S&P Global
Platts

LNG DAILY

Volume 18 / Issue 216 / November 3, 2021

JKM rises as market seeks clearer direction

KEY DRIVERS / MARKET HIGHLIGHTS

- APAC physical LNG MOC: two entities report two bids
- Thailand's EGAT buy tender closes Nov. 3
- Botas returns for 9 winter cargoes
- Atlantic MOC: BP bids TTF minus 10 cents/MMBtu

SHIPPING MARKET HIGHLIGHTS

- Day rates remained at $250,000/d in Pacific
- MU LAN fixed by Pan Ocean at $200,000/d

NEWS HEADLINES

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JKM TM	AAOVQ00	28.152	+1.927 ▲
Cumulative monthly average (Dec)	AAOVS00	32.329	
Previous month average (Nov)	AAOVS03	33.254	
CNL WTW JKTC	ACNLF00	0.684	

PLATTS DAILY LNG MARKERS ($/MMBtu)

Nov 3			Change	
DES Japan/Korea Marker (JKM)				
JKM (Dec)	AAOVQ00	28.152	1.927	▲
H1 Dec	AAPSU00	27.991	1.941	▲
H2 Dec	AAPSV00	28.312	1.912	▲
H1 Jan	AAPSW00	28.653	1.853	▲
H2 Jan	AAPXA00	28.700	1.900	▲
JKM (Dec) Japanese Yen	AAOVR00	3203.979	224.032	▲
JKM (Dec) Chinese Yuan (CNY/mt)	LJCMS00	9380.550	651.643	▲
DES Japan/Korea (JKM) derivatives Singapore close*				
Balmo-ND	LJKMB00	27.960	1.664	▲
Dec	LJKMO00	30.800	0.675	▲
Jan	LJKMO01	28.975	1.925	▲
Feb	LJKMO02	26.800	1.775	▲
DES Japan/Korea (JKM) derivatives London close*				
Dec	JKLMO00	33.950	2.950	▲
Jan	JKLMO01	32.125	4.135	▲
Feb	JKLMO02	29.810	3.161	▲
DES Mediterranean Marker (MED)				
MED (Dec)	AASXY00	27.260	2.981	▲
H1 Dec	AASXZ00	27.135	2.956	▲
H2 Dec	AASYA00	27.385	3.006	▲
H1 Jan	AASYB00	27.360	3.080	▲
DES Northwest Europe Marker (NWE)				
NWE (Dec)	AASXU00	27.260	2.931	▲
H1 Dec	AASXV00	27.135	2.906	▲
H2 Dec	AASXW00	27.385	2.956	▲
H1 Jan	AASXX00	27.460	3.080	▲
Middle East Marker (MEM)				
MEM (Dec)	LMEMA00	25.950	1.925	▲
H1 Dec	LMEMB00	25.800	1.950	▲
H2 Dec	LMEMC00	26.100	1.900	▲
H1 Jan	LMEMD00	26.450	1.850	▲
H2 Jan	LMEME00	26.500	1.900	▲
DES West India Marker (WIM)				
WIM (Dec)	AARXS00	25.950	1.925	▲
H2 Nov	LMEAA00	25.750	1.950	▲
H1 Dec	LMEAB00	25.800	1.950	▲
H2 Dec	LMEAC00	26.100	1.900	▲
H1 Jan	LMEAD00	26.450	1.850	▲
H2 Jan	LMEAE00	26.500	1.900	▲
DES West India Marker (WIM) derivatives Singapore close*				
Dec	AWIMB00	28.550	0.525	▲
Jan	AWIMM01	27.600	1.975	▲
Feb	AWIMM02	25.500	1.775	▲
FOB Gulf Coast Marker (GCM)				
GCM	LGCSM01	25.000	3.250	▲

*For full forward curve, see page 4

SHIPPING RATES, NOV 3

		$/day		Ballast rate
Asia Pacific day rate	AARXT00	250,000	AAXTN00	100%
Atlantic day rate	AASYC00	195,000	AAXTM00	100%
TCR Australia-Japan	ATCRA00	250,000.00		
TCR USG-NWE	ATCRB00	195,000.00		
TCR USG-Japan	ATCRC00	195,000.00		

DAILY CUMULATIVE AVERAGES AND MONTHLY AVERAGES

Nov 3 ($/MMBtu)		Cumulative monthly average			Previous month average	
JKM	AAOVS00	32.329	Dec	AAOVS03	33.254	Nov
DES West India	AALIC00	30.295	Dec	AAWIC03	31.934	Nov
DES Mediterranean	AADCU00	28.433	Dec	AASWC03	29.207	Nov
DES Northwest Europe	AASDF00	28.501	Dec	AASDE03	29.202	Nov
FOB GCM Loading Month	LGCSM00	25.423	Dec	LGCSM31	27.329	Nov
JKM Yen	AAOVT00	3683.828	Dec	AAOVT03	3707.118	Nov
JKM Yuan	LJCWM00	207.016	Dec	LJCWM03	189.189	Nov

LNG NETBACK PRICES ($/MMBtu)

Nov 3			Change	
FOB Australia	AARXR00	25.870	1.870	▲
FOB Middle East	AARXQ00	25.000	1.950	▲
DES Brazil Netforward	LEBMH01	27.560	3.390	▲
FOB Singapore	AARXU00	26.392	1.887	▲
FOB Murmansk	AARXV00	26.270	2.881	▲

PLATTS LNG ASIA JKM RATIONALE & EXCLUSIONS

The S&P Global Platts JKM for December was assessed at $28.152/MMBtu Nov. 3. Platts assessed first-half December at $27.991/MMBtu and second-half December at $28.312/MMBtu, with a narrower intramonth contango structure of 32.1 cents/MMBtu Nov. 3, compared with a contango of 35 cents/MMBtu Nov. 2. Value on Dec. 5 was assessed at $27.93/MMBtu, above BP's bid for a Dec. 3-7 DES JKTC cargo at TTF December plus $3.85/MMBtu, with a GHV of 1,030-1,110 Btu/cu ft. It was normalized 8 cents lower on lower maximum GHV limit compared with the Platts standard of 1,030-1,130 Btu/cu ft, and equated to a fixed price of $27.92/MMBtu.
Vitol placed a bid for a Dec. 27-31 DES JKTC cargo at TTF Dec plus $3.95/MMBtu, with GHV of 1,000-1,110 Btu/cu ft, which was normalized 8 cents lower on lower maximum GHV limit compared with the Platts standard of 1,030-1,130 Btu/cu ft, and equated to a fixed price of $28.02/MMBtu.
Platts assessed January JKM at the Singapore close at $28.975/MMBtu. Platts valued ICE TTF January at $24.125/MMBtu 12:30 pm Singapore time, based on a $4.85/MMBtu differential between JKM January and TTF January. Platts valued ICE TTF December at $24.150/MMBtu at 12:30 pm Singapore time, based on a 2.5 cents/MMBtu differential between January TTF and December TTF.
This rationale applies to symbol(s) <AAOVQ00> Exclusions: None

PLATTS LNG ASIA WIM RATIONALE & EXCLUSIONS

The S&P Global Platts WIM for December was assessed at $25.95/MMBtu Nov. 3. Platts assessed first-half and second-half December at $25.80/MMBtu and $26.10/MMBtu, respectively, with a narrower intramonth contango structure of 30 cents/MMBtu, compared with 35 cents/MMBtu Nov. 2. Platts assessed the December JKM/WIM spread at $2.202/MMBtu Nov. 3.
This rationale applies to symbol(s) <AARXS00>. Exclusions: None

PLATTS LNG US FOB GULF COAST DAILY RATIONALE & EXCLUSIONS

The FOB Gulf Coast Marker (GCM) was assessed at $25/MMBtu on Nov. 3.
The assessment was based on tradable values reported by market participants at $24.2/MMBtu and $24.3/MMBtu by the middle of the day for FOB USGC cargoes loading 30 to 60 days forward, in conjunction with elevated freight rates for shipments through the Atlantic and Pacific, lengthy maximum wait times at the Panama Canal and higher prices in end-user markets.
This rationale applies to symbol(s) <LGCSM01>
Exclusions: None

PLATTS LNG EUROPEAN ASSESSMENT RATIONALE & EXCLUSIONS

The Northwest Europe Marker (NWE) for December was assessed Nov. 3 at $27.260/MMBtu.
H1 NWE for December was assessed at $27.235/MMBtu
H2 NWE for December was assessed at $27.385/MMBtu
The NWE prices were assessed higher day on day reflecting higher flat prices for December TTF. The December TTF contract rose to Eur79.975/MWh on Nov. 3, a Eur14.575/MWh increase from Nov. 2. NBP/TTF premiums rose to an intraday high of $0.780/MMBtu. Toward market close, gains in the December TTF contract led to NBP/TTF premiums ending at $0.445/MMBtu at 4:30 pm London time.
The Mediterranean Marker (MED) for December was assessed at $27.260/MMBtu.
H1 MED for December was assessed at $27.235/MMBtu.
H2 MED for December was assessed at $27.385/MMBtu.
The MED price was assessed higher day on day, due largely to gains in the underlying Eurogas markets. PVB/TTF December premiums were assessed at 3 cents/MMBtu on Nov. 2. PVB/TTF for January was assessed at a 74 cent/MMBtu discount. Market sources alluded to strong inventories in Spain depressing PVB prices. Sources pegged East Mediterranean prices below TTF plus $0.50 for December and the West-East Med freight difference at around $0.20-$0.30/MMBtu.
In the Atlantic MOC, BP bid for a Dec. 15-17, 3.3 +/- 5% TBtu cargo into Rotterdam at the ICE TTF December front-month average minus 10 cents/MMBtu. This was converted to a fixed price of $26.985/MMBtu. This was normalized down 3 cents due to the prompter alternate discharge port nomination than the Platts standard and a lower cargo size for cargoes delivered into NWE, compared to Platts' standard 3.5 TBtu +/- 5% to a final price of $26.955/MMBtu.
The assessments were based on pricing information from market sources for cargoes delivering within the region for December delivery.
This rationale applies to symbol(s) <AASXU00, AASXY00>
Exclusions: None

MARKET COMMENTARIES

JKM rises as market seeks clearer direction

Asia spot LNG prices rose Nov. 3, snapping a five-day trend downward, as supply disruptions led to prompt demand requirements while the market sought clearer direction.

The S&P Global Platts JKM for December was assessed at $28.152/MMBtu Nov. 3.

Platts assessed the first half of December at $27.991/MMBtu and the second half of December at $28.312/MMBtu, with a narrower intramonth contango structure of 32.1 cents/MMBtu Nov. 3, compared to a contango of 35 cents/MMBtu Nov. 2.

During the Platts Market on Close assessment process Nov. 3, BP bid for a Dec. 3-7 DES JKTC cargo, with GHV of 1,030-1,110 Btu/cu ft, at the average of December TTF plus $3.85/MMBtu.

Vitol reported a bid for a Dec. 27-31 DES JKTC cargo, with GHV of 1,000-1,110 Btu/cu ft, at the average of December TTF plus $3.95/MMBtu.

End-users in the region have been closely monitoring the spot market as prices weakened earlier, and spot demand may return if prices ease further to low $20s/MMBtu though buying interest is still largely unchanged, several sources said Nov. 3.

"If coal demand in China can be fulfilled now and gas inventories remain comfortable, it's unlikely that there will be a lot of additional LNG demand from China," a Chinese end-user said.

"Minimal spot demand [from Korea] at the moment due to high price, end-users are trying to manage by term cargoes and swaps," a Korean end-user said.

"The current price is still not feasible for Indian end-users, it will remain quiet [with spot prices] above $26/MMBtu," an Indian importer said.

Another Chinese end-user said that the downtrend could be a temporary correction as the market is generally bullish with a colder winter expected.

"The average ex-terminal trucked LNG prices in China have increased up to 8,000 Yuan/mt on Nov. 3, but wont be able to catch up with Nov JKM at $33/MMBtu," the Chinese end-user added.

In the bilateral market, Petronas was heard to have sold 1-2 GLNG

REPORTED ATLANTIC BIDS, OFFERS AND TRADES ($/MMBtu)

Date	Seller	Loading	Buyer	Basis	Loading window	Offer/Bid	Notes
Best bids/offers							
Nov 03		Rotterdam delivery	BP	DES	DEC 15-17	TTF ICE-0.10 bid	MOC

REPORTED APAC BIDS, OFFERS AND TRADES ($/MMBtu)

Date	Buyer	Destination	Seller	Source	Basis	Delivery period	Bid/Offer	Notes
Best bids/offers								
Nov 03	BP	JKTC			DES	Dec 3-7	Dec TTF+3.85 bid	MOC
Nov 03	Trafigura	JKTC			DES	Dec 13-15	Jan TTF+3.75 bid	MOC, withdrawn
Nov 03	Vitol	JKTC			DES	Dec 27-31	Dec TTF+3.95 bid	MOC
Last 5 trades		**APAC**						
Oct 26	PTT	Thailand		Qatar	DES	Nov 27-29, Dec 3-5	low-33	Tender
Oct 26	Shell, Total		EGAS	Egypt	FOB	Nov 14-15, Nov 24-25	28.25, 28.70	Tender
Oct 22	Vitol	JKTC	PetroChina		DES	Dec 6-8	Dec TTF plus 3.05 traded offer	MOC
Oct 21	Vitol	JKTC	PetroChina		DES	Dec 7-11	Dec TTF plus 3.45 traded bid	MOC
Oct 21	PetroChina	JKC	Shell		DES	Dec 10-12	Dec TTF plus 3.00 traded offer	MOC

cargoes for December deliveries in the week starting Nov. 1, multiple sources said Nov. 3. However, this could not be verified at the time of reporting.

Thailand's EGAT's one-cargo buy tender for Dec. 10-12 or Dec. 16-18 DES Map Ta Phut closed Nov. 3. — *Regina Sher*

European LNG prices gain nearly $3/MMBtu on volatile Eurogas, Botas returns for winter vols

The European LNG market, while largely inactive on the spot, gained on-day amid an uneasy European gas market, reflected in price movements throughout the day.

