Magazine of EU-China Energy Cooperation Platform

EU-China Energy Magazine

2022 October Issue

About ECECP

EU-China Energy Cooperation Platform was launched on 15 May 2019, to support the implementation of activities announced in the 'Joint Statement on the Implementation of EU-China Energy Cooperation'.

The Joint Statement was signed during the 8th EU-China Energy Dialogue that was held in Brussels on 9th April between Commissioner for Climate Action and Energy Miguel Arias Cañete and the Administrator of the National Energy Administration of China Mr ZHANG Jianhua, back-to-back with the 21st EU-China Leaders' Summit on 9 April 2019 and was witnessed by Jean-Claude Juncker, President of the European Commission; Donald Tusk, President of the Council of Europe and Dr Li Keqiang, Premier of China.

The start of the implementation of the EU-China Energy Cooperation Platform (ECECP) was included in the EU-China Leaders Summit Joint Communique.

> The overall objective of ECECP is to
>
> *'enhance EU-China cooperation on energy. In line with the EU's Energy Union, the Clean Energy for All European initiative, the Paris Agreement on Climate Change and the EU's Global Strategy, this enhanced cooperation will help increase mutual trust and understanding between EU and China and contribute to a global transition towards clean energy on the basis of a common vision of a sustainable, reliable and secure energy system.'*

Phase II of ECECP is implemented by a consortium led by ICF, and National Development and Reform Commission - Energy Research Institute.

EU-China Energy Magazine

2022

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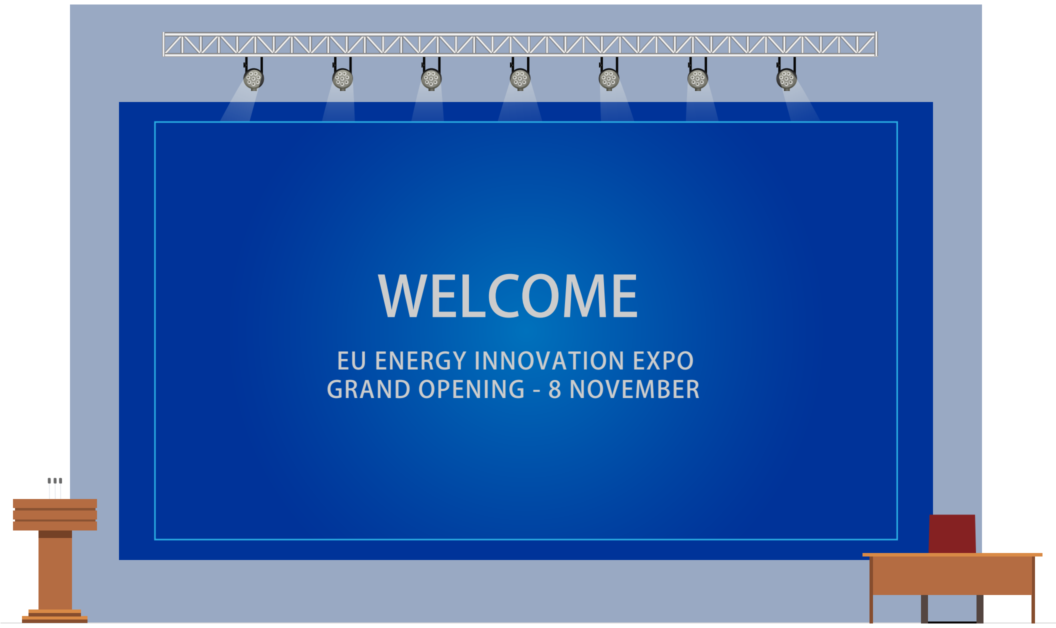

WELCOME
EU ENERGY INNOVATION EXPO
GRAND OPENING - 8 NOVEMBER

Dear All,

Welcome to the October 2022 issue of the EU-China Energy Magazine.

As energy prices continue to rise, there can be no doubt that we are facing a global energy crisis – but as an old Chinese saying goes, there is always opportunity in a crisis. We are now seeing the shift in energy consumption behaviour that we have been trying to achieve for years. The media is full of articles teaching people how to reduce energy consumption - and energy bills: set indoor temperature a few degrees lower; use electric blankets at night; use microwave and air fryers instead of large family ovens; use insulated cooking pots for slow cooking; switch off standby electronic appliances – the list goes on.

The energy crisis was at the forefront of our workshop 'The Future of Gas', in which experts discussed supply issues and decarbonisation options for the sector. The summary and videos of the workshop are available on our website, and an article on the topic appears in this issue.

Our activities will continue through November: on the 8th at 09:00 Beijing time, the ECECP-organised EU Energy Innovation Expo will open. This event will showcase EU companies who wish to introduce their innovative technologies in renewables, energy efficiency, energy storage, power grids and buildings to the Chinese market. Live online events and interviews will be streamed from Europe throughout the three-day event at www.euenergyinnovationexpo.com.

November will also bring the launch of the digest of the Handbook on Electricity Markets. This handbook, published in November 2021, was edited by Jean-Michel Glachant, Director of the Florence School of Regulation, Paul L. Joskow, Massachusetts Institute of Technology, and Michael G. Pollitt, University of Cambridge. It includes contributions from the most brilliant thinkers and experts in the field of electricity markets. ECECP has commissioned Glachant along with Nicolò Rossetto of the Florence School of Regulation to consult with its numerous expert contributors to condense the handbook's contents so that its key points are available to decision-makers.

As always, I would like to thank our hard-working editors, Daisy Chi and Helen Farrell. I'd also like to wish a speedy recovery to Helena Uhde, Assistant Team Leader of ECECP, who is unwell with Covid.

I hope you enjoy reading this issue.

Flora Kan
ECECP Team Leader

The future of gas – Unlocking opportunities in times of crisis

The decarbonisation of the gas sector through CCUS, functioning markets and the growth of renewable gases is a global challenge. Russia's invasion of Ukraine and the resulting supply problems add another challenge for global gas markets. These developments were discussed at the workshop 'The Future of Gas' organised by ECECP in cooperation with Energy Post in September. ECECP Junior Postgraduate Fellow Helena Uhde summarises the key lessons of the workshop.

European gas market under pressure

Russia's invasion of Ukraine has led to a complete restructuring of gas markets, which is particularly evident in Europe. 'We have enjoyed a very well-developed energy market at least in the last 15 years, but we have not tested the system in short supply situations', explains Andrea Stegher, Vice President of the International Gas Union.

According to Walter Boltz, senior advisor on European Energy at Walter Boltz Consulting, this crisis was already foreseeable in the summer of 2021, as Gazprom had already started to empty the stocks in the European storage facilities before Russia's invasion of Ukraine, and Russia has basically reduced supplies to EU since the summer of 2021, thus driving up prices.

This, in combination with the gradual decline in Russian imports since February 2022, has resulted in a massive disruption of the European gas market. Of the 40% of EU gas imports from Russia before the crisis, only 8% remained in August 2022.

Fluctuating gas prices, which reflect the geopolitical situation and perceived changes in the future, have a serious impact on the electricity market, with high volatility expected to continue over the next two years. According to Boltz, gas scarcity led to a price spike with prices at an unprecedented level of €240 / MWh, while before the crisis the highest price was €25 - €30 /MWh.

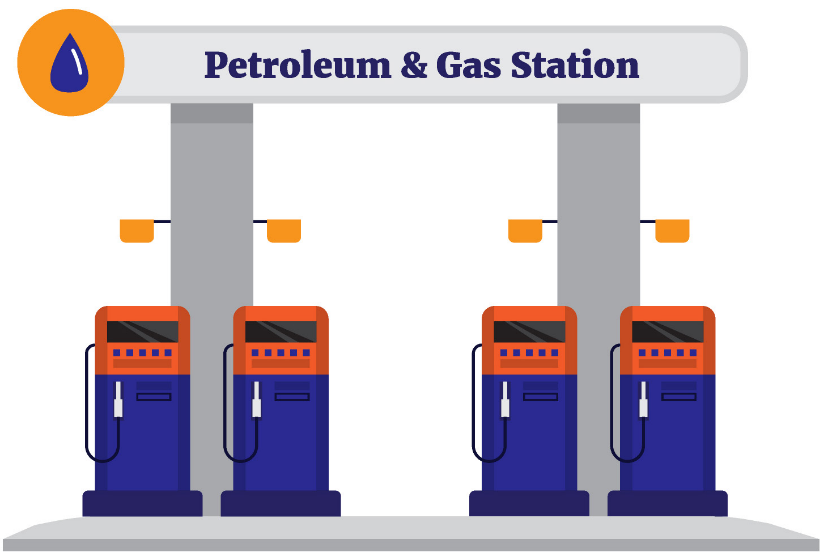
The high volatility of gas prices, and the price differences between the gas markets of Europe, Asia and North America, make it difficult for businesses and policy makers to navigate, creating the risk not only of an economic downturn but also of the disruption of social equilibrium. In addition, energy uncertainty is pushing climate targets into the background, while coal maintains its prevalence because of its price and relative abundance.

Europe's interventions

Octavian Stamate, Counsellor for Energy and Climate Action at the EU Delegation to China, summarised the EU's solutions to the significant supply disruptions: diversification of supply towards more reliable suppliers, acceleration of energy savings, and massive investment in renewable energy. This will partially be achieved through the European Commission's proposal REPowerEU, which aims to reduce demand for Russian gas by two thirds before the end of 2022 by reducing gas demand, diversifying supplies and building out gas storage.

To reduce demand, the European Commission proposed the European Gas Demand Reduction Plan, which was adopted by the EU Energy Ministers Council on 26 July 2022. Member states agreed to reduce their gas demand by 15% between 1 August 2022 and 31 March 2023 compared to their average consumption over the last five years through measures of their choice. To diversify supply, a trilateral memorandum was signed between the EU, Egypt, and Israel to agree on future gas supplies; joint purchase of gas for all member states. To support storage replenishment, EU rules require gas storage to be 80% full by November 2022. This target will be raised to 90% in the coming years.

In addition, Stamate emphasised the importance of cooperation and solidarity between the EU member states: 'We are much stronger when we use the power of the single market and show solidarity. It is a very important step to put our collective weight behind it and to buy gas together as Europeans and not as 27 different members.'



Current situation in China

China's standing under the new geopolitical landscape is very different to that of Europe. Gas is expected to play a key role in the decarbonisation of China's energy mix, but the current situation is driven more by domestic politics than by Russia's invasion of Ukraine. According to Matteo Tanteri, chairman and CEO at SNAM China, China's gas market is mainly influenced by the 14th Five-Year Plan, which emphasises the role of liquefied natural gas (LNG).

The Overall 14th 5Y Plan

Specific targets were set for 5 areas, covering 14 items

Area	Items	Current	Target 2025	Variation
Energy Security	Annual comprehensive production capacity of energy (bln Mtce)	>4.08*	>4.60	12.7%
	Annual Crude Oil Production (mln tons)	199	200	0.5%
	Annual Natural Gas Production (bcm)	>207.6	>230	>10.8%
	Total Installed Capacity of Power Generation (billion kW)	2.38	3	26.2%
Energy Transition	CO2 emissions/GDP (Carbon Intensity)	-18.8% from 2015-2020	-18% in 5 Years	-
	% of Non-fossil Energy Consumption	15.90%*	Ca. 20%	25.8%
	% of Non-fossil Energy Power Generation	32.59%	Ca. 39%	19.7%
	% of Electric Energy at End-use Consumption	-	Ca. 30%	-
Energy Efficiency	Energy Consumption/GDP	9.20% during 13° 5Y Plan	-13.5% in 5 Years	-13.5%
	% of Flexible Power (i.e., storage stations)	-	24%	-
	Demand-side responsiveness (% of max electrical load)	-	3%-5%	-
Innovation Capabilities	Investment in Energy R&D	-	7%+	-
	New Key Technological Breakthrough Areas	-	Ca. 50	-
General	Annual Living Electricity Consumption per Capita (kWh)	775.62*	1000	28.9%

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*2020 Data instead of 2021

Internal Sources: H2 14° 5Y Plan

The 14th Five-Year Plan targets an 18% reduction in CO_2 intensity (CO_2 emissions per unit of GDP) and a 13.5% reduction in energy intensity (energy consumption per unit of GDP) for the period from 2021 to 2025, compared to the level of 2020[1]. The importance of natural gas as a transition energy from coal was also confirmed in 2021 by the 'Central Document No.1', which was jointly issued by the Central Committee of the Communist Party of China and the State Council.

In addition to decarbonisation, security of supply also plays a central role in China. However, China's approach, in contrast to Europe, has historically focused on diversifying supply and maximising the use of domestic resources. Since 2015, China's imports have increased by about 60% (now about 100 bcm) and come from a diversified range of suppliers. Following previous supply shortages, China signed long-term contracts with major LNG suppliers such as the US and Qatar years ago. Compared to Europe, China meets a larger share of its gas demand with domestic gas production, which has increased by 30% since 2015.

The major challenge for China's gas supply targets is the inadequacy of infrastructure and storage capacities. According to Tanteri, there are ambitious expansion targets to solve this issue, and in 2020, PipeChina was established to be a key player in the transition from coal to gas.

