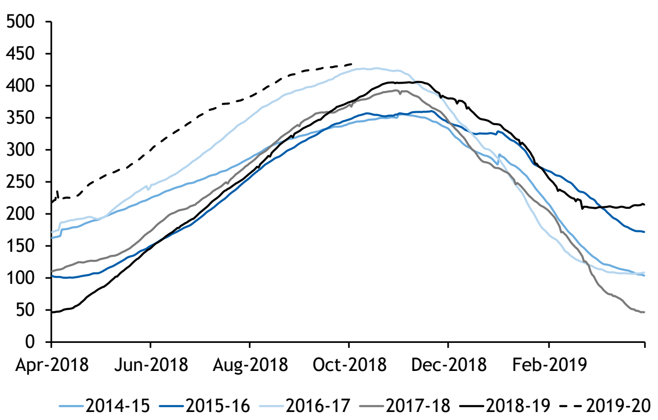
In addition, Russian producer Gazprom's transit contract with Ukraine is to expire at the end of this year and an extension of the deal is yet to be agreed. If flows through Ukraine were to stop completely at the start of 2020, European reliance on storage withdrawals and imports from other sources would be likely to increase. The next round of EU-brokered talks between Russia and Ukraine are scheduled to take place on 28 October.

The fundamental impact of weaker gas production and any loss of pipeline supply would be exacerbated in the event of colder weather driving demand higher. Average temperatures in Munich last winter were 0.92°C higher than the long-term mean through October-March and 1.15°C higher than normal during the peak December-February months.

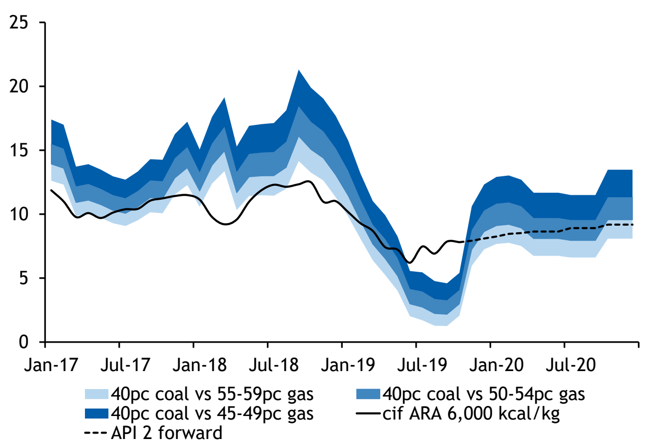
A risk premium regarding the future uncertainty of European winter gas supply has been priced into forward gas contracts, which means forward coal prices are currently below the fuel-switching threshold, making coal-fired plants more competitive than all but the most efficient gas-fired plants over December-March. This gas supply uncertainty could defer the most significant periods of oversupply — if any — to later in the season, potentially supporting coal demand and prices early in the peak heating period but posing a bigger downside risk later in the winter if particularly cold weather does not come to pass in December and January.

With gas stocks already close to capacity, surplus supply before the onset of storage withdrawals and a rise in heating demand is likely to be absorbed through greater power-sector demand and the displacement of coal in October and early November. But surplus gas supply may tighten after that if shippers opt to limit withdrawals to the minimum needed to meet normal winter demand, with a view to retaining stocks as cover for any spike in heating demand early in 2020 or disruption to Russian pipeline imports. This potentiality is reflected in the contango between the Dutch TTF prompt-month gas contract and the quarter ahead, which is around seven times wider than at the same stage last year at a €2.25/MWh premium for the quarter ahead to the prompt month.

