CLEAN ENERGY MINISTERIAL
Accelerating the Global Clean Energy Transition

Thermal Power Plant Flexibility

A PUBLICATION UNDER THE CLEAN ENERGY MINISTERIAL CAMPAIGN

ADVANCED POWER PLANT FLEXIBILITY
A Clean Energy Ministerial Campaign

Danish Energy Agency

Ea Energy Analyses

ENERGINET

电力规划设计总院
Electric Power Planning & Engineering Institute

CNREC
国家可再生能源中心
CHINA NATIONAL RENEWABLE ENERGY CENTRE

CLEAN ENERGY
MINISTERIAL
Accelerating the Global Clean Energy Transition

Copyright

About CEM

The Clean Energy Ministerial (CEM) is a high-level global forum to promote policies and programs that advance clean energy technology, to share lessons learned and best practices, and to encourage the transition to a global clean energy economy. Initiatives are based on areas of common interest among participating governments and other stakeholders.

Advanced Power Plant Flexibility Campaign

The CEM's Advanced Power Plant Flexibility Campaign is set up to build strong momentum and commitment to implement solutions that make power plants more flexible. The governments of China, Denmark and Germany lead the campaign; participating countries are Brazil, Canada, India, Indonesia, Italy, Japan, Mexico, Saudi Arabia, South Africa, Spain, United Arab Emirates and the European Commission.

Acknowledgements

'Thermal Power Plant Flexibility' is a publication under CEM's Advanced Power Plant Flexibility Campaign made by the Danish Energy Agency (DEA), the Electric Power Planning and Engineering Institute (EPPEI), the China National Renewable Energy Centre (CNREC), the Danish TSO Energinet and Ea Energy Analyses (Ea) - and financially supported by Children's Investment Fund Foundation (CIFF).

Contacts:

Shunchao Wang, Electric Power Planning and Engineering Institute, Email: scwang@eppei.com
Laust Riemann, Danish Energy Agency, Email: lri@ens.dk

Executive summary

Integration of variable energy production from renewables creates a need for increasingly flexible power systems – from supply, transmission, distribution and demand. This report zooms in on the benefits of flexible thermal power plants, including the technical aspects related to enhancing the flexibility of power plants, and incentives for investing in and operating flexible power plants.

Denmark is one of the frontrunners in terms of flexible power systems. For decades Denmark has had a close cooperation with neighbouring countries in the exchange of power, which in combination with quite large differences in electricity demand from day to night, encouraged Danish power plants to enhance their flexibility. The creation of a Nordic power spot market with merit order dispatch and hour-by-hour pricing has been instrumental in incentivising thermal plant operators to improve and utilise the flexibility of their plants during the past two decades. This evolution illustrates the opportunities associated with exploiting the flexibility potential of existing infrastructure. With wind power accounting for 43% of annual Danish power consumption in 2017, and targeted to exceed 50% by 2020, the Danish thermal power fleet has been compelled to become the most flexible in the world, and thus an important provider of system flexibility.

China has built a very large fleet of thermal, coal-based power plants over the past 20 years. Focus has been the expansion of the power system to cope with increasing demand for power in the fast-growing Chinese economy. Limited attention had been paid to creating flexibility until recently, except for the establishment of pumped hydro storage plants. During the past ten years China has experienced an equally rapid deployment of wind power, and more recently solar PV. Integration of variable production from wind and solar has been challenging, as evidenced by extremely high rates of curtailment, i.e. forced reduction in power output.

This report examines the situation in China both today and in the future, with detailed analyses of the power system using a power system model developed by the China National Renewable Energy Centre (CNREC), combined with expertise on thermal power plants from the Electric Power Planning Engineering Institute (EPPEI). In the analyses, experiences from Denmark and from the Nordic power market are used in a Chinese context to provide insight in how to incentivise flexibility in the Chinese power system.

1.1 THE CURRENT SITUATION IN CHINA

Integration of VRE in China today is challenging, but recent developments are more promising

A measure for the success of renewable energy integration is the amount of curtailed electricity production from wind and solar power plants. In China, curtailment has been a significant and increasing problem during recent years. In 2016, roughly 17% of production from wind power, and 10% of production from solar power was curtailed on a national level. Meanwhile, curtailment rates in some of the Northern provinces were considerably higher, with some regions experiencing rates exceeding 40%.

In 2017, VRE curtailment was reduced significantly, primarily due to implementation of the following measures:

- A ban on investments in wind and solar (red flag warning mechanism) to slow down investment in regions with high curtailment.
- Launch of an incremental spot market pilot project to stimulate cross-region and cross-province power trading
- Strengthening of grid connections and reduction of bottlenecks in the transmission grid.
- Launch of down-regulation markets in Northern regions to encourage flexible operation of thermal power plants.
- Pilot projects involving investments in flexibilization of existing coal power plants, particularly combined heat and power (CHP) plants in the Northern regions.

In 2017, curtailment of wind power was thereby reduced to 12%, and curtailment of solar power was reduced to 6%. In the first quarter of 2018, wind and solar curtailment rates were further reduced by a third compared to the first quarter of 2017. While some of the implemented measures only provide for temporary improvements to VRE integration, others are key to long-term solutions. The down-regulation markets in particular have proved to bestow incentives for flexible operation by punishing operators of inflexible power plants and rewarding operators of flexible power plants, though these mechanisms need to be further refined in the broader context of the ongoing market reform.

Positive initial results from pilots involving flexibilization of thermal power plants in China, but also challenges ahead

There is a growing awareness amongst stakeholders in China, from policy makers in the National Energy Administration (NEA) to power generation companies, that there lies an untapped potential in improving the flexibility of coal-fired power plants. China has looked to positive international experiences for inspiration and has begun work on transferring these experiences into the Chinese context. As a result, ambitious targets for flexibilization of coal-fired thermal power plants have been announced, a massive demonstration program with 22 power plants is ongoing, and experience has started to materialise from this. As challenges are overcome (prime examples include those from Guodian Zhuanghe, Huadian Jinshan and Huaneng Dandong power plants inspired by Danish experiences), conservative mindsets of technical experts are shifting and becoming open to flexibility implementation.

Going forward, the Chinese thermal power fleet faces several technical and regulatory challenges that require attention. The technical challenges include emission control during low-load operation, lack of experiences with large-scale heat storages, and reduction of frequency control response capability during low-load operation. The regulatory challenges are primarily related to development of a more comprehensive market for ancillary services comprising up and down regulation and fast ramping services, and the development of a mature spot market as a more permanent solution for the Chinese power system.

1.2 FLEXIBILITY IN THE FUTURE CHINESE ENERGY SYSTEM

The analyses of the impacts of a flexible power system in the future are carried out using a detailed power system model for China, the EDO model, to simulate scenarios for the power and heat systems. The scenarios are taken from the work underpinning the China Renewable Energy Outlook 2017 (CREO 2017), with additional assumptions regarding flexible or inflexible operation of the thermal power fleet.

The main findings from the power plant flexibility analyses were:

Increased thermal power plant flexibility results in lower CO_2 emissions and reduced coal consumption

When comparing calculations with and without increased power plant flexibility, annual CO_2 emissions with more flexible power plants are 28 million tonnes lower in 2025, and 39 million tonnes lower in 2030, which is roughly comparable in scale to total annual Danish CO_2 emissions. The primary reasons for these reductions are less heat-only and electricity-only production based on coal, and less curtailment of renewables. The lower coal usage signifies an increase in overall energy efficiency as CHP units are able to produce more (with high efficiency due to heat co-production) substituting less efficient production at power-only and heat-only units. In addition to the CO_2 related benefits of lower coal consumption, there are also a number of local environmental benefits associated with these reductions.

Increased thermal power plant flexibility results in less curtailment of VRE

The implementation of flexible power plants reduces the total modelled VRE curtailment by roughly 30% in both 2025 and 2030. The annual reduction in VRE curtailment is 2.8 TWh in 2025 and grows to 15.3 TWh in 2030. The growth in the curtailment reduction from 2025 to 2030 reinforces the fact that a more flexible coal-based thermal fleet facilitates the integration of growing quantities of VRE within the Chinese power system.

Increased thermal power plant flexibility results in higher achieved power prices for both VRE and coal power

Higher achieved power prices for both VRE and coal are important drivers for continued VRE buildout. Higher realised electricity prices for VRE provide incentive for developers to continue investment in VRE, and at the same time make VRE more competitive with fossil fuel-based generation. It reduces the need for subsidies, which is an important prerequisite for the continued growth of VRE. For coal plant owners, higher realised prices for the electricity they produce incentivises investment in flexibility. Flexible thermal plants can better respond/operate according to varying electricity prices, thus improving their ability to produce when prices are high (and thereby realise greater revenue), and lower production when VRE production is high, thus raising prices for low marginal costs assets.

Increased thermal power plant flexibility gives lower power system costs

The socioeconomic analysis indicates that a more flexible power system results in an economic gain for the Chinese power and district heating sectors. The total benefit of increased power plant flexibility investments analysed are roughly 35 bn RMB annually in 2025, growing to over 46 bn RMB in 2030. The fact that the benefit increases between 2025 and 2030 indicates that the window for focusing on power plant flexibility is beyond 2025 and supports the robustness of the conclusions. There are three additional elements that also reinforce the robustness of the economic conclusions. Firstly, more flexible thermal plants lead to less investment in coal heat-only boilers that have a relatively low capital cost, and the net economic benefit is positive even without the inclusion of these cost savings. Secondly, the contribution from flexibility investments in relation to the overall benefits is minor, so even if these investment costs are highly underestimated (i.e. they could be more than tripled), the results will still be positive. Lastly, despite the fact that the future CO_2 price is quite uncertain, the contribution from this aspect is rather small, i.e. even with a CO_2 price of zero the results change relatively little.

Power plant flexibility plays different roles depending on context

The above findings are aggregated on a China-wide level, but it is also useful to compare the role of enhanced power plant flexibility in different mixes of generation assets as well as different power grid situations – whether the local systems predominantly feature imports, exports, or transit flows, etc. Five different situational contexts are investigated, including four provinces and a perspective on the VRE integration challenge during a period with high need for system flexibility:

1. The north-western province of Gansu, which features high VRE penetration, and through which significant power transit flows.
2. The north-eastern province of Heilongjiang, where cold winters, high district heating penetration and VRE installations coincide.
3. A coastal province, Fujian, which relies on limited power exchange with neighbouring provinces.
4. A selected week on the island province of Hainan, with limited transmission capacity, and large nuclear base-load
5. Spring festival, during which time industrial production is shut down, electricity demand drops to the lowest point of the year, but demand for heating is still high in the North, all of which combine to create significant system challenges.

This portion of the analysis illustrates how power plant flexibility plays different roles depending on context, thereby providing insights for other regions/countries. While the benefit and scope of thermal flexibility measures is demonstrated to be situationally dependent, it plays a role in each of the sub regions analysed. Investment in retrofitting and new flexible power plants happens in all provinces despite the large differences in the provincial context in terms of asset mix, types and grid situation. This is illustrated by the provincial cases of Gansu, Fujian and Heilongjiang where flexibilization of the power plants take place despite the large differences. However, given that flexible CHP plants play a larger role than condensing plants, the provinces with extensive shares of CHP also sees a more pronounced level of flexibilization of their thermal fleet.

1.3 ECONOMIC INCENTIVES FOR FLEXIBILITY

An essential precondition for developing enhanced power plant flexibility is a framework that motivates both the development and utilisation of flexible characteristics in the system. Such a framework can be conceived both within a regulated or market-based framework.

Four elements are highlighted for their value in defining a consistent framework for flexibility:

- Merit order dispatch
- Marginal cost pricing
- Opportunity cost pricing
- Price discovery

Merit order dispatch is the traditional criteria for efficient power system operation. It requires that different units should be selected to generate according to their position in the merit order, i.e. the unit with the lowest short-term marginal costs (or put alternatively, the cheapest to operate based on variable costs), should be selected first. Operation in this fashion allows for the minimisation of total system operating costs.

Having electricity prices determined by the marginal cost of electricity supply, i.e. where the marginal cost of supply meets the marginal willingness-to-pay for consumption, ensures that all generators at any time, are as a minimum compensated for their marginal cost of production, and that all consumers (assuming price-sensitivity of demand), pay no more than they are willing to, or abstain from consumption. This form of pricing ensures that production scheduling is carried out according to the merit order, and therefore is efficient in terms of system-wide resource utilisation. The clearing price is different at any time, e.g. hourly, depending on the level of consumption and availability of generation resources.

Opportunity cost pricing is a key element of ensuring efficient operation vis-à-vis other potential opportunities, e.g. for utilising production resources or pricing in the value of co-produced products, such as CHP, which has a high penetration level in the Chinese thermal asset mix.

Price discovery is a process for establishing the value of a product through competitive interactions between buyers and sellers. It is a critical component in achieving the needed transparency to ensure efficient prioritisation of resources. This includes establishing the price and value of flexibility provision to the power system, such that cost-efficient investments can be made.

In order to promote efficient use and deployment of power system flexibility, all four elements should be put into practice. This calls for:

- Utilisation of merit order dispatch to ensure optimal utilization of existing assets.
- Price incentives and price discovery as key elements to ensuring efficient development of system flexibility.
- Incentives for efficient coupling of heat and power supply should be considered in establishing the regulatory framework for both sectors.
- Newly commissioned units' minimum flexibility characteristics can be regulated through standards. However, the low-cost measure involving flexibility retrofits of existing assets is more difficult to promote using standards, and therefore requires incentives due to the heterogeneity of an existing asset mix.
- A regulated framework with merit order dispatch can ensure efficient utilisation of existing flexibility, but motivation of additional flexibility development requires additional regulatory measures.
- Whether in a regulated or market-based power system, there are elements in the dispatch, market operation or incentive structure, which can be adjusted to enhance power plant flexibility.

1.4 TOWARDS A MARKET FRAMEWORK

Relative to a centrally operated dispatch system, a market framework provides an advantage through the provision of incentives to asset owners to contribute with flexibility from a heterogeneous asset mix. The optimal long-term solution is therefore market-based, but short-term temporary measures can provide substantial flexibility at existing thermal power plants. They should however be seen in the context of the long-term solution and transitional arrangements.

The different market mechanisms and products will have to be reformed as to reflect the future needs of the system, i.e. focus on where scarcity is within the system in order to address e.g. variability, uncertainty, ramping, energy, adequacy etc. Cleverly defined market mechanisms can broadcast these imperatives to market participants, such that the energy system transition can make cost-efficient use of flexibility resources in the system, indicate the value of flexibility characteristics, and allow market participants to develop their assets' flexibility characteristics in accordance with the developing needs of the system.

Spot market implementation is a cornerstone

The cornerstone of this evolution is the successful development of a spot market for bulk power trading in the short-term, with price formation tethering the interrelated markets, products and services being evolved in parallel. While the characteristics of well-developed spot markets are generally well understood, their original introduction is a path-dependent process, affected by the incumbent situation in terms of asset mix, ownership, and legacy regulation. In the process of implementing power market reform there will be a transitional phase during which a mix of market and regulatory mechanisms concurrently govern the power systems.

Further evolution is needed to the down-regulation market

In China, the down regulation market has successfully introduced market principles in a fashion that is compatible with the incumbent plan-based regulatory framework. With the introduction of spot markets, the next stage of must be prepared for active power balancing services. The down-regulation market should utilise spot market schedules as a reference point. Deviations from this reference generates demand for regulation services. The product definition should be expanded to at least include up regulation products (and possibly also ramping products). The market should also transform from one that has a thermal plant reference as baseline and adopt a technology neutral product definition.

Interconnected sectors must be considered

The highest value in terms of economic benefit, VRE integration and CO_2 emissions reductions found within the current analysis come from an improved coupling of CHP and district heating. In systems where this link is relevant, it is important to look holistically at the framework and incentives facing both the power and district heating businesses. In other systems, the analysis may be different, and the flexibility may be found in sector coupling with transport, industrial usage, etc.

Markets to drive transparency and transformation

Marginal cost pricing provides the strongest incentive for efficient competition (absent opportunities for collusion and market power exploitation). By setting bid prices equal to their short-run marginal costs, individual asset owners are incentivised to accurately submit their cost data to the market place or forego potential contribution towards covering their fixed costs. For flexibility to be activated, it must be visible to the dispatcher and/or the market place. This information is challenging to develop centrally, and individual assets' situation cannot be ignored.

Marginal pricing according to accurate information also ensures price discovery, which is essential for efficient investment planning and prioritisation. To drive the right flexibility projects forward, the value of flexibility needs to be transparent.

1.5 POWER PLANT FLEXIBILITY AS A TRANSITIONAL MECHANISM

The energy transition ongoing in China and around the world requires a comprehensive focus on the development of flexibility in power systems. Thermal power plant flexibility is but one important component in this broader challenge. The introduction of market reforms will have winners and losers in the short-run. During energy transitions, this naturally creates resistance from incumbent market players with vested interests in the technologies from which the system is transitioning.

A focus on promoting thermal power plant flexibility provides the opportunity to create positive economic returns from an overall system cost perspective. This provides room for transitional mechanisms that may be needed, e.g. to compensate for stranded assets. More importantly however, through emphasis on the fact that in de-carbonised electricity systems flexibility is a prized commodity, which existing assets could develop at low cost, there is a new positive role to be played for thermal plants in the energy transition.

Through such a process, it becomes possible for stakeholders whom are facing external challenges to the value of their assets to identify opportunities to contribute effectively to the transition, while safeguarding the return on their historical asset investments.

It is an important but non-trivial exercise to establish a transitional pathway of 'least-resistance' by sequencing steps that generate overall efficiency increments. This increases the size of the proverbial pie, and through transitional regulatory mechanisms ensures some level of compensation for stakeholders incurring a loss at each stage of the transition, thereby mitigating the resistance from vested interests. Addressing the challenge of inflexible assets in the thermal generation mix, as analysed in this report, provides new opportunities for thermal asset owners, while furthering the energy transition in the process.

1. Introduction

At the 8th Clean Energy Ministerial meeting in Beijing in 2017 (CEM8), a campaign for Advanced Power Plant Flexibility was launched as a shared effort between the CEM's Multilateral Solar and Wind Working Group and 21st Century Power Partnership.

The Campaign seeks to build strong momentum and commitment from governments and industry to implement solutions that make power generation more flexible. It looks to advance and share best practice between CEM members within power plant flexibility and seeks to highlight best practice that can ensure the necessary economic incentives are in place to drive investments in, and optimal use of, flexible power plants.

As part of the campaign, Denmark and China have joined forces in preparing this report drawing upon experiences and analyses of power plant flexibility in the two countries.

Building upon the long-term Sino-Danish governmental cooperation in the energy sector anchored in the China National Renewable Energy Centre (CNREC), as well as the Sino-Danish cooperation on thermal power plant flexibility between the Chinese Electric Power Planning and Engineering Institute (EPPEI) and the Danish Energy Agency (DEA), the report summarises experiences from both countries and presents new analyses of the benefits of increased flexibility in the future Chinese power system. Furthermore, the report highlights key drivers and incentives for power producers to adapt to the need for a more flexible power system, with primary focus on market-based incentives.

The partners behind the report are:

- **Electric Power Planning and Engineering Institute (EPPEI)** in China, one of the leading institutes for power sector planning and development. EPPEI is entrusted by the National Energy Administration (NEA) to carry out research on power plant flexibility in the Chinese power system and to lead the ongoing pilots for retrofitting existing power plants to flexible operation.

- **The Danish Energy Agency**, which is partnering with 12 countries around the world to create a clean, prosperous and low-carbon energy future by sharing experience, expertise and innovation from the green transition in Denmark. In China the Danish Energy Agency works closely with both EPPEI, CNREC as well as the National Energy Conservation Centre (NECC).

- **China National Renewable Energy Centre (CNREC)**, a think tank as part of the Energy Research Institute under the National Development and Reform Committee (NDRC). CNREC provides policy research on development of renewable energy for the NEA and NDRC, and prepares an annual China Renewable Energy Outlook (CREO), comprising detailed energy system scenarios based on comprehensive energy system models.

- **Energinet.dk** is the Danish transmission system operator responsible for one of the highest levels of security of supply in the world and supports the Danish Energy Agency's Global Cooperation with technical expertise.

- **Ea Energy Analyses** is a Danish company that provides consulting services and undertakes research in the fields of energy and climate mitigation & adaption. Ea Energy Analyses operates in Denmark, the Nordic region and abroad with project activities in Europe, North America, Asia and Africa. Ea has been working with, and embedded within, the China National Renewable Energy Centre.

2. Danish Experiences

2.1 DEVELOPMENT OF ENHANCED POWER PLANT FLEXIBILITY IN DENMARK

The Danish power system features a global leading share of wind power, with wind power accounting for 43% of annual power consumption in 2017 and targeted to exceed 50% by 2020. The incentives underpinning this development are rooted in a consistent and continued political drive and have resulted in Danish companies today being among the global leaders in technologies and solutions supporting the green transition.

With wind power covering almost half of consumption on an annual basis, the system needs to cope with incidents when wind generation exceeds 100% of national consumption. In 2015, this occurred roughly 5% of the time. Despite this, *curtailment*, i.e. forced reduction in power output from VRE generators that could otherwise produce, has been minimal. At the same time, security of supply in Denmark continues to be ranked among the best in the world, and in 2017 Denmark was declared by the World Bank as the world leader in green energy based on assessment of renewable energy, energy efficiency and access.

Danish power system flexibility, and the ability to integrate intermittent renewables, rests on many pillars – but some of the most fundamental ones are:

- Market-based power dispatch ensuring cost-efficient asset allocation on an hourly and sub-hourly basis. This provides a public and unambiguous price signal for market actors.
- Strong market integration with systems in neighbouring countries facilitating a larger physical balancing area.
- A highly refined TSO forecast system for VRE production, which reduces the need for other forms of system flexibility.
- A thermal power plant fleet that has become among the most flexible in the world.

Going forward other sources of flexibility will naturally start to play a growing role, including demand side response, electricity storage, and closer linkage to other sectors, for example through unleashing flexibility from smart charging/discharging of electric vehicles.

While wind power is the main contributor to the decarbonisation of the Danish power system, the overall energy efficiency in the power and heat sector has also improved significantly. This is a result of increased district heating, particularly from combined heat and power (CHP) plants, while power-only (condensing) plants in Denmark has, over time, been taken out of operation. Consequently, practically all thermal power plants are CHP plants that both serve local district heating demand, and while through highly flexible production, optimise their operation in accordance the increasing share of wind power.

The development of highly flexible thermal power plants in Denmark has been driven by clear economic incentives to adjust production according to the increasing shares of wind power in the system. A historic perspective outlining this development is presented in the following section.

1999/2000 - Joining the Nordic power exchange

At the beginning of the new millennium, the Danish power sector was dominated by coal-fired plants supplemented by smaller gas-fired CHP plants and a wind power share of roughly 10%. The thermal power plants were shielded from competition and operated on a not-for-profit basis within vertically integrated utilities. This came to an end in 1999 when Denmark joined the other Nordic countries in the shared power exchange - Nordpool, as part of power market liberalisation.

The Nordpool market had major implications. Firstly, it meant that Danish thermal power plant producers now faced competition from production with lower marginal costs, hydro and nuclear power from the other Nordic countries, and increasingly from domestic wind power. Secondly, the market now delivered a unified and transparent power price for every hour of the upcoming day, which clearly signalled to producers when generation was profitable. This was the main driver in the first development stage of flexible power plants in Denmark. The economic incentive to operate flexibly in accordance with changing market prices was not present.

The power market introduction spurred widespread construction of large-scale heat storages at the large CHP plants. These previously had limited ability to adjust their power output due to their obligation to supply district heating. The heat storage tanks allow for de-coupling of when heat is produced and when it is utilised. Thereby they allow plants to regulate their power and/or heat output according to the electricity price signals in the market.

The small CHP producers were also incentivised to acquire heat storage tanks, driven by a time-varying generation tariff in the period before they were exposed to Nordpool prices. Today, practically all CHP plants in Denmark, both small and large, have heat storages.

2000-2010: From 10% to 20% wind power

From 2000 to 2010 the share of Danish power consumption from wind power generation rose from roughly 10% to 20%, and Denmark's production from power-only (condensing) plants was phased out. Utilising only roughly 40% of the energy from the input fuel by operating in the power market alone (vs. over 90% in CHP mode) was no longer economically viable, thus forcing the remaining power-only plants to be mothballed.

This period was also characterised by the emergence of longer periods with low prices in the power market. Flexible production capabilities on the part of the thermal power plant operators to better respond to price signals from the market to maximise revenues and contain costs, became increasingly important. Consequently, thermal power plant owners started to improve minimum load capabilities, enhance ramping speeds, and further expand the overall potential production area for heat and power production. These elements will be looked at in further detail in the following section.

Many of these flexibility improvements were the result of several smaller incremental enhancements. The majority of enhancements involved limited investments in new hardware but enabled thermal producers to reduce or avoid production in periods of low power prices, as well as tap into higher value markets for ancillary services. Danish experiences from this period showed that the early stages of enhanced thermal power plant flexibility could be achieved with limited investment costs.

2010-today: a doubling of wind's share to 40%

Variable renewable power generation's share of consumption in Denmark has risen from roughly 20% in 2010 to over 40% today. During this period, the market situation has been characterised by more frequent and longer periods with low power prices, and the thermal power plants' utilisation rates decreased. Driven by economic incentives from the market, thermal power plant operators have opted for more extensive flexibility measures, as well as continued efficiency improvements and ways to decrease maintenance costs. At this stage, power plant flexibility improvements started to require larger investments and hardware retrofitting.

Reducing the start/stop time and the associated costs became increasingly important, as it often became more economical to cycle a unit than running at minimum load for an extended period with low power prices. There was also increased investment in electric boilers, which convert power to heat, thus enabling operators to tap into balancing markets and take advantage of the increased number of hours with low power prices, which in some cases can be negative.

In addition to the focus on enhanced thermal power plant flexibility, the sector also experienced other strategic and structural changes during this period. Utilities increasingly shifted their strategic focus towards renewable sources and flexible operation in response to the diminishing earnings from fossil fuel-fired power plants. Examples included investments in offshore wind development, waste-to-energy plants, biomass-fired power plants and other renewable energy segments. Investments in biomass-fired generation include the conversion of large coal-fired CHP plants to biomass-firing. This was motivated by both tax incentives and the political aspirations of the larger cities to decarbonise.

New biomass-fired CHP units are primarily designed to supply district heating, while only producing power during periods of high electricity prices. An example is an old coal-fired CHP plant supplying parts of Copenhagen with district heating, which is now being taken out of operation and substituted with a new wood chip-fired CHP plant to supply the district heating demand. The new CHP plant is designed with the capability to fully bypass power output to reduce, or avoid, power production during periods with low electricity prices.

2.2 THERMAL POWER PLANT FLEXIBILITY IN DENMARK

The development of highly flexible thermal power plants in Denmark has occurred incrementally in response to an increased need for flexible operation as the share of VRE grew significantly. The development has essentially followed a pattern where the cheapest and easiest improvements were implemented first. However, consideration was also given to improvements that would be most profitable given the observed and expected prices and long-term market projections.