However, while gas is supported as an energy transition driver, growth in gas consumption is currently slowing and is forecast to increase only slightly compared to last year. LNG imports are expected to decline due to sluggish domestic gas consumption and high LNG prices. According to Jinsok Sung, an expert on the Asian Gas and LNG market and research professor at Hankuk University of Foreign Studies, the reasons for sluggish domestic gas consumption include COVID restrictions, an unstable and volatile gas market, and disruptions to gas supply.

1. *For more information on the 14th FYP role on decarbonisation, see this Carbon Brief article: https://www.carbonbrief.org/qa-what-does-chinas-14th-five-year-plan-mean-for-climate-change/*

Cooperation and a wide range of instruments

The supply uncertainty and climate pressures currently facing the EU are global challenges that can only be solved through cooperation. The role of China in the new geopolitical situation is the subject of much debate in Europe.

China's figures show a 30% increase of LNG intake from Russia over the past six months. At the same time, China has started to export LNG to Europe, supplying with around 7% of the EU's gas demand. However, Tanteri remarked that the media reports on China's resale of Russian gas to Europe are only speculation. In the first half of 2022, China bought just 7.6 bcm of Russian gas, with a 2022 target of 15 bcm. This is a small fraction of what Russia would have supplied to Europe under previous market conditions.

The increase in gas import volumes from Russia to China was planned years ago, while supplies through the transmission Siberia pipeline were ramped up because a second pipeline had not yet been completed. How the situation will develop in the future remains to be seen.

In addition to security of supply, it is important not to lose sight of decarbonisation targets. However, Stegher emphasised the importance of looking for practicable solutions and considering a mixture of tools: 'The net zero targets are important but also very challenging and we need a wide range of instruments. We are discussing the revival of nuclear energy, we are facing a shift away from coal and gas, and renewable gases have to be part of the scenery'.

Renewable gases

In the long term, Europe could build on renewable gases to overcome supply issues. Dr. Jan Stambasky, vice president at R2Gas, indicated that the technical capacities of biomethane, green hydrogen and blue hydrogen could meet the EU's gas consumption needs by 2040/50 and surpass the capacity of the current three major pipelines, Nord Stream, Yamal and Brotherhood. Domestically produced renewable gases can therefore provide security of supply as well as achieving decarbonisation targets and boosting the economy.

Hydrogen might also play a decisive role on the road to carbon and climate neutrality, particularly in the hard-to-abate sectors – for example, the chemical industry. Nicola Rega, energy director at the European Chemical Industry Council, explained how the chemical industry accounts for around 10% of European natural gas consumption: 56% is used for energy purposes and the

Photo by Mykola Makhlai on Unsplash

remaining 44% as feedstock and for ammonia production. In addition, the chemical industry is now the largest producer and consumer of hydrogen. Hydrogen is part of the production process and is mainly produced as a by-product. Under Fit for 55, the Council of the EU has stipulated that by 2030, 35% of hydrogen used in industry must come from renewable fuels of non-biological origin, and this figure must rise to 50% by 2035[2].

However, transport barriers and the lack of standardised certification of hydrogen and other renewable gases pose a major challenge. In certain cases, the transport of the final product is easier to facilitate than the transport of gas. For this reason, Joachim von Scheele, Global Director of Commercialisation at Linde, suggested that the places where renewable energy is readily available will also be the places where various products are produced in the future. This could be the case for ammonia, methanol, fertiliser and other renewable gases. Rega suggested that hydrogen, biomethane and other synthetic gases should be discussed together, as there were parallels in the areas of use and transport.

Carbon capture, use and storage (CCUS)

CCUS has huge potential for carbon footprint control and removal, especially in hard-to-abate sectors such as steel, chemicals, fertilisers and manufacturing. According to François Issard, international energy consultant and China expert, individual CCUS plants can sequester 1-2 Mt/yr of CO_2. If scaled up, capacities of 5-10 Mt/yr of CO_2 could be reached.

Over the last 20 years, CCUS technology has been developed mainly in the form of demonstration projects, such as

2. *Council of the EU (2022). 'Fit for 55': Council agrees on higher targets for renewables and energy efficiency.* https://presidence-francaise.consilium.europa.eu/en/news/fit-for-55-council-agrees-on-higher-targets-for-renewables-and-energy-efficiency/

the Pycasso project in southwest France (see below). According to the experts, CCUS is a proven technology, but its widespread application is still pending.

According to Simon Goess, founder of Carboneer, CCUS has not yet taken off because it is more expensive to implement the technology than paying the carbon price. Goess presented an overview of instruments to incentivise CCUS, such as financial support, carbon pricing and regulation. In the Emissions Trading Scheme, carbon markets already provide price signals to industries, with CO_2 prices of around €80/tonne. In China, however, the carbon price is not yet high enough to justify the cost efficiency of the CCUS value chain. The panel further pointed out that CCUS projects take time to implement, it is important that incentive schemes are politically stable and provide long-term price signals.

Kevin Tu, senior advisor at Agora Energiewende, pointed out that while China already stores several million tons of CO_2, the country also emits about one-third of total global emissions, meaning that the scale is still small. Since western countries have expressed interest in CCUS, but have not acted on

Pycasso project (France):

The Pycasso project (Pyrenean Carbon Abolition through Sustainable Sequestration Operations) explores how underground storage facilities in the south-west of France, which have supplied gas to France for 60 years, and the industrial area that has emerged around these gas facilities, can provide a solution for decarbonising industrial activities in the south-west of France and the north of Spain and creating employment for the region.

The project states that a carbon price close to 100€/T would make CCUS economically viable.

More information on the project: https://www.pycasso-project.eu/en/home/

Instruments to incentivize CCUS

- Numerous options to support scale-up
- Complex interaction of instruments with existing market mechanisms

Instrument	Mechanism	Examples
Financial support	Grants and loans	US, EU (Innovation Fund), UK, Norway
	Tax breaks	US (45Q)
	Contracts for Difference	NL
CO2-pricing	CO2 tax	Many countries
	Emission trading system	EU (EU ETS), China, California
	Carbon border adjustment mechanism	EU (in preparation)
Regulation	Emission standards	Canada
	Legal requirements	Australia
	Regulated infrastructure	UK
Other options	Public procurement / auctions	EU, US, Sweden
	Reduction of financing risks (loan collateralization, risk sharing)	Australia

Simon Göß
The Future of Gas – CCUS for the gas sector, 21.09.2022 3
carboneer

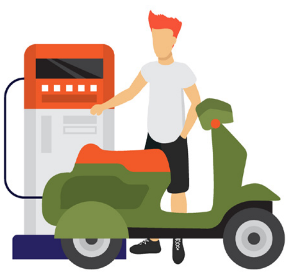
it, the interest in China remains rather subtle. However, President Xi Jinping's announcement of the 2030/2060 dual carbon target gave new impetus to decarbonisation efforts. According to Tu, the potential for CCUS in China is huge, particularly in the coal chemical sector, while blue hydrogen has greater potential in Europe.

Outlook

Despite the difficult situation in the energy markets, both Europe and China seem to be sticking to their decarbonisation goals, with the potential for cooperation between the regions remaining high. The joint development of LNG decarbonisation technologies and the labelling of hydrogen and renewable gases are prime opportunities for cooperation. 'We are appalled by the invasion of Russia to Ukraine, but in terms of energy we have a longer-term issue to be dealt with. We have to continue promoting investments both in natural gas plus CCUS, as well as the renewable gases growth', emphasised Stegher the need for decarbonisation.

By **Helena Uhde**

ECECP Junior Postgraduate Fellow



A price cap on EU gas markets?

In the course of the last year and even more since the unprovoked and unlawful invasion of Ukraine by the Russian army, EU wholesale gas markets faced continuous instability, leading to extremely high price volatility and to gas prices spiking to unprecedented levels. The price of the month-ahead product traded at the main reference EU gas hub, TTF (Title Transfer Facility), touched 350 euros/MWh last summer, a shockingly high level considering that, in the 5-year to Spring 2021, TTF prices had hardly reached 30 euros/MWh (see Figure 1).

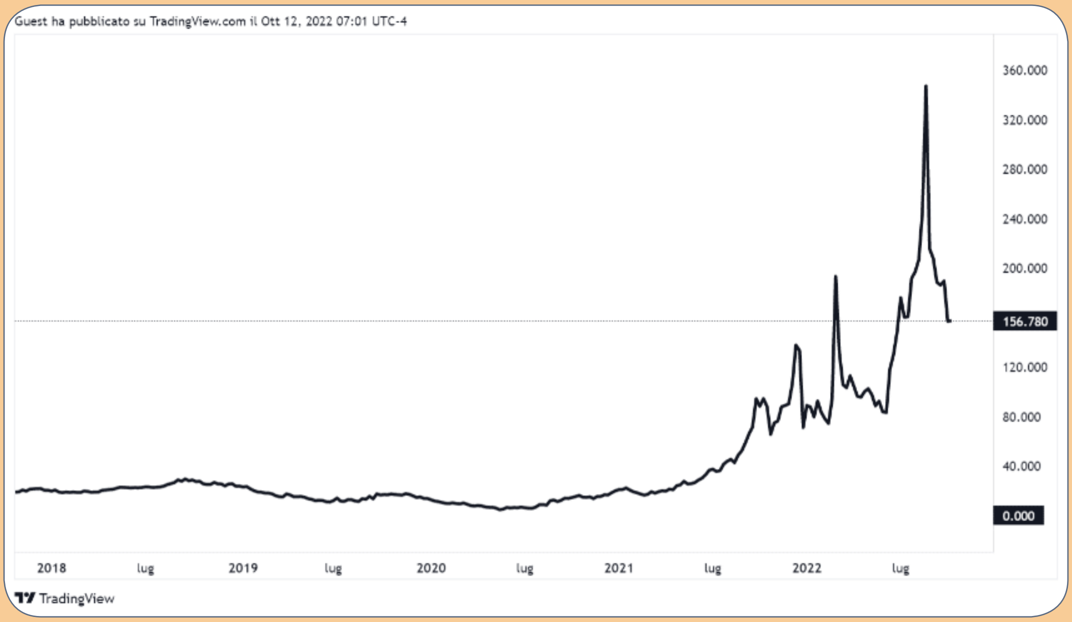
Skyrocketing gas prices, which also resulted in higher electricity prices, as gas is the marginal energy source for electricity generation in most markets in Europe, attracted political attention and the debate focused on the need to protect consumers, especially energy-intensive sectors and vulnerable and energy-poor customers.

Beyond the several measures adopted at the Member State level to cushion the impact of high energy prices on consumers[1], one of the most debated options in the recent energy debate has no doubt been the idea of imposing a cap on European gas prices. We contributed with several publications and other initiatives to the debate, particularly on regulatory interventions and potential reforms of the electricity and gas markets.

Already in May this year, the European Council invited the Commission to 'explore also with our international partners ways to curb rising energy prices, including the feasibility of introducing temporary import price caps for gas when appropriate'[2]. The debate did not evolve significantly over the summer, until a recent letter[3] signed by energy ministers from 15 Member States called on the European Commission to introduce, as a priority, a price cap 'applied to all wholesale natural gas transactions'.

The Florence School of Regulation has supported the EU institutions in their work to assess which measures could be adopted to mitigate the ongoing energy crisis.

Figure. 1: TTF calendar month-ahead 2018-2022



1. *Listed already as early as in October 2021 in the Commission's Tackling energy prices: a Toolbox for action and support. Available here.*
2. *Conclusions of the special meeting of the European Council of 30 and 31 May 2022, point 27)(a), second bullet point, on page 8.*
3. *The letter of the Ministers of Energy to EU Energy Commissioner Kadri Simson can be found here.*

We contributed with several publications and other initiatives to the debate, particularly on regulatory interventions and potential reforms of the electricity and gas markets.

Specifically, on gas price caps, we recently published two Policy Briefs – Capping the European price of gas and Securing gas for Europe – in which, leaving aside the political debate on whether or not an EU gas price cap should be introduced, we analyse how a price cap in EU gas wholesale markets, if agreed at the political level, could be designed.

Capping: handle with care

The gas market has become a global market, particularly due to the increasingly important role played by Liquefied Natural Gas (LNG) in the last 10 years, and presumably even more for Europe in the upcoming years. Indeed, internal dynamics in a regional market of significant dimensions (i.e. Europe) inevitably have direct consequences on a global scale and are likely to impact other markets.

At a general level, if gas prices in Europe were capped, the first challenge would be to ensure that LNG cargoes heading to Europe would not be re-directed to other global markets (typically Asia) where gas prices are higher. So, while spot prices in Europe are indexed to the prices of European gas hubs, when introducing a price cap on EU gas markets, one should not disregard the global dimension of LNG.

On the other hand, albeit Russian supply is progressively being phased out, a significant amount of gas still is and will be delivered via pipelines to Europe. The so-called 'pipeline gas' and 'LNG', although identical in physical terms, are characterised by different market fundamentals and therefore, particularly in the case of Europe, they can, if needed, be addressed separately from a regulatory point of view. In particular, there are limited opportunities for external exporters of pipeline gas to the EU to redirect that gas to other destinations or liquefy it and sell it as LNG on the global market.

FSR's proposal

Based on these assumptions, in our Policy Briefs, we outline a two-part mechanism, addressing the two European gas market segments – pipeline gas and LNG – separately.