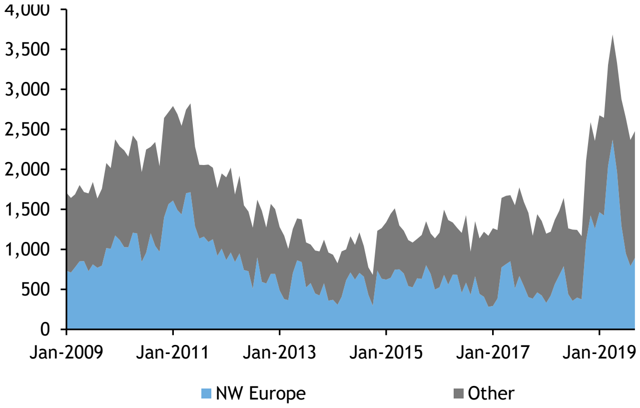
Northwest European gas storage levels *TWh*



Coal prices vs fuel switch thresholds *€/MWh*



European LNG sendout GWh/d



A risk premium on gas prices could keep coal competitive for power generation throughout the peak heating season, if cold weather sparks a heavy and early draw on gas stocks or pipeline and LNG imports falter. But that premium would be liable to erode the longer that storage withdrawals are deferred or if gas imports consistently outpace weather-driven demand. European coal prices would rise throughout the winter under the former scenario, while the latter would apply more pressure as the season progresses, as in the first quarter of 2019.

Day-ahead gas prices fell below the range of fuel-switching thresholds based on different coal and gas-fired plant efficiencies last winter amid high stocks and a surge in LNG receipts. This cut coal's share of fossil fuel generation to 22pc in February and 14pc in March, from 25pc in December-January.

Steep increases in LNG imports were a key driver of the late-winter decline in gas prices in 2018-19, with regasified sendout from European terminals averaging nearly 2.9 TWh/d in January-March, compared with only 1.3 TWh/d in the same quarter of 2018. Some 425mn t/yr of LNG export capacity is now on line globally, up from 406mn t/yr at the end of 2018. Of the 20mn t/yr of new capacity to start up this year, three-quarters of it is in the US, relatively close to the European market.

At present, Dutch TTF month-ahead and first-quarter 2020 gas prices are around $1.70/mn Btu and $1.30/mn Btu weaker than *Argus*' equivalent northeast Asia (ANEA) LNG prices, respectively. This is significantly wider than at the start of October and could divert supply out of the Atlantic basin as the winter progresses. Spot TTF gas prices were $0.90/mn Btu weaker than the ANEA marker on average during the peak demand December-February months last year, when Europe was called upon to absorb a glut of supply in the global market.

Atlantic coal supply adjusts lower

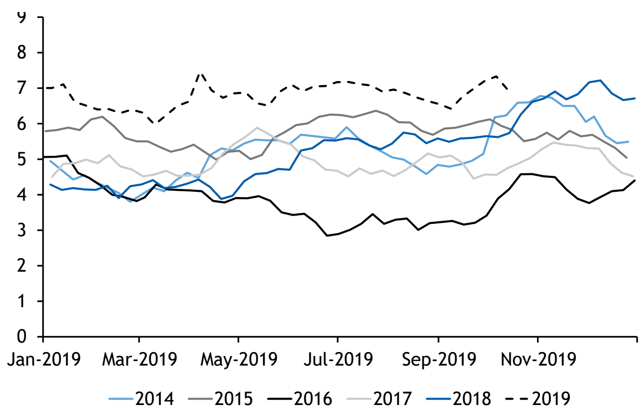
The potential for weaker coal burn in western Europe this winter looks likely to weigh on the continent's imports of seaborne thermal coal, and a much healthier stock situation should exacerbate this trend in the event of normal or above-average temperatures.

Net EU coal imports from countries outside the bloc averaged 10mn t/month last winter and 10.2mn t/month in the three winters before that. It is possible that seaborne thermal coal imports to Europe could fall this winter even in the event of a modest increase in total coal burn, as stocks are likely to be significantly higher than a year earlier.