While enhanced flexibility can be categorised into relatively few aspects, such as lowering minimum load, introducing turbine bypass, etc. the range of possibilities and measures to enhance flexibility is extensive. It depends on plant age, coal type used, boiler type, and not least of which plant and component quality and overall plant configuration. Improvements vary significantly in terms of complexity, investment needed, effect, scope and time needed to design and implement. For this reason, it can be challenging (and an oversimplification) to describe specific flexibility improvements as if they are broadly applicable. That being said, the following section provides a description of the individual power plant flexibility options, including cost estimates for their implementation, as these figures are utilised in the quantitative analysis later in the report.

Despite the large range of possible improvements, a key learning has been that a certain amount of additional flexibility can be unleashed from the existing thermal power plant fleet without undertaking physical retrofitting, but by changing the existing operational boundaries and adjusting the control system and operational practices. A main benefit of enhancing the flexibility of thermal power plants is therefore that it takes advantage of existing assets' potential, often through limited investments. Furthermore, enhanced thermal power plant flexibility can be implemented relatively quickly, thus providing a rapid way to enhance system flexibility and provide relief to certain geographic areas in imminent need of more flexibility.

Individual flexibility components

Most large power plants in Denmark were built in the 1980s and 1990s, and were coal-fired extraction type CHP plants with Benson boilers. The improvement of flexibility capabilities over time has either expanded the operational boundaries, reduced or de-coupled the timing of heat production and utilisation, and lastly improved the speed and reduced the cost of output changes and plant cycling. A schematic overview of the main flexibility improvement measures for CHP and condensing plants is provided in Table 1.

Minimum load

Today the minimum boiler load on the large Danish thermal power plants is typically in the range of 15-30%, while the designed minimum boiler load for Benson (once-through) boilers is normally around 40%. With relatively modest investments, such boiler types can generally be retrofitted to allow the plant to have stable operation with a boiler load in the range of 20-25%. The cost associated with such a retrofit is roughly 15,000 EUR per MW, or approximately 4-5 million EUR for a 300 MW plant (European cost estimates). The

Table 1: Overview of the main flexibility improvements measures used in Denmark

<table>
<tr><th>General operational flexibility improvements</th><th>CHP units</th><th>Condensing units</th></tr>
<tr><td rowspan="3">Expand the operational boundaries (i.e. expand the output area)</td><td colspan="2">Lower minimum load</td></tr>
<tr><td colspan="2">Overload ability</td></tr>
<tr><td rowspan="2">Turbine bypass</td><td rowspan="3"></td></tr>
<tr><td rowspan="3">Decoupling of heat and electric production and/or when heat is produced and when it is utilised</td></tr>
<tr><td>Heat storage</td></tr>
<tr><td>Electric boilers and heat pumps</td><td></td></tr>
<tr><td rowspan="2">More flexible operation mode within output area</td><td colspan="2">Improving ramping speed and fast output regulation</td></tr>
<tr><td colspan="2">Faster/cheaper start/stop of plant</td></tr>
</table>

additional investment cost for a new plant would be less than 1% of the total plant investment.

The investments typically include installation of a boiler water circulation system, adjustment of the firing system, allowing for a reduction in the number of mills in operation, combined with control system upgrades and potentially training of the plant staff. Reducing load to low levels can create challenges, particularly in terms of proper handling of fuel injection, measures to secure the stability of the fire in the boiler, as well as avoiding situations with unburned coal. Finally, lower and more volatile boiler temperatures can be a challenge, and proper control of emissions of NO_x and SO_2 must be dealt with specifically, as flue gas cleaning presents new challenges at low temperatures.

As load decreases, so does efficiency, leading to higher costs and emissions per unit of output. This is in of itself unattractive from both an economic as well as environmental perspective. However, if reducing load enables integration of more VRE in a given operational situation, or contributes to overall system flexibility allowing continued VRE growth, the ability to reduce minimum load can provide a system wide net-benefit in both economic and environmental terms.

Reducing load is valuable when it is economically unattractive to deliver power to the market. However, if the low price periods are sufficiently long and/or the prices are sufficiently low, then it might be more economical for the plant to be shut down for a period despite the direct and maintenance costs associated with making a start/stop. For a CHP plant to cycle, the plant must be able to serve heat demand from other sources (e.g. heat storage or peak/back-up boiler, etc.)

Overload

Danish power plants generally have the capability to operate in overload condition, which enables the plant to deliver 5-10% additional power output relative to normal full-load operation. This provides an option to boost production during situations when additional production is beneficial. This can provide additional value either in day-ahead planning if prices are sufficiently high, or enable the plant to offer (additional) up-regulation closer to the hour of operation. From a system perspective, the ability of plants to deliver additional output reduces the risk of new plants or more expensive reserves being forced to start up when supplementary output is required. If a plant does not have the required technical configuration to start with, the upgrade investment costs are typically in the range of 1,000 EUR per MW nameplate capacity (European cost estimates), equivalent to 0.3 million EUR for a 300 MW plant.

Ramping speed

Danish coal-fired power plants typically have ramping speeds of roughly 4% of nominal load per minute on their primary fuel, and up to 8% with when supplementary fuels, such as oil or gas, are applied to boost ramping. Quick ramping leads to rapid changes in material temperatures, which requires good quality plant components, and quick ramping also requires additional control of the processes. The level of investment needed to improve ramping speed depends greatly on the level of refurbishment required. In some cases, investment can be limited to new software and/or reprogramming of the control-system, while costs will be higher if technical retrofitting is required.

Water-based heat storage tanks

Large water-based heat storage tanks (both pressurized and atmospheric pressure tanks) are a popular technical solution to decouple when heat is produced and when it is utilised in Denmark. Heat storage tanks allow a CHP plant to continually supply the required local heat demand while altering the power output (typically reducing it) depending on the power prices.

The storage tanks can be used to provide district heating, while CHP plants delivering industrial process heat generally cannot take advantage of the heat storage due to the much higher temperatures usually associated with process steam. Heat storage tanks in Denmark typically range from 20,000 to 70,000 cubic meters for the large power plants (300-600 MW nominal power capacity), and investment cost is generally in the range of 5-10 million EUR. The optimal size of a heat storage tank depends on both the type of the tank (pressurized or not), the level of the local heat demand, its seasonal and daily profile, and more general plant characteristics including the flexibility capabilities. The heat losses from a well-operated and maintained heat storage tank are quite limited. During winter, heat storage tanks are typically dimensioned to cover heat demand for a period of 2-6 hours, while in the low heat consumption months enough heat can be stored to cover a weekend or more. This provides the possibility to shut down a plant for a couple of days if the power prices are low.

Retrofit of the Danish CHP plant 'Fynsværket'

The Danish hard coal-fired extraction CHP plant, ‘Fynsværket’ (unit 7) in Odense was commissioned in 1992 and serves a district heating market of approximately 4,000 TJ. In August of 2016, the Danish Energy Agency (DEA) and Electric Power Planning & Engineering Institute (EPPEI) organised a study tour with participants from 16 Chinese demonstration power plants to learn from and be inspired by the experiences at this plant.

The plant was originally designed to deliver a maximum of 410 MW electrical output in condensing mode, or 350 MW power output simultaneously with steam off-take of for 540 MJ/s for district heating supply.

At the time of commissioning, the plant was already designed with a high degree of flexibility, which included a minimum output of around 89 MW (20%) in condensing mode, and 80 MW in backpressure mode.

Since this time, the plant has undertaken 3 main actions to enhance the flexible operation of the plant further:

De-couple combined power and heat production

Establishment of heat storage: In 2002, ten years after commissioning of the plant, a 73,000 m^3 water-based heat storage tank was constructed, with an investment cost of approximately 5 million euro.

The tank can supply the full district heat need for roughly 6-10 hours during the peak heating season, or deliver heat for more than a week during summer.

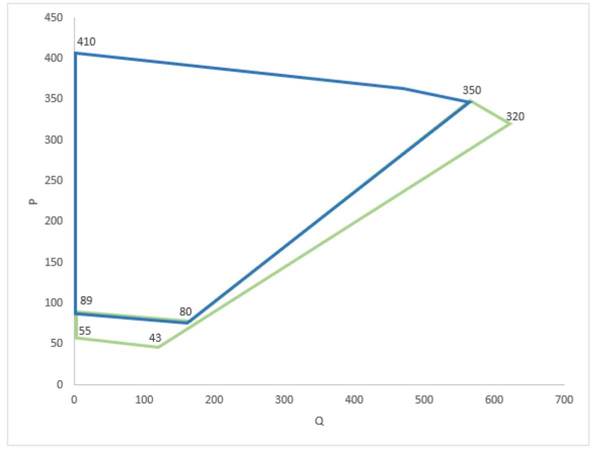
Expanded output area

a) Lowering minimum load: During the years it has been made possible to run the unit continuously at a minimum load of around 55 MW in condensing mode and 43 MW in backpressure mode by means of controller tuning of the feed water supply.

   On this particular plant this improvement did not require any hardware investment but was a result of enhancing the flexibility of the unit with current hardware configuration.

b) Increase maximum heat output: The plant has also developed an operation mode (LP-preheaters shut off), which allows the plant to expand its maximum heat output from 540 MJ/s to 630 MJ/s by lowering the power output. This additional output area is generally profitable to use under relative low power prices during winter season.

Both the original (area covered by blue lines) as well as the increased output area (shown with green lines) is depicted in the figure below showing the plant's possible power and heat output.



Electric boilers

Investment in large electric boilers provide additional peak or reserve heat capacity, an opportunity to take advantage of low power prices by converting power to heat, and a fast down-regulation option in the intraday and balancing markets. However, due to relatively high taxes and tariffs on power consumption in Denmark, the Day-ahead power prices must be very low to make heat production from the electric boilers competitive, an area where the alternative is biomass, which is exempt from energy taxation. The value of an electric boiler increases if it is installed in combination with a heat storage tank, as the heat storage will allow activating the electric boiler during periods with both low prices, and when the heat demand is not sufficiently high enough to offtake the heat production from the boiler. In 2017, electricity consumed by electric boilers was equivalent to approximately 1% of Danish power generation.

Partial or full turbine bypass

A technical solution that expands the operational boundaries (i.e. expands the output area – Figure 1) for CHP plants is partial or full bypass of the turbines. In full bypass mode the plant will effectively function as a heat-only boiler enabling it to completely avoid power output. During periods with low power prices, operating in bypass enables the plant operator to avoid losses on the power output side while still supplying heat demand.

While a heat storage tank typically only allows for a relatively brief period of power-heat decoupling, a partial or full bypass mode enables the plant to stay out of the power market for longer periods of time if required, and in the case of full bypass allows the plant to avoid power production altogether. It can be worthwhile to install bypass, or encourage new plants be designed with partial or even full bypass, if the market situation is characterised by long periods with low power prices and/or high frequency of very low prices.

Heat storage tanks can be used to provide district heating, but CHP plants delivering industrial process steam generally cannot take advantage of the heat storage due to the much higher temperatures generally associated with process steam. Bypass therefore also offers an advantage in relation to heat demands for industry, which could not be satisfied from heat storage tanks. Bypass as a flexibility measure allows CHP plants to continue delivering process heat while allowing for much more flexible power output. Furthermore, if the plant's infrastructure (including district heating network) allows for it, then partial or full bypass also expands the maximum heat output from the plant. This allows the plant to reduce the use of often more expensive peak heating capacity, or simply serve a larger heating demand.

Implementation of bypass at existing CHP plants requires hardware retrofitting and depends to a large extent on the existing plant configuration. The costs associated with retrofitting an existing plant with partial bypass, i.e. bypassing the high-pressure turbine, is in the range of 10,000-20,000 EUR per MW, or roughly 3-6 million EUR for a 300 MW plant. Retrofitting with partial bypass can be challenging due to limitations related to space and the current plant equipment. For a new plant, the additional cost for constructing the plant with partial bypass is assessed to be in the range of 0.5 % to 1%.

Operational boundaries for CHP plants

Some of the individual power plant flexibility options described above improve the operational boundaries of a CHP plant. These are illustrated in Figure 1.

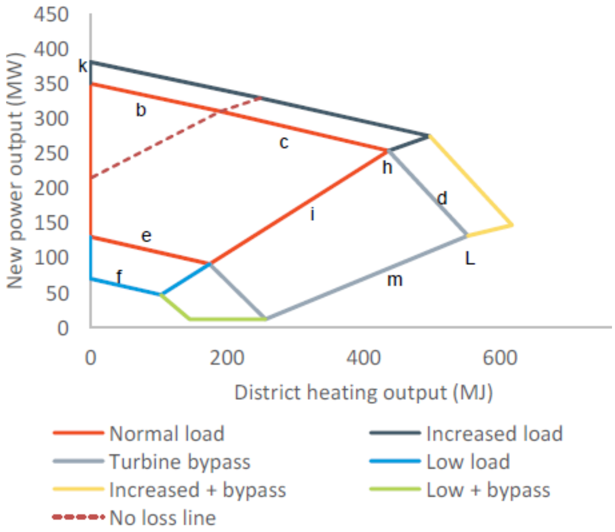


Figure 1: Operational boundaries for a CHP unit with various flexible measures. Source COWI, 2017.

Challenges related to enhanced flexible operation

As with any technological advancement, there are challenges associated with operating a thermal power plant more flexibly. Many of these come from operating at low load and undertaking numerous operational cycles between full and minimum load. Some of the key challenges in this regard are:

- Increased operation and maintenance costs due to increased wear and tear on equipment and reduced lifetime of components.
- Reduced fuel efficiency at low load, which has an adverse effect on emission per unit of output.
- Maintaining a low emission level of NO_x and SO_2 is more challenging, but with the necessary adjustments in the equipment and operational practices, the experience from Denmark demonstrate that it is possible to comply with emission standards.
- Changing the normal operation mode and production boundaries typically requires that the capabilities and qualification of the plant staff must be updated to handle new operational practices. Plant operation outside of its original design values might present a possible risk that manufacturers' warrantees could be voided.

Despite these above challenges, experience from Denmark has shown that the benefits associated with flexible thermal power operation greatly outweigh the costs.

3. Incentives & Measures

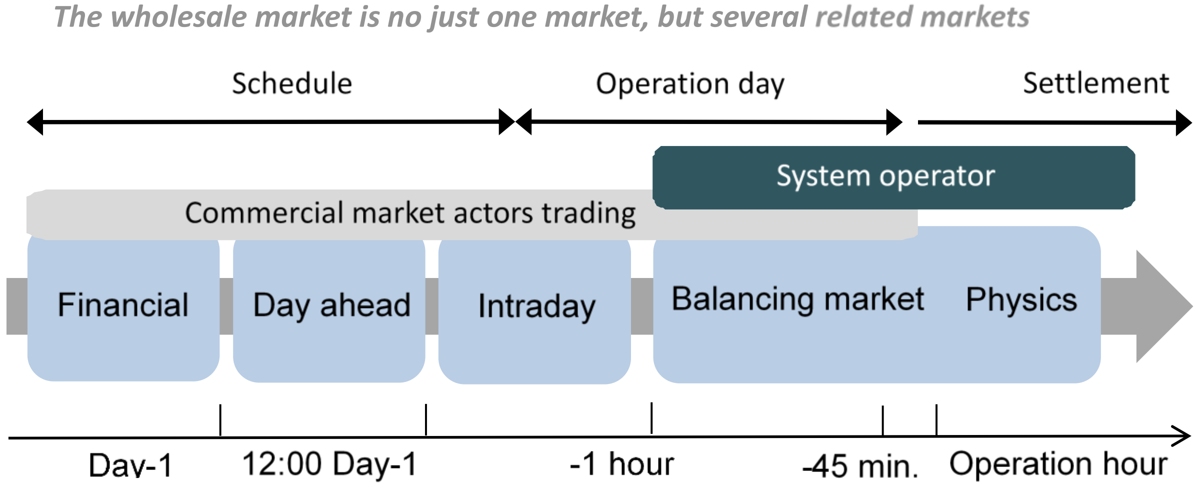


Figure 2: Overview of distinct, but related power markets in the Nordpool market

3.1 INCENTIVISING PLANT FLEXIBILITY IN THE NORDIC MARKET

Without economic incentives or direct regulation, power plant operators lack motivation to enhance the flexibility of their power plants. The establishment of short-term power markets in the Nordics, and most of Europe, has been instrumental in ensuring that market participants are incentivised through price signals, to be in balance up to the hour of operation when the transmission and distribution system operators take over balancing responsibility. Furthermore, the system operator manages a market for intra-hour balancing, which also puts a premium on flexibility.

Regulation

From a direct regulation perspective, grid codes can be one of the measures used to mandate minimum flexibility criteria for different power plant types. For example, in Denmark the grid code mandates that pulverised coal and biomass-fired power plants have a minimum load capability of 35% and ramp rates of 4% per minute in the 50 to 90 percent load range. Despite such minimum flexibility requirements in the Danish grid codes it has been the plant owners' incentive to optimise their economic performance through their market operation that has been the key driving force behind flexibility improvements.

Direct regulation such as stipulating minimum criteria can clearly ensure a certain level of flexibility across the generation fleet. However, it does not ensure that individual solutions are implemented based on the power plant owners' knowledge. This could concern the individual plant's technical situation, possible local district heating demand, plant owners' cost of capital and other relevant company or plant specifics, which all could affect if the most cost-efficient flexibility improvements are being made. Consequently, motivating enhanced power plant flexibility through market-based incentives allows power plant owners to determine which flexibility enhancements are most profitable and viable given the plant's operation and role in the power system.

Economic incentive in the short-term wholesale markets

Short-term wholesale power markets in Europe are generally defined by several distinct, but closely related markets where the market actors trade power and balancing products up to just before real time (referred to as the hour of operation). Today, the Nordpool power exchange's largest market is the Day-ahead market (the majority of all power produced in the Nordic area is sold on Nordpool) that allows for trade to take place on an hourly basis in the time span from 36 hours before consumption up to 12 hours before consumption. Once the Day-ahead market is closed the aggregated production and consumption plans for the upcoming day are in balance on a system level.

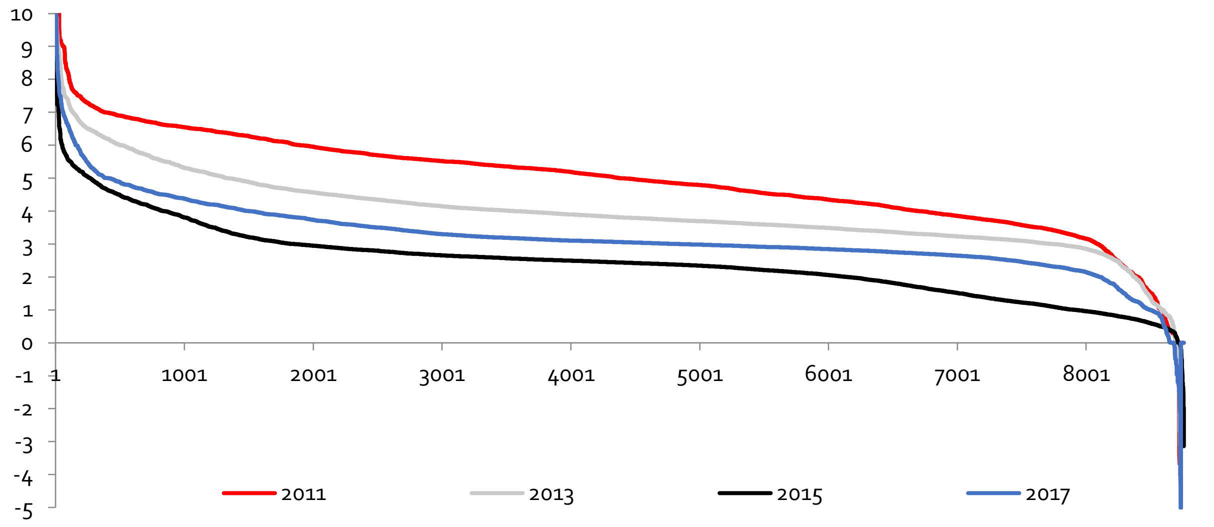


Figure 3: The 8,760 hourly power prices in the Day-ahead market in the East Denmark price area for 2011, 2013, 2015 and 2017 (€ cent/kWh)

Subsequently the Intraday market allows market actors to trade amongst themselves to balance any anticipated changes in their plans (e.g. updated wind forecast or plant outage etc.). This may take place up until 60 minutes before the hour of operation. From this point the system operator will procure and activate faster responding sources of flexibility to ensure the real-time balance. An overview of these distinct but related markets is displayed in Figure 2.

The short-term wholesale power market in the Nordics and most of Europe generates transparent and reliable prices that indicate the need and system value of flexibility. These markets incentivise the cheapest marginal sources of generation to be prioritized in dispatch – and deploy the cheapest (with lowest opportunity cost) sources of flexibility being offered to the market, irrespective of their underlying technology. Flexibility delivered from thermal power plants competes with hydro power plants or flexibility from demand response or storage, etc.

The economic incentives for thermal power plants in the Day-ahead market

The primary motivation for flexible operation of thermal power plants is reducing production when power prices (e.g. in the Day-ahead market) are below marginal production costs. The secondary motivation is taking advantage of high-price periods in scarcity situations. Figure 3 displays the 8,760 hourly power prices in the Day-ahead market in the East Denmark price area for in every second year since 2011.

It is clear from Figure 3 that a baseload operated coal-fired power plant would incur operating losses during a substantial number of hours each year. In 2017, almost a half of the annual 8,760 hours for example had prices below 3 eurocents/kWh. The imperative to by either out of the market or in the market is obviously strongest during periods with the most extreme prices – either negative or positive. Regulating the market forces by for instance designing the market with price floors and price caps can serve to protect consumers against extremely high prices, but also risks removing the strong economic incentives that lie in the very low and high prices that motivate the market actors to exhibit flexibility. A too narrow permitted price spread undermines the rationale of establishing the market in the first place, as it reduces both the loss - and profit - opportunities for dispatchable plants, and thus limits the incentive for providing flexibility.

The ability of the large Danish CHP plants to react to power prices is illustrated in Figure 4, where it can be observed that while zero marginal cost VRE generators are price takers, the dispatchable thermal power plants use their flexibility to adjust production according to the prices, thereby increasing their profitability. At the beginning of the 15-hour period, power production from wind power is high, which drives down prices, thus incentivising the thermal power plants to reduce or fully avoid production. Meanwhile, wind generation is limited during the end of the period contributing indirectly to higher power prices and leading to higher thermal production. As a result of this dynamic,

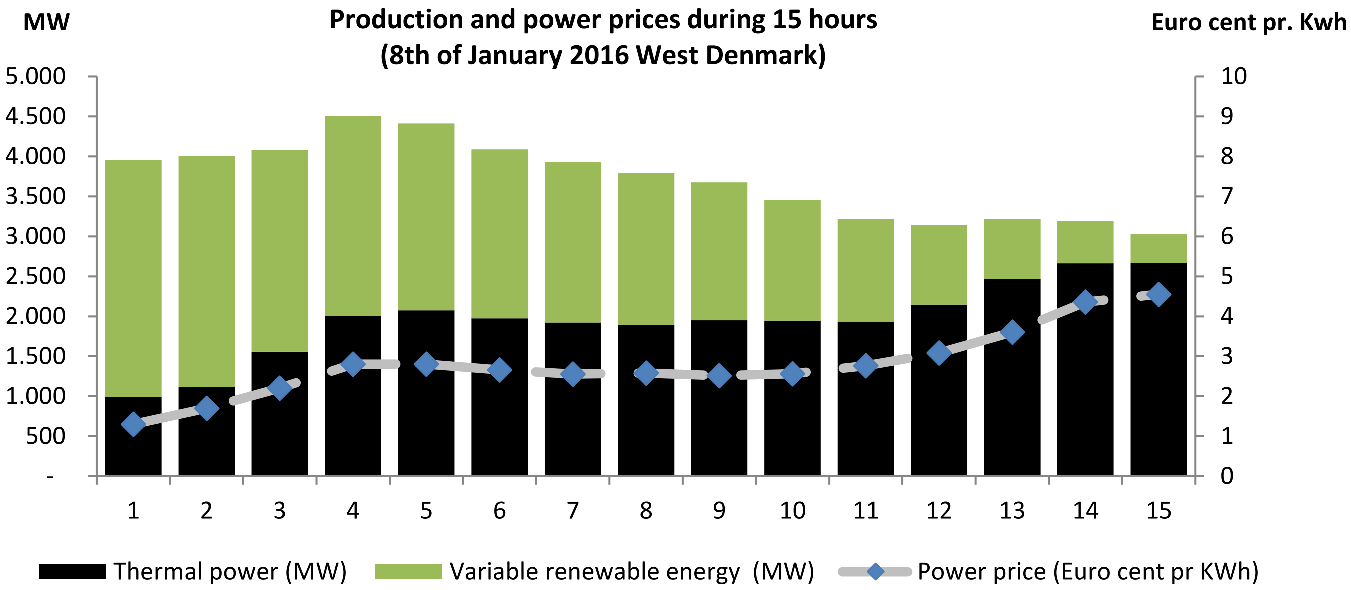


Figure 4: Power from VRE sources, thermal power and prices in a 15-hour period in West Denmark price area.

average realised prices for wind power producers in Denmark in 2017 were roughly 10% lower than the average market prices, while the average realised prices for thermal producers were 10% higher.

The expectation regarding the future short-term price level in the Day-ahead market, as well as the price volatility within the upcoming day, forms the basis from which power plant owners (and other market participants) assess the value of providing flexibility to the system. This enables them to make qualified decisions about what type of investment in enhanced flexibility is most valuable to undertake.

It is the exact price pattern within each of the 24-hour Day-ahead price cycles that ultimately will determine which flexibility capabilities are most valuable in the Day-ahead market.

The intraday market and the balancing markets present earning opportunities for flexibility providers. Since the Nordics are a hydro-dominated area, much of the flexibility offered and activated in the Intraday and balancing markets is based on hydro power plants with reservoir. However, thermal power plants are also active in these short-term markets.

3.2 SUMMARY

The increased operational flexibility of the thermal power plant sector in Denmark has contributed to integrating large shares of variable renewable energy. A move to a market-based power system almost 20 years ago has been instrumental to incentivise improved flexibility capabilities in the thermal power plant sector during the period. The enhanced flexibility is a result of many incremental improvements over time and illustrates well the possibilities to exploit the flexibility potential of existing infrastructure. The clear price signals in the short-term markets allow market actors to acquire the best possible insight into the value of providing flexibility to the system and undertake the appropriate actions to deliver both in the daily operation and in deciding on possible flexibility enhancement investments. Consequently, the minimum flexibility requirements in the Danish grid codes have not been the driving force behind the enhanced flexibility, but rather the power plant owners' incentive to optimise their economic performance through their market operation. As the share of wind power in Denmark has already surpassed 40% of consumption, the role of the thermal power plants has changed from being the backbone of the production system to becoming a provider of flexibility.