For the first segment (pipeline gas), we propose the following:

- regulatory intervention on the price of gas in organised market places, by using their technical functionalities, such as the Interval Price Limits of the Intercontinental Exchange[4]; and/or
- to mandate TSOs to provide gas balancing services at a predefined price or price range, which would act as a driver for price convergence of the gas traded in the EU.

In fact, these two measures might be adopted alongside each other, to increase the effectiveness of the proposed mechanism.

For the second segment (LNG), we propose the introduction of auctions for procuring, on the global LNG market, any volume of gas needed by the TSO to balance the system. These auctions could be run by the TSOs themselves or, more appropriately, by a Single Buyer entity along the lines of the proposed Joint Purchasing Platform[5] included in the Commission's REPowerEU plan. Such an entity could organise auctions in which external LNG suppliers bid a price premium

4. *The IPL functionality, and similar devices used in other trading platforms, acts as a temporary circuit breaker on these platforms, to diminish the likelihood and extent of short-term price spikes or aberrant market moves. While it is designed to be in force throughout each trading day, the protection that these functionalities provide are likely to be triggered only in the case of extreme price moves over very short periods of time. The proposed mechanism would give a more continuous role to these functionalities.*
5. *However, while the Joint Purchasing Mechanism is generally considered voluntary, the Single Buyer entity would be most effective if it were mandatory for the procurement of the balancing gas required by the TSOs.*

above the prevailing price of EU pipeline gas, to supply LNG to the EU. The Single Buyer entity would buy this gas at the prices, including the premia, resulting from the auctions and sell it to the TSOs, according to their needs, at the predefined price or within the predefined price range. The price premia paid by the Single Buyer entity would have to be recovered through regulation[6].

In practice, under our proposal, shippers and traders would likely need to re-focus their trading strategies, having as a reference the capped gas price (or range) at which they would be able to buy or sell any quantity of gas. If the proposed mechanism were introduced as part of a credible commitment of European institutions to tackle the current energy crisis and the resulting skyrocketing energy prices, the gas volumes to be provided by the TSOs through the balancing mechanism could remain quite limited.

However, this is a best-case scenario, and it might well be possible that capping the price of pipeline gas in the EU might lead external suppliers of pipeline gas somewhat to reduce the flows to Europe. This is where the international outreach and energy diplomacy advocated by the Commission[7] could play a role, by explaining the sense of the mechanism and the opportunities it still offers to external pipeline exporters to the EU.

Finally, since many long-term contracts for gas supply to Europe are indexed to the spot price in EU markets, if the measures outlined above were successful in curbing the price of gas in the spot market, they would also have beneficial effects on the price of gas imported through long-term contracts.

Conclusions

As indicated in our Policy Briefs, we are generally not in favour of price caps, but we are currently experiencing a war situation, which might require specific regulation or market interventions.

We very much agree with the 15 Member States that a potential gas cap 'can be designed in such a way as to ensure the security of supply and the free flow of gas within Europe, while achieving our shared objective to reduce gas demand'. However, none of the possible measures currently being discussed at the EU level is without drawbacks, and all involve a degree of risk. The challenge is to find the measure which minimises these drawbacks and risks.

The strategy outlined in our Policy Briefs is based on the different characteristics of the two market segments from which the gas to meet EU demand is sourced – the pipeline gas and LNG – and on certain assumptions on the structure of the market and on the behaviour of gas shippers and other market participants. There are clearly many design elements which would need further to be detailed and verified, as well as challenges which would need to be addressed – and in our two Policy Briefs we attempt to clarify at least some of them.

Only if the strategy is credible – the kind of credibility that the President of the European Central Bank (ECB), Mario Draghi, was able to give to the ECB's commitment to defend the euro with his 'whatever it takes' speech[8] in London on 26 July 2012, it will be able to deliver a reduction in the overall cost of gas consumed in the EU. The question is: does the EU currently have the ability to express the same resolve?

By **Ilaria Conti**

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6. *A detailed description of how the premium could be recovered via regulation is included in our second PB.*
7. *For example, in May the Commission set up an EU Energy Platform Task Force to secure alternative supplies.*
8. *'Within our mandate, the ECB is ready to do whatever it takes to preserve the euro. And, believe me, it will be enough'.*

Europe's decoupling of electricity and gas prices:
The crisis is temporary, so why do it?

The debate is intensifying over how to decouple power prices from the extraordinarily high natural gas prices in Europe. Simona Benedettini and Carlo Stagnaro warn that the current problem of high prices is not caused by the mis-functioning of electricity markets, but by the exceptional trend in gas prices. So should the markets be re-designed at all? Will we lose the benefits of the current design, one being the reliable profits that renewables can make that incentivise further investment. The authors look at the proposals from the EC, Greece, Spain and Portugal, and Italy. They go into detail on the pros and cons, the price caps, market-splitting, the subsidy mechanisms and more. Any re-shaping of the market involves risks. It may also unintentionally increase the differences among member states and their relative competitive advantages and disadvantages. So it should be done with great caution, or perhaps not at all, say the authors.

Everybody wants to decouple power prices from natural gas prices in Europe – or so it seems. Most notably, European Commission president Ursula von der Leyen said in her 2022 State of the Union address: 'The current electricity market design – based on merit order – is not doing justice to consumers anymore. They should reap the benefits of low-cost renewables. So, we have to decouple the dominant influence of gas on the price of electricity. This is why we will do a deep and comprehensive reform of the electricity market'.

Decoupling gas and power is easier said than done. Several proposals have been put forward in the past few months. To mention just a few, Greece had long proposed a mechanism to split power exchanges between low- and high-marginal cost generators. On the other hand, Spain and Portugal have already adopted a mechanism with similar goals and which has been provisionally approved by the European Commission. Italy recently forcibly enrolled some renewable generators in a contract for differences scheme aimed at reaping these assets' infra-marginal rents. The EU Commission itself put out a proposal for a Regulation which, among other things, aims to cap the revenues of infra-marginal electricity generating technologies. But what exactly do these proposals consist of? And what are the pro and cons?

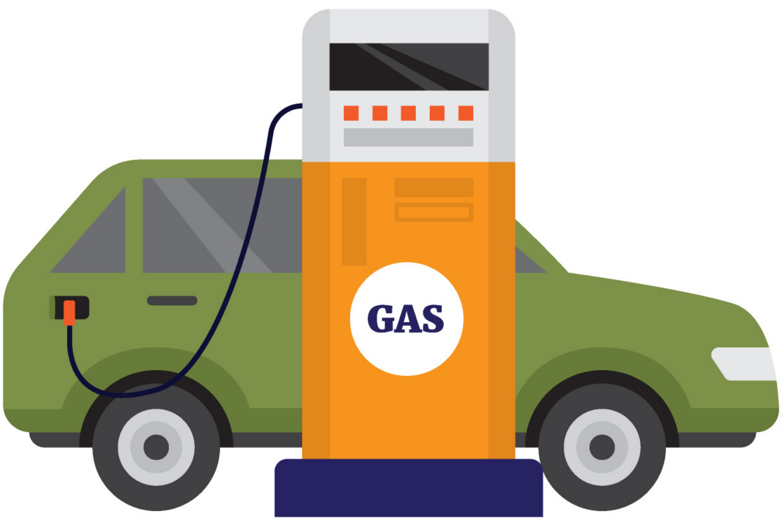
Background: the ratio of system marginal pricing

The price of electricity is determined through a sequence of market sessions, which ensure the balance in real time between supply and demand. The so-called day-ahead market represents the main session. Exchanges on the day-ahead market aim at defining a production schedule for each generator to meet the demand in each hour of the following day.

To this end, a central counterparty collects and aggregates the bids submitted by electricity producers and consumers. Producers' bids are ordered ascendingly according to their marginal costs of production, i.e. the fuel and CO_2 costs: the resulting curve is known as the merit-order curve.

Symmetrically, bids on the demand side are ordered descendingly according to the marginal utility of consumption. From such ordering a demand curve derives.

The point where demand and supply curves meet represents the equilibrium price. This price corresponds to the so-called marginal cost of the system, i.e. the marginal cost of production of the most expensive generating asset which is needed to meet the demand at any given point in time. Such technology is essential to fully meet the scheduled electricity demand of the day after. Such price is equally paid to each power plant. Consequently, while the marginal power plant receives a price which covers only the variable costs of production, the inframarginal power plants – i.e. those that are located to the left of the marginal power plant in the supply curve (see Figure 1 below)



– will earn a price higher than their respective marginal costs and which allow them to also cover capital expenditures.

The ongoing debate at the EU level

The debate on the reform of the price formation mechanism and its adequacy with respect to energy systems dominated by renewable energy sources is not a new one. About a year ago, following the rise in gas prices during the last quarter of 2021, the European Commission required ACER, the agency for the cooperation of European energy regulators, to investigate the problem. Acer concluded that the system marginal price remains the most effective mechanism, as: 1) it allows to minimise the purchase costs of electricity; 2) provides adequate coverage of the investment costs of renewable electricity generation sources and nuclear power plants.

Despite the conclusions of ACER, the war between Russia and Ukraine, which led to new record levels in gas and electricity prices, has revitalised the debate about whether marginal pricing still fits for purpose. The recent proposals on the reform of the electricity market design have one characteristic in common that clearly distinguishes them from others advanced in the past (such as switching to a pay-as-bid rule): the new suggestions are based on the idea that despite electricity being a homogeneous product it may be both possible and desirable to split (physically, financially or administratively) the electricity market in two. One for power plants with high marginal costs and another one for low or zero marginal cost power plants.

Three main proposals stand out at the EU level

Three main proposals stand out at the EU level: 1) the adoption of a cap on the revenues of infra-marginal electricity generating technologies; 2) the creation of two separate power exchanges, one for low-marginal cost generating assets and one for high-marginal cost assets; 3) the payment of a subsidy to gas power plants for the purchase of the natural gas fuelling electricity generation ('el tope al gas').

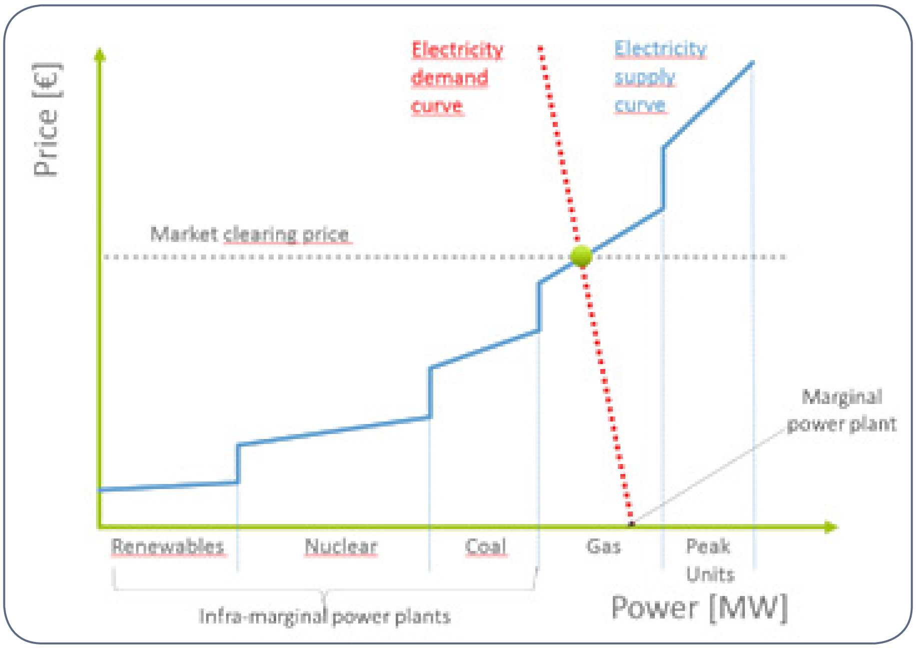
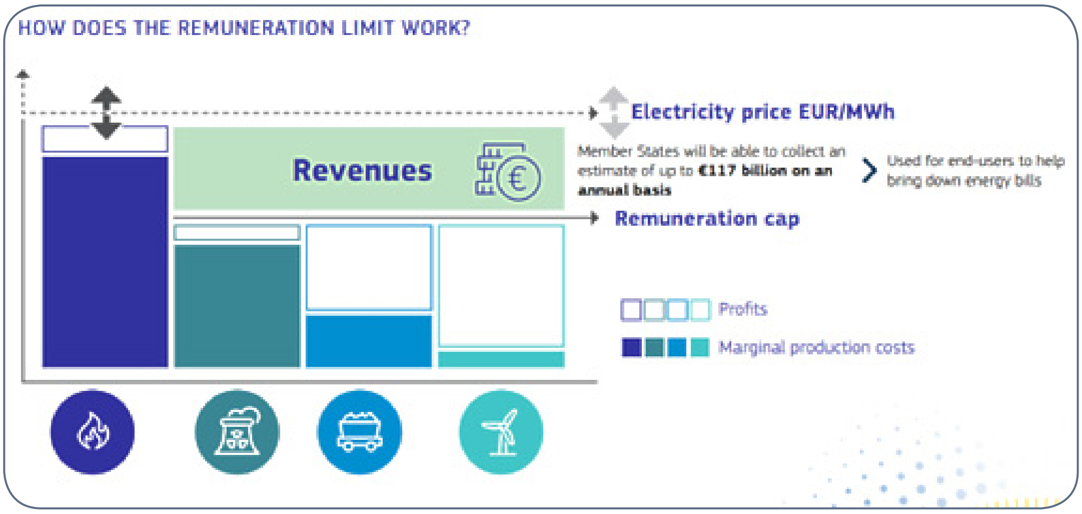


Figure 1:

The system marginal price approach.