The Platts DES Northwest Europe for December was assessed at $27.26/MMBtu on Nov. 3, up $2.931/MMBtu from the previous day. The first half of December was assessed at $27.135/MMBtu, and the second half was assessed at $27.385/MMBtu, raising the intramonth contango to 25 cents/MMBtu from 20 cents/MMBtu day on day.

TTF November futures moved in an intraday range starting the day below Eur70/MWh mark continuously rising up to Eur79.785MWh at close. Platts assessed the TTF November contract at $27.150/MMBtu on Nov. 3, up $3.119/MMBtu on the day. European gas markets remain somewhat nervous given the ongoing exposure to Russia for increased volumes. Reports of lower nominations through the Ukraine, alongside media reports of military activity in Russia near the Ukrainian boarder led to trepidation among market participants. In addition, news regarding Gazprom not being able to purchase transit capacity to Europe for Q1-Q3 next year added to the ongoing sentient. This comes despite the expectation of increased flows into Europe from Nov. 8.

Sources said it would make sense for prices in the Mediterranean for December to weaken owing to the narrower PVB/TTF spread for that period, which was just over 3 cents/MMBtu, according to Platts data Nov. 2.

Sources said with the recent hike in shipping rates, the East Mediterranean would be at a 20-30 cents/MMBtu premium to the West Med.

In the Atlantic MOC, BP bid for a DES Rotterdam Dec. 15-17 delivery cargo at TTF minus 10 cents/MMBtu.

Despite the recent downtrend in the FOB Gulf Coast market, the Henry Hub remains relatively supported still, over the $5/MMBtu threshold, which one source said was largely tracking weather patterns right now.

In the JKM derivatives market, there remains a relatively high degree of price volatility, with increasing interest for monthly contracts in Q1 and Q2 2022.

"Today it's [JKM] been moving around lots with gas," said a broker source. "There has been quite a bit of Jan v Feb activity too. Portfolio players looking at the Jan and Jan v Feb roll."

In tenders, Botas was reported to be looking for nine DES cargoes for December, January and February delivery, closing Nov. 4. Sources were unable to confirm if this was fresh demand or retendering from previous requirements.

In shipping, day rates remained at $250,000/d for the Pacific basin and increased by $5,000 to $195,000/d in the Atlantic.

IOC's tonnage requirement, for a Dec. 11-13 loading ex Cameron LNG terminal, was heard covered by Gunvor.

The MU LAN, 174,000 cu m, was reported fixed by Pan Ocean for a single voyage ex USG for an end-of-December loading and delivery Far East at rate of $200,000/d round-trip basis.

The LNG FINIMA,170,000 cu m, was heard fixed by Vitol with the details of the rate and period not reported. — *Piers De Wilde, Michael Hoffmann*

NEWS

Winter gas stockpiling pushes China's trucked LNG prices over $24/MMBtu

- **Higher auction price for pipeline gas spurs the price rise**
- **Terminals limit spot LNG sales for ensuring stable winter supply**
- **More cold weather forecast in northern China from Nov. 4**

China's trucked LNG prices have breached Yuan 8,000/mt ($1,252/mt), or the equivalent of $24/MMBtu, in several regions, an increase of 23% from a week earlier, driven by higher global LNG prices and several coastal terminals rationing supply and stockpiling reserves for peak winter demand.

ASIA/MIDDLE EAST ($/MMBtu), NOV 3*

DES Japan/Korea Marker (JKM)

JKM (Dec)	AAOVQ00	28.152
JKM (H1 Dec)	AAPSU00	27.991
JKM (H2 Dec)	AAPSV00	28.312
JKM (H1 Jan)	AAPSW00	28.653
JKM (H2 Jan)	AAPXA00	28.700
Asian Dated Brent (16:30 Singapore)	ADBAA00	14.54
JKM vs Henry Hub futures	AAPRZ00	22.622
JKM vs NBP futures	AAPSA00	NA
JKM vs TTF	LNTFJ00	1.002
JKM vs Asian Dated Brent (16:30 Singapore)	AAPSB00	13.616
JKM vs MED (16:30 London)	ALNGB00	0.892
JKM vs NWE (16:30 London)	ALNGA00	0.892

DES Japan/Korea (JKM) derivatives Singapore close

Balmo-ND	LJKMB00	27.960
Dec	LJKMO00	30.800
Jan	LJKMO01	28.975
Feb	LJKMO02	26.800
Mar	LJKMO03	23.200
Q1 2022	LJKQR01	26.325
Q2 2022	LJKQR02	15.475
Summer 2022	LJKSN01	14.925
Winter 2022	LJKSN02	15.500
2022	LJKYR01	17.875
2023	LJKYR02	11.900
2024	LJKYR03	9.275

DES Japan/Korea (JKM) derivatives London close

Dec	JKLMO00	33.950
Jan	JKLMO01	32.125
Feb	JKLMO02	29.810
Mar	JKLMO03	25.960
Q1 2022	JKLQR01	29.298
Q2 2022	JKLQR02	16.550
Summer 2022	JKLSN01	15.950
Winter 2022	JKLSN02	16.525
2022	JKLYR01	19.375
2023	JKLYR02	12.275
2024	JKLYR03	9.625

DES West India Marker (WIM)

WIM (Dec)	AARXS00	25.950

DES West India Marker (WIM) derivatives Singapore close

Dec	AWIMB00	28.550
Jan	AWIMM01	27.600
Feb	AWIMM02	25.500
Mar	AWIMM03	22.000
Q1 2022	AWIMQ01	25.033
Q2 2022	AWIMQ02	14.200
Summer 2022	AWISN01	13.625
Winter 2022	AWISN02	14.250
2022	AWIMY01	16.600
2023	AWIMY02	10.500
2024	AWIMY03	8.100

Carbon Neutral LNG

CNL WTW JKTC Differential (ex-Australia)	ACNLF00	0.684
CNL WTT JKTC Differential (ex-Australia)	ACNLB00	0.151
CNL DES JKTC Differential (ex-Australia)	ACNLG00	0.146
CNL Combustion JKTC	ACNLJ00	0.533

FOB Middle East

FOB Middle East	AARXQ00	25.000

FOB Australia (netback)

JKM (Dec)	AAOVQ00	28.152
(-) Freight	AAUSA00	2.28
FOB Australia	AARXR00	25.87

Key gas price benchmarks

Japan Customs Cleared LNG (Aug)	LAKPN00	10.15	Final
Japan Customs Cleared LNG (Sep)	LAKPM00	10.78	Estimated

Platts Dutch TTF

Dec	GTFWM10	27.150
Jan	GTFWM20	27.133

Competing fuel prices

Japan Customs Cleared crude oil (Aug) ($/b)	AAKOP00	73.78	Final
Japan Customs Cleared crude oil (Sep) ($/b)	AAKOM00	73.81	Estimated
HSFO 3.5% sulfur 180 CST FOB Singapore	LUAXZ00	11.56	
NEAT Coal Index	JKTCB00	7.568	
Minas crude oil	LCABO00	NA	
Naphtha CFR Japan	LNPHJ00	16.968	

EUROPE ($/MMBtu), NOV 3

		$/MMBtu		Eur/MWh		Eur/MMBtu
DES Mediterranean Marker (MED)						
MED (Dec)	AASXY00	27.260	LNMTA00	80.241	LNMXA00	23.534
MED (H1 Dec)	AASXZ00	27.135				
MED (H2 Dec)	AASYA00	27.385				
MED (H1 Jan)	AASYB00	27.360				
Dated Brent (16:30 London)	ADBAB00	14.18				
MED vs Henry Hub futures	AASYF00	21.573				
MED vs TTF	LNTFS00	0.110				
MED vs NBP futures	AASYH00	-0.484				
MED vs Dated Brent (16:30 London)	AASYJ00	13.085				
MED vs NWE	ALNSA00	0.000				
MED vs JKM	AASYM00	-0.892				
DES Northwest Europe Marker (NWE)						
NWE (Dec)	AASXU00	27.260	LNNTA00	80.241	LNNXA00	23.534
NWE (H1 Dec)	AASXV00	27.135				
NWE (H2 Dec)	AASXW00	27.385				
NWE (H1 Jan)	AASXX00	27.460				
Dated Brent (16:30 London)	ADBAB00	14.18				
NWE vs Henry Hub futures	AASYE00	21.573				
NWE vs TTF	LNTFN00	0.110				
NWE vs NBP futures	AASYG00	-0.484				
NWE vs Dated Brent (16:30 London)	AASYI00	13.085				
NWE vs MED	AASYK00	0.000				
NWE vs JKM	AASYL00	-0.892				
NWE as a % of NBP	AASYD00	98.26				

Competing fuel prices

Northwest Europe fuel oil	LAEGR00	12.75
CIF ARA 15-60 day thermal coal	CSAAB00	7.35

NORTH AMERICA ($/MMBtu), NOV 3

FOB Gulf Coast Marker (GCM)

GCM	LGCSM01	25.000
Dated Brent (16:30 London)	ADBAB00	14.18
GCM vs JKM	LGMJM01	-3.152
GCM vs Henry Hub futures	LGMHM01	19.330
GCM vs TTF	LNTFG00	-2.150
GCM vs NWE	LGEUR00	-2.260
GCM vs MED	LGMET00	-2.260
GCM vs NBP futures	LGMNM01	-2.744
GCM vs Dated Brent (16:30 London)	LGMDB00	10.825
GCM vs USGC HSFO	LGMFO00	13.860

Competing fuel prices

US Gulf Coast high sulfur fuel oil	LUAXJ00	10.68
New York Harbor 1%S fuel oil	LUAXD00	12.70

*Japan Customs Cleared value shows latest available CIF price published by the Ministry of Finance, converted to US dollars per MMBtu. All other values reflect Platts most recent one-month forward assessments for each product in each region, converted to US dollars per MMBtu. JKM Marker, SWE LNG and NWE LNG average the assessments of the two half-months comprising the first full month of forward delivery. Asian LNG assessments assessed at Singapore market close 0830 GMT, European LNG assessment assessed at London market close 1630 UK time. NYMEX Henry Hub futures and ICE NBP futures values taken at Singapore market close and London market close. ICE NBP futures converted from Pence/Therm to $/MMBtu. Asian Dated Brent crude oil assessed at Asian market close 0830 GMT and converted from $/barrel to $/MMBtu. Detailed assessment methodology is found on www.platts.com.

RECENT TENDERS AND STRIPS

Tender/ strip November 03	Issuer/location	Tender type	(Loading) or delivery period	Slots/ cargoes	Opening	Closing date	Validity	Notes	Results
Tender	BOTAS - Turkey	Buy	01-Dec-21 - 28-Feb-22	9 DES		04-Nov-21		9 cargo tender, closing Nov.4	
Tender	EGAT - Map Ta Phut	Buy	10-Dec-21 - 18-Dec-21	1 DES		03-Nov-21		One cargo buy tender for Dec. 10-12 or Dec. 16-18 delivery	
Tender	Pakistan LNG - Port Qasim	Buy	19-Nov-21 - 27-Nov-21	2 DES	02-Nov-21	05-Nov-21	05-Nov-21	Two cargo buy tender for Nov. 19-20 and Nov. 26-27 delivery. Closes on Nov. 5, 1200 hours PST. Validity until 2300 hours PST.	
Tender	Oman LNG - Oman LNG	Sell	(01-Dec-21 - 03-Dec-21)	1 DES or FOB		21-Oct-21		Closing 1pm Oman time	heard awarded to Gunvor around $30/MMBtu FOB
Tender	Ichthys LNG - Ichthys LNG	Sell	(13-Nov-21 - 17-Nov-21)	1 DES or FOB	25-Oct-21	27-Oct-21	27-Oct-21	FOB or DES cargo, 13-17 November loading. The tender closes on Oct. 27, noon Tokyo time. Validity until 7 PM Tokyo time (7 hour validity).	heard awarded at approximately $31/MMBtu FOB
Tender	Darwin LNG - Darwin	Sell	(01-Dec-21 - 03-Dec-21)	1 DES or FOB		28-Oct-21		Dec 1-3 load or Dec 14-17 DES JKTC	heard awarded at approximately $31/MMBtu FOB
Tender	Petronet - Dahej	Buy	16-Nov-21 - 30-Nov-21	1 DES	21-Oct-21	27-Oct-21	28-Oct-21	Seller to nominate delivery window for H2 Nov, fixed price only, DES Dahej or Kochi, 3.2 Tbtu	heard not awarded
Tender	Egas - Egypt	Sell	(13-Nov-21 - 25-Nov-21)	2 DES or FOB		26-Oct-21	26-Oct-21		Heard awarded approximately $28s/MMBtu
Tender	PTT - Map Ta Phut	Buy	27-Nov-21 - 05-Dec-21	2 DES	25-Oct-21	26-Oct-21	26-Oct-21	Seeking two cargoes for Nov. 27-29 delivery and Dec. 3-5 delivery. Closes on 4 PM Thailand time on Oct. 26, and has a 3 hour validity until 7 PM Thailand time.	Heard awarded around $33-$34/MMBtu
Tender	IEASA - Escobar	Buy	19-Nov-21 - 19-Dec-21			26-Oct-21		Two cargo buy tender for Nov. 19 & Dec. 19 delivery	
Tender	Novatek - Yamal	Sell	05-Dec-21 - 31-Mar-22	3 DES		21-Oct-21		Dec. 5-23, Jan. 3-21, and March 25-31 delivery	Heard partially awarded
Tender	Sakhalin Energy - Sakhalin	Sell	(01-Dec-21 - 01-Dec-21)	1 DES or FOB		21-Oct-21	22-Oct-21		heard awarded at approximately $34/MMBtu
Tender	Angola LNG - Angola LNG	Sell	05-Nov-21 - 19-Nov-21	1 DES		25-Oct-21	26-Oct-21	Furthest to India, onboard Seri Balqis	
Tender	BOTAS - Turkey	Buy	01-Nov-21 - 31-Mar-22	19 DES		18-Oct-21		DW: Nov.1-7, Nov.8-14, Nov.15-21, Nov.22-28, Nov.29-Dec.5, Dec.6-12, Dec.13-19, Dec.20-26, Dec.27-Jan.2, Jan.3-9, Jan.10-16, Jan.17-23, Jan.24-30, Jan.31-Feb.6, Feb.7-13, Feb.14-20, Feb.21-27, Feb.28-Mar.6, Mar.7-13	Heard partially awarded at TTF+$0.40/MMBtu to +$0.70/MMBtu
Tender	Darwin LNG - Darwin	Sell	20-Nov-21 - 27-Nov-21	1 DES	12-Oct-21	14-Oct-21	14-Oct-21	Nov 14-16 loading or Nov 20-27 DES	heard awarded to a trader at high $36 or approximately $37/MMBtu FOB to BP
Tender	APLNG - Australia Pacific LNG	Sell	(25-Nov-21 - 27-Nov-21)	1 DES	11-Oct-21	12-Oct-21			Heard awarded to Gunvor
EOI	Kogas - Prelude	Sell	(06-Dec-21 - 22-Dec-21)	1 DES or FOB				Dec 6-10 loading or Des 19-22 DES JKTC	heard not awarded
Tender	Tohoku Electric - Japan	Buy	08-Jan-22 - 28-Dec-23	6 Unknown	14-Oct-21	14-Oct-21	15-Oct-21	Jan. 2022-end 2023 delivery on a Brent-linked basis	heard awarded to a portfolio player
Tender	PTT - Map Ta Phut	Buy	18-Oct-21 - 29-Oct-21	2 DES		12-Oct-21		Closes at 10 AM (Thailand time) on October 12	Heard awarded at approximately $35/MMBtu to Shell and PTT International
Tender	EGAT - Map Ta Phut	Buy	10-Nov-21 - 16-Dec-21	2 DES		20-Oct-21		2 cargoes Nov 10-12 or 15-17, and Dec 10-12 or 14-16	

Several domestic LNG terminals have been required to maintain an inventory level of above 75% at their LNG tanks to ensure stable supply for winter, resulting in tighter supply of domestic spot LNG and higher prices, sources said. In some regions, LNG has been diverted to boost pipeline supply to northern provinces where heating demand will be concentrated in coming months.