4. Chinese Experiences

4.1 BACKGROUND AND RATIONAL PROMPTING POWER PLANT FLEXIBILITY IN CHINA

China has set non-fossil targets for 2020 and 2030. The proportion of non-fossil energy (including renewable energy and nuclear energy) shall increase from the current 13.8% in 2017, to 15% in 2020 and 20% in 2030. Wind and solar power, with increasingly competitive cost levels, are expected to play the largest role in fulfilling these non-fossil targets.

At the end of 2017, the installed capacity of wind power and solar photovoltaics reached 163 GW and 130 GW, respectively. Variable renewable energy (VRE), i.e. excluding hydro power, produced roughly 7% of the total annual electricity consumption in China, compared to only 3% in 2013. The VRE penetration levels are much higher in northern and western regions, where 2/3 of VRE capacity is installed. Gansu, one of the provincial grids with the highest VRE penetration levels, experienced in 2017 that VRE production at a peak moment reached 67% of the provincial production. In the Northeast, in the provinces of Heilongjiang and Jilin, the corresponding figures were approximately 42% and 46%. Provinces in the Southern part of China, such as Yunnan and Sichuan, have a large amount of hydro power generation. These provinces, with more than 85% of the local electricity consumption coming from hydro power, are facing challenges related to the seasonal variation of hydro power, which is different from the daily variation of wind and solar power.

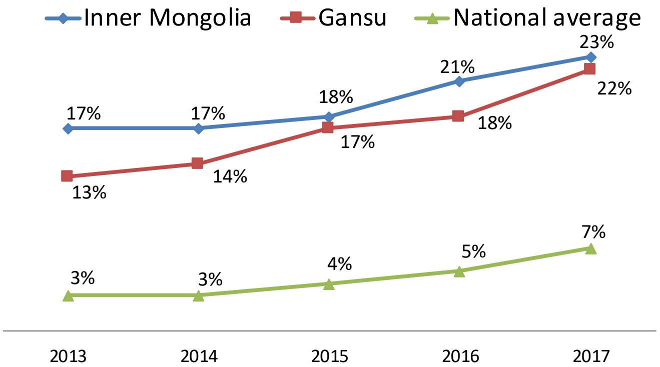


Figure 5: VRE (wind and solar generation) shares in China

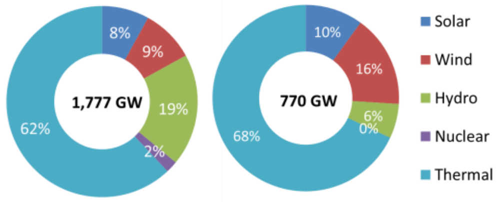


Figure 6: Generation mix in 2017. National to the left, and the three northern regions to the right.

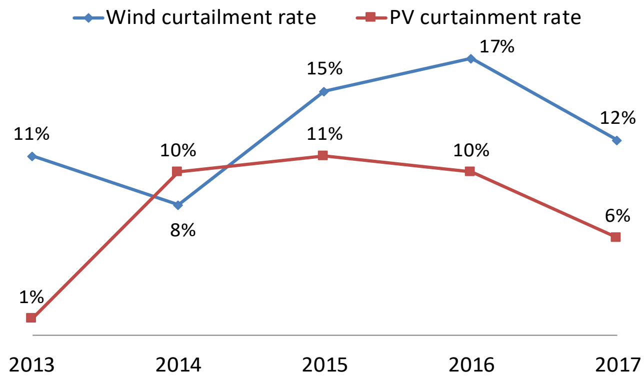


Figure 7: VRE curtailment rates in China

China experiences curtailment of VRE, particularly in some of the regions with high penetration levels. During the recent 3 years, on a national level, wind and solar curtailment rates have been between 12-17% and 6-11%, respectively. Meanwhile some of the provinces with the highest VRE shares have witnessed annual curtailment rates in the 30-40% range.

In 2017, VRE curtailment was reduced significantly, mainly due to the following measures being undertaken:

- Red-flag warning mechanism to slow down the investment in regions with high curtailment.
- Prompt cross-region and cross-provinces trading through launch of incremental spot market pilots.
- Strengthened grid connection and reduced bottlenecks in the grid.
- Down-regulation ancillary service market in Northern regions to encourage flexible regulation of thermal power plants.

- Coal power plants (especially Combined Heat and Power plants) flexibilization in Northern regions.

Regions in China with the highest shares of VRE are also endowed with abundant coal resources, and coal-fired power plants are therefore the back bone of the power system in these areas. The share of coal power plants in the three northern regions (approximately 2/3 of VRE capacities are in these areas) is expected to remain above 60% by 2020. Conventional flexible power generation, i.e. hydro power stations with reservoirs, pumped storages, and peaking gas turbines, account for less than 5% of capacity. During the foreseeable future, coal-fired power plants will still be the candidate with the largest flexibility potential in the power system. By 2020, the proportion of coal power plants in the three northern regions of China will still be above 60%.

Entrusted by the China National Energy Administration, EPPEI (Electric Power Planning & Engineering Institute) carried out research on the pathway of enhancing power system flexibility for the period from 2016-2020. According to EPPEI's research, roughly 220 GW of thermal power plants, including approximately 130 GW of CHP units and 86 GW of condensing units, need to be retrofitted by 2020 to keep curtailment rates under a reasonable level. The goal of 220 GW of retrofits is written into the 13th 5-year plan for the electric power sector, which was jointly released by the NEA and the NDRC in 2016.

Three reasons led to the decision to focus on thermal power plant's flexibility prior to 2020:

- The flexibility potential of thermal power plants remains untapped in China. Coal power plants usually operate in a load rate ranging from 50% to 100%, and CHP power plants usually have a minimum load of 70% during the winter season. After a technical survey was undertaken in China, and technical knowledge exchanges with Denmark and Germany, EPPEI concluded that condensing units and CHP units both have the potential to run under 40%. If the entire 500 GW of coal power capacity in the three northern regions were retrofitted by 2020, roughly 120 GW of down-regulation capability could be freed up.

- Retrofitting existing coal power plants is a cost-effective way to increase the system flexibility on the generation side. The cost of retrofitting a condensing unit is usually in the range of 20~100 Yuan/kW. For CHP units, certain hardware investments are generally needed, such as electric boilers, heat storage or special valves. This cost is usually in the range of 100~300 Yuan/kW for CHP units – relatively higher than for condensing units. However, the cost is much less than building new peaking gas units or pumped hydro stations. The benefit-cost ratio of retrofitting thermal power plants is above 3, even when a relatively high carbon price is considered. Moreover, most northern regions in China suffer from over-capacity, which new units would only serve to exacerbate. In addition, the northern regions in China do not have enough sites for new pumped hydro construction. The untapped pumped hydro potential is only 52 GW in the three northern regions, which are expected to have 250 GW wind and PV generation by 2020.

- Retrofitting the existing large thermal power fleet is considered the fastest way to scale up flexibility in the system. It usually takes 5-6 years to build a pumped hydro station, and 2-3 years to establish gas-fired units. In comparison, it normally takes less than 3 months to retrofit a thermal power plant. Given the current situation, where a large amount of renewable energy is wasted - less time means less waste.

It should be noted that, while flexibilization of power plants could solve the RE curtailment problem in China in the near term, the system needs to be prepared for even higher penetration levels of VRE after 2020. Other measures on the generation side, on the grid side and the demand side, will also be needed. The VRE capacity in China is expected to continue to grow at a relatively fast pace in order to meet or exceed the non-fossil share requirement of 20% by 2030. Optimisation of the generation mix (i.e. building more pumped-hydro, peaking gas units, etc.), promoting demand side response (especially in northern areas where large amount of renewable and price-sensitive energy-intensive industry coincide), increasing the interconnection capacity (both cross-provincial and internally), will all be crucial in order to accommodate 1,000 GW or more of VRE generation.

Electricity market reform in China

China's power sector is now moving from a governmental planning institutional setup towards market-based institutions. China is therefore in the midst of a transitional period of electricity market reform. Presently, market elements and governmental allocations coexist. In 2017, roughly 25% of the electricity generation/consumption was traded on the market. Trading today is mainly based on long-term (monthly and annual) bilateral contracts. The other 75% of electricity generation was allocated by local governments. The price for the volume traded on the market is determined by buyers and seller themselves, while the electricity allocated by governments is bought and sold from grid companies at fixed benchmark prices stipulated by authorities.

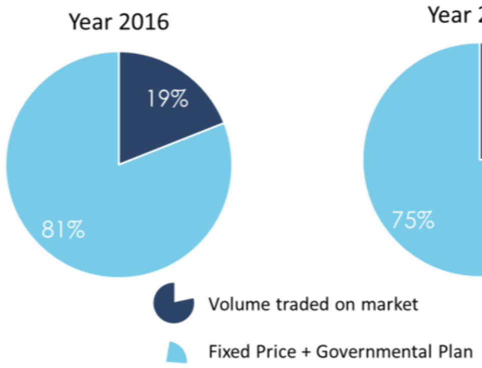


Figure 8: Volume of electricity traded on market vs fixed price

Under the paradigm of fixed benchmark prices, power plants have no strong incentives to operate flexibly. To obtain normal down-regulation capability during the valley time of load (late night), different regions in China had established remuneration rules for power plants down-regulated below 50% of load. For those power plants running below 50% of load, there is certain reimbursement based on the level of down-regulation. The reimbursement is mainly compensation for the reduction of efficiency at lower load, and therefore provides only minimal incentive. This mechanism worked fine before the large increases in wind and solar power penetration when down-regulation served to balance load variations. Firstly, the amount of down-regulation needed was limited, and the down-regulation is usually predictable. Secondly, the reduction of generation due to down-regulation could be made up to the power plants afterwards, so there was almost no opportunity cost for the thermal power plants. However, when large amounts of wind and solar power were introduced to the system, the amount of required down-regulation increased substantially and varied increasingly from day-to-day. Combined with the thermal overcapacity situation, power plants that engage in down-regulation were less likely to fulfil the govern-mental plan for annual generation. This also led to a reduction in revenue.

In 2016, the NEA decided to boost flexibility of thermal power plants. However, under the institutional paradigm in place at the time, it was extremely difficult to mobilise power plants to do so. Since 2016, the NEA used a combination of policy and market-based instruments to push the power plants forward, including:

- Auction based down-regulation markets have been established in different regions to increase the incentives for flexible power plants.

- The 13th 5-year plan with a target of flexible thermal power plants by 2020. The 13th 5-year plan also pointed out that as the share of VRE increases, the role of thermal power plants will shift from base load to a role of providing flexibility. This plan guides the anticipation of asset owners for a transition to a short-term power market, and they are beginning to see the value and need for providing enhanced flexibility.

- Launching two batches of demonstration projects (in total 22 projects) where power producers are to try different technical solutions to make their power plants flexible. Moreover, this will also build knowledge and experiences for the large-scale implementation.

Among the abovementioned aspects, the down-regulation market has served as a crucial driver for power plant flexibilization.

Down-regulation market in China

Down-regulation markets were introduced in Northeast China in 2014. The Northeast is the coldest part of China and has many CHP units to supply district heating. In winter, large amounts of renewable energy are wasted due to an electricity surplus from CHP units. The challenge in the Northeast is not only a wind and solar issue. Even during times with full wind and solar curtailment, the total forced generation from CHP power plants can exceed the valley consumption. Down-regulation became the scarcest of resources in the system, and the down-regulation market was introduced to encourage investment in flexibility in this area.

Payment flows

Essentially, the concept of the down-regulation market is to punish inflexible power plants while rewarding flexible plants. A baseline of down regulation capability is drawn, which in the northeast region is 50%. Power plants operating above the baseline when the system has a generation surplus, pay power plants operating under the baseline.

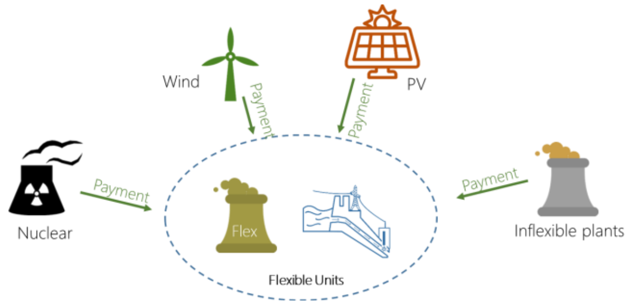


Figure 9: Payment flows in down-regulation market

This side payment mechanism is carried out using a day-ahead auction-based system. The dispatching centre (system operator) runs a day-ahead auction of down-regulation service. Power plants capable of going under the baseline can bid in with a price and possible down-regulation capability. During real-time operations, the dispatching centre will activate the units according to their bid price. The last unit activated will establish the uniform price, and all power plants will receive payment based on this uniform price. The settlement is carried out on a 15-minute basis. The total cost is allocated proportionally to those power plants that operate above the baseline during that time period.

Figure 10: Time flow of down-regulation ancillary service market.

Impact of the down regulation market

Since the introduction of this new market, renewable curtailment has been reduced, e.g. the wind curtailment rate in Liaoning province has been reduced from 13% in 2016 to 8% in 2017. The first quarter of 2018 had a more substantial reduction on both wind and solar curtailment. The curtailed electricity has been reduced by about 1/3 compared to the first quarter of 2017. As for Northeast China, the wind power curtailment issue is close to being solved due to the rapid increase of flexible thermal CHP plants in this region last year.

The down-regulation market can provide strong incentives to power plants without requiring fundamental changes to the status quo. It can for example co-exist with the fixed benchmark pricing mechanism. The power plant can earn revenue by generating, but also profit from the down-regulation market through reducing the generation when the system requires it.

The relative success of the down-regulation market pilot means several other provinces in China are setting up this mechanism. Up to this point, another 8 provinces, including Gansu, Xinjiang, Ningxia, Shanxi, Shandong and Fujian, have established a similar market.

Regional down-regulation markets, aiming at coupling the provincial down-regulation markets, are also on the horizon in North-western and North China.

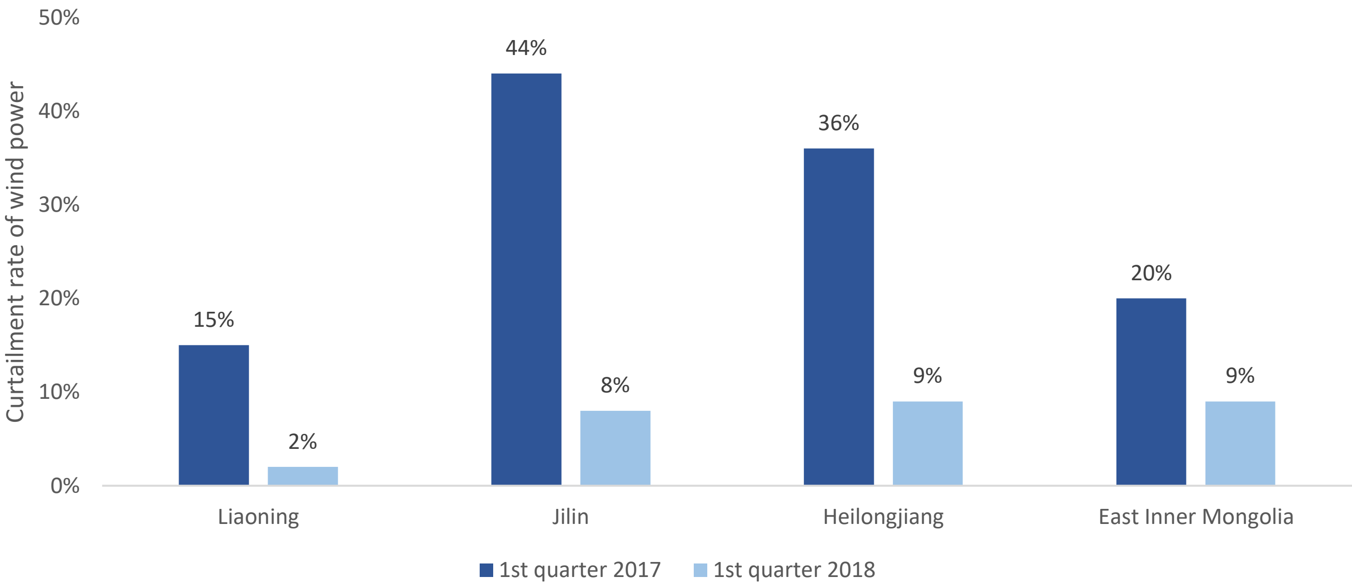


Figure 11: Curtailment rate change in Northeast China

4.2 CURRENT STATUS OF CHINA'S COAL POWER PLANT FLEET

The installed capacity of coal power plants in China reached 940 GW by the end of 2016, accounting for about 57% of the total installed generation capacity (CEC statistics). Roughly 80% of the coal-fired units in China are 300 MW sized units and above. The overall efficiency of the coal power fleet in China has been improved substantially in the past ten years. The average unit kWh (net) coal assumption is 312 grams of standard coal, which is 58 grams less than 2005. The carbon emissions of coal power plants have been reduced to less than 822 grams CO^2/kWh, compared to about 1,000 grams CO^2/kWh in 2005. The boost in efficiency of coal-fired power plants is due to both the newly installed high efficiency units and retrofitting of the existing units. More than 90% of the coal power plants in China are installed with de-NOx and de-SOx facilities.

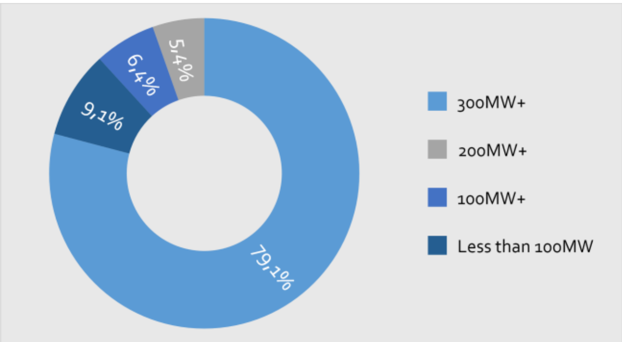


Figure 12: Size of coal-fired units in China

Most of China's coal-fired power plants are designed as base-load power plants. They usually operate in a load rate ranging from 50% to 100%.

Two indicators could be used to specify the flexibility of coal power plants in China:

- the minimum load rate of a typical condensing unit is around 50%,
- and for a CHP unit, the forced power output (due to heat demand) is usually around 70% during the winter season.

The forced power output has served as one of the major reasons for the electricity surplus in the Northern part of China. This leads to large scale curtailment of RE in these regions. The plans to retrofit 220 GW (roughly one fifth of the total coal-based generation) of coal-fired units will contribute significantly to solving the RE curtailment issue by 2020.

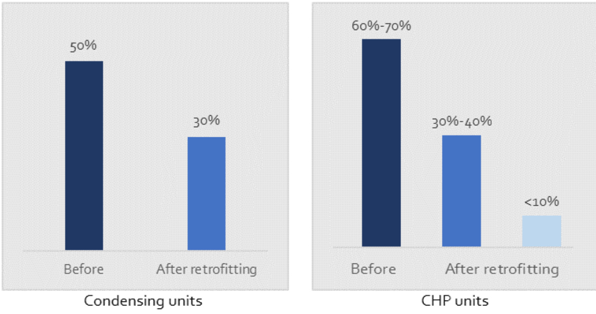


Figure 13: Reduction of minimum load before and after retrofitting

Demonstration projects and recent progress

To identify cost-effective methods to increase the flexibility of coal power plants in China, and accumulate experiences for large-scale implementation, the China National Energy Administration (NEA) launched two batches of demonstration projects in mid-2016. In total 22 power plants, with a total capacity of 17 GW, joined the demonstration project. The minimum load of many of the coal-fired units has been substantially reduced (to around 30% or even less) and therefore left more space for RE.

Many of the demonstration power plants, along with other power plants not in the demonstration projects, have made notable progress on flexibilization of the existing units. The minimum load of some of the condensing units have been lowered from about 50% to 30%. As for CHP units, with some minor retrofitting, the minimum load in winter season has been reduced from 70% to 40%. The net output of those power plants installed with a new electric boiler has even been reduced to nearly zero.

Technical solutions used in demonstration project power plants

There is no universal solution for the flexibilization of coal power plants. Different technical solutions are adopted in the 22 power plants. With respect to the power plants that have completed their retrofitting, they mainly utilised 3 different technical solutions.

Systematic retrofit of boiler and turbines

Reduction of minimum load on condensing units is usually constrained by two factors: flame stability and emission control. To overcome these two obstacles, the operation mode and control logic needs to be optimised. New investments in the emission control system is also required in many cases.

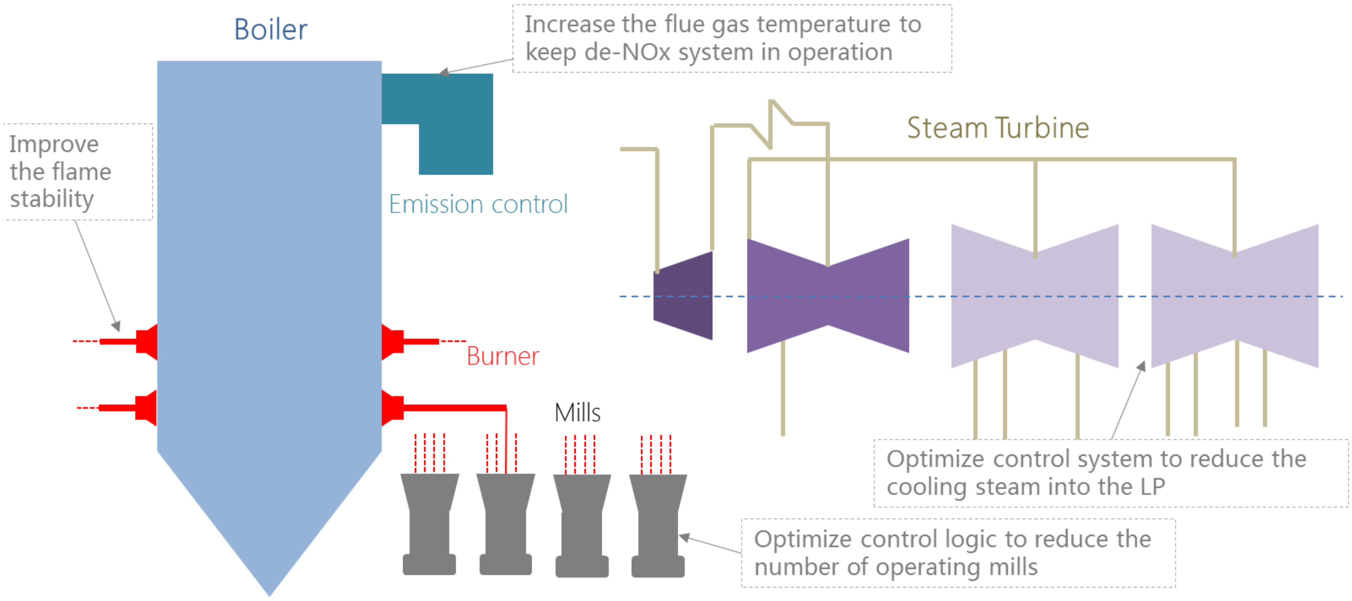


Figure 14: Systematic retrofit of condensing unit.

One of the successful examples in the 22 demonstration project power plants is the Guodian Zhuanghe power plant. This power plant has two 600 MW units commissioned in 2007. The 600 MW units used to have a minimum load above 280 MW. After the refurbishment in the last two years however, the minimum load dropped to 180 MW. The main technical solutions utilised at the Zhuanghe plant included:

- Using low heat-value coal in the low load region to keep more mills and burners in operation to maintain the flame stability.
- Bypassing the economiser to increase the flue gas temperature before the de-NOx facilities.
- Systematic optimisation of control logic.

Another major achievement of the Zhuanghe power plant is that in the range from 30%-100% load, the emissions are well below the very strict Ultra Low Emission (ULE) standard (Dust< 5mg/m^3, SO_2< 35mg/m^3, NOx< 50mg/m^3).

The cost of using this technology is highly dependent on the situation in each power plant. In the demonstration power plants, the cost of retrofitting was between 40~100 Yuan/kW.

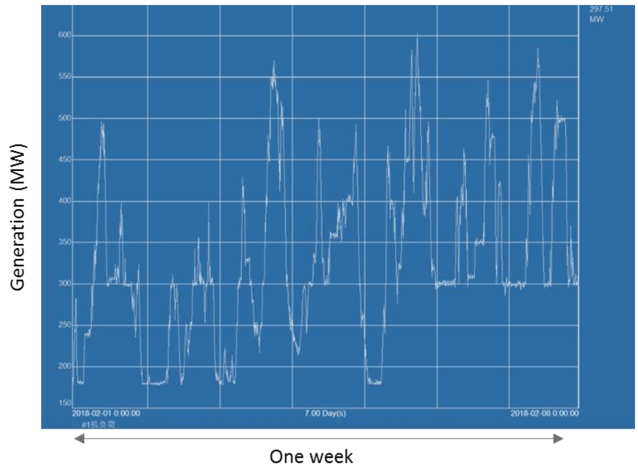


Figure 15: Operational profile of Guodian Zhuanghe 600 MW condensing unit (One week)

Optimisation of turbine and steam flow in a CHP unit

As outlined above, the reason that CHP units (usually extraction units in China) must maintain a 60% or 70% minimum load rate during the winter season is due to heat demand from the district heating system. If the technical constraints for reducing the electricity output are further explored, issues related to the minimum cooling steam of the LP (low-pressure) turbine will present themselves. Due to the fast rotation of blades in the turbine there is always heat generated from friction. To prevent over-heat and blast, a certain amount of cooling steam needs to flow into the LP turbine. To reduce the electricity output, the minimum cooling steam must be reduced. This could be achieved through optimisation of control logic and valves. After the steam flowing to the LP turbine is reduced to a minimal value, the extraction unit will operate almost as a back-pressure unit. Under this mode (LP-cut-off mode), the CHP unit will be able to produce more heat than under normal mode (therefore, with the same amount of heat demand, the electricity output can be reduced). The LP-cut-off mode used to be considered technically impossible in China.

In August of 2016, the DEA and EPPEI organised a study tour a to a CHP plant (Fynsværket) in Odense in Denmark where the participants, including senior technical experts from 16 demonstration power plants, noticed that the Danish CHP plant used this mode during the heating season. The delegation had a thorough discussion with the operations manager of the power plant and they realised that LP-cut-off mode could also be achieved in China. After the study tour, Huaneng Linhe, Huadian Jinshan and a number of power plants had successful pilot runs in 2017.

One of technical barriers is that the LP turbine will have a transitional blast and over-heat operation, and the key to success is thus how to safely slide from the normal mode to LP-cut-off mode.

A successful example using this technique is Huadian Jinshan power plant. Through invoking LP-cut-off mode, the forced electricity output of the 200 MW unit in Huadian Jinshan is reduced from 170 MW to roughly 70 MW (see Figure 16). This has freed up roughly 100 MW for wind and solar power production in Liaoning province.