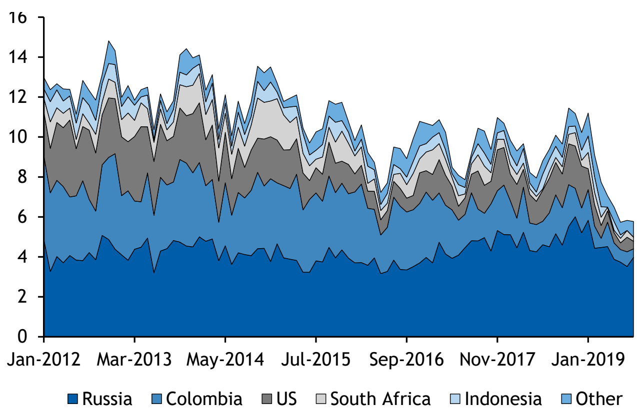
Particularly hot and dry conditions reduced German river levels last year, creating inland bottlenecks for barge transport for nearly all of the second half of 2018, impeding the flow of coal from northern European ports to German power plants. This forced utilities to draw down local stocks while backing up inventories at ports in the Amsterdam-Rotterdam-Antwerp (ARA) region, which rose steadily over May-December to around 7mn t.

A recovery in river levels from December 2018 eased barging restrictions and enabled utilities to replenish local stocks with seaborne supplies. Firm forward clean dark spreads for peak-winter output provided a further incentive to restock quickly, and net EU imports were around 1mn t higher on the year in January-February.

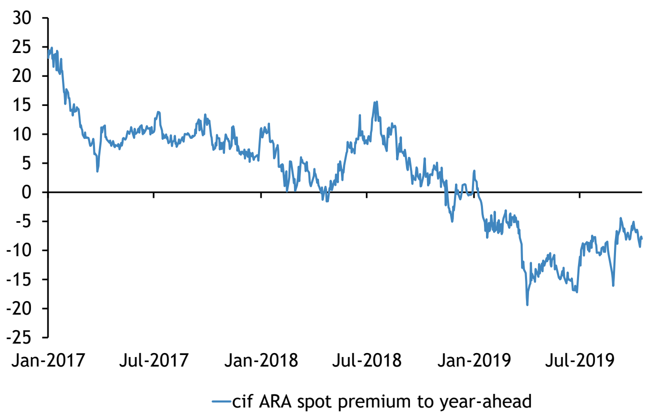
ARA port coal stocks mn t



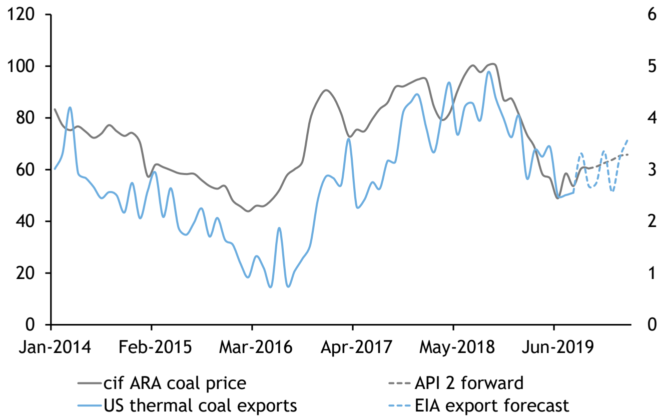
Net EU thermal coal imports mn t



European coal contango *$/t*



US thermal coal exports vs cif ARA *$/t, mn t*



Since then, net EU thermal coal imports have slumped to historical lows, but so has coal burn, and aggregate ARA port stocks have remained at near-capacity levels of close to 7mn t for most of 2019.

The heavy fall in physical coal prices since mid-December 2018 was also accompanied by the development of a contango in forward prices, creating a commercial incentive to store relatively cheap spot supply for consumption or sale at higher prices in the future. River levels have been much higher this year, leading to less disruption to barge shipments and enabling greater stockpiling at inland locations than in 2018.

Higher stocks across Europe may limit the continent's ability to absorb seaborne coal this winter, unless coal burn rises markedly, although the forward curve remaining in contango means there is still some commercial incentive to maintain high inventories for companies with the capacity to do so.

Argus' cif ARA physical coal price assessment was at a $7.62/t discount to the year-ahead API 2 swap as of mid-October. This was down from a high of close to $20/t at the start of the summer, but in stark contrast to the $3/t premium that physical prices held over the year ahead in October 2018.

If low coal burn and high stocks do curb seaborne imports this winter, the supply adjustment will affect US and Colombian coal in the first instance. Russian coal accounted for 52pc of total imports last winter, with US and Colombian material accounting for 15pc and 13pc, respectively. In the three winters prior to that, Russian coal accounted for 41pc of the winter total, with the US and Colombia taking 13pc and 26pc respective shares.