CNOOC Ningbo terminal has cut its trucked LNG sales volume to around 300 trucks/day from 400 trucks/day, ENN Zhoushan terminal to around 150-160 trucks/day from 230-240 trucks/day and Guanghui Qidong terminal to around 130 trucks/day from 160 trucks/day, while PetroChina Rudong terminal was selling only 25 trucks/day, according to sources in eastern China.

While trucked LNG prices offered by coastal LNG receiving terminals in east, south and north China typically see price fluctuations due to market sentiment, this year trucked LNG prices in landlocked provinces in the northwest have also surged to around Yuan 8,000/mt.

These landlocked plants convert pipeline gas to LNG for trucking due to network constraints, and the price hike in the northwest regions has added to bullish sentiment for trucked LNG prices in the rest of China that already face price pressure from seaborne LNG imports.

China's overall trucked LNG price averaged Yuan 7,813/mt across the entire country Nov. 1, up 14% from Oct. 25 and 32% higher than early October, data from Shanghai Petroleum and Gas Exchange showed.

Qidong LNG terminal in eastern Jiangsu province raised its offer for trucked LNG by Yuan 500/mt end October and by another Yuan 400/mt to Yuan 8,500/mt Nov. 1, a market source in east China said.

The Platts JKM price for spot LNG in Northeast Asia averaged $33.25/MMBtu over Sept. 16-Oct. 15 for November-delivery cargoes on a DES basis, up nearly 75% from a month earlier, and equating to almost Yuan 11,000/mt after adding taxes and fees.

ICE Brent crude price has risen 55.5% in the past three months and this was expected to reflected in the import cost of term LNG cargoes from November. Oil-linked LNG contracts are mainly pegged to the prior three-month crude prices.

Northwest price surge

China's LNG plants that process pipeline gas into LNG are mostly concentrated in the northwest where cheaper pipeline gas from domestic sources and imports from Russia and Central Asia are available. Trucked LNG volumes there are lower than at coastal terminals.

Trucked LNG prices in the northwest have seen the highest increase in the past week, mainly driven by higher cost feedstock pipeline gas, implying that supply of pipeline gas is tight.

Northwest China plants sold trucked LNG at Yuan 8,084/mt Nov. 1, up from Yuan 6,578/mt a week earlier, according to Chongqing Petroleum and Gas Exchange. Plants in the Sichuan-Chengdu region sold trucked LNG at Yuan 7,972/mt, up from Yuan 6,737/mt, and in the Beijing-Tianjin-Hebei region at Yuan 7,814/mt, up from Yuan 6,918/mt, exchange data showed.

Many cities in the northwest started centralized heating from mid-October, 10-15 days earlier than previous years due to an early cold snap, which is believed to have tightened gas supply.

A batch of 28 million cubic meters of feedstock pipeline gas offered by state-owned PetroChina's northwest branch to LNG plants

SOUTH AMERICA ($/MMBtu), NOV 3

DES Brazil Netforward		
DES Brazil (Dec)	LEBMH01	27.560
DES Brazil vs NWE Fuel Oil Derivative	LAARM01	14.810
DES Brazil vs DES MED LNG	LASWM01	0.300
DES Brazil vs Dated Brent	LADBM01	13.385
DES Brazil vs Henry Hub (16:30 London)	LAHHM01	21.873
DES Brazil vs JKM (16:30 London)	LAJKM01	-0.592
DES Brazil vs NBP (16:30 London)	LABPM01	-0.184

NORTH AMERICAN FEEDGAS ($/MMBtu), NOV 2

Daily average US LNG feedgas cost	ALNFG00	5.324
30-day moving average US LNG feedgas cost	ALNUS00	5.295
Daily average USGC LNG feedgas cost	ALNFH00	5.334
30-day moving average USGC LNG feedgas cost	ALNUG00	5.340

Export facility		Estimated feedgas cost
Sabine Pass	ALNFA00	5.346
Corpus Christi	ALNFB00	5.314
Cove Point	ALNFC00	5.223
Cameron	ALNFD00	5.372
Freeport	ALNFE00	5.281
Elba Island	ALNFF00	5.472

Facility feedgas costs represent a calculation derived from S&P Global Platts' North American gas spot price indices at the hub(s) from which feedgas would be procured most economically for the export facility. The average summary costs are an average of the relevant export facilities' feedgas costs weighted by Platts Analytics' daily estimated volume delivered to each facility.

US CARGO CANCELLATIONS, NOV 3

Dec-21	0
Nov-21	0
Oct-21	0
Sep-21	0
Aug-21	0
Jul-21	0
Jun-21	0
May-21	0
Apr-21	0
Mar-21	0
Feb-21	5
Jan-21	2

The figures are collected from market sources.

NATURAL GAS FUTURES ($/MMBtu), NOV 3

NYMEX HH Singapore close	(Dec)	AAPSD00	5.530
NYMEX HH Singapore close	(Jan)	AAPSE00	5.627
ICE NBP Singapore close	(Dec)	AAPSF00	NA
ICE NBP Singapore close	(Jan)	AAPSG00	NA
NYMEX HH London close	(Dec 21)	AASYN00	5.687
NYMEX HH London close	(Jan 22)	AASYO00	5.790
ICE NBP London close	(Dec 21)	AASYR00	27.744
ICE NBP London close	(Jan 22)	AASYS00	27.831
NYMEX HH US close	(Dec 21)	NMNG001	5.670
NYMEX HH US close	(Jan 22)	NMNG002	5.780

MARINE FUEL LNG BUNKER, NOV 3

		$/MMBtu		$/mt (Oil)		$/mt (LNG)
Singapore	LNBSG00	27.652	LNBSM00	1068.556	LNBSF00	1437.904
		Eur/MWh		$/mt (Oil)		$/mt (LNG)
Rotterdam	LNBRT00	78.975	LNBRM00	1035.700	LNBRF00	1395.160

MMBtu to $/mt (oil) factor: 38.643; MWh to $/mt (oil) factor: 11.322; MMBtu to $/mt (LNG) factor: 52.000.

on the Chongqing Petroleum and Gas Exchange was auctioned at around Yuan 5.43-5.46/cu m Oct. 29 for delivery over Nov. 1-7, market sources said.

Traders said this was a 40% increase from the last batch of pipeline gas auctioned on the exchange on Oct. 14 for the second half of October, and equates to around Yuan 8,450-8,500/mt after processing into LNG.

Higher feedstock gas prices have prompted many LNG plants in northwest China to raise their offers for ex-plant trucked LNG to around Yuan 8,500/mt at end October, but actual traded prices early this week eased, although they remained above Yuan 8,000/mt.

Prices retreated to around Yuan 7,500-7,600/mt in north China Nov. 2 due to weaker buying interest, a source in Beijing said, but noted that prices could pick up again with another cold snap forecast for later this week.

Tianjin started heating from Nov. 1, earlier than the normal start of centralized heating in north China from Nov. 15. The China Meteorological Administration warned of cold weather from Nov. 4, bringing blizzards and strong winds and 10-15 degree Celsius drop in temperatures in the northern region, according to a Nov 1 notice. — *Staff*

PLATTS WIM RLNG DAILY PRICES, NOV 3

		$/MMBtu		Rupee/MMBtu
Ex-Terminal				
Dahej	RLEDA00	27.62	RLEIA00	2061.78
Hazira	RLEDB00	27.78	RLEIB00	2073.60
Dabhol	RLEDC00	27.70	RLEIC00	2067.87
Mundra	RLEDE00	27.74	RLEEI00	2070.60
Kochi	RLEDD00	28.24	RLEDI00	2107.78
Average	RLEDF00	27.82	RLEIF00	2076.33
Location				
Ahmedabad	RLDDJ00	28.12	RLDIJ00	2098.91
Morbi	RLDDK00	28.24	RLDIK00	2107.73
Panvel	RLDDL00	28.38	RLDIL00	2118.24
Dabhol	RLDDC00	28.38	RLDIC00	2118.24
Vijaipur	RLDDM00	28.30	RLDIM00	2112.61
Kota	RLDDN00	28.30	RLDIN00	2112.61
Chhainsa	RLDDO00	28.37	RLDIO00	2117.38
Jagdishpur	RLDDP00	28.37	RLDIP00	2117.38
New Delhi	RLDDQ00	28.37	RLDIQ00	2117.38
Koottanad	RLDDR00	28.88	RLDIR00	2155.69
Kakinada	RLDDS00	28.98	RLDIS00	2163.37
Average	RLDDT00	28.42	RLDIT00	2121.78

Prices are net-forward calculations derived from the Platts WIM and exclude VAT and CST sales taxes. Delivered prices represent the cost of delivery from the nearest connected LNG terminal via pipeline.

Norwegian gas flows to Europe rise to highest level since January 2019

- **Norwegian supplies top 10 Bcm in October**
- **Higher Troll, Oseberg permits boost flows**
- **Producers diverting injection volumes for export**

Norway's pipeline gas exports to continental Europe and the UK topped 10 Bcm in October, reaching the highest monthly level since January 2019, an analysis of data from S&P Global Platts Analytics showed Nov. 3.

Norwegian deliveries totaled 10.1 Bcm in October, well above the five-year average, as suppliers looked to make the most of record high European gas prices and some producers diverted re-injection gas for export.

European gas prices have risen strongly in the past few months, building on a sustained rally from the start of 2021.

S&P Global Platts assessed the TTF day-ahead price at a record high of Eur116.10/MWh on Oct. 5, with price volatility continuing through October and into November. The TTF day-ahead price was assessed at Eur69.38/MWh on Nov. 2.

(continued on page 9)

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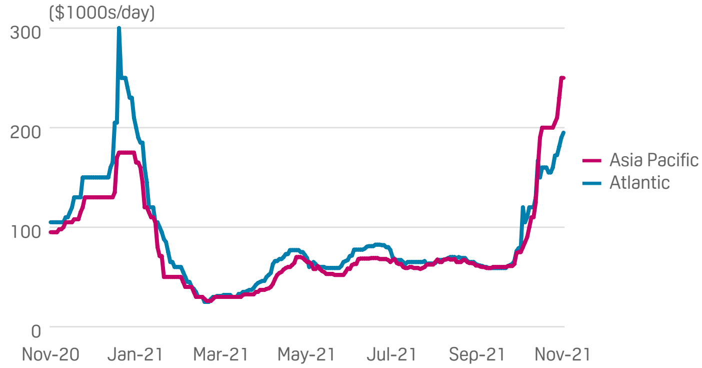
SHIPPING PRICES

SHIPPING RATES, NOV 3

		$/day
Asia Pacific day rate	AARXT00	250,000
Atlantic day rate	AASYC00	195,000
TCR Australia-Japan	ATCRA00	250,000.00
TCR USG-NWE	ATCRB00	195,000.00
TCR USG-Japan	ATCRC00	195,000.00
		$/MMBtu
PLF1 Middle East-Japan/Korea	AAUUA00	3.63
PLF2 Middle East-NWE	AAUTE00	4.06
PLF3 Trinidad-NWE	AAUUC00	1.91

SHIPPING RATES



Source: S&P Global Platts

SHIPPING CALCULATOR, NOV 3

	Australia-Japan/Korea	Middle East-India
Ship size (mt)	72980.77	72980.77
Trip length (days)	9	3
Carrier day rate ($/day)	250000	250000
Day rate cost ($/MMBtu)	1.44	0.61
Boil-off cost	0.57	0.19
Supplementary boil-off cost ($/MMBtu)	0.18	0.06
Cost of voyage* ($/MMBtu)	2.28	0.90

*Includes port cost.