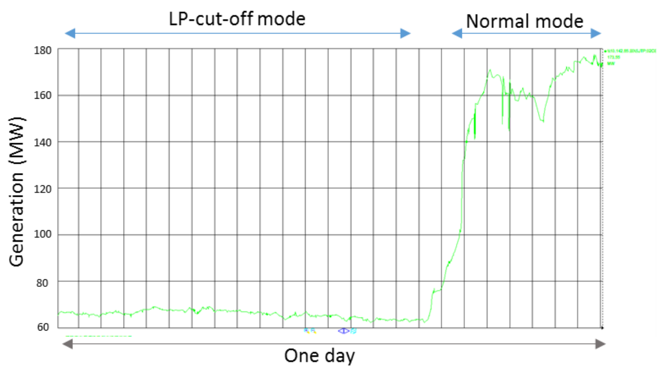


Figure 16: Operational profile of Huadian Jinshan 200 MW extraction unit (Transition from LP-cut-off mode to normal mode)

The cost of using this technology is relatively low because little hardware investment is required. The cost is estimated to be less than 50 Yuan/kW.

Electric boiler and large scale solid-medium heat storage

Four CHP power plants have installed large-scale electric boilers and heat storages. The electric boilers in these projects have a capacity of roughly 300 MW, and the heat storages have a capacity of 1,500-2,000 MWh. The medium used in the heat storage is MgO brick, which can be heated

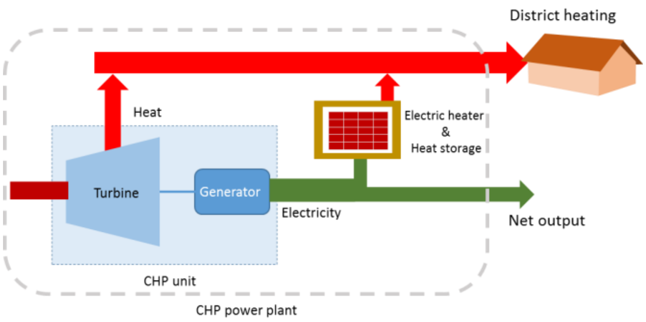


Figure 17: CHP power plant installed with electric boiler and heat storage)

up to 500°C when there is surplus electricity in the grid. The energy density of MgO bricks, in terms of kJ/L, is about 3 times of that of hot water storage.

The net output of the CHP unit can reach almost zero net electricity output, without significantly influencing the district heating temperature. In one winter season, each of these large storage facilities could absorb more than 200 GWh of surplus electricity.

The cost of using electric boilers and heat storage is relatively high. The typical investment cost of a combined 300 MW electric boiler and a 2,000 MWh heat storage is about 320 million Yuan (about 50 million USD).

List of demonstration projects

A full list of the 22 demonstration projects is provided in the table below (Table 2), including the basic unit information, technical solutions being implemented and current progress.

Table 2: List of demonstration projects

		Capacity	Technical Solutions	Progress
1	Huaneng Dandong CHP Power Plant	2 * 350 MW	Boiler & $DeNO_X$ system retrofitting, Heat accumulator (HA)	Partially completed HA pending construction
2	Huadian Dandong CHP Power Plant	2 * 300 MW	Electric heater and Solid-medium heat storage	Completed
3	Guodian Dalian Zhuanghe Power Plant	2 * 600 MW	Systematic retrofitting	Completed
4	Benxi CHP Power Plant	2 * 350 MW	Heat accumulator	Under construction
5	Dongfang Power Generation Company	1 * 350 MW	Heat accumulator	Under construction
6	Yanshanhu CHP power plant	1 * 600 MW	Extra heat exchanger	Completed
7	Diaobingshan CHP power plant	2 * 300 MW	Electric heater and Solid-medium heat storage	Completed
8	Shuangliao Power Plant	2 * 330 MW 2 * 340 MW 1 * 660 MW	Turbine bypass	Pending
9	Baicheng CHP Power Plant	2 * 600 MW	Electric Boiler	Completed
10	Harbin First CHP Power Plant	2 * 300 MW	Electric Boiler	Partially completed
11	Jingyuan Second Power Plant	2 * 330 MW	Systematic retrofitting	Pending
12	Beifang Linhe CHP Power Plant	2 * 300 MW	Optimisation of turbine operation mode	Partially completed
13	Baotou Donghua CHP	2 * 300 MW	Heat accumulator	Under construction
14	Zhungeer Power Plant	4 * 330 MW	Systematic retrofitting	Pending
15	Beihai Power Plant	2 * 320 MW	Systematic retrofitting	Pending
16	Shijiazhuang Yuhua CHP power plant	2 * 300 MW	Heat accumulator	Under construction
17	Changchun CHP power plant	2 * 350 MW	Electric heater and Solid-medium heat storage	Completed
18	Liaoyuan CHP power plant	2 * 330 MW	Heat accumulator	Under construction
19	Jiangnan CHP power plant	2 * 330 MW	Heat accumulator	Under construction
20	Yichun CHP Power Plant	2 * 350 MW	Electric heater and Solid-medium heat storage	Completed
21	Harbin CHP Power Plant	2 * 350 MW	Boiler and $DeNO_X$ system retrofitting	Partially completed
22	Tongliang Second CHP Power Plant	1 * 600 MW	Heat accumulator	Pending construction

Demonstration projects and new business model

A new business model has been established in demonstration power plants using heat storage. The investment in heat storage is a large investment for power plants, but the remuneration that can be obtained from the down-regulation market is highly unstable, especially in the long term: high prices will encourage more investment in flexibilization and will reduce the price in turn. That makes this particular investment quite risky, and the power plants, which are usually state-owned, and risk-adverse. Moreover, because of reductions in plant utilisation, power plants cannot support such a large investment financially, and banks are also reluctant to provide large loans to conventional power plants.

Therefore, almost of all the large heat storage facilities are invested in by a third party private company. These companies usually have more capital and are willing to take risks. The business model is illustrated in Figure 18, in a situation when the system needs down-regulation service (usually during time periods with strong wind at night). The CHP power plant will sell some of its generation to heat a storage facility investor, and the heat storage investor will pay the power plant based on the fuel cost. The revenue they get from the down-regulation market will be distributed according to a predefined contract. The heat will be stored and transferred back to the CHP power plant according to the requirements of the power plant.

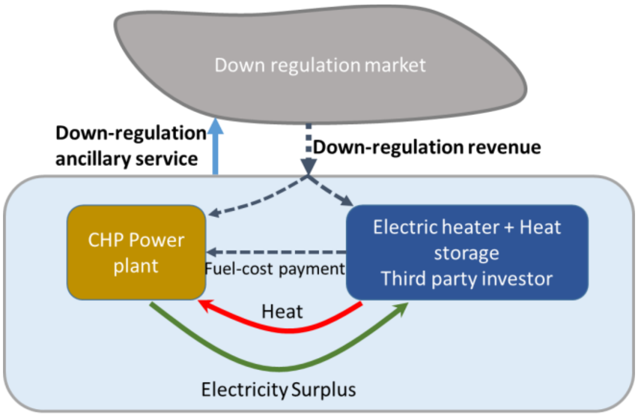


Figure 18: Business model for heat storage in CHP power plant

4.3 CHALLENGES FOR FLEXIBILISATION OF CHINA'S THERMAL FLEET

Going forward, the Chinese thermal fleet faces several technical and regulatory challenges that need attention if the promise of thermal plant flexibilization in China shall be delivered.

Technical:

- **Emission control.** Most of the thermal units in China will need to meet the Ultra-Low Emission (ULE) standard (Dust< 5mg/m^3, SO_2< 35mg/m^3, NOx< 50mg/m^3) by 2020. One of the technical challenges is how to meet the ULE standard at extremely low load levels.

- **Large-scale heat storage.** A heat storage facility in the scale of 5,000 GJ and above is always needed for a typical CHP plant. There are limited experiences in this area in China, especially for the design and construction of large heat accumulators.

- **Balance between down-regulation and primary and secondary frequency response.** Operating in a low load range reduces the primary and secondary frequency response capability of thermal units. As VRE shares increase, the need for automatic ramping up and down of thermal units for primary and secondary frequency control will increase. Balancing these two kinds of need from the power system will be essential for thermal power plants.

Regulatory:

- **Development of a full-fledged down-regulation ancillary service market**. Down-regulation is currently the only product in the ancillary services market. This mainly reflects the current situation involving a large generation surplus. As peak load and the VRE penetration rates increase, so will the need for up-regulation and fast ramping capabilities. The ancillary service market should be further developed to reflect these needs.

- **Transition from the down-regulation market to a mature spot market.** In addition to increasing the types of products in the down-regulation market, the time resolution also needs to be refined to reflect more short-term variation. The down-regulation market currently only has day-ahead trading. A potential development would be to add intraday or real-time trading, as many mature spot markets have already done.

4.4 SUMMARY

China has set non-fossil targets for 2020 and 2030, which dictates that the share of VRE will continue to increase, and with it, so does the need for system flexibility. The scale of China's coal fleet makes coal-based thermal power plants a resource of untapped flexibility that the country cannot afford to overlook. However, the current inflexibility of this coal fleet is a significant contributor to curtailment, and while national curtailment rates declined in 2017, they are still many times higher than global norms (i.e. in Europe or North America).

The awareness has grown amongst stakeholders in China, from policy makers in the NEA to power generation companies, that there lies an untapped potential in improving the flexibility of coal plants. China has looked to positive international experiences for inspiration and has begun work on transferring these experiences into the Chinese context. As a result, ambitious targets for coal flexibilization have been announced, a massive demonstration program is ongoing, and experience has started to materialise from this. As challenges are overcome (prime examples include those from Huadian Jinshan and Huaneng Linhe), conservative mindsets of technical experts are shifting.

Despite the progress, both technical and regulatory challenges remain, and the thermal power plant flexibilization effort should be seen as an ongoing process, where further support can be relevant in order to overcome existing challenges. On the other hand, the rapid transformation currently underway is worthy of international attention, as the approaches utilised, and lessons learned, could be replicated and utilised in other coal-plant intensive power systems.

5. Energy Models & Scenarios

5.1 INTRODUCTION

Scenario analysis and system models

Scenarios can be described as stories about how the future might unfold. They are not predictions or forecasts, but plausible futures based on the underlying assumptions. Instead of only focusing on a single technology or instrument, a scenario provides an insight into the correlation between different instruments and offers a holistic approach to understanding the possible development to reach a set goal.

Scenario analyses utilising energy system models are useful in identifying measures and actions which are required to transform energy systems in a sustainable direction. A strength of power system models is that they allow for a systematic analysis of different scenarios, including the ability to highlight the impact of different power market policies, and in the current context, sources of system flexibility.

While the current analysis focuses on the effect of power plant flexibility in a Chinese context, the approach and type of models utilised in the analysis could be applied in other countries/regions. In this sense, the aim of the work is two-fold. Firstly, to illustrate the effect of power plant flexibility measures in China given stated and assumed power sector development trends, and secondly, to demonstrate how other regions can undertake similar analysis

The EDO Model

The Electricity and District Heating Optimisation (EDO) model used in the present analysis was developed within the China National Renewable Energy Centre, and forms part of the Centre's core modelling suite used to produce the annual China Renewable Energy Outlook (see text box on following page). EDO is a combined capacity expansion and production cost optimisation model and has its roots in the opensource Balmorel model (www.Balmorel.com).

5.2 QUANTITATIVE ANALYSIS

Analysis overview

The overarching aim of the current analysis was to determine both the value of power plant flexibility in China, as well as the system effect/impact of plant flexibility on aspects such as CO_2 emissions, curtailment, fossil fuel use and not least impact on achieved power prices for VRE producers. This was done by comparing the anticipated development path, referred to as the Stated Policies scenario (please see text box on the following page describing the Chinese Renewable

EDO model components

EDO has a fundamental representation of power generation, transmission, storage and consumption as well as district heating generation, storage and consumption. It represents all major generation technologies including nuclear plants, hydro plants with and without reservoir, thermal power plants fired by various fossil and renewable fuels, combined heat and power plants, heat only boilers, and power to heat technologies such as electric boilers and heat pumps. It also represents a range of electricity storages including pumped-storage, various forms of chemical storages, compressed air energy storage as well as thermal storage for district heating.

On the consumption side the model represents time varying electricity demand as well as various forms of demand response including peak shaving, load shifting (e.g. in industry) and smart charging of electric vehicles. Main transmission bottlenecks in the power system are represented, e.g. between provincial grids, and transmission capacity expansion can be carried out endogenously co-optimised with generation investments and operations. The model operates with relaxed unit commitment to represent the number of units that are brought online and offline during each time segment.

Capacity expansion simulations are carried out using a smart aggregation of hourly data into representative time slices. The resulting capacity expansion solution, i.e. the capacities, can be fed into a more detailed hour-by-hour model operating mode that takes the capacities as given. This also serves to verify the feasibility of the capacity expansion solutions.

The model represents 31 provinces in China including the four provincial level municipalities. Due to the scope of key data sources for populating the model, the model does not include Hong Kong and Macau SAR, nor Taiwan province. Inner Mongolia is divided into the Eastern and Western parts creating a total of 32 distinct geographical regions in the model.

Chinese Renewable Energy Outlook

Each year, the China National Renewable Energy Centre, a think tank within Energy Research Institute under the NDRC, prepares a China Renewable Energy Outlook (CREO) with comprehensive scenarios for the future energy system in China.

CNREC's CREO 2017 has two scenarios, the Stated Policy scenario and the Below 2°C scenario. The Stated Policy scenario shows how the Chinese energy system could develop when the current and planned policies are efficiently implemented. The Below 2°C scenario illustrates a development where China's CO_2 emissions are constrained to contribute to the Paris agreements targets.

Key development trends for an efficient energy system towards 2050

1) Economic transformation. The energy consumption in the industrial sector is reduced substantially as the economic reform in China shifts the industrial sector from heavy to light industry and services. The energy consumption in the building and the transport sector will increase due to higher urbanisation and more transport
2) Electrification. The use of fossil fuels is to a large extent replaced by electricity, especially in the industrial and transport sectors. This increases energy efficiency in end-use sectors on top of the other energy efficiency measures introduced towards 2050.
3) RE gradually becomes the back-bone of the energy system. Adding to the efficiency gain in the end-use sectors, the power supply becomes more efficient because the thermal power plants are replaced by wind and solar power, which have no transformation losses. In 2050, renewable energy accounts for 37% of the total primary energy demand in the Stated Policy scenario, and 54% in the Below 2 °C scenario.
4) The power sector reform is assumed to be implemented gradually. This implies a phase out of generation allocations and a gradual introduction of interprovincial trade, an hourly level, governed by fluctuating market prices.

Focus on flexibility

In the Stated Policies scenario, in addition to power plant flexibility options (such as lower minimum load, stable overload operation, partial bypass, heat storage, and electric boilers), numerous other flexibility options are introduced both exogenously and endogenously. These include demand response, electricity storage investments, grid investments and gas turbines.

Energy Outlook and the scenarios utilised), with an alternative scenario referred to as the 'No Flex' scenario, in which specific flexibility options relating to coal-fired power plants were *not* available.

In the Stated Policies scenario the following previously, described power plant flexibility investment options were available:

- Reduction of minimum boiler load
- Stable overload operation
- Partial bypass
- Heat storage
- Electric boilers

Simulation approach

As the focus of the current study was narrowing in on the value of thermal power plant flexibility, it was important that other aspects remained the same when comparing the two scenarios. This meant that while the technical characteristics of a power plant could change (i.e. new lower minimum load), the nameplate capacity and location of the units remained the same. For example, units that were retrofitted for flexibility in the "Stated polices" scenario were not retrofitted in the 'No Flex" scenario, and similarly, newly installed flexible units in the Stated Polices scenarios were assumed instead to be non-flexible versions of the same technology in the "No Flex" scenario.

The electricity and heat demands are the same under both development paths, but when power plants in a system are less flexible this means the energy system will (relative to a system with more flexible power plants) have some periods that electricity and/or heat demand cannot be met and will therefore have to rely on additional peak electricity and/or heat generation[1]. In the No Flex scenario, the most cost-effective form of this alternative capacity in China will largely be coal-based.

[1] Due to the dynamic and short-term nature of the value of power plant flexibility, all operational simulations utilised hourly time resolution.

Aspect	Flex (Stated Policies from CREO)	No Flex
Name plate capacity	Exact same in both	
Retrofit of existing *or* investment in new flexible CHP plants	***Included***	Not included
- Lower minimum load		
- Stable overload operation		
- Partial bypass		
Retrofit of existing *or* investment in new flexible condense plants	***Included***	Not included
- Lower minimum load		
- Stable overload operation		
Investment in new 'non-flexible' CHP plants	Included	
Investment in new 'non-flexible' condense plants	Included	
Investment in heat only boilers	Included	
Investment in electric boilers	***Included***	Not included
Investment in heat storage	***Included***	Not included
Investment in alternative flexibility sources (grid investments, gas turbines, pumped storage, industrial demand response, smart charging of EVs, and stationary repurposed batteries)	Exact same in both	

The table above highlights the main components and investment options in the two scenarios. As can be seen, both scenarios include investment in new non-flexible plants (both CHP and condensing) and heat only boilers, while only the Flex scenario includes investments in electric boilers, heat storage, and new or retrofitted flexible plants. The capital costs associated with a new flexible plant vs. a new 'non-flexible' plant is roughly 3.3% higher for a CHP plant, and 0.7% higher for a condensing plant. The additional cost associated with turbine bypass in a CHP plant is the reason for this difference. Note that the Flex Scenario is the same as the Stated Policy scenario from CREO as described above, although re-run since publication with a more fine-grained time resolution to adequately represent the deployment of flexibility measures.

Model is deterministic

The EDO model is deterministic and schedules generation according to realised values of factors that in practice are uncertain (demand, wind, solar, etc). The model includes reserve requirements. This implies there is not a clear distinction between different markets, such as day-ahead, or balancing markets. The deterministic nature is likely to result in a conservative valuation of flexibility.

The starting point is the State Policies scenario, where the model makes optimal investment decisions, and operates heat, power and storage units in an optimal fashion. The results of the analysis (i.e. investments in retrofitting, storage, etc.) reflect both this full foresight, as well as core assumptions regarding the future development in market incentives and reforms. What happens in reality is unlikely to be exactly as assumed in the analysis, and the results should therefore not be seen as a forecast, but a plausible future development given the assumptions utilised. The Flex and No Flex scenarios in this report, are calculations, made with given capacities as described above, where the system operations are determined for each with an hourly time resolution.

Alternative flexibility

In analysing the value of power plant flexibility, it is important to note that alternative sources of flexibility are also available in both development paths. This includes grid investments, gas turbines, pumped storage, industrial demand response, smart charging of EVs, and stationary batteries. The number of batteries is expected to grow significantly towards 2030, as a growing portion of Chinese road transport becomes electrified. This will be driven by both reductions in the cost of batteries and a desire to reduce local emissions.

The assumed amount of these alternative flexibility sources is the same in both scenarios, and these assumptions affect the results in terms of the additional system value that is provided via the implementation of flexible power plant measures. For example, if other sources of flexibility such as batteries or a national fully coupled power market do not materialise as anticipated, then the value of power plant flexibility will be more pronounced than indicated in the current analysis.

Display years

A comparison of the two development paths was carried out for all years between 2018 to 2030, but the years 2025 and 2030 have been selected for display throughout this report. It should be noted that precise years and exact numerical values displayed are not forecasts or goals and focus instead is on the general tendencies and findings that the quantitative comparison give rise to.

6. System wide quantitative comparison

Chinese energy system overview

While the Chinese energy system encompasses a large geographic area comprised of regions with varying energy generation portfolios (some areas have large shares of hydro, some have nuclear, while others are heavily coal dependant), as a whole, the Chinese power and heat system is highly interrelated. Power and heat is generally produced at a) power only units (primarily coal and renewable based), b) heat only units (primarily coal-based) and c) CHPs (primarily coal-based). The system wide effects of power plant flexibility therefore reflect this context.

6.1 MAIN FINDINGS

The four primary findings when comparing the flex and no-flex scenarios are that increased thermal power plant flexibility:

- Lowers CO_2 emissions and coal use
- Reduces VRE curtailment
- Increases achieved power prices for VRE
- Results in significant economic system benefits

The effects of the flexibly improvements on CO_2 emissions, curtailment, coal use, achieved power prices for VRE, and socioeconomic benefits are displayed in the table below.

Table 3: Effects of flexibility package (relative to No-Flex scenario)

	2025	2030
Reduced CO_2 emissions (million tonnes)	28	39
Lower coal usage (PJ)	300	430
Renewable production not curtailed (TWh)	3	15
Increase in achieved power prices for VRE (%)	3%	10%
Annual cost savings of flexibility package (bn RMB)	35	46

Lower CO_2 emissions and reduced coal usage

When comparing calculations with and without increased power plant flexibility, annual CO_2 emissions with more flexible power plants are 28 million tonnes lower in 2025, and 39 million tonnes lower in 2030. In a Chinese context this equates to a 0.7% reduction in 2025 and a 1.2% reduction in 2030. However, this CO_2 emission reduction is by no means negligible. It is comparable in scale to the total CO_2 emissions of a small country such as Denmark (47 million tonnes in 2017).

The primary reasons for lower CO_2 emissions and reduced coal use are:

a) Less heat only and electricity only production based on coal.
b) Less curtailment of renewables.

The largest contributing factor to reduced CO_2 emissions when a flexibility package has been applied is the reduction in both power and heat that are produced in heat or power only coal units and thus overall lower coal consumption. In 2025 for example, on the electricity generation side the flex scenario sees a reduction in condensing coal electricity of 78 TWh. Despite the fact that electricity generation from coal CHP increases by more than this (108 TWh) and heat generation from CHP increases by 410 PJ, because heat generation from coal boilers is reduced by 565 PJ, the net reduction in coal usage is over 300 PJ. In 2030 this figure grows to 430 PJ, with the increase primarily due to a growing replacement of coal-based heat from CHP rather than heat-only boilers. The reduction of coal consumption represents a fraction of China's total coal consumption, but a 430 PJ reduction represents approximately 14% of Germany's total coal consumption (and roughly 25% of hard coal), which is the second largest in Europe.

The lower coal usage signifies an increase in overall energy efficiency as combined power and heat production via CHP units are enabled to produced more (with high efficiency due to coproduction) substituting less efficient production at power only and heat only units. In addition to the CO_2 related benefits of lower coal consumption, there are also a number of local environmental benefits associated with these reductions.[2]

As discussed previously (section 4.1), the curtailment of renewable generation is an extensive problem in China and significant efforts are underway to reduce curtailment rates. The scenario analysis indicates that the implementation of the flexibility options in the flex scenario results in an

[2] The non-CO_2 related benefits of reduced coal consumption have not been quantified in the current study.

additional 2.8 TWh of electricity production from solar and wind in 2025 that would otherwise be curtailed. Driven primarily by continued large investments in solar and wind from 2025 to 2030, the reduction in VRE curtailment in the flex scenario grows to 15.3 TWh in 2030. The implementation of flexible power plants reduces the total modelled VRE curtailment by roughly 30% in both 2025 and 2030, i.e. the total modelled curtailment from solar and wind in 2030 is 53.8 TWh in the No Flex scenario, while it is 38.5 TWh in the Flex scenario.

The increased reduction in VRE curtailment from 2025 to 2030 (from 2.8 to 15.3 TWh) highlights the fact that a more flexible coal-based thermal fleet facilitates growing quantities of VRE within the Chinese power system.

Higher achieved power prices for VRE

Higher achieved power prices for both VRE and coal are important drivers for continued VRE buildout. Higher realised power prices for VRE provide stronger incentive for developers to continue investment in VRE, and at the same time make VRE more competitive with fossil fuel-based generation. This is an important outcome of having a more flexible thermal power plant fleet.

In China, achievement of grid parity between wind, solar and coal by 2020 is a clear target. Higher achieved power prices for VRE will reduce the need for VRE subsidies, which is always a desired outcome. In the case of China, this is particularly pronounced as there are larges delays in the collection of renewable energy subsidies from the government. China's renewable energy subsidy deficit is widening, reaching 100 bn RMB by end-2017. Higher achieved VRE prices are instrumental in this regard, as they allow for continued build-out while allowing subsidies to decline.

For coal plant owners, higher realised prices for their electricity provide incentive to investment in flexibility, which as highlighted above, facilitates the integration of VRE. Flexible thermal plants can better respond/operate according to varying electricity prices, thus better enabling them to 'enter the market' when prices are high (and thereby realise greater revenue), and essentially, "leave the market", when VRE production is, "ample", thus raising prices for low marginal costs assets such as wind and solar.

Higher achieved prices for coal plant owners also makes it easier to avoid conflicts with vested interests. For example, higher prices for coal-based electricity may also support the political feasibility of implementing market reforms leading to a decrease in full load hours for coal based-thermal power plant owners.

The above challenges (i.e. the need for reduction of RE subsidies and encouraging thermal power plant flexibility) are not unique to China, but are instead a global challenge, and many of the lessons learned in China can be applied elsewhere.

Socioeconomic benefits

The socioeconomic analysis indicates that the above four benefits can be realised in conjunction with a net economic gain for the Chinese power and heat sector. The total benefit of the power plant flexibility investments analysed is roughly 35 bn RMB annually in 2025, growing to over 46 bn RMB in 2030. The fact that the benefit increases between 2025 and 2030 indicates that the window for focusing on power plant flexibility is beyond 2025, and supports the robustness of the conclusions.

There are three additional elements that also reinforce the robustness of the economic conclusions. Firstly, coal heat-only boilers have a relatively low capital cost, and the net economic benefit is positive even without their inclusion. Secondly, the flexibility investments in relation to the overall benefits are minor, so even if these investments costs are highly underestimated (i.e. they could be more than tripled), the results still appear positive. Lastly, despite the fact that the future CO_2 price is quite uncertain, the contribution from this aspect is rather small, i.e. even with a CO_2 price of zero the results will change relatively little.

The system benefit consists of operational benefit from variable production costs as well as changes in capital costs. Each of the individual components of the flexibility package (i.e. plant flexibility improvements, heat storage and electric boilers) provide a positive benefit.

6.1 SCENARIO RESULTS

Lower CO_2 emissions

A reduction in curtailment rates, and a shift towards cogeneration instead of separate production of heat and electricity, lead to significant CO_2 emission reductions in the Flex scenario of over 28 million tonnes in 2025, and nearly 40 million tonnes annually in 2030 (Figure 19). To put this figure into perspective, total Danish CO_2 emissions were roughly 47 million tonnes in 2017.