Figure 2:
The European cap on the revenues of infra-marginal generating technologies.



1) The adoption of a cap on the revenues of infra-marginal electricity generation technologies

This is the proposal made by the President of the European Commission in the context of the speech on the State of the Union of September 14^{th}. The measure consists in setting a cap on the price that the infra-marginal power generating technologies can earn for each MWh sold. Electricity generation will continue to be sold at the market price and the equilibrium price will continue to be determined according to marginal pricing. However, if the equilibrium price exceeds the cap, inframarginal generators will have to claw back the difference between the market price and the cap. The financial resources so collected shall be used by Member States to finance interventions in support of household and business bills. The European Commission suggests setting such cap at €180/ MWh. See Figure 2 above for a simplified representation of the mechanism.

Italy, among the others, introduced a similar mechanism. The latter is applied to: 1) photovoltaic power plants with an installed capacity greater than 20 kW and which benefit from feed-in tariffs; 2) renewable power plants with an installed capacity greater than 20 kW and which, while not benefitting from incentives, entered into operation before 2010. The Italian mechanism has set a cap approximately equal to €60/MWh.

2) Market splitting

During the EU Council of Energy Ministers on July 26th, Greece made a proposal providing for the establishment of two distinct and consecutive sessions of exchanges on the day ahead market. A first session would involve only power plants whose cost structure is characterised by high fixed costs and low variable costs, i.e. infra-marginal generating technologies. A second session would instead entail programmable generating technologies characterised by positive marginal costs such as coal and gas power plants. In this second session, operators would bid for the electricity generation necessary to meet the residual demand, i.e. the share of consumption which is not satisfied by the production sold in the first session.

The profits for the power plants participating in the first session shall come from contracts for difference signed between electricity generators and public or private counterparties (such as final consumers, traders or aggregators). For power plants that are not able to find a counterpart in the market, so that a contract for difference could be signed, a voluntary participation in a newly set up market is envisaged. Such a market is called the green power pool and would be managed by a public entity operating as a single buyer. Power plants participating in the second session of the market would continue to value their production according to the System Marginal Price mechanism.

The equilibrium price for the electricity purchased and sold would be determined by the weighted average of three values: (1) the average price paid for the contracts for difference in the first trading session; (2) the clearing price of the second trading session; (3) the weighted average price, for the quantities traded on the green power pool. The mechanism appears complex and, in some respects, obscure. For example, it is not clear according to which rules the green power pool will be organised and operated.

The goal of the Greek proposal seems to structurally abandon marginal pricing (which is, in truth, the norm in commodity markets) to shift towards average pricing (i.e. a pricing mechanism based on average generation costs, including both variable and fixed costs).

3) El tope al gas

Spain and Portugal established a cap ('tope') on the cost that gas power plants may pay for the purchase of natural gas needed for electricity generation. The cap is set at €40/MWh for the first six months of application of the measure. From the seventh month, the cap will be increased by €5/MWh every month until reaching the maximum value of €70/MWh.

If the market price of natural gas exceeds the cap, thermal generators are subsidised to cover the difference between the fuel cost and the cap. For example, if gas costs €100/MWh, thermoelectric producers will bid on the power exchange at a price consistent with the cap (i.e. as if gas costs only €40/MWh) and will be refunded the difference (€60/MWh). The corresponding subsidy is financed by different subjects: (i) buyers on wholesale markets in proportion to the volumes purchased; (ii) end customers who, having not chosen a supplier on the liberalised retail market, continue to buy electricity at regulated prices; (iii) the higher revenues due to the additional electricity exports to France caused by the reduction in the Spanish electricity prices due to the introduction of the tope.

By subsidising the cost of natural gas, marginal generators may bid a lower price in the day ahead market, driving down both the equilibrium price and infra-marginal rents.

Conclusions

These proposals all aim to lower the price of electricity. And, in a different way, they succeed. However, none of them are cost-free. Not only because in some cases, such as for the Iberian tope, it is a question of finding resources to finance an explicit subsidy or, as for the Greek proposal, it is necessary to resort to a public entity that buys electricity from those operators who have not been able to stipulate contracts for differences on the market. The most significant costs are, indeed, the collateral effects arising from interventions on the electricity market design.

Each proposal has pros and cons. The mechanism to cap the inframarginal rent has the advantage of not affecting equilibrium prices on the day ahead market. Therefore, this mechanism does not affect cross-border exchange of electricity between Member States.
The Greek proposal has on its side the ambition to rethink the functioning of the market without attempting to patch up a mechanism considered obsolete. The Iberian mechanism fully safeguards the market design and intervenes upstream to address what is considered an exceptional phenomenon, that is, the rise in gas prices.

The last two mechanisms – the Greek and the Iberian ones – have an impact on wholesale prices and, therefore, they should be adopted at EU level in order to prevent distortions in cross-border electricity trades. In the case of the 'tope al gas' as well as the cap on infra-marginal revenues, there is a further issue. If the cap is set 'too low', in the case of the tope the risk is to exacerbate the effects on exports and on the safety of the electricity system described above. In the case of the cap on infra-marginal revenues, the risk would also be to hamper the coverage of power plants' investment costs.

The Greek proposal has further and specific limits. In the first place, there being no obligation to participate in the so-called green power pool, it is not clear how power plants that fail or do not find it convenient to sign contracts for differences on the market could be remunerated. Secondly, in the second session of exchanges (i.e. the exchange for high-marginal cost assets) there is a significant risk that the power plants may exercise market power if some of them find it essential to meet the electricity needs with respect to certain hours of the day and certain market zones. This possibility may prevent the goal of lowering the price of electricity. In addition, the complexity of implementing the mechanism should not be underestimated. A long time would be needed, indeed: 1) to adapt the rules for the functioning of markets and cross-border electricity exchanges; 2) to set up agreements between the power exchange operators and between them and TSOs to implement the new mechanism.

Finally, all measures – even if adopted at EU level – may unintentionally increase the differences among member states. For example, moving from marginal pricing to average pricing would obviously result in lower prices where the average costs of production are lower – i.e. where the incidence of natural gas in the national generation mix is lower. This may result in competitive advantages or disadvantages in downstream industries, particularly in the industries that are both energy-intensive and trade-exposed (such as steel, cement, paper, glass, etc.).

The idea of decoupling markets – through administrative interventions that separate renewable electricity generation sources from the others – has great political success but can take on many different meanings. Almost all, however, have to do with the desire to contain prices, reducing the amount of inframarginal rents. In the design of post-liberalisation markets, the marginal price system finds its justification in the need to encourage investment in new generation capacity, especially in plants – such as renewables – with high fixed costs but low or zero marginal costs. Direct or indirect caps on revenues may discourage new investments, to the detriment of both the efforts to get out of the current crisis by reducing dependence on gas, and the European decarbonisation programs. In any case, from this point of view the question is eminently empirical: a sufficiently high cap (for example the €180/MWh suggested by the European Commission) is not necessarily an obstacle in this respect, while a too low threshold (such as €60-70/MWh set in Italy) may be counterproductive. On the other hand, decoupling looks like an attempt to address a problem that does not stem from the mis-functioning of electricity markets: it derives from the exceptional trend in gas prices. One therefore wonders if this is not a case of following the ancient wisdom: if it ain't broke don't fix it.

By **Simona Benedettini** **and Carlo Stagnaro**

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A By-product hydrogen: bridge to a green hydrogen economy?

Cheap hydrogen produced from industrial by-products may help the hydrogen sector develop, but there is a risk of locking in carbon emissions.

As demand for green hydrogen rises and costs fall, investment is needed in the infrastructure for producing and transporting it

Over 30 hydrogen filling stations, almost 1 000 hydrogen fuel cell vehicles providing the bulk of the transportation, and a hydrogen-fuelled Olympic torch. The widespread use of hydrogen at the 2022 Winter Olympics was designed to spur development of the sector in China.

In March, shortly after the Games ended, the central government issued its first medium- to long-term plan for the hydrogen sector, for the period up to 2035. The document put particular emphasis on the short-term use of 'by-product hydrogen', which is extracted from industrial waste gases rich in the element, by pressure swing adsorption or other techniques. Such hydrogen is to be given priority in parts of the country where coking, chlorine production and propane dehydrogenation is concentrated.

(Image: Yu Fangping / Alamy)

The plan set a target for 2025: having an initial hydrogen economy running, relying on local sources of by-product and renewable hydrogen.

The top-level policy design has prompted over 30 provincial administrations to produce their own plans and policy for hydrogen power. Shandong, Shanxi and Inner Mongolia have all said they will make use of local by-product hydrogen.

Such hydrogen is cheap and can help spur development of local hydrogen economies. But experts warn that China's targets of peaking carbon before 2030 and reaching net zero by 2060 mean this cannot be the approach. There will have to be a rapid switch to renewable hydrogen, and so over-investment should be avoided.

Is hydrogen power green enough?

Using hydrogen power produces water but no carbon, making it clean and renewable. But manufacturing the gas is not necessarily carbon free. Hydrogen has various names depending on the carbon emissions incurred during its production. That produced from fossil fuels is known as grey hydrogen. When combined with carbon capture and storage (CSS), grey hydrogen becomes blue hydrogen. And when the gas is produced by renewable energy-powered electrolysis of water, it is known as green hydrogen.

China is the world's biggest producer of the hydrogen. Its output of 33 million tonnes a year is over one-third of the global total. Globally, 60% of all hydrogen is sourced from natural gas, 19% from coal, and 21% from industrial processes where hydrogen is a by-product. In China, coal is still the main source of the gas. It accounts for 62% of the country's hydrogen output. Natural gas provides 19%, by-product hydrogen 18%, and electrolysis only 1%.

So hydrogen supplies both at home and overseas are not yet green enough. Cost and technology are the problem. According to a report from the Energy Transitions Commission, a kilogram of grey hydrogen costs between USD 0.70 and USD 2.20, depending on the cost of natural gas and coal locally. Adding CCS technology for blue hydrogen is naturally more expensive again. The cleanest of all, green hydrogen, costs USD 3–5 a kilogram.

Some experts say green hydrogen is rapidly needed if hydrogen power is to support China's dual carbon targets. Others see by-product hydrogen as an important stepping stone for the sector in the medium to long term.

As a major industrial power, China has plenty of raw material to work with. According to a white paper on its hydrogen and fuel cell industry, it costs CNY 0.30–0.60 (USD 0.04–0.08) to extract a kilogram of hydrogen from industrial waste gases. Add in the costs of buying by-product gas, where that is necessary, and the overall cost of by-product hydrogen is in the region of CNY 10–16 (USD 1.4–2.25) a kilogram.

By-product hydrogen is still 'grey', but it represents a more efficient use of resources than

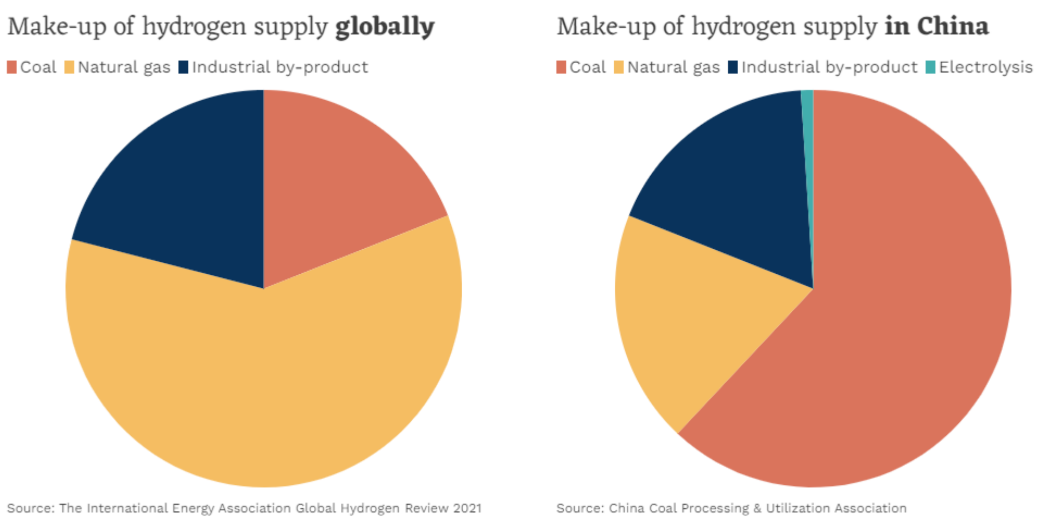


Image: China Dialogue

that produced directly from fossil fuels and to some extent helps reduce air pollution. According to the white paper, China's coke oven gas, chlorine, synthetic ammonia, synthetic methanol and propane dehydrogenation industries can provide millions of tonnes of hydrogen – a cheap and widely distributed source of the gas which could help the industry grow.