FREIGHT ROUTE COSTS, NOV 3 ($/MMBtu)

Asian discharge ports

		Japan/Korea		South China/Taiwan		West India
Middle East	AAUUA00	3.63	AAUSH00	3.17	AAUSP00	0.90
Australia (Dampier)	AAUSA00	2.28	AAUSI00	1.84	AAUSQ00	2.20
Australia (Gladstone)	ACABA00	2.29	ACABB00	2.52	ACABC00	3.54
Bontang	AOJKA00	1.59	AOCTA00	1.15	AOWIA00	2.17
Bintulu	ABJKA00	1.61	ABCTA00	0.96	ABWIA00	1.98
Singapore	ASJKA00	1.80	ASCTA00	1.15	ASWIA00	1.52
Tangguh	ATJKA00	1.57	ATCTA00	1.35	ATWIA00	2.59
Trinidad via Suez	AAUSB00	7.14	AAUSJ00	6.70	AAUSR00	4.61
Trinidad via Panama	AAUXB00	4.96	AAUZB00	6.02		
Trinidad*	AAUZC00	4.96	AAUZD00	6.02		
Nigeria	AAUSC00	5.62	AAUSK00	4.98	AAUSS00	3.61
Algeria	AAUSD00	5.22	AAUSL00	4.80	AAUST00	2.87
Belgium	AAUSE00	6.07	AAUSM00	5.43	AAUSU00	3.44
Peru	AAUSF00	5.07	AAUSN00	5.80	AAUSV00	6.33
Russia	AAUSG00	0.93	AAUSO00	1.36	AAUSW00	3.50
Spain	ACAAA00	5.46	ACAAB00	4.83	ACAAC00	3.08
Norway	ACAAH00	6.96	ACAAI00	6.09	ACAAJ00	4.24
USGC*	LAUVA00	5.20	LAUVB00	6.27	LAUVC00	5.05
USGC via Panama	LAUVI00	5.20	LAUVL00	6.27		
USGC via Suez	LAUVJ00	7.85	LAUVM00	6.96	LAUVO00	5.05
USGC via Cape	LAUVK00	8.07	LAUVN00	7.39	LAUVP00	6.26

EMEA discharge ports

		South West Europe		North West Europe		Kuwait/UAE
Middle East	AAUSX00	3.41	AAUTE00	4.06	LMEMM00	0.49
Australia (Dampier)	AAUSY00	5.29	AAUTF00	5.98	LMEMN00	2.65
Australia (Gladstone)	ACABD00	6.75	ACABE00	7.47	ACABI00	4.01
Trinidad	AAUSZ00	1.94	AAUUC00	1.91	LMEMP00	4.22
Nigeria	AAUTA00	2.17	AAUTG00	2.33	LMEMQ00	3.86
Algeria	AAUTB00	0.47	AAUTH00	1.00	LMEMR00	2.50
Belgium	AAUTC00	0.83			LMEMS00	3.26
Peru	AAUTD00	5.53	AAUTI00	5.74	LMEMT00	6.84
Russia	AAUUB00	6.70	AAUTJ00	7.17	LMEMU00	4.89
Spain			ACAAD00	0.83	LMEMV00	2.72
Norway	ACAAK00	1.41	ACAAL00	0.82	LMEMW00	3.86
Murmansk			AARXW00	0.99		
USGC*	LAUVD00	2.55	LAUVE00	2.52	LMEMX00	4.86
USGC via Suez					LMEMY00	4.86
USGC via Cape					LMEMZ00	6.07

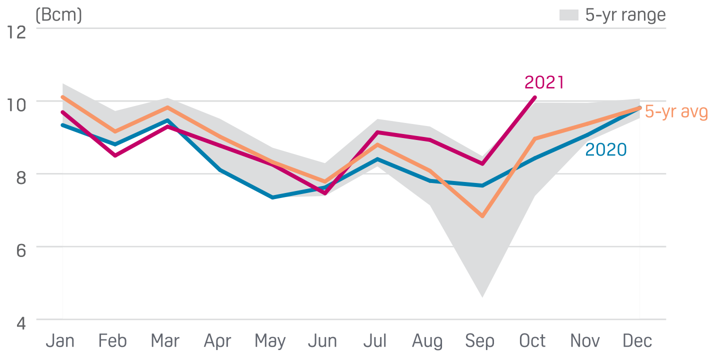
Americas discharge ports

		US Atlantic Coast		Argentina		Brazil
Middle East	AAUTK00	4.59	AAUTS00	4.96	ACAAP00	5.72
Australia (Dampier)	AAUTL00	5.77	AAUTT00	4.98	ACAAQ00	5.98
Australia (Gladstone)	ACABF00	5.58	ACABH00	4.28	ACABG00	5.27
Trinidad	AAUTM00	0.99	AAUTU00	2.25	ACAAR00	1.53
Nigeria	AAUTN00	2.42	AAUTV00	2.49	ACAAS00	2.14
Algeria	AAUTO00	1.61	AAUTW00	2.86	ACAAT00	2.51
Belgium	AAUTP00	1.45	AAUTX00	3.25	ACAAU00	2.89
Peru	AAUTQ00	4.77	AAUTY00	2.23	ACAAV00	3.39
Russia	AAUTR00	7.21	AAUTZ00	6.39	ACAAW00	8.97
Spain	ACAAE00	1.33	ACAAF00	2.89	ACAAG00	2.34
Norway	ACAAM00	1.62	ACAAN00	3.87	ACAAO00	3.71
USGC*			LAUVG00	3.47	LAUVH00	2.72

*Most economic.

All values calculated based on prevailing spot market values during the day for LNG, bunker fuel and ship chartering. No route cost is calculated for Zeebrugge to NW Europe, or Spain to SW Europe. Other routes appear blank on days when a public holiday in one or another location means underlying values are not published. Detailed assessment methodology, including assumed route times and underlying values, is found on www.platts.com.

NORWEGIAN GAS SUPPLIES TO EUROPE TOP 10 Bcm IN OCTOBER



Source: S&P Global Platts Analytics

With the summer maintenance season now complete, Norwegian flows rose to close to 350 million cu m/d at times in October.

Norway's state-controlled Equinor said in September it expected to produce more gas from its key Troll and Oseberg fields in the fall and through the winter after the country's energy ministry approved higher production permits for the new gas year.

Both permits have been increased by 1 Bcm, meaning the Troll permit is up from 36 Bcm to 37 Bcm and Oseberg up from 5 Bcm to 6 Bcm.

The higher permit for Troll will in part also take into account production from the field's third phase, which started up in late August.

Troll Phase 3, which will extend both the life of the field and its plateau production, is considered key to Norway's plans to offset declining gas production elsewhere on the Norwegian Continental Shelf.

Injection volumes

Norway's October flows were also boosted by moves by Equinor and others to divert gas — usually used for re-injection for oil recovery — for export to Europe.

Equinor said Oct. 27 it had decided to redirect injection gas produced at the Gina Krog field to supply more gas volumes to Europe, while Aker BP said Oct. 28 it would divert injection gas from its Skarv field into the European market.

Equinor also said it would look across its whole Norwegian portfolio to see if similar action could be taken at other fields.

The decision to use injection gas for exports is set to give Norwegian supply volumes to Europe a boost over the whole winter, according to S&P Global Platts Analytics.

"Platts Analytics started forecasting a reduction in the Norwegian gas injections directed towards oil recovery back in August," analyst James Huckstepp said Oct. 27.

"We also expect this to occur at the Gullfaks and Asgard fields, driving our Winter-21 Norwegian pipeline export assumption 24 million cu m/d higher year-on-year."

Country flows

On a country-by-country basis, supplies of Norwegian gas in October were up compared with September to all markets apart from the Netherlands.

Norwegian exports to the UK rose sharply to 2.67 Bcm, from 1.71 Bcm in September, while deliveries to Germany rose to 2.65 Bcm from 1.95 Bcm in the previous month.

Supplies to France and Belgium rose month on month to 1.53 Bcm and 1.3 Bcm, respectively.

NCS production, meanwhile, continues to be hampered by the long-term outage at the Hammerfest LNG export facility, which was hit by a fire in September last year.

As a consequence of the shutdown of Hammerfest LNG, the Snohvit, Albatross and Askeladd fields have also been shut in.

The latest guidance from Equinor is for the plant to resume operations at the end of March 2022. — *Stuart Elliott*

Qatar's investment in Pakistan's LNG terminal to help capture downstream demand

Qatar Energy's plan to invest in Pakistan's privately held Energas Terminal will help the latter capture downstream demand for its LNG output and tie-up long-term customers for its contracted volumes.

The move is in line with oil majors and gas suppliers who have invested in Asian regasification terminals in China and replicates a strategy to corner captive demand as seen in oil markets, where oil producers take equity stakes in Asian refineries.

For buyers, tying-up with a long-term supplier provides supply security, which has emerged as a major concern after the recent winter price spikes, exposing Pakistan to unreliable suppliers.

Qatar Energy, formerly known as Qatar Petroleum, is expected to invest in Pakistan's Energas Terminal that will have a capacity of 1 Bcf/day and is expected to start in two years, following regulatory approvals, according to industry sources.

The LNG terminal is expected to cost around $400 million-$500 million, out of which 49% will be owned by Qatar Energy and 51% by Energas, sources said. Qatar Energy and Energas have yet to respond to Platts' queries on the matter.

Energas' LNG facility is expected to be the first private sector LNG terminal in Pakistan and the company plans to supply the gas to end-users in the cement, textile and automotive sectors, the sources said.

The terminal will be designed to handle large Q-Flex and Q-Max LNG carriers, overcoming berthing restrictions faced by existing LNG terminals at Port Qasim.

"The development is positive for the long run because it ensures a more reliable and stable supply of LNG in future," Saad Ali, director for research at Karachi-based brokerage Intermarket Securities, said.

Pakistan has not been able to grow its gas reserves and production, and LNG is necessary for future demand, he said. "Having another terminal and long-term contracts makes Pakistan less vulnerable to high spot prices in future."

Currently, Pakistan has two terminals — Engro Elengy Terminal Ltd. with a capacity of 650 MMcf/d and Pak GasPort Terminal Ltd. with a capacity of 750 MMcf/d, to meet demand from state-run gas distributors like Sui Southern Gas and Sui Northern Gas.

Pakistan has two existing gas purchase agreements with Qatar, the first signed in 2016 for 15 years with pricing at 13.37% slope of Brent for five cargoes per month, while the second was signed in February 2021 for 10 years at a price of 10.2% slope of Brent for four cargoes per month starting January 2022.

"There is an acute gas shortage in the country, where local gas is depleting fast and dependence on imported gas is increasing," Fahad Rauf, head of research at Ismail Iqbal Securities Ltd., a Karachi-based brokerage firm, said. However, supply is limited to only two LNG terminals with a combined capacity of 1.2-1.3 Bcf/d. — *Haris Zamir*

Spain gas demand seen rising 10% in December: Enagas

- **Gas-to-power demand seen 36% higher on year**
- **January gas demand seen up 5% on year**
- **Q1 demand forecast slashed by 10 TWh**

Gas demand in Spain is forecast to be 37.5 TWh in December, gas grid operator Enagas said Nov. 2, an increase of 10% year on year, driven by rising demand from the power generating sector.

Demand for gas to power is expected — in a median-case scenario — to be 8.2 TWh, which is an increase of 36% year on year with Enagas citing two of Spain's seven nuclear plants being offline for refueling and "normal to dry" hydro reservoirs.

Conventional demand, from homes and businesses in December is seen at 29.3 TWh, a 3% decrease year on year, with moderate consumption from the industrial sector, Enagas said.

The strong gas-to-power demand is seen persisting into January 2022, outweighing an expected decline in conventional consumption. This is due to a strong-year-ago comparison when Spain saw a prolonged period of record low temperatures.

January gas-to-power demand is seen at 6.9 TWh, an increase of 22% year on year with the "normal to dry" hydro conditions still expected, but nuclear and wind production is expected to rise from December.

Conventional demand is expected to fall 6% year on year at 30.3 TWh meaning an overall gas demand forecast of 37.2 TWh in the month, up 5% year on year.

The strengthening gas-to-power forecast would be a flip from the year-to-date figures, which show a 13% decline year on year to 68.7 TWh, compared to a 6% increase year on year for conventional demand to 226.8 TWh.

Spanish legislation approved in October is set to recoup "windfall gains" from non-emitting plants that have been benefitting from the record gas prices.

However, prices have tanked during the last week, with both the prompt and front curve coming back from record highs.

Spain's day-ahead gas price has fallen from a record high Eur111.66/MWh on Oct. 6 to Eur65.81/MWh on Nov. 2 while the December price has dropped from Eur100.50/MWh to Eur70.90/MWh.

However, the year-ahead contract has risen from Eur43.85/MWh to Eur47.06/MWh over the same period.

Enagas' curve forecast sees Q1 gas demand at 99 TWh, down from last month's forecast of 109 TWh, mostly due to lower expected conventional demand.

Q2 demand is seen at 81 TWh, roughly unchanged, while Q3 demand is seen at 89 TWh, up from last month's forecast of 84 TWh, due to increases in both conventional and gas-to-power demand. — *Gianluca Baratti*

Gazprom Export CEO slams allegations of 'ill-intended' gas market actions

- **Gazprom not interested in record high prices: Burmistrova**
- **Hits out at 'wrong perception' of company's actions, interests**
- **Optimistic about future of European gas demand**

The head of Gazprom Export, Elena Burmistrova, on Nov. 3 slammed allegations that Gazprom was engaged in "ill-intentioned" behavior in the gas market, saying she wanted to "set the record straight" on the company's actions.

Gazprom has come in for criticism for not increasing supply to Europe at a time of sky-high gas prices, but the company has repeatedly said it was meeting all of its customer obligations in full.

In a pre-recorded message to the Flame conference in Amsterdam, Burmistrova said that a misunderstanding of Gazprom's long-term strategy often led to the "wrong perception of the company's actions and interests."

"In recent days, I have been very disappointed to see statements in the media alleging ill-intentioned actions from Gazprom, such as looking to capitalize on record high gas prices in Europe," Burmistrova said.

"I will say again: we are not interested either in record low, or in record high, gas prices. The latter leads to gas demand degradation in Europe, which is clearly against our interests as a gas producer and supplier," she said.

"We want to see a balanced and predictable market, where we and our customers can successfully develop our business," she said.

European gas prices have risen strongly in the past few months, building on a sustained rally from the start of 2021.

S&P Global Platts assessed the TTF day-ahead price at a record high of Eur116.10/MWh Oct. 5, with price volatility continuing through October and into November. The TTF day-ahead price was assessed at Eur69.38/MWh Nov. 2.

Previous criticism

Burmistrova said Gazprom was also criticized in 2020 for not reducing supply to Europe when prices were low to help balance the market.

"Let me remind you of the previous year, when prices were very low because of the weak demand and extensive supply, and when Gazprom was criticized for not cutting deliveries to Europe," she said.

"Now, the situation has changed 180 degrees and correspondingly the complaints against Gazprom from some politicians, media and even a number of experts have also turned around. At the same time, our business partners and clients make no such allegations," she said.