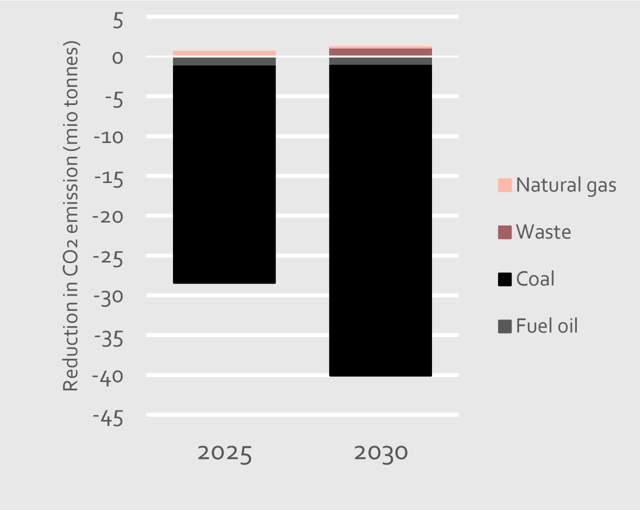


Figure 19: Change in CO_2 emissions given a flexible thermal power plant fleet in 2025 and 2030.

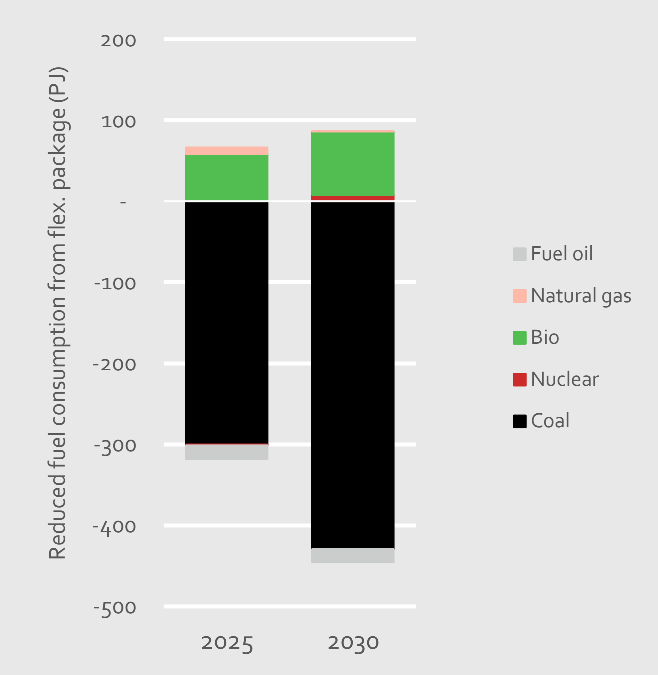


Figure 20: Change in fuel consumption given a flexible thermal power plant fleet in 2025 and 2030.

Lower curtailment

One of the positive aspects of increased flexibility is that curtailment reductions lead to increased production from wind and solar generation totalling 2.8 TWh in 2025. Looking further ahead to 2030, the benefits of plant flexibility become even more pronounced, as net generation increases from wind and solar are 15.3 TWh. However, as indicated in Table 4, total curtailment is still anticipated to be an issue that requires further action, particularly in 2030, when even in the Flex Scenario, the model runs indicate that there will be nearly 40 TWh of VRE curtailment. The reason for the growing curtailment figures is the scenarios' continuing expansion of VRE from 2025 to 2030.

Fuel consumption

While increased thermal power plant flexibility allows for a reduction in curtailment, and therefore more electricity from renewable sources, the largest benefit is the ability for greater reliance on CHP units for electricity and heat generation. I.e. CHP units replace production from condensing units for electricity, and separate heat-only boilers for heat generation, the effect of which is apparent in Figure 20. The figure displays the fuel consumption differences between a flexible and non-flexible system and highlights the large decrease in fuel consumption, particularly for coal, where the roughly a 300 PJ reduction in 2025 equates to over 14 million tonnes of standard coal and the 430 PJ reduction in 2030 equates to 20 million tonnes.

Table 4: Total VRE curtailment in both scenarios

Curtailment (TWh)	2025		2030	
	Flex	No Flex	Flex	No Flex
Wind	2.2	3.1	27.3	34.8
Solar	3.8	5.7	11.2	19.0
Total	**6.0**	**8.8**	**38.5**	**53.8**

To put this into perspective, a 430 PJ reduction is around 14% of the total annual (PJ) coal consumption (both hard coal and brown coal) in Germany, which is the EU's largest coal consumer.

6.2 SCENARIO CALCULATIONS

The above findings and results become more nuanced when reviewing the development in generation capacities and annual electricity and heat generation profiles in the two scenarios.

Generation capacity

In a situation with less flexible power plants the total generation capacity, and capacity per fuel, are almost the same. However, when power plant flexibility options exist, it is cost-effective for roughly 25% of the 626 GW of condensing coal plants to be retrofitted by 2025. When looking at CHP plants, of the 370 GW of capacity in 2025, 165 GW is retrofitted, an equal amount of newly built plants will be flexible (instead of slightly cheaper inflexible units). For coal-based power generation, the picture is very similar in

2030. The results for 2025 and 2030 reveal a significant emphasis on enhancing flexibility, which extends the scale and scope of the official policy to make 220 GW thermal power plants flexible by 2020. As mentioned, these results should not be seen as prescriptive of precise levels, but rather as an indication that thermal plant flexibility could have a significant role to play in the medium term.

Table 5: Installed flexible capacity and 'non-flexible' coal power capacity in the flex scenario.

	Until 2025		Until 2030	
	Power (GW)	Heat (GW)	Power (GW)	Heat (GW)
New Flexible capacity:				
CHP coal plants – flex (new)	171	183	203	217
CHP coal plants – flex (retrofit)	165	180	165	180
Condensing coal – flex (retrofit)	154	-	175	-
Electric boilers	-	57	-	60
Heat storage	-	192	-	227
Total new flexible capacity	**490**	**611**	**543**	**684**
Non-flexible capacity:				
CHP coal plants – not-flex	34	32	34	31
Condensing coal – not-flex	472	-	343	-
Total non-flexible capacity	**507**	**32**	**377**	**31**

When a fleet of combined heat and power plants are more flexible, one of the key consequences is that they can produce more heat, often at the expense of reduced electricity production (via bypass), or by using electricity directly for heat production (via electric boilers). This coupling between electric and heat production is evident when reviewing the potential heat capacity development paths (see Figure 21).

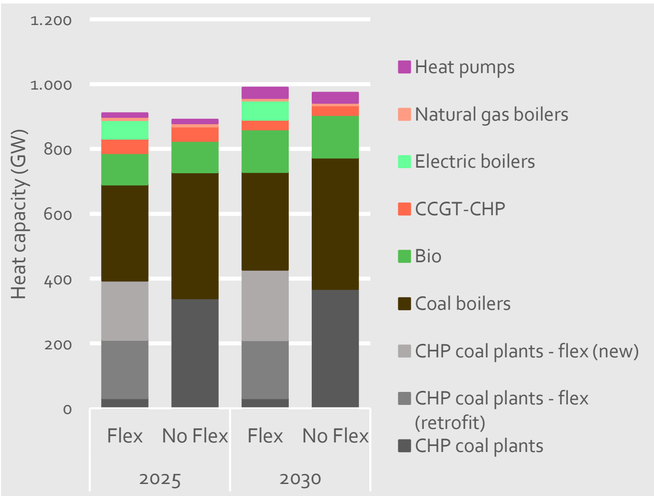


Figure 21: Heat generation capacity in 2025 and 2030

In 2025, the flexible power plant fleet has an additional 54 GW of heat generation capacity from coal CHP, and an additional 57 GW of capacity from electric boilers, but it is possible to reduce the amount of coal heat-only boilers required in the system by over 92 GW.

Heat storage capacity

The heat storage capacity invested in within the Flex scenario as part of the flexibility package is 192 GW in 2025, growing to 227 GW in 2030. Each unit of storage capacity in GW terms is assumed to provide 8 hours of full load storage volume, thus resulting in 1,534 GWh of storage volume in 2025 and 1,815 GWh in 2030.

Generation - electricity

While total electricity generation with or without flexible thermal units is quite similar (see Figure 22), total generation with enhanced flexibility is roughly 35 TWh higher in 2025. This is largely due to increased demand from electric boilers (37 TWh), while pumped storages are less active, which reduces the impact of losses between charging and discharging, assumed to be roughly 25%.

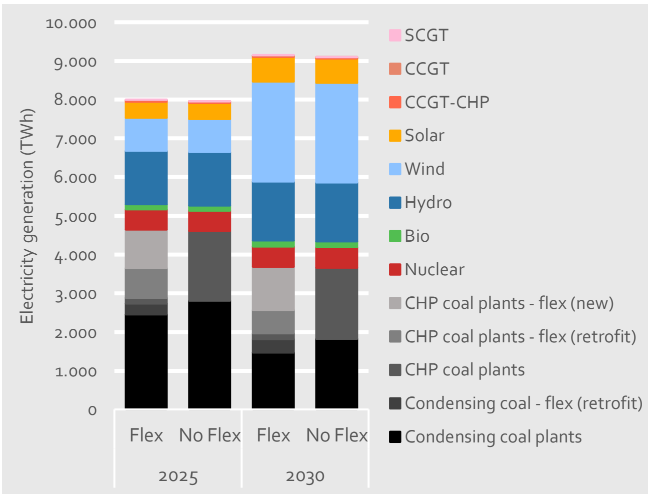


Figure 22: Electricity generation by plant type in 2025 and 2030

The effect of increased flexiblity on generation for the years 2025 and 2030 is further outlined in Table 6. In 2025, net electricity production from coal is increased by 30 TWh. While condensing plants reduce production by 78 TWh, CHP production is increased by 108 TWh. The net effect is the result of a large increase in overall efficiency. This is a benefit that becomes particularly apparent when looking at the heat generation figures later in the chapter.

Looking at 2030, the shift from condense to CHP coal-based electricty produciton becomes less pronounced, as the

Table 6: Effect on power generation when flexibility package is applied (TWh)

Generation source	2025	2030
Condensing coal	-77.8	-3.8
CHP coal	108.0	23.2
Hydro	0.3	4.1
Wind	0.9	7.5
Nuclear	-0.1	0.7
Solar	1.9	7.8
Bio	2.4	3.3
Natural gas	-0.2	-0.5
Total	**35.3**	**42.2**

energy system as whole has become more flexible in 2030. The amount of alterative flexibliity options (industrial demand response, smart charging of EVs, repurposed batterie increases, transmission capacity etc.) increases signifinatly from 2025 to 2030.

Overall generation efficiency gain

A reasonable concern with coal plant flexibility is that both overload, lower minimum load, and bypass operations allow for the plants to run at set points, which have a lower efficiency when considering the single plant. While the difference is not profound, the average efficiency of power generation on coal plants in the situation with flexibility is actually increased by 0.1 percentage points in 2025, and 0.8% higher in 2030. Both the condensing and the co-generation fleets overall efficiencies increases.

For the CHP units, a higher co-generation proportion (note: the co-generation benefit in this calculation is shared between the power and heat sides), is the major contributor, which offsets the reduced efficiency in overload, bypass and low-load operation. For the condensing plants, the improved system flexibility allows for a higher share of generation on more efficient plants overall.

Generation - heat

As was the case with generation capacity, more significant differences are to be found when looking at heat generation relative to electricity generation (see Figure 23).

The most striking difference is the additional heat production from heat-only coal boilers, which in a non-flexible development path generate 565 PJ more heat in 2025 and growing to over 660 PJ in 2030. With a more flexible fleet of power plants the majority of this heat is instead produced at a CHP plant, thus greatly improving the overall system efficiency. In addition to this shift from coal boilers to coal CHP, total heat production from coal is also reduced. This is primarily replaced by production from electric boilers (some of which however is coal-based electricity), but biomass-based heat also replaces some of this coal-based heat production.

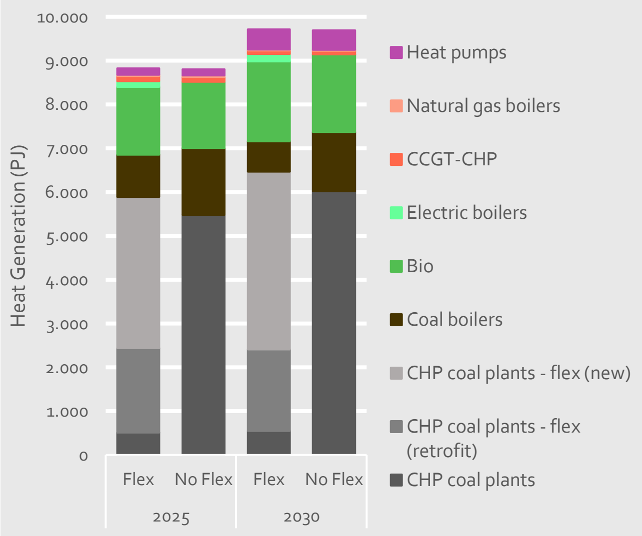


Figure 23: Heat generation by technology type in 2025 and 2030. Note that "CHP coal plants" (dark grey) represents existing and new non-flexible CHP plants in both scenarios.

Table 7: Effect on heat generation when flexibility package is applied (PJ)

Generation source	2025	2030
CHP coal	410.0	446.0
Coal boilers	-565.4	-660.0
Bio	35.3	52.3
Electric boilers	134.1	169.4
CCGT-CHP	-9.2	-10.2
Natural gas boilers	0.8	0.0
Heat pumps	0.3	10.0
Total	**5.8**	**7.5**

6.3 SYSTEM COST BENEFIT ANALYSIS

System value effects

VRE system value increases

The economic analysis finds that both the system value of VRE, and the relative system value of VRE increase in a scenario with increased thermal power plant flexibility. These are significant findings, as they suggest that improved power plant flexibility improves the system's ability to integrate VRE in a cost-effective fashion.

Table 8: Improvement in the system value of VRE sources from including thermal plant flexibility

VRE	2025	2030
System value	3%	10%
Relative system value	1%	4%

An increase in the system value of VRE indicates that average achieved power prices for VRE are higher, i.e. when solar and wind generators produce electricity, the value of this electricity is higher than it would be in a situation without flexible power plants. Higher realised electricity prices for VRE provide incentive for developers to continue investment in VRE, and at the same time make VRE more competitive.

The relative system value increase implies that the system value of VRE generation increase relative to the average system value of generation. I.e. that the value of generation increases more at times with high levels of VRE generation, indicating that VRE sources are better integrated in the system in the Flex scenario.

Coal power system value increases

Another relevant finding is that the system value of coal power also increases in a scenario with flexible power plants. This provides coal plant owners with an incentive to invest in power plant flexibility, as this flexibility allows plant operators to better capitalise on high prices, but also exit the market when electricity prices are below their short term marginal costs.

A well-documented contributing factor to the high curtailment rates in China are the agreements that guarantee a minimum number of full load hours for coal power plants. If these power plants achieve higher prices for their electricity, it may reduce resistance to implementing market reforms such that coal-fired plants' full load hours decrease.

System value of other sources of flexibility

The system value effects should also be seen in the context of other sources of flexibility. Two obvious alternatives are gas-fired generation and electricity storages.

Gas-fired generation and full-load hours decrease when thermal coal plants become more flexible. However, the average system value of the gas-fired generation that remains increases. In the context of the flex scenario, this essentially points to gas being a source of flexibility for the system that is higher on the supply curve. It should be noted that gas-fired generation plays a comparatively small role in the Stated Policies scenario, both in the Flex, and No flex variants.

Electricity storages', including both pumped storages and batteries, average operating system value, i.e. the average system price difference between loading and unloading, is decreased in the Flex case significantly (40% in 2025 and 22% in 2030). The full load hours of storage operation also decrease with increased plant flexibility. Hence the other flexibility sources are freed-up allowing the system to integrate further deployment of VRE resources.

Summary of system value effects

The two primary consequences of increased system value of both VRE and electricity production from coal are:

1) A power and heat system that is more prepared for continued integration of VRE in a cost-effective manner
2) Given the right regulating structure and incentives, thermal fleet owners will be motivated to invest in flexibility.

From this it can be concluded that power plant flexibility is a cost-efficient way of allowing for more VRE integration in the short and medium term. The simulations carried out within the analysis assume the same installed VRE capacity, as well as most other capacity. Given that the system benefit of VRE generation is higher in the Flex scenario it indicates that more VRE generation could likely be installed and integrated to the grid with the same costs of system integration.

Total costs and benefits

Increasing the flexibility of a power plant fleet involves additional upfront costs for new flexible compared to normal "inflexible" thermal units, costs associated with retrofitting existing units, and investment in electric boilers and heat storage. The additional costs associated with these investments in a flexible power plant development path are displayed in Table 9.

Table 9: Total investment costs of flexibility package (bn RMB)

	Until 2025	2025 to 2030	Total
CHP coal plants - flex (new)	23.4	4.4	27.8
CHP coal plants - flex (retrofit)	31.9	-	31.9
Condensing coal - flex (retrofit)	4.4	0.6	4.9
Subtotal of plant flexibility	**59.6**	**5.0**	**64.6**
Electric boilers	31.4	1.6	33.0
Heat storage	30.7	5.6	36.3
Total	**121.7**	**12.2**	**133.9**

The total investments in flexibility are split evenly between power unit enhancements (condensing and CHP) on the one hand, and heat storages and electric boilers on the other.

With greater power plant flexibility, these additional costs are however more than offset by reduced investments in alternative heat supply capacity from coal heat-only boilers, lower fuel costs, as well as savings related to O&M and CO_2 emissions. The annual savings for a flexible power plant system relative to a system without thermal power plant flexibility for 2025 and 2030 are displayed below.

Table 10: Annual cost savings associated with improved flexibility (bn RMB)

	2025	2030
Fuel Cost	10.5	14.1
Variable O&M	2.8	4.5
Start-up costs	3.3	4.2
CO_2 Cost	2.1	3.9
CAPEX & fixed O&M	16.3	19.6
- Electric boilers	-3.2	-3.4
- Heat storage	-4.2	-4.9
- Coal boilers	33.0	37.4
- SCGT	-3.9	-3.7
- Plant flexibility	-5.4	-5.7
Total	**35.0**	**46.4**

In reviewing Table 10, given the large fuel savings described in the previous section, considerable cost savings related to fuel are to be expected. In 2025, of the 10.5 bn RMB in savings, 10 bn RMB are attributed to savings due to reduced coal consumption.

Lower O&M costs are largely due to reduced operational hours from coal heat-only boilers, as a flexible development path instead sees this heat production coming from a CHP plant. With more flexible power plants, it is also possible to reduce the number of times a unit must start and stop, thus resulting in cost savings.

In line with the Stated Policies Scenario in the CREO 2017, assumed CO_2 emission costs of 75 and 100 RMB/tonne were applied respectively in 2025 and 2030, thus yielding cost reductions of 2.1 and 3.9 bn RMB annually in 2025 and 2030.[3]

On the CAPEX side, the additional invested capital associated with electric boilers, heat storage and increased plant flexibility sum to annualised costs of 12.8 bn RMB in 2025.[4] These figures include the cost of capital, and thereby the investors' minimum profit requirement, and the fixed O&M costs. These increased costs are overshadowed by cost savings of 29.1 bn RMB from the displacement of alternative capacity, which would be needed without the flexibility package. These displaced costs relate to the district heating side in the form of heat-only coal boiler capacity, since bypass, electric boilers and heat storages all supply additional heat capacity.

Key uncertainty

The key economic uncertainty lies in the exact value of coal CHP versus coal-based heat-only boilers & coal condensing generation. There is no question that this value is real, and well established. While it may not be deployed as widely as indicated in the scenarios, the measure has value where it is introduced. Moreover, there is uncertainty regarding which energy sources would be displaced, and the results may differ.

Flexibility measures

The system benefit consists of operational benefits from variable production costs, as well as changes in capital costs. Each of the individual components of the flexibility package provide a positive benefit.

Comparing the situation with and without flexibility provides the total system benefit result, but not the allocation of system benefit to the individual measures. To estimate this distribution, a series of variants to the main simulations are calculated.

The attribution of the total system benefits, including changes in both operational and capital expenditure, are displayed in Figure 24. These values are estimates because if the value of each component were calculated individually, and these values summed, the total value would be greater, i.e. doing everything in the package reduces the specific benefit of the individual components if undertaken alone. The estimated benefit is found as the average of Compared

[3] Note that the CO_2 emission costs in the CREO 2017 are inputs to the model calculations and are based on analysis of future potential developments related to CO_2 markets, etc. However, these analyses were undertaken prior to the launch of CO_2 markets and should therefore be treated with a degree of uncertainty.

[4] The assumed lifetime for electric boilers and heat storage is 20 years, and 15 years for plant flexibility measures. The WACC is assumed to be 5.9% (real)

Methodology for calculating the benefit of the individual flexibility components:

There are two groups of calculations:

- **Compared to No Flex**: Using the assumed capacity from No Flex and adding one flexibility measure at a time.
- **Compared to Flex**: Using the assumed capacity from Flex and removing one flexibility measure at a time.

Both groups of calculations examine the three components: plant flexibility (overload, bypass and lower minimum load), electric boilers and heat storages.

Compared to No Flex provides an estimated upper limit for the benefit of the flexibility component. Performing a calculation where e.g. the plant flexibility measures is added and comparing this to No Flex yields the estimated maximal benefit of the plant flexibility.

Compared to Flex provides an estimated lower limit for the benefit of the flexibility component. Performing a calculation where e.g. the plant flexibility measures is removed and comparing this to Flex gives the estimated minimal benefit of the plant flexibility.

to No Flex and Compared to Flex in regard to the total system benefit between No Flex and Flex.

When looking at the value of the three flexibility components (plant flexibility, electric boilers, and heat storage) in 2025, fuel cost savings are the largest source of system benefits for each category (Figure 25).

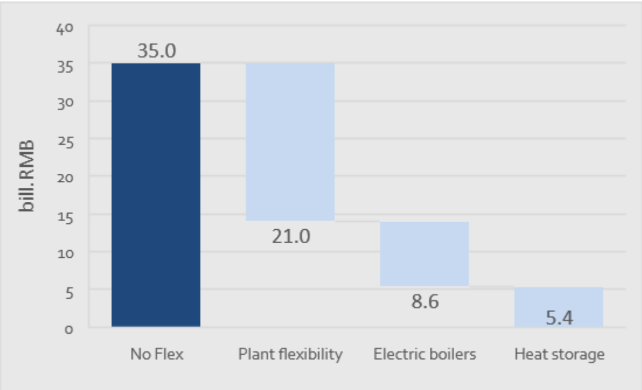


Figure 24: Individual flexibility components' effect on system value in 2025

The economic system benefit of plant flexibility consists largely of fuel cost savings due to increased generation at more efficient coal plants, as lower fuel costs represent approximately half of the total benefits. The remaining half is relatively evenly distributed between reduced costs related to CO_2, variable O&M, and start-up costs.

For electric boilers, the economic benefit is comprised almost entirely of fuel savings since they are able to exploit a surplus of efficient electricity generation to replace more expensive heat generation.

With respect to heat storages, the economic system benefit largely relates to fuel cost savings, as well as reduced start-up costs. The flexibility of the heat storages provides efficient heat generation units with the possibility of increasing generation at times available capacity exceeds the heat demand. Also, the heat storages can keep committed units on line even though heat demand drops and would otherwise need to shut down, thus avoiding start-up costs when heat demand rises again.

In terms of the flexibility components effects on CO_2 emissions, the reduced emissions come from both plant flexibility and heat storage, with plant flexibility having the largest impact of the two (approximately 65% of the CO_2 emissions reductions). On the other hand, the electric boilers actually increase CO_2 emissions slightly due to an increased electricity generation from fossil fuel plants.

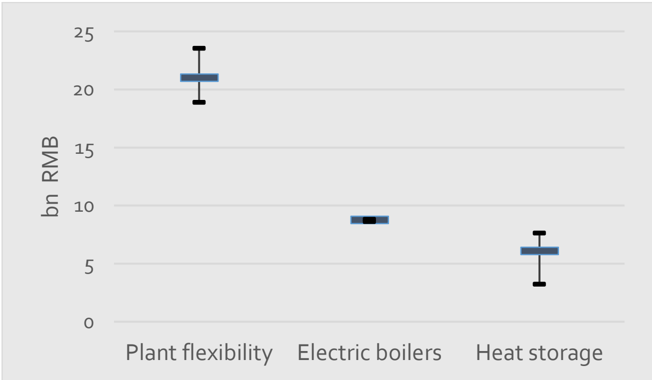


Figure 25: System net cost reduction from individual flexibility measures in 2025

7. Specific cases

In this chapter, the analysis is expanded to look at thermal flexibility in different parts of the Chinese power system and supplemented with analysis that narrows down on specific challenging situations that can arise during shorter periods. The value of power plant flexibility for China has been demonstrated in the previous chapter, and this chapter provides further insight into contexts where enhanced power plant flexibility can be particularly beneficial, or conversely only play a limited role. It is useful to compare the role of enhanced power plant flexibility in different mixes of generation assets as well as different power grid situations – whether the local systems predominantly feature imports, exports, or transit flows, etc. A few key situations for the power system when there may be a special role for power plant flexibility are also investigated. The main purpose of this chapter is therefore to provide insight into the Chinese case, but it is also to illustrate how power plant flexibility plays different roles depending on context, thereby providing insights for other regions/countries.

7.1 THE SITUATIONAL ANALYSIS

Five different situational contexts are investigated, including four provinces and a perspective on the VRE integration challenge during a period with high need for system flexibility.

1. The north-western province of Gansu, which features high VRE penetration, and through which significant power transit flows.
2. The north-eastern province of Heilongjiang, where cold winters, high district heating penetration and VRE installations coincide.
3. A coastal province, Fujian, which relies on limited power exchange with neighbouring provinces.

Figure 26: Map emphasising the areas in focus in the situational analysis, along with the neighbouring areas that the exchange power flows with. This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

4. A selected week on the island province of Hainan.
5. Spring festival.

These focus areas were selected due to their varying geography, climate, and/or generation mix. In addition, Fujian and Gansu have both been selected since they will initialise pilot spot markets in 2018. While the benefit and scope of thermal flexibility measures is demonstrated to be situationally dependent, it plays a role in each of the sub regions analysed.

7.2 GANSU

Gansu is in the cold north-western part of China and borders six other provinces. Gansu has one of the highest rates of renewable electricity production in China, with solar and wind production accounting for 22% of provincial demand in 2017. However, the province also has some of the highest curtailment rates in China. This is due to both congestion bottlenecks, and the high level of co-generation during the cold winter months. As Gansu is situated between the major electricity exporting province of Xinjiang to the west, and the large power importing regions in the east and south east, Gansu is also a transit province. In the scenarios there is therefore 45 GW of transmission capacity to western regions (Xinjiang, Qinghai, Ningxia and West Inner Mongolia) and 17 GW to the eastern regions (Hunan, Shaanxi and Sichuan), totalling over 62 GW of transmission capacity in 2025. These capacities are unchanged in the scenarios towards 2030.

Table 11: Gansu power capacities in 2025 and 2030 in the scenarios.