The release of the national plan prompted local governments to speed up their hydrogen projects. According to the media, 18 hydrogen production projects got off the ground in the first half of this year, with an even split between by-product and renewable hydrogen. A look at the by-product projects underway shows that this will only be the first stage in developing the sector. The cheap hydrogen produced will allow the building of hydrogen power infrastructure in the surrounding area and nearby cities.

Fuel cell-powered buses at a hydrogen filling station in Shanghai, China

(Image: Alamy)

Using cheap hydrogen to build up the industry

The hydrogen industry chain runs through manufacturing, transportation, filling stations and fuel cells. The International Energy Agency has found developing a hydrogen sector needs efficient and cost-effective transportation and storage to link supply and demand and create a liquid market. China's existing by-product hydrogen projects usually involve a filling station attached to the production facility, to supply local demand. Those filling stations are frequented by local hydrogen-powered vehicles and buses, as well as the heavy trucks used by local industry.

Early figures from Shandong indicate the province produces 2.6 million tonnes of hydrogen a year, more than any other province, most of which is the by-product variety. In 2021, Shandong's first hydrogen 'mother station' went into operation, at Taishan Steel. That facility can fuel almost 100 hydrogen-powered vehicles within a 150-kilometre radius. Its hydrogen comes from steel-making waste gases. The rollout of hydrogen filling stations has also led the Shandong Heavy Industry Group to put ten 49-tonne hydrogen fuel cell-powered cranes into use.

Wuhai in Inner Mongolia has taken a similar approach. By-product hydrogen from a Wuhai Chemicals chlorine plant is piped to a mother station in front of the facility. It is then sent onwards to hydrogen filling stations either by truck or pipeline, for use by the city's 50 hydrogen fuel cell-powered buses. If the 80 000 diesel trucks and mining vehicles in the city could be converted to hydrogen fuel cells, there would be even greater scope for hydrogen take-up.

Infrastructure such as hydrogen filling stations are key parts of the hydrogen industrial chain – and in China, a weak link. As with hydrogen production, cost is hampering the building of more of those stations. According to data in the white paper, a filling station able to provide 500 kilograms of hydrogen a day costs about CNY 12 million (USD 1.7 million) – three times the price of a normal filling station. There are also maintenance, operational and labour costs. Together, these have created a bottleneck in development of the sector. Overcoming these problems requires matching up supply of hydrogen and demand from hydrogen fuel cell vehicles. If there aren't enough vehicles requiring hydrogen, the filing stations will not reach economies of scale and will be unprofitable.

In its report, the IEA said by-product hydrogen can provide a cheap source of the gas in industrial areas, where there are also hydrogen-powered trucks and buses serving local industries. That would maximise utilisation of the filling stations and resolve the main cost barriers to hydrogen rollout.

By-product hydrogen isn't just cheap to make. Use near the point of production means transport and storage costs are also minimal. The white paper points out that a local hydrogen value chain can benefit from synergies. For example, hydrogen-powered truck fleets can operate more cheaply within an industrial cluster and its transportation corridors.

A project in Shanxi converting diesel vehicles to hydrogen ones is an example. The Shanxi Coking Coal Group can supply cheap hydrogen from its coking facilities. That is used to fuel trucks transporting coal – up to 2 200 of them, all operating at full load. One partner in the project is the State Power Investments Corporation. Its head of hydrogen business, Zhang Yinguang, said in an interview that coal mining areas have a huge and reliable demand for trucking. Thousands or even tens of thousands of hydrogen-fuelled trucks in an area would provide the economies of scale needed to bring costs down. And those trucks will be competitive with their diesel equivalents assuming hydrogen can be provided at CNY 25 (USD 3.51) a kilogram, or less.

Challenges abound

There is huge potential for by-product hydrogen to provide supply and spur development along the hydrogen chain. But there won't be enough to meet sustained increase in demand, and difficulties with storage and transportation will remain. Also, excessive development of by-product hydrogen could risk locking in carbon-intensive infrastructure.

China's dual carbon targets mean that output from the steel and chemical industries is bound to fall, in turn resulting in less by-product being produced, and so a crunch in supply of by-product hydrogen. Hebei is an example. There, work to meet the dual carbon markets will see the number of coking firms in the province drop to around 40 by 2025 – and so the output of waste gases available for hydrogen-making will drop from 940 000 tonnes a year to 450 000 tonnes.

Currently, most hydrogen filling stations rely on external supplies, delivered at high pressure. Delivery costs increase significantly if supply distances are over 200 kilometres. Local use is the key to success for by-product hydrogen, but not all industrial zones can follow the example set by the Shanxi Coal Coking Group. Unfortunately, there is little hope of a quick technical solution to high transportation costs.

Independent energy analyst Julien Armijo believes that by-product hydrogen from industrial processes based mostly on coal could present an opportunity in the short term, but over-reliance on it could be risky: investing in the wrong infrastructure could lock in carbon emissions. And if companies see it as an easy way to deploy hydrogen value chains, that could extend the life of carbon-intensive infrastructure that needs to be phased out.

Similar issues have been seen in other regions, especially Europe. The oil and gas sector often claims that blue hydrogen production can be quickly scaled up and should therefore be used as an interim solution until green hydrogen can be produced at scale. However, a report by E3G warns that such an approach may be counterproductive and again risk locking in high-carbon infrastructure and jobs, potentially hindering the development of green hydrogen.

Armijo holds the same view. 'When companies invest heavily in building infrastructure, they usually expect it to run for decades or more before considering replacing or retiring it,' he says. E3G suggests that mechanisms will be needed to avoid a lock-in of fossil fuels and ensure a later switch to green hydrogen, including clear timelines and targets, accountability and transparency mechanisms, and regulations and standards which support the phase out. But Armijo is not optimistic: 'Urgent action on climate change is needed but it is obvious that every government is acting much too slowly'.

Towards green hydrogen

A report by the Mercator Institute for China Studies (MERICS) pointed out that China's near-term hydrogen policy focuses on 'industry development first, greening second'. Compared to European strategies, which aim to leverage green hydrogen for rapid and deep decarbonisation, China's policy remains conservative.

The good news is that green hydrogen costs have been falling and there is hope that it will become the main source of the gas. The ETC's report predicts that green hydrogen will cost less than USD 2 a kilogram in most parts of the world by 2030. That will make it cheaper than either blue or grey hydrogen.

Alexander Brown, an analyst at MERICS, said industrial by-products provide a cheap source of hydrogen, but it is still grey hydrogen and has a significant carbon footprint. 'Hydrogen can play an important role in achieving China's dual carbon goals, but only with green hydrogen.' He believes that China cannot rely on industrial by-product hydrogen to meet growing demand: 'If China is serious about its climate goals, it must turn to green hydrogen as soon as possible.'

By **Niu Yuhan**

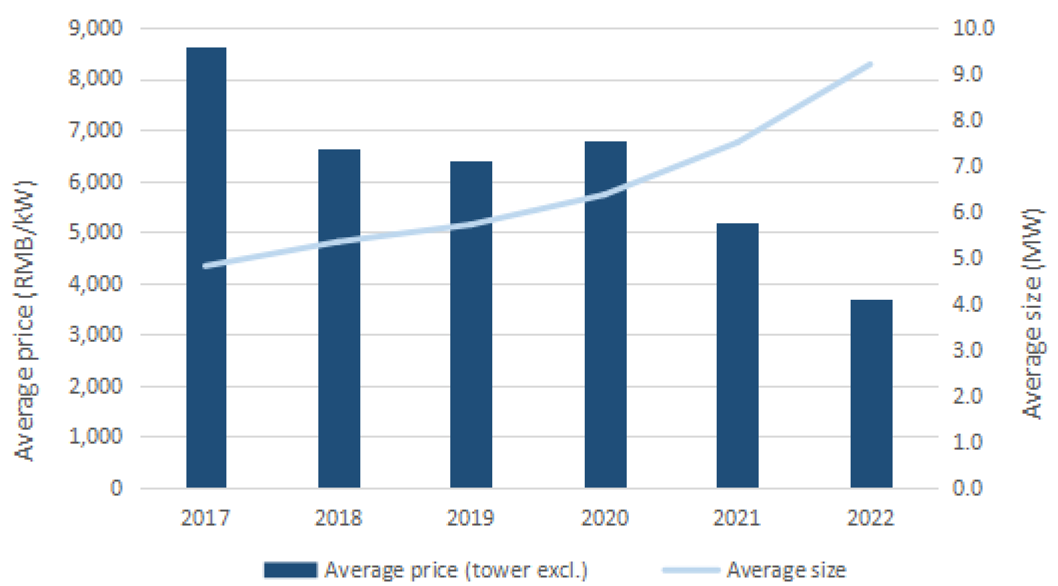
China's 'low specific power' offshore wind turbines: a game changer for the global market?

In 2021, the Chinese offshore wind sector was subsidy-driven and experienced explosive growth. In 2022, at the start of the grid parity era, growth has slowed markedly. Market dynamics have also suddenly shifted from a situation dominated by supply shortages to one governed by overcapacity, affecting most components of the supply chain. Whether or not this was intentional on the part of China's policy makers, the resulting cut-throat competition between wind turbine manufacturers (also known as OEMs) is having noticeable consequences, including unprecedented drops in wind turbine prices and a stronger focus on international markets.

Today we look closer at another remarkable trend of the Chinese offshore wind supply chain: the emergence of 8+MW wind turbines with low specific power.

Before diving deeper in an analysis of these trends, we should define 'specific power' – the ratio between rated power and rotor sweeping area (W/m^2)[2]. The smaller the specific power, the higher wind energy capturing capability the turbine has. In another words, for a with given rated power, a turbine with lower specific power will have a larger rotor. The chart below shows the specific power of typical wind turbine generator (WTG) types in Chinese and European markets.

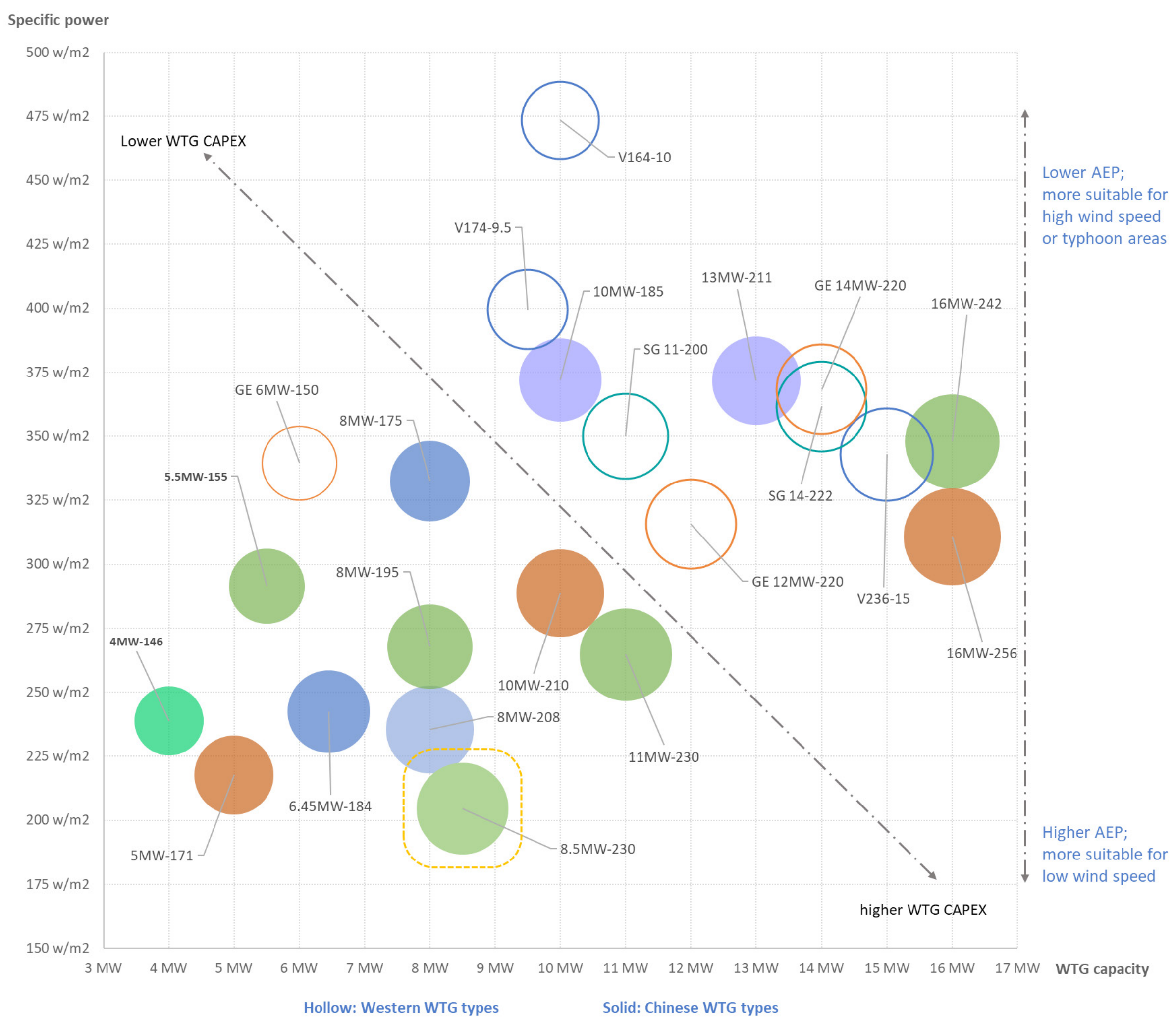
2017-August 22 China offshore wind turbine average prices (excluding towers[1]) and capacity.