Burmistrova said it was "no exaggeration" to say that it was a unique time in the history of energy markets, and again criticized non-industry professionals for their views toward Gazprom.

"The current developments require detailed, expert analysis and interpretation," she said. "Unfortunately, the internet and media today are awash with fanciful assumptions and theories, suggested by people who are, at best, very loosely connected to our industry," she said.

"Within this, there has been some inaccurate reporting and speculation about Gazprom's actions. Thus, today, I feel the need to set the record straight."

Burmistrova also pointed to US LNG not coming to Europe in greater volume. “The US has increased gas exports by as much as 35% since the beginning of the year. But US LNG supplies to Europe remained at the same level as in 2020,” she said.

“Against this background, it is confusing to hear accusations that Gazprom’s actions led to the rise of gas prices in Europe. Let me remind you that, unlike flexible LNG suppliers, it is us who are rigidly tied to Europe by the gas pipeline system,” she said.

“We physically cannot leave the European market, we are closely connected with it, and that’s why we treat it with great responsibility. Therefore, we must reject these unfounded claims, allow our actions to prove our case and continue to develop on the basis of our own long-term business model.”

Long-term view

Burmistrova said Gazprom had a long-term view of the gas market and did not perceive “any pressure to sell as much as we can in a short time.”

“It would undermine the market’s predictability, both for us and for our customers,” she said.

The company’s long-term business strategy, she said, was based on the assessments of future demand in Russia and its key export markets.

“This is all about the balanced business development in view of the demands of our clients and partners, and not about short-term gains,” she said.

Burmistrova also reiterated Gazprom’s long-held view that long-term contracts were the basis of market stability. “We have always stood for long-term contracts with take-or-pay conditions, and will continue to do so,” she said.

“Our industry is capital-intensive and has a long investment cycle, and only such long-term contracts can provide confidence along the whole production chain. These contracts make the market balanced and predictable, therefore profitable for investors,” she said.

Burmistrova said Gazprom had also long warned against a “heavy” shift to hub indexation, pointing to the recent extreme price volatility on spot markets.

“Obviously, such a market is neither attractive to the investors, nor more predictable to the participants,” she said.

“In order to understand the advantages of long-term contracts versus spot ones, we should ask large players on the European market. They will attest that oil-indexed contracts are more profitable than spot ones,” she said.

“Long-term contracts with the take-or-pay obligations not only provide predictability along the whole value chain, but also protect from current price volatility demonstrated by the spot market recently.”

Burmistrova also said Gazprom remained optimistic about gas demand in Europe. “The situation there is not so definitive. Gas demand in Europe is growing steadily this year and record European gas prices themselves are the best evidence that gas is still in demand there,” she said. — *Stuart Elliott*

Tokyo Gas considers new term LNG contracts linked to European, US gas hubs

- **Optimization and trading official touts supply diversity**
- **Utility has offtake commitments in Maryland, Louisiana**

Tokyo Gas is considering linking new LNG term contracts to European and US gas hubs as it further diversifies its global supply, an executive said Nov. 3 during a presentation to a market conference in Louisiana.

The utility is interested in short- and medium-term supply deals, in addition to the long-term contracts for LNG volumes it currently has with producers in six countries, including the US, Atsunori Takeuchi, senior general manger of LNG optimization and trading, said in a video address to the World LNG & Gas Series Americas Summit & Exhibition in Lake Charles.

Tokyo Gas’ expansion of its LNG supply sources has previously included non-traditional contracts. In 2019, for instance, it announced an LNG contract with Royal Dutch Shell that was partly linked to coal prices. As global trade flows shift amid volatile LNG prices in end-user markets, Tokyo Gas, as a major consumer of the super-chilled power plant fuel, wants to ensure it has sufficient supplies in the future at a cost that reduces or mitigates its risk.

“To establish a global LNG network, we will work with our partners to build business relationships linking Europe, Asia and North America,” Takeuchi said.

In the US, Tokyo Gas has a long-term offtake commitment to buy LNG from the Berkshire Hathaway-operated Cove Point Liquefaction terminal in Maryland, It also has a long-term deal to buy LNG produced at Sempra Energy’s Cameron LNG terminal in Louisiana, via an agreement with an equity partner in the terminal.

Beyond those agreements, Takeuchi said Tokyo Gas was also considering short-term and medium-term LNG contracts. Despite elevated US Henry Hub gas prices this year, the executive said linking to Henry Hub remained a viable option.

“US gas prices are as stable as possible,” he said. — *Harry Weber*

Bulgaria to restore gas flows into Serbia after pipeline repair

- **Supplies had been halted Nov. 1 after pipeline rupture**
- **Russian gas flows via Bulgaria to Serbia, Hungary, Romania**
- **Had knock-on effect on gas supplies to Bosnia**

Bulgaria’s state-owned gas grid operator Bulgartransgaz said late Nov. 2 that it was to restore gas flows into Serbia after it carried out repairs on a pipeline that suffered damage Nov. 1, leading to the suspension of flows into the Serbia-Hungary route.

In a statement, Bulgatransgaz said flows into Kireevo on the border with Serbia were to be resumed at midnight local time (2200 GMT).

Flows were also set to be resumed in full to Romania during the Nov. 3 gas day.

"Bulgartransgaz performed emergency repair works on a part of the gas pipeline in the section from Vetrino to Hrabrovo," it said.

"The repair works were completed and the transmission of natural gas to Serbia and Hungary will be resumed at 2400 on Nov. 2," it said. "At the same time, the transmission to Romania will be increased."

The damaged pipeline section is part of the onshore infrastructure bringing Russian gas via the TurkStream pipeline into central Europe. Russia's Gazprom now supplies all of its gas to Bulgaria, Romania and Serbia via TurkStream and the dedicated onshore pipeline network.

In addition, the bulk of Hungary's Russian gas imports now come in via Serbia after the supply via Ukraine was halted Oct. 1.

Since the start of October, Hungary had been taking 6 million cu m/d of gas via Serbia, according to data from S&P Global Platts Analytics.

Flows from Bulgaria into Serbia at the Kireevo interconnection point had been running at around 13 million cu m/d, according to the data, meaning some 7 million cu m/d of gas supply was for Serbia itself as well as small onward deliveries to Bosnia and Herzegovina.

Bosnia's gas distribution company Sarajevogas on Nov. 1 had asked gas users to switch off appliances to preserve the gas network.

Serbia's Srbijagas also provided emergency volumes of gas sourced from Hungary to supply Bosnia, Sarajevogas said.

TurkStream shift

The start in January 2020 of the two-string 31.5 Bcm/year TurkStream pipeline triggered an unprecedented reshuffle in the way Russian gas reaches Southeast Europe.

One of the 15.75 Bcm/year strings feeds directly into the Turkish market, replacing volumes previously delivered via Ukraine in the Trans-Balkan pipeline, while the other 15.75 Bcm/year string enters Bulgaria at Strandzha.

Initially, gas mostly either stayed in Bulgaria or was transited to Greece and North Macedonia, with small volumes also moving into Romania.

However, since the start of 2021, Russian gas sent via TurkStream can also now be transited onto Serbia, Bosnia and Herzegovina, with Hungary also supplied via the new route since October.

Gas deliveries into Southeast Europe via TurkStream in the first 10 months of 2021 totaled 9.33 Bcm, an average of 31 million cu m/d. — *Stuart Elliott*

Norway's Equinor warns of continued energy price increases, volatility

- **System more fragile, 'sensitive' to market variabilities**
- **Very cold winter could see insufficient gas supply: Vitol**
- **Market liquidity drops on price volatility**

The recent energy price increases and extreme price volatility in Europe are likely to be repeated in the future given the "fragile" energy system, a senior official at Norway's state-controlled Equinor said Nov. 3.

Helge Haugane, Equinor's senior vice president for gas and power marketing, told the Flame conference that the autumn had been "a really tough test for our energy systems."

"It has also been a reality check for what it takes to get to net zero at the same time as there is a need to ensure security of supply," Haugane said.

European gas prices in particular have risen strongly in the past few months, building on a sustained rally from the start of 2021.

S&P Global Platts assessed the TTF day-ahead price at a record high of Eur116.10/MWh Oct. 5, with price volatility continuing through October and into November. The TTF day-ahead price was assessed at Eur69.38/MWh Nov. 2.

Haugane said both the price increase and the volatility were "completely unprecedented."

"Unfortunately, I'm convinced that something similar to this will happen again," he said.

Haugane said the reasons for the price rises included lower summer gas production and more LNG headed to Asia.

However, he said, some of the changes in the gas market that had led to the higher prices were "not that dramatic."

"What is new is the result of the stress that has now been added to the energy system, making it more fragile and and more sensitive to what we used to see as quite normal variabilities in the market," he said.

He said he understood why governments were looking at short-term measures to mitigate the impact of higher prices, but said "I'm afraid that the physical issue is not likely to be solved by what you write on paper."

Haugane added that Equinor had changed its gas sales strategy "a few years ago because we were seeing this picture of increasing volatility."

"That we got to this extreme situation now, and that it started to happen in the summer, that caught us very much by surprise," he said. "This is clearly not sustainable."

Weather impact

Also speaking at the conference, Vitol's head of LNG, Pablo Galante Escobar, said a very cold winter could see insufficient gas for markets in Europe and northeast Asia.

"There is a 10% or 15% probability that the winter is very cold and significantly colder than average," he said.

"If that is the case, there is not enough gas in the world to supply Europe's needs and to supply northern Asia's needs," he said, adding that there was also then a "5%, 10%, 15%" chance that prices could spike above the highs already seen in global markets.

Galante Escobar also said the weather phenomenon La Nina would be "almost a certainty" this winter, which has a strong correlation with colder winters in northern Asia. "That means a colder winter in huge demand centers, China, Japan and South Korea," he said.

"It is a very, very tight market. I think you have to be incredibly brave to be short in a market like this," he added.

The higher LNG prices have also seen a drop in trading liquidity due to the extreme price volatility, industry players said at the conference.

Sophie Ducoloner, managing director at Axpo Singapore, said LNG had "suddenly become very expensive."

"You need a lot of cash liquidity to cover your exposure to the soaring gas price," she said.

She said that with the value of one LNG cargo at more than $100 million, "you start to be very selective on the deals you chase."

She said some companies had also stopped trading because they had insufficient credit lines. "Some counterparties tend to be weaker than others," she said, adding that liquidity in the physical market had slowed as a result, especially in Asia.

Andree Stracke, CEO of Germany's RWE Supply & Trading, added that with highly volatile markets, trading had become like "poker or roulette."

"Therefore, we refrain from being in the market. And being a liquidity provider to the market, when we are absent from the market, there is higher volatility," Stracke said. — Stuart Elliott

UK would not be better protected from gas price spikes with Rough storage: BEIS

- **Prices would be high regardless of Rough: Howe**
- **UK constantly reviewing how gas system works**
- **UK bases security of supply on diversity of supply**

The UK would not be better protected from the current high gas prices if it still had access to the Rough gas storage site off the coast of eastern England, a UK government official said Nov. 3.

Alexandra Howe, head of gas security, networks and markets at the UK Department for Business, Energy and Industrial Strategy (BEIS), said the UK did, however, continue to review the gas network and its operations, including storage.

"We're asked whether the UK would be better protected from the price spikes we're seeing at the moment if we had Rough. Our answer in short is no, we'd still see the high prices at the moment," Howe said at the Flame conference in Amsterdam.

"We base our security of supply on diversity of supply," Howe said, conceding that this meant the UK was also "beholden to international prices."

The UK has only limited, medium-range gas storage since the UK's Centrica moved to close the seasonal Rough gas storage facility off the east coast of England in June 2017, deciding instead to produce the remaining cushion gas from the site.

With the record high gas prices, there have been calls for the UK government to look to reinstate Rough as a storage facility.

According to S&P Global Platts price assessments, the UK NBP front-month price hit a peak of 298.6 p/th ($40.74/MMBtu) on Oct. 5. Prices have been volatile since then, with the NBP front-month assessed Nov. 2 at 181 p/th.

In continental Europe, countries such as Germany, the Netherlands and Italy have significant storage capacity to help meet winter demand.

Howe said this was not necessarily advantageous at current prices. "It perhaps isn't helping some of our European colleagues out that much having to fill up their sites at the moment," she said.

"That being said, it's something we're considering. We're doing a lot of reviews on how the gas system works and we engage with all the players in the gas market in the UK and we're trying to develop some of that forward thinking policy," she said.

Hydrogen storage

Howe said the approach to storage could differ if considering future storage capacity in the UK for hydrogen.

"It's a different question if you're thinking about Rough or different storage sites for hydrogen," she said.

"There might be a different model, and some different storage might be needed for that going forward. That's something we're consulting on as well," she said.

Centrica said in January it was also looking at the possibility of converting Rough into a facility for storing hydrogen, and in late October confirmed to S&P Global Platts it was still engaging with the UK government about the issue.

In response to questions about the future of Rough, a spokeswoman for the company said: "[Since long before the energy crisis], we have been in conversation with government about our proposal to repurpose Rough to be a hydrogen storage facility. This has not changed."

"Rough is a flexible storage site, and we can provide a solution for whatever the market needs." — Stuart Elliott, Neil Hunter

China's upstream investments unlikely to slow despite energy transition

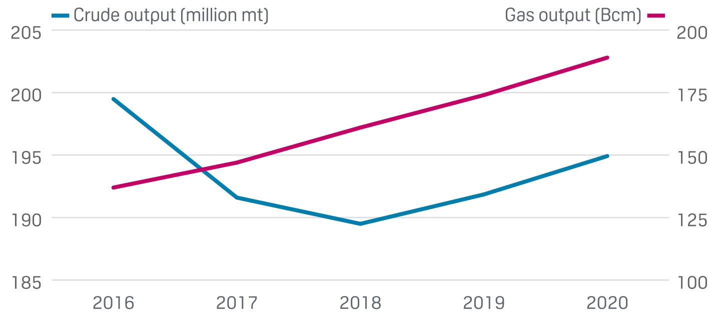
- **CNOOC, PetroChina push ahead with upstream plans**
- **China's state oil firms to keep focus on upstream sector: Platts Analytics**
- **Beijing plans billions of dollars investment in energy security**

PetroChina and China National Offshore Oil Corp. Ltd posted sharp increases in oil and gas output in the first nine months of 2021, a sign that China's top state oil firms are aggressively pursuing plans to boost domestic fossil fuel output despite the nation's energy transition journey gaining speed.