	2017		2025		2030	
	GW	%	GW	%	GW	%
Thermal	20.6	41	18.8	36	16.4	28
- Coal - condensing			6.7	13	3.1	5
- Coal - CHP			10.0	19	10.4	18
- Nuclear				0		0
- Other*			2.1	4	3.0	5
Hydro	8.7	17	9.6	19	10.6	18
Wind	12.8	26	12.8	25	21.5	36
Solar	7.9	16	10.5	20	10.5	18
Total	**49.9**	**100**	**51.6**	**100**	**59.0**	**100**

* Other represents biomass, CCGT and SCGT

Impact of increased thermal plant flexibility in Gansu

Generation and transmission - electricity

With the introduction of increased power plant flexibility, condensing coal plants in Gansu see their production reduced from 17 to 10 TWh in 2025, and from 10 to 7 TWh in 2030. In 2025, CHP coal plants maintain their power generation at 37 TWh, yet 31 TWh are shifted to either retrofitted or new flexible units. Looking further ahead to 2030, 35 TWh of CHP generation is reduced to 30 TWh, with 23 TWh shifted to flexible units.

With respect to VRE, in the flex scenario, wind production increases (due to reduced curtailment) by 81 and 909 GWh in 2025 and 2030 respectively, while solar generation increases by 266 and 365 GWh in these years.

In both scenarios Gansu is a net importer of electricity, but net imports are increased as a function of flexibility from 27 TWh to 33 TWh in 2025, and from 40 TWh to 46 TWh in 2030. A main reason behind the large flows from Xinjiang to Gansu (and other regions), and the subsequent reduction in other regions power generation from coal units, is an assumed continuation of Xinjiang having lower coal prices.

Generation – heat

Despite the fact that electricity production from CHP plants in the flex scenario is unchanged in 2025, and lower in 2030, relative to the No Flex scenario, heat generation from CHP increases in 2025 by 4.1 PJ, and by 1.6 PJ in 2030. In the Flex scenario, electric boilers also play an increased role, as they deliver 1.9 PJ of heat in 2025, with this growing to 5.7 PJ in 2030. As a result, coal boiler generation is reduced from 31.3 to 24.9 PJ in 2025, and from 30.8 to 22.6 PJ in 2030. Figure 27 displays the heat production distribution for Gansu in the two scenarios and highlights the extensive shift in production from non-flexible CHP units to flexible CHP units.

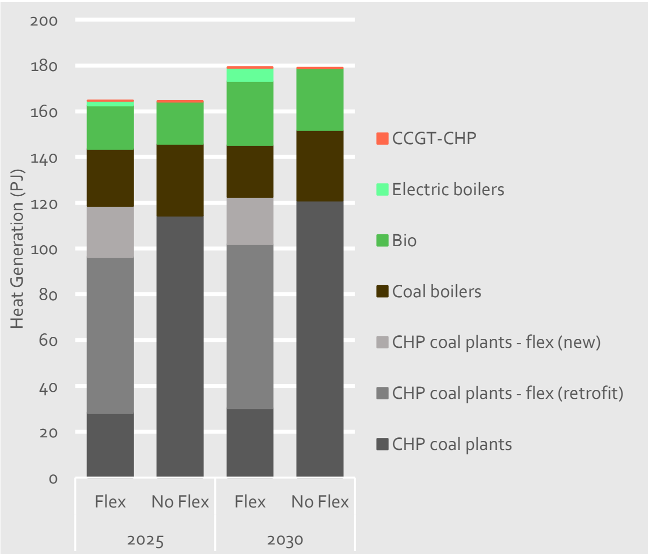


Figure 27: Heat generation by technology type in 2025 and 2030 in Gansu.

Curtailment

VRE curtailment is a major issue in Gansu today as wind and solar curtailment rates were 43% and 30% respectively in 2016. These rates are reported to have fallen in 2017 and should be aided by the 8 GW 800 kV UHV DC transmission line to Hunan that was recently commissioned. However, curtailment rates are still well-above the national average and the VRE buildout was put on hold until this issue is resolved. The province has a target of 5% curtailment by 2020, but given the current situation this may be difficult to achieve.

The scenario analysis indicates that improved thermal plant flexibility can lead to VRE curtailment reductions of nearly 350 GWh in 2025 and over 1,630 GWh in 2030 (Table 12). This would reduce total VRE curtailment to 1% in 2025, and although this increases to 2.4% in the calculations by 2030, this is due to the assumed resumption of the wind build out after 2025 in both scenarios.

Table 12: Total VRE curtailment, and % curtailment, in both scenarios in Gansu

Curtailment (GWh & %)	2025		2030	
	Flex	No Flex	Flex	No Flex
Wind	76 (0.3%)	157 (0.7%)	627 (1.3%)	1,536 (3.1%)
Solar	337 (2.2%)	603 (4.0%)	887 (5.9%)	1,252 (8.4%)
Total	**413 (1.1%)**	**760 (2.0%)**	**1,154 (2.4%)**	**2,788 (4.3%)**

CO_2 emissions

With the implementation of the flexibility package, CO_2 emissions are reduced in Gansu by 5.4 million tonnes in 2025 and 7.0 million by 2030. This is primarily due to a 6 TWh increase in imports in both years, which reduces coal-based electricity generation within the province. When correlated for these imports, the net CO_2 emission reductions are roughly 2.3 and 4.8 million tonnes in 2025 and 2030 respectively.

Economics

The implementation of power plant flexibility options in Gansu allows for increased imports of low-cost electricity from neighbouring areas, and thus leads to significant savings in operational costs, largely in the form of fuel costs, but also costs related to O&M and CO_2. These cost savings outweigh the cost associated with the additional purchased electricity imports by a large margin in both 2025 and 2030. The capital costs associated with implementing the flexibility package are roughly 100 million RMB in 2025, but in 2030 Gansu realises net CAPEX savings due to reduced investments in alternative heat capacity (Table 13).

Table 13: Annual cost savings associated with improved flexibility for Gansu (million RMB)

	2025	2030
Operational costs	1,682	2,314
CAPEX	-100	158
Savings on net-imports	-1,088	-773
Total	**494**	**1,699**

Observations from Gansu focus

The net increase of imports in 2025 of 6 TWh correspond quite closely with the reduced electricity production from coal condensing plants. Meanwhile, in 2030 the 8 TWh reduction in coal-based electricity (3 TWh from condensing plants and 5 TWh from CHP), is replaced by a 6 TWh increase in imports, 1.3 GWh from wind and solar that is not curtailed, and the remaining difference is comprised of increased electricity demand from electric boilers and other generation. In looking at the transmission results, it bears keeping in mind that they are highly influenced by assumptions regarding the expected build out of transmission lines, and also how they are likely to be dispatched.

That heat production from CHPs increase despite similar or less electricity production from the same units indicates that bypass and heat storages are being utilised. Storing heat for later use allows the CHPs to operate at a higher overall efficiency, while the utilisation of bypass instead of coal boilers in a worst-case scenario involves the same efficiency.

One of the key findings of the system wide analysis is that the system value of both VRE and coal-based electricity generation is higher in a scenario with increased power plant flexibility. As Gansu is a net electricity importer in both 2025 and 2030, Gansu as a whole does not benefit from increasing system value (i.e. relative higher electricity prices). Despite not benefiting from this particular positive aspect of increased power plant flexibility, Gansu does benefit from two other major advantages highlighted in the country wide analysis, i.e. less heat-only and electricity-only production based on coal, and less curtailment of renewables, and as a result the net economics are positive for the province.

7.3 HEILONGJIANG

Heilongjiang province covers 455 thousand km^2, making it the 6th largest province in China and is located in the Northeast, bordering Inner Mongolia to the West, Jilin to the South, and Russia to the North. Wind power development has been rapid in the province, reaching 5.7 GW of installations by the end of 2017, but only increasing by 1.7% in 2017. This was down from increases of 11.5% in 2016 and 10.9% in 2015. This has put pressure on the power grid as it must ensure the balance in the power grid while adapting to a larger share of fluctuating energy and ensuring the essential district heating is provided without interruption. In 2017, the NEA issued a Red Alert for wind power deployment that included Heilongjiang, thus allocating no quotas for build out from now until 2020, which is the primary reason for the slowdown in wind power installations in 2017. Solar installations meanwhile soared in 2017 by 476%, reaching 941 MW. Wind power curtailment in 2016 was 19%, and 16% in the first half of 2017.

The backbone of the Heilongjiang power grids are 500 kV and 220 kV voltage level lines. There are no existing nor firm plans for ultra-high voltage lines from Heilongjiang towards consumption centres.

Heilongjiang is included as a case as it is a system combining significant VRE installations, mainly wind but increasingly solar, with extremely cold winters (average temperatures in January between -31 and -15) and a high penetration of CHP. The Heilongjiang power system is a net-exporting system as surplus electricity is exported to Jilin and Liaoning provinces.

Table 14: Heilongjiang power capacities in 2017 and 2025 and 2030 in the scenarios.

	2017		2025		2030	
	GW	%	GW	%	GW	%
Thermal	22.0	73	26.7	67	24.5	46
- Coal - condensing			5.5	14	3.4	6
- Coal - CHP			19.3	48	19.3	36
- Nuclear				0		0
- Other*			1.9	5	1.7	3
Hydro	1.0	3	3.1	8	4.1	8
Wind	5.7	19	5.6	14	20.4	38
Solar	0.9	3	4.4	11	4.4	8
Total	**29.7**	**100**	**39.8**	**100**	**53.4**	**100**

* Other represents biomass, CCGT and SCGT

Impact of increased thermal plant flexibility in Heilongjiang

Generation - electricity

In the Stated Polices simulation (i.e. the Flex scenario) and the No Flex simulation, the stagnation in deployment of wind power persists until and including 2025, but an additional 15 GW are installed towards 2030. The pick-up in solar power deployment continues through to 2025, leading to 4.4 GW of cumulative installations in 2025. Thereafter however, there is a pause in further deployment.

In the Flex scenario, the vast majority of coal CHP becomes flexible within Heilongjiang, while no investments are made in flexible condensing plants. In fact, the amount of condensing capacity decreases from 2025 to 2030 in both scenarios, which is related to the current over-capacity of coal generation in the province.

Table 15: Installed flexible capacity and 'non-flexible' coal power capacity in the Flex scenario for Heilongjiang.

	Until 2025		Until 2030	
	Power (GW)	Heat (GW)	Power (GW)	Heat (GW)
New Flexible capacity:				
CHP coal plants – flex (new)	12.7	13.6	12.7	13.6
CHP coal plants – flex (retrofit)	5.6	6.1	5.6	6.1
Condensing coal – flex (retrofit)	-	-	-	-
Electric boilers	-	5.4	-	5.8
Heat storage	-	16.4	-	19.2
Total new flexible capacity	**18.3**	**41.5**	**18.4**	**44.7**
Non-flexible capacity:				
CHP coal plants – not-flex	0.9	0.9	0.9	0.9
Condensing coal – not-flex	5.5	-	3.4	-
Total non-flexible capacity	**6.5**	**0.9**	**4.4**	**0.9**

The reason for the phase-out of condensing coal capacity in Heilongjiang becomes clear when reviewing the coal-based electricity production in 2025 and 2030 (see Table 16). In both scenarios coal electricity production from condensing plants is roughly 1% of total production from coal in 2025, with this falling to close to 0 by 2030.

Table 16 also illustrates the large extent to which coal-based electricity production from CHP units shifts to more flexible units when given the opportunity in the Flex scenario, as roughly 93% of CHP production comes from flexible units in both 2025 and 2030. The table also highlights the fact that total coal-based electricity production falls in the Flex scenario, by roughly 2.7 TWh in 2025, and 1.0 TWh in 2030.

Table 16: Coal-based electricity production in both scenarios for Heilongjiang

TWh	2025		2030	
	Flex	No Flex	Flex	No Flex
Coal CHP (flexible)	77.6		66.5	
Coal CHP (non-flexible)	5.4	85.5	5.4	73.1
Coal condense (non-flexible)	1.0	1.2	0.2	0.0
Total coal-based production	**84.0**	**86.7**	**72.1**	**73.1**

With respect to VRE production, there is virtually no difference between the Flex and No Flex scenarios in 2025, but in 2030 there is an additional 2.1 TWh in the flex scenario (the vast majority of which is solar PV production).

With slight reductions in electricity generation from coal (and total generation) in the Flex scenario in 2025, one might assume that net imports would increase correspondingly, but instead they increase by nearly 8 TWh. The same holds true for 2030, as the Flex scenario involves a net reduction in exports of over 6 TWh.

Table 17: Electricity imports/exports in both scenarios for Heilongjiang

TWh	2025		2030	
	Flex	No Flex	Flex	No Flex
Imports	12.4	8.1	16.8	14.0
Exports	4.2	8.3	18.2	21.5
Net imports	**8.1**	**0.2**	**-1.4**	**-7.5**

In reviewing the import/export figures, it should be noted that there is no planned ultra-high voltage transmission capacity coming online in Heilongjiang. There are also no model determined transmission capacity expansions, and transmission capacities are therefore constant in the period analysed. Absent any expansions of the transmission capacity, the gradual effect of demand growth slowly catches up with the deployment level, and this helps to explain why curtailment is significantly reduced over time, and is all but eliminated in the Flex scenario in both 2025 and 2030. Another contributing factors is that other flexibility sources are expanded.

Generation – heat

The reason that net electricity inflows increase in Heilongjiang in a Flex scenario become apparent when narrowing in on the heat generation results in the scenarios. In the Flex scenario, heat generation from electric boilers and heat pumps increase by 21 PJ in 2025, and over 30 PJ in 2030 (see Table 19). This increase in imported electricity from neighbouring Inner Mongolia and Jilin assists these regions in reducing their VRE curtailment.

Table 19: Effect on heat generation when flexibility package is applied for Heilongjiang (PJ)

Generation source	2025	2030
CHP coal	33.1	30.7
Coal boilers	-53.8	-61.5
Electric boilers	20.8	27.8
Heat pumps	0.0	2.9

Reduced coal usage and CO2 emissions

The electricity-based heat production, along with increased heat and electricity production from CHP units, allows for large reductions of heat production from coal boilers in the flex scenario in both 2025 and 2030. This is the primary reason for significant reductions in both coal usage and CO_2 emissions. In the Flex scenario, coal consumption falls by 65 PJ in 2025, and 73 PJ by 2030, while CO_2 emissions are reduced by 5.9 million tonnes in 2025, and 6.6 million tonnes by 2030. When corelated for the increase in net imports (or reduction in net exports in 2030) CO_2 emissions are reduced by 1.7 million tonnes in 2025 and 4.4 million tonnes in 2030.

Economics

The large benefit from greater co-generation arising from improved thermal plant flexibility is clear when reviewing the economic figures for Heilongjiang. In the Flex scenario, operational costs savings of 2.2 and 2.7 bn RMB are realised respectively in 2025 and 2030, which are primarily attributable to fuel savings (i.e. lower coal consumption). Similar cost savings are realised on the CAPEX side, where large savings are brought about due to reduced investments in coal boiler capacity equivalent to 8.5 GW in 2025 and 9.0 GW in 2030.

Table 18: Annual cost savings associated with improved flexibility for Heilongjiang (million RMB)

	2025	2030
Operational costs	2,172	2,691
CAPEX	2,211	2,247
Savings on power trade	-1,434	388
Total	**2,949**	**5,326**

Observations from Heilongjiang focus

Heilongjiang is a perfect example of how thermal plant flexibility enables increased co-generation efficiency, which results in large reductions in coal consumption and CO_2

emissions, while realising lower fuel, emission-related, and overall costs.

As the wind buildout is put on pause in the scenarios, curtailment reductions are not significant in Heilongjiang. However, the increase in imports from neighbouring areas enables curtailment reductions in East Inner Mongolia and Jilin.

From an economic perspective, it is worth noting that the operational cost savings are so large, that even without the contribution from CAPEX savings, the net benefit of the flexibility improvements is still positive.

Another interesting economic aspect is that despite the fact that Heilongjiang is a net exporter of electricity in 2030, relative to a situation with no flexibility measures in place, the province realises savings on power trade because the Flex scenario sees 84% higher prices during times of export, and only 6% higher electricity prices during times of import.

7.4 FUJIAN PROVINCE

Fujian is a coastal province located by the Taiwan strait in South-eastern China. Relative to most Chinese provinces Fujian is currently not very interconnected to its neighbours, nor is it by 2025 according to the Stated Policies scenario. In this scenario, the transmission capacity to neighbouring Zhejiang province is 10.3 GW by 2025, and transmission flows are primarily imports. According to the market development assumptions in the Stated Policies scenario, the transmission flows to and from Fujian do not follow hourly market prices in 2025, i.e. they instead occur according to fixed flows that are continually updated and adjusted (e.g. X GW during the day, and/or Y GW during the night). While, these aspects are naturally debatable, it affords the opportunity to look at the simulations of Fujian as a case of a relatively isolated system, where balancing is predominantly achieved using local assets.

Table 20: Fujian power capacities. Capacities for 2025 and 2030 are assumed.

	2017		2025		2030	
	GW	%	GW	%	GW	%
Thermal*	39.5	70	52.9	65	51.3	46
- Coal - condensing			17.5	21	12.6	11
- Coal - CHP			18.4	22	18.9	17
- Nuclear	8.7	16	12.3	15	12.6	11
- Other*			4.7	6	7.2	7
Hydro	13.0	23	11.8	14	11.8	11
Wind	2.5	5	16.7	20	46.1	41
Solar	0.9	2	0.4	1	2.1	2
Total	56.0	100	81.8	100	111.4	100

* CEC statistics only provide total thermal capacities
* Other represents biomass, CCGT and SCGT
* The CREO scenarios use 2016 as a baseline. New installations in 2017, has in some cases exceed the scenario projections, e.g. hydro and solar in Fujian.

Power generation in Fujian comes primarily from condensing coal plants, wind, nuclear and hydro power. Fujian is also slated to be the province with early deployment of offshore wind. From 2017, wind installations (including both onshore and offshore) of 2.5 GW increase by more than a factor of 6. As Fujian is in a warm climate part of China, there is relatively little CHP capacity, and this capacity is predominantly for industrial heat supply.

Impact of increased thermal plant flexibility in Fujian

Generation and transmission capacity - electricity

Given a flexible development path, 65% of CHP coal plants in Fujian are retrofitted in 2025, while 32% of condensing coal plant capacity is retrofitted between 2025 and 2030.

The significant retrofitting and investment in more flexible plants in Fujian allows for coal-fired plants to increase their power generation (this is due to, among other things, the introduction of overload capability). Thermal generation increases by 609 GWh in 2025, and 1,295 GWh in 2030. VRE generation (primarily wind) also increases, by roughly 5 GWh in 2025, and 208 GWh in 2030.

With the implementation of greater power plant flexibility, the net imports to Fujian are decreased. The net imports to Fujian are small however, amounting to approximately 1.4% of the in-province generation in 2025, and roughly 2.1% in 2030.

Curtailment

Compared to the national average, and particularly to the situation in the Northern regions, curtailment is very low in Fujian (under 1%). With the implementation of thermal flexibility investments, curtailment in Fujian is further reduced, by 5 GWh (16%) in 2025 and 208 GWh (17%) in 2030. However, the relatively insulated power system, as forecasted in the scenarios, creates some situations where curtailment occurs.

Generation - heat

For Fujian, being in a relative warm climate means that the introduction of flexibility options does not provide enough incentive to change the capacity of the heat generating mix, meaning that coal boiler capacity remains the same, and no additional electrical boilers are invested in. This is in stark contrast to the findings provided in the previous chapter for China as a whole, where coal boiler capacity was reduced significantly. However, as nearly 80% of the CHP coal plants in Fujian are either retrofitted or new in the calculations for 2025, CHP coal plants produce roughly 77% of heat in 2025. Furthermore, when CHP coal plants are made flexible, and are provided with heat storage options, they can then produce and utilise more heat, which in the case of Fujian reduces the use of coal boilers by 31% (i.e. coal boiler capacity is unchanged, but the usage falls by nearly a third).

Simulated week 4 in 2025

To highlight the differences in heat and power production in Fujian, Figure 28 zooms in on week 4 during 2025. Note that heat demand is the same in both scenarios, with the bottom-most figure representing the heat demand profile, because without heat storage, heat generation will equal heat demand. As the heat systems are not interconnected for the entire province, when heat storage options are implemented, total heat generation for the province as a whole during a particular time period can be significantly higher in a Flex scenario as one area may be filling its heat storages, while another may be discharging its heat storages. Meanwhile, power production profiles (for a specific week or the year as a whole) can be different as there are differing amounts of imports/exports and electricity use for heat production in the two development paths. The red power load curve includes electricity storage loading and is adjusted for the effect of smart charging and demand response.

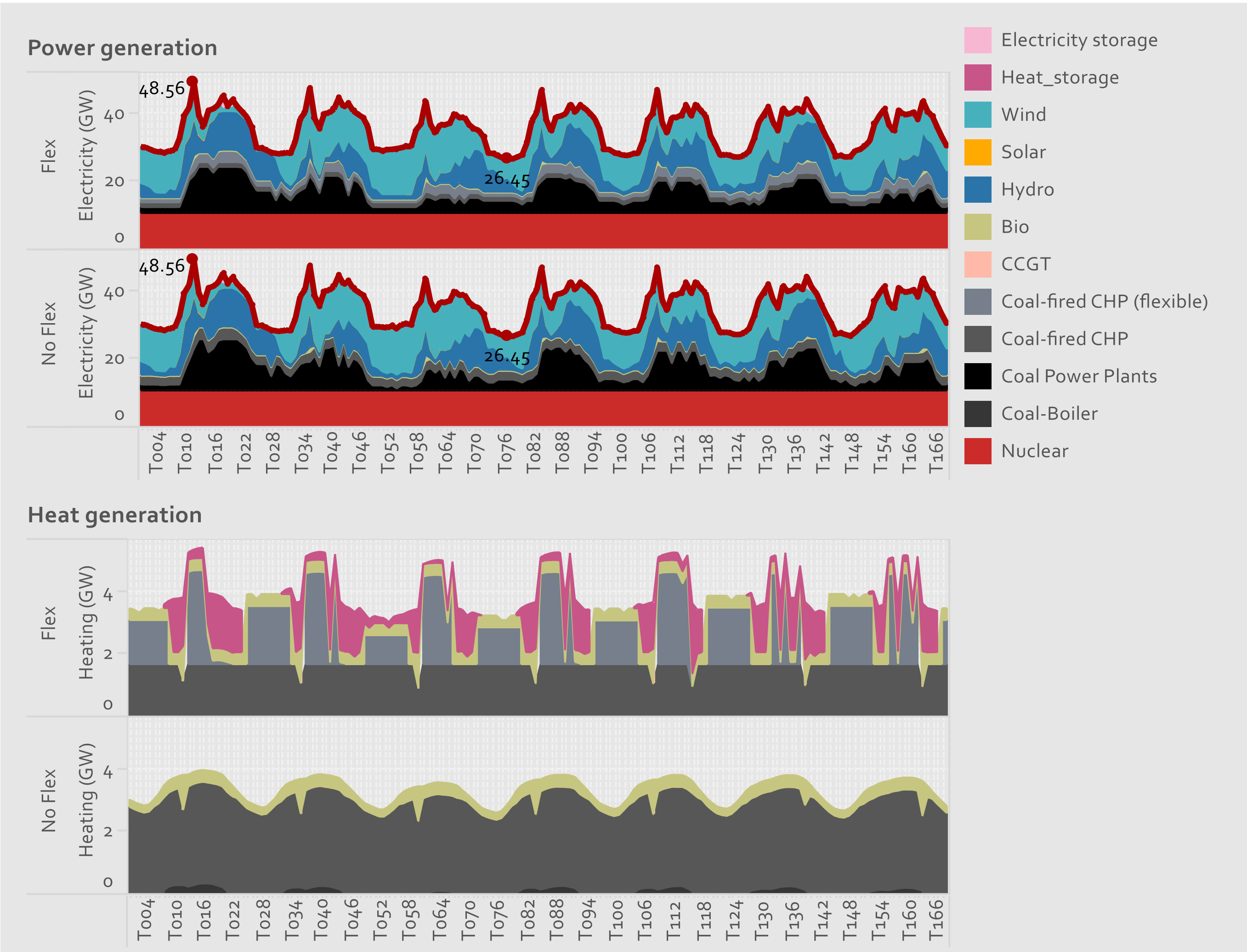


Figure 28: Simulated generation and electricity load in Fujian week 4 in 2025.

The figure highlights the fact that the use of coal boilers become phased out of heat production in the flexible development path (lack of black portion in the bottom of the 3rd figure, which are present in the 4th figure). It is also apparent that the non-flexible CHP plants (dark grey portions in the figures) produce power, and particularly heat, at a more constant rate in the flexible scenario, which allows for more efficient generation. In the Flex scenario, the flexible CHP units stop and start heat production more often (light grey portion in the 3rd figure) which is possible due to the heat storages, which provide additional heat when needed (pink portion in 3rd figure), but also stores produced heat at other times. This is reflected by the lower valleys in the 3rd figure where heat generation (i.e. without the pink portion which is heat from storage) is close to 2 GW, whereas during the same periods, generation is roughly 3 GW in the non-flexible scenario, thus signifying that the heat storages are being released during these hours. Conversely, during hours with high electricity demand the coal CHP units can continue to operate in their more efficient state, i.e. producing large quantities of both heat and electricity, as the excess heat can now be stored for later use.

Of note, during this week Fujian largely self-balances itself in both the Flex and No Flex case, which is interesting, and this is not the case for all weeks. This is a key characteristic of Fujian, that the system is less dependent on imports than many other regions and can partly be explained by the large hydro resources in the province.

Economics

In looking at Fujian alone, the net financial impacts of implementing power plant flexibility are quite minimal, and highly dependent on the valuation of imports/exports (see Table 21).

Table 21: Annual cost savings associated with improved flexibility for Fujian (m RMB)

	2025	2030
Operational costs	-46	-220
CAPEX	-126	-597
Savings on net imports	137	861
Total	-35	**44**

In 2025, additional CAPEX in the Flex scenario relates only to plant flexibility and heat storage investments at CHP plants, i.e. there is no need to invest in additional peak capacity as there is currently over capacity in Fujian. Despite savings of 137 million RMB due to reduced electricity imports[5], the 2025 simulations point to a net cost of 35 million RMB. In 2030, investments in retrofitting in the Flex scenario are limited to condensing plants, and the majority of additional CAPEX is due to investments in peak capacity. The net loss has now changed to a net benefit of roughly 44 million RMB, driven once again by savings on net imports.

CO_2 emissions

In the Flex scenario, CO_2 emissions in Fujian increase slightly, by 249 ktons in 2025 and 778 ktons in 2030. However, net electricity imports decrease by 569 GWh in 2025 and 1,702 GWh in 2030. When this is correlated for, CO_2 emissions in Fujian are reduced by 42 ktons in 2025 and increase by of 233 ktons in 2030.

In the first round of power plant flexibility investments CHP plants are converted in the simulations until 2025, while in the second phase, the condensing units are converted. Combined with the CO_2 figures from above, this highlights the fact that when looking at Fujian in isolation, the CHP plant conversions have a positive net impact on CO_2 emissions, while the condensing units in the simulations have a negative effect. This is logical because a) the new available production set points have lower efficiencies, and b) there is very limited room for improvements in curtailment rates, as even in the No Flex case these rates are quite low.