[Source: Azure database]

1. *Whether tower is in the scope of supply is defined in the bidding document. Tower price deduction (RMB/kW) in the chart is based on market prices and reasonably averaged.*
2. *In the Chinese market, a more commonly used term is 'swept area per power unit' (m2/W) which is the reciprocal of specifc power. Such term has been used as a qualitative requirement for WTG in some recent tenderings in China.*

Chinese WTG vs. Western WTG



[Source: Azure database]

It can be easily imagined that larger rotors produce more power for a given turbine capacity, but they also have drawbacks such as severe loading on both turbine and foundation, as well as logistical and installation challenges. The table below provides a high-level comparison of each type's advantages and drawbacks.

Table 1: Comparison of high/low specific power turbines

Higher specific power	Lower specific power
Lower capacity factor (less energy per installed kW)	Higher capacity factor (more energy per installed kW)
More suitable for high wind speed or typhoon-impacted areas	More suitable for low wind speed areas
Lower WTG CAPEX due to shorter blades	Higher WTG CAPEX (but not always reflected in turbine prices)
Lower foundation cost / kW (due to lower loading)	Higher foundation cost / kW (due to higher loading)

First 123m blade produced by Zhongfu Lianzhong in August 2022.

Image: BJX

China is focusing on long blade, low specific power wind turbines

On August 30, 2022, an exciting announcement made the headlines: '123 meters – world record blade produced at Zhongfu Lianzhong'. In fact, it is not the first 100m+ blade in China. Since 2021, around 10 types of 100m+ blades have been manufactured by Chinese companies.

Two aspects of these recent announcements have caught our attention:

It is the first time that Chinese companies have independently produced and tested wind turbine blades that break the global record for length. Historically, most

Table 2: 100m+ blades developed by Chinese suppliers.

Blade Company	WTG OEM	Type	Length (m)
Zhongfu Lianzhong	Shanghai Electric	S102	102
Shuangrui	CSSC Haizhuang	SR210	102
Dongfang Wind	Dongfang Electric Corp (DEC)	B1030A	103
Shuangrui	CSSC Haizhuang	SR220	107
Dongfang Wind	DEC	B1085A	108.5
Zhongfu Lianzhong	Windey (or Yunda)	YD110	110
Mingyang	Mingyang	N/A	111.6
Zhongfu Lianzhong	Shanghai Electric	S112	112
Zhongfu Lianzhong	Undisclosed	N/A	123

blade length records have been held by Denmark's LM Wind Power, acquired by General Electric in 2017. The majority of 100m+ blades were produced by international OEMs, including LM's 107m blades for the 'Haliade-X 12MW' (produced in 2019), Spanish-German Siemens-Gamesa's 117m blades for the 'SG 14-236 DD' (currently under production and testing), as well as the Danish company Vestas' 117.5m blades for the 'V236-15 MW' (currently under production).

Secondly, while the race for longer blades in the West is coupled with appetite for larger 12MW+ turbines, in China, these long blades are being used initially for medium sized machines, in the 8MW range.

China's developers and OEMs have been lowering specific power for years, for onshore and offshore markets, in turbines ranging from 4MW to 10MW in capacity. The main drivers for choosing such a 'hard road' are as follows:

- Wind resources
  The best offshore wind resources in China are in the Taiwan Strait, in Fujian and in neighbouring areas in Guangdong and Zhejiang. Average wind speeds in these regions can exceed 10 m/s. However, the development of offshore wind is constrained by geotechnical challenges, typhoons, and other factors (such as military). These rich wind resource areas account for a minority of China's offshore wind potential. The remaining areas feature wind speeds averaging 7.0-8+m/s. Under such conditions, having long blades per unit capacity is required to achieve an adequate energy yield.

- Market demand
  Investment in offshore wind is driven by Return On Investment (ROI) expectations and supported by policies. China's government trialled competitive allocation policies (V1.0) in the early 2010s, encouraging developers to bid for feed-in tariffs (FIT). It was not a successful trial due to regulatory, technical and commercial immaturity at the time. Later on, a nationwide fixed FIT of RMB 0.85/kWh (EUR 0.12/kWh) was implemented, which attracted developers and ensured the industry's healthy development.
  At the end of 2019, the National Development and Reform Commission (NDRC) announced that from the start of 2022, the RMB 0.85/kWh fixed FIT would no longer be applied to offshore wind farms (OWFs) that were fully grid connected. Since then, all new projects have been allocated through competitive allocation (V2.0) with a FIT no higher than the local coal based benchmark price (though in some cases there have been small local government subsidies). This reform has put the whole industry at peril, leaving developers and OEMs no choice but to reduce WTG costs and aggressively roll out new technology platforms with improved Annual Energy Production (AEP).

- Balance of plant cost drivers in the West vs. China
  Another possible reason for China's push for low specific power wind turbines lies in the cost drivers of the wind farm's balance of plant. Material, equipment, and labour costs are notoriously high in the West compared to China, especially for work performed at sea, pushing developers to use larger and therefore fewer wind turbines for a given project. In China, cost optimisation may result in a different paradigm. With lower balance of plant costs, the savings from using larger turbines (which usually have higher specific power) may not justify the loss of potential energy yield. This is especially true in provinces like Jiangsu, where there are relatively shallow waters and favourable soils, and where wind turbine foundations, transport and installation costs can be kept at a reasonable level.

The road from 4 MW to 8 MW wind turbines

There are three main families for low specific power WTG in China:

4MW: 4MW has been the main platform for years. Starting from 4MW-130 (4MW WTG with 130m rotor), the typical low specific power types have now evolved to 4MW-146 (see image) or 4.5MW-148. Since 4MW components are lighter, they are more suitable for areas with shallow waters (on some sites, the seabed may even be visible during low tides) or where geotechnical conditions are not optimal for larger turbines (such as very thick and soft mud layers).

6MW: though 4MW may be suitable for many areas, they can prove expensive due to high foundation and installation costs per MW. OEMs have developed a large range of 6MW platofrms starting from 6MW-154 to 6.25/6.45MW with 180m rotor diameter. The 6MW platforms took a significant market share during the period 2019-21 (sometimes called ‘the gold rush’), when Chinese developers were racing to get their approved offshore wind projects grid connected before the FIT deadline.

New generation (8-10 MW): Low specific power WTGs are mainly limited to ≤10MW levels, because larger capacity WTGs would require blades with lengths exceeding current design and manufacturing capabilities. These 8-8.5MW WTGs are becoming the popular platform for low specific power turbines in China as they combine larger turbine capacity and long blades, resulting in record low levelised cost of energy (LCOE).

[Source]

Shanghai Electric 4MW-146 for Jiangsu Rudong H14# Offshore Wind Farm.

[Source]

Installation of Goldwind 6.45MW-184 for CTG Jiangsu Dafeng project.

[Source]

CSSC Haizhuang H220-8.XMW completed installation for Shandong Bozhong site A.

Key offshore OEM players have announced several low specific power WTG types, such as:

Table 3: Low specific 8.xMW WTGs from key Chinese players

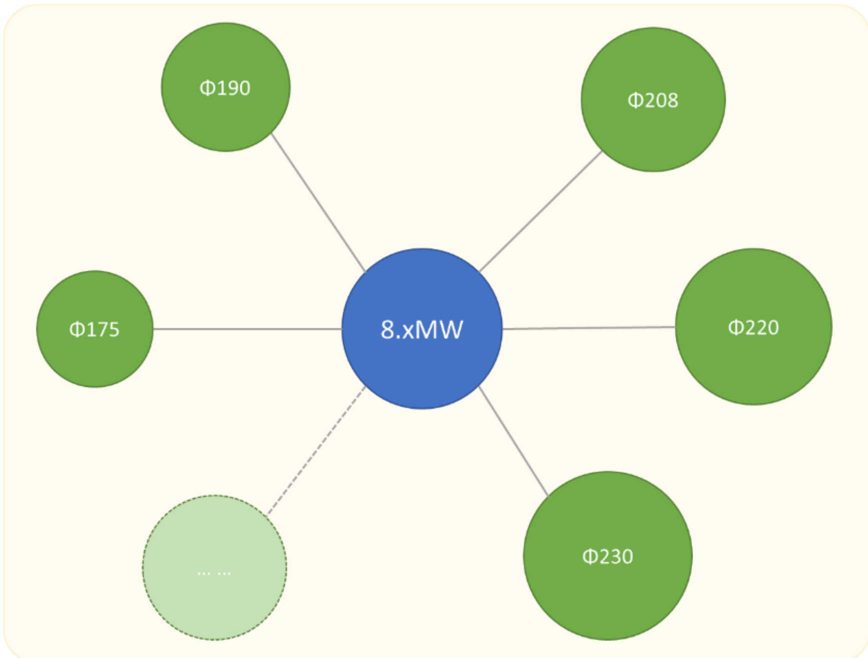
MINGYANG SMART ENERGY 明阳智能	MySE8.5-230
上海电气 SHANGHAI ELECTRIC	EW8-208, EW8.5-230
GOLDWIND 金风科技	GW8.5-230
ENVISION 远景能源	WD225-9000
CSSC 中国海装	H220-8.X

Long blade low specific power wind turbines could benefit the global market

The global market and international developers could reap benefits from the development of long blade low specific power turbines in China:

- Rich and optimised options
  Because there are different combinations of blades for a given turbine (e.g. 184/193/210/220/230m rotor for 8.xMW turbine), the optimisation of turbine (rotor) sizes for specific sites could help achieve better AEP and LCOE.

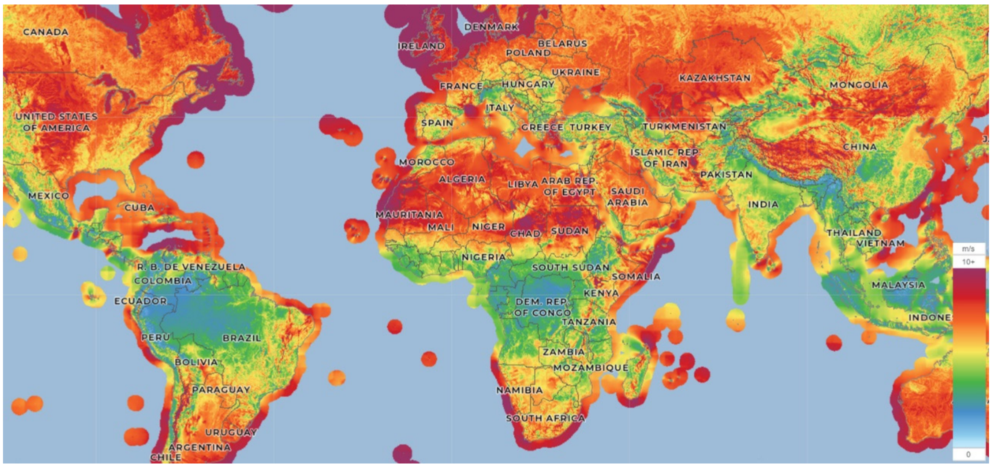
Rich options for rotor sizes.



[Source: Azure]

- Global market

  These turbines are not only suitable for China but also a good fit for markets where wind resources are lower such as in the Mediterranean area, South Asia, South-East Asia, Brazil, and the Gulf of Mexico, where significant pipeline has recently been announced.



Various offshore areas fit for low specific power WTGs.

[source: Global Wind Atlas 3.0]

- Strong references

  The 100m+ blades have been tested since 2021, while turbines featuring these long blades have been installed in China since 2022. In the coming years they are likely to be deployed massively in China, offering an opportunity to fully test and prove the technology.

  Along the deployment of these turbines, the supply chain will mature at all levels and help international investors gain confidence with these new products.

YD110 blade under static loading test per IEC61400-23.

[Source]

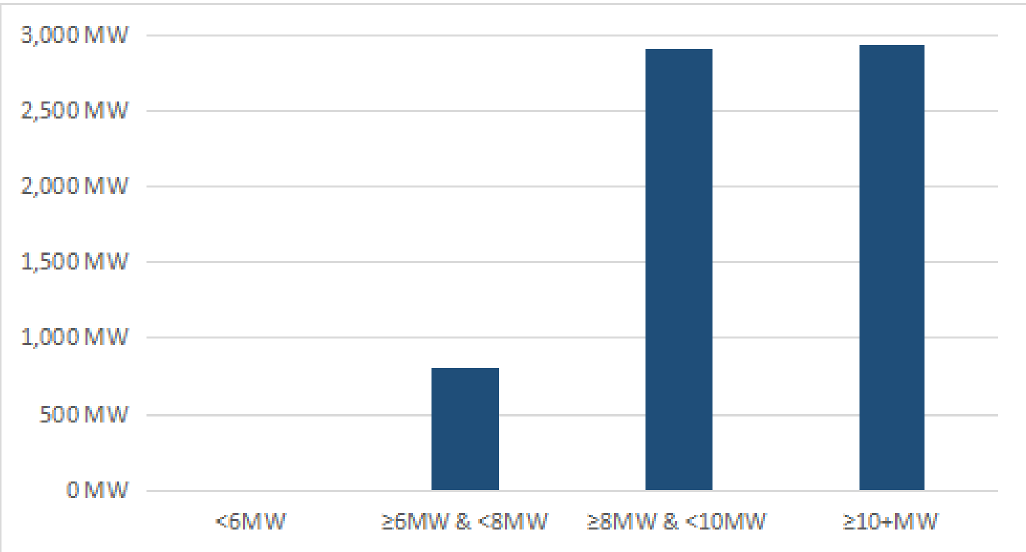
- Competitive price
  According to requirements for return on investments and information on public tendering, it is likely that long blade low specific power turbines will be widely used in China, providing a good opportunity to lower prices. As shown in the graph below, close to 3GW of wind turbines in the 8~10MW range have been tendered for in 2022 up to August (for tenderings that turbine types are available).