Analysts said most major state-owned companies would be aiming to invest billions of dollars in the coming years to ensure that its upstream sector continues to post production growth, in line with Beijing's vision for energy security.

"China's state oil companies will keep a unique focus on upstream sector investments given the country's growing dependence on imported oil," Kang Wu, head of Asia Analytics and Global Demand at S&P Global Platts, said.

CHINA'S OIL AND GAS PRODUCTION OVER PAST FIVE YEARS



Source: National Bureau of Statistics

"With energy transition underway and the energy sector set to witness big changes in coming decades, it appears that Beijing wants to ensure that sufficient investments keep flowing in to boost domestic oil production for its own energy security. Whether or not this strategy works to prevent China's oil production from eventually going down in the long run, remains to be seen," he added.

CNOOC's domestic crude output jumped 11.5% year on year to 233.9 million barrels in the January-September period. The 24.1 million-barrel rise in production over the nine-month period accounted for 90% of China's production increment of 26.79 million barrels during the period, the company's recently released Q3 results showed.

It boosted domestic gas output by 11.8% year on year to 348 Bcf in the January-September period as part of efforts to increase the country's supply of clean energy. This growth was slightly higher than the 10.8% year-on-year increase in gas output during the same period, data from the National Bureau of Statistics showed.

The growth is expected to be sustainable as its Lingshui 17-2 deepwater gas field in the South China Sea reached full operation in September after commissioning on June 25. The gas field is estimated to add 3 Bcm to the company's annual output.

Energy security focus

The Chinese government has been urging upstream companies to boost output and lift reserves to secure fossil energy supplies, while starting the nation's energy transition journey.

"As state-owned entities, China's major operators are not solely profit-driven. They also play an important and integrated role in social economics. So even in a less favorable oil price environment, we expect Chinese NOCs to perform in line with government expectations and to continue to make an effort to shore up domestic supply," Peng Li, research analyst at Rystad Energy said in a recent note.

CNOOC has targeted its non-fossil resources to account for more than half of the company's energy resource mix by 2050, and lift gas output to 35% of its upstream production by 2025 from the current 21%.

The company plans to invest 5%-10% of its annual capital expenditure in new energy business developments, led by offshore wind power projects, during the 14th Five Year plan (2021-25), up from about 3%-5% at end-2020. The company spent Yuan 56.96 billion ($8.9 billion) in the first three quarters, up 5.4% year on year. It's total 2021 budget is Yuan 90-100 billion.

Aiming to meet target

PetroChina is also aiming to meet its 2021 oil production target of 924 million barrels, or 2.53 million b/d, Brian Xing, the company's deputy director of investor relations, said.

PetroChina produced 662.3 million barrels, or 2.43 million b/d, of crude over January-September, down 5.6% year on year due to a 28.7% slump in overseas output, the company's results showed.

The reduction in overseas oil and gas output was mainly due to the production curbs set by OPEC+, Wei Fang, assistant secretary to Petrochina's board of directors said.

While its overseas output fell, PetroChina lifted its domestic crude production by a marginal 0.3% year on year to 2.05 million b/d over January-September. Its domestic output accounts for 85% of the company's total crude output and 50.7% of China's total crude production.

Rystad said China was looking to lift oil and gas production in the years ahead to meet rising domestic demand and reduce the record-high share of oil imports.

National oil companies are expected to spend more than $120 billion on drilling and well services in the 2021-2025 period, seeking to meet rising oil and gas demand. At the same time, the country aims to supply more of its oil demand from domestic sources, after the share of imported crude oil has risen steadily from 2014 to a high of almost 75% last year, it added

"To be exact, CNPC, CNOOC and Sinopec together are expected to spend about $123 billion on drilling and well services in the coming five-year period, up from a total $96 billion between 2016 and 2020," Rystad said. — *Staff*, Sambit Mohanty,

Composition of EU gas demand to change dramatically by 2050: EC official

- **Hydrogen, green gas to meet bulk of gas demand**
- **Significant changes on the horizon, says official**
- **EC to propose new gas regulatory framework in December**

The composition of gas demand in the EU is to change "dramatically" by 2050, a senior European Commission official said Nov. 3, with hydrogen and other green gases set to meet the bulk of the demand.

Speaking at the Flame conference, Augustijn van Haasteren, team leader for decarbonization at the EC's energy directorate, also said the EC was also planning a new rulebook to make sure green gases could gain effective access to the network.

The EC is due to publish its proposals for changes to gas market rules in mid December as part of its gas decarbonization package.

Van Haasteren said "significant changes are on the horizon" for gas demand in the EU, but that "does not mean the EC doesn't foresee a continuing role for gas in the economy."

He said the EC predicted that by 2050 overall demand for gas would decrease, "but not by that much."

"But what is very clear is that the composition of the gas demand will be met by very different gases than we know today," van Haasteren said.

He said that currently, 95% of gas demand was met by natural gas. However, he said, by 2050 it is projected that approximately one third would be met by hydrogen, with another third or 40% to be met by biomethane or synthetic gases.

"The role of natural gas will still be there, but it will be insignificant related to the gases used today, and it will be abated natural gas," he said.

"The composition of gas demand will change very dramatically whereas overall demand will remain comparable with today."

Gas pathways

Van Haasteren said the EC was focusing on two different development pathways for gas demand.

The first is to develop a hydrogen value chain, including the establishment of a hydrogen market and building hydrogen infrastructure, with the second to cover natural gas, biomethane and synthetic gas supply.

"With the decrease in demand for natural gas, quite a bit of infrastructure will become available to repurposing, and this presents an opportunity for the EU gas market that we want to exploit," he said.

On hydrogen, van Haasteren said it was important to think about the specifics of the market, which he said was only just emerging and was very different compared with the mature natural gas market.

"We need scope for business models to develop and have a phase that is transitionary," he said, adding that the regulatory framework needed to be long-term based in order to have a "vision of the direction of travel" and to create more investor certainty.

"As well as creating investor certainty, we can hopefully avoid ex-post interventions like in the gas and electricity markets, which have been difficult to implement and costly to do," van Haasteren said.

He added that it was important to make sure the regulatory framework was also adapted to certain elements of a hydrogen market, for example the role of storage and import terminals.

Van Haasteren also said it was important to make it easier for biomethane to be fully integrated into the market and the network to help remove barriers to the decarbonization of the methane network.

"We have to make sure that whatever gas network we have remains interoperable," he said, adding that the production structure for green gases would also change with more production connected at the distribution level. — Stuart Elliott

LNG SHIPPING WEEKLY: Atlantic and Pacific rates climb

The LNG shipping markets saw increased levels of spot and period activity from Oct. 27 to Nov. 3, with many reported fixtures and day rates increasing in the Atlantic and Pacific basins.

The Pacific shipping rate increased at $250,000/d from $200,000/d during the period, while the Atlantic shipping rate also increased at $195,000/d from $160,000/d. Tight ship availability along with open arbitrage between JKM and TTF were the main driving factors for higher rates. The Atlantic and Pacific ballast rates remained steady at 100% during the same period.

In the Pacific, up to two cold TFDE or DFDE tankers were heard marketed open for loading from Nov. 22 until the end of December. However, up to four steam turbine ships were reported open for November-December laycans in the Pacific basin, including the ISH. On the X-DF class type, two LNG tankers were heard marketed open for loading from Nov. 5 until Nov. 24-25.

In the Atlantic, one TFDE LNG tanker was heard marketed open for loading from mid-January onwards. On the steam turbine class type, one ship was reported open for loading from Nov. 7 onwards.

Elsewhere in the market, the SM Eagle, 174,000 cu m, was heard fixed for an end of November loading by K Line with the rate and period not reported. The tonnage requirement of Santos, for a TFDE LNG tanker for a one-year period starting December with delivery in Darwin-Australia, was reported still not covered. CNOOC's tonnage requirement for a Dec. 8-10 loading ex-Australia for a period of 17 days was heard still not covered. — Alkis Mouratis

SHIPPING RECAP AND DELIVERIES, OCT. 27 TO NOV. 3

Vessel	Capacity	Source	Load date	Delivered port/country	Delivered date	Commentary
BW Pavilion Leeara	154,880	Freeport	10/13/2021	Salvador de Bahia	10/29/2021	
Cool Runner	160,000	Freeport	10/4/2021	Port Qasim	10/31/2021	
Flex Courageous	173,400	Dampier	10/21/2021	Map Ta Phut	10/29/2021	Shell-controlled ship delivers cargo
Gaslog Singapore	155,000	Corpus Christi	10/10/2021	Aliaga/Turkey	10/26/2021	
Golar Crystal	160,000	Sabine Pass	9/22/2021	Chittagong/ Bangledesh	10/24/2021	Gunvor-controlled ship delivers cargo
Kita LNG	160,000	Das Island	10/27/2021	Dabhol/India	10/31/2021	Trafigura-controlled ship delivers cargo
Methane Spirit	165,500	Gladstone	10/21/2021	Yuedong/China	10/31/2021	
Minerva Chios	174,000	Pampa Melchorita	9/29/2021	Milford Haven/UK	10/30/2021	Shell-controlled ship delivers cargo
Seri Bakti	152,000	Singapore Port	10/7/2021	Dangjin/Korea	10/27/2021	Jera-controlled ship delivers cargo
Solaris	155,000	Pampa Melchorita	10/7/2021	Canaport/Canda	11/1/2021	Shell-controlled ship delivers cargo
Attalos	174,000	Corpus Christi	10/12/2021	Rio de Janiero/Brazil	10/31/2021	BP-controlled ship delivers cargo
Tangguh Sago	155,000	QCLNG	10/11/2021	Dalian/China	10/26/2021	BP spot voyage

RECENT FIXTURES, OCT. 27 TO NOV. 3

Vessel	Capacity	Note
Gaslog Santiago	154,950	Trafigura extends option for one year
Gaslog Seattle	154,950	Total extends option for one year
Gaslog Westminster	180,000	Fixed by Chevron for mid-December loading at rate of $175,000/d
Flex Courageous	173,400	Fixed by an energy major for a period of three years with options for another two
Flex Resolute	173,400	Fixed by an energy major for a period of three years with options for another two
Flex Volunteer	174,000	Fixed by Shell at rate of $250,000/d
MU LAN	174,000	Fixed by Pan Ocean for a single voyage ex USG for an end of December loading and delivery Far East at rate of $200,000/d round trip basis.

Source: S&P Global Platts

HYDROGEN

Energy transition strategic to China's long-term economic goals

"Crossing the river by feeling the stones" is an expression that describes the approach to reforms and opening up under Deng Xiaoping, the architect of modern China who ended decades of isolation and laid the groundwork for the country's current economic ascent.

The expression refers to the concept of taking small and measured steps and making gradual progress, as opposed to implementing big policies that shock the system into change. It reflected a more nuanced and realistic policy making approach that contrasted with the ideological, social, and political turmoil of the decades preceding China's economic reforms.

Feeling the stones served China well through the 1990s and early 2000s, and the approach in many ways underpins China's current decarbonization policies. It also describes how the country's future climate policy is likely to be devised and implemented, following President Xi Jinping's pledge to peak carbon emissions by 2030 and achieve net-zero emissions by 2060.

More importantly, China's calibrated policy approach highlights an important aspect of its decarbonization road map — energy transition is unlikely to happen at the cost of economic growth and energy security.

Fortunately, Beijing's goals are in alignment. China under Xi sees a huge economic opportunity, and the creation of new industries of the future, in the pursuit of energy transition. It has already leveraged its manufacturing prowess to bring down global renewable energy costs and is pushing to build an economy around electric vehicles and clean energy.

On the energy security front, Xi laid out the country's energy strategy in 2014 at the conference of the Leading Group for Financial and Economic Affairs under the CPC Central Committee.

The so called "Four Reforms and One Cooperation" strategy comprised four reforms — one demand-side reform to curb unnecessary energy consumption, a supply-side reform to diversify energy sources, one reform to improve energy technologies and one to introduce market-based mechanisms to boost growth of the energy sector. The cooperation referred to the greening of its Belt and Road Initiative.

These will continue to guide future climate policy.

Broadly, China's energy choices will be instrumental in the global climate fight because of its sheer size as the world's largest energy consumer and producer. The launch of its national carbon market in July 2021 put a price on 7.4% of global GHG emissions covering 4.00 GtCO2e in one go, surpassing the EU's carbon market that was the biggest until then.

China already accounts for the world's largest annual wind and solar capacity additions, and an emissions peak in 2030 or 2035 could also mean a peak for global emissions.

Coal is too strategic to fully eliminate

The power sector is estimated to account for 40% of China's energy consumption-based carbon emissions, and over 60% of the country's power generation comes from coal, making it the prime target for decarbonization.

However, China's energy demand is still growing, and instead of paring back existing coal-fired generation, it is much more likely to switch new capacity to renewables.

S&P Global Platts Analytics' base case scenario for China is that the country is in line to reach most of its Paris Agreement targets for 2030 via a combination of renewables and efficiency gains, such as electric vehicles replacing combustion engines, and an economy that becomes overall less carbon intensive.

It expects hydro, nuclear, and other renewables to account for about 26% of China's primary energy demand by 2030, with the country meeting its goal of 1,200 GW of installed wind and solar capacity by the end of this decade.

"This will also help them in achieving peak carbon emissions within that time period," Matthew Boyle, manager, Global Coal and Asia Power Analytics at S&P Global Platts, said.

"The announcement of a 2060 net zero target in China suggests that the country will seek to reduce the role of coal in its energy mix, although we believe this may be more aspirational rather than achievable," Boyle added.

He said Chinese electricity generation is overwhelmingly concentrated in coal-fired plants, and Platts Analytics' base case assumption is that China will continue to develop clean energy capacity but also continue to increase its coal-fired generating capacity.

Hence, decarbonization in China's power sector is likely to be achieved through renewables capacity additions, which means utilization of coal-fired power plants will continue to rise along with increasing nuclear, wind and solar generation capacity.

"Our current view implies around 5-6 GW of new nuclear plant builds annually out to 2050, whereas coal and gas plant additions will stop after 2040. In terms of plant load factors, loads are expected to increase toward the end of our forecast period to 2050 as capacity comes offline," Boyle said.