From a national CO_2 emissions perspective, Fujian increasing its electricity production is a positive, as Fujian's CO_2 emissions' intensity from power generation are below the national average in the scenario, and the average CO_2 emissions per unit of power generation in the province decrease by 1 percentage point in both 2025 and 2030.

Observations from Fujian focus

As a coastal province in the warmer Southern part of China, far from the curtailment afflicted northern regions of China, Fujian is not the most apparent candidate for a region where power plant flexibility should play a major role. However, in order to see what effect increased thermal power plant flexibility may have in differing situations, there are a number of aspects that make it interesting to investigate nonetheless. Firstly, compared to most provinces in China, the power system remains relatively detached in the simulations. This is especially the case in 2025, where none of the transmission flows between Fujian and adjacent

[5] Note - In the simulations, the marginal prices do not fully cover the overall system costs as the system has overcapacity, and hence the reduction in import bills is likely higher, rather than lower.

regions are assumed to follow hourly market prices. Secondly, Fujian stands to increase VRE penetration quite significantly in the scenarios, given that Fujian will be front runner in terms of offshore wind installations. Thirdly, the penetration of district heating is less than in the north, and the usage is predominantly for industrial heating. Finally, the development of nuclear power in Fujian is an additional inflexible low marginal cost generation source that does not contribute to balancing, and occupies baseload, such that a larger proportion of the thermal-fired generation capacity in any case needs to be used for system balancing.

The results confirm that the impact of enhanced power plant flexibility is very context dependent, and in Fujian are particularly reliant on the ability to increase the flexibility of CHP plants. Corrected for changes in net imports, there is a reduction in CO_2 emissions from thermal plant flexibility in 2025 within the province. At this time, the investments are focused on CHP plants, confirming the significant benefits of co-generation. The investment in heat storages in 2025 allow for reduced use of heat-only coal boilers. As Fujian is not a high curtailment province in the scenarios, the benefits from curtailment reductions are not as significant as seen nationally. The economics for Fujian as an individual area are negative in 2025, though not significantly so. In 2030, when adjusted for import/export effects, increased plant flexibility results in a slight increase in CO_2 emissions in Fujian. At that point in time, the additional flexibility comes from flexible condensing plants. Adjusted for trade flows, there is a net economic benefit to Fujian from power plant flexibility in 2030.

7.5 WEEK 9 IN HAINAN DURING 2025

The next situation to be investigated is the week 9 power and heat generation on the southern island province of Hainan, which is only connected to Guangdong via a 0.7 GW line subsea HVDC cable. With its tropical climate, heat demand comes only from industry, and electricity consumption peaks during the summer in order to provide cooling. As a result, there is no CHP production on the island and heat generation is primarily provided via coal and biomass boilers.

Electricity production is dominated by nuclear baseload, and supplemented with condensing coal, hydro, wind, solar and limited amounts of biomass and natural gas-based electricity production.

The power and heat generation profiles in the Flex and No Flex scenarios for Hunan during week 9 of 2025 are displayed in the figure below. The solid black line in all 4 figures indicates the electricity price in the simulation.

Table 22: Hainan power capacities in 2017 and 2025 in the scenarios.

	2017		2025	
	GW	%	GW	%
Thermal	4.7	77	5.8	47
- Coal - condensing			0.9	7
- Nuclear	1.3	17	3.3	26
- Other*			1.7	14
Hydro	1.1	15	0.9	7
Wind	0.3	4	3.1	25
Solar	0.3	4	2.7	21
Total	**7.7**	**100**	**12.5**	**100**

* Other represents biomass, CCGT and SCGT

Figure 29 clearly illustrates that when electricity prices are extremely low, it is cost-effective to produce industrial heat from electric boilers (purple in 3rd figure), and thereby replace heat that would otherwise be produced by coal boilers (dark grey in 4th figure). In fact, during week 9, the addition of electric boilers and heat storages in the Flex scenario allow for the complete replacement of all heat production from coal boilers. For 2025 as a whole, 1 PJ of heat production from coal boilers is replaced by heat production from electric boilers.

During this particular week, wind curtailment in the Flex scenario is reduced from 9.1 GWh to 3.5 GWh, and solar curtailment from 0.8 GWh to 0.4 GWh. While it is difficult to see the reduction in solar curtailment in the figure, the increase in wind production between hours 44 and 51 is quite noticeable in the figure (depicted by comparing the aqua coloured portions in the 1st and 2nd figures). On an annual basis in 2025, total solar curtailment is reduced by 200 GWh, while wind curtailment is reduced by 40 GWh.

The case of Hainan illustrates that power plant flexibility options also can have value in areas that are not dominated by CHP, for example in areas with rather inflexible nuclear production, where it is important that the residual loads have greater flexibility in order to integrate VRE.

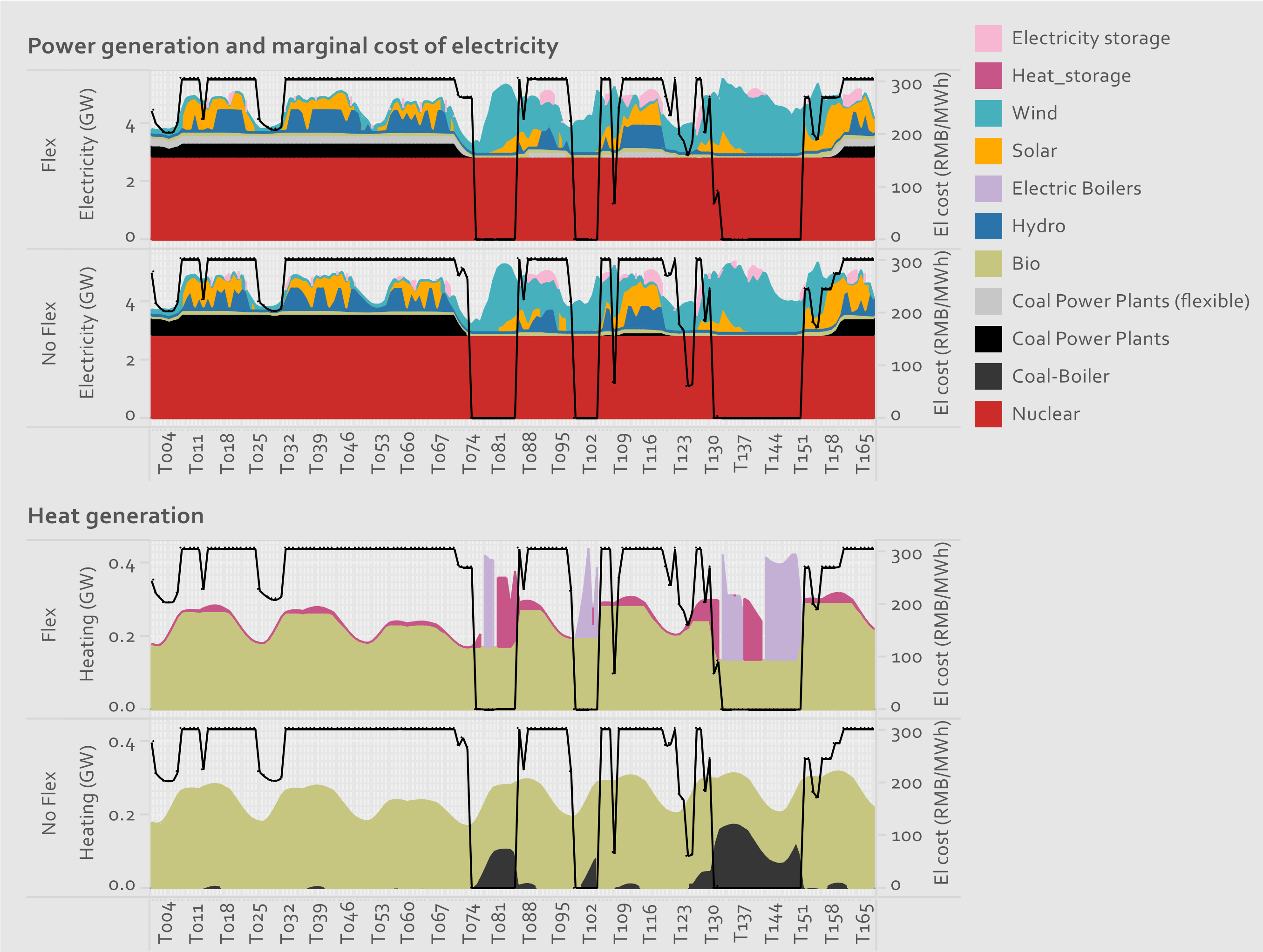


Figure 29: Simulated generation and electricity load in Hainan week 9 in 2025.

7.6 CURTAILMENT DURING SPRING FESTIVAL

Spring festival in China is one of the most important festivals of the year, as it celebrates New Year according the Chinese lunar calendar. The first day of the festival shifts between January 21st and February 20th, depending on the timing of the lunar cycles. Millions of people travel to and from their ancestral homes to celebrate the holiday with their families.

Spring festival also presents an interesting and challenging situation for the power system. As industrial production is shut down during the festival, electricity demand drops to the lowest point of the year during this period. In the meantime, particularly in the northern regions, January-February are normally the coldest months, and therefore have the highest levels of heat demand. This creates a recurring challenge where the demand for heating from CHP plants is at very high levels while electricity consumption is low. The capability for wind and solar power accommodation in this period is therefore particularly challenged.

Spring festival 2025

The 2025 electricity generation by week in China is displayed in Figure 30. In terms of the reduction in electricity consumption, the climax of the Spring festival is during week 7. Relative to the adjacent weeks, the electricity generation therefore takes a significant dive across all technologies, also making this a week with relatively high VRE curtailment.

On an annual basis, the challenge of VRE integration (and resulting high curtailment rates) will hopefully be greatly reduced by 2025, as is the case in the simulations presented in this report. However, during the Spring festival, it is evident that the challenges persist in the simulations.

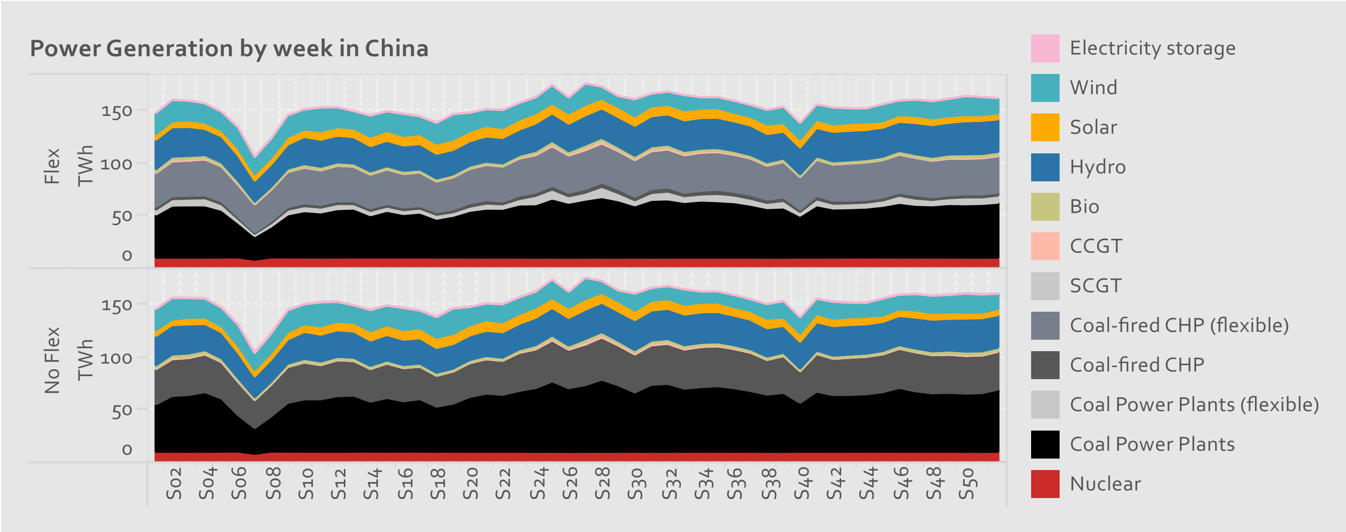


Figure 30: China electricity generation by week in 2025.

In Figure 31 the load dispatch situation is aggregated for China during the week of the Spring Festival. The hourly generation dispatch for the week shows a recurring diurnal pattern for the thermal plants. As the load increases in the morning, it is essentially offset by increased generation from solar, and the aggregated thermal generation is reasonably stable. During the evening as the sun sets, the load increases again, and here thermal and other sources must compensate for both load increase and decline in solar PV production.

The timing of spring festival is not during the period with the highest solar generation, and wind power generation is generally highest during the winter months, particularly in the areas which have historically developed wind power, i.e. in the 3-norths regions, as described in chapter 4. In the simulation of the Spring festival week, Figure 32 displays the curtailment of wind and solar power with and without power plant flexibility. Without flexibility, on a national basis the curtailment peak is roughly 39% for wind, and 29% for solar.

The chart shows how curtailment is reduced in the situation with enhanced flexibility in relation to without. During the week wind curtailment is reduced from 1,140 GWh to 886 GWh, and solar curtailment is reduced from 804 GWh to 701 GWh.

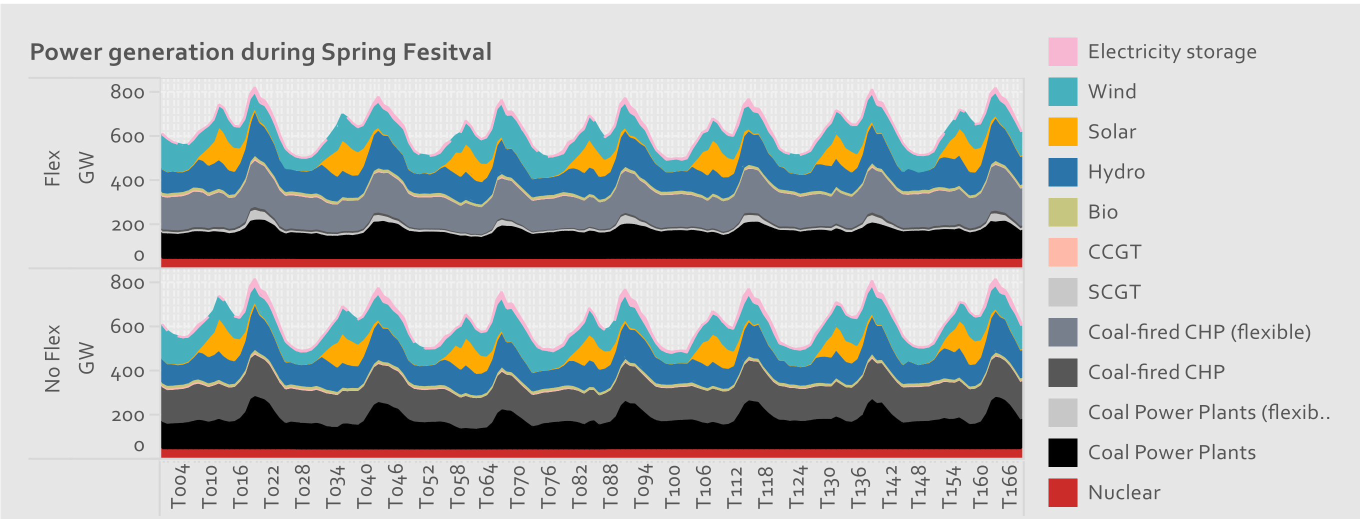


Figure 31: Hourly dispatch of generation during the selected week of Spring Festival in 2025.

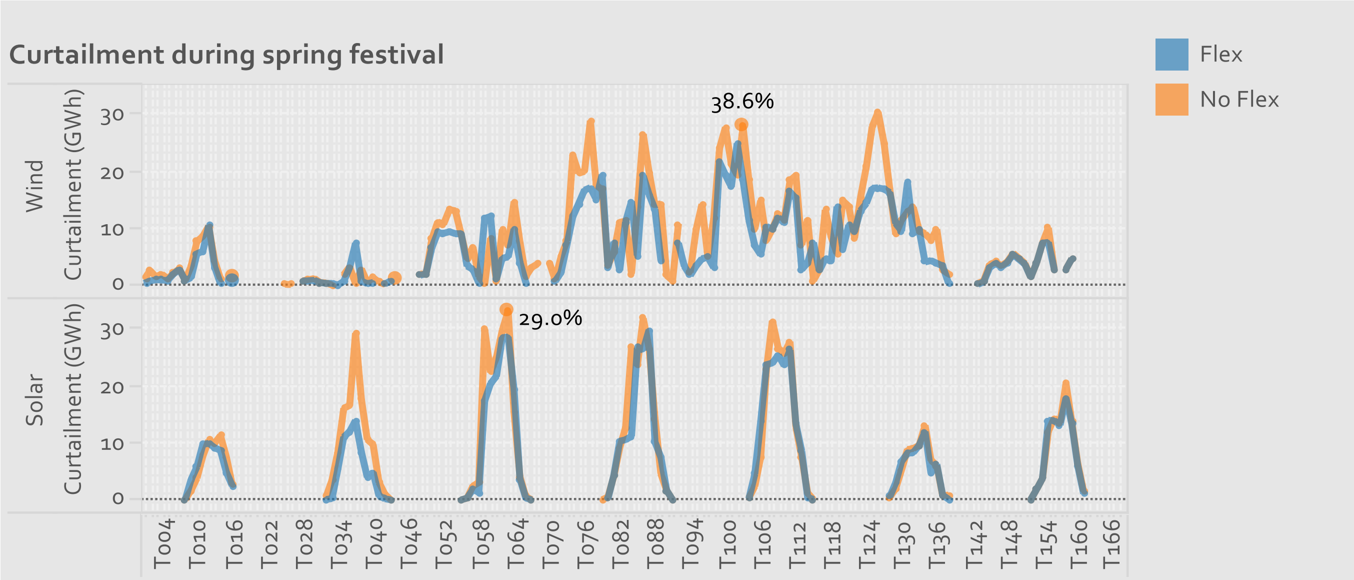


Figure 32: China electricity generation by week in 2025.

Key takeaways

The peak of Spring Festival features a structured imbalance which leads to comparably high levels of curtailment even in 2025, where curtailment overall has been significantly reduced from the levels witnessed today.

While power consumption and industrial district heating consumption is reduced significantly from normal levels, the cold weather, especially in the north, maintains a high level of heat consumption. These factors in combination make it difficult to integrate variable renewable electricity in the system. While the enhancement of power plant flexibility improves the situation, the level of flexibility is not such that the challenge is removed. CHP plants are still forced to generate, and since they cannot bypass the power generation completely, wind and solar curtailment remains at a comparatively high level.

8. Impact of incentives and market design

An essential precondition for developing enhanced power plant flexibility is a framework that motivates both the development and utilisation of flexible characteristics in the system. Such a framework can be conceived both within a regulated or market-based framework. Yet, as is discussed in the following chapter, and as exemplified in both the Danish experiences previously introduced and the recently introduced down regulation market in China, a market framework provides an advantage through the provision of incentives to asset owners to contribute with flexibility from a heterogenous asset mix.

8.1 MAIN PRINCIPLES

The analysis relies on the application of four important principles.

1. Merit order dispatch
2. Marginal cost pricing
3. Opportunity cost pricing principle
4. Price discovery

Each of these principles is briefly described in the following sections as a preamble to the analysis.

Merit order dispatch

Merit order dispatch is the traditional criteria for efficient power system operation. It requires that different units should be selected to generate according to their position in the merit order, i.e. the unit with the lowest short-run marginal costs (or put alternatively, the cheapest to operate based on variable costs), should be selected first. Operation according to this principle results in minimisation of total system operating costs.

Marginal cost pricing

Having electricity prices determined by the marginal cost of electricity supply, i.e. where the marginal cost of supply meets the marginal willingness-to-pay for consumption, ensures:

- That all generators at any time, are as a minimum compensated for their marginal cost of production.
- That all consumers (assuming price-sensitivity of demand), pay no more than they are willing to, or abstain from consumption.

This form of pricing ensures that production scheduling is carried out according to the merit order, and therefore is efficient in terms of system-wide resource utilisation. The clearing price is different at any time, e.g. hourly, depending on the level of consumption and availability of generation resources. Remuneration contributing to covering fixed costs, including return on capital, can be achieved in the hours where the market clears above the individual generator's marginal costs.

Opportunity cost pricing

Opportunity cost pricing is a key element of ensuring efficient operation vis-à-vis other potential opportunities e.g. for utilising production resources or pricing in the value of co-produced products, such as CHP, which has a high penetration level in the Chinese thermal asset mix.

Price discovery

Price discovery is a process for establishing the value of a product through competitive interactions between buyers and sellers. It is a critical component to achieve the needed transparency to ensure efficient prioritisation of resources. This includes establishing the price and value of flexibility provision to the power system. It is a precondition for cost-effective investments made by actors with different stakes/assets in the system.

8.2 IMPORTANCE OF MARKET-BASED SHORT-TERM ELECTRICITY PRICING

Internationally, it is well-established that properly designed spot markets and merit order dispatch are appropriate and efficient mechanisms to ensure optimal utilisation of power system assets. Thereby, least-cost electricity service can be achieved, while also supporting efficient integration of variable renewable energy sources. This is confirmed by experiences in Denmark and other European countries, as well as several regions of the USA and elsewhere.

Merit order dispatch can be introduced within either a regulated or market-based framework. In regulated power systems the responsibility falls on the central dispatching authority to ensure that units are dispatched according to the merit order. The central dispatcher needs to collect operating cost information from all units under its authority and then schedule and dispatch the generation levels of each unit taking account of all this information. Assuming the information is correct, the dispatching can be considered cost-optimal.

The regulated power system generally suffers from several deficiencies. Firstly, if ownership of all generating (as well as storage and demand response) assets is not under the central dispatcher, and absent clear price incentives delivered by the market place, asset owners may neither be inclined to invest in flexibility, nor even reveal the true flexibility characteristics they possess. Secondly, the regulated power system must ensure that the information provided by generators be both accurate and complete, which presents a challenging regulatory conundrum.

It is therefore important that the regulatory setup aligns the incentives of stakeholders with that of the overall system.

Stakeholder cost-benefit of power units

When looking at the Chinese coal plant fleet as a whole, Table 23 displays the change in total contribution (and consequentially gross profit) coal power plants realise as a result of enhanced flexibility. In absolute numbers, the increase in gross profit is roughly the same for the fleet of CHP plants and condensing plants. However, per unit of capacity, the benefit for CHP units is larger. CHP plants generate both heat and power, and therefore expand their revenues from both heat and power sales.

Table 23: Increase in contribution of coal power plant fleet (gross profit) from enhanced flexibility

	CHP	Condensing	Total
Electricity sales	30.5	-8.1	**22.4**
Heat sales	12.6	0.0	**12.6**
Operating costs	31.9	-20.4	**11.5**
Contribution	11.2	12.3	**23.5**

This calculation assumes a marginal pricing principle is implemented. The increased electricity sales of 30.5 bn for CHP plants can be attributed to both additional sales volumes (more GWh), worth 20.4 billion RMB at unchanged prices, and higher achieved market prices contributing 10 bn RMB. Together with the increased heat sales,[6] the additional revenue for CHP significantly exceed the higher operational costs, leading to the positive contribution.

The benefit to gross profit for condensing units is positive despite the decline in generation volume. Electricity sales reductions are cushioned by the increase in the prices captured accruing 7.4 billion RMB.

In total, the benefits arising from the ability to capture higher power prices amounts to 18 billion RMB for condensing and CHP units together.

If electricity prices for generation were fixed, the benefit to gross profit for condensing units would be eroded, and the benefit to gross profit for CHP plants would only just be sufficient to justify the annualised investment cost in plant flexibility of 5.4 billion RMB as presented in Table 10, leaving little margin for contingencies[7].

This calculation demonstrates that absent the market incentive to feedback a sufficient proportion of the total system benefit to the stakeholders driving the change, these stakeholders would not find a positive business case to support the necessary investment.

Absent incentives

When electricity remuneration is set to a fixed value, either by regulation of an on-grid tariff as in the pre-market reform system in China, or a fixed contractual value, the incentive for revealing and developing flexibility is hampered. Asset owners have little incentive to challenge flexibility properties of their plant, much less enhance them. The efficiency of thermal plants is generally highest at full load, as determined by the *gross profit of operations* calculated by *sales volume* (generation) multiplied by the *contribution margin* (i.e. the sales price less the variable operating costs).

If prices do not change to reflect varying supply and demand conditions, profit maximisation of thermal power plants involves:

- Maximising sales volume, which motivates running at full load.
- Maintaining a high contribution margin, which also motivates operating at full load where costs per MWh are lowest.

Even in a situation when the potential sales volume is limited, e.g. by an oversubscribed system with PPA's, generation rights or quota system, the incentive of the generator is still to generate its sales volume while operating at full load. A stable on-grid electricity price provides

[6] Absent specific data on the pricing of district heating from individual units, a heat price is set in the analysis that conforms to the 'benefit sharing' principle, i.e. the efficiency benefit of co-generation is shared between the purchasers of heat and the owner of the power unit. See World Bank (2003): Regulation of Heat and Electricity Produced in Combined-Heat and Power Plants.

[7] Contingencies were assumed to be an additional 25% to CAPEX in the China Renewable Energy Outlook 2017.

economic motivation for maximum operation in the most economic generation point from the plant's perspective, not the overall system perspective. Given this motivation, the incentive to reveal down regulation capability is absent. As a power system must be operated with system security as a primary concern, the dispatcher will not violate minimum (or maximum output) capacities provided by the asset owner.

Therefore, as the need for system flexibility increases, the market framework and product definitions need to be defined beyond delivery of kilowatt-hours of electricity. It is important to signal the market participants which services are necessary for the system, as well as which services provide value for efficient system operations.

Revisiting the down regulation market

The transition between a regulated and market-based model power sector is challenging to manage, as the different markets and mechanisms feature strong interdependencies. It is inherently difficult to replace all mechanisms at once. Thus, gradual introduction of new markets must heed existing regulated structures, while they should be compatible to other mechanisms likely to be introduced during future steps of the market transition. At any given time, the design of mechanisms to be introduced in these next stages will be uncertain.

The down regulation market previously described in chapter 4 is an innovative adaptation of market principles to the Chinese power system prior to the completion of a more fundamental market reform. The setup satisfies key criteria for efficient market operations:

- The remuneration and penalty mechanisms provide incentives for efficient operations.
- The market setup provides price discovery, promoting efficient flexibilization projects.
- The uniform clearing price provides incentive for accurate provision of cost and capability data for the dispatcher.

However, the starting point of the mechanism is a generation and commitment schedule based on planned operation, and over commitment of units, making the balancing task to be solved by the down regulation market and the dispatcher more challenging than is necessary.

When the dispatcher determines the unit commitment schedule, i.e. which units should be online, and which should be offline for the day-ahead of operations, this is naturally done based on imperfect information as forecasts of demand, wind, and solar can never be perfect. In this process, it is natural for system operators to be conservative when the true costs are hidden.