Thanks to the development of long blades, Chinese turbines are able to capture more wind energy. The CAPEX disadvantage of such blades could be compensated by developing a robust supply chain and optimising project economical performances, notably via higher AEPs. Another concern could be regarding site suitability. So far, international certification of such turbines has not been completed. Wind turbines with low specific power might be less suitable for sites with high extreme wind speeds, such as areas prone to tyhoons or hurricanes.

To conclude, the higher performance of China's long blade turbines could make them competitive in international markets, particularly in areas with medium/low wind speeds. However, it remains to be seen whether they can compete in areas outside China with higher wind speeds, where players like Vestas and Siemens Gamesa still reign supreme.

By **Ziguang Zhang**
Director of Engineering at Azure International

2022 China offshore WTG tendering (turbine type available), January to August 2022.



[Source: Azure database]

'ESCO-in-a-Box™': Bringing the 'Cinderella' of the energy world into the mainstream

If energy efficiency is to grab the world's attention, a new approach is needed, argues Steve Fawkes, managing director of ep group. His firm's initiative sees ESCOs sharing the benefits of energy savings with their clients, offering an adaptable approach that can be tailored to fit individual circumstances.

Energy Service Companies, or ESCOs, which identify, develop and deliver projects that save energy (and sometimes water), and share the benefits with the client while offering some form of guaranteed performance, are an old idea. In the 1770s, James Watt and Matthew Boulton sold Watt's more efficient steam engine for pumping water, replacing the less efficient Newcomen engine. They shared the money saved with their tin miner customers. This innovation helped catalyse the industrial revolution, and the payment arrangements massaged the customers' fear of innovation. '*There was some local resistance in Cornwall, where the new engines were certain to save costs in pumping out water from the tin mines… the 'no cure, no pay' terms offered by Boulton and Watt – based on third of the savings in fuel over a period of twenty-five years – saved the day*, writes historian Thomas Crump[1].

The ESCO industry has since evolved in growth spurts following events such as the 1970s oil crises. In the UK, the National Coal Board created Associated Heat Services in 1966 to provide outsourced boiler houses (fired by coal), and in 1980 the first ESCO was formed, based on energy performance contracting. In the same decade, the oil majors BP and Shell both formed energy service companies.

1. *Crump, T. The Age of Steam, London, Constable and Robinson, 2007, p.58.*

In Europe, the idea of outsourced utilities has been particularly common in France where large companies, often linked to energy suppliers, provide heat as a service to buildings – usually called 'chauffage'. Pure heat supply providers, however, don't incentivise the customers to reduce energy usage, although a project such as new boilers may of course improve performance compared to older technologies.

In the US, the Energy Performance Contract (EPC), now more often called Energy Savings Performance Contract (ESPC), emerged in the late 1970s and early 1980s. In the 1980s and 1990s, the US agency USAID promoted the concept around the world, supporting the formation of ESCOs in Central and Eastern Europe with the end of the Cold War, and in South East Asia and China. Many of these efforts were not particularly successful as they did not adequately address project financing.

By the mid-1990s 'proto-ESCOs' - typically energy consultancies - were seeking funding throughout Europe, as they still do today. The problem is that promotion of the US model ignores the fact that 90% of ESPC business in the US is within the Municipal, University, School and Hospital (MUSH) market, which in the US has access to municipal funding – a source unavailable outside the US. In the US, domestic ESCOs have grown in number, in response to large projects sponsored by state and federal legislation that encouraged and even forced facilities such as military bases to use ESCOs and EPCs. ESCOs and outsourcing of energy efficiency grew dramatically until the collapse of major player Enron in 2001. This led to a retrenchment of the industry.

ESCOs have experienced something of a resurgence over the last decade, thanks to an increased focus on reducing emissions, and the current high energy prices. The idea of 'shared savings' is being embraced as if it were a new concept, and hailed as a panacea that will improve energy efficiency. Yet the fact that the ESCO industry globally remains largely focused on the public sector suggests that it is not the 'silver bullet' some people think. In 2018, the IEA estimated the global ESCO market at USD 28.6 billion, with China accounting for USD 16.8 billion. For all the conversation, on a global scale, and compared to the energy supply industry as a whole, ESCO activity remains a niche sector.

ESCOs and EPCs face many problems getting projects implemented:

- High transaction costs: it can take many months or even years to take a project from concept to implementation – often projects never reach fruition.
- EPC contracts are complex, and users frequently fail to understand them.
- The long-term nature of EPC contracts (often seven to 15 years or even more) can be problematic, particularly in a fast-moving world where industries and businesses change quickly.
- Accounting treatments can be confusing; many organisations want the investment off their balance sheet but achieving this requires real transfer of risk rather than simple finance models such as leases.
- EPC contracts do not work well in commercial real estate, particularly where there are multiple tenants and split incentives between the landlord and the tenants.
- Measuring results can be difficult when there are changes in technology or practices that affect energy use. In the early days of ESCOs many contracts ended up in court, leading to the introduction of the globally available International Performance Measurement and Protocol (IPMVP) – but applying IPMVP can be costly for smaller contracts.
- Projects can be very diverse due to the different technologies being implemented.

- ESCO guarantees of performance are not adequate to de-risk the project for the investor.

- Capital costs for energy efficiency, even for the largest projects, are small compared to the requirements of financial institutions. Even in the much-admired Empire State Building retrofit in 2010, which used an EPC contract, the capital spent on the energy efficiency elements was only USD 13 million.

- Despite growing interest within the financial sector in funding energy efficiency and ESCOs, there is still a lack of capacity and know-how.

Given these problems, and the urgent need to scale-up investment into energy efficiency, particularly in sectors, such as commercial real estate and SMEs, that cannot currently access financed energy efficiency services, the ep group has developed the 'ESCO-in-a-box™' operating system, supported by funding from the UK government department BEIS. The initiative aims to provide a simpler ESCO model that allows other companies such as energy consultancies, or public bodies like local economic development agencies, to launch an ESCO that addresses their particular market, whether it be in a geographic area or a particular sector. In doing so they have drawn on the team's extensive international experience in the ESCO business. The team believes in the power of standardising business processes and takes its inspiration from global franchise businesses which use the same production and operating systems, regardless of their country of operation.

ESCO-in-a-Box™ provides licensees with everything they need to launch a successful ESCO, including a start-up package, a marketing package, standardised contracts, an operations package and defined levels of support from ep group.

The system was developed working with Oxford Low Carbon Hub and is now being rolled out across several UK regions. Local economic development agencies view it as a way of addressing the pressing needs of decarbonisation, skills and capacity building, and attracting investment. Local users are free to develop their own branding and marketing.

ESCO-in-a-Box™ in Kenya

When the UK project was in its early stages, the ep group was approached by leading Kenyan energy consultancy Eenovators and with the help of development consultancy ENSO Impact the system has been adapted for the Kenyan legal and business environment. The main target sector was food and agriculture which plays a very large part of the Kenyan economy. Eenovators used ESCO-in-a-Box™ to develop c.USD 20 million of energy efficiency projects that will help local businesses save money and become more competitive, as well as reduce emissions and improve local air quality. These projects are now being taken forward to funding in partnership with specialized funds whose mainstream activity is funding renewables. Another positive impact of the system was that Eenovators used it in their Youth in Energy Empowerment Programme (YEEP) which aims to equip young people with a background in engineering, and with the skills and experience required to position them for employment and entrepreneurship in the energy space. This is an important social benefit.

ESCO-in-a-Box™ now has its first US customer, where NuWorld Energy is addressing the energy efficiency needs of small, minority owned businesses in New Jersey and New York. The system has also received a grant from UN OPS to introduce it to the Philippines. In line with ep group's vision, the system has been proven to work in many markets with minimal adaptation. The main issue facing an international rollout is the need to align contracts with local law but the overall system has been found to be useful everywhere.

Energy efficiency: no time to waste

Scaling-up energy efficiency globally is now an urgent need. As well as being the cleanest, quickest and cheapest way of reducing emissions, improved energy efficiency can reduce the stress on energy supply systems and thus help countries achieve the aims of the UN Assembly's Sustainable Development Goal 7, 'Ensure access to affordable, reliable, sustainable and modern energy'. It also has the potential to reduce reliance on energy imports, an issue that is particularly relevant in Europe in 2022 as the region attempts to wean itself off Russian oil and gas.

The work of ep group in energy efficiency and the issues of financing energy efficiency over many years, and indeed decades, has led it to the conclusion that in order to scale-up energy efficiency, four elements need to be present in any project or programme. These are:

- A pipeline of projects.
- Standardisation of project development, contracts and under-writing.
- Building capacity in:
  - » The supply chain.
  - » The target market.
  - » The finance industry.
- Ensuring project finance is available but also the higher-risk finance needed to take projects from concept to being bankable.

How these elements should be brought together, and the nature of the entity or entities

responsible, whether private or public sector, will vary from country to country. The elements tackled by ESCO-in-a-Box™ address standardisation, building capacity, and building a pipeline of projects. To date it has addressed finance by partnering with local financial institutions who see the advantages of deploying capital into energy efficiency and are prepared to embark on a learning curve, assisted by the ep group and ESCO-in-a-Box™.

The next step in the growth of ESCO-in-a-Box™ in the UK and Kenya is to recruit additional entities to be ESCOs. This will increase the flow of projects, all developed using the standards embedded within the system, which in turn will help attract additional providers of finance. In Africa, there is already demand from companies outside Kenya and a plan to bring them into the ESCO-in-a-Box™ eco-system. In view of the particular financing needs in Africa, and the difficulties accessing local funding, the ep group and its partners are developing a dedicated Sub-Saharan Africa ESCO fund which will be able to fund all viable projects coming through the system. Putting such a fund in place will complete the eco-system of ESCOs and provide the funding necessary for scale-up.

Traditional ESCOs that use EPCs and guarantee performance have their role to play in improving energy efficiency in large sophisticated enterprises, but they cannot meet the market needs that ESCO-in-a-Box™ is addressing in the UK, Kenya, the US and soon the Philippines. This initiative represents an important new tool in the task of increasing investment into energy efficiency.

By **Steve Fawkes**

Managing Partner of ep group

Monthly News Round-Up

ECECP highlights the key energy news headlines from the past month in the EU and China

EU agrees eighth package of sanctions against Russia

On 5 October 2022, European Union ambassadors agreed an eighth package of sanctions against Russia on 5 October, including a ban on maritime transportation for Russian oil to third-party countries unless the oil is sold at or below a certain price cap. The sanctions also extend import bans on including steel products, wood pulp, paper, machinery and appliances, chemicals, plastic, and cigarettes. Additionally, the EU is banning the provision of IT, engineering, and legal services to Russian entities, and is expanding the tech-export ban.

+ More

EU ministers reach EUR 20 billion deal to ditch Russian fossil fuels

EU finance ministers reached a controversial deal on 4 October 2022 to raise EUR 20 billion from the bloc's carbon market to support the transition away from Russian energy.

+ More

EU lays out further measures to tackle energy crisis

The European Commission proposed a new emergency regulation on 18 October to address high gas prices in the EU and ensure security of supply this winter. Measures include joint gas purchasing, price limiting mechanisms on the TTF gas exchange, new steps to ensure transparent infrastructure use and solidarity between Member States, and continuous efforts to reduce gas demand.

+ More

Commission sets out actions to digitalise the energy sector

On 18 October, the EU Commission released an action plan that would boost data sharing, promote investments in digital electricity infrastructure, ensure benefits for consumers and strengthen cybersecurity.

+ More

UK launches new North Sea licensing round

In a bid to boost domestic production and reduce reliance on fossil fuel imports, the UK has launched its 33rd offshore oil and gas licensing round, covering 898 blocks. The initial aim is to award over 100 licences starting in Q2 2023.

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Clean hydrogen accelerator receives UK government backing

The Carbon Trust has announced a Clean Hydrogen Innovation Programme, which aims to speed up the deployment of clean hydrogen by reducing the end-to-end cost through technical innovation so that it becomes cost competitive with conventional alternatives. The project is backed by BEIS, the UK Government's Department for Business, Energy and Industrial Strategy.