He said Chinese coal-fired power generation is the largest globally, and likely to remain so in 2060, even though the use of fossil fuels in the electricity mix will have declined by 2060 when compared to 2020 levels.

Other key things to note are that China's coal plant fleet is quite young, with plants likely to continue operating through to 2050. With China moving toward self-sufficiency in coal, and the current focus on economic growth and energy security over decarbonization, dependency on coal will continue through to 2060.

"Putting this another way, the more focused the government is on GDP growth, the more it necessitates a build out in power generation, and therefore the more likely they are to rely on their fleet of young, supercritical and ultra-supercritical coal-fired power plants," Boyle said. "The economics of renewables and the required investment to replace coal in the power stack are just not there at the moment," he added.

The long-term outlook by state-run China National Petroleum Corp.'s research arm Economics and Technology Research Institute has indicated that the share of coal in China's primary energy mix will drop from 57.7% currently to around 50% by 2025, 42.5% by 2035 and 33% by 2050.

Boyle said one of the key things to look out for will be how technologies like Carbon Capture Utilization and Storage are developed, along with producing gray hydrogen from unused or uneconomical coal mines, which will help monetize China's vast coal reserves and young coal-fired power plants.

"This could create a form of additional revenue for the industry that might provide the financial incentive to help it meet its targets," he added.

Implementation challenge looms

China's policy challenge is interesting because in regions like Europe, coal-to-gas switching has been triggered by market-based mechanisms.

China will largely rely on a top-down system, the limits of which were seen in haphazard anti-pollution coal-to-gas policies in the northern regions a few years ago, which led to more hardship for the community and prompted Premier Li Keqiang to call for a more measured approach.

China lacks a dedicated energy ministry, and regulation of its energy sector has traditionally been split between its most powerful economic planning agency the National Development and Reform Commission, the National Energy Administration, and state-run enterprises that often wield as much power as the government in directing energy policies.

Further down the chain are a mix of provincial and city-level governments and numerous government-backed energy companies that handle the local operations of power utilities, transmission networks and oil refiners.

The tussle between state-run refiner China Petroleum & Chemical Corp. or Sinopec and provincial independent refiners once called teapots is an example of how localized industries that create jobs and generate tax revenue can clash with national energy mandates. Beijing recently tightened controls on independent refiners this year by supervising their crude quota usage and tax reporting.

This is truer for industries like coal. China's most carbon-intensive industries are also the most coal-intensive, and heavy industries are concentrated in the northern provinces, while eight out of the 10 provinces with the highest GDP are southern provinces that collectively contributed almost half of China's GDP, official data showed.

An imbalanced decarbonization policy risks affecting northern provinces' economic development and exacerbating existing income inequalities. For instance, northern provinces like Shanxi, Inner Mongolia and Shaanxi have much heavier dependency on coal mining and power sector for taxation, Peng Wensheng, Chief Economist at China International Capital Corp, said at an industry event in July.

In the power sector, generation and distribution is concentrated among a few players.

China's five largest independent power producers, or IPPs, accounted for around 44% of the country's total installed generating capacity of 2.2 TW at the end of 2020. Together called the Big 5 they are Huaneng Group, Huadian Group, China Energy Investment Corp (CEIC), State Power Investment Corporation (SPIC) and Datang Group.

In addition, there are four smaller generation companies — SDIC Huajing Power Holdings (SDIC Power), China Shenhua Group Guohua Power Branch (Guohua Power), China Resources Power Holdings and China General Nuclear Power Group — and numerous provincial power producers that together make China the world's largest electricity producer.

The Big 5 were formed after power sector reforms designed to decentralize power generation and separate electricity production from transmission and distribution. So far, the Big 5 have been ahead of the curve in aiming for peak emissions by 2025 even before national pledges were announced, including announcing renewables targets and a higher share of clean fuels in their energy mix by 2025.

But the power generation companies lack a dedicated road map for coal plant decommissioning, face high costs of renewable capacity additions, and a nascent carbon trading market.

Like the rest of the world, the conversation and debate around climate change in China has accelerated significantly in the past two to three years — and it's now more likely a question of how its decarbonization will evolve, rather than if it will evolve.

(This story was first published on Oct. 28 on https://www.spglobal.com/platts/en/market-insights/blogs) *— Eric Yep, Analyst Ivy Li, Oceana Zhou*

COP26: Hydrogen Council calls on world leaders to back pledges on clean hydrogen investment

- **Investment at 'critical threshold': Hydrogen Council**
- **Follows international goals on hydrogen, steel, energy**
- **Hydrogen projects up 550% in 2021: Platts Analytics**

The Hydrogen Council called on world leaders in the public and private sectors to back pledges on clean hydrogen investment and capacity installations with concrete action, saying investment has reached a "critical threshold."

The call comes a day after a coalition of national leaders at the UN Climate Change Conference signed up to aspirational decarbonization targets in the hydrogen, road transport, energy and steel sectors by 2030.

"Swift uptake of renewable and low-carbon hydrogen by 2030 and expansion to an economy-wide solution by mid century are essential to deliver on global net-zero targets," the Hydrogen Council said in a statement Nov. 3.

"Investment has reached a critical threshold and urgent, decisive policy action is now needed to fully unlock hydrogen's climate and societal benefits," it added.

Hydrogen is a critical element in global decarbonization ambitions, seen as a way to cut emissions in hard-to-electrify sectors such as heavy transport and industry.

The Hydrogen Council said global demand for renewable and low-carbon hydrogen could grow by 50% by 2030, cutting the equivalent annual CO2 emissions of the UK, France and Belgium combined.

However, a significant scaling up of production, infrastructure and end uses was needed to unlock this demand, it added.

"We know from past experiences with technologies such as wind and solar that front-loading investments and policy support in the early market development phase can bring down costs quickly, enabling deployment at pace and scale," Hydrogen Council Executive Director Daryl Wilson said in the statement.

The industry group identifies over 90 GW of announced electrolyzer capacity globally, but said a four-fold increase in investments by 2030 was needed to put the world on course for net zero by 2050.

S&P Global Platts Analytics said the low-emissions hydrogen project pipeline had grown 550% in 2021.

"Despite rapid recent expansion, the clean hydrogen industry has massive growth potential. The entire current pipeline would supply just 33% of 2021 pure hydrogen demand," Platts Analytics said in an Oct. 26 report.

New demand

The Hydrogen Council in its "Hydrogen for net zero" report, also released Nov. 3, said the deployment of 75 million mt of clean hydrogen was needed by 2030 to reach global decarbonization goals.

It sees two-thirds of this demand coming from new markets such as steel, industry, mobility, aviation and shipping.

The clean hydrogen could replace 25 million mt of fossil-fuel derived hydrogen in ammonia, methanol and refining, as well as 50 billion liters of diesel in ground mobility and 60 million mt of coal used for steel production, it said.

The Hydrogen Council also released a "policy toolbox for low-carbon and renewable hydrogen" to guide on effective policy and regulatory measures to underpin investor confidence in the sector, helping to drive down costs and stimulate international trade.

Platts hydrogen price assessments show northwest European and Japanese markets as price takers, with Australia one of several lower-cost renewable hydrogen production sources well placed to develop future exports.

The spread between proton exchange membrane electrolysis assessments (including capex) Nov. 2 showed European prices (Netherlands, $14.03/kg) almost three times those in Australia (New South Wales, $4.85/kg). The comparable assessment for Japan was $12.10/kg.

Glasgow breakthroughs

A group of 40 global leaders at COP26 on Nov. 2 announced 2030 ambitions to make clean technology widely available across a range of sectors, notably in road transport, energy, steel and hydrogen.

The initiative, dubbed "Glasgow Breakthroughs," aims to:

- Make clean hydrogen available at affordable levels globally.
- Make clean power the cheapest and most reliable source globally.
- Make zero-emission vehicles commonplace and affordable.
- Establish near-zero-emission steel production as the "preferred choice in global markets."

At COP26 Nov. 2, US President Joe Biden said his administration was partnering with the World Economic Forum to launch a "first movers coalition" of companies to build demand for technologies to cut emissions from hard-to-abate sectors, with a focus on renewable hydrogen.

"The coalition represents eight major sectors that comprise 30% of the global emissions we now are dealing with: steel, shipping, aluminum, concrete, trucking, aviation, chemicals, and direct air capture," Biden said. — *James Burgess*

SUBSCRIBER NOTES

Platts proposes new daily carbon neutral hydrogen assessments

S&P Global Platts is proposing to launch its first suite of carbon-neutral hydrogen assessments, effective Dec. 9, 2021.

Building on its industry-leading price valuations for hydrogen, Platts would launch new carbon-neutral hydrogen price assessments that incorporate the cost of carbon capture, renewable energy certificates and where appropriate the cost of offsetting carbon emissions generated during production.

Carbon offset costs would be accounted for using Platts CNC nature-based carbon credits, as measured in $/mtCO2e in certain markets. Platts would complement these backstop calculated prices with available source data including bids, offers and reported trades as these become available. Other factors that will be considered include market information on power-purchase agreements and hydrogen offtake agreements. In the absence of spot market activity, Platts would consider carbon neutral hydrogen production costs as a baseline against which market prices would be assessed.

Platts would start publishing daily assessments in six locations, which have the potential to become hydrogen hubs as global markets emerge: California and US Gulf Coast in the Americas, the Netherlands and Saudi Arabia in Europe and the Middle East, and Japan and Australia in Asia-Pacific.

Assessments would be measured in $/kg, $/MMBtu, Eur/kg, Eur/MMBtu, Yen/kg, Yen/MMBtu, A$/kg, A$/MMBtu.

The prices would be published on Platts Dimensions Pro and under the Market Data Category: HY.

The following symbols would be created:

-Australia Carbon Neutral Hydrogen A$/kg
-Australia Carbon Neutral Hydrogen A$/kg MAvg
-Australia Carbon Neutral Hydrogen A$/MMBtu
-Australia Carbon Neutral Hydrogen A$/kg MAvg
-Australia Carbon Neutral Hydrogen $/kg
-Australia Carbon Neutral Hydrogen $/kg MAvg
-Australia Carbon Neutral Hydrogen $/MMBtu
-Australia Carbon Neutral Hydrogen $/MMBtu MAvg
-California Carbon Neutral Hydrogen $/kg
-California Carbon Neutral Hydrogen $/kg MAvg
-California Carbon Neutral Hydrogen $/MMBtu
-California Carbon Neutral Hydrogen $/MMBtu MAvg
-Far East Asia Carbon Neutral Hydrogen Yen/kg
-Far East Asia Carbon Neutral Hydrogen Yen/kg MAvg
-Far East Asia Carbon Neutral Hydrogen Yen/MMBtu
-Far East Asia Carbon Neutral Hydrogen Yen/MMBtu MAvg
-Far East Asia Carbon Neutral Hydrogen $/kg
-Far East Asia Carbon Neutral Hydrogen $/kg MAvg
-Far East Asia Carbon Neutral Hydrogen $/MMBtu
-Far East Asia Carbon Neutral Hydrogen $/MMBtu MAvg
-Middle East Carbon Neutral Hydrogen $/kg
-Middle East Carbon Neutral Hydrogen $/kg MAvg
-Middle East Carbon Neutral Hydrogen $/MMBtu
-Middle East Carbon Neutral Hydrogen $/MMBtu MAvg
-NW Europe Carbon Neutral Hydrogen Eur/kg
-NW Europe Carbon Neutral Hydrogen Eur/kg MAvg
-NW Europe Carbon Neutral Hydrogen Eur/MMBtu
-NW Europe Carbon Neutral Hydrogen Eur/MMBtu MAvg
-NW Europe Carbon Neutral Hydrogen $/kg
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-NW Europe Carbon Neutral Hydrogen $/MMBtu MAvg
-USGC Carbon Neutral Hydrogen $/kg
-USGC Carbon Neutral Hydrogen $/kg MAvg
-USGC Carbon Neutral Hydrogen $/MMBtu
-USGC Carbon Neutral Hydrogen $/MMBtu MAvg

Please send all questions and comments to hydrogenassessments@spglobal.com and pricegroup@spglobal.com by Nov. 11, 2021. For written comments, please provide a clear indication if comments are not intended for publication by Platts for public viewing. Platts will consider all comments received and will make comments not marked as confidential available upon request.

Platts launches Atlantic LNG physical eWindow

S&P Global Platts has launched the Platts Editorial Window, or eWindow, communication tool for its Atlantic LNG physical Market on Close (MOC) assessment process for its DES Northwest Europe (NWE), DES Mediterranean (MED) and FOB Gulf Coast Marker (GCM) price assessments on Sept. 24, 2021. Participants in the Platts MOC process are now able to submit bids, offers and expressions of interest to trade for publication directly through the eWindow communication tool or through an editor, who would then publish the information using the software.

The instruments that are launched for the Platts Atlantic LNG are from the third to the fifth half-month forward (H+3 to H+5) in dollars per MMBtu for the DES NWE and DES MED assessments, and 30-60 days forward for FOB GCM.

Market participants can state their specific bid or offer delivery windows — for example, 3-day or 5-day delivery or loading windows — within these instruments.

The instruments will allow for a variety of different delivery or loading locations to be used in bids and offers, such as: DES UK, DES Spain, etc.

For delivery locations that are not listed individually, market participants can select "DES in TQC" and input the details directly the DES basis of the bid or offer in the Terms, Quality & Comments (TQC) box.

The instruments will allow for a volume range to be expressed for bids and offers, up to 0.3 TBtu.

If the bid or offer is in a volume range, then the instrument called Platts Atlantic LNG (Qty Range) would be selected. The instruments will also allow for a variety of pricing basis.

Market participants can also input directly other terms related to their bids or offers in the TQC box.

The eWindow instruments will generate a different format for headlines of bids, offers and trades published on Platts LNG Alert and via other Platts services.