The down regulation market will need future adjustment at a later stage, specifically:

a) The reference point will need to transition from a baseline technical limitation of a thermal plant, to a market determined schedule for generation, transmission and consumption based on the clearing of a spot market. This implies that the generation schedule coming into the hour of operation establishes the rights and responsibilities of stakeholders and their assets, and that payment flows should be carried out in accordance with schedules.

b) The 'product', i.e. down-regulation, will need to be supplemented with an 'up-regulation' product. The ability to adjust generation output upward (or consumption downward) is just as important as down regulation when the starting point is a schedule. There is for instance no incentive for allowing one's plant to operate in overload, thereby at lower efficiency with higher operating costs. An upregulation product could be ideal for this. The spot market schedule in such a case could be to run the plant at the rated capacity, and the overload option could be activated as up-regulation, but only when needed and cost-effective. This would allow the dispatcher to commit fewer units beforehand, while still maintaining system security. This would result in less system aggregated minimum generator output, and potentially less curtailment.

c) Ensuring the broadest possible participation in the market for delivery of the services needed to operate the power system. System services should not be defined based on specific technologies' ability to deliver the service, but instead by the system's requirement for, and value of, the service. Once the service is clearly defined, it can be re-introduced in a technology neutral form. Hence, the active power output adjustment services (up and down regulation), could be delivered by any generator, demand, storage or even transmission technology able to make cost-competitive adjustments from the schedule.

These steps are necessary to extend the price discovery mechanism to cover a fuller range of services needed.

A positive result of the down-regulation market is that it introduces price discovery, competition, and incentive for generators to supply this service. It is apparent however, that the limitation in both the technology scope (generation) and product definition, will constrain its effectiveness going forward.

8.3 EFFICIENT HEAT AND POWER COUPLING

As evidenced in chapters 6 and 7, a very large source of the system benefits in terms of CO_2 emissions reductions, curtailment reductions, VRE integration benefits, and economic benefit are brought about as a result of the increased efficiency of the heat and power sector coupling. This is demonstrated by the calculations for China presented in this report and is also supported by the flexibility experiences in Denmark as described in chapter 2.

Opportunity costs is the central lens through which to understand the efficient coupling between power and district heating. When determining the efficient dispatch of district heating supply technologies, the opportunity value of co-generated electricity is central to ascertaining the heat supply costs from CHP units. Similarly, the opportunity cost of electricity consumption is central to determining the position of electric boilers (and heat pumps) in the heating merit order.

Conversely, at any given time, with knowledge of the local heat supply and demand situation, CHP generators must understand their opportunity costs for heat supply in order to correctly submit generation bids to achieve the right position in the merit order taking account of the value of heating they can provide.

Dynamic cost of heat generation

Based on the data used in the simulations, Figure 33 displays how the cost of supplying district heating is a function of the opportunity cost of providing electricity.

- The green line indicates the variable costs of heat supply from an electric boiler that increases with the electricity price.
- The black line displays the heat-only boiler which is independent of the electricity price.
- The grey lines indicate the cost of heat supply from an extraction CHP unit. The dashed grey line indicates the unit's heat supply cost at low electricity prices if the unit does not have the bypass option.

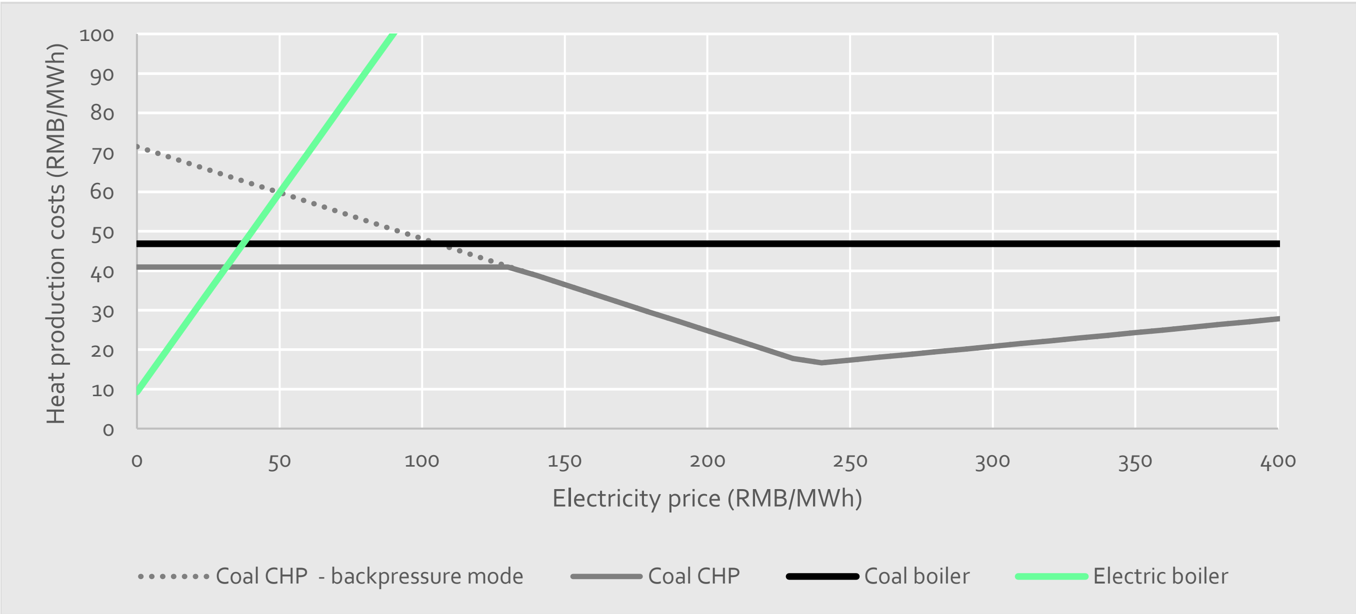
Depending on the electricity price, the lowest line segment is the cheapest heat supply option.

Based on the figure, it can be seen that for electricity prices below roughly 130 RMB/MWh, flexible CHP plants should run in bypass mode rather than co-generation mode since electricity generation has limited value for the power system. If bypass is not an option on the CHP unit, coal boilers would be a cheaper source of heat supply starting at electricity prices below 100 RMB/MWh level, and electric boiler generation is most cost-effective when the price falls below 30 RMB/MWh. At electricity prices higher than 240 RMB/MW (where the grey line kinks), it becomes economical to run the CHP plant even without supplying heat, i.e. in condensing mode. At this level, the cost of heating becomes the foregone profit from selling electricity, as the unit will run at full capacity (and perhaps overload). For the sake of simplicity, the figure does not include the implications of running in overload mode. Although not visible in the chart, at very high electricity prices, the cost of CHP heat generation moves above the cost of heat-only boilers once again. Naturally, with more different heating supply sources in the same heating system, the situation becomes increasingly complex, but also economically more flexible.

As demonstrated previously in this report, a high proportion of the value realised by investing in enhancing thermal power plant flexibility comes from running a more efficient system, where the more efficient generation assets are prioritised in terms of both heat and power generation during times when they are in fact the most efficient option. Based on Figure 33 it is evident that the lowest cost of heat supply can occur both at times of high electricity prices, by running the cogeneration unit, and at times of very low electricity prices by utilising the electric boiler.

As evidenced by the simulations in the scenario calculations, the value of heat storage can be expressed in terms of taking advantage of the cheaper heating supply options more frequently when available. By moving heat generation to times when either the electric boiler can generate cheap heating (when electricity prices or low), or the sweet spot for CHP (around 240 RMB/MWh in the example) the heat dispatcher can thus avoid more expensive generation via heat-only boilers or bypass, as well as make the full power capacity of the CHP unit be available in the power system to alleviate scarcity at times of very high electricity prices.

Figure 33: Illustration of the impact of electricity side opportunity costs (electricity price) on the Short-run costs of heating.



Based on the example of electric boiler operation as shown in Figure 33, it is quite clear that given the mix of assets, it would not be efficient to run the electric boiler unless the electricity price is below ~35 RMB/MWh. This very low price would only occur in the electricity market if VRE sources or nuclear are the marginal generation unit, or if thermal plants are operating at minimum load and want to avoid shutting down – broadly speaking at times of curtailment. During these times, it is efficient to operate the electric boiler and recover value from reducing curtailment.

If electric boilers' operation is not limited to these times, they will be powered by the marginal generation source in the system, most often from coal. This leads to a reduction in overall efficiency, as even an aging coal-fired heat-only boiler would be more efficient.

This is also reflected in the simulations, where electric boilers on average only run for 653 full load hours in 2025, and 785 full load hours in 2030. It is not efficient from a system point of view that electric boilers should act as the primary heat source, but rather should be co-situated with other heat supply sources in order to only take advantage of time periods with surplus electricity.

Necessary conditions for optimal heat supply incentives

In order to accurately place electricity generation offers to the power market in a power market setting, an asset owner must consider alternative costs of heat supply, i.e. from heat-only boilers, electric boilers, or via extraction from storage. Both price, quantity and timing of bids are more complex than when setting short-run costs for condensing units.

Using the district heating assets' flexibility efficiently can further integration of variable renewables on the power side. This requires that the real flexibility and costs must be revealed either to the central dispatcher, or the market place. The complexity and heterogeneity of opportunity costs of heating in different district heating plants presents a challenge towards the efficiency of a regulated centralised dispatch of power units. It is generally not reasonable to assume that the power dispatch centre is able to make heat-side opportunity costs calculations in determining the merit order. If there is not a power market that places incentives on the asset owners to disclose their true marginal generation costs, the centralised dispatcher would need to rely on inputs from the asset owners, whose motivation is not aligned with achieving overall system efficiency.

The remuneration for heat supply can also present a challenge for motivating power plant flexibility. The heat side opportunity cost calculations above are applicable to an overall system perspective, as well as a system where district heating assets within a single heating network are horizontally integrated, i.e. owned by the same entity with an obligation to provide heat to the network. When owned by the single entity, the opportunity costs directly relate to that firms profit maximisation, and thus the incentives are aligned with overall system efficiency. However, it is common to have numerous suppliers feeding into the same district heating system. In this case, heat sales will settle according to contracts that may not be sophisticated enough to ensure operation according to the merit order of supply as electricity prices fluctuate.

Establishing incentives for efficient sector coupling between district heating and electricity may therefore require changes to the framework and agreements regulating the provision of heat to the network.

Reform of district heating sector framework needed

The process of power market reform and energy transition towards increasing variable power generation creates a new economic paradigm for heat supply. Since the system economic benefits of plant flexibility measures such as bypass, heat storages and electric boilers become positive from a system perspective, the regulatory framework for district heating also needs to be revisited. Innovative business models being deployed can to some extent help to release value trapped between the inconsistent regulations of the power and heating sectors. An example was provided in section 0, involving the combination of a third party owned electric boiler and heat storage, which could be pooled with a CHP plant to take advantage of opportunities in the down regulation market. However, there is also a risk, especially in the transitional stage, that investment signals promote solutions which are not optimal from a system perspective, while system efficient solutions for heat provision cannot generate a positive business case.

8.4 MARKETS TO DRIVE TRANSPARENCY AND TRANSFORMATION

Marginal cost pricing provides the strongest incentive for efficient competition (absent opportunities for collusion and market power exploitation). By setting bid prices equal to their short-run marginal costs, individual asset owners are incentivised to accurately submit their cost data to the market place or forego potential contribution towards covering their fixed costs. Units whose submitted marginal generating costs are below the market price will generate, and units whose short-run marginal cost lie above will not generate. The previous sections described several common deficiencies which can occur if market participants do not have the correct incentives to reveal their flexibility. For flexibility to be activated, it must be visible to the dispatcher and/or the market place. It has also been discussed how this information is challenging to develop centrally, and individual assets' situation cannot be ignored.

Pricing according to accurate information also ensures price discovery, which is essential for efficient investment planning and prioritisation. To drive the right flexibility projects forward, the value of flexibility needs to be transparent. The comparison of different potential sources of flexibility is a complex planning exercise if centrally controlled. To some extent, normative measures and standards can ensure that newly commissioned units are required to be flexible, e.g. via connection standards. The low-cost measure of flexibility retrofits however, require incentives due to the heterogeneity of an incumbent asset mix.

8.5 BREAKING THE DEADLOCK OF VESTED INTERESTS

The introduction of market reforms will have winners and losers in the short-run. During energy transitions, this naturally creates resistance from incumbent market players with vested interests in the technologies from which the system is transitioning. These players often stand to lose out on the benefits of a transition, which can be seen introspectively as an unwanted disruption of an efficient economic activity. Meanwhile, these players, with their incumbent positions, often have control of key assets in the market where change is needed to achieve the transition goals.

Two elements are important to assist in finding solutions to the conundrum of transition deadlock:

1. It must be ensured that reforms, to the greatest extent possible, create an overall socio-economic surplus.
2. Special consideration be given to finding a positive role, and potentially new opportunities, for the 'losers' in a transition.

In working to promote a politically and socially desired transition, efforts should be made to find the 'least-resistance pathway' from the current framework to the transitioned framework, with a focus on individual stakeholder perspectives. A sequence of steps can be laid out, one leading to the next, along a pathway towards market reform. At each stage, the winners and losers can be identified, and considerations undertaken, as to how and if losses encountered by losers can be softened. Through highlighting the potential gains at each step, e.g. in terms of economic efficiency or total system costs reductions, a foundation for moving forward can be established. Via an understanding of the economic impact for specific stakeholder groups, situations can be identified where incumbent players can be compensated directly through transitional mechanisms.

It is an important but non-trivial exercise to set up a transition pathway of 'least-resistance' by sequencing steps that generate overall efficiency increments, i.e. create a total net gain, and through transitional regulatory mechanisms ensuring some level of compensation for stakeholders incurring a loss at each stage of the transition, thereby mitigating the resistance from vested interests.

Power plant flexibility as a transitional mechanism

Addressing the challenge of inflexible assets in the thermal generation mix, as analysed in this report, provides new opportunities for thermal asset owners, while furthering the energy transition in the process.

Promoting power plant flexibility investments can yield positive economic returns from an overall system cost perspective, hence increasing the size of the proverbial pie. This provides room for transitional mechanisms which may be needed, e.g. compensation for stranded assets. More importantly however, through emphasising the fact that in de-carbonised electricity systems flexibility is a prized commodity, which existing assets could develop at low cost, there is a new positive role to be played for thermal plants in the energy transition. Regulatory reforms are needed to ensure that the incumbent players see a benefit from undertaking these investments. If implemented successfully, the process of power market reform can drive efficiency in the sector. Promoting economic dispatching according to the merit order and through a centralisation of the bidding process provides further opportunities for effective opportunity cost pricing to drive efficient resource utilisation in relation to interconnected markets, as highlighted herein with respect to district heating.

9. Conclusions & Policy Recommendations

9.1 MAIN FINDINGS

Increased thermal power plant flexibility results in lower CO_2 emissions and reduced coal consumption

When comparing calculations with and without increased power plant flexibility, annual CO_2 emissions with more flexible power plants are 28 million tonnes lower in 2025, and 39 million tonnes lower in 2030, which is roughly comparable in scale to total annual Danish CO_2 emissions. The primary reasons for these reductions are less heat-only and electricity-only production based on coal, and less curtailment of renewables. The lower coal usage signifies an increase in overall energy efficiency as CHP units are able to produce more (with high efficiency due to heat co-production) substituting less efficient production at power-only and heat-only units. In addition to the CO_2 related benefits of lower coal consumption, there are also a number of local environmental benefits associated with these reductions.

Increased thermal power plant flexibility results in less curtailment of VRE

The implementation of flexible power plants reduces the total modelled VRE curtailment by roughly 30% in both 2025 and 2030. The annual reduction in VRE curtailment is 2.8 TWh in 2025 and grows to 15.3 TWh in 2030. The growth in the curtailment reduction from 2025 to 2030 reinforces the fact that a more flexible coal-based thermal fleet facilitates the integration of growing quantities of VRE within the Chinese power system.

Increased thermal power plant flexibility results in higher achieved power prices for both VRE and coal power

Higher achieved power prices for both VRE and coal are important drivers for continued VRE buildout. Higher realised electricity prices for VRE provide incentive for developers to continue investment in VRE, and at the same time make VRE more competitive with fossil fuel-based generation. It reduces the need for subsidies, which is an important prerequisite for the continued growth of VRE. For coal plant owners, higher realised prices for the electricity they produce incentivises investment in flexibility. Flexible thermal plants can better respond/operate according to varying electricity prices, thus improving their ability to produce when prices are high (and thereby realise greater revenue), and lower production when VRE production is high, thus raising prices for low marginal costs assets.

Increased thermal power plant flexibility gives lower power system costs

The socioeconomic analysis indicates that a more flexible power system results in an economic gain for the Chinese power and district heating sectors. The total benefit of increased power plant flexibility investments analysed are roughly 35 bn RMB annually in 2025, growing to over 46 bn RMB in 2030. The fact that the benefit increases between 2025 and 2030 indicates that the window for focusing on power plant flexibility is beyond 2025, and supports the robustness of the conclusions. There are three additional elements that also reinforce the robustness of the economic conclusions. Firstly, more flexible thermal plants lead to less investment in coal heat-only boilers that have a relatively low capital cost, and the net economic benefit is positive even without the inclusion of these cost savings. Secondly, the contribution from flexibility investments in relation to the overall benefits is minor, so even if these investment costs are highly underestimated (i.e. they could be more than tripled), the results will still be positive. Lastly, despite the fact that the future CO_2 price is quite uncertain, the contribution from this aspect is rather small, i.e. even with a CO_2 price of zero the results change relatively little.

The contribution of thermal plant flexibility is situationally dependent

The above findings are aggregated on a China wide level, but it is also useful to compare the role of enhanced power plant flexibility in different mixes of generation assets as well as in different power grid situations – whether the local systems predominantly feature imports, exports, or transit flows, etc.

The analyses demonstrate how power plant flexibility plays different roles depending on context, and that the benefit and scope of thermal flexibility measures are situationally dependent. However, it plays a role in each of the provinces analysed, with investment in retrofitting and new flexible power plants in all provinces despite the large differences in the provincial context in terms of asset mix, types and transmission line situation. However, given that flexible CHP plants play a larger role than condensing plants, the provinces with extensive share of CHP also sees a more pronounced level of flexibilization of their thermal fleet, and a larger share of the total benefits.

Positive initial results from pilots involving flexibilization of thermal power plants in China, but also challenges ahead

There is a growing awareness amongst stakeholders in China, from policy makers in the National Energy Administration (NEA) to power generation companies, that there lies an untapped potential in improving the flexibility of coal-fired power plants. China has looked to positive international experiences for inspiration and has begun work on transferring these experiences into the Chinese context. As a result, ambitious targets for flexibilization of coal-fired thermal power plants have been announced, a massive demonstration program with 22 power plants is ongoing, and experience has started to materialise from this. As challenges are overcome (prime examples include those from Guodian Zhuanghe, Huadian Jinshan and Huaneng Dandong power plants inspired by Danish experiences), conservative mindsets of technical experts are shifting and becoming more open to flexibility implementation.

Going forward, the Chinese thermal power fleet faces several technical and regulatory challenges that require attention. The technical challenges include emission control during low-load operation, lack of experiences with large-scale heat storages, and reduction of frequency control response capability during low-load operation. The regulatory challenges are primarily related to the development of a more comprehensive market for ancillary services comprising up and down regulation and fast ramping services, and the development of a mature spot market as a more permanent solution for the Chinese power system.

9.2 RECOMMENDATIONS FOR NEXT STEPS IN CREATING MARKET INCENTIVES FOR FLEXIBILITY

Spot market implementation is a cornerstone

Spot markets' characteristics are generally well understood, but the introduction of a full compilation of market mechanisms is a path-dependent process, affected by the incumbent situation in terms of asset mix, ownership, and legacy regulation. In the process of implementing power market reform there will be a transitional phase during which a mix of market and regulatory mechanisms concurrently govern the power systems.

In order to promote efficient use and deployment of power system flexibility, the key aspects identified in this analysis are:

- Utilisation of merit order dispatch to ensure optimal utilisation of existing assets.
- Price incentives and price discovery are key elements in ensuring efficient development of system flexibility.
- Newly commissioned units' minimum flexibility characteristics can be regulated through standards. However, the low-cost measure involving flexibility retrofits of existing assets is more difficult to promote using standards, and therefore requires market incentives due to the heterogeneity of an existing asset mix.

The different market mechanisms and products will have to be reformed as to reflect the future needs of the system, i.e. focus on where scarcity exists in the system in order to address e.g. variability, uncertainty, ramping, energy, adequacy, etc. Cleverly defined market mechanisms can broadcast these imperatives to market participants, such that the energy system transition can make cost-efficient use of flexibility resources in the system. This also encourages market participants to indicate the value of flexibility characteristics, and allows them to develop their assets' flexibility characteristics in accordance with the developing needs of the system.

Through such a process, it becomes possible for stakeholders facing external challenges to the value of their assets to identify opportunities to contribute effectively to the transition, while safeguarding the return on their historical asset investments. The cornerstone of this evolution is the successful development of a spot market for bulk power trading in the short-term, with price formation tethering the interrelated market, products and services being evolved in parallel.

Further evolution is needed to the down-regulation market

In China, the down regulation market has successfully introduced market principles in a way that is compatible with the incumbent plan-based regulatory framework. With the introduction of spot markets, the next stage must be prepared for active power balancing services. The down-regulation market should utilise spot market schedules as a reference point. Deviations from this reference generates demand for regulation services. The product definition should be expanded to at least include up regulation products (and possibly also ramping products). The market should also transform from one that has a thermal plant reference as baseline, and adopt a technology neutral product definition.

Interconnected sectors must be considered

The highest value in terms of economic benefit, VRE integration and CO_2 emissions reductions found within the current analysis, come from an improved coupling of CHP and district heating. In systems where this link is relevant, it is important to look holistically at the framework and incentives facing both the power and district heating businesses. In other systems, the analysis may be different, and the flexibility may be found in sector coupling with transport, industrial usage, etc.

Markets to drive transparency and transformation

Marginal cost pricing provides the strongest incentive for efficient competition (absent opportunities for collusion and market power exploitation). By setting bid prices equal to their short-run marginal costs, individual asset owners are incentivised to accurately submit their cost data to the market place or forego potential contribution towards covering their fixed costs. Units whose submitted marginal generating costs are below the market price will generate, and units whose short-run marginal cost lie above will not generate. For flexibility to be activated, it must be visible to the dispatcher and/or the market place. This information is challenging to develop centrally, and individual assets' situation cannot be ignored.

Marginal pricing according to accurate information also ensures price discovery, which is essential for efficient investment planning and prioritisation. To drive the right flexibility projects forward, the value of flexibility needs to be transparent. The comparison of different potential sources of flexibility is a complex planning exercise if centrally controlled. To some extent, normative measures and standards can ensure that newly commissioned units are required to be flexible, e.g. via connection standards. The low-cost measure of flexibility retrofits however, requires incentives due to the heterogeneity of an incumbent asset mix.

9.3 POWER PLANT FLEXIBILITY AS A TRANSITIONAL MECHANISM

The energy transition ongoing in China and around the world requires a comprehensive focus on the development of flexibility in power systems. Thermal power plant flexibility is but one important component in this broader challenge. The introduction of market reforms will have winners and losers in the short-run. During energy transitions, this naturally creates resistance from incumbent market players with vested interests in the technologies from which the system is transitioning.

A focus on promoting thermal power plant flexibility provides the opportunity to create positive economic returns from an overall system cost perspective, hence increasing the size of the proverbial pie. This provides room for transitional mechanisms which may be needed, e.g. to compensate for stranded assets. More importantly however, through emphasis on the fact that in de-carbonised electricity systems flexibility is a prized commodity, which existing assets could develop at low cost, there is a new positive role to be played for thermal plants in the energy transition. Regulatory reforms are needed to ensure that the incumbent players see a benefit from undertaking these investments. If implemented successfully, the process of power market reform, can drive efficiency in the sector.

In working to promote a politically and socially desired transition, efforts should be made to find the 'least-resistance pathway' from the current framework to the transitioned framework, with a focus on individual stakeholder perspectives. A sequence of steps can be laid out, one leading to the next, along a pathway towards market reform.

In this regard it must be ensured that:

- Reforms, to the greatest extent possible, create an overall socio-economic surplus.
- Special consideration be given to finding a positive role, and potentially new opportunities, for the 'losers' in a transition.

Key message

It is an important but non-trivial exercise to establish a transition pathway of 'least-resistance' by sequencing steps that generate overall efficiency increments, increasing the size of the proverbial pie, and through transitional regulatory mechanisms ensuring some level of compensation for stakeholders incurring a loss at each stage of the transition, thereby mitigating the resistance from vested interests. Addressing the challenge of inflexible assets in the thermal generation mix, as analysed in this report, provides new opportunities for thermal asset owners, while furthering the energy transition in the process.

CLEAN ENERGY MINISTERIAL
Accelerating the Global Clean Energy Transition

Thermal Power Plant Flexibility

Integration of variable energy production from renewables (VRE) creates a need for increasingly flexible power systems. This report presents experiences from Denmark and China regarding the technical aspects and benefits of enhancing thermal power plant flexibility. The report describes how different measures promote flexibility investments in, and flexible operation of, thermal power plants, highlighting the importance of market-based incentives.

The experiences from Denmark illustrate that:

- A well-designed short-term wholesale market for electricity provides strong incentives for power producers to operate their thermal power plants in a particularly flexible fashion.
- Refurbishing of thermal power plants delivers a proven source of flexibility that utilises the flexibility potential of existing infrastructure, and the relatively low costs associated with these improvements are greatly outweighed by the benefits from flexible thermal power operation.
- Flexible power plants, together with other measures, allow for the integration of a large share of VRE without significant curtailment or compromising security of supply.

The experiences from China show that:

- Integration of VRE can be challenging, particularly in areas with rapid growth in VRE, often resulting in high curtailment rates.
- Introduction of market-based solutions, such as down-regulation markets in Northern China, represents promising ways to reduce curtailment and improve power system flexibility.
- Enhancing the flexibility of thermal power plants offers a swift way to improve power system flexibility, and due to the relative low refurbishing costs, in a very cost-effective manner.

The analyses in the report demonstrate that for China:

- Increased thermal power plant flexibility results in lower CO_2 emissions, reduced coal consumption and less curtailment of VRE.
- Increased thermal power plant flexibility results in higher achieved power prices for both VRE and coal power, and delivers lower power system costs.
- A power market set-up with merit order dispatch, marginal cost pricing, efficient bidding taking account of opportunity cost, and price discovery creates strong incentives for flexibility, and provides an advantage relative to a centrally operated dispatch system.
- Moving from a regulated system to a market framework requires well-designed transitional arrangements. As a next step, the down-regulation market should have spot market schedules as a reference point and include other flexibility products such as up regulation.
- The most valuable aspect of increased power plant flexibility in China relates to higher overall efficiency, which is primarily brought about by improved utilisation of more flexible CHP units, and addressing frameworks for power and district heating businesses in parallel.