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Spain unveils EUR 3 billion plan to help households cope with soaring energy prices

The Spanish government has unveiled an EUR 3 billion package to help vulnerable households cope with soaring energy prices, notably by increasing the amount of discounted energy by 15% as well as increasing the rebate on power tariffs for 'vulnerable' and 'severely vulnerable' households to 65% and 80% respectively.

The authorities have also lowered value-added tax (VAT) on gas to 5% from 21% until at least December 2022 to reduce the effect of rising international price on household utility bills. Spain has already cut the VAT on electricity twice over the past year; however, this is the country's first VAT reduction on gas.

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Netherlands shuts down Europe's biggest gas field

Netherlands is in the process of shutting down Groningen, Europe's largest natural gas reserve. Production will be capped at 2.8 bcm in 2023, although 470 bcm remains beneath the surface. Despite the energy shortfall, the Netherlands is hesitating to pump more gas due to potential earthquake risks. To ensure energy security, the country has decided to remove limits on coal-fired power plants and double import capacity for LNG.

+ More

Eight large scale Dutch hydrogen projects secure EU funding

Eight Dutch projects have secured EU funding to produce green hydrogen on a significant scale. Electrolysers range in size from 100 MW to 850 MW. The eight projects have been selected as part of a larger European financing project of more than EUR 5 billion for H2 projects in the EU. Four of them are located in Rotterdam.

+ More

France unveils energy efficiency plan, with no binding measures

France has announced plans for a 10% cut in energy consumption by 2024. The government has slated 15 key measures, from reducing heating to a maximum of 19°C in offices to encouraging people to carpool. However, the plan contains no binding measures, putting it at odds with a new regulation adopted by EU countries a week earlier.

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Gas crisis forces Uniper nationalisation

The German Federal Government has acquired a 99% stake in Uniper, signalling the gas importer's nationalisation. Uniper used up its cash reserves buying gas on the spot market after Russia cut flows to Germany, triggering a series of rescue packages from Berlin that now totals EUR 29 billion.

+ More

H2 Green Steel partners with Midrex for DRI technology

Sweden's H2 Green Steel is to partner with US-based Midrex to integrate its direct reduced iron (DRI) technology into the 'world's first' 100% green hydrogen-powered DRI plant.

+ More

Equinor to build Blandford Road battery storage project in UK

Norwegian energy firm Equinor has made a final investment decision for its Blandford Road 25MW/50MWh battery storage project developed in partnership with Noriker Power in the UK. Upon completion, the battery asset will be linked to the SSE distribution network, enabling it to manage power intermittency, balance supply and demand and deliver grid services to SSE and National Grid.

+ More

Ørsted to restart oil- and coal-fired power plants amid supply crunch

In response to the European energy supply crisis, the Danish authorities have ordered energy company Ørsted to continue and resume operations of three of its oil- and coal-fired power station units, two of were originally scheduled to be decommissioned on 31 March 2023. Despite the Danish authorities ordering the three units to be kept operational until 30 June 2024, Ørsted declares it remains committed to its sustainability targets.

+ More

China to work toward carbon goals actively, prudently

President Xi Jinping highlighted energy security in his two-hour long speech on the opening session of the 20th CPC National Congress on 16 October, restating that the nation will work actively and prudently toward the goals of reaching peak carbon emissions and carbon neutrality.

+ More

China publishes action plan for energy standardisation

A set of technical standards to support the low-carbon transition of China's energy system will be established by 2025, the National Energy Administration (NEA) has stated in an action plan for energy standardisation.

+ More

PV surpasses wind energy to power up China

Latest statistics from National Energy Administration (NEA) shows that by the end of August 2022, cumulative installed capacity of China's PV generation reached 349.9GW, outstripping wind power (344.5GW) to become the third largest power source.

+ More

Energy infrastructure to be further enhanced during 14th FYP

China plans to further enhance the construction of the infrastructure of the new energy system and to promote its digital transition, said China National Development and Reform Commission (NDRC) in September. The country aims to increase spending on key energy investment by 20% during the 14th Five-Year Plan, and to achieve a power transmission capacity of 360GW from energy-rich west regions to supply demand centres in the east of the country.

+ More

Produce carbon peaking action plan before end-2022, SOEs told

China's State-owned Assets Supervision and Administration Commission (SASAC) has told state owned enterprises (SOEs) to come up with action plans by the end of this year, showing when their carbon emissions will peak, and providing information about their emissions. Twenty SOEs have already released their plans, but several are described as not sufficiently ambitious.

+ More

Rural grid upgrading to focus on distributed renewable integration

In October, NDRC and NEA jointly released a draft guidance paper on rural power grids consolidation and upgrading, highlighting the demand for the modernisation of rural power grids to allow flexible integration of distributed renewables and diversified loads. This will improve the penetration rate of distributed renewable energy in rural power grids and promote local consumption of renewable energy.

+ More

China to encourage the adoption of EPCs for public institutions

Three departments have jointly issued an Opinion paper on encouraging public institutions to adopt Energy Performance Contracting (EPC) to improve energy efficiency. The document aims to support the green and low-carbon transformation of public institutions while stimulating the local energy management service market.

+ More

NEV subsidies to be extended to end-2023

China is to extend its subsidy program for new energy vehicles (NEVs) for another year, according to the Ministry of Industry and Information Technology (MIIT). The program was due to end in 2022. The move is intended to support development of the NEV sector and stimulate EV sales.

+ More

China's power battery output surges amid booming NEV market

China's installed power battery capacity rose by 176.2% year on year to 372.1 GWh in the first nine months of 2022, according to the China Association of Automobile Manufacturers, driven by the booming new energy vehicle (NEV) market.

+ More

China Development Bank ups loan support for clean energy

China Development Bank issued a total CNY 406.9 billion of loans to support clean energy development, offer energy supply guarantees, and promote clean and efficient coal use in the first 3Q of 2022.

+ More

China plans for harmless treatment and utilization of sludge

The NDRC, the Ministry of Housing and Urban-Rural Development, and the Ministry of Ecology and Environment have jointly issued an Implementation Plan of Sludge Harmless Treatment and Resource Utilisation. Sewage source heat pumps and the application of sludge biogas cogeneration technology for heating and cooling solutions are set to be boosted. The country will further promote the construction of highly energy efficient green and low-carbon benchmark plants for sewage treatment.

+ More

Zhejiang to promote distributed power trading

Zhejiang province released its Electric Power Regulations on 29 September, the first such local regulation since China's announcement of dual carbon targets. The document proposes direct trade between distributed PV and wind power producers with nearby users, leveraging market-based mechanisms to stimulate renewable power consumption. The move is set to promote the rise of prosumers and boost distributed energy.

+ More

Nuclear plant to provide heating in north-east China this winter

Northeast China's first commercial nuclear heating project is scheduled to get under way this winter. With a planned heating area of 242,400 square metres, it is expected to replace the 12 existing small boilers in the town of Hongyanhe (population 20 000). With a total installed capacity of 6.7 million kilowatts, the Hongyanhe nuclear power plant is the largest operating nuclear power plant in China and the third largest in the world. It became fully operational in June 2022.

+ More

Midea starts work on new heat pump plant in Italy

Work has begun on a new heat pump production and R&D facility in Feltre, northern Italy. China's Midea Group is spearheading the EUR 60 million project, which is located inside a production area of Italy's Clivet, a leading European company that designs, produces and distributes systems for cooling, heating, air ventilation and air purification for residential, commercial and industrial markets. The new base, which is designed to include an annual capacity of 100 000 external and 200 000 internal heat pump units, is expected to be brought into operation in the second quarter of 2024. Midea owns an 80% stake in Clivet.

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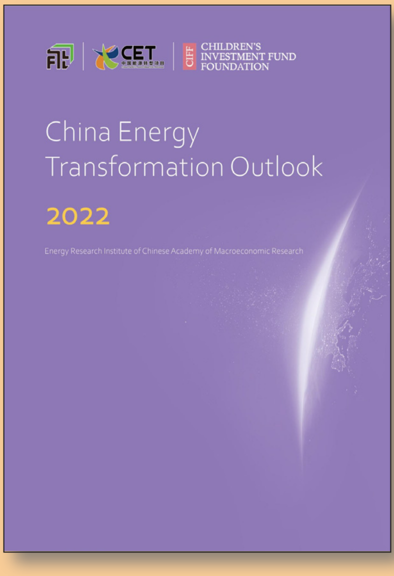
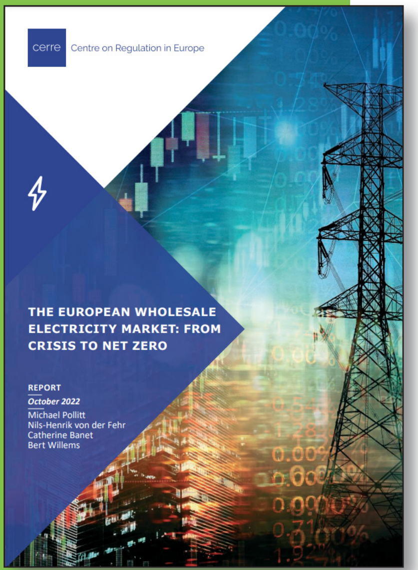
Featured Publication



China Energy Transition Outlook 2022

This report offers a comprehensive analysis of the Chinese energy system. Put together by the Energy Research Institute, Chinese Academy of Macroeconomic Research (ERI of AMR), it presents an analysis of the sustainable pathways towards fulfilment of China's ambitious carbon targets. Prepared in close cooperation with the Danish Energy Agency (DEA), the Center for Global Energy Policy (CGEP) and Norway's Norad, the report focuses on two different energy transition pathways under a Baseline Scenario (BLS) and Carbon Neutral Scenario (CNS). The report includes several sectoral analyses, including end-use sector transformation, power sector transformation, power market reform, power-to-X, carbon pricing, and the status and prospects of carbon capture underground storage (CCUS) in China.

→ Read More



The European wholesale electricity market: from crisis to net zero

The Brussels-based Centre on Regulation in Europe (CERRE) has issued this report with the aim of examining wholesale electricity market design and the proposed changes and interventions in light of Europe's current energy crisis and carbon neutrality goals. While much of the report is centred on the current crisis, it also warns about the potential lasting repercussions of short-term action, and presents some initial findings on what this could mean for energy market regulation as Europe tries to move out of the current energy crisis and towards Net Zero.

→ *Read More*

Power market and pricing mechanism reform in China: A vital step toward zero-carbon electricity growth and new power system

Market and pricing enhancements play a vital role in boosting the growth of zero-carbon electricity and supporting a more resilient power system. This report by Rocky Mountain Institute (RMI) focuses on the challenges faced by China's power market in zero-carbon power capacity development and power consumption, as well as system adequacy in zero-carbon power growth. The study reveals how market development and power pricing reform could help address these challenges through multi-year electricity contracts, interprovincial trade and transmission tariff optimisation, as well as capacity pricing for system adequacy.

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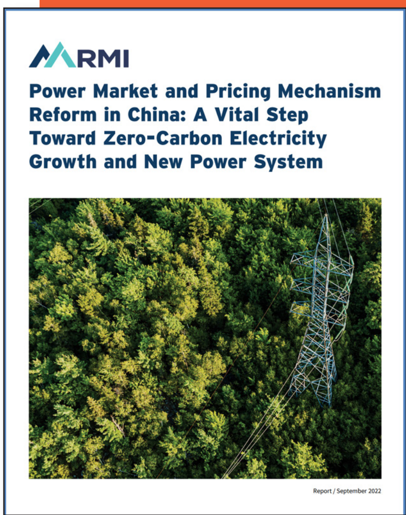

Demand-side flexibility: Quantification of benefits in the EU

This study, published by European business association Smart Energy Europe (smartEn), provides the first comprehensive assessment of Demand-Side Flexibility (DFS) potential in the EU. Norway's DNV was commissioned by smartEn to identify and quantify the benefits in the EU of a full activation of the flexibility from buildings, transport, and industry to achieve the 55% GHG emissions target in a cost-efficient way both for the energy system as a whole and for consumers. The findings serve as a clear warning not to undervalue DSF, given its potential to have a huge impact on development of an efficient, clean electricity system.

→ Read More

Blockchain solutions for the energy transition: experimental evidence and policy recommendations

How could blockchain solutions enable, and potentially revolutionise, the energy market and system operations, asks this report, which summarises the main outcomes of several experimental studies carried out by the Joint Research Centre on blockchain solutions for energy systems. It presents considerations and recommendations for policymakers regarding blockchain deployment across the energy value chain.

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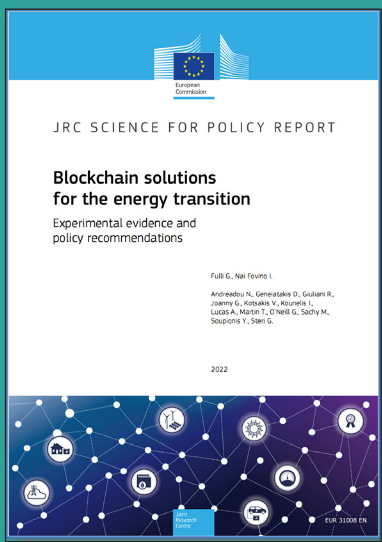

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EU-China Energy Cooperation Platform Project (ECECP) is funded by the European Union.