Comparatively high-cost US coal exports enjoyed a resurgence in 2017 and 2018, driven by a steep recovery in global prices. But the recent downturn has resulted in weaker exports throughout 2019, and forward prices have offered little opportunity to sell supply ahead for 2020 delivery.

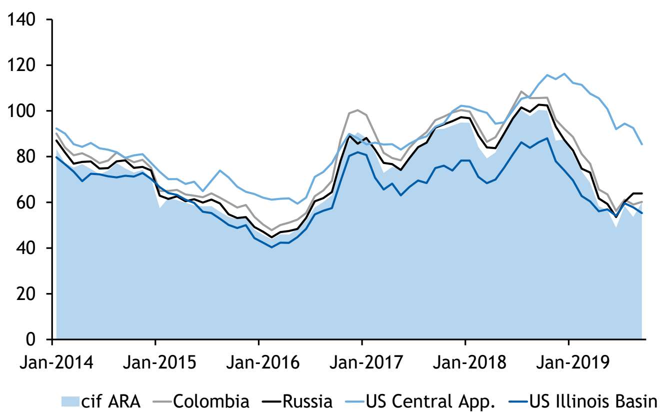
Exports of US thermal coal totalled 24.5mn t in January-August at a rate of 3.1mn t/month, of which Europe accounted for 5.8mn t, or 24pc. This was down from 32mn t in the same period last year, when Europe received 7.9mn t. The US Energy Information Administration (EIA) recently forecast exports to average just 3mn t/month through to March 2020.

A 24pc share of total US exports would imply shipments to Europe of 4.4mn t this winter, which would be down from the 7.4mn t shipped in October-March last winter.

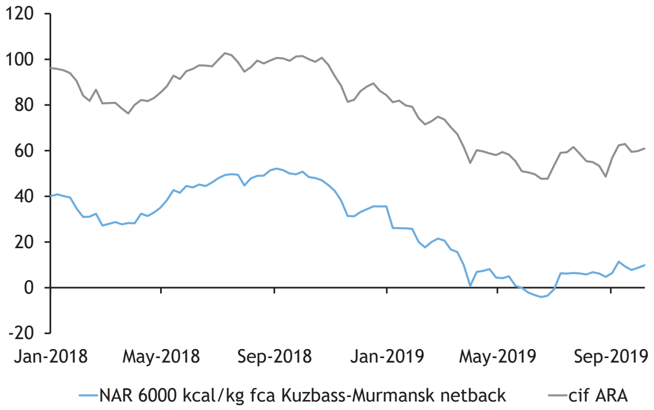
Colombian coal exports to Europe have faded gradually in the past three-to-four years, but they are currently more competitive than US supply and may prove more resilient over the winter period.

High-sulphur US Illinois basin coal priced at a discount to *Argus*' cif ARA price assessment in 2017 and 2018, making it a commercially attractive grade to use in a blend with low-sulphur coal to reduce average costs. But this cost advantage has evaporated as Europe-delivered prices have weakened, with the landed cost of high-sulphur US coal converging with Russian and Colombian grades.

cif ARA vs Europe-delivered coal prices *$/t*



Russian netback coal price $/t



Net EU receipts of Colombian coal averaged 1.3mn t/month last winter, but volumes have weakened so far in 2019. January-August receipts were 870,000 t/month, down from 1.6mn t/month a year earlier, with only a moderate seasonal increase expected this winter and a decline on the year still likely.

Lower-cost exports from the nearby Russian market have been most resilient in 2019. Net EU receipts averaged 4.3mn t/month in January-August, down only slightly on last year's 4.6mn t/month over the same period. Russian production costs could set a floor for Europe-delivered prices in the event of a weak coal demand scenario this winter.

Cif ARA spot coal prices fell as low as around $47/t in mid-June, before meeting resistance that arrested the decline, despite further weakness in gas prices. At that time, Russian fob Baltic coal prices were assessed around $45/t, yielding negative fca Kuzbass netback prices, according to *Argus* calculations.

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