For example, a headline that currently appears as:

Atlantic LNG MOC: COMPANY Offers Oct TTF ICE Front Month Average +0.15 $/MMBTU DES Pricing 24-30 September. 2 Day Delivery Window: 11-12 October. Base Discharge Port: Buyer to advise during CN process. No later than 20 days prior to the 2 Day Arrival Period, Buyer can nominate substitute Discharge Port in Mugardos, Rotterdam, Dragon, Isle of Grain, South Hook, Montoir, Dunkirk, Zeebrugge, Bilbao, Huelva, Barcelona, Sagunto, FOS. GHV: 1000 to 1120 Btu/SCF. Contract Quantity 3.65 Tbtu +/-5%. Base ship: will be nominated upon completion of deal. No later than 15 days prior to the 1 Day Arrival Period, Seller may nominate an Alternate LNG Ship subject to SSCS and terminal acceptance. Base Load Port: Freeport. Seller's option to nominate an Alternative Load Port no later than 15 days prior to the 2 day Arrival Period. Laytime 36 hours., will be published as:

Platts Atlantic LNG DES NWE+MED H3-H5, COMPANY offers Oct11-Oct12 100% TTF Full Month Oct $0.15 for 3.65 Pricing 24-30 September. Base Discharge Port: buyer to provide at trade confirmation. No later than 20 days prior to the 2 Day Arrival Period, Buyer can nominate substitute Discharge Port in Mugardos, Rotterdam, Dragon, Isle of Grain, South Hook, Montoir, Dunkirk, Zeebrugge, Bilbao, Huelva, Barcelona, Sagunto, FOS. GHV: 1000 to 1120 Btu/SCF. Base ship: will be nominated upon completion of deal. No later than 15 days prior to the 1 Day Arrival Period, Seller may nominate an Alternate LNG Ship subject to SSCS and terminal acceptance. Base Load Port: Freeport. Seller's option to nominate an Alternative Load Port no later than 15 days prior to the 2 day Arrival Period. Laytime 36 hours.

TIMING: All bids and offers will still have to be submitted by 16.00.00.000 London time. Following any trade, market participants will have 60 seconds to rebid or re-offer. No price changes are allowed from 16:28:00:000 to the close of the MOC process at 16.30.00.999. A rebid or re-offer, following a trade, in last 120 seconds prior to the close of the MOC will trigger a 120-second extension from 16.30.01.000 to 16.32.00.999, in order to adequately test that rebid or re-offer.

INCREMENTABILITY: Bids and offers can be improved by a maximum of $0.05/MMBtu and a minimum of $0.01/MMBtu every 120 seconds. As per Platts editorial guidelines, buyers or sellers can withdraw bids/offers at any time when communicating through eWindow, provided no prior interest to transact has been expressed by any potential counterparty. All bids and offers are firm from the moment they are submitted into eWindow to the moment they are traded, the MOC process closes or the bid/offer is withdrawn from the system by the trader or a Platts editor. Market participants can still send bids and offers directly to an LNG editor for publication via eWindow. In markets where Platts eWindow is in operation, the eWindow clock will be used to determine the correct sequence of events when a bid or offer is amended, withdrawn, or traded by an interested counterparty. Bids or offers submitted by phone, or any other medium, such as instant messaging software, shall be measured at the time the bid, offer or trade indication is actually transmitted through the eWindow system via the editor.

Guidelines for the publication of bids and offers in the MOC process are published in the LNG Timing and Increment Guidelines available here: https://www.spglobal.com/platts/en/our-methodology/methodology-specifications/lng/lng-timing-and-increment-guidelines.

Full information relevant to these assessments can be found in the Global LNG specifications guide available here: https://www.spglobal.com/platts/en/our-methodology/methodology-specifications/lng/liquefied-natural-gas-lng-assessments-and-netbacks-methodology.

Platts expects credit relationships that prevail inside its assessment environment to fully reflect relationships in the markets as a whole. eWindow provides direct entry and management of credit filters which should mirror those normally applied in the marketplaces.

Where Platts editors publish bids and offers on behalf of a company that submits data to an editor, counterparty credit settings are set to "open" for regular participants in the assessment process unless companies have notified Platts in advance of any restrictions.

If a counterparty submitting information through an editor has not already notified Platts of any counterparty credit restrictions, they should notify Platts at least one hour prior to the start of the MOC process if any counterparty credit filters need to be modified.

Please send all feedback, comments and questions to lngeditorialteam@spglobal.com and pricegroup@spglobal.com.

For written comments, please provide a clear indication if comments are not intended for publication by Platts for public viewing.

Platts will consider all comments received and will make comments not marked as confidential available upon request.

Deepavali publishing schedule for S&P Global Platts Asia LNG

The S&P Global Platts Singapore office will be closed on Thursday, Nov. 4 for the Deepavali holiday, and there will be no daily LNG assessments published from Singapore on that day.

Additionally, Platts in Asia will close its Market on Close assessment process early on Wednesday, Nov. 3, and all assessments will be on basis 12:30 pm Singapore time (0430 GMT).

Normal Singapore publishing schedule will resume on Friday, Nov. 5.

For full details of Platts' publishing schedule and services affected, refer to http://www.platts.com/HolidayHome. For queries, please contact support@spglobal.com.

Vercer Capital Markets Trading Limited changes entity name to Dare Global Limited

Vercer Capital Markets Trading Limited has advised Platts that it would like to change its participating entity name in the Platts Market on Close assessment processes for:

Americas Fuel Oil - Paper
Asia Naphtha-Paper
Asia Mogas-Paper
Asia Jet Fuel-Paper
Asia Gasoil-Paper

Asia Fuel Oil-Paper
Asia APAC LNG - Paper
EMEA Naphtha-Paper
EMEA Mogas-Paper
EMEA Jet Fuel-Paper
EMEA Gasoil/Diesel- Paper
EMEA Fuel Oil - Paper
EMEA Crude BFOE CFDs- Paper
This follows the Vercer Capital Markets Trading Limited name change to Dare Global Limited.

Platts has reviewed Dare Global Limited and will consider information from Dare Global Limited in the Americas, Asia and EMEA assessment processes for the abovementioned markets, subject at all times to adherence with Platts editorial standards.
Platts will publish all relevant information from Dare Global Limited accordingly.
Platts welcomes all relevant feedback regarding MOC participation. Platts considers bids, offers and transactions by all credible and creditworthy parties in its assessment processes. For comments and feedback, please contact: Platts editors at oilgroup@spglobal.com and PriceGroup@spglobal.com.

HYDROGEN & CARBON

NORTH AMERICA HYDROGEN ASSESSMENTS, NOVEMBER 2*

	Excluding Capex		Including Capex	
Production Pathway	**$/kg**	**Change**	**$/kg**	**Change**
Alberta (C$/kg)				
SMR w/o CCS	0.8900	-0.0112	1.6090	-0.0092
Alkaline Electrolysis	3.8965	-2.0698	5.0839	-2.0664
PEM Electrolysis	4.5011	-2.3910	6.6285	-2.3849
Appalachia				
SMR w/o CCS	0.8050	+0.0400	1.4004	+0.0401
Alkaline Electrolysis	3.5109	+0.2318	4.3903	+0.2318
PEM Electrolysis	4.0557	+0.2678	5.6313	+0.2678
Gulf Coast				
SMR w/o CCS	0.8244	+0.0420	1.3284	+0.0420
Alkaline Electrolysis	2.6179	+0.0090	3.4503	+0.0090
PEM Electrolysis	3.0241	+0.0104	4.5154	+0.0104
Midcontinent				
SMR w/o CCS	0.8107	+0.0479	1.3420	+0.0479
Alkaline Electrolysis	3.1887	-0.1262	4.0426	-0.1262
PEM Electrolysis	3.6835	-0.1458	5.2133	-0.1458
Northeast				
SMR w/o CCS	0.8499	+0.0636	1.4845	+0.0635
Alkaline Electrolysis	2.8835	+0.2883	3.7881	+0.2883
PEM Electrolysis	3.3309	+0.3330	4.9517	+0.3331
Northern California				
SMR w/o CCS	1.0556	-0.0063	1.7859	-0.0063
Alkaline Electrolysis	3.3403	-0.2239	4.3266	-0.2238
PEM Electrolysis	3.8586	-0.2586	5.6256	-0.2586
Northwest				
SMR w/o CCS	0.8110	-0.0575	1.3936	-0.0575
Alkaline Electrolysis	2.7259	-0.2819	3.6221	-0.2819
PEM Electrolysis	3.1489	-0.3256	4.7545	-0.3256
Rockies				
SMR w/o CCS	0.8217	+0.0307	1.3798	+0.0306
Alkaline Electrolysis	3.1675	-0.0332	4.0341	-0.0331
PEM Electrolysis	3.6590	-0.0383	5.2116	-0.0383
Southeast				
SMR w/o CCS	0.8642	+0.0565	1.3839	+0.0566
Alkaline Electrolysis	2.7032	+0.1036	3.5579	+0.1037
PEM Electrolysis	3.1226	+0.1197	4.6539	+0.1197
Southern California				
SMR w/o CCS	0.9257	-0.0942	1.6265	-0.0942
Alkaline Electrolysis	3.2382	-0.2528	4.2041	-0.2528
PEM Electrolysis	3.7406	-0.2921	5.4712	-0.2921
Upper Midwest				
SMR w/o CCS	0.8419	+0.0364	1.4103	+0.0364
Alkaline Electrolysis	3.5592	+0.3068	4.4655	+0.3067
PEM Electrolysis	4.1114	+0.3544	5.7353	+0.3544

*Assessed previous day

JAPAN HYDROGEN ASSESSMENTS, NOVEMBER 3

	Excluding Capex		Including Capex	
Production Pathway	**Yen/kg**	**Change**	**Yen/kg**	**Change**
SMR w/o CCS	500.2211	+30.3966	586.2695	+30.5327
Alkaline Electrolysis	695.4864	-274.5994	837.5869	-274.3747
PEM Electrolysis	803.4015	-317.2096	1058.0035	-316.8069

ASSESSMENT RATIONALE

The S&P Global Platts hydrogen prices are daily valuations that incorporate the cost of variable natural gas, electricity, and carbon inputs, where applicable. A second set of valuations include fixed assumptions for capital and operating expenses. The Platts hydrogen prices are not based on observed or reported market transactions. Details on the Platts hydrogen methodology can be found at: https://www.spglobal.com/platts/en/our-methodology/methodology-specifications/energy-transition/hydrogen-methodology.

VOLUNTARY CARBON CREDITS, NOVEMBER 3

	$/mtCO2e	Change	Eur/mtCO2e	Change
Platts CEC	7.450	+0.300	6.430	+0.268

Note: The Platts CEC assessment reflects the value of CORSIA-eligible credits in the voluntary carbon market, and is not a component of Platts hydrogen assessments.

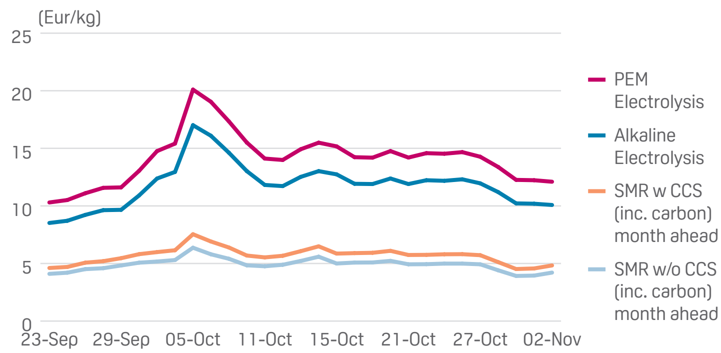
UK HYDROGEN ASSESSMENTS, NOVEMBER 3

Production Pathway	GBP/kg	Change	GBP/KWh	Change
ATR w CCS	4.1630	+0.4152	0.1249	+0.0125
ATR w CCS (inc. Capex & Carbon)	4.4822	+0.4153	0.1345	+0.0125
Alkaline Electrolysis	10.6382	+0.5696	0.3192	+0.0171
Alkaline Electrolysis (inc. Capex)	11.2473	+0.5671	0.3375	+0.0171
PEM Electrolysis	12.2863	+0.6580	0.3686	+0.0197
PEM Electrolysis (inc. Capex)	13.3775	+0.6535	0.4014	+0.0196

NETHERLANDS HYDROGEN ASSESSMENTS, NOVEMBER 3

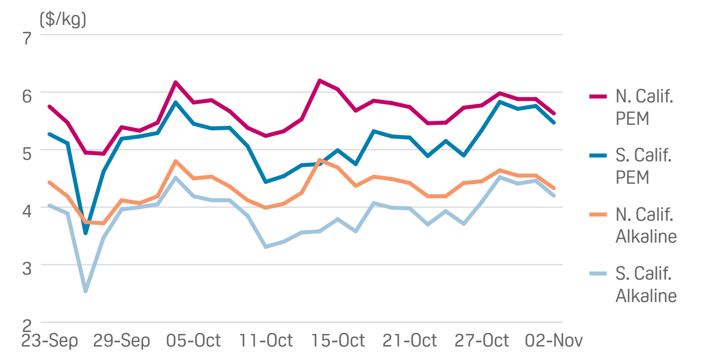
Production Pathway	Eur/kg	Change	Eur/KWh	Change
SMR w/o CCS	3.6528	+0.4106	0.1096	+0.0123
SMR w/o CCS (inc. Capex)	4.0880	+0.4106	0.1227	+0.0124
SMR w/o CCS (inc. Carbon)	4.1865	+0.4150	0.1256	+0.0124
SMR w/o CCS (inc. Capex & Carbon)	4.6216	+0.4148	0.1387	+0.0125
SMR w CCS	4.5614	+0.4912	0.1369	+0.0148
SMR w CCS (inc. Capex)	5.2661	+0.4911	0.1580	+0.0147
SMR w CCS (inc. Carbon)	4.6148	+0.4916	0.1385	+0.0148
SMR w CCS (inc. Capex & Carbon)	5.3194	+0.4915	0.1596	+0.0147
Alkaline Electrolysis	10.0904	+0.7253	0.3027	+0.0217
Alkaline Electrolysis (inc. Capex)	10.8090	+0.7251	0.3243	+0.0218
PEM Electrolysis	11.6533	+0.8378	0.3496	+0.0251
PEM Electrolysis (inc. Capex)	12.9409	+0.8376	0.3883	+0.0252

NETHERLANDS HYDROGEN (INCLUDING CAPEX)



Source: S&P Global Platts

CALIFORNIA ELECTROLYSIS (INCLUDING CAPEX)



Source: S&P Global Platts